A DEVELOPING-COUNTRY-ORIENTED OVERVIEW OF TECHNOLOGIES AND COSTS FOR CONVERTING BIOMASS FEEDSTOCKS INTO GASES, LIQUIDS, AND ELECTRICITY

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Abstract

This report provides a developing-country-oriented overview of the performance and cost of technologies for up-grading solid biomass into the following energy carriers: direct-combustion steam-turbine electricity, biogas, producer gas, biogas-IC engine electricity, producer gas-IC engine electricity, producer gas-gas turbine electricity, methanol from wood, ethanol from sugarcane, and ethanol from wood by acid and enzymatic hydrolysis. To facilitate cost comparisons among these, a consistent costing methodology and set of assumptions are applied to calculate total costs of production using basic capital and operating cost data reported by a variety of sources. The sensitivity of costs to key parameters is also indicated in each case.

Contents

1. Introduction

Biomass accounts for about one-third of all primary energy used in developing countries today [1]. It is the principal energy source for the half of the world's population living in rural areas of these countries. It is used very inefficiently, however, primarily for cooking. Thus, it provides only a low level of energy services. Inefficient use of biomass is also intensifying pressures on biomass resources that are being depleted in the creation of new pasture or crop land, the felling of trees by commercial timber interests, and through widespread dry-season fires. This deforestation contributes to a host of major environmental problems: the global greenhouse warming (1/4 of global anthropogenic CO_2 emissions); the loss of biological diversity (especially acute in tropical regions); soil erosion and desertification; siltation of rivers; decreased agricultural productivity (agricultural residues are diverted for uses other than soil nutrition); and increasing shortages of cooking fuel and associated detrimental impacts on diet (the UN Food and Agriculture Organization has estimated that over three billion people will face a fuelwood deficit in 2000).

Biomass has the potential to play a much larger and sustainable role as an energy source globally. This is especially true in developing countries, because many of these have climates well-suited to growing biomass. Biomass has a number of attractive characteristics as an energy source. First, it is available in perpetuity if, overall, it is grown at the same rate as it is consumed. Second, renewably-operated bioenergy systems would make no net contribution to atmospheric CO_2, since carbon released in consuming biomass for energy would be photosynthetically reabsorbed by new plant growth. Third, biomass is equitably distributed globally, and it is an indigeneous energy source not requiring expenditure of foreign exchange. Fourth, biomass can typically be grown in greatest concentrations in rural areas, where most people in developing countries live. Thus, establishing bioenergy industries would bring an infusion of capital into rural areas that could help promote rural industrialization more generally. Rural-based bioenergy industries could also provide the energy inputs needed for agricultural modernization. Fifth, biomass production and use is labor intensive, which could create direct rural employment that would help stem urban migration.

While biomass energy could play a larger role in the future than at present, care must be taken to insure that biomass-energy strategies are environmentally sensitive at all points from the cultivation of the biomass, to its conversion to secondary carriers, to the end use of the carriers. The environmental impacts of uncontrolled exploitation of existing biomass resources is already evident in many parts of the world, as mentioned above. Efforts to produce biomass specifically for energy purposes, e.g. on energy plantations, must also address environmental concerns such as the impact of monocultures, fertilzation, land use changes, etc. on the sustainability of production and on biological diversity. These and other issues associated with the production of biomass are addressed in a companion report [1].

A major prerequisite for biomass to begin to play a more important role in supplying energy services in developing countries is the availability of technologies for converting biomass efficiently and cost-effectively into more convenient energy forms, e.g. gases, liquids, and electricity. Converting biomass into such "modern energy carriers" leads to a significant expansion in the range of energy services that can be derived from biomass. It will also often decrease the amount of biomass needed to provide a given energy service. For example, first converting biomass into electricity to power a light bulb can require less biomass than providing the same amount of light by burning biomass directly. Cooking with a gas produced efficiently from biomass can require less total biomass than cooking directly with wood in a traditional stove [2].

Conversion of biomass into modern energy carriers would also make bioenergy more easily marketed. Much biomass energy circulates outside of cash economies today. The possibility of monetary marketability could provide an incentive for bioenergy to be produced sustainably. It could also provide a mechanism that would facilitate the flow of cash into rural areas.

This report has been prepared at the request of the Office of Technology Assessment to provide an assessment of alternative technologies for converting biomass into gases, liquids and electricity. An assessment of the biomass resource base is covered in a companion report [1]. Particular attention is focussed here on understanding basic operating principles, estimating the long-run costs of alternative technologies and their energy products, assessing the success of some of these technologies to date in developing countries, identifying possible future developments that would lead to important cost reductions, and estimating the time scales likely to be involved in the development of some new technologies.

The technologies addressed in this report cover a broad spectrum of scale and commercial readiness. They include producer gas generators and biogas digesters; electricity production using direct-combustion steam-turbines, producer gas-IC engines, biogas digester-IC engines, and producer gas-gas turbines; methanol production; and ethanol production from either sugarcane or lignocellulose (Table 1.1, technologies marked by asterisk). Other technologies, including charcoal production and direct combustion of wood in cook stoves, both of which are widely practiced in developing countries today, are not addressed here, as these were excluded from the scope of work proposed by the Office of Technology Assessment. Hydrogen derived from biomass via thermochemical gasification and its use in fuel cells for electricity or motive power are potentially important technologies for the long term [2a]. Fuel cells are unlikely to be commercially ready until the beginning of the 21st century at the earliest. They are not addressed in this report.

2. Overview of Biomass Conversion

Biomass has attractive attributes as a feedstock for producing modern energy carriers, particularly by comparison to coal, the solid energy source used most widely today. Sustainable biomass use releases no net CO_2 to the atmosphere. Also, biomass contains much less fixed carbon, ash, sulfur, and nitrogen than coal, and much more oxygen (Table 2.1). Biomass is thus more readily chemically converted than coal to gases, liquids, or electricity, which tends to make conversion technologies less costly. On the other hand, the variability in physical and chemical composition from one type of biomass to another complicates the use of biomass, e.g., by increasing the need to tailor-make conversion technologies to specific biofuels. Also, the relatively low bulk densities of biomass (Table 2.2) tend to limit the amount of biomass available at any given site. This constrains the size of individual conversion systems, which limits the extent to which economies of scale in capital and other costs can be captured.

Typical rates of biomass fuel production or use at individual sites range from 1-4 kW_{fuel} (0.2 to 0.4 kg/hr of dry biomass, assuming a dry-biomass energy content of 20 MJ/kg) for residential cooking up to a maximum of some 300-400 MW_{fuel} (54-72 dry tonnes/hr) at large factories that produce biomass as a byproduct and use it for energy (e.g. cane sugar and kraft pulp factories) (Table 2.3). (This can be compared to the 800-4000 MW of coal consumed at large central station electric power plants.) Larger concentrations of biomass could be made available, e.g. from plantations dedicated to producing biomass for energy. Under such schemes, transportation costs and land availability will be limiting factors on the quantity of biomass that can be concentrated at a single site.

3. Basic Assumptions for Cost Calculations

This report draws on reported capital and operating costs for the production of gases, liquids, and electricity from biomass. Reported costs are based on actual experience in many cases and on engineering-design studies in other cases. To provide a basis for comparisons, a common costing methodology and set of assumptions are applied to all reported data. Data originally reported in non-US currencies are converted to US dollars using the official exchange rate prevailing in the year of the originally-reported costs, and then converted to 1990 dollars using the US GNP deflator. All levelized costs presented in this report are expressed in constant 1990 US dollars using the same costing procedure. Amortization of the capital cost is based on the capital recovery factor: $i/(1-(1+i)^{-N})$, where i and N are the assumed real (inflation-corrected) discount rate and technology lifetime, respectively. No real cost escalations (e.g. in labor or other operating costs) are assumed. Baseline assumptions for the analysis include a 7% discount rate,[1] insurance on large projects of 0.5%/year of the initial capital cost, \$2/GJ for biomass fuel, \$3/GJ for charcoal, and \$6.5/GJ for diesel fuel. The biomass cost of \$2/GJ is an estimated cost (including chipping, drying, and transport) of eucalyptus produced on the best commercial plantations in Brazil today [3] (Table 3.1).[2] For comparison, the year-2000 target for short-rotation energy plantations in the US is about \$3/GJ, including tranport, chipping, and drying [5].

4. Electricity and Gases from Biomass

Power generation is probably the most readily accessible route to the large-scale "modernization" of biomass for energy. Already in the US, the installed biomass-electric generating capacity stands at close to 9000 MW_e (Table 4.1), up from about 10%

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[1] Selected on the basis of discussions with staff of the Office of Technology Assessment.

[2] The \$2/GJ biomass cost may be a relatively conservative estimate of long-run costs in many developing countries. For example, Mukunda, et al. [4] report wood costs from a plantation developed to provide fuel for a 5 kW wood-gasifier engine system of \$0.85/GJ. Perlack et al. [4a] estimate plantation-biomass costs of \$0.5/GJ in Yunnan Province, China. See [21] for additional plantation-wood cost estimates for some developing countries.

of this level in 1980. The rapid growth in the US was largely the result of incentives provided by the Public Utilities Regulatory Policies Act of 1978 (PURPA), which required utilities to purchase electricity from cogenerators and other qualifying independent power producers at a price equal to the utilities' avoided costs. Similarly rapid growth in biomass power generating capacity has not occurred in most of the rest of the world, where PURPA-type incentives have not been provided. Essentially all medium to large scale biomass power plants installed today are based on boiler/steam turbine systems, as discussed below.

Gases and electricity from biomass are included together in this section because there are several electricity generating technologies that use a combustible gas derived from biomass as a fuel. Such a gas can be produced from biomass through a thermochemical process (producer gas) or through a biological process (biogas). Producer gas or biogas can be burned directly to produce heat, e.g. for residential cooking or industrial process heating or steam raising. The gases can also be burned in a secondary conversion system such as an engine or a gas turbine to produce electricity, shaft or motive power.[3]

4.1. Direct Combustion Steam-Electric Power Generation

Essentially all biomass power plants today operate on a steam-rankine cycle, a technology initially introduced into commercial use about 100 years ago.

4.1.1. Steam-Electric Technology

In a steam-electric power plant the biomass is burned in a boiler producing pressurized steam, and the steam is expanded through a turbine to produce electricity. In the production of power only, a fully-condensing turbine is used (Fig. 4.1), while in the production of electricity and heat (cogeneration), a condensing-extraction turbine (Fig. 4.2) or a back-pressure turbine (Fig. 4.3) is commonly used. Boiler systems in common use today include manually-fed, brick-lined "Dutch ovens" in which the biomass burns in a pile ("pile burners"). More sophisticated units include automatic (stoker-fed) systems in which the biomass burns on a stationary or moving grate ("grate

[3] Thermochemical gasification is also the first step in producing methanol, a liquid fuel, from biomass. Methanol production is discussed in Section 5.1. Gasification is also the first step in the production of hydrogen from biomass [2a], a process that is not discussed in this report.

burners"), suspension burners in which the biomass burns while free-falling, and recently-introduced fluidized-bed units in which the biomass burns as it is "fluidized" from below by a continuous jet of combustion air.

In general, the higher the peak pressure and temperature of the steam in a cycle, the more efficient, sophisticated, and costly the system (e.g., at higher pressures and temperatures, higher quality steels are needed, water purity must be higher, etc.). Biomass-rankine power units used today operate with steam conditions that are far more modest than those used in large, modern electric-utility coal-fired rankine systems. For example, the majority of the 100 well-documented [5a] biomass plants operating in California (Table 4.1) operate with a steam pressure and temperature of about 6 MPa and 480°C [5a], compared to typical steam pressures of 10 to 24 MPa and temperatures of 510°C to 537°C in utility coal plants [5b]. Most biomass plants in developing countries use lower steam temperatures and pressures than those in California [5c].

The modest steam conditions in biomass plants arise primarily because of the strong scale-dependence of the capital cost ($/kW) of steam turbine systems--the main reason coal and nuclear steam-electric plants are build big. Biomass plants are restricted to modest scale (less than about 100 MW_e) because of the dispersed nature of biomass supplies, which must be gathered from the countryside and transported to the power plant. If bio-electric plants were as large as coal or nuclear power stations (500 to 1000 MW_e), the cost of delivering the fuel to the plant would often be prohibitive. To help minimize the dependence of unit cost on scale, vendors use lower grade steels in the boiler tubes of small-scale steam-electric plants and make other modifications that reduce cost, but also require more modest steam temperatures and pressures, thereby leading to reduced efficiency. The California plants operate with efficiences of 14% to 18%, compared to 35% for a modern coal plant.[4]

Such low efficiencies explain the reliance of the biomass power industry in the US, as well as biomass power facilities elsewhere in the world, on low, zero, or negative cost biomass feedstocks (primarily residues of agro- and forest product-industry operations). Once low-cost feedstocks are fully utilized, continued biomass power expansion will require the use of higher cost feedstocks, such as residues that

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[4] In this paper, efficiencies and fuel heating values are presented on a higher heating value basis.

are hard to recover and biomass that is grown for energy on dedicated energy farms. In order for low-cost biomass to provide more kWh of power and to make higher-cost biomass resources economically interesting for power generation, it is necessary to have technologies that offer higher efficiency and lower unit capital costs than steam-electric systems at modest scale. An as yet uncommercialized alternative that could produce several times more electricity per unit of biomass, the gas turbine, is discussed in Section 4.2.5.

Until such alternatives are available (the late 1990s at the earliest), the steam-rankine technology will continue to be the dominant biomass-fired power generating technology. There are significant untapped supplies of low-cost biomass feedstocks available in many regions of the world (Table 4.2), for which the economics of steam-rankine systems would be favorable.

4.1.2. Costs of Steam-Rankine Cycle Power Generation

The costs of steam-rankine systems vary widely depending on the level of sophistication. A typical installed capital cost for a 25 MW unit is $1600 to $2100/kW [5a]. With characteristic O&M costs for the US [121], the total cost of electricity production at a stand-alone power plant would be in the range of 7 to 8 cents/kWh, assuming wood fuel cost $2/GJ. For a cogeneration operation, electricity production costs would be in the range of 5 to 7 cents per kWh.

4.2. Producer Gas

Producer gas, deriving its name from the "gas producer" in which it is made, is a combustible mixture consisting primarily of carbon monoxide, hydrogen, carbon dioxide and nitrogen, and having a heating value of 4 to 6 MJ/Nm^3, or 10% to 15% of the heating value of natural gas (hence its French name "poor gas").[5] It can be made from essentially any carbon-containing feedstock, including woody or herbaceous biomass (lignocellulose), charcoal, or coal [6,7].

The use of producer gas dates back well into the 1800s [8], when coal-derived producer gas was used in a number of cities worldwide for cooking and heating. This "town gas" is still used in Calcutta [9], in Beijing and Shanghai, where about half of all

[5] One Nm^3 (normal cubic meter) is one cubic meter at 0°C and 1 atmosphere pressure.

households use it for cooking [10], and elsewhere. Producer gas from wood-charcoal was a prominent civilian fuel in Europe during the Second World War [11], running several hundred thousand vehicles and powering industrial machinery [12]. The development of inexpensive petroleum supplies after the war led to abandonment of producer gas use.

Since the early 1970s, there have been many efforts to resurrect the producer gas technology, largely for use in developing countries [13]. Efforts to build and operate village-scale or smaller gasification systems on a commercial basis have met with mixed success, as discussed below for specific applications. Understanding reasons for past successes or failures and the future prospects for implementing biomass conversion technologies in developing countries requires as a starting point a basic understanding of the technologies.

4.2.1. Gasification Fundamentals

Gasification consists of two basic sets of thermochemical reactions: pyrolysis and char conversion. Pyrolysis refers to a complex set of reactions during which the volatile components of the feedstock vaporize at temperatures below about 600°C and leave behind fixed carbon (char) and ash [14,15]. Biomass consists of 70-90% volatile matter compared to half or less this level with coal (Table 2.1), so pyrolysis plays a larger role in biomass gasification. In addition, biomass generally pyrolyzes at lower temperatures than coal (Fig. 4.4a). Products of pyrolysis include water vapor and heavy hydrocarbon compounds (tars and oils) that condense at relatively high temperatures. In some gasifiers, the tars and oils constitute an important energy component of the raw gas. In other cases, gas-phase reactions occur in higher temperature regions of the gasifier, converting most of the primary pyrolysis products into lower-molecular-weight permanent gases.

Char conversion refers to the gasification and/or combustion of the fixed carbon that remains after pyrolysis. In biomass gasifiers, a relatively small amount of char remains after pyrolysis due to the low fixed carbon fraction (Table 2.1). Some of the char burns to provide heat for pyrolysis and to gasify the remaining char. Biomass chars gasify much more readily than coal chars because they are 10-30 times more reactive [16]. Thus, biomass gasifiers can typically operate at lower temperatures than coal gasifiers to achieve the same char conversion (Fig. 4.4b).

4.2.2. Gasifier Technologies

The intended use of the gas, together with the type of feedstock to be used, influence the design and operation of the gasifier and any auxiliary equipment. Gasification systems can be classified as small-scale--those with a fuel input of less than say about 2 GJ/hr (100 kg/hr dry biomass)--or large scale. Economies of scale permit large-scale systems to generally be more technologically sophisticated.

Small-scale gasifiers. Three basic gasifier designs have been used in small-scale applications: updraft, downdraft, and crossdraft. They are distinguished most readily by the relative locations of the air inlet and gas outlet (Fig. 4.5). In general, when charcoal is used as the feedstock, the three designs can be used almost interchangeably, the reasons for which will be discussed below. Because of the large energy losses associated with charcoal production, however, raw biomass is a preferable gasifier feedstock from the perspective of overall resource use efficiency [17]. When raw biomass is used for fuel, updraft units are used almost exclusively for direct heat applications, while downdraft units are used for heat or engine applications. Crossdraft units have been used only with charcoal and generally only for engine applications.

In an updraft unit, the simplest and in some sense the most efficient of the three gasifier designs, biomass is fed in the top of the reactor and air is injected into the bottom of the fuel bed (Fig. 4.5a). The feedstock successively undergoes drying, pyrolysis, char gasification (reduction) and char combustion. Some of the charcoal burns on a grate at the point where air is introduced. The resulting heat and carbon dioxide drive chemical reactions as the combustion products travel up through the fuel bed. In the char reduction zone, charcoal (carbon) reacts with carbon dioxide to form carbon monoxide:

$$CO_2 + C \rightarrow 2CO$$

Hydrogen is formed by reactions between the carbon and water vapor contained in the air or fuel:

$$H_2O + C \rightarrow CO + H_2$$

Additionally, the water-gas reaction helps establish the relative fractions of CO and H_2 that are produced:

$$H_2 + CO_2 \rightarrow H_20 + CO$$

As the hot gases travel up through the fuel bed, they cool while driving devolatilization (pyrolysis) reactions. The low-temperature pyrolysis reactions produce tars, oils and water vapor that are entrained in the gas. Updraft gasifiers have high energy efficiencies, typically 80% to 90% (chemical energy in gas output divided by feedstock energy input), due to the efficient counter-current heat exchange between the rising gases and descending solids.

With raw biomass feedstocks, tars produced by updraft gasifiers are problematic in applications where the gas must be cooled before it can be used, e.g. in internal combustion engines. (With charcoal as the feedstock essentially no tar is produced since the charcoaling process devolatilizes the biomass.) If not removed from the gas, tars cause a multitude of problems that can ultimately reduce engine performance and lifetime and increase maintenance costs [18]. Removing tars from the gas efficiently and cost-effectively has proven difficult in practice. Tar removal also results in a substantial energy penalty, since tars can constitute an important fraction of the energy output of an updraft gasifier. Thus, in practical operations, the use of updraft gasifiers has been limited to direct heating applications where no gas cooling is required.

Downdraft gasifiers are characterized by an order of magnitude lower level of tar production [19]. In a downdraft gasifier, the combustion zone is fixed above the bed of hot charcoal by injecting combustion air at this point and drawing the producer gas out of the reactor from below (Fig. 4.5b). Devolatilization occurs at high temperatures in the fuel bed just above the combustion zone, as well as throughout the combustion zone. All combustion and devolatilization products are thus forced to pass through the hot bed of charcoal (reduction zone) before leaving the gasifier. Tars produced by devolatilization "crack" into lighter molecular-weight permanent gases. While the design of downdraft gasifiers is intended to eliminate tar production, in practice it has proven extremely difficult to reduce tar production to acceptable levels [18]. Thus, fairly elaborate gas cleaning systems are typically used in applications where a cool, tar-free gas is needed, such as for powering an engine (Fig. 4.6). Cooling of the gas, combined with incomplete char conversion in the short reduction zone of most downdraft gasifiers, results in overall energy efficiencies of 60% to 70%.

The crossdraft gasifier design (Fig. 4.5c) was commonly used with charcoal for vehicle applications during World War II. It responds particularly quickly to changes in load, but produces a tar-laden gas if raw biomass is used instead of charcoal. Because of the requirement for charcoal, crossdraft units have not been favored for developing country applications.

Large-scale gasifiers. For larger-scale applications, there are three basic gasifier designs that are commonly considered: updraft, downdraft, and fluidized-bed. The updraft and downdraft units are typically somewhat more elaborate versions of their small-scale counterparts. For example, they may use a rotating grate to support the fuel bed, they may inject steam at the grate to keep the bed below a temperature at which ash would melt, or they may use oxygen instead of air. (When oxygen is used instead of air, the produced gas is not diluted with nitrogen and thus has a higher energy content--typically about 10 MJ/Nm^3).[6]

In a fluidized-bed gasifier, the feedstock is typically fed continuously and the bed is kept in suspension ("fluidized") with an inert heat-distributing material such as sand, by air or oxygen and/or steam injected from below. In any fluidized bed, pyrolysis and char conversion occur throughout the bed. The excellent heat and mass transfer leads to relatively uniform temperatures throughout the bed, better fuel-moisture utilization, and faster reactions than in fixed beds. The latter leads to much higher throughput capabilities per unit volume for fluidized beds, particularly for circulating fluidized-bed units [21]. Fluidized-beds are generally more expensive than fixed-beds below a fuel input rate of 35-40 GJ/hr (1.8-2.0 tonnes/hr of dry biomass) due to the high unit cost of blowers, continuous feed systems, control systems and other instrumentation [21]. The bubbling-bed (Fig. 4.7a) was the first fluidized-bed design developed. A variation of this, the circulating fluidized-bed (CFB) (Fig. 4.7b), has been commercialized more recently. There are a number of modifications to these basic designs which are generally at much more limited stages of development [20].

4.2.3. Direct Heat Applications

Industrial heat and residential/commercial cooking. The most successful recent application of producer gas from biomass has been as a replacement for fuel oil or natural gas in industrial boilers and furnaces. The country with the most experience in this area is Brazil, where gasifiers are made by a number of competing companies for use in a variety of applications [22]: ceramics, cement, and lime production, in ore drying, heat treating, and bakeries. Installed Brazilian units are typically either updraft or downdraft designs ranging in size up to about 350 kg/hr of dry biomass

[6] The unit cost of oxygen ($/kg) is very sensitive to scale. In general, it is not cost-effective to use oxygen in small-scale installations.

input [22]. There are a handful of large (8-16 tonnes/hr input) circulating fluidized-bed gasifiers operating at kraft-pulp mills in Europe [21]. These use waste wood available on site and produce gas that is burned in the lime kilns that are part of the pulp-making process.

Producer gas from biomass can also be used as a household or service-sector cooking fuel. Some studies recommend against this because of concerns about the toxicity (CO content) of the gas [13], but cooking would appear to be a viable application, based on successful past and ongoing use of coal-derived producer gas in large urban areas in developing countries (see Sec. 4.2). Biomass-derived gas has not been used to any significant extent for this purpose, although some applications have been reported [23]. Using biomass energy for cooking by first converting it to a gas would offer several advantages over traditional direct-burning. If the gas replaces inefficient traditional stoves, it could reduce the amount of primary biomass used in cooking [2]. Gas cooking would also bring other benefits, among the most important of which would be reductions in indoor smoke and particulate levels[7] and less time spent collecting cooking fuel.[8]

Costs. Installed capital costs for producer gas generators that could be used for direct heat applications will vary depending on the specific reactor design, the design feedstock, the quality of materials and workmanship, and other factors. Given this, it is not surprising that reported capital costs for various small and intermediate-sized gas producers manufactured in developing countries vary widely (Fig. 4.8 and Table A.1). The most recent data (Mukunda, et al. [4] in Fig. 4.8a and Conventos [26] and Cientec [26] in Fig. 4.8b) are probably the most representative of commercially viable systems today. The work of Mukunda, et al. has been carefully documented [4,26a,27,28] and is backed by several years of development work [29]. Conventos and Cientec are well-established and well-respected gasifier suppliers in Brazil [30].

The generally higher cost of the intermediate-sized units compared to the small units can be attributed largely to the cost of automatic feed systems incorporated in the

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[7] The exposure to smoke and particulate levels that comes from cooking over an open flame indoors, as is commonly done in many developing countries, can be extremely high. For example, the measured intake of the carcinogen benzo*(a)*pyrene by some Indian women during cooking is the equivalent of that received by smoking 20 packs of cigarettes per day [24].

[8] Some households in parts of India spend an average of two hours per day gathering fuelwood for cooking [25].

larger units. In the small size range, units designed for charcoal will be less costly than those designed for wood [31], but the differences are not large.

Producer gas has been used most widely for direct heating in industrial applications, in part because such applications are often characterized by relatively high capacity utilization rates and more importantly because biomass is often available relatively inexpensively, e.g. as in the forest products industries. There are relatively few reported data, however, on costs of producer gas in such applications. Fig. 4.9 shows some estimates by the author of gas production costs using data reported in a comprehensive economic assessment (Table A.2). For the relatively small capacity units covered in this figure, the calculated cost of gas ranges from \$3.2/GJ to \$4.8/GJ for wood-fueled systems and \$4.7/GJ to \$7.4/GJ for charcoal-fueled systems. In industrial applications, producer gas would typically be substituted for heavy fuel oil. At \$5/GJ, producer gas would be competitive with fuel oil when crude is priced at about \$38 per barrel.[9]

Cooking or other residential or service-sector applications would be characterized by lower capacity utilization factors. Because of its low capital intensity, variations in the capacity factor (beyond about 15%) or assumed discount rate do not influence the cost of gas strongly (Fig. 4.10a,b). In contrast, the cost of the feedstock has a strong effect on gas cost (Fig. 4.10c).

4.2.4. Internal Combustion Engine Applications

History and technology. Internal combustion engines can be fueled by producer gas--sometimes called "suction gas" because the engine suction is used to draw the required combustion air into the gasifier. Gasifiers providing fuel for engines would generally be relatively small, having capacities typically ranging from 0.1 to 3 GJ/hour (5 to 150 kg/hr dry biomass). Producer gas engines could power vehicles, as they did on a wide scale during World War II (see Sec. 4.2), although a revival of this application seems unlikely given the much greater convenience and energy density of liquid fuels. More interesting are stationary engine applications, which are particularly appealing for many remote areas of developing countries. The IC engine has proven itself as a versatile, durable technology for producing small increments of stationary

[9] Assuming that the per barrel wholesale price of residual fuel oil is 0.87 times the refiner acquisition cost of crude oil (characteristic for the US) and that a barrel of residual oil contains 6.6 GJ.

power, e.g., for irrigation pumping, electricity production, motive power, or for cottage industries and rural processing facilities. Millions of IC engines (excluding those in vehicles) are already in use in developing countries. For India alone, it has been estimated that some 4 million small diesel engines were in use in the mid-1980s solely to drive irrigation pumpsets, with the number growing in excess of 10% per year [32]. The average Indian engine has been estimated to consume energy at about the same rate as the average automobile in the US--1500 liters of diesel fuel annually [29].

Producer gas can be used in either compression ignition (diesel) engines or spark ignition (gasoline) engines. Diesel engines have been favored because of their higher efficiency, greater durability and reliability, simpler maintenance, and the more ready availability of diesel fuel compared to gasoline in most developing countries. Producer gas can typically replace up to 70-80% of the diesel fuel that would be used in normal operation of a deisel engine. Some diesel fuel is still needed because the low energy density of producer gas prevents it from self-igniting under compression.

Costs. Reported unit capital costs for producer-gas engine-generator electricity plants are generally below \$1000/kW, even for very small (5 kW) units (Fig. 4.11a). Calculated costs of electricity production with gasifier-engine systems, assuming a 50% capacity factor, range from 13 to 24 cents/kWh for small units (4 to 5 kW capacity) and from 10 to 15 cents per kWh for units larger than about 100 kW (Fig. 4.11b). The most important cost component for small units is labor (Fig. 4.12a). For larger units it is fuel (Fig. 4.12b). With the wood fuel cost reported by Mukunda, et al [4], \$0.85/GJ, the cost of electricity would be below 10 cents per kWh for a 100 kW unit.

The 50% capacity factor assumed in Fig. 4.11 and 4.12 would characterize units that supply more than a single load (e.g., some combination of irrigation, domestic water supply, lighting, cottage industry power, etc.). For many isolated applications, e.g. irrigation pumping alone, a capacity factor closer to 10% would be more characteristic [32]. Also, discount rates applied by users in such cases could be expected to be significantly higher than the 7% baseline used in this study. Because producer-gas electricity systems are not capital intensive, however, the cost of electricity is not a strong function of the capacity factor beyond values of 30% to 40% (Fig. 4.13a) or the assumed discount rate (Fig. 4.13b). The electricity cost is much more sensitive to the cost of wood fuel (Fig. 4.13c).

While the calculated costs of electricity from producer gas are higher than the busbar cost of electricity from new central station coal, nuclear or other facilities, gasifier-engine generators are generally considered for remote areas without access to the grid. Thus, a more appropriate comparison might be to the costs of central station power generation including costs to extend the transmission and distribution system. One such detailed analysis for rural applications in the state of Karnataka, India indicates that gasifier-engine systems would produce electricity on a competitive basis with a large coal and nuclear central station power plants [33].

For many developing countries, there would be considerations beyond strict economics in comparisons between producer-gas and central station power plants. In many countries, the electrical grids cannot accept large increments of new supply such as provided by a large coal-fired plant. The diseconomies of building smaller central station power plants would thus shift the economics more toward producer gas systems. Even where gasifier-engine systems may not be strictly cost-competitive with central station power, they might be favored for their low capital intensity (Fig. 4.11a) and shorter lead times (6 months versus 3 to 6 years for coal-fired central station plants).

Different analysts have come to contrary conclusions regarding the relative economics of gasifier-engine systems from a national perspective. Counting only investment costs and foreign exchange expenditures for fuel (zero for biomass), Jain [32] concludes that irrigation pumping would be about 10% less costly with gasifier-based systems than through extension of the national grid. He indicates savings of 30% for gasifier-based units over use of remote diesel-fueled engine systems. Bhatia [42] concludes that small (2-3 kW) producer gas systems would be 9% and 26% more costly than grid-electricity and desiel-generated electricity, respectively.

Technical problems and prospects. The bulk of efforts to revive producer gas technology for developing country applications beginning in the 1970s have focussed on the use of downdraft gasifiers in engine applications. Until recently, most of these efforts have failed. Downdraft units were chosen to minimize tar production, but the single most important technical reason that projects failed was excessive tar production. As noted in Sec. 4.2.2, tar entering an engine deposits on components, causing loss of performance and, if unchecked, complete engine failure.[10]

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[10] Tar problems with gasifier-engine systems have been widely reported: "(After) only a few hours of operation (with wood), tar deposited on the valves and ultimately seized up the engine." [34]; "The piston of cylinder number 2, that is, the cranking side has the oil ring completely seized within the groove." [35]; "Blocking of fuel injector nozzles was noted with all engines in dual fuel operation at irregular intervals,

There have been a few isolated efforts to better understand and solve the tar problem through careful application of principles of chemical and mechanical engineering. Fundamental and applied research efforts have been important in this regard [29,18,37,38,39,40]. Particularly notable efforts in research and implementation have been ongoing in India at the Center for the Application of Science and Technology to Rural Areas (ASTRA) [4]. The 5 kW_e gasifier-engine-generator system developed by ASTRA researchers relies on strict specification of the feedstock and careful design, operation and maintenance of the gasifier and gas cleaning system. The design has proven to be a technical success in the field [4,27,28]. The ASTRA effort suggests that the tar problem can be "cracked" cost-effectively: the cost of the ASTRA gasifiers are not significantly higher than other reported costs (Fig. 4.8a).

Implementation issues. The field experience of the last two decades with gasifier-engine systems in developing countries has been disappointing. An important reason for this, as just discussed, has been an inadequate understanding on the part of disseminators and users, of a technology that appears simple on the surface. There do not appear to be any inherent technological problems, however, as suggested by the successful development efforts noted above. To better understand the reasons for the disappointing implementation record of gasifier-engine systems, it is instructive to compare the major gasifier-engine implementation effort undertaken beginning in 1981 in the Philippines against a more recently initiated effort in India.

A 1981 presidential decree in the Philippines called for a strong national commitment and effort at reducing dependence on imported oil through use of gasifier-engine systems. Irrigation pumpsets were identified as an important target market, and a goal was set of replacing 1150 diesel fueled units with biomass/diesel dual fuel gasifier-engine systems. By 1985, when implementation efforts were halted, 319 units were installed, and by 1987 an estimated 99% of these were non-functioning, primarily due to lack of maintenance. According to a recent analysis [41] the fundamental reasons for the failure of the program were institutional and management-related rather than technical problems. Political pressures pushed an un-debugged technology (charcoal gasifiers) into the field prematurely and without a full understanding of the

while in some cases also tar formation necessitating engine clean up became apparent." [36].

users needs.[11] A single quasi-government agency (the Farm Systems Development Corporation--FSDC) was given responsibility for technology development, dissemination, financing, and maintenance, as well as for implementation of a new fuel (charcoal) supply infrastructure. Together with its other responsibilities, the under-funded, over-burdened FSDC was unable to provide adequate service to the user: training of users was inadequate; monitoring equipment needed for proper operation and maintenance was not installed in order to reduce costs; and the charcoal production system was insufficiently developed to meet demand, which resulted in high charcoal prices and thus marginal or negative fuel cost savings to farmers. Furthermore, gasifiers were produced by a single quasi-governmental company (GEMCOR) controlled by the FSDC, so that competitive market pressures were absent in the program.

There is a strong national commitment to gasifier systems in India, as there was in the Philippines, but the Indian program appears to be proceeding at a more deliberate pace, with a keen appreciation of the need for evolutionary development of the technology. The prospects for developing sound technologies is auspicious in India, given its generally strong technological intrastructure. Also, market pressures are present, as there are several competing manufacturers of gasifier-engine systems. Some 360 units were installed as of 1988 [41a], mostly for 3.5 to 7.5 kW irrigation engine-pumpsets, and hardware monitoring/feedback efforts have been in-built in many cases. Carefully measured efforts to understand and meet user needs are ongoing [42]. Furthermore, many of the constraints to commercial implementation that were recognized only in retrospect in the Philippines appear to be well understood in India: the need for sound technology and a maintenance infrastructure, the need for committed and trained users, the need to understand and meet user demands, the need for financing to help small farmers, the more attractive economics from a macro versus a micro perspective, and negative societal perceptions of increased wood use (deforestation concerns). Jain estimates the market potential for gasifier-engine systems in India could be as large as 10-20 GW by the year 2000, though acknowledges that achieving this potential will require a "tremendous" effort in the next few years [32].

[11] For example, farmers generally saw less benefit in irrigation than presumed. Thus, the actual number of hours per year a typical farmer irrigated his land was relatively low, contributing to marginal cost-effectiveness of switching from diesel fuel to biomass.

4.2.5. Gas Turbine Applications

At a larger scale than IC engines, a potentially interesting application of producer gas is as fuel for stationary gas turbines generating electricity in amounts of 5 to 100 MW_e. At this scale, gas turbines would be competing with steam-rankine systems. In contrast to steam-cycle technology, the unit capital costs of Brayton-cycle (gas turbine) systems are relatively insensitive to scale, so that from a capital cost perspective the gas turbine is an interesting candidate for biomass-based power generation. The gas turbine is also a good candidate for achieving higher thermodynamic efficiency because the peak cycle temperature--the key parameter determining rankine or brayton-cycle efficiency--of modern gas turbines (about 1260°C for the best gas turbine on the market) is far higher than that for steam turbines (about 540°C).

Gas turbine systems are projected to have biomass-to-electricity efficiencies ranging from 35% to more than 40%, which would double or triple the amount of power that can be derived from a unit of biomass using common Rankine-cycle systems. Gas turbines are today limited to use with "clean" fuels like natural gas or distillate fuel, but ongoing development of systems coupling biomass to gas turbines show promise of commercial viability by the mid-to-late 1990s.

Technology. In a biomass-gasifier/gas turbine system, the biomass would be gasified in a pressurized air-blown reactor and the products cleaned of particulates and other contaminants (especially trace alkali metals) before being burned in an efficient power cycle based on aeroderivative gas turbines, such as the steam-injected gas turbine (STIG), intercooled STIG (ISTIG), or a combined cycle [43,44,45] (Fig. 4.14). Hot gas cleanup avoids cost and efficiency penalties that would reduce economic attractiveness, and pressurized gasification avoids energy losses associated with compressing the fuel gas after gasification.

The technical requirements of gasification for gas turbines are quite different from those for other gasifier applications discussed above. Particulate cleanup requirements are much stricter than for heating applications and comparable to those for IC engines. However, with hot gas cleanup, tar removal is not required since the tar would remain in its vapor state until it is burned in the combustor. Thus, the fundamental technical problem that has plagued gasifier-IC engines would not be present in gas turbine applications. An added complication, however, is the need to remove trace amounts of alkali vapor from the gas before it enters the gas turbine. There appears to be a basic understanding of the means for adequately cleaning gases for gas turbine applications with either fluidized-bed gasifiers [46] or updraft gasifiers [21], though there has been no commercial demonstration of alkali removal.

Economics. Biomass-gasifier/gas turbines (BIG/GTs) are characterized by high conversion efficiencies and low expected unit capital costs ($/kW) in the 5-100 MW_e size range [47,48,21], the upper end of which is probably near the practical upper limit on the size of a biomass installation. The expected performance and costs compare favorably with direct-combustion steam-turbine systems, the current state of the art in large-scale biomass electricity generation and cogeneration (Table 4.3). The technology also has the potential to compete with much larger central-station fossil-fuel and nuclear plants. For example, Fig. 4.15 shows busbar cost comparisons between BIG/GT units and alternative coal-fired power plants with fuel costs ranging from $1.8/GJ to $3.6/GJ. The higher fuel cost figure corresponds to a target fuel cost for biomass (after processing for use in the gasifier) from energy plantations in the US. Plantations in many developing countries might be able to produce biomass at a lower cost than this [3,21]. Fig. 4.16 shows a cost comparison similar to Fig. 4.15 between BIG/GT and coal, natural gas, and oil-fired power plants based on an analysis by the Shell International Petroleum Company. The impact of an assumed carbon tax on fossil fuels is also shown there.

While the economics of plantation-based BIG/GT power generation appear attractive, initial BIG/GT applications are likely to be at industrial sites where biomass processing residues are readily available today, such as at cane sugar processing mills [49,50] and mills in the forest products industry [51]. Biomass-fired steam-turbine cogeneration systems are typically used in these industries today to meet on-site steam and electricity needs. BIG/GT systems have much higher electrical efficiencies that would permit them to meet onsite electricity needs and produce large quantities of excess electricity that could be sold to utilities (Fig. 4.17a,b,c). Because BIG/GTs would produce less steam than steam-turbines (Table 4.3), steam use efficiency would generally need to be improved in a factory to enable BIG/GT systems to meet on-site steam needs. It appears technically and economically feasible in many cases to reduce steam use sufficiently to use BIG/GT systems, because most mills using biomass residues for fuel are intentionally designed to be somewhat inefficient so as to be able to consume all of the biomass and thus avoid waste disposal problems [52,50,51]. The quantity of biomass processing residues produced globally is large (Table 4.2), and these residues are generally cheap. Electricity generated by BIG/GT systems and exported from mill sites would compete with alternative central station power generation options under a variety of conditions (Fig. 4.18a,b and Table 4.4). The cane sugar industry presents a particularly interesting possibility for developing countries. The present level of cane production globally (970 million tonnes in 1987) could support up to 95 GW of BIG/GT generating capacity, most of which would be in the 80 cane-growing developing countries, where the electricity produced by year-round operation (807 TWh/yr) would be equivalent to half of all utility electricity produced there in 1987 (Table 4.5).

Commercial Status. BIG/GT systems are not commercially available, but are likely to be available by the mid-1990s, based on five independent development efforts ongoing in Scandinavia, Brazil, and the US [51].

Sydkraft, the largest private electric utility in Sweden, began constructing in the fall of 1991 a 6 MW_e BIG/combined cycle cogeneration demonstration plant in Varnamo, in Southern Sweden [53]. Ahlstrom, a Finnish gasifier manufacturer will provide a pressurized circulating fluidized-bed gasifier, a proprietary alkali removal system, and ceramic filters for particulates. Preliminary tests by Ahlstrom and Sydkraft indicate that wood fuels can be gasified at pressure and the gas filtered at elevated temperature to specifications for gas turbines. Gas production at the demonstration site is scheduled to begin in March 1993.

In Brazil, the Companhia Hidro Eletrica do Sao Francisco (CHESF), a major electric utility in the Northeast, has an ongoing R&D program aimed at developing biomass from planted forests as a major fuel source for power generation, with conversion to electricity using BIG/GT units [53a]. CHESF is leading the effort to develop a BIG/GT demonstration project in Brazil, an effort that includes the participation of Eletrobras (the Brazilian federal electric utility), General Electric, Shell, Siemens, Stewart and Stevenson, Vale do Rio Doce (a major Brazilian forest products company), and several additional Brazilian companies and research laboratories. The project is seeking to run a demonstration unit of about 18 MW_e output on wood chips in the Northeast of Brazil, most probably at the site of a forest product manufacturing facility.

In the US, the Department of Energy (DOE) announced in late 1990 a major new initiative to carry out R&D on BIG/GT technology [54]. The US DOE also recently selected the IGT pressurized bubbling-fluidized bed RENUGAS gasifier for a large-scale biomass gasification demonstration [55]. A pressurized pilot-scale Renugas unit has extensive operating experience on a variety of biomass feedstocks [56]. The scaled-up unit will be built in Hawaii and be run initially on sugarcane bagasse (50 tonne per day capacity). Start-up is anticipated in late 1992. The demonstration unit will be evaluated primarily for chemical synthesis applications, but the USDOE's BIG/GT program initiative might build on this effort in the longer term.

Also in the US, the Vermont Department of Public Service, in cooperation with in-state electric utilities, is exploring possibilities for a commercial demonstration of BIG/GT technology fueled by wood chips derived from forest management operations [57]. In preparation for this demonstration project, the US Department of Energy, the US Environmental Protection Agency, and the US Agency for International Development are jointly supporting gasification tests for wood chips and alternative biomass fuels, using the pilot-scale fixed-bed gasifier at the corporate research and development headquarters of the General Electric Company in Schenectady, New York.

The Finnish electric utility, Imatran Voima Oy (IVO), has begun development of a modified BIG/STIG cycle designed to take advantage of the moisture in wet feedstocks [57a]. In the IVOSDIG cycle, wet fuel is first dried in a pressurized dryer, the moisture in the feedstock being recovered as high-pressure steam. The steam is injected into the gas turbine, as in a conventional STIG, while the dried biomass is fed to the gasifier. IVO is targetting initial development of the "IVOSDIG" process for peat, which would be dried from an initial moisture content of 60% to 75% down to 10% to 30% for gasification. A 92 MWe IVOSDIG cycle is estimated to have an efficiency of 35%, starting with 70% moisture content biomass. IVO is developing the fuel supply and drying systems, which they plan to couple with gasifier and gas turbine systems developed elsewhere. Commercialization of the cycle is targetted for the late 1990s.

Developing-country considerations. BIG/GT systems have a number of characteristics that make them particularly attractive for developing country applications. Their low anticipated capital costs are especially attractive in light of the unaffordability of capital investments for electricity based on conventional sources

(Table 4.6). Also, many industrializing countries could draw on indigenous management and engineering talent for much of the design and construction effort required: most components of the system can probably be manufactured in developing countries. The primary exception would be the high-technology core of the gas turbine that is derived from advanced jet engines. As a result of R&D spending averaging $0.5 billion/yr on aircraft engines for military applications, US companies would appear to have an untouchable competitive advantage in this technology.

The maintenance characteristics of the high-technology core of the aeroderivative gas turbines at the heart of a BIG/GT system are also attractive. Their compact, modular nature makes it possible to replace failed parts and even whole engines quickly, with replacements flown or trucked in from centralized maintenance facilities. This would be attractive in many developing countries, where sophisticated maintenance capabilities are typically unavailable at power generating sites. Also, the required maintenance network is already largely in place in most developing countries that have their own commercial airlines; their planes are typically maintained through centralized lease-pool arrangements.

The scale characteristics of these systems are also well suited to developing countries. In most developing countries, the total utility grid capacity is too small to be well matched to much larger hydroelectric or fossil fuel-fired steam-electric power plants. Adding new capacity in small increments with BIG/GT systems would make it possible to avoid alternating periods of power glut and power shortage associated with utility planning based on large plants. It would also lead to lower total investments needed for the power sector, both because of the comparatively low capital costs of the technology and because only as many plants could be built as actually needed to meet demand. Finally, overall system reliability would be higher for a utility operating many small plants compared to one with a few large plants.

4.3. Biogas

Biogas is the term used to describe a combustible gas consisting primarily of methane and carbon dioxide, having a heating value of about 22 MJ/Nm^3, and produced by the biological process of anaerobic (without air) digestion of organic feedstocks. Almost any carbon-containing biomass feedstock except lignin (a component of wood) can be converted to biogas. Feedstocks that have been widely used in digesters include animal and human wastes, sewage sludge, crop residues, carbon-laden industrial processing byproducts, and landfill material. A clean, high-quality energy carrier is one product of digestion. A second is the effluent sludge from the digester, which is typically nitrogen-rich and an excellent fertilizer and soil conditioner. Also, the digestion process reduces or eliminates pathogens originally contained in the feedstock.

Biogas digesters have been used most extensively in China and India, where millions of units have been installed to serve individual households or communities. A total of several thousand units have been introduced in other developing countries, most notably South Korea, Brazil, Thailand and Nepal [58]. About 5000 digesters are installed in industrialized countries [59]. These are typically large units located primarily at large livestock processing facilities (stockyards) and municipal sewage treatment facilities. There are also an increasing number of digesters located at food processing plants and other industrial facilities, where they are used primarily to reduce the negative environmental impacts of releasing waste streams with high biological oxygen demands.[12]

4.3.1. Fundamentals of Anaerobic Digestion

There are a variety of digester designs all utilizing similar basic principles. In the absence of oxygen, organic matter introduced into the digester is degraded by the action of three classes of bacteria: fermentative bacteria, acetogens, and methanogens. The first two convert the complex organic compounds in the feedstock into simpler intermediates (short-chain fatty acids, alcohols, acetate, hydrogen, and others), which are then converted to methane and carbon dioxide by the methanogens. A mineral-rich slurry, in which disease vectors have been largely destroyed, is co-produced in the process.

Proper operation of a digester relies on a dynamic equilibrium among the three bacterial groups. This balance, and hence the quality and quantity of gas produced, are affected by changes in digester temperature and pH and by the composition and rate of loading of the feedstock.

There are two distinct temperature regimes within which a digester can be operated. Mesophilic digestion refers to the lower-temperature regime (with a peak in

[12] Biological oxygen demand (BOD) is a measure of the amount of organic matter in a waste stream that can be biochemically oxidized.

microbe activity at around 35°C). Thermophilic digestion refers to the higher-temperature regime (with a peak in microbe activity around 55°C). Gas production rates under thermophilic conditions can be higher than with mesophilic conditions, but the thermophilic regime is more difficult to maintain in a steady state [59a]. In addition, external heating is typically needed to maintain thermophilic conditions.[13] Most digesters operate in the mesophilic regime. Up to the temperature of peak microbial activity, higher operating temperatures produce greater metabolic activity within either regime. The variation in gas production rates with temperature in the mesophilic regime are illustrated by data from plants operating in Hubei province, China (Table 4.7) and in India (Fig. 4.19).[14]

A neutral pH provides best conditions for digestion. A low pH can result when acid compounds are formed at a faster rate than they can be consumed by methanogens. To correct the pH, feeding can be interrupted or a neutralizing chemical such as lime can be added.

An appropriate ratio of carbon-to-nitrogen (C/N) in the digester feedstock is needed to support bacterial activity. A C/N ratio of 30 is generally considered optimal [58]. However, since not all of the carbon and nitrogen in a feedstock are accessible by the bacteria, particular feedstocks with actual C/N values ranging from less than 10 to over 90 can still support efficient digestion. Small amounts of other nutrients, including phosphorus, magnesium, sodium, manganese, calcium, and cobalt are also needed, but they are generally found in more than sufficient quantity in most feedstocks.

A wide variety of digester feedstocks are used. Cattle dung, moderately degradable and nutritionally balanced (C/N = 25), is widely used, particularly in small-scale reactors in India. In China, nitrogen-rich pig manure and human wastes (nightsoil) are typically combined with carbon-rich rice or other straw to create a nutritionally-balanced feed for household digesters. At larger scales, digester feedstocks include industrial food-processing waste streams, stillage from ethanol production,

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[13] Alternatively, thermophilic conditions can be present when the feedstock enters at an elevated temperature, as might be the case when warm industrial waste is the digester feedstock.

[14] A few isolated digester designs utilizing some form of solar heating to raise gas production rates are reported in the literature. For example, in one case in South India [60], a solar-assisted digester achieved an 11% increase in gas yield (gas output per unit mass of feedstock input) compared to a standard design.

municipal solid waste, and municipal wastewater. Herbaceous biomass (e.g. grasses) and marine biomass have also been used as feedstocks.

In addition to biogas, digesters produce a slurry that has significant value as a fertilizer. Wet slurry from a digester fed with fresh cattle dung has essentially the same nitrogen fertilizer value as the input dung. Because water is also added to the digester, however, about twice as much fresh digester effluent is needed to supply the same amount of nitrogen as fresh cattle dung (Table 4.8). On the other hand, the fertilizer value of dried digester effluent may be as much as 70% greater than dried cattle dung (Table 4.8). This is because nitrogen in dung is more readily volatilized in drying dung than that in digester effluent [61].

Biogas digesters also act to reduce or eliminate pathogens and to reduce the BOD of waste streams, benefits which are sometimes difficult to quantify. Industrial and municipal digesters are used predominantly for the environmental benefits they provide.Significant declines in parasite infections, enteritis, and bacillary dysentery have been noted in areas following installation of small-scale digesters [58]. Thermophilic temperatures are especially conducive to the destruction of pathogens (Fig. 4.20), but with sufficient retention time significant destruction occurs under mesophilic conditions (Fig. 4.20 and Table 4.9). Air drying or composting of digester effluent can further reduce or completely eliminate pathogens. A secondary health benefit where biogas replaces wood used in traditional cook stoves is the virtual elimination of the inhalation of noxious gases and particulates from wood fires.

4.3.2. Digester Technologies

Two broad classes of digester technologies can be identified by the relationship between characteristic hydraulic retention time (HRT) and solids retention time (SRT). The HRT is the average residence time influent feed remains in the reactor, or roughly the reactor volume divided by the influent volume flow rate. The SRT indicates how long the solid biomass portion of the feed remains in the reactor. Since the microorganisms that digest biomass grow relatively slowly, long SRTs are needed to achieve reasonable conversion of biomass to gas. On the other hand, short HRTs are desired to improve the economics by maximizing the rate of reactor throughput. The simplest digester designs that are widely used with animal and human wastes for small-scale applications in developing countries, unmixed tanks, have long SRTs (of the order of weeks), but also HRTs essentially equal to the SRTs. Thus, the throughput rates are relatively low. For more dilute feed streams, e.g. many industrial waste streams, such low throughput rates would prove unecomical in most cases. More complex reactor designs, sometimes categorized as retained-biomass reactors, have been developed for dilute fees to provide long SRTs together with short HRTs.

Unmixed-tank digesters. Two basic unmixed-tank digester designs are used widely for small-scale applications in developing countries. The floating-cover digester was originally developed in India in the 1950s and continues to be the standard design used there. Fixed-dome digesters are the standard in China. Other designs that are receiving some attention include the bag-type digester (gaining popularity in China and elsewhere), the plug-flow digester, and the two-stage digester (where the acid formation takes place in a separate reactor from the methane production stage).

The floating-cover digester was introduced commercially in 1962 in India by the Khadi and Village Industries Commission [58]. It is widely known as the KVIC design. Improvements to the technology have been made continuously over time, but the basic design remains the same. A gas holder floats on a central guide and provides constant pressurization of the gas produced (Fig. 4.21a). The reactor walls are typically brick or concrete. Traditionally the cover is made of mild steel, though more corrosion-resistant materials are being used to a limited extent. The digester is fed semi-continuously, with input slurry displacing an equivalent amount of effluent sludge. A partition wall is included in reactors that are deep relative to their diameter to prevent short-circuiting of the input slurry. The primary drawback of the KVIC design is the high cost of the steel cover.

The fixed-dome design originated in the 1930s in China. In this digester (Fig. 4.21b), biogas collects under a fixed brick or concrete dome, displacing effluent sludge as the gas pressure builds. The dome geometry is used to withstand higher pressures than are generated in the floating cover design. Millions of fixed-dome units have been built, primarily small household-scale units. Relatively few large-scale units have been built, most likely due to the difficulty of constructing large domes. A major shortcoming of the fixed-cover units, even in small sizes, has been the difficulty of constructing leak-proof domes. A number of improved versions of the fixed-dome design have been introduced, including those designed to operate with plug flow conditions and/or with storage of gas in variable-volume "bags" [65].

The gas production rate of a digester is commonly expressed in terms of its daily volumetric gas production per unit of digester volume. A typical value observed in practice with floating or fixed-cover reactors is 0.2 m^3/m^3 at an ambient temperature of 18-20°C. This value appears to reflect a need to balance the benefit of higher gas production rates against the higher associated "costs": higher gas production results from higher feeding rates [66], which lead to lower yields of gas per unit weight of feed inputs and involve shorter residence times in the digester, which can reduce the amount of pathogen destruction. Some innovative designs have successfully achieved higher outputs, with reduced capital costs and satisfactory yields. In one case [61], a daily gas production of 0.5 m^3/m^3 has been achieved.[15]

The typical digester feedstock in India is wet cattle dung mixed with water in a ratio of 1:1. A typical yield of gas with the KVIC digester is 0.02 to 0.04 m^3 per kg of fresh manure input at a design ambient temperature of 27°C [58,67]. Table 4.10 shows an estimate of the minimum number of animals required to support different sized digesters. Obviously, the dung production per head will influence this number substantially. The dung production rate suggested for use in planning a digester installation in India is about 10 kg/day per head for a stable-bound bullock or cow of medium size [67].[16] The design gas use rate for cooking suggested for planning purposes is about 0.3 m^3 per person per day [67]. Based on this figure and Table 4.10, a family of 5 would need a digester of about 10 m^3 volume and the dung output from a minimum of 2-3 animals to meet their cooking fuel needs.[17]

In China, the feedstock is typically a mix of nitrogen-rich pig manure, cow manure and nightsoil, and carbon-rich straw and grass [65]. Water is added to achieve a total input solids concentration of about 10%. The gas production from a 6-8 m^3 digester is considered sufficient to meet the cooking and lighting (2 hours, 60 W equivalent) needs of a rural family of five [65].

Retained-biomass digesters. A variety of retained-biomass digester designs have

[15] The unit is one developed at the Center for the Application of Science and Technology to Rural Areas (ASTRA) of the Indian Institute of Science (Bangalore), and installed in Pura village, state of Karnataka, India. The geometry of the unit is shallower and wider than that of the conventional KVIC design. It thus more closely approximates a plug flow design.

[16] In contast, 500-kg beef or dairy cattle in the US are estimated to produce about 40 kg/day per head [66].

[17] Assuming a daily gas yeild of 0.2 m^3 per m^3 of digester volume.

been developed primarily for use with dilute industrial or municipal waste streams. The basic designs include the anaerobic contact reactor, the anaerobic filter reactor, the upflow anaerobic sludge blanket reactor [58,62,63,64,65a].

The anaerobic contact (AC) reactor, sometimes called a stirred tank with solids recycle, was the first retained-biomass reactor to be developed (in the late 1950s). It includes a stirring device and provides for longer SRTs by recycling solids that are separated from the liquid substrate in a settling tank (Fig. 4.22a). The AC reactor is particularly well-suited to feedstocks with some difficult-to-digest solids that settle readily. Operating problems stem most commonly from poor settling characteristics of feedstocks and inadequate mixing. The AC process has been applied commercially in several industrialized countries.

The original design of the anaerobic filter (AF) reactor incorporates a fixed-bed of rocks, plastic or other high surface area-to-volume ratio material through which the waste stream flows (from top down or vice-versa) during the digestion process (Fig. 4.22b). The packing and interstitial spaces trap and retain biomass, providing for long SRTs with short HRTs. Gas production rates as high as 4 Nm^3/m^3-day have been measured. The AF reactor is well suited for dilute waste streams that do not contain hard-to-digest, easy-settling solids. The most common operating problem with this type of reactor is clogging of the packing. Relatively few AF reactors are operating commercially. One notable successful installation in a developing country is at a tapioca starch factory in Thailand [65b].

There are several variants on the original AF design. The downflow stationary fixed-film (DSFF) reactor utilizes a series of fixed parallel vertical surfaces to which biomass and digesting microorganisms are attached. The DSFF reactor is less prone to clogging than the loosely-packed AF. Probably the most famous DSFF unit operating today is at the Bacardi rum distillery in Puerto Rico, which has a gas production capacity of some 50,000 Nm^3/day, with an approximate maximum gas production rate of 5 Nm^3/m^3-day [65c,65d]. Another variant of the AF reactor is the fluidized-bed reactor, in which solids are attached to small, inert particles (sand, plastic, or other material). The particles are "fluidized" by the force of the liquid influent that is pumped through the bed from below.

The upflow anaerobic sludge blanket (UASB) reactor was developed around 1980 in part to address the clogging problems with AF reactors. The UASB uses no packing, but incorporates a gas-solid-liquid separating device (Fig. 4.22c). In steady-state operation, a granular sludge blanket forms at the bottom of the reactor. Solids that settle are digested in the blanket, while HRTs can be very short (hours). Gas production rates as high as 8 Nm^3/m^3-day can be reached. The main operating problem with UASB reactors relates to whether the granular sludge blanket forms easily during startup. Some wastes form the sludge more readily than others. The UASB process has been applied commercially in several industrialized countries. A number of UASB units are used in Europe, and some 500 units have been installed since the mid-1980s at ethanol distilleries in Brazil to treat stillage [65e].

4.3.3. Cost of Biogas

Household and community systems. There have been extensive analyses done of the costs of biogas from small-scale unmixed-tank digesters. Most of these analyses relate to floating-cover digesters. With the exception of some capital cost data for fixed-bed reactors, the cost analysis here is restricted to floating cover designs.

Reported installed capital costs for floating-cover digesters are shown in Fig. 4.23. Because of the standardization of the design (unlike the case with producer gas generators), there appears to be a fair degree of consistency among different sources on the cost of digesters. Sharply rising unit costs are evident in the very small sizes appropriate for household applications. (For reference, a 100 GJ/yr capacity digester corresponds to a gas production rate of about 12 m^3/day). Taken together, the data of Reddy, et al. [61,77], Bhatia [42], and Rana and Verma [68], suggest that capital costs for 1980s technology are lower than those for 1970s technology (Santerre & Smith [69], Kashkari [67]).[18] This indicates significant learning in the intervening years. This conclusion is supported by Sinha and Kandpal [72] who cite the "Pragati" variant of the KVIC design with 30% to 40% lower cost. They also cite a "Deenbandhu" ("friend of the poor") design (fixed-dome) with still lower costs. The ASTRA plant installed at Pura village (see footnote 15) is some 40% less costly than the KVIC design [61].

Reported capital costs for fixed-dome digesters are much more scarce in the literature. However, there is general agreement that fixed-dome units are significantly

[18] The five sets of data referred to here are all based on experiences with digesters in India, and thus comparisons among the data sets are meaningful. The Rijal [71] and Orcullo [70] estimates in Fig. 4.23 are from experiences in Nepal and the Philippines and are thus probably not strictly comparable to the Indian data.

less costly, at least for household-scale digesters, primarily because they do not require a steel cover. For digesters of two to six m^3 volume, Reddy and Rajabapaiah indicate that the capital cost for a Chinese-type "Janata" digester is about half of that for a KVIC digester [73]. For digester capacities of 3 to 5 m^3/day, Rijal [71] reports unit costs ($/$m^3$/day) for fixed-dome units to be less than 40% of those for floating-cover digesters. Still lower costs for small fixed-dome units are reported by Daxiong, et al. [74]. Both Rijal and Daxiong, et al. report slightly increasing unit costs with capacity (Fig. 4.24). This is probably due largely to the greater difficulty of constructing larger domes.

With floating-cover digesters, labor costs arise from the required collecting of water and dung, mixing and loading of inputs, and distributing of effluent sludge. Maintenance typically consists of minor repairs, periodic cleaning out of the plant, and occasional painting of the steel cover. Reported annual costs for labor and maintenance for floating cover digesters are given in Table A.4. These data are generally representative of present conditions in India. For example, daily wage rates in the rage of $1 to $1.5 per worker are assumed. For household-size units (less than 10 m^3/day gas production capacity), a constant labor-plus-maintenance cost is reported by Santerre and Smith. Combined annual labor and maintenance costs per unit of digester capacity for larger units fall modestly.

Fig. 4.25 shows levelized costs of biogas production from floating-cover digesters calculated based on different sets of reported capital, labor, and maintenance cost data (Table A.4) and a common set of baseline assumptions (see caption). Costs of feed material for the digesters are assumed to be offset by the income that could be derived from selling the effluent as fertilizer, and no credit is taken for the health benefits that might accrue from use of the digester, since these are difficult to quantify.

Based on Fig. 4.25, community-sized digesters (100 GJ/yr to 1000 GJ/yr capacity) would appear to produce gas for $9/GJ to $5/GJ. At the household-scale, the cost appears to be roughly about $11/GJ.[19] For small-scale units, labor is the largest cost

[19] For household-sized units, an alternative perspective on production cost might be more appropriate, however. Householders would probably use family labor to operate and maintain a digester and might not consider this a cost. In addition, capital costs converted using a purchasing-power-parity (PPP) exchange rate might better represent the capital cost for a rural dweller with little or no access to hard currency. Also, capital is generally likely to be scarce for the household, which would be reflected by a much higher discount rate than the 7% assumed above. Neglecting labor and maintenance costs, converting capital costs to US$ using a PPP exchange rate [75], and applying a 30% discount rate would result in biogas costs up to five times those shown in Fig. 4.22 for household-sized units (25 GJ/yr), corresponding to a gas

component, followed closely by capital (Fig. 4.26a). For larger units (Figs. 4.26b and 4.26c), the capital cost component is relatively smaller. The greater capital intensity of the smaller unit leads to a greater sensitivity at smaller scale of the gas cost to the assumed discount rate (Fig. 4.27a) and capacity utilization rate (Fig. 4.27b). Ambient temperature influences the gas production rate, as discussed earlier, which in turn influences the cost of gas as shown in Fig. 4.27c.

Industrial systems. Reported capital costs for industrial digester plants are shown in Fig. 4.28. The data of Tanticharoen are for packed-bed anaerobic filter reactors. Hochgrebs's data are for a packed-bed AF (smaller unit) and for a UASB (larger unit). Orculla's data are for a modified floating-cover reactor. The data point of Tilche et al. is for a plug-flow design and that of Alaa El-Din et al. is for a two-stage reactor. Based on Fig. 4.28, unit capital costs for systems larger than about 20,000 GJ/yr capacity appear relatively independent of plant size. Also, the relatively close correlation of all data shown suggests that the unit cost is relatively independent of the design. The large-scale systems (larger than 20,000 GJ/yr capacity) are seen to have lower unit costs than smaller floating-cover digesters (compare Fig. 4.28 and Fig. 4.23).

Relatively few authors give estimates of the total costs (including labor and maintenance) for producing biogas in large-scale plants. Fig. 4.29 shows estimates for the cost of gas from stillage produced at autonomous ethanol distilleries in Brazil. A typical distillery might operate for 200 days per year, corresponding to a 55% capacity factor. With the UASB reactor developed by Methax, the total cost of gas at a distillery would be about \$2.5/GJ. With the packed-bed reactor developed by Petrobras, the cost of gas would be about \$1.4/GJ. In both cases, the cost of gas would be far lower than in small-scale unmixed-tank reactors (compare Fig. 4.29 and Fig. 4.25).

4.3.4. Small-scale electricity generation using biogas

One application of biogas that has received considerable attention in developing countries is small-scale electricity generation. Biogas can be used to fuel either compression- or spark-ignited internal combustion engines, which can provide shaft power or drive an electrical generator. One of the most carefully-documented, long-term field experiences with biogas-engine electricity generation has been at Pura village in the state of Karnataka, India. The discussion here is based on data from this

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cost of perhaps \$25/GJ.

experience [61,76,77].

The biogas plant at Pura village was designed and implemented by researchers from the Center for the Application of Science and Technology to Rural Areas (ASTRA) of the Indian Institute of Science (Bangalore). The ASTRA researchers developed an innovative floating-cover digester design with a daily gas production of 0.5 m^3 of gas per m^3 digester volume (see footnote 15). In addition to superior performance, the ASTRA design was about 40% lower in capital cost than the conventional KVIC design. The plant was originally started up in 1982 to supply all 87 households in the village with cooking fuel, using cattle dung as the input. A reluctance on the part of the villagers to contribute dung and the resulting inadequate production of gas to meet daily cooking needs caused the plant to be shut down after 2.5 years of otherwise successful operation.

The plant was restarted in September 1987 on the request of the villagers, and it continues to operate today. The gas output replaces about 70% of the diesel fuel needed to run a 5 kW diesel engine. The engine drives a generator providing electricity to pump well water into an overhead storage tank, from which it is distributed by gravity to nine street taps located at distributed sites in the village and 29 private taps inside households. Electricity is also provided to 48 of the 87 households for lighting. (The other 39 households are connected directly to the utility grid.) The engine currently operates for 4.3 hours per day. Operation for a longer period is currently limited by the availability of dung in the village. As a result of the success with the biogas plant to date, villagers are seeking loans for the purchase of additional cattle so as to increase the dung supply. Villagers are paid a fee of \$0.0016/kg for delivered dung and are also returned digester sludge in proportion to their dung contribution. The sludge is passed through a simple sand-bed filter system to concentrate the solids content before it is returned. The village biogas-engine operation employs two village youths full time.

The major capital cost components of the Pura system are the biogas digester and the electrical generator (Table 4.5). With the current operating hours of the system (4.3 hours/day), corresponding to a capacity factor of about 18%, the total levelized cost of electricity is about 15 cents/kWh. Raising the capacity factor to about 50% (12 hours/day) would reduce the cost to about 10 cents/kWh, but increasing the capacity factor beyond 50% would result in relatively smaller decreases in cost (Fig.

4.30a). With a 50% capacity factor, the cost of electricity would vary with the assumed discount rate as shown in Fig. 4.30b.

The majority of costs associated with the biogas system over its lifetime are local expenditures, as illustrated by Fig. 4.31 showing a breakdown of the levelized electricity generating costs. The cost for diesel fuel and "new engines"--several engines would need to be purchased over the 25-year lifetime of the digester--represent 1/3 of the total cost. These are expenditures that would leave the immediate community. The balance of expenditures would remain in the local community. Rajabapaiah, et al. [61] note that this means the biogas electricity system, in contrast to centralized electricity generation, helps stimulate local prosperity very directly.

4.3.5. Implementation issues

The implementation of biogas technologies in developing countries has been relatively successful, both at the industrial and household/community scales. The attractive economics of large-scale applications (suggested by Fig. 4.28 and reported for a number of installations [65b,65c,95]), together with increasingly stringent emissions regulations, appear to have provided sufficient impetus in many cases for industrial investments in biogas. Given the more marginal economics of smaller scale systems and the lack of access to capital of many potential small-scale biogas users in developing countries, the successful implementation of household and community biogas systems merits scrutiny for lessons that might be transfered to other bioenergy technologies.

There are an estimated five million digesters operating in China today, mostly at the household scale [74] and some 300,000 in India [59]. The efforts in China and India to popularize biogas have been very different in nature historically, but the associated institutional frameworks appear to be evolving toward having a common set of attributes necessary for success [78,42]. First, national commitment has been essential, since this has helped address a number of key problems: distorted user economics due to subsidized prices for electricity and alternative fossil fuels, valuing of non-pecuniary benefits such as improved sanitation, and supporting R&D efforts aimed at cost reduction and technology improvement. Second, the need for two stages of development and dissemination has come be recognized: an experimental and limited field-test stage followed by large-scale dissemination. Third, an interdisciplinary approach has evolved, recognizing the multiple benefits of digesters and the mutliple needs and capabilities (financial and technical) of users. Fourth, training of disseminators and users has come to be recognized as essential. Fifth, an overall infrastructure that is a mix of centralized and decentralized institutions and/or actors appears to have been most effective in dissemination. Also, implementation efforts have generally been more successful where some competitive market-type forces have been made to work. Sixth, there has been a recognition of the need for a strong technology base to insure development and continuing improvement of sound technology. A brief review of the Indian and Chinese experiences helps illustrate the evolution of what appear presently to be more-or-less similar national biogas programs in these countries.

In India, the KVIC design was promoted as the standard unit for 15 years from the initiation of the biogas program in the early 1960s. While technologically sophisticated, the KVIC design was costly, was designed only for use with cattle dung, and required the dung output from a minimum of 3 to 5 head. Thus the choice of technology immediately placed biogas out of the reach of the majority of rural Indian householders [73]. This was eventually recognized, and alternative technologies based on Chinese designs were introduced in the 1970s. Greater efforts were undertaken to make the technology accessible to more of the population, including an emphasis on community-scale digesters. The strong community of scientists and engineers in India, of which the KVIC design was a product, has increasingly focussed its R&D efforts on reducing digester costs and diversifying feedstocks. In addition, more widespread training efforts are ongoing and there is a general emphasis on more decentralized and locally-tailored dissemination efforts.

Compared to the Indian approach that historically was centralized and technologically oriented, the Chinese program has historically given less attention to technological sophistication and placed more emphasis on mass diffusion and low cost [79,78,74]. The long tradition of recycling and composting in rural areas in China made for relatively easier acceptance of digesters. In fact, gas, fertilizer and sanitation were considered equally valuable benefits. In addition, the relatively equitable distribution of livestock holdings, particularly pigs, and the practice of keeping animals penned near the household led to an emphasis on use of household-size units. Cooperatives to which the household belonged would typically help provide financing to individual householders for the initial capital cost.

Efforts at mass dissemination of digesters in China began in 1958 when Chairman Mao gave instructions to pursue development of biogas in the countryside. Several million digesters were reportedly built within a year, but most did not function due to poor design or construction. A second mass effort began in the early 1970s. Some seven million digesters were installed between 1973 and 1978. Again, however, due to poor quality most of these units (85%) were not functioning by the end of the 1970s.

Since the mid-1970s, the government has more strongly encouraged a more deliberate approach, emphasizing quality in both the technology and its administration [74]. From 1979 to 1985, some 2.5 million digesters were installed, and a wide-spread and sophisticated three-level support infrastructure was put in place. At the county-level there are over 700 quasi-private biogas "service stations" employing some 10,000 technically-trained individuals.[20] The service station employees undertake construction of digesters, sales of materials and accessories, management and technical consultancies, and training of technicians. At the village level are an additional 7000 construction teams employing some 40,000 biodigester "doctors." The third level of support consists of some 70 institutes or universities engaged in biogas-related R&D. The opening of the economy to greater financial incentives in the late 1980s is shifting the direction of the Chinese biogas effort. Capital cost subsidies for biodigesters are beginning to be lifted, causing service stations and construction teams to emphasize larger, more economical community-scale installations. This is consistent with the overall expected trend in China toward larger-scale plants [74], both in urban and rural areas. Scale economies can be exploited, plants can be more technologically sophisticated, and individual users do not have to be experts in biogas technology.

5. Liquid Fuels from Biomass

The production of liquid fuels from biomass, with the exception of ethanol from sugarcane and corn, has not been widely implemented commercially. The primary reason for this has been high cost. In the case of ethanol from cane and corn, government subsidies have supported commercial production. Research and

[20] Another report indicates that there are 2230 service stations employing 158,000 professionals [80].

development work to reduce costs and improve yields of liquid fuels from biomass has been ongoing at a relatively slow pace, except in the case of ethanol from sugarcane in Brazil. Nevertheless, advances being made indicate that liquid biofuels could become competitive with fossil fuels perhaps as soon as the year 2000 with accelerated RD&D efforts.

This section discusses three alternative liquid fuels from biomass: methanol from lignocellulose (any woody or herbaceous biomass), ethanol from sugarcane, and ethanol from lignocellulose. Most of the analysis here relies on studies that have been carried out in the US on these technologies. In the case of ethanol from sugarcane, extensive reference is made to the Brazilian experience--by far the largest and most ambitious liquid biofuels program implemented anywhere. Ethanol from corn is generally not considered a practical option for most developing countries, both because feedstock costs are high and feedstock use for food is a higher priority.

5.1. Methanol from lignocellulose

Methanol (CH_3OH) is produced today primarily from natural gas using technology that has been available since the 1930s. Methanol can also be produced from coal and, through a similar process, from lignocellulosic biomass feedstocks [81].

5.1.1. Technology

Three basic thermochemical processes are involved in methanol production from biomass (Fig. 5.1). The first step is production of a "synthesis gas" (a close relative of producer gas) via thermochemical gasification. (See Sec. 4.2.2.) The gasification step typically uses oxygen, rather than air, in order to eliminate dilution of the product gas with nitrogen that would ultimately need to be removed. Oxygen plants have strong capital cost scale economies, which contributes to most proposed biomass-to-methanol facilities being relatively large (typically 2000 tonnes/day or more input of dry biomass). In the second step, the synthesis gas is cleaned and its chemical composition is adjusted. The objective of this processing step is the production of a gas consisting purely of hydrogen (H_2) and carbon monoxide (CO) in a molar ratio of 2:1--the ratio that characterizes methanol (CH_3OH). In the final step, the gas is compressed and passed through a pressurized catalytic reactor that converts the CO and H_2 into liquid methanol. Biomass-to-methanol plants would typically convert 50%

to 60% of the energy content of the input biomass into methanol [2a].

Biomass gasifiers designed for methanol production are not commercially available, but a number of pilot and demonstration scale units were built and operated in the late-1970s/early-1980s [82,21]. Notable biomass-gasifier R&D activities revolved around the demonstration-scale Canadian Biosyn [83] and French Cruesot-Loire [82] gasifiers and the pilot-scale Swedish MINO [84] and four US-based gasifiers. The US gasifiers included indirectly-heated units developed at the Battelle-Columbus Laboratory [85] and the University of Missouri [86], a downdraft unit developed at the Solar Energy Research Institute [87], and a fluidized bed unit developed by the Institute of Gas Technology (IGT) [56]. Most of these efforts were halted when oil prices fell in the early 1980s. Work on the IGT unit has recently been revived, with the construction of a bagasse-fueled demonstration unit now being planned. (See Sec. 4.2.5.) In addition, there are a number of commercial gasifiers originally designed for coal that may be amenable to biomass use [20,21,88,89].

The specific equipment configuration after the gasifier will vary depending on the gasifier used. A reactor common to all systems is a "shift" reactor used to achieve the desired 2:1 ratio of H_2 to CO by reacting steam with the synthesis gas. The water-shift reaction governs the chemical balance in this reactor:

$$CO_2 + H_2 \leftrightarrow H_2O + CO$$

The shift reactor is a commercially established technology. Other equipment may be required before the shift reactor depending on the composition of the synthesis gas leaving the gasifier. For example, if the synthesis gas contains tars, these must be removed or cracked into permanent gases. Also, the gas output from a high-pressure gasifier contains a greater fraction of methane (CH_4) than gas from a low-pressure unit. The methane must be converted into H_2 and CO ("reformed") before the gas can be fed to the final conversion step.

In the final step of production, one of a variety of commercial processes can be used. Each one involves reactions of CO, H_2, and steam over a catalyst (typically copper-zinc oxide) at temperatures of 225°C to 300°C and pressures of 50 to 100 atmospheres to produce methanol.

5.1.2. Costs of Methanol

A number of engineering-design studies have been carried out to estimate the cost of methanol from biomass under varying technology assumptions [20,81,88,89,90]. Data from four of these studies are given in Table A.6, and unit capital costs are shown in Fig. 5.2. All except the smallest unit shown there include the cost of an oxygen plant, which probably explains the lower-than expected capital cost for the smallest unit. The cost estimates of Wyman et al. [81] are based on designs incorporating the indirectly-heated Battelle-Columbus Laboratory gasifier. The low cost arises because of scale economies and, more importantly, because of very high assumed wood-to-methanol energy conversion efficiencies (up to 86% in the best case). Whether such high efficiencies can be achieved in commercial-scale installations remains to be demonstrated.

It appears that methanol can probably be produced for about \$10-\$13/GJ with commercially ready technology in a plant with a capacity of about 10 million GJ/yr (about 500 million liters/yr) (Fig. 5.3). At larger scale--40 million GJ/year--costs would be about \$7.5/GJ. If the cost estimates of Wyman, et al. are realized, methanol could cost about \$7/GJ at the 10 million GJ/year level and less than \$5/GJ at the 40 million GJ/year level (Fig. 5.3). For small plants, the Stone and Webster estimate in Fig. 5.3 indicates that costs would be significantly higher, even with significant capital cost reductions in the future.

Capital represents the largest fraction of the total cost of methanol produced in small plants, while feedstock is the dominant cost in large plants (Fig. 5.4). Thus, increases in biomass conversion efficiency will have the greatest impact on reducing methanol costs from large plants, while capital cost reductions will be most important at small scale.

5.2. Ethanol from Sugarcane

Two varieties of ethanol are being produced today from sugarcane for use as fuel in developing countries: anhydrous ethanol--essentially pure ethanol--and hydrous ethanol containing about 5% water. Anhydrous ethanol can be blended with gasoline up to a maximum ethanol content of about 20% without need for modifying conventional spark-ignition vehicle engines [91]. Hydrous ethanol cannot be blended with gasoline, but can be used alone as a fuel (neat fuel) in engines specifically designed for ethanol.

With the exception of Brazil, most developing countries that produce ethanol make anhydrous ethanol for blending. Molasses, a by-product of cane sugar production, is the feedstock, and most distilleries are annexed to sugar factories. Most national ethanol programs aimed at anhydrous ethanol production are relatively small due in part to uncertain economics deriving from oil-price fluctuations and in part to the limited size of the potential market for anhydrous ethanol (20% of gasoline consumption). Some of the smaller national ethanol programs have been unqualified technical and economic successes (e.g. see [91a]). The discussion in this section focusses on the Brazilian ethanol experience, which has been mixed.

Brazil is by far the largest producer of fuel ethanol from sugarcane today (Table 5.1). It reached this position by launching a national ethanol program in 1975 (PROALCOOL) in the wake of the 1973 oil price shock and during a period of depressed world sugar prices. Ethanol production grew an average of about 25% per year from 1976 to 1989 [93]. Brazil produced some 12 billion liters of ethanol in 1990, and ethanol consumption equaled gasoline consumption on a volume basis. About 90% of new cars sold in Brazil today are designed to use neat ethanol (Fig. 5.5). Thus, the majority of Brazil's production is hydrous alcohol, produced in distilleries annexed to sugar mills or in autonomous distilleries.

The PROALCOOL program has been an unquestioned technological success, but economic assessments of the program have been mixed, largely because of the difficulty of including social costs and benefits in the analysis [93]. These issues are discussed in greater detail in Section 5.3.

5.2.1. Technology

Sugarcane consists of a main stalk, a green top, and a significant amount of leaves (Fig. 5.6) In most operations worldwide, only the cane stalk (without the tops and leaves) is delivered to the mill for processing. The length of the harvesting season ranges from a low of about 3 months in Thailand to a more typical 6 months in Brazil, or longer. In most regions of the world, tops and leaves are burned on the field, typically before harvesting to promote pest control and facilitate harvesting.

Autonomous distillery. At an autonomous alcohol distillery producing hydrous alcohol (Fig. 5.7a), raw sugarcane is washed, chopped, and crushed in rolling mills to separate the sugar-laden juice from the bagasse, the fiber portion of the cane. The raw cane juice, containing over 90% of the sucrose in the cane, is filtered and heated, after which its sugar solids content is typically about 13% (13° Brix). In some distilleries the juice is cooled and then sent directly to a fermentation tank. In other cases the juice is limed, clarified and then concentrated in an evaporator up to 18-20° Brix before going to the fermentation tank. Beer, the fermented mixture, contains water and ethanol in about a 10:1 ratio. The beer is then distilled, typically through two distillation columns in series to concentrate the ethanol.[21] A typical yield of hydrous alcohol in Brazil is 73.6 liters per tonne of cane processed [93]. Stillage, a potassium-rich liquid, is drained from the bottom of the distillation columns.

Bagasse accounts for about 30% of the weight of fresh cane, or about 60% of the cane's energy content. In a typical Brazilian distillery, all of the bagasse is burned in boilers to produce steam at 15 to 20 bar pressure. The steam is expanded through turbines to produce electricity, and the resulting low pressure steam (2-3 bar pressure) is used for process heating. A few distilleries with some excess bagasse are now beginning to use it to generate additional electricity on-site for sale to the local electric utility. This practice can be expected to grow significantly in the near term, as it is expected that legislation similar to PURPA in the US, which encourages private power sales, will soon be enacted in Brazil [93]. The potential for exporting large amounts of electricity from alcohol distilleries is significant via the introduction of (a) new process technologies that reduce on-site energy needs and (b) new cogeneration technologies that increase the ratio of electricity to heat produced using bagasse [50,94]. Revenues associated with electricity exports, if credited against the cost of ethanol production, could significantly alter the economics of ethanol production, as discussed in Sec. 5.2.2.

Stillage contains about 6% of the energy contained in the cane delivered to a mill. In the early phases of the Brazilian PROALCOOL program, stillage disposal was an environmental problem (due to its high biological and chemical oxygen demand and trace metals content). However, nearly all stillage is now treated in closed circuits, anaerobic lagoons or digesters before being released, and in many areas the treated stillage has been found to be effective in fertilizing and irrigating sugarcane crops. Stillage-derived biogas is produced at several hundred distilleries, and is typically used to run vehicles associated with cane transport and processing. The energy contained in biogas from stillage represents about 20% of the energy in the alcohol [95].

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[21] Additional distillation steps are needed to produce anhydrous ethanol.

An important consideration in ethanol production is the ratio of energy contained in the outputs to the energy contained in the inputs to the process.[22] Detailed studies indicate a ratio of ethanol-energy output to energy input (in both agricultural and industrial phases) of 5.9 for the average autonomous distillery in the state of Sao Paulo (where 70% of Brazil's ethanol is produced) and 8.2 for the most efficient mills in Sao Paulo [93]. The ratios for the Northeast of Brazil, the other major producing region of the country, would be higher primarily due to lower mechanization of agricultural operations [96]. Energy output/input ratios would be lower considering indirect energy inputs (e.g. the energy needed to make the steel used in distillery equipment): ratios of 3.3 to 4.0 have been reported as typical for ethanol production in Southeastern Brazil [96].

Most energy-ratio studies have considered ethanol as the only output. For distilleries generating significant amounts of excess electricity for export to the grid, output/input ratios could be significantly higher than those reported to date, primarily because of the large fraction of sugarcane's energy that is contained in bagasse. Energy ratios would be improved still further if cane tops and leaves were also used for electricity generation. The in-field burning of tops and leaves is coming under increasing criticism due to the local air pollution problems it causes. Burning is now banned in parts of Hawaii. Tops and leaves are increasingly being recognized as an important energy resource, though there is currently still little use of these for energy [97].

Annexed distillery. In an annexed distillery (Fig. 5.7b), the fermentation feedstock is typically molasses produced as a minor by-product of the adjacent sugar factory. The molasses is diluted to 18-20° Brix and then converted to ethanol as in an autonomous distillery. Some Brazilian factories are designed to use either molasses or a mixture of molasses and raw cane juice as the fermentation feedstock. This flexibility permits them to produce varying relative amounts of sugar and ethanol to better match market demands [98].

The energy analysis of annexed distilleries is complicated by the multiple outputs produced. One detailed analysis for an annexed distillery in Zimbabwe [99] indicates an output/input ratio of 1.9. A major reason for this much lower value

[22] Not including the energy content of sugar cane in the inputs.

relative to ethanol production in autonomous distilleries is the use of a substantial amount of coal to produce steam and electricity to meet the distillery's energy needs during the non-cane harvesting season, when purchased molasses is used as the fermentation feedstock. Using available cane tops and leaves in place of coal during the off-harvest season would raise the ratio to about 4.

5.2.2. Costs of Hydrous Ethanol from Autonomous Distilleries

The discussion here of the costs of ethanol production is limited to hydrous ethanol from autonomous distilleries. Analysis of the cost of ethanol from annexed distilleries is complicated by the multitude of options for feedstocks and relative product mixes [94].

The application for which hydrous ethanol is most often considered is as an automotive fuel to replace gasoline. Its energy value relative to gasoline is thus an important consideration in assessing its cost. The energy content per liter of ethanol is about 63% that of gasoline. However, ethanol engines operate with higher thermodynamic efficiencies than gasoline engines (due primarily to higher compression ratios). Thus, overall, 1.19 liters of ethanol will carry an autombile as far as one liter of gasoline [100]. The cost of ethanol required to compete with gasoline on this basis under different crude oil prices are shown in Table 5.2.

Costs with current technology. Several estimates of the installed unit capital cost for Brazilian autonomous ethanol distilleries are shown in Fig. 5.8 and Table A.7. At a typical Brazilian distillery today, capital accounts for 1/5 of the total cost of ethanol (Fig. 5.9). The sugarcane feedstock (at $10 per delivered tonne) accounts for 2/3 of the total, assuming production of 73.6 liters of ethanol from one tonne of cane. The more efficient mills in Brazil can reach 80 liters/tc [93], which would bring the total cost of ethanol to $10.1/GJ ($0.22/lit) from the $10.6/GJ ($0.23/lit) shown in Fig. 5.9. With yields of 74 to 80 lit/tc, mills would produce ethanol competitively with gasoline when the price of crude oil is about $30 per barrel or higher (Table 5.2).

The costs calculated here are consistent with a number of evaluations of the cost of ethanol production under the Brazilian program (Table 5.3). Taken together, these suggest an average production cost of $0.22 to $0.26 per liter ($10.0 to $11.8 per GJ), corresponding to an equivalent crude oil price of $30 to $35 per barrel (Table 5.2). Costs have been falling about 4% per year since the inception of the program [93,134], due in part to more efficient distillery operation (increased liters of ethanol per tc), but more importantly to increased productivity of land (tc/ha). A continuation of this rate of cost reduction is feasible over the next several years [93]. Nevertheless, under present conditions, the average cost of ethanol in Brazil does not appear to be competitive on a strict cost basis with gasoline unless crude oil prices are above $30 per barrel.

The cost of delivered cane is the single most important factor determining the cost of ethanol. Cane growing, harvesting and transporting costs vary significantly from one region of the world to another. Brazilian costs are among the lowest because of the large scale of production, relatively low-cost labor, and the emphasis that has been placed on cane varieties and cultivation practices to maximize yield [98]. Cane costs in Brazil are not expected to escalate (and may even decline) in the future, if harvesting practices shift toward greater mechanization with higher-paid labor [93].Fig. 5.11 shows the total cost of ethanol and the fraction due to cane costs as a function of cane cost.

Costs considering cogeneration potential. One strategy increasingly being considered for improving the competitiveness of cane ethanol is to make more efficient use for electricity generation of the fiber derived from cane. Most distilleries today use bagasse as a boiler fuel to cogenerate enough steam and electricity for on-site use. No distillery uses the tops and leaves of the cane for any purpose today. By reducing distillery energy demands and adopting more efficient cogeneration technology, on-site energy demands can be met while producing a large surplus of bagasse that can be used in the cogeneration plant to produce additional electricity that can be exported to the national grid. The tops and leaves of the cane can be collected and used in the non-milling season to continue generating electricity for sale to the utility. The electricity revenues can be credited against the cost of ethanol production to the extent that the price paid by the utility for the exported electricity exceeds the cost of electricity generation.

A recent study [50] illustrates the possibilities assuming that a cogeneration facility operates as a distinct economic entity from the distillery (Fig. 5.11). The distillery sells all its bagasse to the cogenerator at an agreed upon price and also receives steam and electricity to meet on-site needs. The cogenerator also purchases tops and leaves from the distiller or a third party (e.g. the farmer) to use as fuel during the period of the year when bagasse is unavailable. The ethanol production cost will decrease with the price the cogenerator pays for bagasse and the tops and leaves, assuming the distiller takes the revenues as a credit against the cost of ethanol. The cost of cogenerated electricity increases correspondingly.

Results of a detailed analysis [50,94] are shown in Fig. 4.18b, based on Brazilian conditions and assuming the use of three different cogeneration technologies. With state-of-the-art steam turbine technology (CEST), ethanol costs can be reduced to levels competitive with gasoline, but the cost of exported electricity would not be competitive with most central station alternatives. The use of advanced gas turbine cogeneration technologies (BIG/STIG and BIG/ISTIG, see Sec. 4.2.5) could also lead to ethanol production costs substantially lower than today's level, and simultaneously to electricity production costs that would be competitive in many cases with central station alternatives.

5.2.3. Social Impacts of Ethanol from Cane in Brazil

The Brazilian PROALCOOL program has been considered successful in achieving three of its major initial goals: reduced dependence on foreign oil, increased employment, and expanded capital goods (distillery equipment) production capabilities in Brazil [93]. Its success in creating jobs has been debated, and concern has been raised about land use conflicts.

On the basis of the number of jobs created, the PROALCOOL program has been a success. It is estimated that the current national production of ethanol, some 12 billion liters per year, supports about 700,000 jobs [93], with the labor intensity of the industry being much greater in the Northeast than in the South-Central region (Table 5.4). The capital invested to create these jobs--some $32,000 per job in the South-Central region and $8,200 per job in the Northeast--has been relatively small compared to other industries [96]. The average for all industry in Brazil is some $53,000; for the paper and pulp industry, $88,000; and for petrochemicals, $250,000.

The quality of jobs created by the PROALCOOL program has been debated. The large component of required seasonal labor has led in some cases to low wages, poor working and living conditions, and a lack of social benefits for workers [96]. Conditions have been particularly poor in Brazil's Northeast. On the other hand, the quality of sugarcane industry jobs relative to those in other sectors does not appear too poor [93]:

within the state of Sao Paulo wages are higher for workers than those of 80% of workers in other agricultural, forestry, and fishing jobs, 50% of workers in the service sector, and 40% of workers in industry. Also sugar and ethanol producers are making efforts to improve job quality further. One strategy being pursued by a few distillers to help alleviate seasonal labor requirements has been to extend the harvest period from six to eight or nine months by planting cane varieties that mature at different times [96]. (The extended season also increases the annual output of the distillery and thereby increases the effectiveness of capital utilization.) In the Northeast region, legislation has been enacted to funnel 1% of the net sugar cane price and 2% of the net ethanol price into health and education benefits for workers [93].

The use of land for fuel versus food is often argued in and out of Brazil. Some 4.3 million hectares are currently planted with sugar cane in Brazil [101], compared to a total crop area of some 52 million hectares [102] and a total potential agricultural area of 520 million hectares [103]. About half the cane area is devoted exclusively to ethanol production [93]. Many analysts appear to agree that cane production has not displaced domestic crop production [96,93,103]. On the other hand, production of export crops such as soybeans has been growing faster than domestic crops, due to agricultural pricing policies that make export crop production more attractive to farmers [103]. One analyst has thus suggested renaming this issue the food versus fuel versus export issue [96].

5.3. Ethanol from Lignocellulose

In the US, commercial production of ethanol from corn is ongoing. Costs for producing fuel-ethanol from corn are relatively high, primarily because of high feedstock costs [104,81]. Large government subsidies make ethanol cost-competitive to consumers as an octane-enhancing additive to gasoline. The high cost of corn has motivated efforts to convert lower-cost biomass, primarily woody and herbaceous materials, into ethanol. These feedstocks are less costly largely because they do not compete as food crops. However, the same reason that they are not considered for animal or human consumption (indigestability), makes them more difficult (and to date more costly) to convert into ethanol.

5.3.1. Fundamentals

Woody and herbaceous biomass, referred to generally as lignocellulosic materials, consist of three chemically-distinct components: cellulose (about 50%), hemicellulose (25%), and lignin (25%) [105]. Cellulose consists of a crystalline lattice of long chains of glucose molecules. Its crystalline structure makes it difficult to unbundle into simple sugars. Once they are produced, however, the sugars are relatively easily fermented into ethanol. Hemicellulose consists of polymers of the 5-carbon sugar, xylose. Unlike cellulose, hemicellulose is relatively easily broken down into simple sugars, but the xylose sugars are difficult to ferment. Lignin is made up of phenols, not sugars, and therefore cannot be fermented to ethanol.

A number of alternative process routes have been tested or proposed for converting lignocellulose into ethanol [105]. Most proposed processes involve separate processing of cellulose, hemicellulose, and lignin (Fig. 5.12). In the first step, pretreatment, the hemicellulose is broken down into its component sugars and separated out. The lignin is also removed. The xylose is typically either converted into furfural, a saleable by-product, or combined with the lignin and used as fuel for meeting the plants energy requirements. The cellulose is treated in either an acid or enzyme-catalyzed hydrolysis (adding water) process to convert it into fermentable glucose. Following fermentation the products are distilled into ethanol.

Depending on the production process, a number of different by-products can be co-produced with the ethanol. The most important of these are furfural and electricity. The revenue derived from sale of these by-products reduces ethanol cost when they are taken as a credit against the cost of ethanol production.

5.3.2. Acid Hydrolysis

Technologies. Acid hydrolysis is essentially a commercial technology [106], with commercial installations having been built as long ago as the 1930s. Ongoing R&D efforts are directed toward improving the technology, which is not economically viable under present market conditions. A number of variants on the basic process have been proposed, each typically involving use of a different acid and/or reactor configuration [81,106,107,108]. Fig. 5.13 shows one system incorporating two stages of hydrolysis using dilute sulfuric acid.

In the hydrolysis step, the acid attacks the feedstock to break it down into simple sugars. Traditionally-used acids will also attack and degrade some of the product sugars so that they cannot be fermented, which reduces overall yield. Thus, much R&D effort has been aimed at improving the relatively low yields (55% to 75% of the cellulose) achievable with currently available technology based on dilute sulfuric acid [105]. Several acids have been identified that can achieve higher yields [106,81]. Typically, large amounts of inexpensive acids, e.g. concentrated H_2SO_4, or smaller amounts of more costly acids, e.g. HF, are needed. In either case low-cost recovery and reuse of the acids is necessary to keep production costs down [106]. Recycling of acids is challenging, in part because of their corrosive nature, and has yet to be proven commercially viable.

Costs. Traditional dilute sulfuric acid hydrolysis technology is relatively capital intensive and modestly scale sensitive (Fig. 5.14 and Table A.8). The maximum overall efficiency of converting energy in the biomass feedstock into ethanol using dilute H_2SO_4 or other processes that have been proposed is only about 30%. Thus, the estimated total cost of ethanol produced by different proposed acid hydrolysis processes is relatively high (Fig. 5.15).

Ethanol produced by the dilute-H_2SO_4 process becomes more competitive when furfural production from the hemicellulose fraction is maximized [107,108], and the revenues from the sale of furfural are credited against the cost of ethanol production (Fig. 5.16). The size of the market for furfural is small compared to the volume that would be produced by a large-scale fuel-ethanol industry, however, so that in the long-term furfural revenues will not provide the basis for economic sustainability of an acid hydrolysis ethanol industry.

By-product electricity could be another potentially important revenue source to off-set ethanol costs, but the amounts of exportable electricity co-produced in process configurations proposed to date are relatively small. This situation might change if more advanced cogeneration technologies are considered. For example, the gas turbine technologies discussed in Sec. 5.2 in connection with ethanol production from sugarcane (see also Sec. 4.2.5) may be able to produce much larger quantities of exportable electricity than is the case with acid hydrolysis plants proposed to date. No evaluation of such high-efficiency cogeneration has been undertaken.

Unless world oil prices rise considerably (over $40 per barrel), ethanol from acid hydrolysis appears to be an unpromising technology, particularly in light of promising developments in enzymatic hydrolysis.

5.3.3. Enzymatic Hydrolysis

Technology. Enzymatic hydrolysis has been under development for about 2 decades. Advances that have been made in the technology specifically and in biotechnology more generally suggest economically-competitive commercial systems could be developed by the year 2000.

In enzymatic hydrolysis, biological enzymes essentially take the place of acid in the hydrolysis step. The additional step of enzyme production is also included in the process. Enzymes typically act only to break down the cellulose and do not attack the product sugars. Thus, in principle, yields near 100% from cellulose can be achieved. Typically a feedstock pretreatment step is required since biomass is naturally resistant to enzyme attack. The most promising of several options for pretreatment appears to be treatment by a dilute acid [109], in which the hemicellulose is converted to xylose sugars that are separated out, leaving a porous material of cellulose and lignin that can more readily be attacked by enzymes [81]. A number of bacteria and yeasts have been identified and tested as catalyzers of cellulose hydrolysis, and several variants of the basic process have been proposed. Three process configurations (SHF, SSF, and DMC--see following) have received the most attention from researchers. Improving the fermentation of xylose is also receiving attention.

In the separate hydrolysis and fermentation (SHF) of cellulose, three separate operations are used to produce enzymes, hydrolyze cellulose, and ferment the glucose (Fig. 5.17a). The presence of glucose produced during hydrolysis slows or stops the catalytic effect of enzymes typically used in SHF processes. This end-product inhibition limits glucose yields and hydrolysis reaction rates and leads to higher enzyme consumption, all of which contribute to relatively high costs of ethanol production (see below). Some enzymes have been identified which are less susceptable to end-product inhibition, but the improvement in overall economics of the SHF process are relatively modest [105].

A more promising modification of the SHF process involves continuously removing the glucose during hydrolysis by simultaneously hydrolyzing and fermenting in the same reactor (Fig. 5.17b). This simultaneous saccharification and fermentation (SSF) improves the economics substantially over SHF processes because it permits more complete hydrolysis of the cellulose (higher product yields) at higher rates, and a single reactor vessel replaces two [110]. This currently appears to be the most promising route to achieving reasonable economics in converting cellulose to ethanol.

There have been some efforts to combine enzyme production, cellulose hydrolysis and glucose fermentation in a single reactor--direct microbial conversion (DMC) (Fig. 5.17c) [81,111]. In limited efforts to date, ethanol yields have been lower than for the SHF or SSF processes, and a number of undesired products in addition to ethanol have been produced.

The xylose fraction of biomass contains 30% to 60% of total fermentable sugars in biomass [112], but yeasts and bacteria used in SSF processes cannot ferment xylose sugars to ethanol. The single most important factor that can increase the yield of ethanol from biomass, therefore, is xylose fermentation. Recent research has identified alternative yeasts, bacteria, fungi, and enzymes that can ferment xylose [113]. Incorporating xylose fermentation with SSF cellulose fermentation promises signficant reductions in the cost for ethanol from biomass [114], as discussed further below.

Costs. Captital cost estimates for several enyzmatic hydrolysis processes are shown in Fig. 5.18 and Table A.9. The SHF process is relatively costly due in large part to low ethanol yields (25% of energy in feedstock converted to ethanol). Capital costs for the SSF process are substantially lower, due to improved yields. The most recent estimate is for about a 40% increase in yield over the SHF process. Two estimates of SSF capital costs are shown, one made in 1987 and one in 1991, giving some indication of the rate of R&D progress with the technology. Fig. 5.18 also shows that scale economies could be exploited to reduce SSF costs further. The next anticipated advancement is increased xylose conversion to ethanol, which could drop the capital costs to much lower levels (Fig. 5.18). The projected total conversion efficiency with improved xylose fermentation is about 64% (from Table A.9). If this target can be achieved at a commercial scale, hydrous ethanol from enzymatic hydrolysis would cost \$6 to \$6.5/GJ, which would be competitive with gasoline when the crude oil price is \$20 per barrel or higher (Table 5.2). Most of the cost would be in the feedstock (Fig. 5.20). Thus, improvements in conversion efficiencies (feedstock energy to ethanol energy) beyond the projected 64% could lead to further significant decreases in ethanol cost.

6. Summary

The emphasis in this report has been on calculations of the costs of alternative modern energy carriers derived from biomass. Calculated costs may differ significantly from actual costs in any particular application, because assumed conditions may differ from actual conditions. Nevertheless, the consistent set of assumptions applied in this study to all reported capital and operating costs provides a basis for making comparisons among different energy carriers and for drawing some general conclusions.

Table 6.1 draws together cost estimates from this report.[23] This summary is intended to be representative, but not exhaustive. All costs assume a 7% discount rate, \$2/GJ for biomass fuel, and characteristic capacity utilization rates for applications of the individual technologies. (See specific relevant sections of this report for details in any particular case.) Several levels of technological maturity are reflected in the different estimates shown: (E) indicates costs based on reported experiences; (CR) indicates costs based on engineering-design studies of commercially-ready technology that has yet to be commercially implemented; (NC) indicates near-commercial technology that could become available within about 5 years; and (Y2) indicates technology that could become available about the year 2000 with concerted RD&D efforts. The following conclusions are supported by Table 6.1 and earlier analysis:

- Among gas generating technologies, biogas systems are an order of magnitude more capital-intensive than producer gas systems. However, at an equivalent production capacity of 1000 GJ/yr, producer gas and biogas are about equal in cost due to the high feedstock cost for producer gas.

- At the very small scale (less than 20 GJ/yr), biogas may be more costly than producer gas, but the health and fertilizer benefits of biogas technology are not included in the biogas cost. The costs shown in Table 6.1 are based on floating cover digesters, capital costs for which could be reduced by 40% or more. The lower capital cost would lead to an important reduction in the total cost of gas for small units, but would provide relatively less cost reduction for larger units, for which operation and maintenance are the most important cost components.

- Electricity from IC engine systems fueled with biogas or larger-sized producer gas systems may be marginally competitive with central station options, if the costs of transmission and distribution are appropriately included in the central station generation costs. The cost of producer-gas electricity is very sensitive to the assumed cost of biomass.

- Electricity production using direct-combustion steam-turbine systems is a well-

[23] Where blanks are shown in Table 6.1, no costs were estimated in this study.

proven and relatively widely utilized technology. However, it is relatively capital intensive and inefficient, particularly at smaller scale. At stand-alone power plants, the electricity would generally not be cost-competitive with most traditional large central station power options. Cogeneration operation would convert more of the biomass into a useful product, and electricity could be generated competitively in many cases with central station power.

- Larger-scale gas turbine-based electricity technology that is nearing commercial readiness would be competitive with the busbar cost of most large scale central station power plants. Future advances in the technology would reduce gas turbine electricity costs still further. The lower total costs for gas turbine electricity in Table 6.1 represent generating costs in cogeneration applications. The higher costs are for stand-alone power generation.

- With commercially available technologies, no alcohol fuels from biomass are cost-competitive with gasoline, with oil prices below about \$30/bbl.

- For methanol costs to fall to the lowest level indicated in Table 6.1 will require very high biomass conversion efficiencies that have yet to be demonstrated at any scale, as well as very large-scale production facilities.

- With future technology, both ethanol from sugarcane (under Brazilian conditions) and ethanol by enzymatic hydrolysis could become competitive with oil at \$20/bbl or less. For cane-ethanol, this would be accomplished by cogenerating electricity on-site using biomass-gasifier/gas turbine technology and crediting electricity revenues against the cost of ethanol production. With enzymatic hydrolysis, expected advances in technology for fermenting the xylose fraction of biomass integrated with current technology for simultaneous saccharification and fermentation of cellulose would lead to the indicated cost reductions.

Table 1.1. Alternative upgraded forms of biomass energy. Those marked with an asterisk are addressed in this report.

Processed Solids
- Densified biomass
- Charcoal

Gases
- * Biogas
- * Producer gas
- Hydrogen

Liquids
- * Methanol
- * Ethanol by direct fermentation
- * Ethanol by hydrolysis/fermentation
- Vegetable oils
- Pyrolysis oils

Electricity/Shaft Power
- Via direct combustion
  - * Steam turbines
  - Steam engines
  - Stirling engines
- With intermediate gas production
  - * Gas-fired internal combustion engines
  - * Gas turbines
  - Fuel cells

Table 2.1. Chemical characteristics of various biomass feedstocks compared with some coals.

	Proximate Analysis Volatiles	Fixed Carbon	Ash	Ultimate Analysis C	H	N	S	O	Ash	Higher Heating Value, MJ/kg
Biomass										
Douglas Fir										
wood	86.2	13.7	0.1	52.3	6.3	0.1	0.0	40.5	0.8	21.0
bark	70.6	27.2	2.2	56.2	5.9	0.0	0.0	36.7	1.22	22.0
Eucalyptus grandis	82.6	16.9	0.5	48.3	5.9	0.15	0.01	45.1	0.4	19.4
Poplar	82.3	16.4	1.3	48.5	5.9	0.47	0.01	43.7	1.4	19.4
Leucaena	80.9	17.5	1.5	49.2	6.1	0.47	0.03	42.7	1.5	19.1
Sawmill waste										
redwood shavings	76.2	23.5	0.3	53.4	6.0	0.1	0.1	39.9	0.6	21.3
oak chips	74.7	21.9	3.3	49.5	5.7	0.2	0.0	41.3	3.3	19.2
Sugar cane bagasse	74.0	23.0	3.0	45.0	6.0	0.2	0.0	46.0	3.0	19.1
Rice hulls	65.5	16.7	17.9	41.0	4.3	0.4	0.02	35.9	18.3	16.1
Rice straw (fresh)	69.3	17.3	13.4	41.8	4.6	0.7	0.08	36.6	15.9	16.3
Corn cobs	80.1	18.5	1.4	46.6	5.9	0.47	0.01	45.5	1.4	18.8
Cattle manure[b]	-	-	-	45.4	5.4	1.0	0.3	31.0	15.9	17.4
MSW[c]	65.9	9.1	25.0	47.6	6.0	1.2	0.3	32.9	12.0	19.8
Coals										
Texas Lignite	38.9	44.5	16.6	65.1	4.8	1.1	1.2	16.9	10.8	24.3
Illinois No.6	35.7	54.3	10.0	68.0	5.2	1.2	3.8	9.8	12.0	29.6

(a) From [21] and [115] for oven-dry biomass, unless otherwise noted.

(b) Fresh manure from feedlot cattle.

(c) Municipal solid waste typically found in the USA in 1970.

Table 2.2. Typical bulk densities of biomass materials,[a] and coal.[b]

Type	Form	Bulk Density (kg/m^3 dry basis)
Straw and stover	loose	20-40
	chopped	40-80
	baled	110-200
	moduled	96-128
	hammermilled	40-100
	cubed	320-640
	pelleted	560-720
Wood		
hardwood	chips	224
softwood	chips	176-192
wood	pellets	560-608
	sawdust	160
	planer shavings	96
Orchard prunings	hammermilled	140-200
Municipal solid waste		
Refuse-derived fuel	12.7-mm pellets	575
Refuse-derived fuel	25.4-mm pellets	432
Coal		
Bituminous	crushed	1100

(a) Biomass figures from [115].

(b) Coal figure from [115a].

Table 2.3. Illustrative rates of biomass use or production today.

Biomass type	Rate (MW) of biomass consumption or production
Fuelwood for rural developing-country household cooking[a]	0.001 - 0.004
Sawdust/wastewood produced at Indonesian plywood mills[b]	0.055
Rice hulls at typical rice mills in Thailand[c]	0.200
Cane input to Brazilian autonomous ethanol distilleries[d]	100 - 200
Bagasse production at cane sugar mills[e]	up to 350
Hog fuel and black liquor production at modern kraft pulp mill[f]	350 - 400

(a) From Fig. 3-1 in [116], showing per-capita energy use in village households in developing countries ranging from about 5 GJ/yr to 20 GJ/yr.

(b) Based on [117].

(c) Average of some 40,000 mills in Thailand [118], assuming a 3 month milling season.

(d) For distilleries producing 120,000 liters/day to 240,000 liters/day, assuming 70 liters per tonne of cane.

(e) The average bagasse production capacity and reported total number of factories in some major cane producing countries are [119]: China, 16 MW (150 factories); India, 58 MW (296 factories), Brazil, 88 MW (450 factories); Mexico, 150 MW (84 factories); and Thailand, 320 MW (39 factories).

(f) From [51], for a mill in the Southeastern US with a production capacity of 1000 tonnes of air-dried pulp per day. Approximately 3/4 of the available biomass energy is in the form of black liquor, a lignin-rich product of cellulose extraction.

Table 3.1. Estimated costs of Eucalyptus from commercial plantations in Brazil.

	\$ per oven dry tonne[a]	
	Low estimate	*High estimate*
Production cost[b]		
Establishment		
Nursery Production	0.78	0.78
Planting	3.20	7.09
Land rent	0.62	1.85
Maintenance		
Management	0.33	0.33
Cultivation	1.64	1.64
Research	0.62	0.62
Subtotal	*7.19*	*12.31*
Harvest/transport[c]	14.71	14.71
Chipper/conveyor	3.15	3.15
Storage/drying		
Storage	6.77	6.77
Drying	11.08	11.08
Subtotal	*17.85*	*17.85*
Total (\$ per oven dry tonne)	*42.9*	*48.0*
Total (\$ per GJ)	*2.1*	*2.4*

(a) Production, harvesting and transport costs are based on [3] for plantations currently operated by several forest-products and charcoal industries. Chipping, drying and storage costs are estimated for US conditions [45].

(b) The levelized production cost is given by: $[\mathrm{CRF}(i,N)\cdot E + i\cdot L + M]/Y_L$, where i = discount rate = 0.07; N = plantation life = 18 years; $\mathrm{CRF}(i,N)$ = capital recovery factor = $i/[1-(1+i)^{-N}]$ = 0.0994; t = rotation period = 6 years; L = land price; E = plantation establishment cost; M = annualized maintenance cost; Y_L = levelized yield = $\mathrm{CRF}(i,N)\cdot\sum Y_t\cdot(1+i)^{t}$; Y_t = yield at each harvest.

High and low estimates of land prices (L) are \$108/ha and \$324/ha. The land rent is $(i\cdot L)$. The establishment cost includes \$97/ha for nursery production and high and low planting costs of \$396/ha and \$876/ha. The annualized maintenance cost is \$31.6/ha, which includes: (i) startup management costs of \$20.3/ha and \$2.1/ha/yr in years 1-18; (ii) cultivation costs of \$20.2/ha/yr in years 1-18; and (iii) research costs (to improve future productivity) of \$7.6/ha/yr in years 1-18. The total yield at successive harvests is estimated to be 97.3, 87.6, and 70.0 dry tonnes per hectare, respectively, corresponding to a levelized yield of 12.4 t/ha/yr. This corresponds to an actual average yield of 14.1 t/ha/yr. For comparison, Carpentieri [3] estimates average yields to be 12.3 t/ha-yr in the Northeast of Brazil and 15.3 t/ha-yr in the state of Minas Gerais, which contains most existing plantations in Brazil today. [In experimental plantations, yields as high as triple today's averages have been achieved in the Northeast of Brazil, where soil and climate are not as well suited to tree production as in the Southeast and South regions].

(c) Harvesting costs are \$1421/ha for the first-rotation, \$1280/ha for the second rotation, and \$1026/ha for the final harvest. The harvested wood dries in air to about 33% moisture before it reaches the user. The transport cost assumes a 70 km haul.

(d) For 6 months of storage, with the wood covered by heavy polyethylene film and drying with an unheated forced-air system.

Table 4.1. Electricity generating plants burning biomass fuels in the United States as of 1989.[a]

	Number of facilities		Installed capacity (MW)		
State	*Stand-alone*	*Cogeneration*	*Stand-alone*	*Cogeneration*	*Total*
Alabama	0	15	0	375	375
Arkansas	1	4	2.4	10	12
Arizona	2	0	45	0	45
California	64	30	736	255	991
Connecticut	4	3	155	14	169
Delaware	1	0	13	0	13
Florida	12	15	314	474	788
Georgia	0	5	0	36	36
Hawaii	2	13	70	129	199
Iowa	2	1	11	2.2	13
Idaho	1	6	0.2	116	116
Illinois	0	1	0	2	2
Indiana	0	7	0	36	36
Kentucky	1	1	1	1	2
Louisiana	1	12	11	300	311
Massachussetts	2	9	38	252	290
Maryland	2	2	214	94	308
Maine	4	22	88	704	792
Michigan	3	13	78	247	325
Minnesota	3	23	63	161	224
Missouri	0	2	0	60	60
Mississippi	0	10	0	230	230
Montana	2	17	18	340	358
North Carolina	3	27	60	351	411
New Hampshire	3	5	15	65	80
New Jersey	2	0	14	0	14
New York	11	17	154	425	579
Ohio	1	6	17	90	107
Oklahoma	2	1	8	17	25
Oregon	3	24	69	185	254
Pennsylvania	0	9	0	144	144
South Carolina	1	13	49	46	95
Tennessee	2	12	6	43	49
Texas	1	9	2	146	148
Utah	0	1	0	20	20
Vermont	5	3	80	218	298
Virginia	0	9	0	136	136
Washington	3	11	72	120	192
Wisconsin	5	9	55	117	172
US TOTAL	149	367	2459	5962	8421

(a) Based on [138]. The total here is an underestimate, because the directory from which the data were taken is incomplete.

Table 4.2. Global residue production rates.[a]

	10^9 GJ/year
Forest Products Industries	
Kraft Pulp	
Hogfuel	0.7
Black Liquor	2.7
Forest Residues	0.8
Subtotal	**4.2**
Sawnwood and Wood Panels	
Mill Residues	3.6
Forest Residues	6.2
Subtotal	**9.8**
Agricultural Industries	
Sugar Cane	7.6
Wheat	12.9
Rice	10.6
Maize	7.3
Barley	3.8
Subtotal	**42.2**
Total	**56.2**

(a) From [120].

Table 4.3. Comparative performance and capital cost of biomass-gasifier/gas turbine systems and condensing-extraction steam turbine systems for cogeneration of steam and electricity. [a]

	Cogeneration Performance				***Full Electricity Performance***		***Installed Capital Cost***[e]
	Electricity		*Maximum Process Steam*				
	(MW)	(%Effic.)	(kg/hr)	(%Effic.)	(MW)	(%Effic.)	(1990 $/kW)
15% mc Fuel							
BIG/ISTIG[b]							
LM-8000	97	37.9	76,200	25.4	111.2	42.9	890
BIG/STIG[b]							
LM-5000	39	31.3	47,700	30.0	53	35.6	1150
LM-1600	15	29.8	21,800	33.8	20	33.0	1420
LM-38	4	29.1	5,700	32.4	5.4	33.1	1900
50% mc Fuel							
BIG/STIG[c]	38.3	29.5	47,700	28.9	52.3	33.5	1250[f]
CEST[d]	37	10.0	319,000	52.1	77	20.9	1560

(a) From [51]. All efficiencies are based on the higher heating value of the fuel. The indicated fuel moisture contents (MC) of 15% and 50% are fractions of the wet weight of the biomass.

(b) The BIG/ISTIG and BIG/STIG technologies are biomass-gasifier/intercooled steam-injected gas turbines and biomass-gasifier/steam-injected gas turbines, respectively.

(c) The lower efficiencies and slightly lower electricity production compared to the case with 15% mc fuel reflect the estimated energy use associated with drying the fuel to 15-20% mc. The drying technology considered here consumes high-pressure steam to provide the heating and evolves low-pressure saturated steam from the drying biomass. The low pressure steam can be used to meet process needs on-site. Thus, the energy penalty for drying with this technology is relatively modest.

(d) This is a double-extraction/condensing steam turbine, with assumed boiler efficiency 68%, feedwater temperature 182°C, turbine inlet steam conditions 6.2 MPa, 400°C. Maximum process steam corresponds to operation with minimum flow to the condenser. Saturated process steam conditions are 12.9 bar (119 t/hr) and 4.4 bar (300 t/hr). Maximum electricity corresponds to minimum required extraction of 72 t/hr of saturated steam at 4.4 bar.

(e) The unit installed costs for the BIG/ISTIG, BIG/STIG and CEST are given by the following equations (Larson, 1990a): $(\$/kW)_{ISTIG} = 2516(MW)^{-0.22}$, $(\$/kW)_{STIG} = 2746(MW)^{-0.22}$, and $(\$/kW)_{CEST} = 6279(MW)^{-0.32}$.

(f) Includes $86/kW for a steam-based drier (see note c above).

Table 4.4. Economics of excess electricity production at a hypothetical kraft pulp mill with production capacity of 1000 tonnes of air-dried pulp per day.[a]

Fuels and Cogeneration Technologies	*Utility Ownership*[b] (Busbar Cost, cents per kWh) Capital	O&M	Fuel[d]	TOTAL	*Private Ownership*[c] (Internal rate of return)	*Electricity* *Sales* (GWh/ year)	*Revenues* @ \$0.05c/kWh (\$/tp)[e]
Black liquor							
+ *hog fuel*							
CEST	5.98	0.72	0.0	6.7	2.8	113	16
BIG/STIG	1.64	0.72	0.56	2.9	18.7	417	60
BIG/ISTIG	1.32	0.60	0.43	2.4	25.1	546	78
+ *Forest residues*							
(low-cost case)							
CEST	3.25	0.72	2.00	6.0	2.7	275	39
BIG/STIG	1.38	0.72	1.53	3.6	16.1	683	97
BIG/ISTIG	1.16	0.60	1.20	3.0	18.1	866	124
(high-cost case)							
CEST	3.25	0.72	3.00	7.0	neg.	275	39
BIG/STIG	1.38	0.72	1.92	4.0	13.5	683	97
BIG/ISTIG	1.16	0.60	1.51	3.3	20.6	866	124

(a) From [51]. All costs are given in 1990 US\$.

(b) Assuming a 7% discount rate, an insurance charge equal to 0.5% of the initial capital cost per year and a 30-year life. No taxes or tax incentives are considered.

(c) Real (inflation-corrected) internal rate of return before taxes, assuming a 25-year life, an insurance charge equal to 0.5% of the initial capital cost per year, and electricity revenues of 5 cents per kWh.

(d) Fuel costs for CEST are assumed zero for hog fuel and black liquor. For BIG/STIG and BIG/ISTIG, \$1/GJ is charged for hog fuel for drying and other pre-gasification handling. No charge for black liquor. The low and high forest-residue costs are assumed to be \$3/GJ and \$4/GJ charged to the gas turbine systems, respectively. CEST charges are \$2/GJ and \$3/GJ. The lower costs for CEST account for less required pre-processing (e.g. drying).

(e) Dollars per tonne of air-dried pulp.

Table 4.5. Potential electricity production at sugarcane processing facilities at the 1987 level of cane production in all cane growing developing countries compared to electricity production from all sources in those countries in 1987.[a]

	1987 Cane Production (10^6 t/yr)	Potential Electricity from 1987 cane crop (10^6 kWh/yr)	1987 actual electricity Production from all sources (10^6 kWh/yr)
India	182.48	161.49	217.50
China	52.55	46.51	497.30
Pakistan	31.70	28.06	28.40
Thailand	24.45	21.64	29.99
Indonesia	21.76	19.26	34.81
Philippines	13.33	11.80	23.85
Bangladesh	6.90	6.11	5.90
Vietnam	6.60	5.84	5.20
Burma	3.28	2.90	2.28
Iran	1.15	1.02	36.80
Malaysia	1.15	1.02	16.22
Sri Lanka	0.80	0.71	2.71
Nepal	0.62	0.55	0.54
Kampuchea	0.21	0.19	-
Laos	0.11	0.10	0.88
ASIA	347.09	307.17	902.38
Brazil	273.86	242.37	202.29
Colombia	24.97	22.09	35.37
Argentina	14.00	12.39	52.17
Peru	5.95	5.27	14.20
Venezuela	7.00	6.19	50.21
Ecuador	5.20	4.60	5.67
Guyana	3.30	2.92	-
Paraguay	3.19	2.82	2.83
Bolivia	2.73	2.42	1.50
Uruguay	0.65	0.58	4.53
Suriname	0.11	0.10	-
SOUTH AMERICA	340.96	301.75	368.77
Cuba	65.60	58.06	13.20
Mexico	42.56	37.67	104.79
Dominican Republic	8.60	7.61	5.00
Guatemala	6.90	6.11	2.08
El Salvador	3.18	2.81	1.89
Honduras	3.00	2.66	1.81
Costa Rica	3.00	2.66	3.13
Haiti	3.00	2.66	0.45
Nicaragua	2.58	2.28	1.24
Jamaica	2.01	1.78	2.39
Panama	1.60	1.42	2.85
Trinidad & Tobago	1.24	1.10	3.30
Belize	0.86	0.76	0.08
Guadaloupe	0.75	0.67	-
Barbados	0.73	0.65	0.43
St. Kitts Nevis	0.25	0.22	-
Martinique	0.25	0.22	-
Bahamas	0.24	0.21	-
CENTRAL AMERICA	146.35	129.53	142.64

(table continues on following page)

Table 4.5 (continuation)

	1987 Cane Production (10^6 t/yr)	Potential Electricity from 1987 cane crop (10^6 kWh/yr)	1987 actual electricity Production from all sources (10^6 kWh/yr)
South Africa	20.00	17.70	122.30
Egypt	9.50	8.41	32.50
Mauritius	6.23	5.51	0.49
Sudan	5.00	4.43	1.06
Swaziland	4.00	3.54	-
Kenya	4.00	3.54	2.63
Zimbabwe	3.80	3.36	7.01
Reunion	2.11	1.87	-
Madagascar	1.80	1.59	0.50
Ivory Coast	1.75	1.55	2.20
Ethiopia	1.65	1.46	0.81
Malawi	1.60	1.42	0.58
Nigeria	1.55	1.37	9.91
Cameroon	1.28	1.13	2.39
Zambia	1.25	1.11	8.48
Zaire	1.09	0.97	5.30
Tanzania	1.08	0.95	0.87
Morocco	0.80	0.71	8.32
Senegal	0.70	0.62	0.75
Mozambique	0.67	0.59	0.50
Uganda	0.60	0.53	0.66
Congo	0.51	0.45	0.24
Somalia	0.37	0.33	0.26
Burkina Faso	0.33	0.29	0.13
Angola	0.32	0.29	0.81
Chad	0.29	0.26	-
Mali	0.22	0.19	0.20
Guinea	0.20	0.18	0.50
Liberia	0.16	0.14	0.83
Gabon	0.14	0.13	0.88
Niger	0.11	0.10	0.16
Ghana	0.11	0.10	4.71
Sierra Leone	0.07	0.06	0.20
Rwanda	0.03	0.03	0.17
AFRICA	73.32	64.89	216.35
Fiji	3.49	3.09	0.43
Papua New Guinea	0.23	0.20	1.80
OCEANIA	3.72	3.29	2.23
TOTAL FOR ALL DEVELOPING COUNTRIES	911.50	806.63	1632.37

(a) From [50].

Table 4.6. Projected capital requirements for the power sector in developing countries.[a]

	1980	2000-L[b]	2000-H[b]
Cost for New Generating Capacity ($/kW)			
Hydroelectric	2740	3360	4110
Nuclear	2060	2540	3080
Fossil Fuel, Thermal	1030	1230	1510
Average Capital Requirements by Region ($/kW)			
Industrial Countries			
Generation	1480	2000	2390
T & D	2740	2770	3030
Developing Countries			
Generation	1690	2070	2480
T & D	810	1700	2480
Centrally Planned Economies			
Generation	1370	1810	2320
T & D	1370	1960	2620
Overall Capital Requirements for Electricity [10^9 $/yr (% of GDP)]			
Industrial Countries	226(2.2)	302(2.0)	488(2.7)
Developing Countries	44(1.5)	148(2.6)	381(5.5)
Centrally Planned Economies	60	147	233

Average Growth Rates (%/yr)	1980-2000-L[b]	1980-2000-H[b]
For GDP		
Industrial Countries	2.0	3.0
Developing Countries	3.5	4.5
For Primary Energy Consumption		
Industrial Countries	0.15	1.3
Developing Countries	2.5	4.7
Centrally Planned Economies	1.8	2.3
For Electricity Generation		
Industrial Countries	1.3	2.5
Developing Countries	4.5	6.8
Centrally Planned Economies	2.7	3.2

(a) According to a 1987 World Energy Conference (WEC) study [122].

(b) 2000-L and 2000-H refer to the WEC low and high economic growth scenarios, respectively.

Table 4.7. Reported gas output with temperature for fixed-dome biogas digesters in Hubei province, China during different seasons of the year.[a]

Season	Mean Temperature (°C)	Range of daily gas production (m^3/m^3 of digester)
Winter	6-10	0.05-0.1
Spring	16-22	0.1-0.2
Summer	22-23	0.2-0.33

(a) From [74].

Table 4.8. Comparison of mass of cattle dung and biogas-digester sludge containing equal amounts of nitrogen.[a]

Material	Quantity required (kg) per kg of nitrogen
Cattle dung	340
Cattle dung (dried to 20% of fresh weight)	130
Anaerobically digested cattle dung sludge (wet)	680
Anaerobically digested cattle dung sludge (dried to 10% of wet weight)	80

(a) From [69].

Table 4.9. Die-off of enteric microorganisms of public health significance during anaerobic digestion.[a]

Organism	Temperature (°C)	Digestion Time (days)	% Die-Off
Poliovirus	35	2	98.5
Salmonella ssp.	22-37	6-20	82-96
Salmonella typhosa	22-37	6	99
Mycobacterium tuberculosis	30	Not reported	100
Ascaris	29	15	90
Parasite cysts	30	10	100

(a) From [66].

Table 4.10. Estimated head of cattle required to support given capacities of KVIC-design floating-cover biogas digesters.[a]

Plant Capacity (m^3 gas/day)	Approximate Number Animals Required
2	2-3
3	3-4
4	4-6
6	6-10
8	12-15
10	16-20
15	25-30
20	35-40
25	40-45
35	45-55
45	60-70
60	85-100
85	110-140
140	400-450

(a) From [66].

Table 5.1. Approximate ethanol production rates, mid- to late-1980s in some developing countries.

Country	Ethanol Production (10^6 liters/yr)
South America	
Brazil	11,700
Argentina	380
Colombia	38
Paraguay	26
Latin America	
Costa Rica	31
El Salvador	15
Jamaica	15
Guatemala	0.2
Africa	
Kenya	18
Malawi	11
Zimbabwe	42
Mali	2
Asia and Oceania	
Thailand	203
Phillipines	10
New Zealand	15

(a) From [98].

Table 5.2. Required production cost of ethanol for competition with wholesale gasoline.[a]

Crude Oil Price	Gasoline Price[a]		Equivalent hydrous ethanol price[b]		Equivalent anhydrous ethanol price[c]	
($/bbl)	($/bbl)	($/lit)	($/lit)	($/GJ)[d]	($/lit)	($/GJ)[d]
20	28	0.176	0.148	6.73	0.204	8.71
25	35	0.220	0.185	8.42	0.255	10.91
30	42	0.264	0.222	10.10	0.306	13.09
35	49	0.308	0.259	11.78	0.357	15.27
40	56	0.352	0.296	13.47	0.408	17.45

(a) Gasoline price relative to crude price is based on Brazilian conditions [96].

(b) Assumes 1 liter of hydrous ethanol as a neat fuel is worth 0.84 liters of gasoline [123].

(c) Assumes 1 liter of anydrous ethanol is worth 1.16 liters of gasoline when the ethanol is used as an octane-boosting additive [124].

(d) Higher heating value basis.

Table 5.3. Previous estimates of the cost of ethanol production in Brazil.[a]

	1990 US cents per liter	$/GJ
World Bank, 1984	22.5 - 24.3	10.2 - 11.1
Borges, 1984	20.1 - 27.4	9.1 - 12.5
CENAL, 1984	25.3 - 28.2	11.5 - 12.8
Mello & Pelin, 1984	49 - 56	22 - 25
Comissao Nacional de Energia, 1987	21.3 - 23.1	9.7 - 10.5
Motta, 1987	28 - 44	12.7 - 20

(a) The results of the different studies indicated here are all taken from [134], where they were given in US dollars. The US GNP deflator has been applied to convert the costs into 1990 dollars.

Table 5.4. Employment associated with standard-sized (120,000 liters per day capacity) autonomous ethanol distilleries in Brazil, producing approximately 20 million liters of ethanol per year.[a]

	Total Jobs		Total Labor (person-yrs)	
Type	Central South	North-East	Central-South	North-East
Agricultural				
Permanent	230	890	230	890
Temporary	450	1770	225	885
SUBTOTAL	680	2660	455	1775
Industrial				
Permanent	85	85	85	85
Temporary	125	125	65	65
SUBTOTAL	215	215	150	150
TOTAL	895	2875	605	1925

(a) From [96].

Table 6.1. Comparative summary of calculated costs for modern energy carriers produced from biomass. This table is based on data and analysis in this report. (E) indicates the results are based on operating experiences; (CR) on commercially-ready, but not commercially implemented technologies; (NC) on technologies that are near commercialization; and (Y2) technologies which could become available by the year 2000 with a concerted RD&D effort. All costs are in 1990 US dollars.[a]

	Production capacities		*Installed capital costs*		*Total production costs*[b]	
	10^3 GJ/yr	kW	$ per GJ/yr	$/kW	$/GJ	$/kWh
Biogas						
Domestic (E)	0.016-1.2	0.50-38	30-12	950-375	11-5	
Industrial (E)	3.6-167	114-5290	13-2.5	410-80	1.4-2.5	
Producer Gas[c]						
Small (E)	1-12	32-380	2-0.7	65-20	5-3	
Medium (E)	20-200	634-6340	6-3	190-95	ne	
Large (E)	1420-2840	$45\text{-}90 \times 10^3$	ne	ne	ne	
Electricity						
Steam-turbine (E)		5-50000		1900		0.05-0.07[d]
Biogas-IC engine (E)		5		1200		0.10
Prod. gas-IC eng (E)		5-100		680-420		0.24-0.15
Prod. gas-gas turb (NC)		50000		1150		0.04-0.05[d]
(Y2)		100000		890		0.03-0.04[d]
Methanol						
(CR)	10000	316×10^6	30-50	950-1580	10-13	
(Y2)	10000-40000	316×10^6-1268×10^6	30-12	630-315	5-9	
Ethanol from cane						
(E)	1000	32×10^6	10	315	10	
(Y2)	2000	63×10^6	9	280	8.5[e]	
Ethanol by hydrolysis						
Acid						
(CR)	1000-2000	$32\text{-}63 \times 10^6$	80-60	2520-1890	19-21	
(Y2)	2000	63×10^6	50	1580	15	
Enzymatic						
(NC)	5500-27000	142×10^6	18-27	1260	9-11	
(Y2)	6500-12700	205×10^6	11-15	500	6-6.5	

(a) All figures are approximate for purposes of cross-fuel comparisons. Total production costs assume a 7% discount, $2/GJ for biomass, and capacity utilization rates as discussed in appropriate sections of the report. "ne" indicates that no estimate was made in this study.

(b) Units are $/kWh where the product is electricity and $/GJ where the product is a gas or a liquid.

(c) Wood fuel (not charcoal).

(d) Low cost is for electricity production via cogeneration at industrial sites. High cost is for stand-alone electric power generation.

(e) Assumes use of biomass-gasifier/gas turbine cogeneration, with export of excess electricity, the revenues from which are credited against the cost of ethanol production.

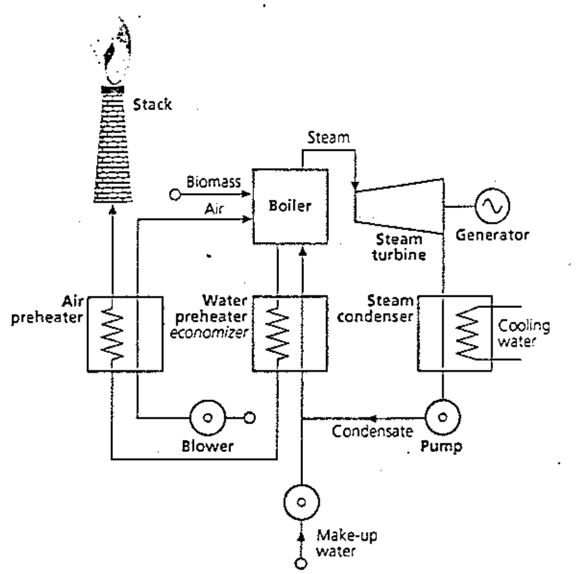


Figure 4.1. Electricity generating system based on direct combustion of biomass, with steam raised in a boiler to drive a fully-condensing steam turbine.

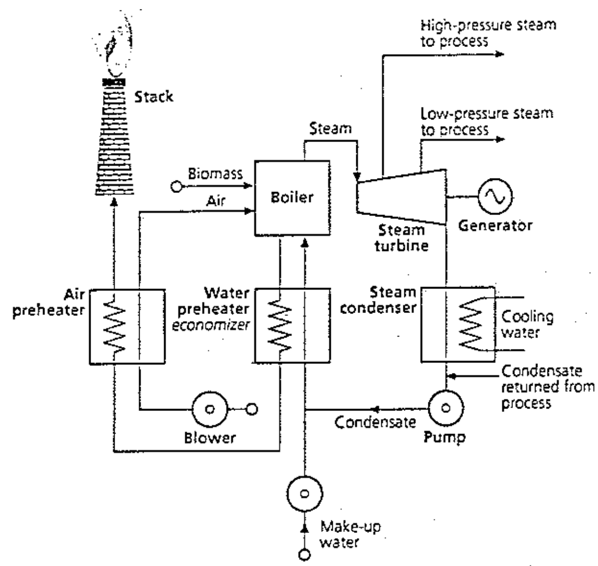


Figure 4.2. Cogeneration of steam and electricity based on direct combustion of biomass, with steam raised in a boiler to drive a condensing-extraction steam turbine (CEST) producing electricity. In the system shown here, two extractions of steam for process use are shown.

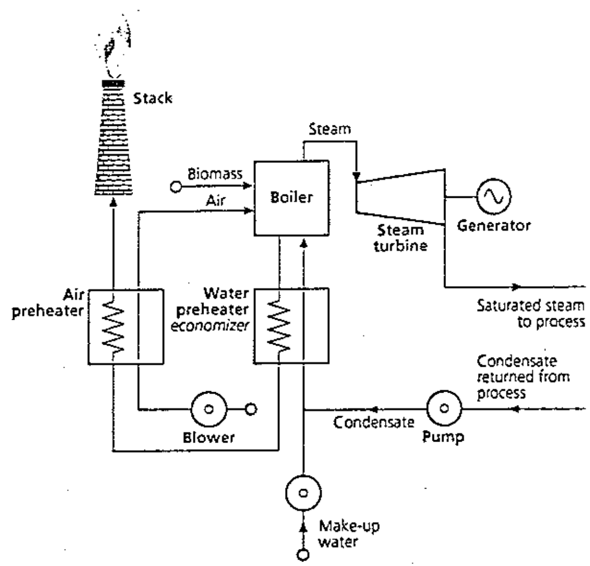


Figure 4.3. Cogeneration of steam and electricity based on direct combustion of biomass, with steam raised in a boiler to drive a back-pressure steam turbine producing electricity. The exhaust steam from the turbine is available for use as process steam.

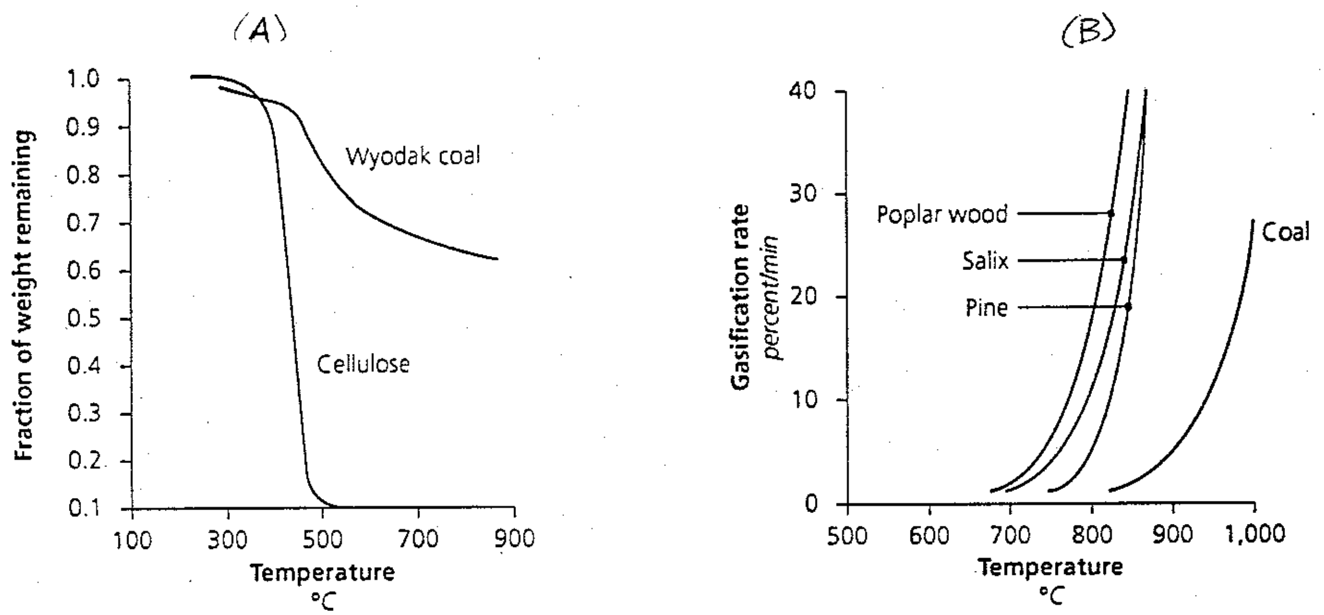


Figure 4.4. Comparison of the gasification characteristics of biomass relative to coal. *(a)* The left figure [125] shows the rate at which coal and cellulose (which accounts for typically half the weight of biomass) lose weight, or devolatilize, as they are pyrolyzed, i.e., heated in the absence of air. Pyrolysis is a principle process involved in converting solid fuels into combustible gases. Nearly complete devolatilization occurs with the cellulose at under 500°C. In contrast, only about 40% of the coal is devolatilized and only after heating to close to 900°C. The slower weight loss with coal reflects its inherently lower thermochemical reactivity. The much higher fraction of weight remaining even after heating to 900°C reflects the much lower content of volatile components in coal compared to cellulose. *(b)* The right figure [126] shows the rate at which solid carbon that remains after pyrolysis (char) is converted into carbonaceous gases in the presence of steam. This char gasification is also a principle process involved in converting solid fuels into combustible gases. Because of the higher reactivity of biomass chars, these gasify much more rapidly and at lower temperatures than coal chars. Thus, lower temperatures can be used in biomass gasifiers compared to coal gasifiers to achieve the same level of char conversion to gas.

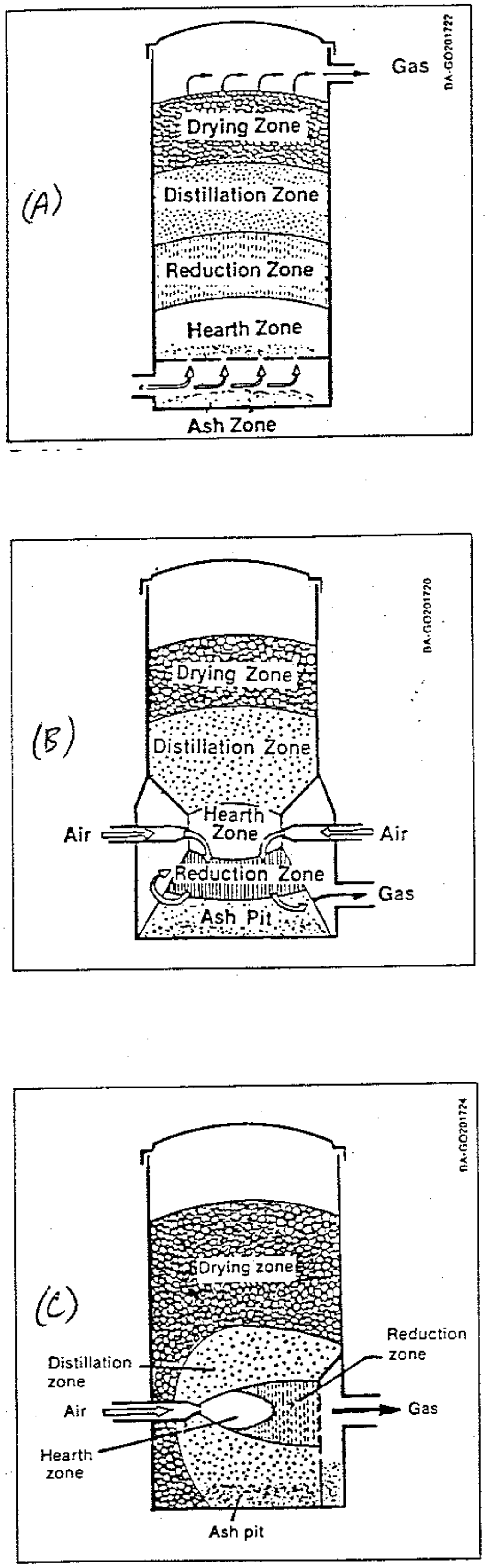


Figure 4.5. *(a)* Updraft, *(b)* downdraft, and *(c)* crossdraft gasifiers. Source: [40].

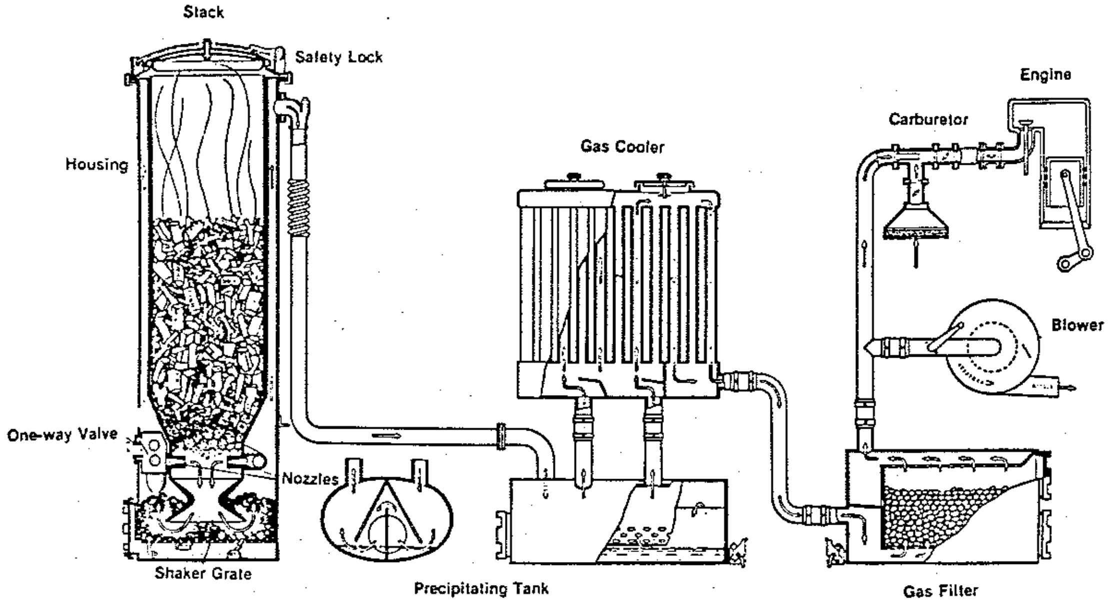


Figure 4.6. A typical gasifier, gas cleanup, engine equipment configuration (1940s design) [12]. The raw gas from the gasifier passes through a water scrubbing unit, a heat exchanger, and a filter (to remove remaining contaminants and entrained water droplets) before reaching the engine.

(A)

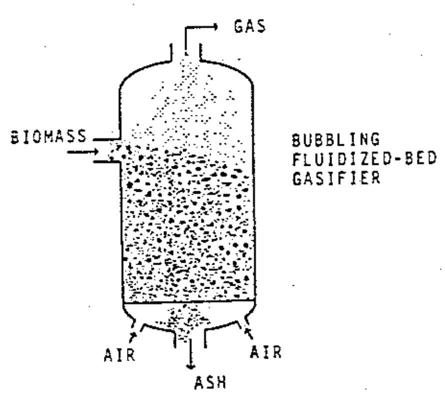
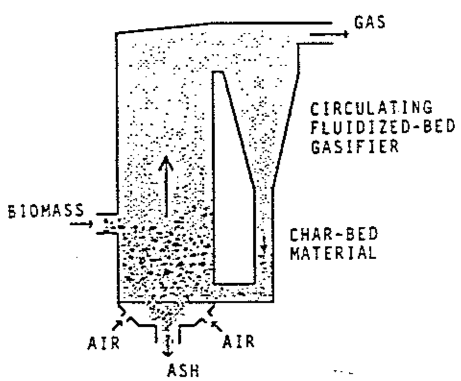


Figure 4.7. Basic designs of *(a)* bubbling fluidized bed gasifier and *(b)* circulating fluidized-bed gasifier [21].

(B)



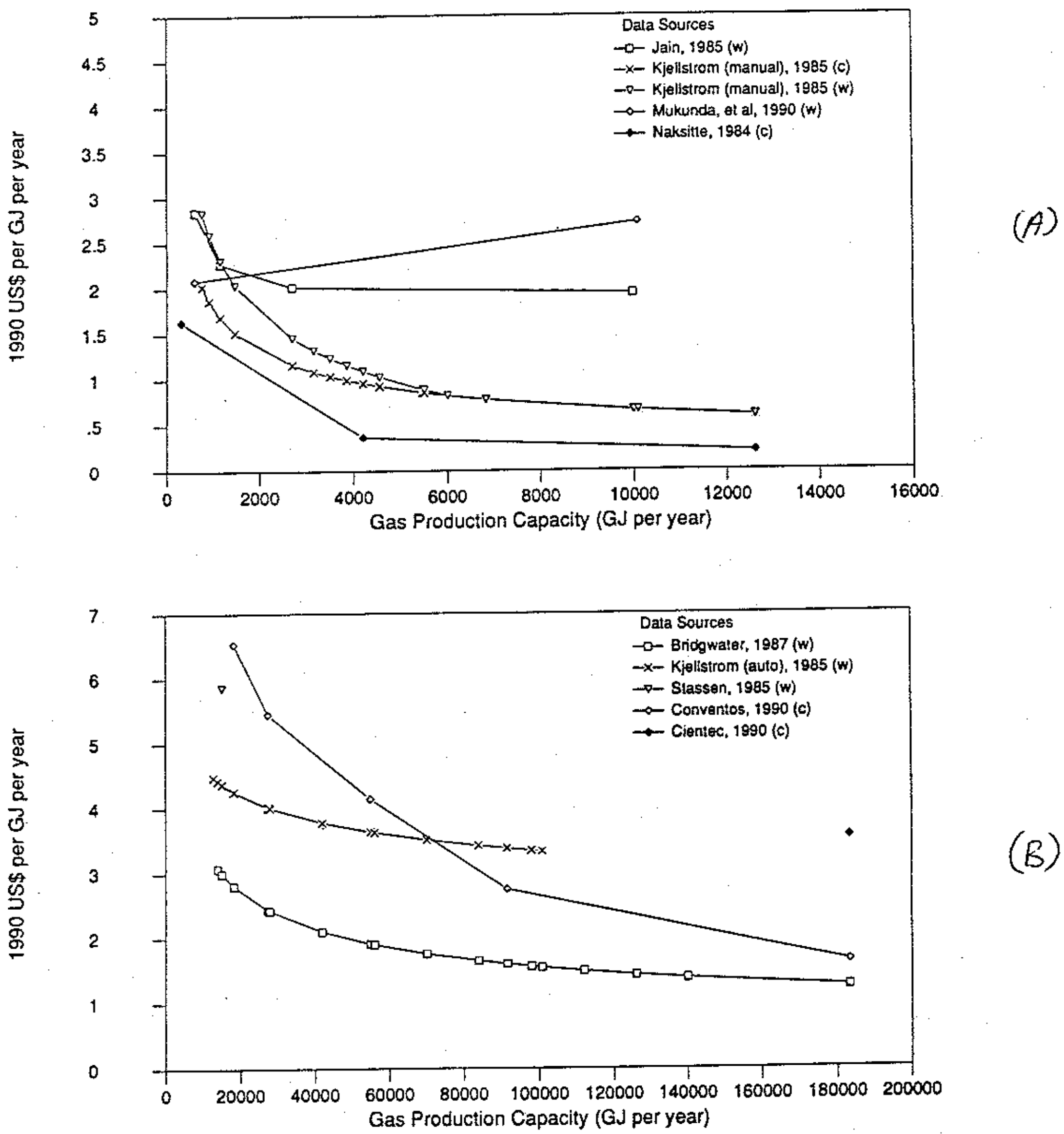


Figure 4.8. *(a)* Reported installed capital costs for small producer gas generators with gas cleaning systems. (See Table A.1.) The legend indicates (w) and (c) for wood and charcoal fuel, respectively. The capacity of units is typically reported as the rate of input biomass. A gasification efficiency of 80% has been assumed to calculate gas production capacity. The costs of Jain and Mukunda, et al. are for applications in India (the larger unit includes an automatic feeding system, unlike all others in this figure); Naksitte Coovattanachai for Thailand [127]; and Kjellstrom for general developing country conditions. (Kjellstrom's costs are for manually fed units. His costs for auto-feed units are given in Fig. 4.8b). *(b)* Reported installed capital costs for larger producer gas generators with gas cleaning and automatic feeding. The Conventos and Cientec data are for Brazil and were reported originally in terms of gas production capacity. The Bridgwater [128], Stassen [129], and Kjellstrom data are estimates for general developing country conditions. For these three cases, a gasification efficiency of 80% has been assumed.

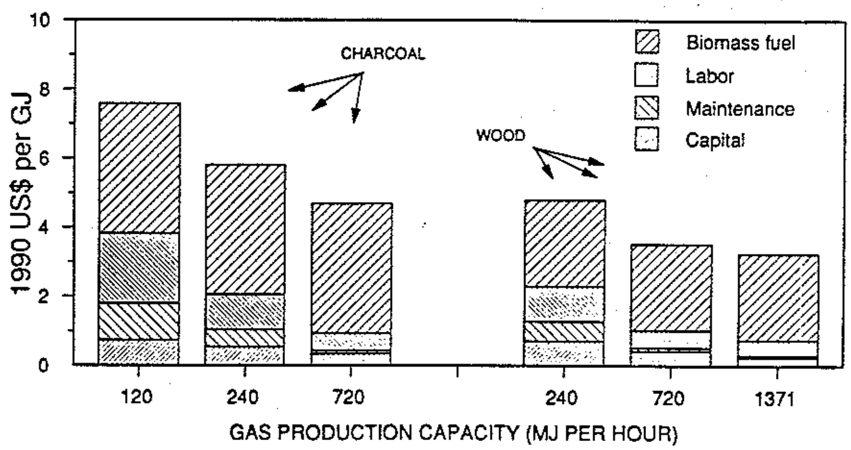


Figure 4.9. Levelized costs of producer gas from wood and charcoal as a function of gas production capacity. Calculations are based on Table A.2 and assume a 7% discount rate, 6-year lifetime, 50% capacity factor, \$2/GJ for wood fuel, and \$3/GJ for charcoal.

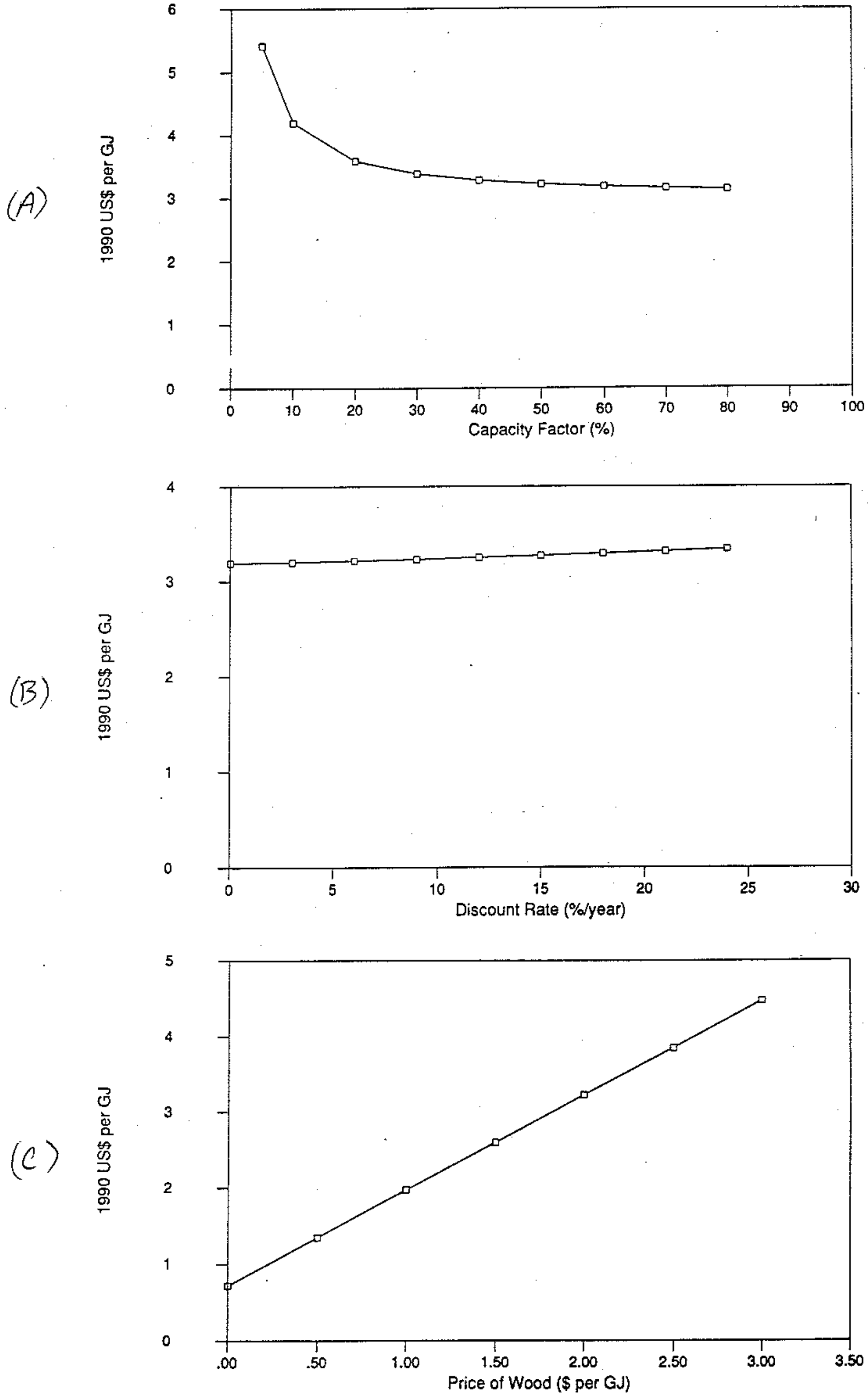
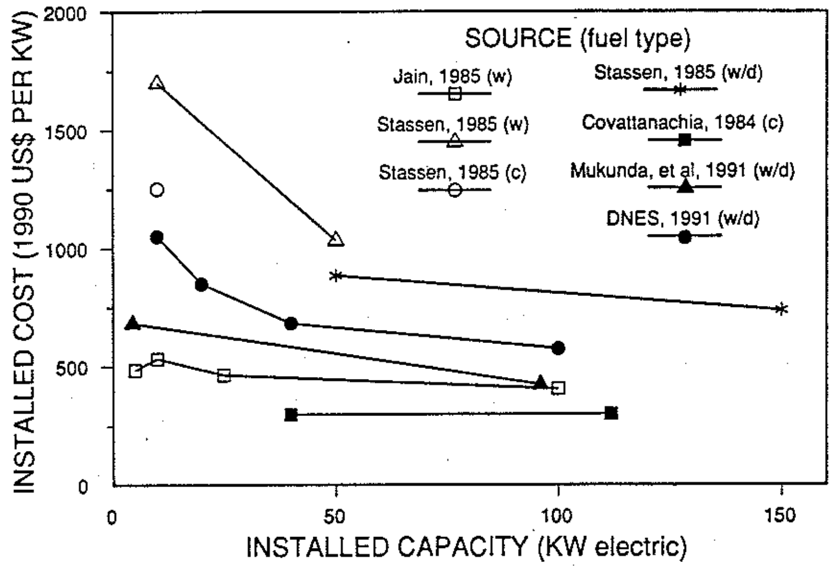


Figure 4.10. **Calculated levelized costs of producer gas as a function of *(a)* capacity factor, *(b)* discount rate, and *(c)* wood fuel cost for a unit with a gas production capacity of 1.4 GJ/year. Calculations are based on capital cost and O&M estimates in Table A.2, and baseline assumptions include a 7% discount rate, 6-year lifetime, and $2/GJ for wood fuel.**

(A)



(B)

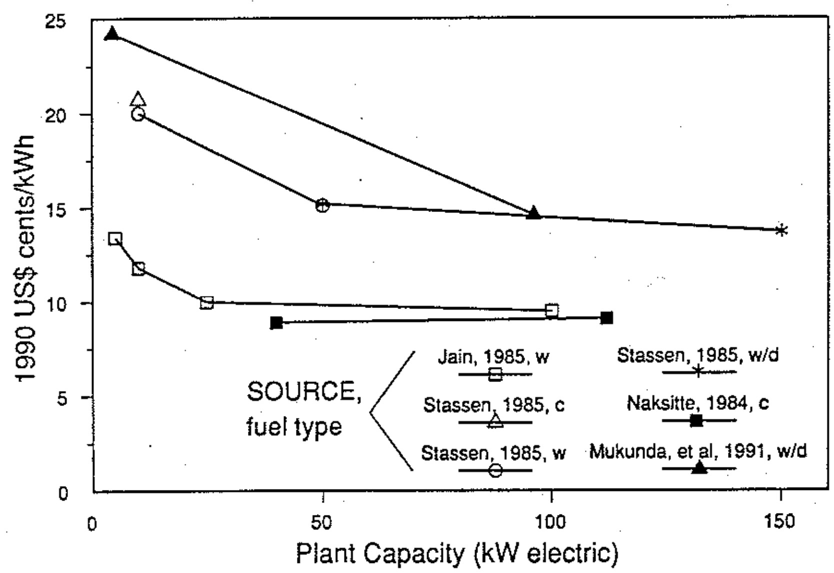


Figure 4.11. *(a)* Reported capital costs for producer gas engine-generator electricity production plants, based on data given in Table A.3. The DNES data are not given in Table A.3. These refer to cost norms for gasifier-engine systems established by the Department of Non-Conventional Energy Sources in India [H.S. Mukunda, Indian Institute of Science, Bangalore, personal communication, April 1991]. *(b)* Levelized costs of electricity generation as a function of plant capacity for producer gas engine-generator systems. The wood fuel, "w," and charcoal fuel, "c," systems use spark-ignited engines. The wood/diesel dual fuel system, "w/d," uses compression-ignition egnines. Calculations are based on Table A.3 and assume a 7% discount rate, 50% capacity factor, $2/GJ for wood fuel, $3/GJ for charcoal, $6.5/GJ for diesel fuel, and $3/liter for lube oil. All calculations assume a 25-year analysis period and include the cost of replacement units required during this period. Zero salvage value is assumed.

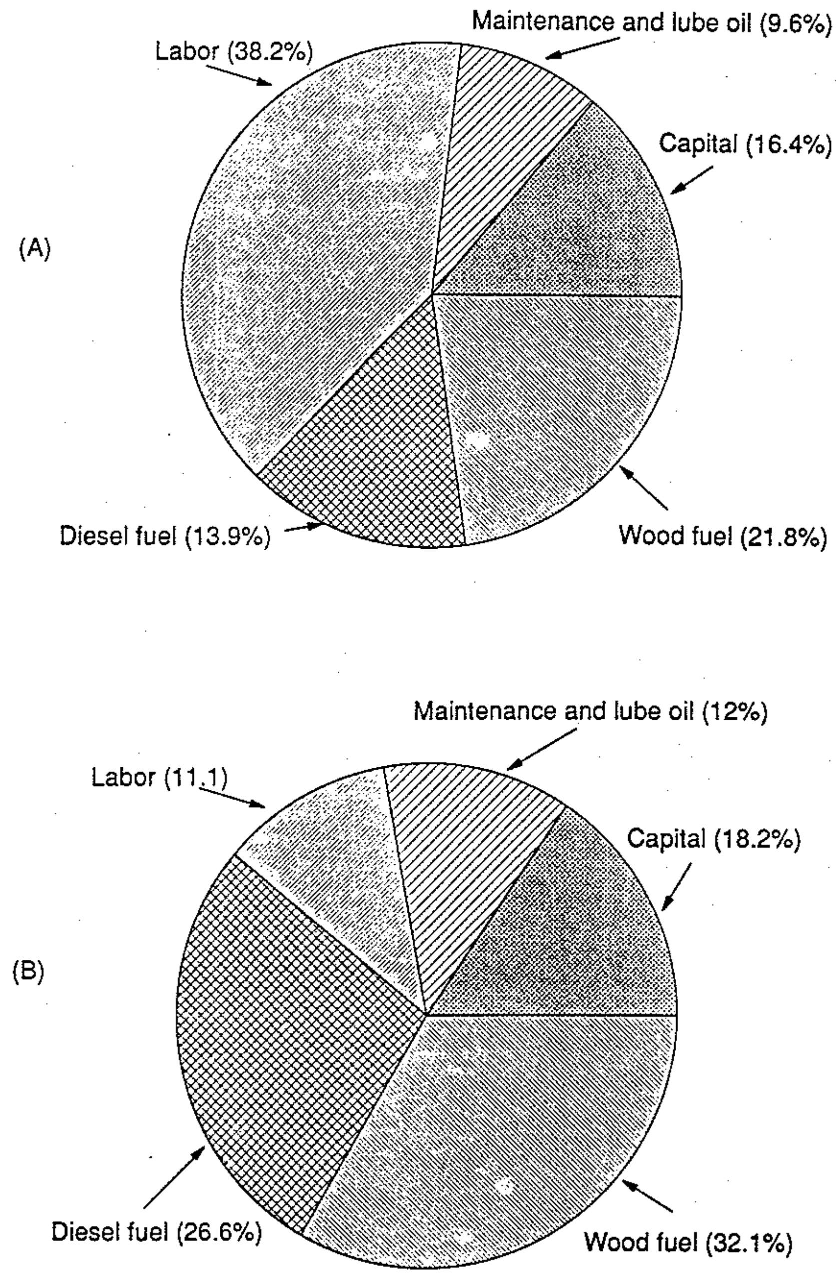


Figure 4.12. Component costs for electricity from *(a)* 4.4 kW_e and *(b)* 96 kW_e wood/diesel dual fuel producer gas engine-generator systems, based on data reported by Mukunda, et al. See Table A.3. All assumptions are as given in caption to Fig. 4.11.

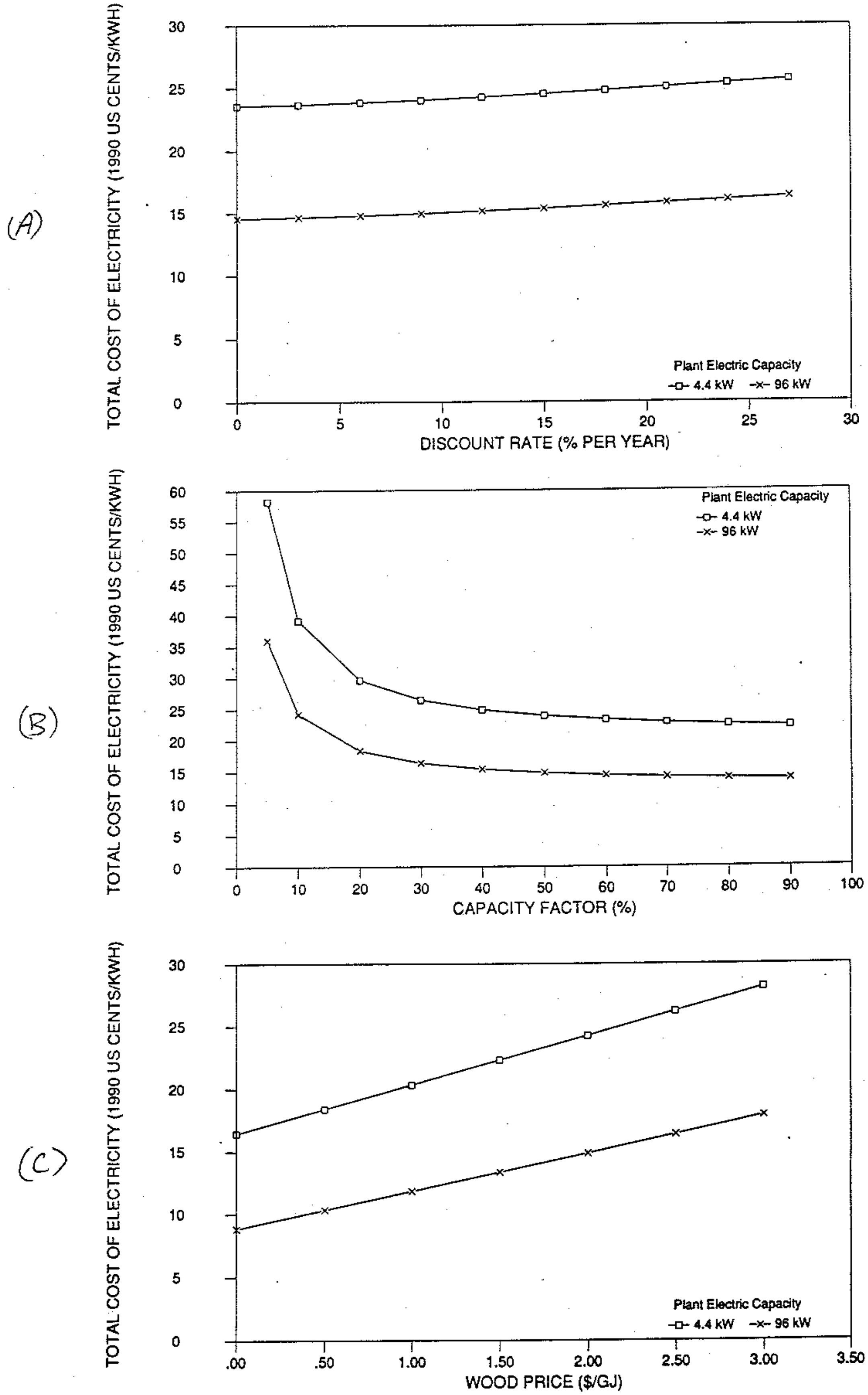


Figure 4.13. **Cost of electricity versus** *(a)* **capacity factor,** *(b)* **discount rate, and** *(c)* **wood fuel cost for two wood/diesel dual fuel producer gas engine-generator plants, based on data reported by Mukunda, et al. See Table A.3. Assumptions are as given in caption to Fig. 4.11.**

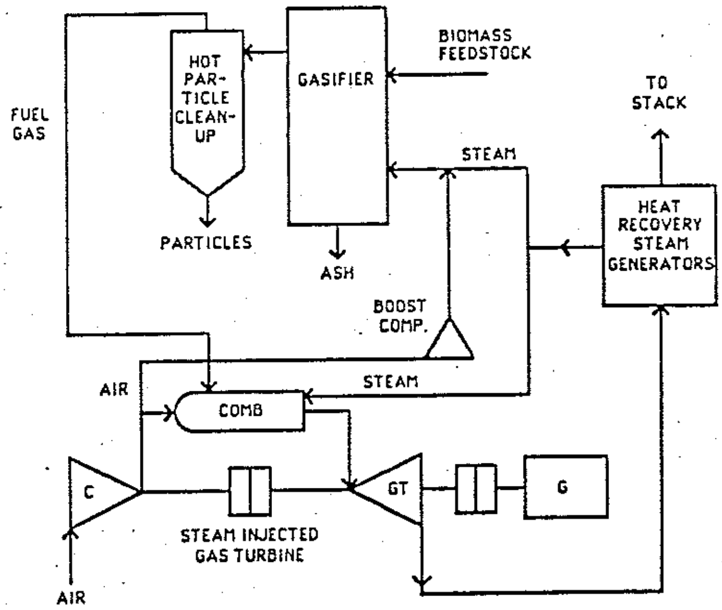


Figure 4.14. Schematic of a biomass-gasifier/gas turbine power generating cycle based on use of a steam-injected gas turbine [21]. Processed biomass (sized and/or dried) is fed into a pressurized fixed- or fluidized-bed gasifier, the resulting hot gases are cleaned of particulates and other contaminants, and the hot gas is fed to the combustor of a steam injected gas turbine.

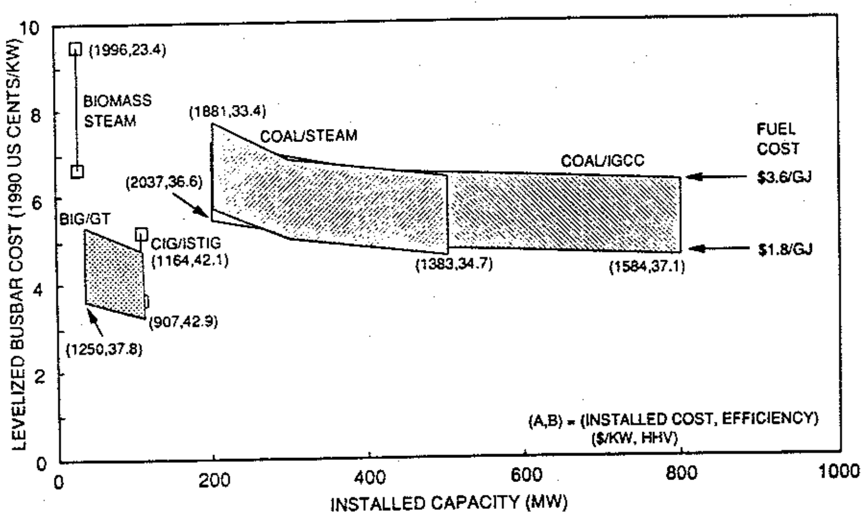


Figure 4.15. Comparison based on [130] of the costs of electricity generation using biomass-gasifier/gas turbines and alternative coal-fired central station plants. The calculated costs assume a 7% discount rate, a 30 year lifetime, capital costs and conversion efficiencies as shown, and a range of fuel costs (as shown) from $1.8/GJ to $3.6/GJ. Coal/IGCC refers to integrated coal-gasifier/gas turbine-steam turbine (combined cycle) technology. Coal/steam refers to conventional pulverized-coal systems using wet flue gas desulfurization. Biomass/steam refers to a conventional condensing steam-turbine plant. The coal and biomass/steam estimates are from [121]. CIG/ISTIG refers to a coal-integrated gasifier/intercooled steam-injected gas turbine. The estimate for the smaller-scale BIG/GT is for a BIG/combined cycle, based on [4?]. The larger-scale estimate is for a BIG/ISTIG, based on [45].

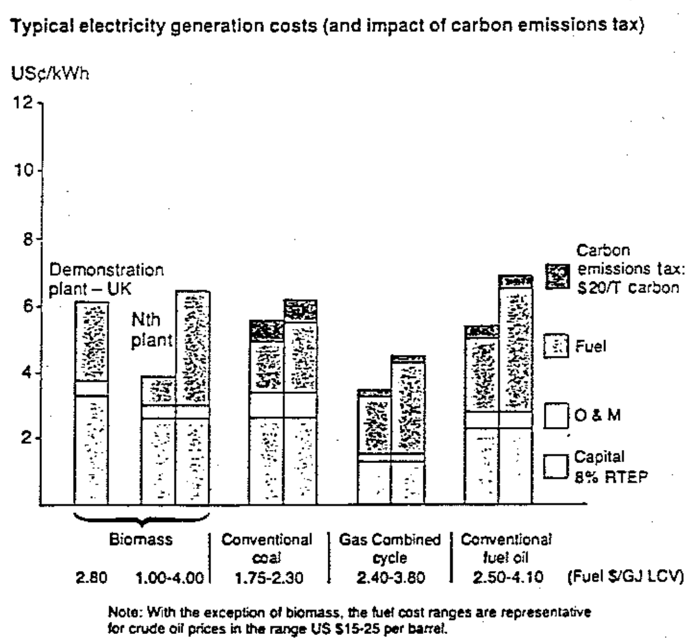
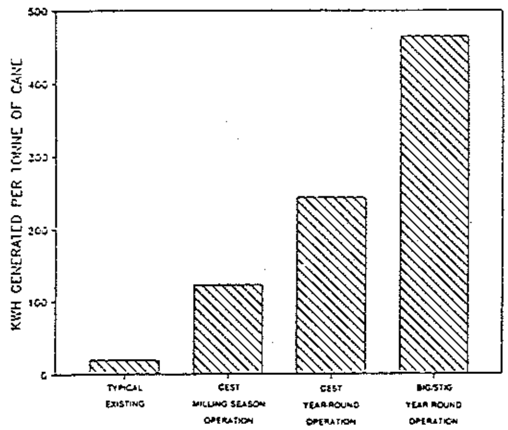
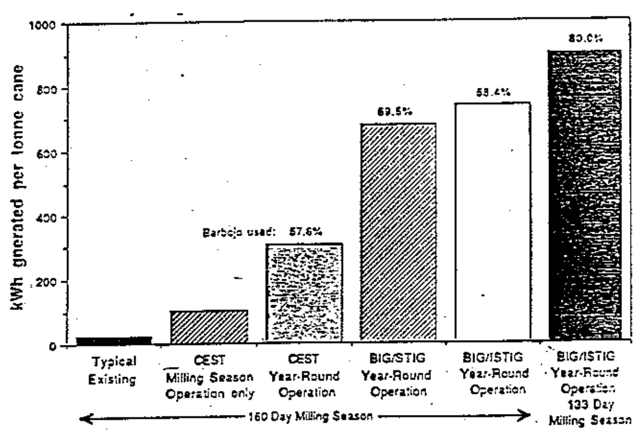


Figure 4.16. **Comparison of total electricity generation costs for a 37 MW biomass-gasifier/gas turbine-steam turbine combined cycle and alternative fossil fuel power plants [48]. The Nth plant refers to the expected costs for commercially mature technology.**

(A)



(B)



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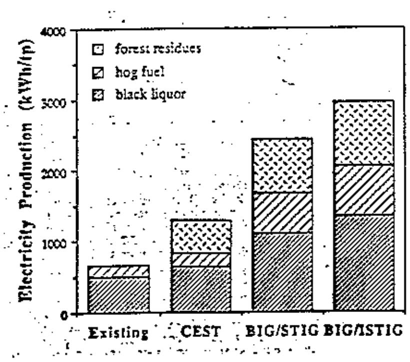
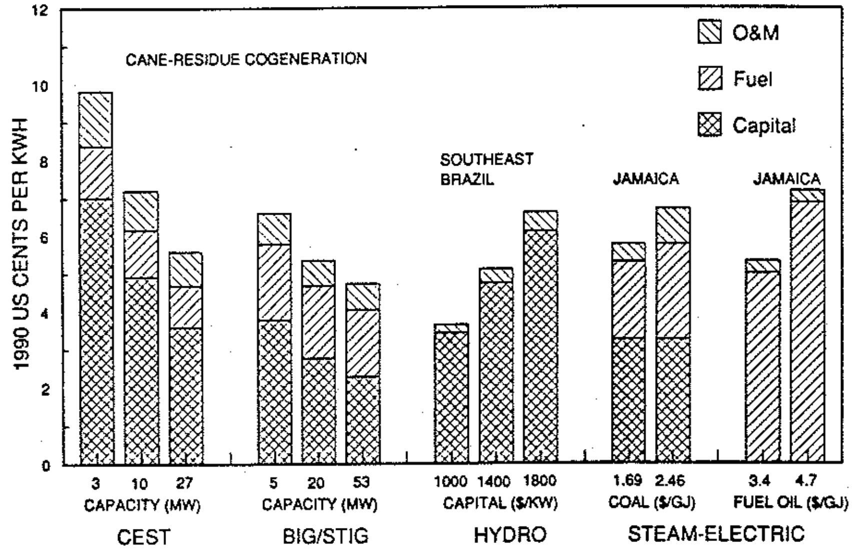


Figure 4.17. Comparison of the electricity production potential with alternative cogeneration technologies at industrial sites where biomass processing residues are available. Existing technology is typically some variety of back-pressure steam turbine and is designed to consume all available biomass residues which just meeting on-site steam and electricity needs. CEST refers to condensing-extraction steam turbines. BIG/STIG is a biomass-gasifier/steam-injected gas turbine. BIG/ISTIG is a biomass-gasifier/intercooled steam injected gas turbine. The CEST, BIG/STIG and BIG/ISTIG technologies produce significant quantities of electricity in excess of on-site needs. Some improvements in steam use efficiency are assumed for mills that would use these technologies since these technologies produce insufficient steam to meet on-site needs. (See indicated references). *(a)* From [47], based on a cane sugar factory in Jamaica. The left bar, existing technology includes operation only during the milling seaason (about 6-months). The two right-most bars assume year-round operation, using tops and leaves of the cane as fuel during the non-milling season. *(b)* From [50] for an autonomous alcohol distillery. Barbojo refers to the tops and leaves of the cane. The same tonnage of cane processed during a shorter milling season (133 versus 160 days) leads to greater electricity production per tonne of cane because more electricity would be produced per unit of fuel consumed in the off-season than during the milling season. *(c)* From [51] for a kraft pulp mill in the Southeastern US (tp refers to a tonne of pulp product having about 10% moisture content). Hog fuel refers to bark, sawdust, and other waste wood available on-site. Forest residues are associated with pulpwood harvesting, but are not currently used for energy in the pulp and paper industry.

(A)



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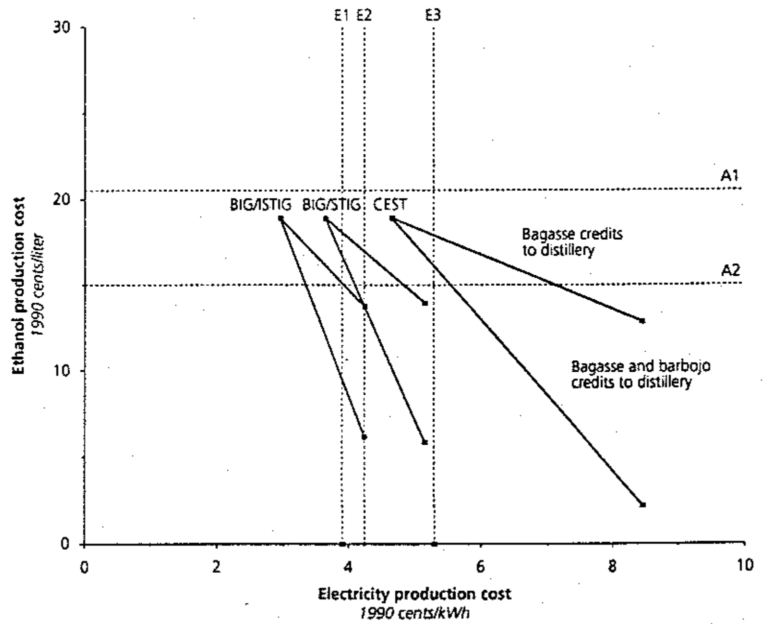


Figure 4.18. Estimated costs of generating exportable electricity at sugarcane-residue-fired cogeneration plants, assuming use of bagasse during the milling season and cane tops and leaves (barbojo) during the non-milling season.

(a) At a cane sugar factory, assuming use of tops and leaves for fuel during the non-milling season. Shown for comparison are estimated costs of central station electricity from steam-electric plants in Jamaica and of hydroelectric power supplied to the Southeast of Brazil [47]. A 7% discount rate has been used in the calculations.

(b) Cost of electricity versus cost of ethanol at an autonomous alcohol distillery under Southeast Brazilian conditions [50]. The cogeneration facility is assumed to be a distinct economic entity from the distillery (see Fig. 5.11). A real discount rate of 7% and a 20-year (30-year) plant life are assumed for the distillery (cogeneration) operations. For each technology, a range of costs are shown, corresponding to different prices for the cane residues. As the residue price to the cogenerator increases (moving left to right along each sloped line), the cost of electricity increases and the corresponding cost of ethanol decreases, assuming the distiller credits the biomass revenues against the cost of ethanol. Two lines are shown for each technology. The top line represents the case where only the bagasse revenues are credited against ethanol costs. This would be the case where the cane tops and leaves are purchased from a third party, e.g directly from independent farmers. The steeper line is for the case where the distiller owns the cane in the field and sells both bagasse and barbojo to the cogenerator. Where the two lines meet represents the point when the distiller gives the biomass fuel to the cogenerator in exchange for steam and electricity needed to operate the distillery. At the right end points, the cost of biomass to the electricity generator is $3/GJ. Shown for comparison are lines indicating: (A1), the price at which ethanol would be competitive as a neat fuel and (A2) as an octane-enhancing addititive, with crude oil at $20 per barrel, (E1), the busbar cost of a new hydroelectric power plant, (E2), the operating cost (O&M plus fuel only) of an oil-fired central station power plant, and (E3), the busbar cost for a new coal-fired power plant.

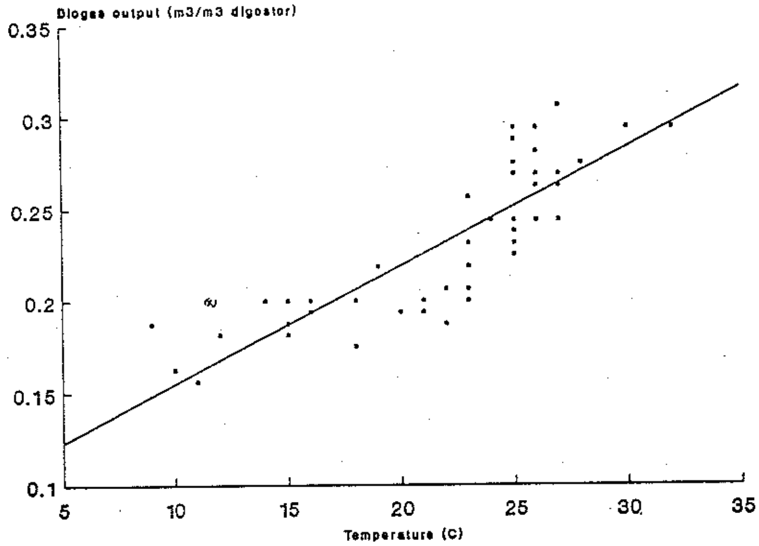


Figure 4.19. Temperature dependence of the daily gas output of a biogas digester per cubic meter of digester volume. The line is a linear regression of data from [131]. The regression correlation is gas output (daily m^3/m^3) = 0.0875 + [0.0065 * temperature (°C)].

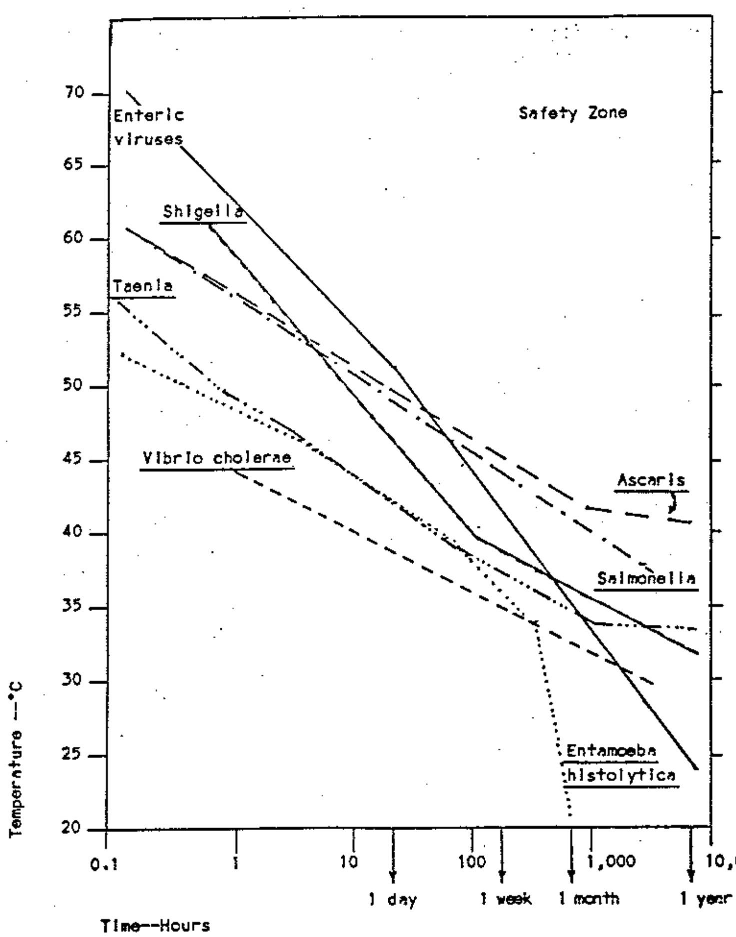


Figure 4.20. Conservative estimates of temperature-residence time combinations required for complete destruction of various pathogens in nightsoil and sludge [58].

(A)

(B)

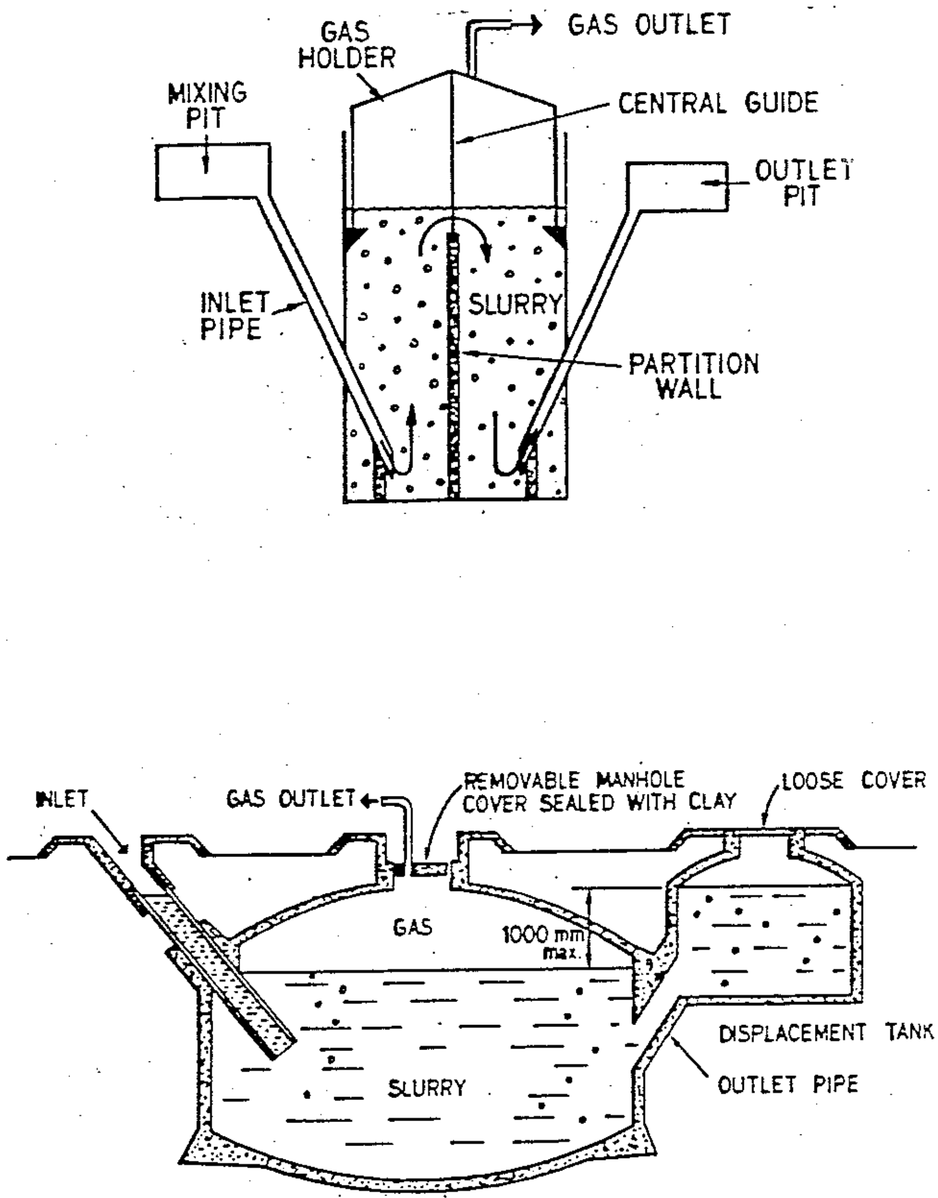


Figure 4.21. Traditional biogas digesters [58]: (a) floating-cover (KVIC) design; (b) fixed-dome (Chinese) design.

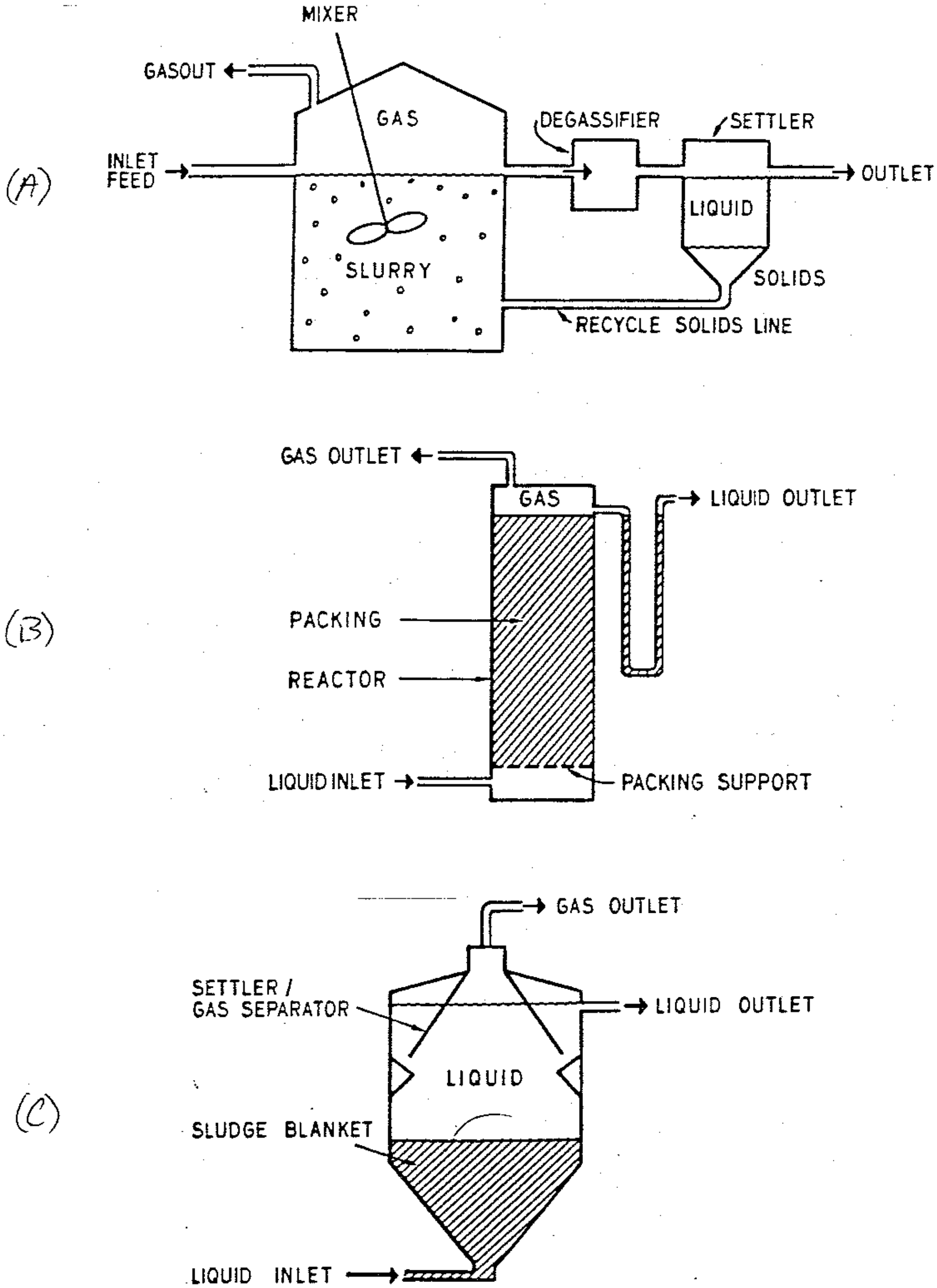


Figure 4.22. *(a)* Anaerobic contact digester; *(b)* Anaerobic filter digester; *(c)* Upflow anaerobic sludge blanket digester. Source: [58].

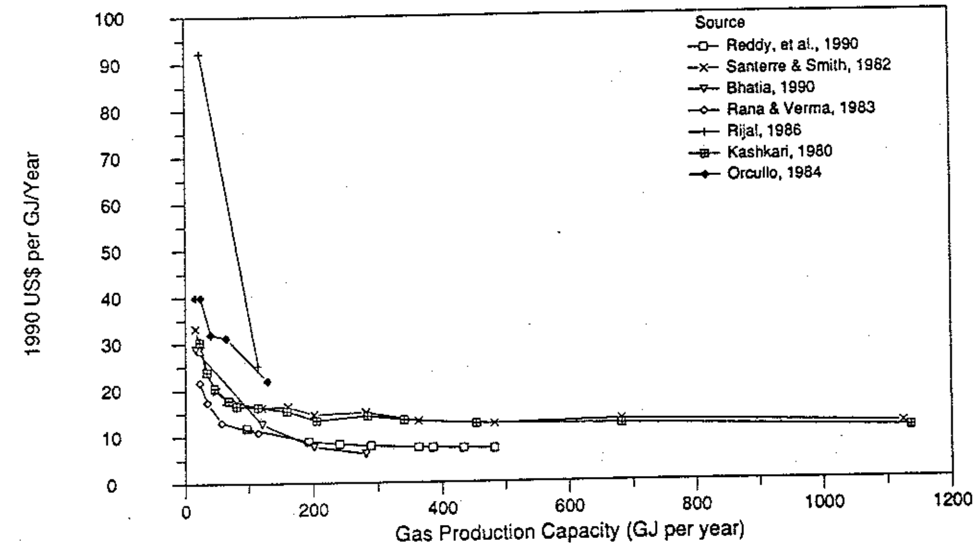


Figure 4.23. Reported installed capital costs for floating-cover biogas digesters, based on Table A.4.

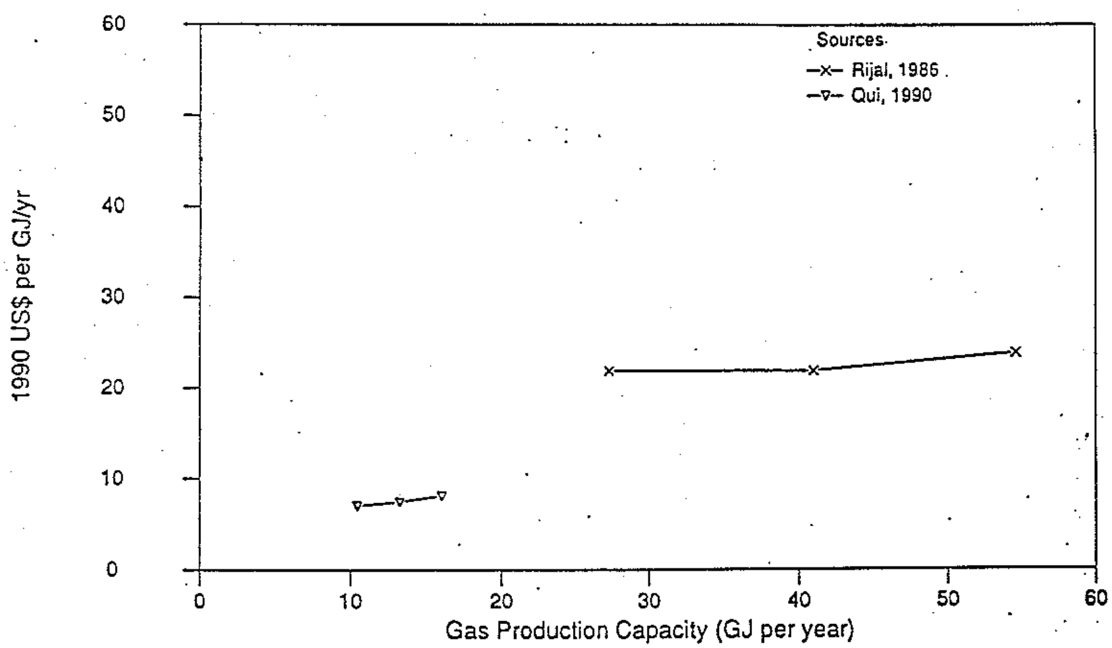


Figure 4.24. Reported installed capital cost estimates for fixed-dome biogas digesters. Sources: Rijal [71], Qui [74].

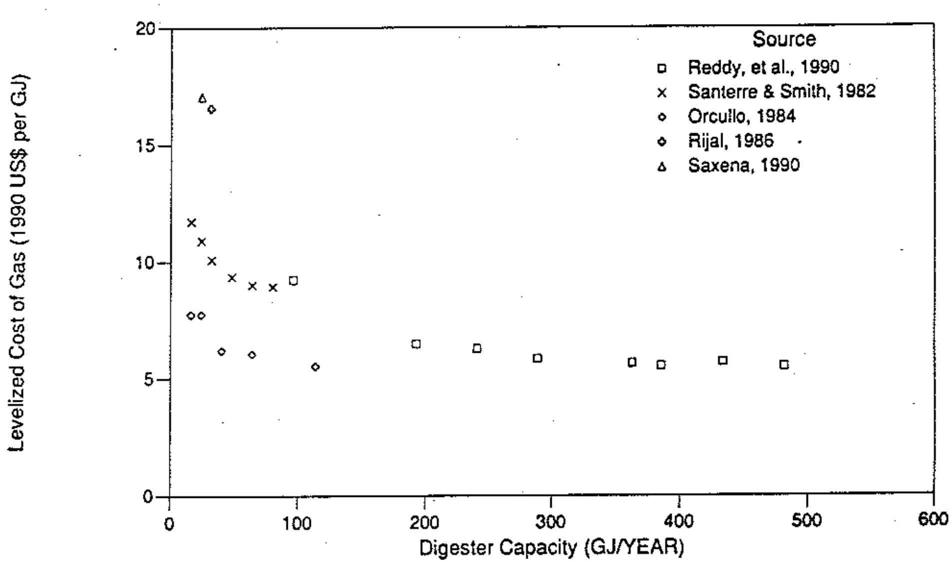
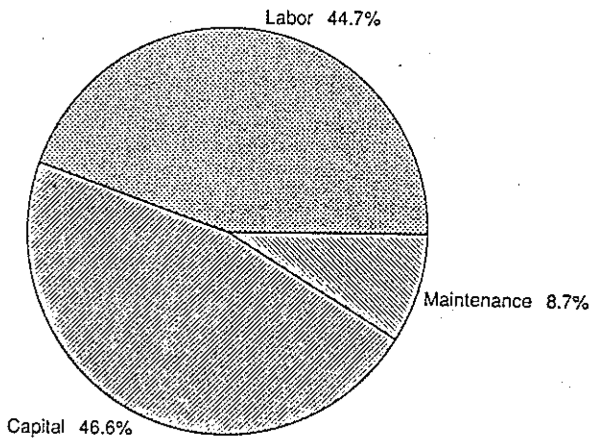


Figure 4.25. **Levelized cost of biogas production, assuming a 7% discount rate, a 15-year plant life, a daily gas production capacity of 0.2 m³ per m³ of digester volume, and a 75% capacity utilization rate. The cost of the input feedstock is assumed to be offset by the revenue value of the effluent sludge. In the case of Reddy, et al., the biogas cost includes a cost of approximately $0.0016 per kg of fresh cattle dung, which can be viewed as the labor cost required to collect dung and redistribute the effluent. See Table A.4 for basic data used in the calculation.**

(A)



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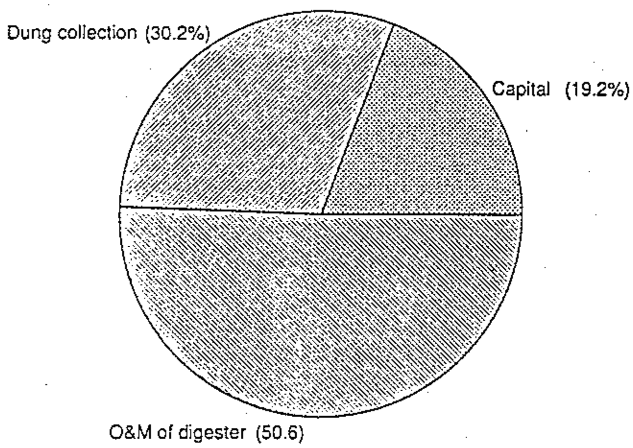


(C)

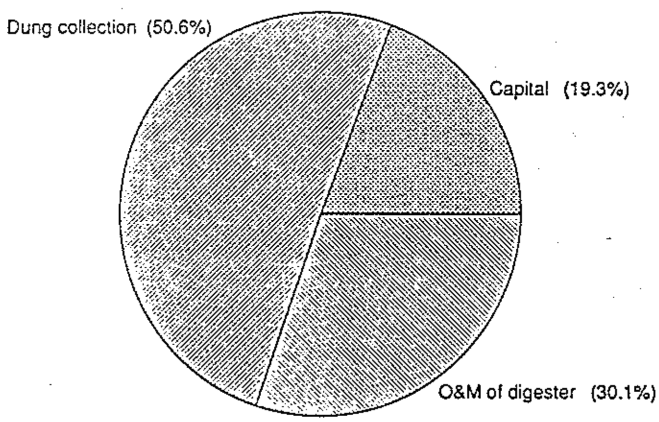


Figure 4.26. Breakdown of the total cost of biogas for three different sized digesters with assumptions as in caption to Fig. 4.25. (See Table A.4.) *(a)* For a digester with a gas production capacity of 2 m^3/day. The total cost is \$10.6/GJ, based on Santerre and Smith's costs. *(b)* For a digester with a gas production capacity of 12 m^3/day. The total cost is \$8.8/GJ, based on Reddy, et al.'s costs. *(c)* For a digester with a gas production capacity of 60 m^3/day. The total cost is \$5.3/GJ, based on Reddy, et al.'s costs.

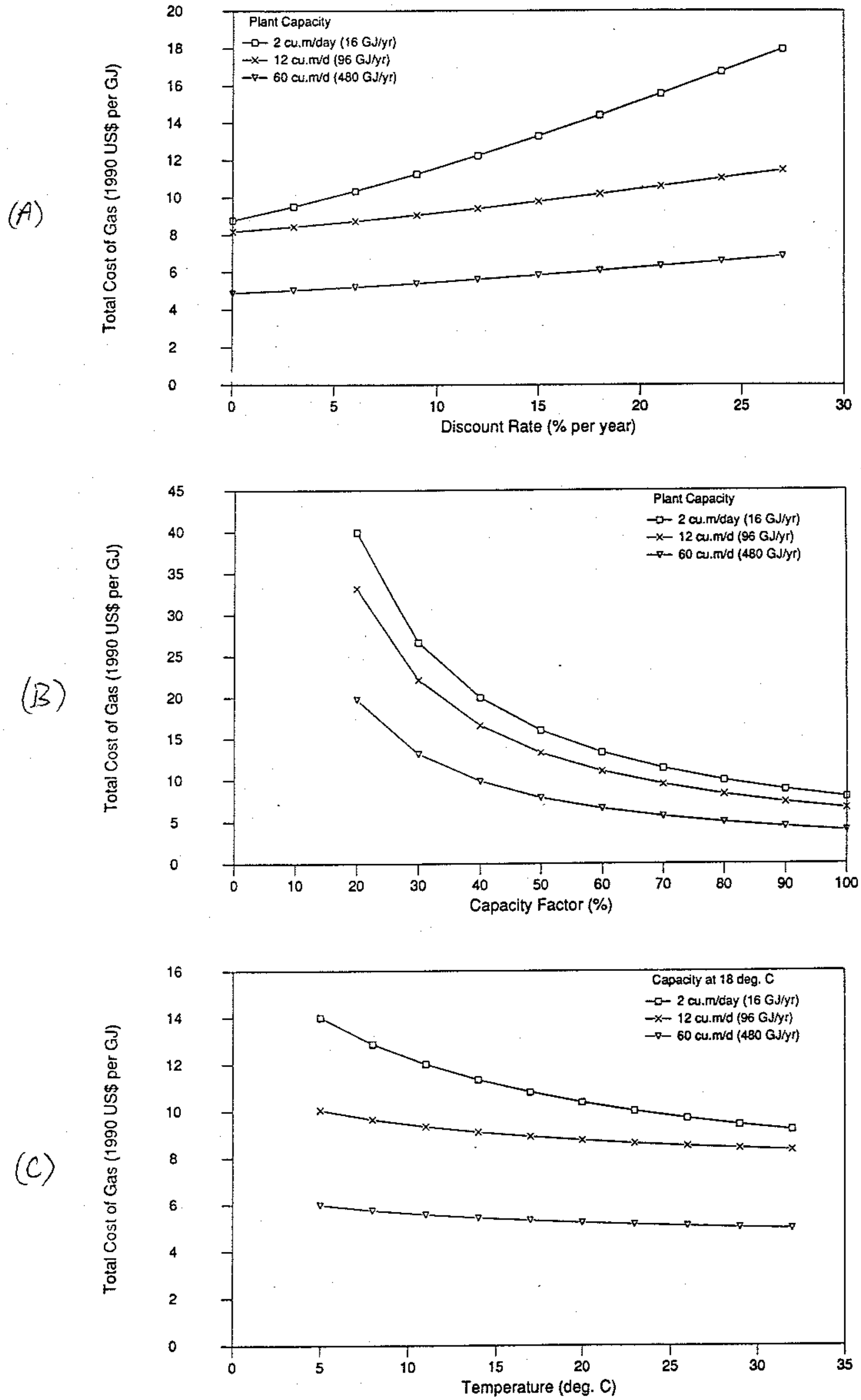


Figure 4.27. **Levelized cost of biogas for the three different sized digesters identified in Fig. 4.26 as a function of *(a)* discount rate, *(b)* capacity utilization rate, and *(c)* ambient temperature. For (c), daily gas production is assumed to vary with temperature according to the regression line in Fig. 4.19.**

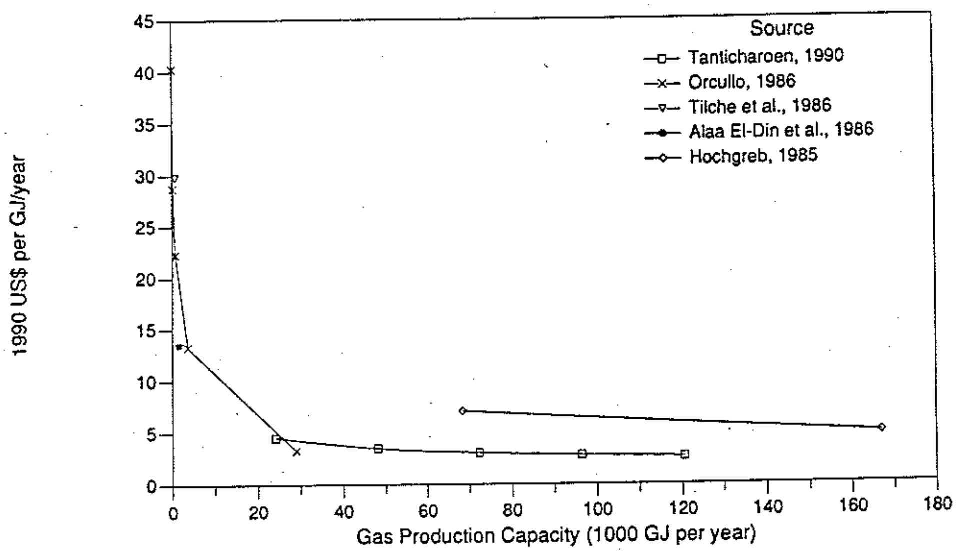


Figure 4.28. Reported capital costs for industrial-scale biogas digesters in developing countries. Sources: Tanticharoen [65b] for Thailand, Orcullo [70] for the Philippines, Tilche et al. [136] for Italy, Alaa El-Din [137] for Egypt, and Hochgreb [95] for Brazil.

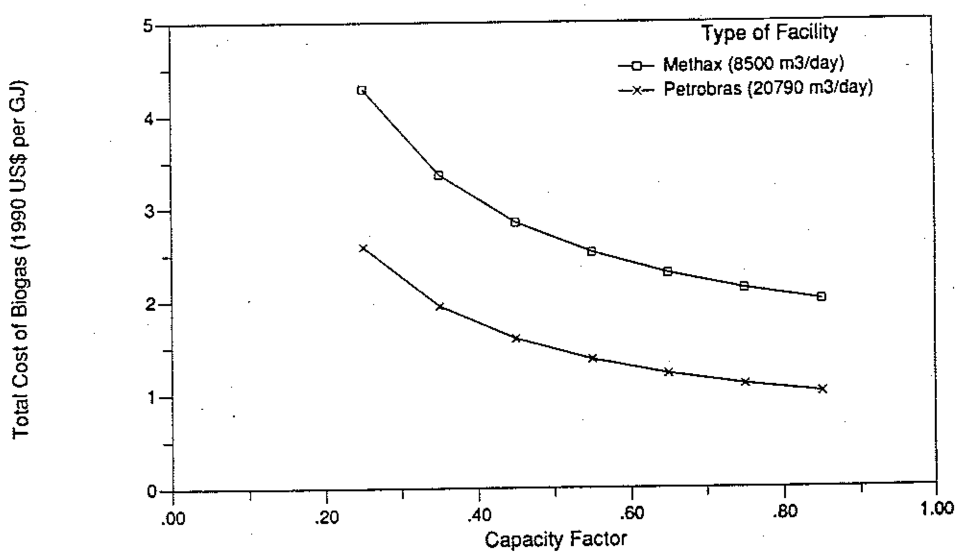
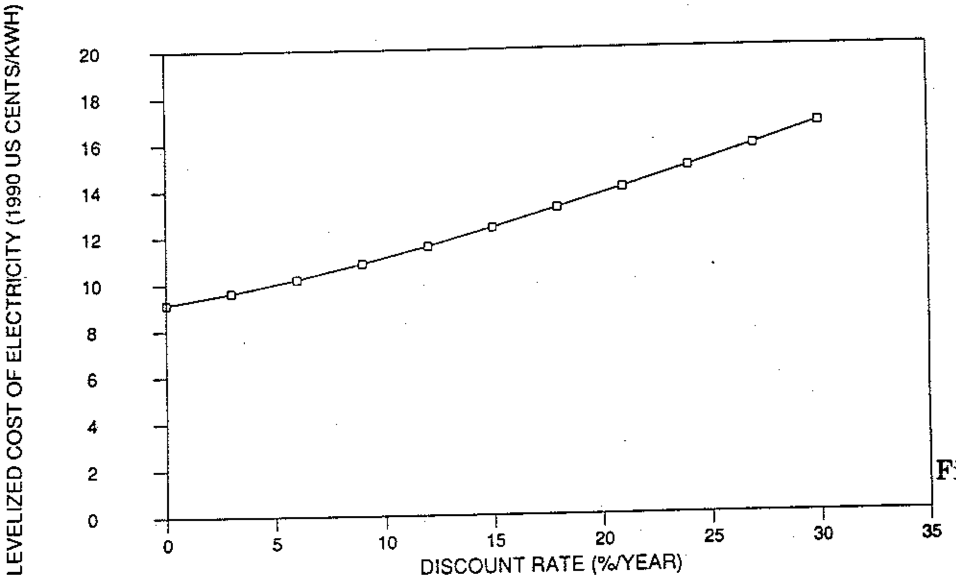


Figure 4.29. Estimated biogas costs from ethanol stillage in Brazil, based on Hochgreb [95]. The Methax units are upflow anaerobic sludge blanket digesters. The Petrobras unit is a packed-bed anaerobic filter.



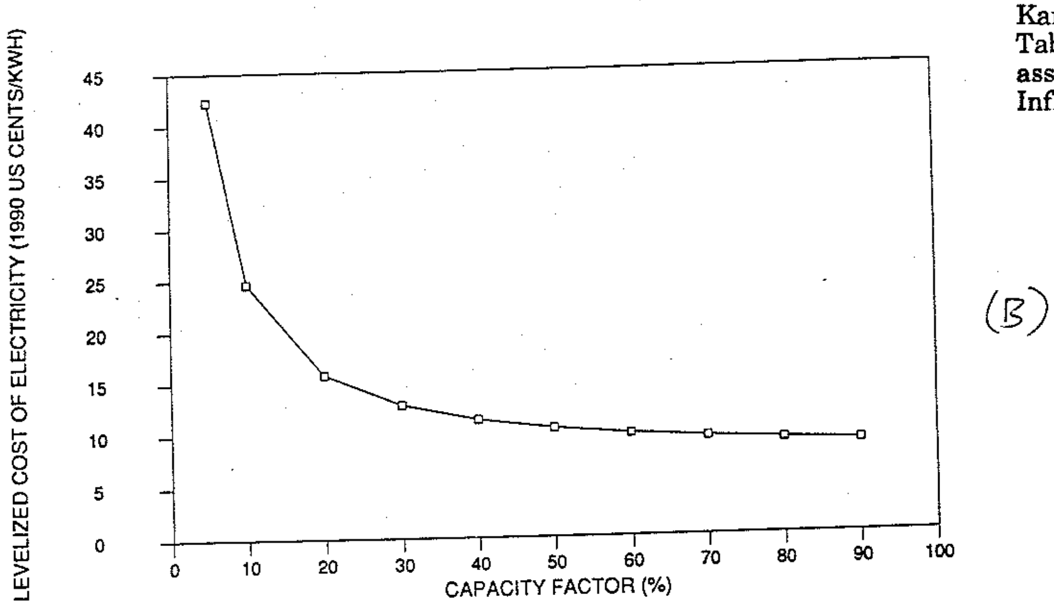


Figure 4.30. Total cost of electricity from a 5 kW$_e$ biogas/diesel dual fuel engine generator system based on the experience in Pura village, state of Karnataka, India [61]. (See Table A.5.) *(a)* Influence of assumed discount rate. *(b)* Influence of capacity factor.

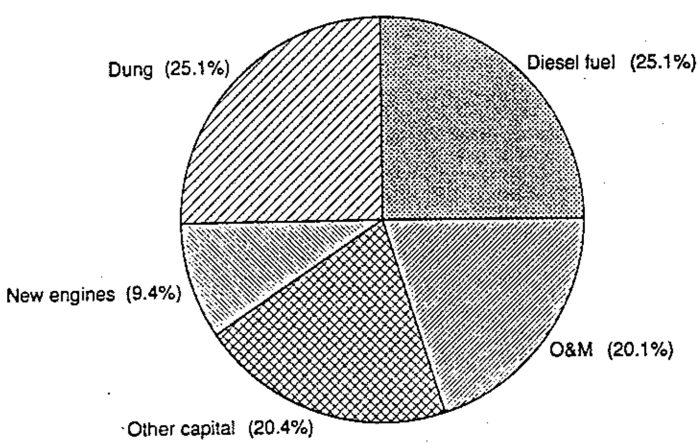


Figure 4.31. Breakdown of electricity generating cost for 5 kW$_e$ system described in Table A.5. The total calculated cost is $0.10 per kWh, assuming a 7% discount rate, 50% capacity factor, and $6.5/GJ diesel fuel cost.

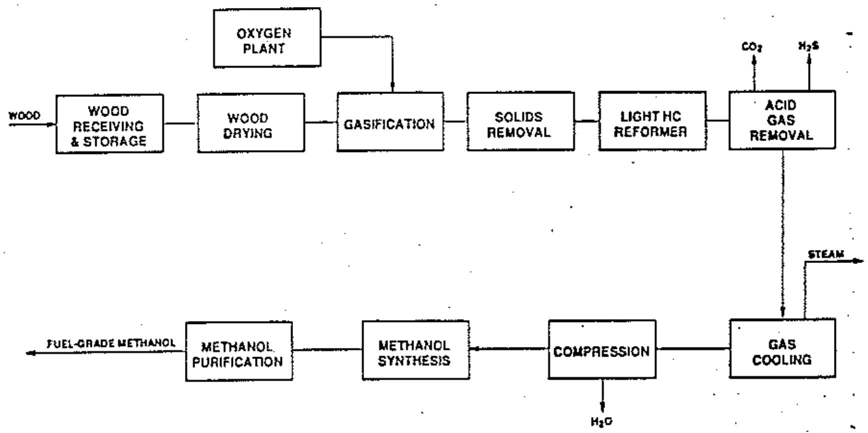


Figure 5.1. Basic process diagram for production of methanol from biomass.

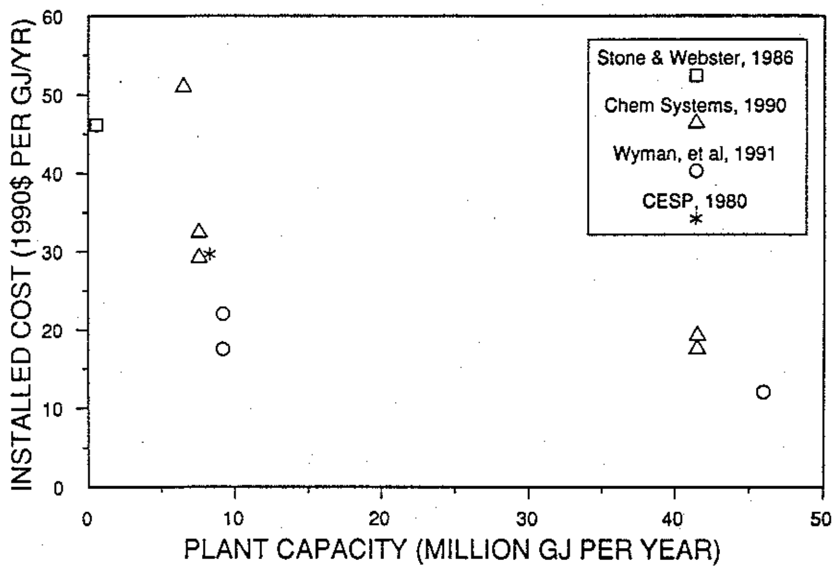


Figure 5.2. Installed capital costs for proposed methanol-from-biomass plants estimated in engineering design studies. See Table A.6.

The Stone and Webster study [90] assumed use of a low-pressure (10 bar) downdraft oxygen-blown gasifier, under development at the time of the study at the Solar Energy Research Institute, and a commercial Lurgi low-pressure (69 bar) methanol synthesis plant.

In its highest-cost estimates, Chem Systems [20] assumed the use of a commercially-mature, atmospheric-pressure Koppers-Totzek entrained-bed gasifier (modifed for biomass from its original coal-based design) followed by a commercial low-pressure methanol synthesis plant such as those made by ICI or Lurgi. The pair of Chem Systems' estimates at the 8 million GJ/year size assume use of high-pressure (> 40 bar) oxygen-blown fluidized-bed gasifiers under development by the Institute of Gas Technology and use of an advanced liquid-phase methanol synthesis unit. The higher estimate of the pair assumes installation of two parallel oxygen production units rather than a single unit. Technology assumptions for the pair of Chem Systems' estimates at the 41 million GJ/year size level are the same as those for the pair of plants at the 8 million GJ/year size.

Wyman, et al [81] consider the atmospheric-pressure Battelle Columbus Laboratory (BCL) indirectly-heated gasifier, which produces a methane-rich gas that must be reformed before methanol synthesis. The BCL unit has only operated at pilot scale. The high cost estimate at the 9 million GJ/year size assumes quenching of the gas to remove tars, followed by a methane reforming step. The lower cost estimate and the cost estimate at the 46 million GJ/year size assume use of a catalytic hot-gas conditioning process that combines tar destruction and methane reforming. This technology has operated only at bench scale.

The plant proposed in the CESP study [88] is a conventional system using a commercially-mature pressurized Winkler bubbling bed coal gasifier adapted for wood chips, followed by a commercial conventional methanol synthesis plant. The plant location considered in the study was Brazil.

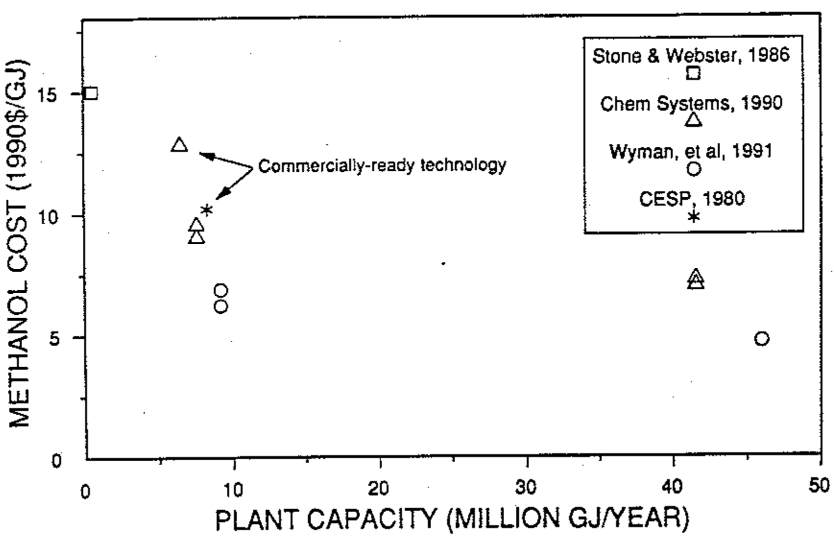


Figure 5.3. Calculated levelized costs of methanol from biomass, assum-ing a 7% discount rate, 20-year life, 90% capacity factor, and biomass costing \$2/GJ. See Table A.6. Costs using commer-cially-ready technology are indicated.

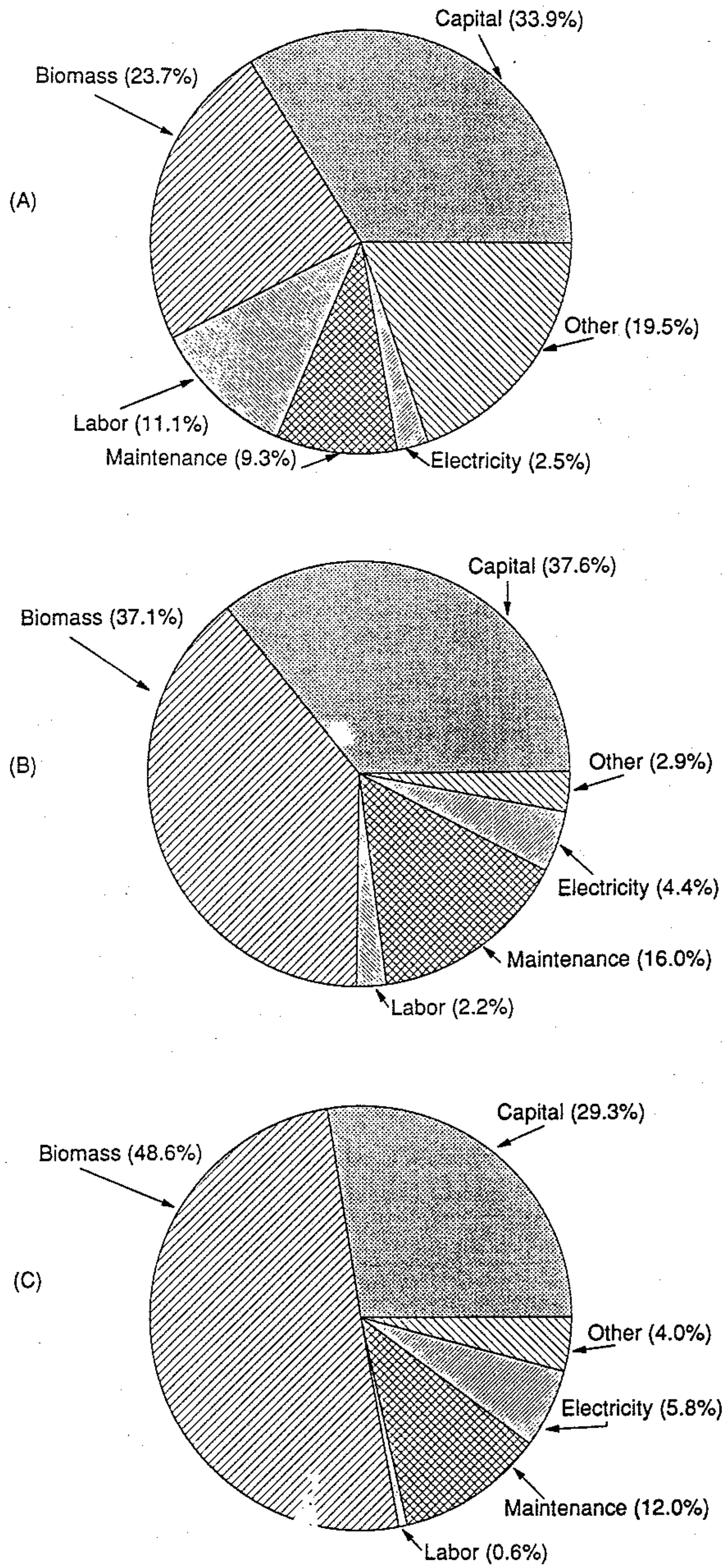


Figure 5.4. Breakdown of levelized costs of methanol production shown in Fig. 5.3 for *(a)* 0.58 million GJ/year capacity plant [90], for which the total cost is \$15.0/GJ; *(b)* 7.6 million GJ/year plant [20], for which the total cost is \$9.5/GJ; and *(c)* 31.5 million GJ/year [20], for which the total cost is \$7.3/GJ. All cases assume a 7% discount rate, 20-year life, 90% capacity factor, and biomass cost of \$2/GJ.

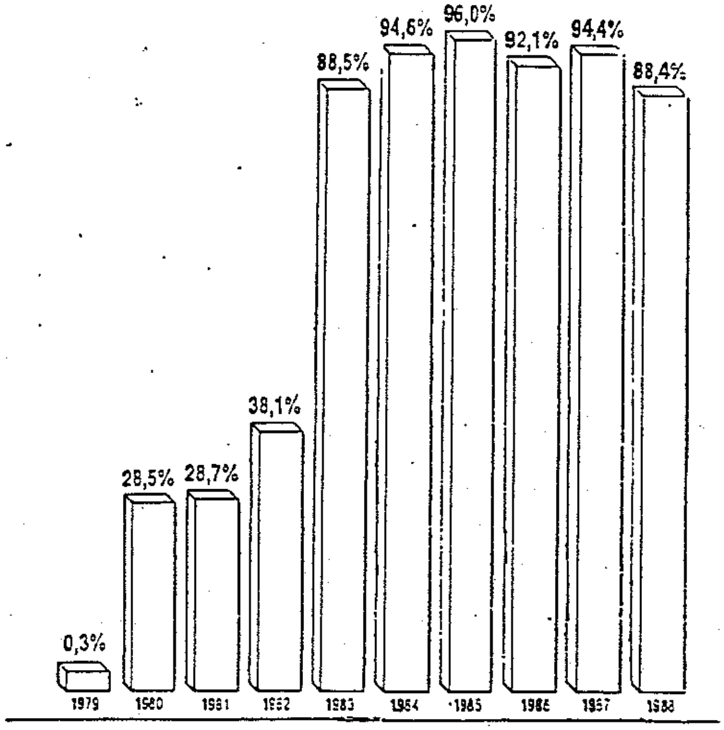


Figure 5.5. Fraction of all new cars sold in Brazil that operate on pure ethanol [132].

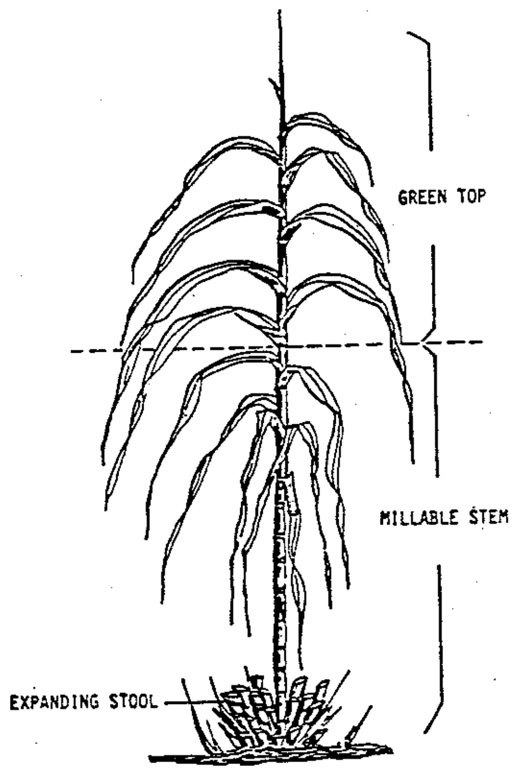
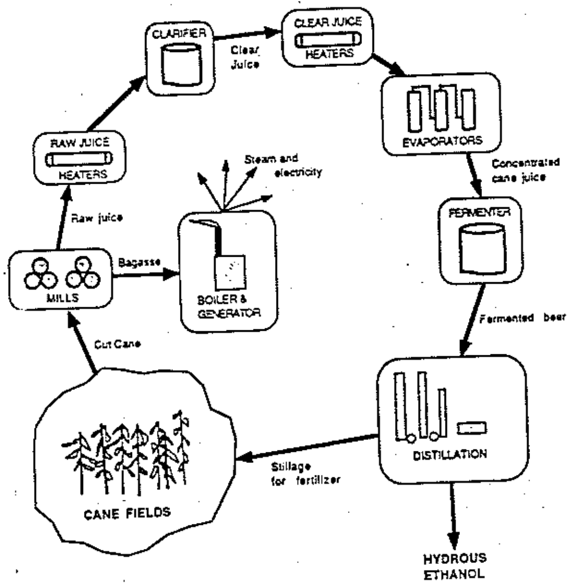


Figure 5.6. Sugarcane [133]. On a dry basis at harvesting age, the millable stem accounts for 54% of the total mass. Detached leaves (not shown) account for 31%. Attached leaves and the green top account for 8% and 7%, respectively. The millable stem, stripped of leaves and without the top, is the only portion of the plant which is delivered to the sugar or alcohol factory.

(A)



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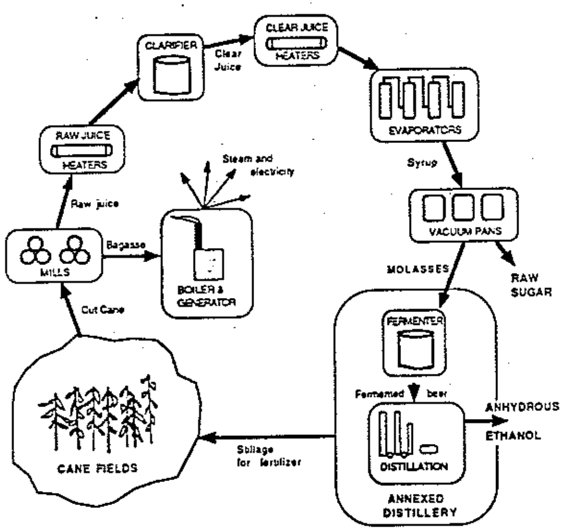

Figure 5.7. Basic steps in the production of ethanol from sugarcane at *(a)* an autonomous distillery and *(b)* a distillery annexed to a sugar factory [94].

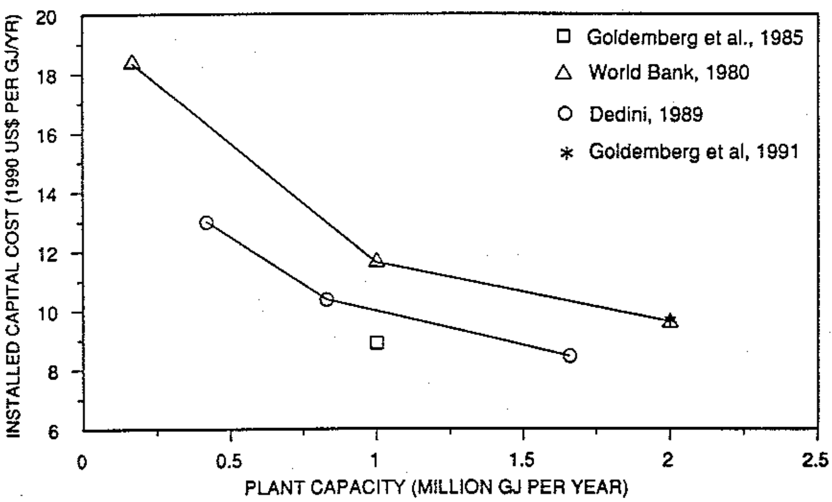

Figure 5.8. Reported capital costs for Brazilian autonomous ethanol distilleries. See Table A.7.

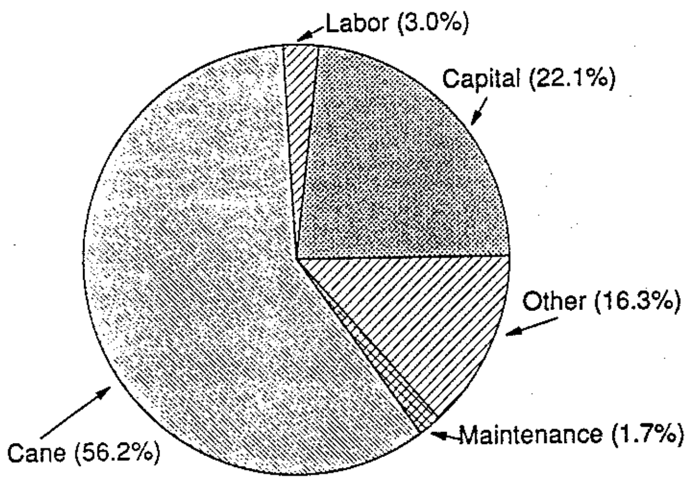

Figure 5.9. Breakdown of the cost of hydrous ethanol from sugarcane. See Table A.7. Assuming a 7% discount rate, a 41% capacity factor (150 days/year operation), \$10 per tonne of delivered cane, and an ethanol yield of 73.6 liters per tonne of cane. The total cost is \$10.6/GJ (\$0.23/lit).

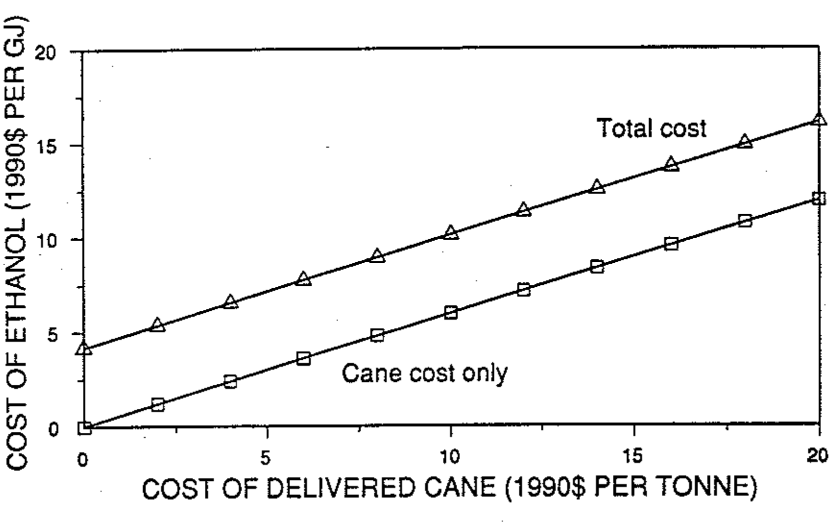

Figure 5.10. Ethanol cost versus cost of cane, assuming conditions as noted in Fig. 5.9 caption.

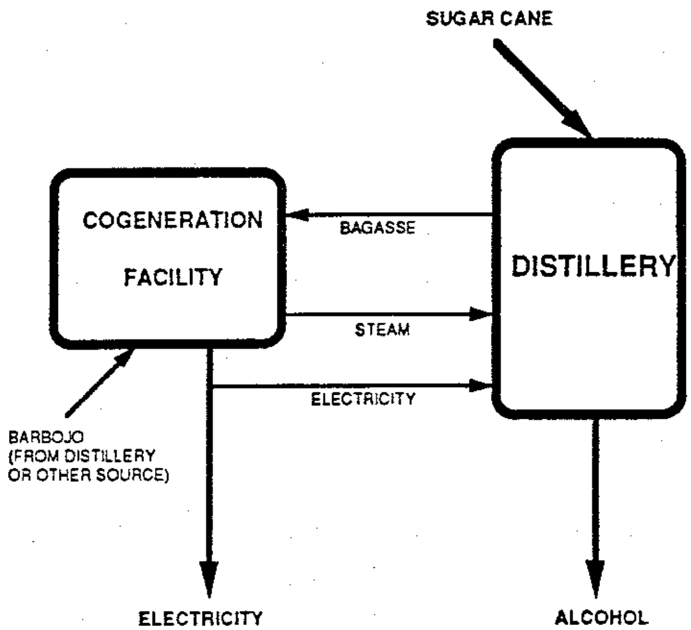

Figure 5.11. Material and energy exchanges between an autonomous ethanol distillery and cogeneration facility, as assumed for purposes of the ethanol and electricity cost analysis shown in Fig. 4.18b. It is assumed that during the milling season the cogenerator buys bagasse fuel from the distiller and sells back steam and electricity. It is assumed that during the off-season, the cogenerator buys barbojo as fuel—either from the distiller (if the distiller owns the cane fields) or from independent cane producers.

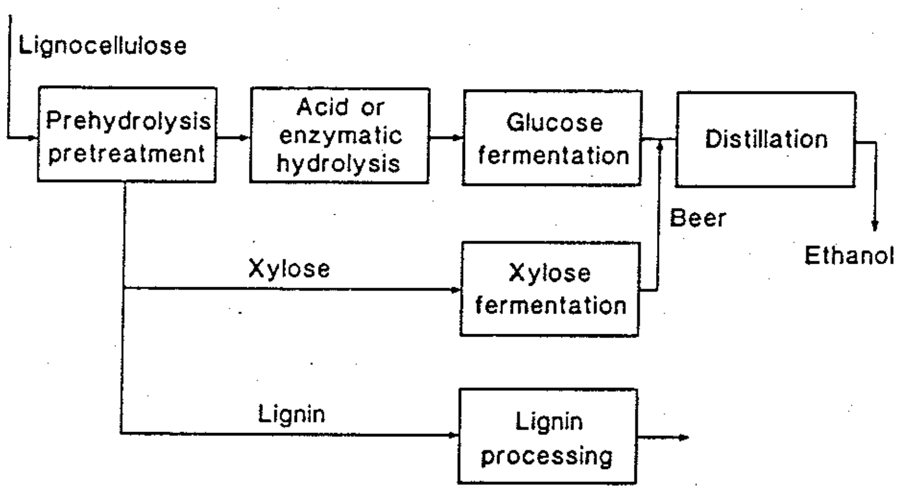

Figure 5.12. Basic steps in the conversion of lignocellulose (woody or herbaceous biomass) to ethanol by acid or enzymatic hydrolysis [105].

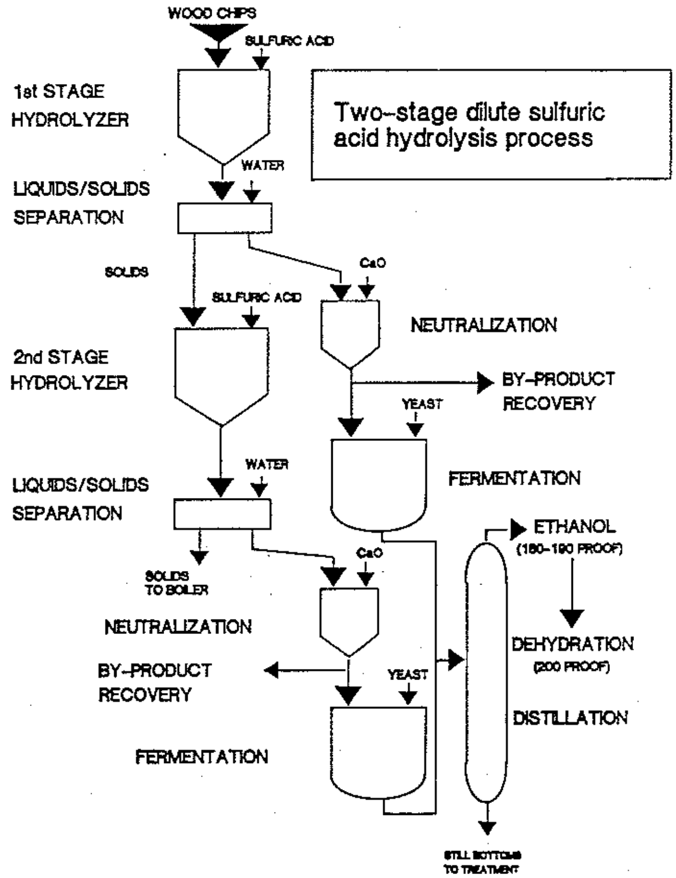

Figure 5.13. Example of a dilute sulfuric acid hydrolysis process [108].

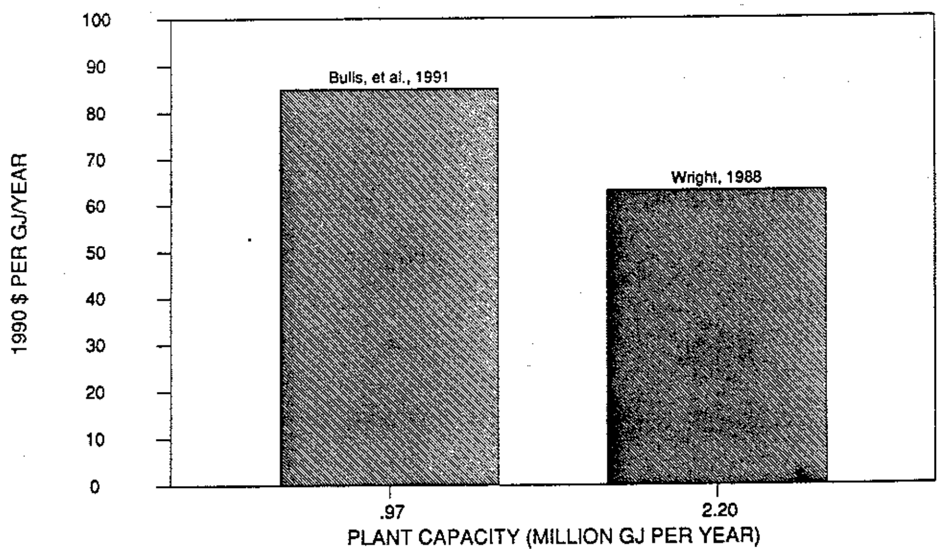

Figure 5.14. Capital cost estimates for dilute sulfuric acid hydrolysis plants. Sourc‹ s: [108] and [105]. See Table A.8.

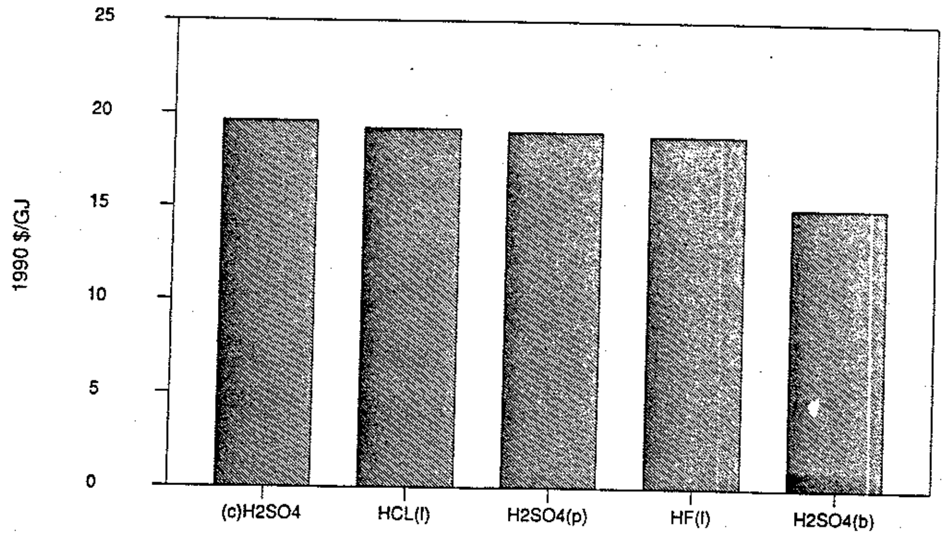

Figure 5.15. Total cost of ethanol by alternative acid hydrolysis processes at plants with a production capacity of 2.2 million GJ/year [105], and including credits for by-product electricity sales. (c)H2SO4 refers to a concentrated sulfuric acid process, HCL(l) to a liquid hydrochloric acid process, H2SO4(p) to a dilute sulfuric acid plug flow process, HF(l) to a concentrated liquid hydrogen flouride acid process, and H2SO4(b) to a dilute sulfuric acid progressing batch process. All cases assume a 7% discount rate, 20-year life, 90% capacity factor, 4 cents/kWh revenue for by-product electricity, and $2/GJ for wood. (See Table A.8.).

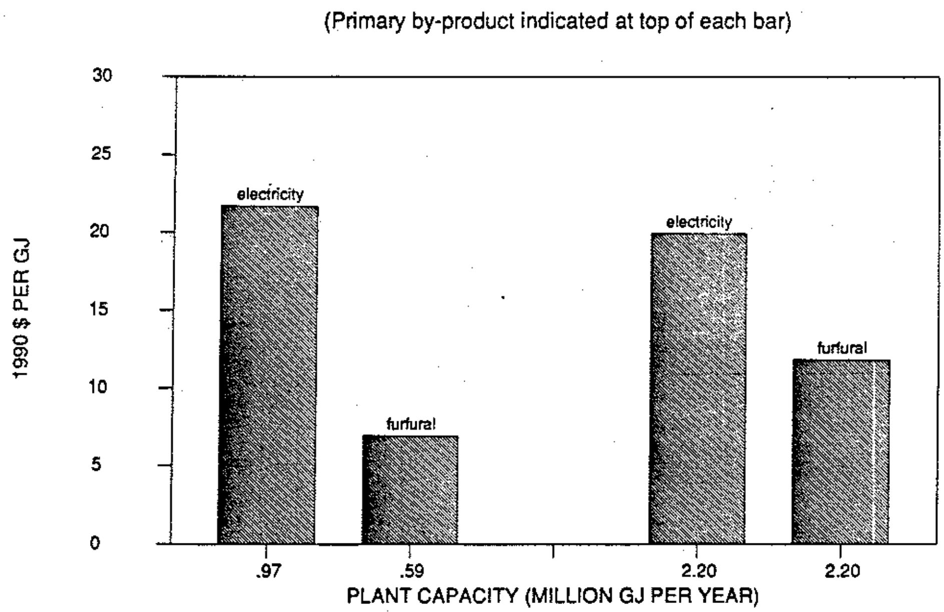

Figure 5.16. Comparison of ethanol costs when production of by-product furfural (from the xylose fraction of the feedstock) is emphasized. Estimates for the small and large plants are from [108] and [105], respectively. (See Table A.8.) For the small plants, the bar marked electricity refers to a plant configuration in which the xylose fraction is partially fermented to ethanol and partially burned on site for electricity production. Some of the electricity is used to meet on-site needs and some is exported. The bar marked furfual refers to the same basic plant, with all of the xylose fraction being recovered as furfural for resale. In the larger plant, the entire xylose fraction is either burned for electricity production or recovered as furfural.

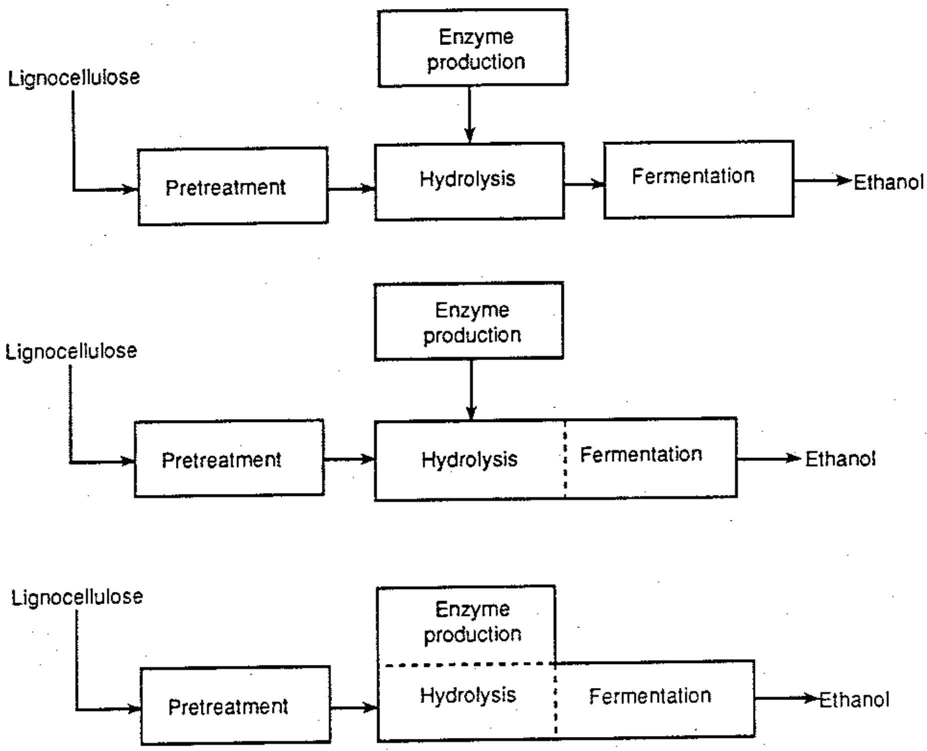

Figure 5.17. Ethanol production from lignocellulose by enzymatic hydrolysis involving *(a)* separate hydrolysis and fermentation (SHF), *(b)* simultaneous saccharification and fermentation (SSF), and *(c)* direct microbial conversion.

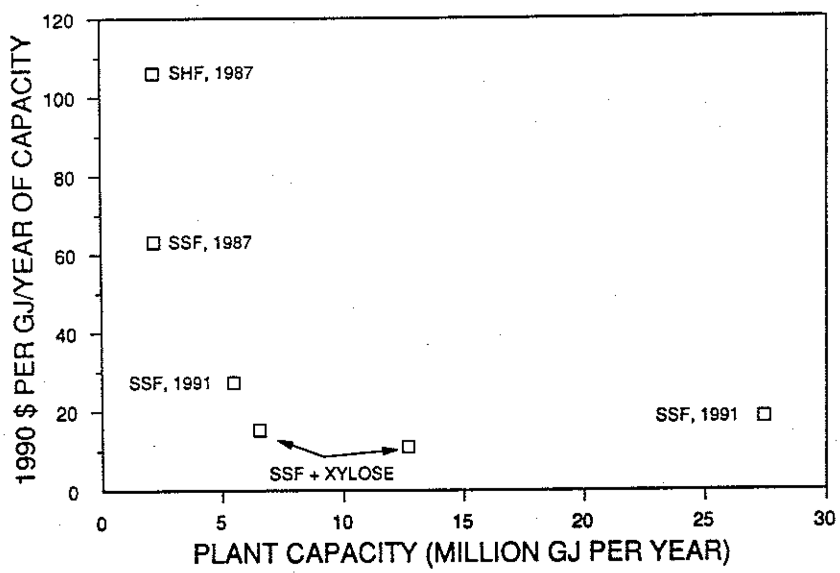

Figure 5.18. Installed capital cost estimates for alternative enzymatic hydrolysis ethanol production plants. (See Table A.9.) SHF, 1987 and SSF, 1987 refer to estimates by Wright [105]. SSF, 1991 is a more recent estimate by Wyman, et al [81] of what is believed to be currently achievable. SSF + XYLOSE are estimates for the year 2000, assuming a concerted research and development effort, for plants incorporating significant xylose fermentation in an SSF-based process [81,135].

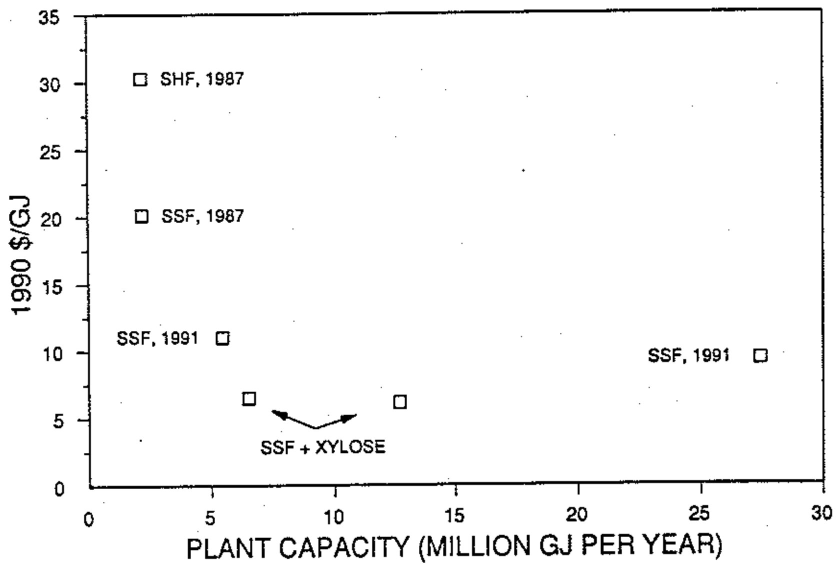

Figure 5.19. Total cost of ethanol by enzymatic hydrolysis, assuming a 7% discount rate, 20-year life, 90% capacity factor, and $2/GJ for wood. (See Table A.9.)

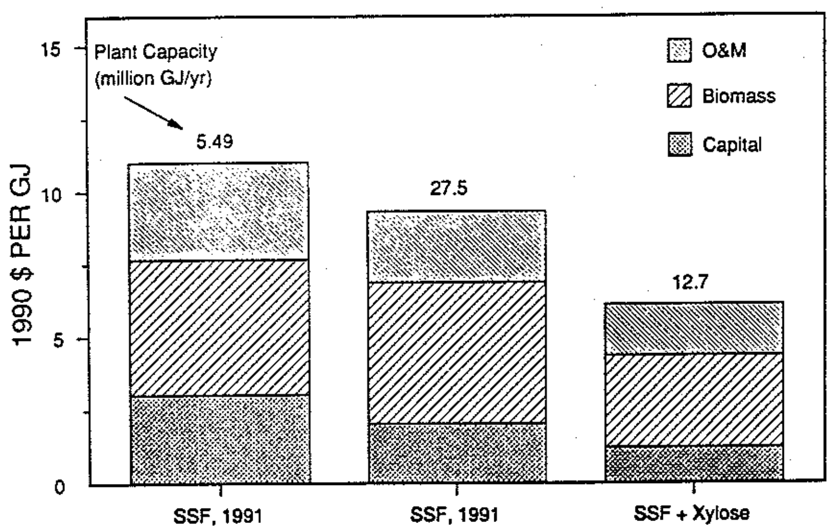

Figure 5.20. Breakdown of total levelized ethanol costs for the two SSF, 1991 costs indicated in Fig. 5.19 and for the larger of the SSF + XYLOSE cost.

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APPENDIX

This appendix contains cost and performance data reported in the literature. Some tables contain costs in different national currencies and for different years, as they were originally reported. In the text and the graphical presentations in this report, all costs have been converted to constant 1990 US dollars to facilitate comparisons. The methodology used to convert the costs to 1990 US dollars is described in Section 3 of the text.

Table A.1. Reported installed capital costs for wood and charcoal-fired producer gas generators manufactured in developing countries. Gas cleaning equipment is included in all the estimates. The year and currency of the indicated costs are given in parentheses beneath the source.

Source	Capacity (GJ/hour fuel input)	Cost	Comments
WOOD-FIRED			
Jain, 1985 [23] (1985 Rs)	0.0876	18,000	
	0.164	27,000	
	0.385	56,250	
	1.425	200,000	
Mukanda, et al., 1991 [4] (1990 Rs)	0.0855	25,000	Includes controls and building
	1.44	550,000	
Kjellstrom, 1985 [31] (1984 US$)	0.108-1.714		Cost is 40% greater than for charcoal (see below) at 0.108 GJ/hr. Same as charcoal at 1.714 GJ/hr. Manual feed. Includes building.
	0.560-14.4		Curve fit of manufacturer quotes. $\$ = 28{,}142*(GJ/hr)^{0.855}$ Automatic feed. Includes building.
Stassen, 1985 [129] (1985 $)	0.780	26,500	
	0.975	32,750	
	2.160	75,000	
Bridgwater, 1987 [128]	2-200		$\$ = (1.143x10^{6})*(GJ/hr)^{0.65}$
CHARCOAL-FIRED			
Coovattanachai, 1984 [127] (1984 Baht)	0.045	10,000	
	0.60	30,000	
	1.80	50,000	
Conventos, 1990 [26] (1990 $)	1.672	119,760	Brazilian manufacturer quotes, assuming 80% gasifier efficiency.
	2.51	149,700	
	5.02	227,545	
	8.40	251,497	
	16.7	299,401	
Chazan (Cientec), 1990 [26] (1990 $)	16.7	650,000	Brazilian mfg. quote for biomass or charcoal fuel, assuming 80% eff.
Stassen, 1985 [129] (1985 $)	0.240	5,900	
Kjellstrom, 1985 [31] (1984 $)	0.108-1.714		Curve fit to mfg. quotes: $\$ = 4426*(GJ/hr)^{0.565}$ Includes building

Table A.2. Performance and cost characteristics used to estimate production costs of producer gas.[a]

Fuel	charcoal	charcoal	charcoal	wood	wood	wood
Fuel input (MJ/hr)	150	300	900	300	900	1714
Gas Prod. Capacity (MJ/hr)	120	240	720	240	720	1371
Installed capital cost ($)	1515	2242	4170	2940	5200	6000
Maintenance costs ($/MWh$_{fuel}$)	2.52	2.34	1.40	2.70	1.40	1.26
Labor (person-hrs/operating hr)	0.2	0.2	0.3	0.2	0.3	0.5
Equipment lifetime (years)	6	6	6	6	6	6

(a) From [31]. All costs are given in 1984 US$. The maintenance and labor requirements have been estimated by comparing diesel-fueled electricity generating systems to comparably-sized producer-gas fueled electricity generating systems. The difference in maintenance and labor costs between the two are considered to be representative of the costs that would be associated with gas production alone.

Table A.3. Summary of reported capital and operating cost estimates for electricity production with producer-gas based systems. Both diesel and biomass consumption are given for dual-fuel units.

Jain, 1985 [23]	5 kW	10 kW	25 kW	100 kW
Diesel (kg/hr):	0.252	0.636	1.910	8.880
(kg/kWh):	0.0504	0.0636	0.0764	0.0888
Biomass (20% moisture)				
(kg/hr)	5.840	10.960	25.670	95.000
(kg/kWh):	1.168	1.096	1.027	0.950
Capital (1985 Rs):	25,000	55,000	120,000	420,000
Maintenance:	0.07 Rs/hr per kW installed (1985 Rs)			
Labor (1985 Rs/hr):	2.50	2.88	3.20	9.60
Lifetime (years)	5	5	5	5

Coovattanachai, 1984 [127]	40 kW	112 kW
Diesel (kg/hr):	2.68	7.54
(kg/kWh):	0.067	0.067
Charcoal (kg/hr):	20	60
(kg/kWh):	0.50	0.53
Capital (1984 Baht):	230,000	650,000
Maintenance:	6% of initial capital cost per year	
Labor (person-hours/hr):	0.4	0.79 (wage @ 10 B/hr)
Lifetime (years):	6	6

Stassen, 1985 [129]	10 kW	10 kW	50 kW	50 kW	150 kW
Fuel	Charcoal	Wood	Wood	Wood/diesel	Wood/diesel
Diesel (kg/hr):	0	0	0	2.70	7.0
(kg/kWh):	0	0	0	0.054	0.047
Biomass (kg/hr):	8.0	14.0	65.0	52.0	144.0
(kg/kWh)	0.8	1.40	1.30	1.04	0.96
Capital (1985$):	10,600	14,400	43,750	37,500	93,750
Maintenance:	$ 0.03/kWh in all cases (1985$)				
Lube Oil (lit/hr):	0.08	0.08	0.3	0.3	0.9
Labor (person-hr/hr):	0.1	0.1	0.1	0.25	0.25
Lifetime (years):	6	6	6	6	6

Mukunda, et al., 1991 [4]	4.4 kW	96 kW
Capital costs (1990 Rs)		
Gasifier:	5,000	100,000
Cooling, Cleaning, Control:	10,000	350,000
Engine Gen-set:	35,000	265,000
Building:	10,000	100,000
Diesel (kg/kWh):	0.093	0.093
Wood Use (kg/kWh):	1.3	1.0
Labor (Rs/hr):	6	20
Maintenance (%/yr of initial capital)		
Gasifier	5	5
Engine gen-set	10	10
Building	5	5
Lube Oil (grams/kWh):	1.36	1.36
Lifetimes:		
Gasifier, engine, genset (hours)	25,000	25,000
Cleaning system (years)	10	10
Building	40	40

Table A.4. Reported capital and O&M data for biogas digesters. Note that national currency and year are indicated for each source.

Source	Digester Capacity (m^3/day)	Installed Cost	Operation and Maintenance	
Santerre & Smith, 1982 [69] [69]	2.0	2332 (1976 Rs)	Maintenance: 25 Rs per m^3/day ($2 < m^3/day < 9$)	
	3.0	3016		
	4.0	3360		
	6.0	4175	Labor: 130 Rs per m^3/day ($2 < m^3/day < 9$)	
	8.0	5000		
	10.0	6100		
	15.0	8500		
	20.0	11500		
	25.0	12800		
	35.0	18400		
	45.2	20740		
	60.0	26000		
Reddy, et al., 1990 [77]	12.0	12121 (1986 Rs)	3440 Rs/yr, O&M	2044 Rs/yr, dung
	24.0	18145	3440	4088
	30.0	21157	4100	5110
	36.0	24169	4100	6132
	45.2	28794	4760	7701
	48.0	30193	4760	8176
	54.0	33205	6080	9198
	60.0	36217	6080	10220
Rijal, 1986 [71]	3.9	27,951 (1984 NCR)	1080 NCR/year	
	14.2	36,011	1080 NCR/year	
Bhatia, 1990 [42]	2.0	4800 (1985 Rs)	120 Rs/year	
	15.0	15840		
	25.0	16020		
	35.0	18000		
Rana & Verma, 1983 [68]	2.8	3900 (1983 Rs)		
	4.3	4800		
	7.1	5940		
	14.2	9900		
Kashkari, 1980 [67]	1.7	1575 (1973 Rs)		
	2.8	2075		
	4.2	2475		
	5.7	2850		
	8.5	3675		
	9.9	4050		
	14.2	5650		
	19.8	7450		
	25.5	8300		
	35.4	12300		
	42.5	13850		
	56.6	17200		
	84.9	25200		
	141.5	37600		
Orcullo, 1984 [70]	1.0	5500 (1984 Philippine	83 Peso/year, O&M	
	2.0	8800 Peso)	132	
	3.0	13200	198	
	5.0	17600	264	
	8.0	27500	413	
	16.0	38500	578	

Table A.5. Cost and performance characteristics of the 5 kW_e capacity biogas/diesel engine generator system at Pura village, state of Karnataka, India [61]. All costs are given in 1986 US dollars.

Installed capital cost	($)
Digester	2283
Piping, etc.	148
Sand filters for effluent	74
7 horsepower diesel engine	674
5 KVA 3-phase genset	1397
Accessories, tools, etc.	371
Engine room	296
TOTAL	5243

Lifetimes for
- Digester: 25 years
- Engine: 20,000 hours (with overhauls at 5000, 10000, and 15000 hours)

Cost of engine overhaul: $236

O&M costs: $1130 per year

Fuel consumption: Dung: 14 kg/kWh ($0.0016/kg paid to dung suppliers)
Diesel fuel: 0.06 liters/kWh

Table A.6. Cost estimates for methanol from biomass. All costs expressed in 1990 US$.

Source	Production 10^6 GJ/yr	Capacity liters/day	Capital Cost (10^6 \$)	Labor (10^3\$/yr)	Mainten. (10^3\$/yr)	Biomass[a] (kg/GJ_{Me})	Electricity (kWh/GJ_{Me})	Other ($\$/GJ_{Me}$)
[90]	0.580	88,493	26.74	870	730	89	9.25	2.94[b]
[20]	6.50	991,397	331.1	1,430	13,750	104	7.92	0.10
	7.58	1,156,630	245.4	1,430	10,360	88	10.39	0.28
	7.58	1,156,630	221.2	1,430	9,400	88	10.39	0.28
	41.49	6,331,315	799.2	1,760	32,430	88	10.39	0.29
	41.49	6,331,315	727.0	1,760	29,590	88	10.39	0.29
[81]	9.20	1,403,288	202.4	1,610	8,730	72	included	0.98[c]
	9.20	1,403,288	160.7	1,610	7,430	72	else-	0.99[c]
	45.98	7,016,438	553.5	7,870	23,590	58	where	0.90[c]
[88]	8.29	1,264,219	245.5	9,980	6,140	84	31.40	0.12

(a) Dry biomass, assuming a heating value of 20 MJ per kg of biomass.

(b) Of this, \$2.33 is for purchase of oxygen.

(c) Includes electricity and chemicals.

Table A.7. Capital and operating cost estimates for Brazilian autonomous distilleries producing hydrous ethanol.

Source[a]	Distillery Capacity 10^6 GJ/yr	10^6 lit/day	Installed Capital Cost (10^6 US$)	Operating Costs (1985 US$)
World Bank, 1980	0.166	20,000	2.00 (1980$)	
	0.999	120,000	7.60	
	1.997	240,000	12.50	
Dedini, 1989	0.416	50,000	5.00 (1988$)	
	0.832	100,000	8.00	
	1.664	200,000	13.00	
Goldemberg, et al., 1985	0.999	120,000	7.30 (1985$)	Labor (105 men, 3 shifts): $226,100/year Maintenance: 2%/year of initial capital Chemicals: $41,800/year Supplies: 10% of maintenance cost Insurance: 0.5%/year of initial capital
Goldemberg et al., 1991				
Average SE Brazil	1.997	240,000	18.60 (1989$)	Labor: $223,990/yr Maintenance: $149,330/yr Chemicals: $74,660/yr Other: $1,045,300/yr Cane: 73.6 liters EtOh/tc
Best SE Brazil	1.997	240,000	18.60	Labor: $261,320/yr Maintenance: $223,990/yr Chemicals: $74,660/yr Other: $1,343,950/yr Cane: 80 liters EtOH/tc

(a) World Bank, 1982 [91]; Dedini, 1989, as quoted in [98]--Dedini is a major Brazilian manufacturer of turn-key distilleries; Goldemberg, et al., 1985 [92].

Table A.8. Cost estimates for ethanol production from biomass by acid hydrolysis, assuming production of hydrous ethanol. All costs expressed in 1990 US$.

Source	Production 10^6 GJ/yr	Capacity liters/day	Capital Cost (10^6 \$)	Labor (10^3\$/yr)	Mainten. (10^3\$/yr)	Biomass[a] (kg/GJ_{Et})	Chemicals[b] (\$/GJ_{Et})	By-prod. Credit[c] (\$/GJ_{Et})
[108]								
Dilute	0.97	125,342	82.1	2,764	5,970	159	2.36	6.12
H_2SO_4	0.59	76,932	68.8	2,104	3,868	259	5.42	31.79[d]
[105][e]								
(c)H_2SO_4	2.20	284,877	140.9	2,161	10,208	171	4.05	3.76
HCL(l)	2.20	284,877	138.3	2,104	10,038	175	3.82	3.85
HF(l)	2.20	284,877	109.6	1,679	7,934	156	6.12	3.04
H_2SO_4(b)	2.20	284,877	112.4	1,706	8,131	194	1.84	4.53
H_2SO_4(p)	2.20	284,877	138.3	2,020	9,583	262	1.93	5.34
H_2SO_4(p)	2.20	284,877	133.7	2,047	9,667	262	1.93	12.99[d]

(a) Dry biomass, assuming a heating value of 20 MJ per kg of biomass.

(b) Also includes cost for utilities (primarily water).

(c) In most cases the by-product credit is for electricity sold at 4 cents per kWh. Where noted, revenues from the sale of furfural are also included.

(d) Includes sale of furfural as a by-product.

(e) See caption to Fig. 5.15 for description of specific processes.

Table A.9. Cost estimates for ethanol production from biomass by enzymatic hydrolysis, assuming production of hydrous ethanol. All costs expressed in 1990 US$.

Process [Source]	Production 10^6 GJ/yr	Capacity liters/day	Capital Cost (10^6 $)	Labor ($10^3$$/yr)	Mainten. ($10^3$$/yr)	Biomass[a] (kg/GJ_{Et})	Chemicals[b] ($/$GJ_{Et}$)
SHF							
[105]	2.20	284,877	233.1	3,582	17,032	201	0.85
SSF							
[105]	2.20	284,877	138.6	2,104	10,038	168	0.76
[81]	5.49	659,342	149.6	2,346	8,303	116	1.18
[81]	27.46	3,299,726	505.6	4,697	26,605	121	1.18
SSF + Xylose							
[135]	6.54	785,781	99.6	---	5,217[c]	97	---
[81]	12.70	1,526,411	139.1	2,093	7,313	78	0.93

(a) Dry biomass, assuming a heating value of 20 MJ per kg of biomass.

(b) Also includes cost for utilities (primarily water).

(c) Includes labor, maintenance and chemicals.