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ASSESSMENT OF LARGE SCALE BIOMASS GASIFICATION SYSTEMS FOR LESS DEVELOPED COUNTRIES

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FOREWORD

This study was performed by Battelle Pacific Northwest Laboratries for the United States Department of Agriculture Forest Service (USDA/FA) under the direction of Dr. Harold Gus Wahlgren, USDA/FA technical monitor, whose assistance and guidance is gratefully acknowledged. We would also like to thank Dr. Jack Fritz for his assistance in initiating this study.

SUMMARY

This study was to develop an analysis of the state-of-the-art of large scale biomass gasification systems and potential applications in less developed countries (LDCs). Applications considered in this study were industrial and electric power applications and production of synthesis gas for liquid fuels and chemicals. Related biomass conversion technologies are covered in separate companion state-of-the-art studies of small scale gasification, pyrolysis, and production of methane by other contractors.

Large-scale (.2 million Btu/hr) air-blown biomass gasifiers are commercially available in the U.S., Canada, and Europe. Several companies have accumulated enough operating time with their gasifiers to consider them proven technology. In the U.S. the most common application of large-scale biomass gasification is the use of fixed-bed, updraft gasifiers to produce fuel gas for boilers. In Europe several manufacturers offer fixed-bed, downdraft gasifiers which are commonly used to produce fuel gas for diesel engines. Several of this type of unit have been installed and operated in LDCs.

There has been no recent commercial use of large scale oxygen-blown gasifiers for production of medium-Btu gas or synthesis gas. Three large (300 ton/day) prototype gasifiers are being planned for Brazil. They will produce synthesis gas for methanol production. Biomass gasification has also been considered for production of ammonia synthesis gas. Several commercial gasifiers, both air-blown and oxygen blown, have been developed specifically for municipal solid waste. These units are operating in both Japan and Europe.

Low-Btu gas from biomass can be produced for \$2-5 per million Btu. This gas can be used in boilers, kilns, dryers, internal combustion engines, and other equipment normally fueled by natural gas or oil. In many instances the modifications necessary to burn low-Btu gas are minor. Electricity from new generating capacity based on biomass gasification will cost \$0.06-0.10/kW-hr. Methanol can be produced from biomass derived synthesis gas from \$0.70-1.00 per gallon (utility financing) for a 500 ton/day methanol plant. Ammonia can be produced from biomass for \$140-180 per ton (utility financing) for a 500 ton per day ammonia plant.

The two factors which contribute to the range of costs shown here are the method of financing and the cost of the biomass feedstock. Industrial Financing versus utility financing increases the cost of methanol about $0.25/gallon and ammonia about $70/ton.

The key to the impact of large-scale biomass gasification in LDCs is the availability of feed materials. Biomass already accounts for a large portion of the energy consumed in LDCs particularly in the poorer countries, and shortages of these traditional fuels are not uncommon. Production of ammonia and methanol on an economic scale wll require development and careful management of biomass resources. There are other constraints to utilization of large-scale biomass gasification particularly in rural areas. To succeed, rural biomass conversion programs must be introduced with the full cooperation of the people involved. Educational services and support networks must be provided to assure that the local people can operate and maintain the equipment.

Based on our technical and economic evaluation of large-scale biomass gasification and taking into account the various constraints imposed by LDCs we believe the most promising applications of large-scale biomass gasification in developing countries are:

- Rural electrification using air-blown biomass gasifiers and diesel generators.
- Retrofitting existing oil and gas fired equipment in various industries, particularly these which process agricultural products.
- Producing ammonia based fertilizers from biomass derived synthesis gas.

These conclusions are based on generalizations about needs and resources in LDCs. Each country or region represents a unique set of conditions and the choice of biomass conversion technologies msut be based on specific needs and resources as well as the merits of the various competing technological approaches.

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INTRODUCTION

The Forest Service of the U.S. Department of Agriculture (USDA/FS) in behalf of the Office of Energy in the Agency for International Development (AID/OE), has undertaken the task of improving the utilization of renewable energy resources in developing countries. The present focus of the project is the identification of viable, existing technologies for conversion of biomass to energy. This report presents an assessment of the state-of-the-art of large-scale biomass gasification technology, with particular emphasis on less developed country (LDC) applications.

Gasification as used here signifies the reaction of solid fuels with air, oxygen, steam, carbon dioxide, or mixtures of these, to yield a gaseous product that is suitable for use either as a source of energy or as a raw material for synthesis of other products. Pyrolysis is defined as heating solid fuels without addition of oxidizing or reacting gases and is generally directed toward production of a liquid fuel and char as well as a gaseous product. Pyrolysis processes as such are not considered here.

Solid fuels of concern to this study are wood, wood waste, agricultural crops, crop residues and other plant matter commonly referred to as biomass and two other materials sometimes referred to as biomass - municipal solid waste and manure. For the purpose of this assessment large-scale gasification systems have been defined as those with a gas production capacity greater than 2 million Btu/per hour. This corresponds to a minimum of about 3-7 tons per day of solid fuel depending on the feedstock. This is not large by some standards but gasifications systems of this size closely match the energy requirements of small industries and are too large for individual family or small village needs.

There are many potential uses of the fuel gas produced from biomass gasification. Biomass gasification applications of particular interest to USDA/FS and AID/OE are industrial steam generation, electric power generation, and production of liquid fuels and chemicals (particularly methanol). Production of substitute natural gas is not included in the scope of this study.

BIOMASS FEEDSTOCKS

Biomass includes many different carbonaceous materials each of which has somewhat different requirements for collection, preparation, and gasification. This section of the report identifies potential feedstocks for large scale biomass gasification projects and discusses the pretreatment required prior to gasification.

TYPES OF FEEDSTOCKS

Solid fuels that will be considered in this study are wood, forest residues and other wood wastes, agricultural crops, crop wastes and residues, and municipal solid waste (MSW). For the purpose of this report they will be collectively referred to as biomass.

Biomass is a resource which is distributed over large areas. Harvesting, collection, and transportation expenses may be considerable in many biomass applications. Transportation costs alone may limit the size of large scale biomass systems. If the biomass is collected for other reasons (i.e. food or lumber harvesting) the use of residues is often economical. For this reason the forest products industries and processors of agricultural products have led the way in applications of biomass gasifiers. Municipalities with large quantities of municipal solid waste available at one location have also been active in gasification, particularly in Europe and Japan. Now, with increasing prices of conventional fuels, biomass gasification systems are being considered by other industries, state and federal governments, schools, farmers, and individual citizens.

Wood is the most common biomass fuel. Sources for wood fuel are mill wastes, forest residue, and wood harvested specifically for fuel. Mill wastes consists of sawdust, bark, coarse residues, and planar shavings. In the US, most mill residues are well utilized already. Over 72 percent of these residues are used by the mills for their own energy needs. Plywood producers use 92 percent of their wood residues (Howlett 1977).

Forest residues primarily consist of tops, stumps, trunks and branches remaining in the forest after a logging operation. Other significant forest residue sources are wood from cleaning and thinning operations, removal of noncommercial trees, and trees damaged by fire, disease, and insects. In addition energy farms where trees are grown specifically for use as a fuel are envisioned.

Various crops can also be grown specifically for fuel, however, for gasification applications crop residues and wastes have received more attention. There are two basic sources of these residues.

- By products of food processing such as walnut shells, bagasse, corn cobs, olive pits, and coconut shells
- Residues collected from the field specifically for use as a fuel such as wheat straw, corn stover, and rice straw.

By-products from food processing have been used as gasifier fuel in the U.S. and other countries. In the U.S. it has not been economical to collect residues from the field; however such residues have been collected and gasified in developing countries. Table 1 shows estimates of the ratio of dry residue weight produced to the harvested crop weight for various crops in the U.S. The amount of residue varies with the crop and growing conditions. These figures are given just to show the potential for using the residues.

Another large source of potential fuel is municipal solid waste (MSW). This consists of both household and industrial wastes and probably represents the largest collection of feedstock available at any one location. MSW has been successfully gasified in both pilot and commercial scale facilities. MSW is normally disposed of in landfills so the feedstock cost would be significantly less than biomass feedstocks. In many instances a credit can be taken for disposal of the waste via gasification. MSW does cost somewhat more to process and gasify than biomass fuels because it usually contains a large quantity of inerts such as metal and glass.

A potentially large source of fuel in rural areas of LDCs is animal manure (dung). Manure has not been used in a commercial gasification facility however it has been gasified in a small developmental reactor.

Table 2 presents analyses of some potential gasification feedstocks. The heating value of these materials ranges from 7000-9000 Btu per pound on a moisture and ash free basis. Biomass materials generally have a low ash

TABLE 1. Tons of Dry Residue Per Ton of Crop Yield for 1975 in USA (Ernest 1979)

Corn	0.58
Cotton	1.23
Grain Sorghum	0.63
Sugarcane	0.13
Rice	1.14
Wheat	1.85

content between 0-2 percent unless inert materials (such as dirt, sand, metal, etc.) are picked up in the process of collecting the biomass. Such is the case for the data on forest residue and rice husks presented in Table 2. Municipal solid waste (MSW) contains inert materials (metal) which results in the high ash content indicated. The moisture and ash free material of most biomass feedstocks consists mainly of carbon, hydrogen, and oxygen with little or no nitrogen and sulfur. The hydrogen/carbon ratio of biomass materials and MSW is higher than coal and similar to petroleum. Biomass and MSW both contain significantly more oxygen than coal or petroleum. Both coal and petroleum contain significant quantities of nitrogen and sulfur which biomass and MSW do not. The fixed carbon content of most of the feedstocks about is 20 percent on a moisture and ash free basis. This compares to 50-80 percent for coal. The moisture content of these materials has a wide range. Green wood has a moisture content of around 50 percent but it can be higher. The moisture content of municipal solid waste is about 25 percent generally.

FEEDSTOCK HANDLING AND PREPARATION

Large scale biomass gasification will require a significant feedstock storage capacity. In addition some feedstocks may require preparation before they can be fed to a gasifier. The feed preparation requirements depend on the feedstock properties and the type of gasifier. Feed preparation can involve sizing, drying, and densification. Most commercial experience in this area has

TABLE 2. Analyses of Potential Feed Stocks

	Wood (hog Fuel)	Forest-residue	MSW	Bagasse	Rice Husks	Coconut Shells	Corn Cobs
Higher Heating Value (dry basis) Btu/lb	8700	8700					
Lower Heating Value (dry basis) Btu/lb			4500	7430	6340	7890	7820
Ultimate Analysis (dry basis)							
C	50	46	38				
H	6	6	54				
O	43	40	24				
S	nil	nil	—				
Ash	1	8	33				
Proximate Analysis (dry basis)							
volatile	80	68	55	82	61	76	76
fixed carbon	19	24	12	16	17	21	21
ash	1	8	33	2	22	3	3

been with wood in the forest products industries. The following discussion applies mostly to wood processing; however other feedstocks can be handled in much the same manner.

Storage

For large scale biomass conversion applications, considerable fuel storage is required. The amount of storage required depends on the reliability of the supply. Municipal solid waste is perhaps the most steadily available feedstock, and therefore requires the least amount of storage. On the other hand, an application relying totally on crop residues will need a large storage area because residue harvesting may only occur once or twice a year. Mill residues would be a relatively steady supply, whereas forest residues supplies may fluctuate with the weather.

The cheapest storage of biomass is outdoor piles exposed to the weather. Retrieval of the biomass is accomplished by conveyors, screws, bulldozers, and front end loaders. Biomass moisture content may increase during outdoor storage, and moisture is detrimental to the efficiency of any gasification scheme.

An expensive alternative is dry storage in silos and bins. These are usually loaded by mechanical or pneumatic conveyors. They are discharged from live bottom bins by augers or sweep bucket chains. Dry storage should be considered when the feedstock is already available in dry form. Most densified feedstocks (cubes, pellets, extrudates) require dry storage.

Some potential fire hazards exist with each storage system. Spontaneous combustion is possible in deep storage piles. Dust in silos and bins represents a potential for explosion.

Sizing

Most gasification systems have upper and lower limits on the size of the material they can handle. In addition non-uniform sized feedstocks can cause operational difficulties (bridging) in feed handling systems and in some gasifiers. As a result size reduction and/or classification may be necessary for some feed materials. Commercial equipment used to properly size feedstocks includes vibrating screens and disc screens, air classifiers, chippers, and densifiers.

Screens and classifiers are commonly used to classify feedstocks by particle size. They can be used upstream of size reduction equipment to remove tramp materials and to prevent processing of fuel already in the proper size range. They may be used downstream to catch oversized material which passed through the size reduction equipment.

Two common types of screens are disc screens and vibrating screens. A disc screen consists of rows of spaced, rotating discs through which properly sized matter can pass. Vibrating screen systems have lower capacity than disc screens. They are more often used to sift out fine dirt.

Size reduction equipment for wood includes whole tree chippers and hogs. Whole tree chippers are usually used in the field to reduce trees, branches, and stumps to chips as small as 3/4inch nominal. Mobile units are available that will pick up trees that have been cut and pushed into berm rows, reduce them to chips, and load the chips into a van. Mobile units that will fall and chip tress at the same time are being developed (Eakin 1979).

Oversize wood waste is comminuted by a hog, a shredding machine serving the same purpose as a chrusher in a coal-preparation system. Hogging can be done either before or after the wood waste is placed in storage. The two main types of hogs are knife hogs and hammermills. Knife hogs can handle large logs, reducing them to chip-size particles with minimal power consumption. Because the cutting edges are sensitive to tramp iron, rock, sand, and other contaminants they are generally used with relatively clean wood. Hammermills by contrast are far more versatile. They can handle light tramp iron and other contaminants without any damage. Figure 1 shows how a hammermill hog works: woodwaste is gravity-fed through a large opening in the top of the hog, chopped between the hammers and the breaker plate, and then ground between the hammers and the screen at the bottom of the unit (Schweiger 1980). Hogs are normally adjusted to give a discharge product with a top size of 2-3 inches. Smaller sizes are possible, but additional power consumption is required.

Drying

Feedstocks with up to 50 percent moisture have been gasified successfully. However, wet feedstocks reduce the quality of the product gas and this may reduce the efficiency of downstream processes. In addition some types of

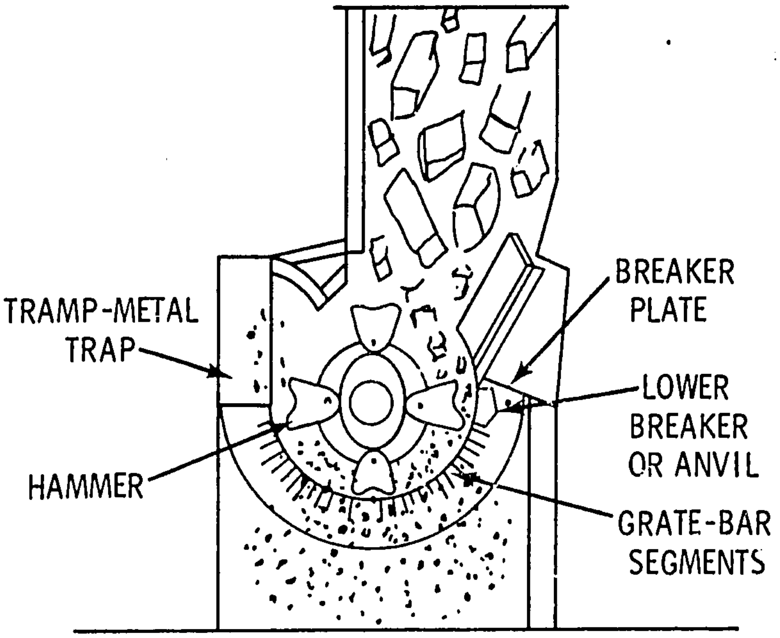

FIGURE 1. Typical Hammermill Used to Hog Woodwaste

gasifiers require dry feed material. The decision to dry the biomass feed material will depend on the moisture content of the feed, the type of gasifier, and the downstream process which utilizes the gas.

There are two basic types of dryers for wood: one uses mechanical energy to wring the water out of wood (hydraulic presses) while the other uses hot gases to evaporate the water. Applications for hydraulic presses are limited because they can reduce the moisture content to only about 55 percent. Hot gas dryers can be either the fired or unfired type. The unfired type using a source of waste heat is the most desireable for large scale gasification plants. Hot air, flue gases, or superheated steam can be used to dry the wood. Rotary drum dryers like the one shown in Figure 2 are the most common type of hot gas dryer in use today. Sized wood is fed to the top of a cylinder inclined slightly to the horizontal. Feed solids progress through the cylinder by virtue of rotation and the slope of the cylinder. Hot gases can flow either cocurrent or countercurrent to the solids depending on the design.

If an indirect fired rotary drum dryer is used, a supplementary burner can be installed to regulate product moisture within tight limits. Other dryers that have been used with wood include cascade dryers, hot hogs, and hot

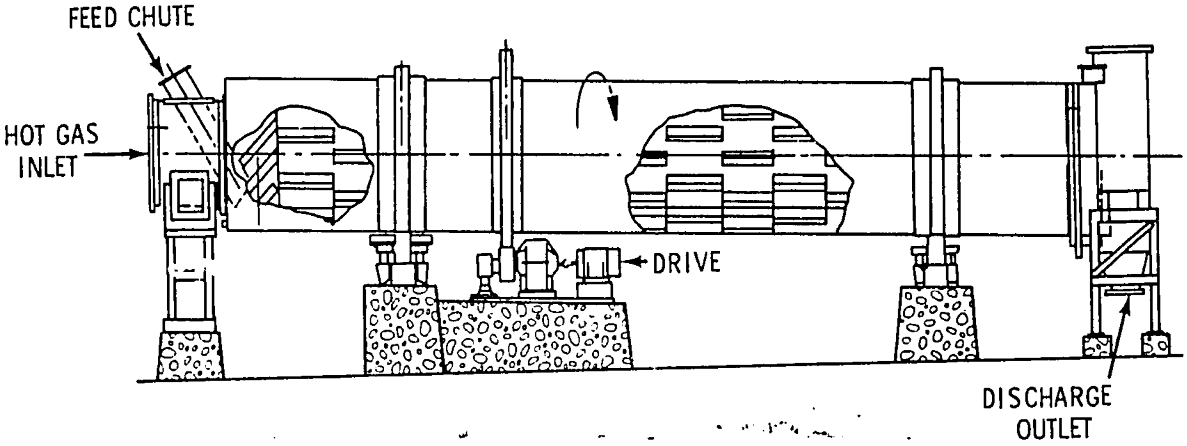

FIGURE 2. Rotary Drum Dryer Used to Dry Woodwaste

conveyors. Forest Fuels Inc., which builds small gasifiers for boiler retrofit applications also builds a hot screw feeder/dryer for their units. Boiler flue gas is diluted with air and flows through the screw conveyor which feeds the gasifier (Caughey 1979).

Densification

A biomass feedstock with a low density (straw, husks, etc) or small particle size (fine sawdust) will tend to plug (bridge) in some feed systems and in certain types of gasifiers. To solve these problems feed materials like this can be densified. Other potential reasons for densifying the fuel include decreased shipping and storage volumes and increased throughput in the gasifier.

Densification consumes energy, typically 1 to 3 percent of the energy represented in the feed material (Reed 1978). It also represents increased capital investment. The ability of a material to undergo densification is a function of the type of material and its moisture content. In some cases a binder will need to be added to the fuel in order to allow densification.

Five methods of densification are used commercially. They are pelleting (1/4 to 1/2" pellets), cubing (1 to 2" cubes), extrusion, briquetting (as in charcoal production), and rolling-compressing.

Pelleting employs a hard steel die which is perforated with an array of holes. The die rotates against inner pressure rollers forcing the biomass feedstock through the die holes with high pressure. As the pellet is extruded through the die it is broken off at a specified length. Cubing is a modification of pelleting which produces large cylinders or cubes. Extrusion uses a screw to force a feedstock under high pressure into a die thereby forming large cylinders. Briquetting compacts a feedstock between rollers with cavities producing forms like charcoal briquettes. Rolling-compressing is based on the natural tendency of forage crops to wrap tight around rotating shafts. Reed et al. lists vendors of densification equipment (Reed 1978).

Several companies produce and sell densified biomass fuels. The most common feedstocks are wood and municipal solid waste (MSW). Densified MSW is often referred to as refuse derived fuel (RDF). Companies that make densified biomass fuels are listed by Reed et al. (Reed 1978).

BIOMASS GASIFICATION

Gasification of coal and coke began in the mid 1800's in the iron industry. Many other applications of gasification were developed in the early 1900's. The most common applications were to produce fuel for gas engines, steam boilers, kilns, and metallurgical furnaces. A variety of carbonaceous materials have been gasified successfully including many materials we now refer to as "biomass".

Between 1912 and 1940, Crossley Brothers Ltd. apparently installed about 600 small biomass gasifiers in Africa and Australia for shaft power (Levelton 1978). These were fixed bed updraft units. From 1934 to 1967 the Power-Gas Corporation (now Davy Powergas) installed 22 gasifiers in many countries (Rooker 1980). These operated on various feedstocks such as cotton seed husks, sugar cane refuse, olive refuse, bagasse and wood. These gasifiers were fixed bed updraft units operating at slight negative pressures. The producer gas was used for steam boilers, shaft work, and synthesis gas for ammonia. An early Power Gas fuel gas producer is shown in Figure 3.

During World War II there was an increase in the use of gasifiers, particularly for vehicular application due to the tightening of fuel supplies in Europe. Typical fuels were wood, charcoal, and peat. After the war, with cheap fossil fuels and electricity, the use of gasifiers declined sharply. Although gasification systems may have been competitive economically, they could not compete with the convenience of other energy sources.

Presently the energy crisis in the United States, other industrialized nations, and less developed countries has caused a rebirth of gasifier applications. There are many successful current applications of biomass gasifiers, many vendors of gasification equipment, and numerous projects in the development stage at this time.

Gasification technology has been reviewed extensively several times. These reviews include an excellent summary of the early work (von Fredersdorff 1963), descriptions of twenty-two gasifiers in operation or under development (Dravo 1976), and three recent reviews of wood and biomass gasification (Wan 1979; Reed 1979; Fritz 1979).

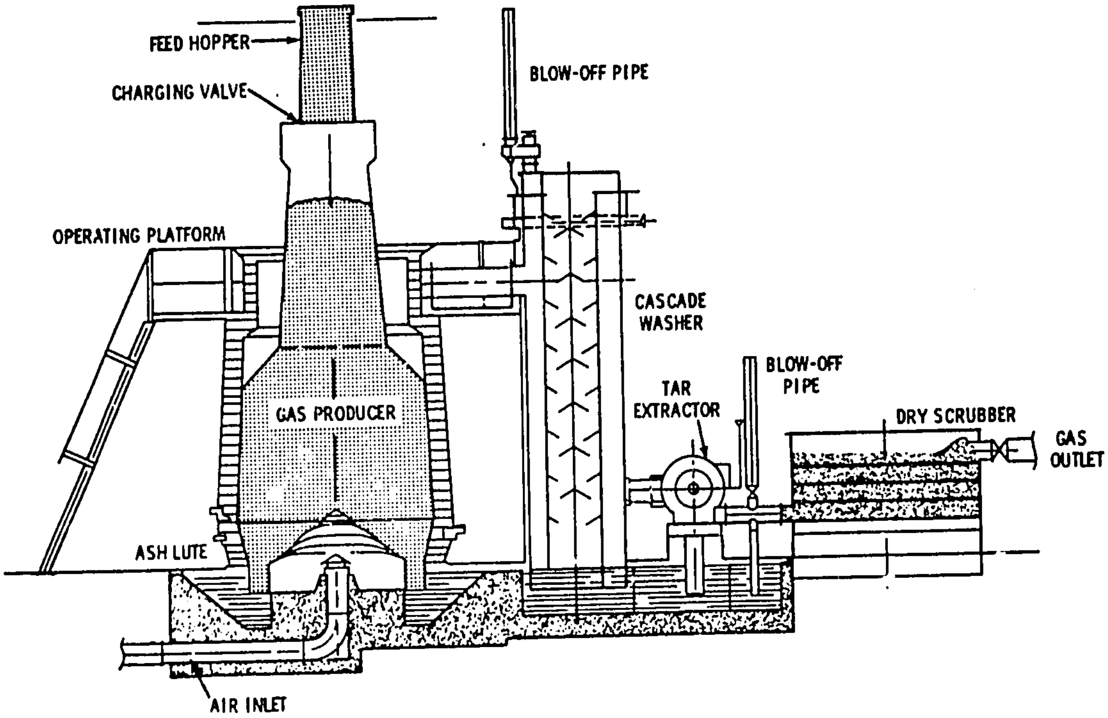

FIGURE 3. Schematic of an Early Powergas Corp. Waste Fuel Producer Gas Plant

GASIFICATION CHEMISTRY

Pyrolysis of biomass is thermal degradation of the material in the absence of reacting gases. The pyrolysis of biomass will occur prior to or simultaneously with gasification reactions in a gasifier. Pyrolysis is a nearly autothermal reaction which occurs at about 300 C-400 C. Pyrolysis products consist of gases (CO, CO_2, H_2O, H_2 CH_4, and traces of C_2-C_5), liquids, and char (mostly carbon). For wood and many other types of biomass the liquid fraction consists of an insoluble viscous tar (phenolics) and a soluble fraction containing acetic acid, methanol, acetone, esters, aldehydes, and furfural which collectively are known as pyroligneous acid.

Distribution of the pyrolysis products varies depending on the feedstock composition heating rate, temperatures, and pressure. The products may also undergo subsequent reactions in a gasifier.

Gasification reactions consume solid carbon or char as shown below:

(1) $C + O_2 \rightarrow CO_2$ exothermic

(2) $C + 1/2O_2 \rightarrow CO$ exothermic

(3) $C + H_2O \rightleftharpoons CO + H_2$ endothermic

(4) $C + CO_2 \rightleftharpoons 2CO$ endothermic

(5) $C + 2H_2 \rightarrow CH_4$ exothermic

In conventional gasification, reactions 1 and 2 provide the energy required for drying, pyrolysis, and the other endothermic reactions occurring in the gasifier.

If the air (or oxygen) rate to the gasifier is less than about 20 percent of the stoichiometric air required for combustion, char will be a significant product. Reactors operating in this mode are generally referred to as pyrolyzers or carbonizers. If the air (or oxygen) rate to the gasifier is above 20 percent of stoichiometric for combustion the only major products are low Btu gas and heavy hydrocarbon liquids. Reactors operating in this mode are generally called gasifiers. Approximately 6.1 pounds of atmospheric air is required for combustion of one pound of dry wood (Perry 1973) and 1.2 to 1.3 pounds of air (0.25 pounds of oxygen) are required to eliminate production of char.

A variety of other significant reactions may occur in a gasifier. These are:

(1) $H_2O + CO \rightleftharpoons CO_2 + H_2$

(2) $CH_4 + H_2O \rightleftharpoons 3H_2 + CO$

(3) hydrogenation

(4) cracking

Reaction (1) is the water-gas shift reaction which is exothermic. The second reaction is the methane-steam reforming reaction. This reaction is reversible and endothermic in the direction shown. Hydrogenation is the reaction of hydrogen with organic compounds. Cracking is the breakdown of one molecule into two molecules due to heat or steam reaction. Cracking reactions are endothermic and hydrogenation is exothermic.

The temperature in a gasifier may vary from ambient to 2000°C depending on the type of gasifier, the gasifying medium, and the location in the gasifier. Increasing the temperature in the reactor reduces the amount of char produced. Methane, H_2O and CO_2 concentrations decrease with increasing temperatures while H_2 and CO increase with increasing temperature. Hydrocarbon liquids and gases are reformed at higher temperatures.

Higher pressure favors formation of methane and larger hydrocarbons. Higher pressure will slightly decrease the amount of char at a given temperature. CO and H_2 will decrease at higher pressures. These effects are explained by examining the following reactions:

$$CO + 3H_2 \rightleftarrows CH_4 + H_2O$$

$$C + 2H_2 \rightarrow CH_4$$

Both are favored by higher pressures in the direction shown because the product volume is less than the reactant volume (Le Chatelier's principle).

The choice of the gasifying medium depends on the desired product. If air is used the gas contains 40-60 percent nitrogen and is referred to as low-Btu gas (100-200 Btu/scf). If oxygen is used, medium-Btu gas (250-400 Btu/scf) is produced. Addition of steam to the gasifying medium increases the H_2/CO ratio and reduces the amount of heavy hydrocarbons in the gas. This is desireable if synthesis gas is the end product. Table 3 shows typical gas composition data for air-blown and oxygen blown wood gasification using an updraft gasifier.

TABLE 3. Typical Gas Composition for Biomass Gasification (Mudge 1980)

Gasifying Medium	Air	Oxygen/steam	Oxygen/steam
lb/lb dry wood	1.4	0.31/0.08	0.29/0.57
Dry Gas Composition vol. percent			
H_2	6.3	21.3	37.2
CO	27.5	49.5	22.9
CH_4	2.3	5.8	4.5
C_nH_m	0.2	0.4	0.2
O_2	1.4	0.4	0.9
N_2	55.5	0.1	0.7
CO_2	6.7	22.5	33.6
Heating Value Btu/scf	136	295	244

TYPES OF GASIFIERS

There are many different gasifiers, but they may be divided into four main categories: fixed bed updraft, fixed bed downdraft, fluidized bed, and entrained bed. Each type has advantages and disadvantages depending on the particular application.

Fixed Bed Updraft

A schematic of a fixed bed gasifier is shown in Figure 4. Solid fuel is fed from the top by lock hoppers or feeders. The bed of fuel is supported by a grate at the bottom of the reactor. The fuel flows down through the drying zone, pyrolysis zone, reduction zone, and oxidation zone. Ash and unreacted fuel (char) exit through the grate at the bottom. Reactant gases (air, oxygen, steam) are introduced into the reactor through the grate. As the reactant and product gases rise, they pass through successively lower temperature zones and exit at the top of the gasifier saturated with pyrolysis oils and water. Approximately 20-25 percent of the carbon in feed is recovered as liquid

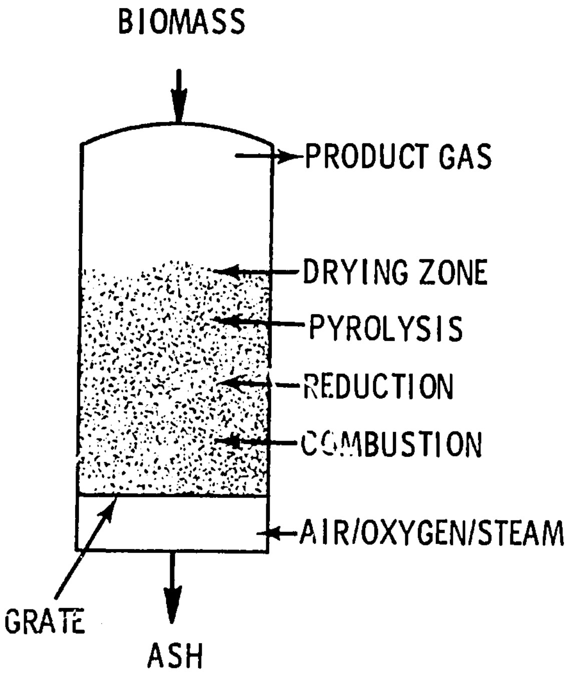

FIGURE 4. Schematic of a Fixed Bed Updraft Gasifier

products. Of this about 70 percent is water soluble pyroligneous acids and 30 percent is insoluble tar. Because of the slow velocity of the gases in the reactor the product gas contains little or no particulate matter.

Fixed Bed Downdraft

Production of pyrolysis oils is largely eliminated in downdraft gasifiers. As in updraft units solid fuel is fed from the top. However, air, which is used in most downdraft units, is introduced into the combustion zone through a distributor as shown in Figure 5. Pyrolysis oils and moisture from pyrolysis and drying are drawn down through the combustion and reduction zones and the product gases exit the bottom of the reactor. Ash and char leave through a grate at the bottom of the reactor.

The uniform combustion area is critical for proper operation of this type of gasifier and scale up of the air distribution system is difficult. As a result downdraft gasifiers are usually small compared to the other types of gasifiers.

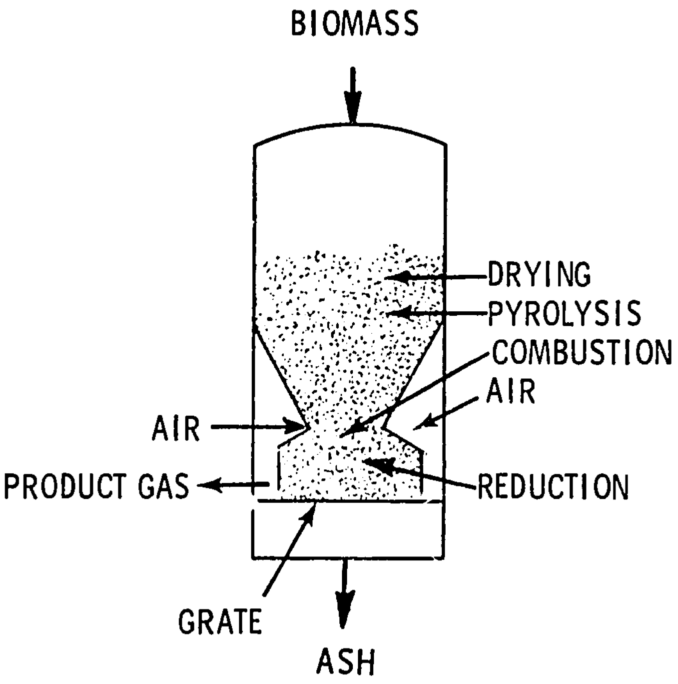

FIGURE 5. Schematic of a Fixed Bed Downdraft Gasifier

Fluid Bed

In a fluid bed gasifier the incoming gases and the evolved gases maintain the reactor bed in a turbulent fluid-like state. The result is an expanded bed having a greater feed surface area to promote chemical reactions. The reactor bed consists of char particles and, in most biomass gasifiers, an inert solid such as sand. Because biomass is less dense and has less fixed carbon than coal the inert solid is used to maintain proper fluidization (prevent bridging and channeling) and to provide additional heat capacity in the bed.

No distinct zones exist in a fluid bed gasifier as near isothermal operation is maintained. The product gas contains little or no pyrolysis oils but does have a fairly large loading of particulates (ash and char). Depending on the design, ash and char are removed from the top of the reactor with the product gases, from the bottom of the reactor, or from the top of the bed.

Entrained Bed

In an entrained bed gasifier finely sized fuel particles are entrained in the feed gas (usually oxygen and steam) prior to entry into the reactor.

Gasification takes place with the feed particles suspended in the gas phase. The product gas and some of the ash and char leave the top of the reactor. The rest of the ash is removed from the bottom.

General Considerations

Gasification of biomass at up to 500 psig is thought to be technically feasible although most experience to date has been at atmospheric pressure (Kam 1980). Companhia Energetica de Sao Paula (CESP) is planning a commercial scale fluidized bed biomass gasifier operating at 10 atmospheres. High pressure increases the methane production and reduces the required size of the reactor vessel. If synthesis gas is produced (oxygen-blown) the amount of compression required prior to downstream synthesis is reduced or eliminated. Design and materials requirements are much more stringent for pressurized systems. In addition, design of high pressure gas cleanup equipment is more difficult.

For coal, operation at higher temperatures (1500-1800°C) is desirable because that it increases conversion of the char to gas. At temperatures above 1300-1400°C the ash from some coals melts and is removed from the reactor as a liquid slag. Ash from some coals and most biomass materials do not slag. It may be possible to add a small proportion of slagging material to the wood feed to provide formation of a slag and allow high temperature operation. Because of the increased reactivity of wood versus coal, high temperature gasification of biomass is usually not necessary.

Gasifier Comparison

The advantages and disadvantages of various types of gasifiers are summarized in Table 4. Fixed bed updraft gasifiers are the simplest to construct, easiest to operate, and least expensive of all the gasifiers. In addition they have high heat recovery in the gasifier which is important for wet feed materials. The fuel can be dried in the gasifier using low quality heat from the product gases. The biggest drawback to updraft units is the large amount of pyrolysis oils produced. This reduces the conversion to gas and makes gas cleanup more difficult. The best application of these units is for small gasification projects (where the low capacity is not a big drawback) producing fuel gas for combustion devices. It is particularly attractive if

TABLE 4. Comparison of Gasifier Types

Gasifier Type	Fixed Bed - Updraft	Fixed Bed-Downdraft	Fluid Bed	Entrained Bed
Significant Characteristics	- Discrete reaction zones - Temperature gradient exists	- Discrete reaction zones - Temperature gradient exits	- Uniform temperature and composition throughout fluidized zone	- Upflow suspension gasification - High temperature, high rate process
Advantages	- High carbon conversion efficiency - Low ash carryover - Low temperature operation - High turndown capability - High heat recovery in gasifier - Least expensive	- High carbon conversion efficiency - Low ash carryover - Low temperature operation - High turndown capability - No pyrolysis oils in product gas	- High turndown capability - High degree of process uniformity - Excellent solids/gas contact - Lower residence time than fixed bed gasifier (smaller reactors) - Good utilization of solids moisture content - High conversion to gas, no pyrolysis oils	- Handles all types of feedstocks, no pretreatment required - Excellent solids/gas contact - No tar formation - Highest capacity per unit volume of reactor (smallest reactors)
Disadvantages	- Low capacity per unit volume of reactor - Poor solids moisture utilization - Large quantity of pyrolysis oils produced. Lower conversion to gas	- Low capacity per unit volume of reactor - Requires complicated gas distributor making scale-up difficult - Lower heat recovery in gasifier than updraft	- Requires size reduction of feed - Requires complicated gas distributor - Fluidization requirement sensitive to fuel characteristics - Inert solid sometimes necessary for biomass applications - High ash carryover-high carbon loss with ash	- Low fuel inventory (control and safety consideration) - Poor turndown capability - Air-blown still under development - High ash carryover-high carbon loss with ash - Most expensive

dirty gas can be used directly thus utilizing the heating value of the pyrolysis oils. In most of these instances the gasifier will be airblown as the advantages of medium Btu gas over low Btu gas are outweighed by the additional cost of oxygen over air.

Downdraft gasifiers are somewhat more complex than updraft units. Their major advantage is the elimination of pyrolysis oils. The complex air distribution system limits the practical size of these units so their main application has been small projects producing fuel gas for combustion devices, particularly internal combustion engines, both stationary and vehicular.

The major advantages of fluid bed gasifiers are the high conversion to gas (no pyrolysis oils) and the short residence time (smaller reactors). For com- mercial air-blown biomass gasification projects (boiler retrofitting, diesel engines) these advantages are outweighed by the disadvantages. These include high ash carryover in the gas, the need for a gas distributor, use of an inert solid for fluidization and the additional size reduction of the fuel. As a result the commercial use of fluid beds for air-blown gasification is minimal. The best application of fluid bed units will most likely be for synthesis gas production. The high conversion to gas and the effective utilization of the solids moisture content (increases the H_2/CO ratio in the gas) are particularly important for synthesis gas production and favor the fluid bed over fixed bed gasifiers.

There has been little use of entrained bed gasifiers for biomass even in developmental or laboratory studies. One French firm markets an entrained bed unit for biomass. They claim it can handle light agricultural residues such as straw and husks without pretreatment. These materials must be densified for use in other gasifiers (Pillard 1979). Based on coal gasifiers, entrained bed units are the most expensive gasifiers. However, entrained bed gasifiers have the highest conversion to CO and H_2 and deserve consideration for synthesis gas applications.

CURRENT TECHNOLOGY

We identified over twenty firms with an active interest in large scale air-blown biomass gasification ($> 2\times10^6$ Btu/hr). They are listed in Table 5.

TABLE 5. Manufacturers of Air-Blown Biomass Gasifiers

Company	Location	Type	Size tons/day	Size million Btu/hr	Auxiliary Equipment	Status	Comments
Halcyon	U.S.	updraft	--	6-50	dryer, low-Btu gas burner	P	For boiler retrofitting, internal combustion engines
Biomass Corporation	U.S.	downdraft	—	1-15	feed preparation, gas cleanup	C	
Forest Fuels	U.S.	updraft	--	2-30	dryer	P	For boiler retrofitting
Alberta Industrial (Thermex)	Canada	fluid bed	72-288	—		C	Can also be used as pyrolyzer for charcoal production
Energy Products of Idaho	U.S.	updraft fluid bed	— --	2-100 2-100	low Btu gas burner	C	
ADENAP	U.S.	fluid bed	100		gas turbine, waste heat boiler	D	Gas turbine cycle for cogeneration of electricity and steam
Guaranty Performance	U.S.	--	—	--	--	D	
Industrial Combustion	U.S.	—	—	—	—	D	
Vermont Wood Energy	U.S.	--	--	--	—	D	
Pyroflow	Finland	fluid bed	—	28-50	—	C	
Lamb Cargate (B.C. Research)	Canada	updraft semi fluid bed	—	25 4-20	secondary combustion chamber, gas cleanup	C D	
Imbert	Germany	downdraft	1-5	—	gas cleanup, diesel electric set	P	For internal combustion engine applications
Pioneer Hi-Bred (Gasodyne)	U.S. Canada	downdraft	--	9	--	C	
Duvant Motuers (Industrial Development and Procurement) (Quebec Electro Marine Diesel)	France U.S. Canada	downdraft	—	1-8	gas cleanup, diesel electric sets	P	For internal combustion engine applications
Davy Powergas	U.S.	updraft	—	1-12	gas cleanup	P	Are no longer making the gasifier that was marketed from 1930-196O. However, are still promoting biomass gasification.
Century Research	U.S.	updraft	—	85	—	C	
American Fyr-Feeder	U.S.	stirred bed, updraft	—	1-8	—	P	For boiler retrofitting
Andro-Torrax	U.S. Europe	updraft slagging	75-[illegible]0		combustion chamber, waste, heat boiler air preheaters, gas cleanup	P	For municipal solid waste
Applied Engineering, Inc.	U.S.	updraft	—	3-20	—	C	
Eso Research, Ltd (Canadian Industries)	Canada	fluid bed	24	—	—	C	MSW, wood
Westwood Polygas (Moore-Canada)	Canada	updraft	60	25-30	—	D	
Pillard	France	fixed bed	1-15	—	burners, gas cleanup, engines, dryer	C	
Hitachi-Zosen	Japan	updraft	20	—	—	C	For municipal solid waste

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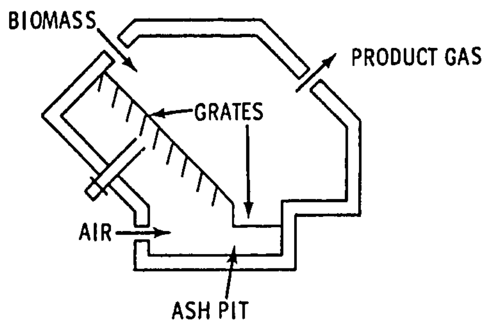
P - Proven, numerous commercial plants in operation
C - Commercial, gasifier is commercially available but actual operating experience is limited
P - Developmental, gasifier is developmental but will be commercial in the short term

About one-third of these firms have enough commercial experience with their gasifiers to consider them proven technology. Another one-third have gasifiers commercially available but have limited operating experience with their commercial size units. The other third are in the latter stages of development and hope to be commercial in the near future. Gasifiers in the early stages of development will be considered in the next section on advanced gasification systems.

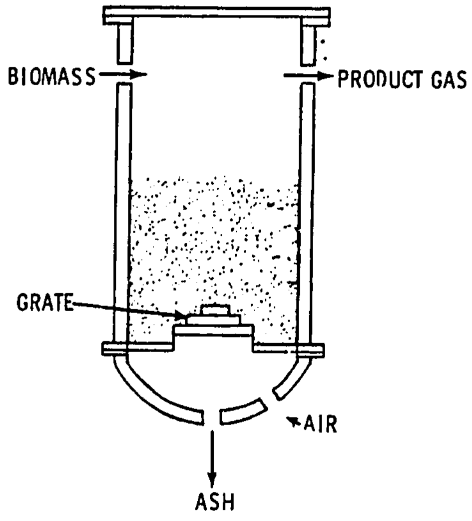
The companies with the most commercial operating experience include Duvant Moteurs and Imbert in Europe and Halcyon, Forest Fuels, American Fyr Feeder, and Davy Powergas in the U.S. They offer fixed bed (both updraft and downdraft) gasifiers in the size range of 1-50 million Btu/hr. One other firm with significant operating experience is Ando Inc., several large Andco Torrax gasifiers have been installed in Europe to dispose of municipal solid waste. These have ranged in size from 50 to 150 million Btu/hr.

Many of the commercial gasifiers are modular shop-built units and some include auxiliary components such as dryers, feeding systems, and gas cleanup equipment. Some are designed for a specific application such as retrofitting boilers or firing diesel engines. The gasifiers produce a gas with a heating value of 100-200 Btu/scf. The energy content of the hot dirty gas is about 85 percent of the energy content of the feed. This includes the heating value of the heavy hydrocarbons and the sensible heat of the gas. Other gasifiers that have reached the commercial stage are often larger and include several fluid bed gasifiers. Figure 6 shows cross sections of four air-blown biomass gasifiers that are typical of those commercially available.

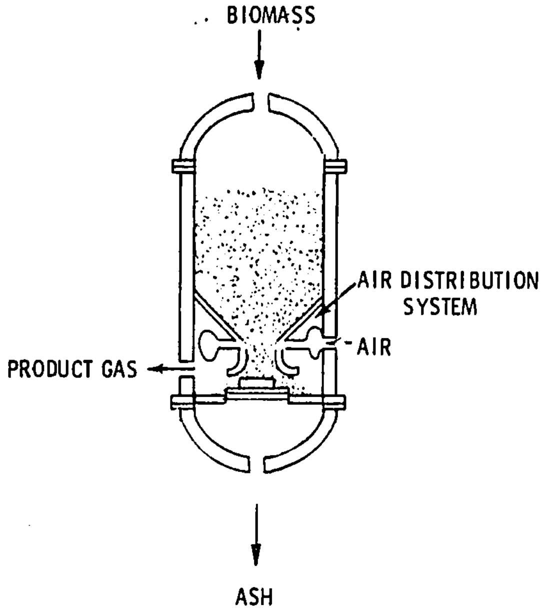
- An inclined grate, updraft gasifier designed specifically for boiler retrofitting. This type of gasifier is similar to semi-pile wood combustors used to fire boilers.
- A standard updraft gasifier like the old Power Gas Corp. fuel gas producer.
- A downdraft gasifier commonly used with internal combustion engines.
- A fluid bed gasifier.



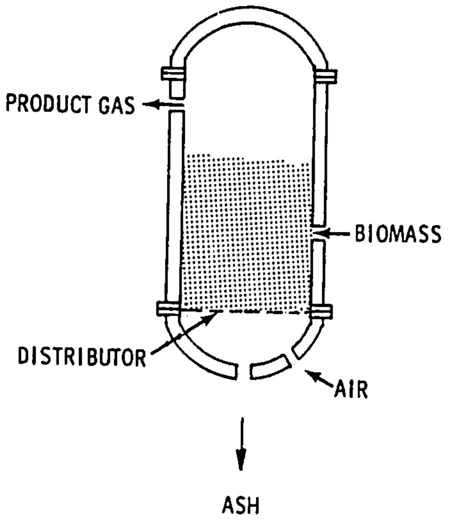
) fixed bed, inclined grate



b) fixed bed, updraft



c) fixed bed, downdraft



d) fluid bed

FIGURE 6. Schematics of Typical Commercial Air-Blown Biomass Gasifiers

In addition several companies other than those listed in Table 5 offer or will soon offer pyrolysis systems. These units produce either charcoal or a liquid fuel as a major product. Nichols-Herreschoff has been active in this area for many years with their multiple hearth furnace.

There has been much less activity in the area of oxygen-blown gasification of biomass as shown in Table 6. At least two processes for disposal of municipal solve waste have reached the commercial stage. The Purox process developed by Union Carbide is best known. In addition several commercial coal gasifiers have been tested or considered for biomass applications. They are listed in Table 6.

In a recent study by Science Applications Inc., (SAI) on production of methanol from wood (Wan-1979) the following conclusions were made:

- "In the near-term commercial application (before 1985), opportunities exist to transfer existing coal gasification technologies or solid waste gasification technology to biomass gasification. Among those existing gasification processes oxygen-blown entrained-bed gasifiers such as the Koppers-Totzek Gasifier, oxygen-blown fixed bed gasifiers such as the Wellman-Galusha Gasifier, and the PUROX reactor appear to have the greatest potential for producing synthesis gas from biomass for methanol synthesis."

TABLE 6. Manufacturers of Oxygen-Blown Gasifiers

Company	Location	Type	tons/day	Comments
Biomass Gasifiers				
Union Carbide (Purox)	U.S.	updraft slagging	200	For municipal solid waste
Saarberg-Fenwarme (SFW-Funk)	Germany	updraft	500	For municipal solid waste
Coal Gasifers				
Wellman-Galusha	U.S.	updraft		
Koppers-Totzek U.S.	Germany bed	entrained		
Davy Powergas	U.S.	updraft		
Winkler (Davy Powergas)	Germany U.S.	fluid bed		

- "For longer term application, advanced biomass gasification processes currently under development offer potential for improving the production of synthesis gas from biomass."

The Purox gasifier, designed to gasify refuse, is considered to be easily adaptable to a biomass feed, since the major constituents of refuse (paper, food wastes and yard wastes), are cellulose originally from biomass. The Wellman-Galusha (W-G) gasifier, commercially used with coal, has been operated successfully with biomass (wood with 35 percent moisture), and the Koppers-Totzek (K-T) gasifier has been operated with processed wood feed (Wan 1979). SAI did not consider a fluid bed gasifier because no commercial oxygen-blown units have been operated with biomass. However CESP is planning on constructing a commercial scale oxygen-blown fluid bed gasifier as part of their methanol from wood demonstration program in Brazil (Filho 1980). They will also be constructing a standard updraft fixed bed unit. Figure 7 shows three commercial coal gasifiers that have been considered for biomass gasification.

Gasification of municipal solid waste (MSW) is somewhat unique compared to gasification of other types of biomass because of the characteristics of the feed material. The main difference is the large amount of ash and inerts in MSW. The heating value of MSW is lower than wood mainly due to high ash/inert content.

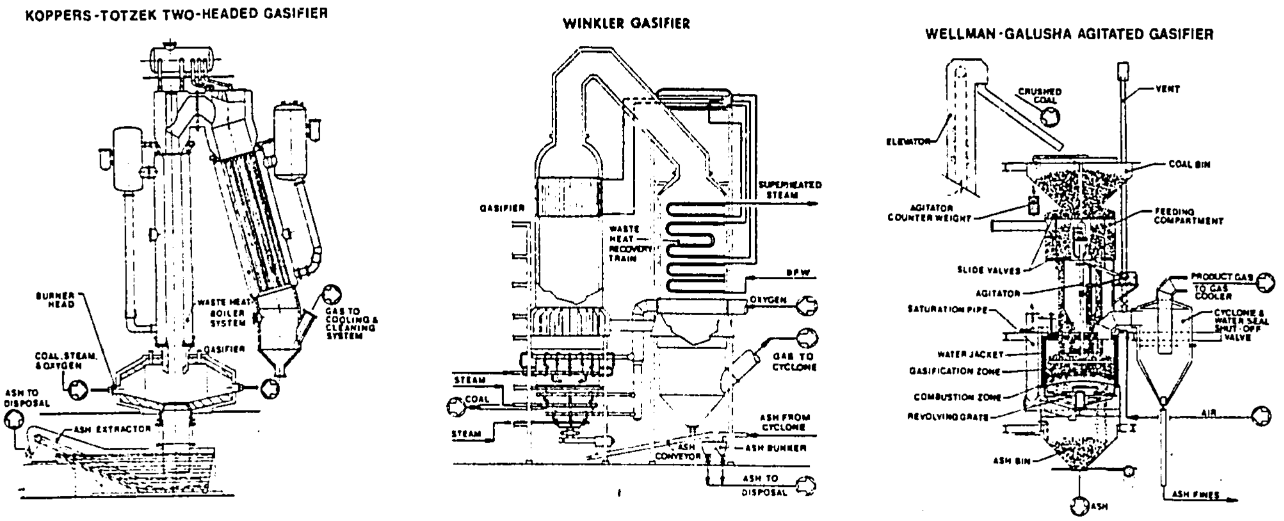


FIGURE 7. Three Commercial Coal Gasifiers (Dravo 1976)

Most gasifiers designed for MSW are fixed bed updraft reactors often referred to as vertical shaft furnaces. The major advantage of this type of reactor is its ability to handle non-uniform feedstocks such as MSW. Use of fluid bed and entrained bed reactors would be difficult for this reason. One problem that has occurred in fixed bed updraft MSW gasifiers is a phenomenon referred to as "gross channeling." When this occurs essentially all of the gases flows up through a relatively small zone near the gasifier wall, sometimes forming an open chimney (Mark 1980, Hammond 1972).

Because of the high ash content most gasifiers designed for MSW remove the ash as a molten slag, while most other biomass gasifiers remove the ash as a solid. To melt the ash and inerts the hearth of the gasifier must be maintained at nearly 3000°F (1650 C), (Desrosiers 1979, Davidson 1978). Maintaining the hearth at 3000°F requires that oxygen or preheated (2000°F) air be used to gasify MSW.

Table 7 shows some commercial or near commercial MSW gasification processes. For the processes listed the only major product from the gasifier is a low or medium-Btu gas. Several other similar processes pyrolyze MSW and produce significant quantities of liquid or char.

There are four Andco-Torrax plants in operation in Europe and two more planned or under construction. All of plants in operation combust the low-Btu gas from the gasifier in a secondary combustion chamber and use the hot combustion gases to generate steam in a waste heat boiler. The steam is used for process heat or to generate electricity. A schematic of the Andco-Torrax system is shown in Figure 8.

Several other companies have large scale demonstration in plant operation and are planning commercial ventures. The Purox process developed by Union Carbide is the best known in the U.S.

The cost of commercially available air-blown biomass gasifiers can be estimated from Figure 9. This is based on actual and estimated costs for thirteen commercial or near commercial gasifiers (Mathur 1979, Assaly 1979, Goss 1978, Ammundsen 1976, Davidson 1980, Levelton 1978, Finnie 1980, Moreno 1980, Engstrom 1980, Fritz 1979). It applies to updraft, downdraft, and fluid bed gasifiers operating on relatively dry, dense biomass fuel. The bold line

TABLE 7. Commercial or Near Commercial Municipal Solid Waste Gasifiers

Company	Location	Type of Gasifier	Gasifying Medium	Largest Plant Built tons/day
Andco-Torrax	U.S., Europe	Updraft, slagging	Air	200
Saarberg-Fernwarme (SFW-Funk)	Europe	Updraft	Oxygen	24
Purox	U.S., Japan	Updraft, slagging	Oxygen	200
Nippon Steel	Japan	Updraft, slagging	Oxygen enriched air	40
Hitachi-Zosen	Japan	Updraft	Air/Steam	20
Environmental Energy Corporation (Teledyne/BSP Envirotech)	U.S.	Multiple Hearth Furnace	--	--
Nichols Engineering	U.S.	Multiple Hearth Furnace	--	--

indicates the average cost and the shaded area shows the range of the costs. The cost obtained from Figure 9 includes the installed cost of a feed bin or hopper, a feed system, the gasifier, and all piping instrumentation and controls. It does not include the cost of feed preparation equipment or gas scrubbers. A cyclone separator to remove ash and char from the product gas is included in the cost of downdraft and fixed bed units. The cost in Figure 9 also does not include the cost of offsites (utilities, storage, buildings, etc) or indirect costs (engineering and supervision, contingency, etc).

As no commercial scale oxygen-blown biomass gasifier has been built only estimates of the cost are available. The estimated installed cost of gasifiers and gas cleanup equipment including all piping, instrumentation, and electrical equipment for a plant feeding 1000 dry tons per day of wood ranges from $14-37 million (Rooker 1980, Kam 1980, Wan 1979). The lowest value was for a Wellman-Galusha fixed bed unit; the highest was a Koppers-Totzek entrained bed gasifier. Scaling the cost of a large air-blown gasifier (100 tons per day)

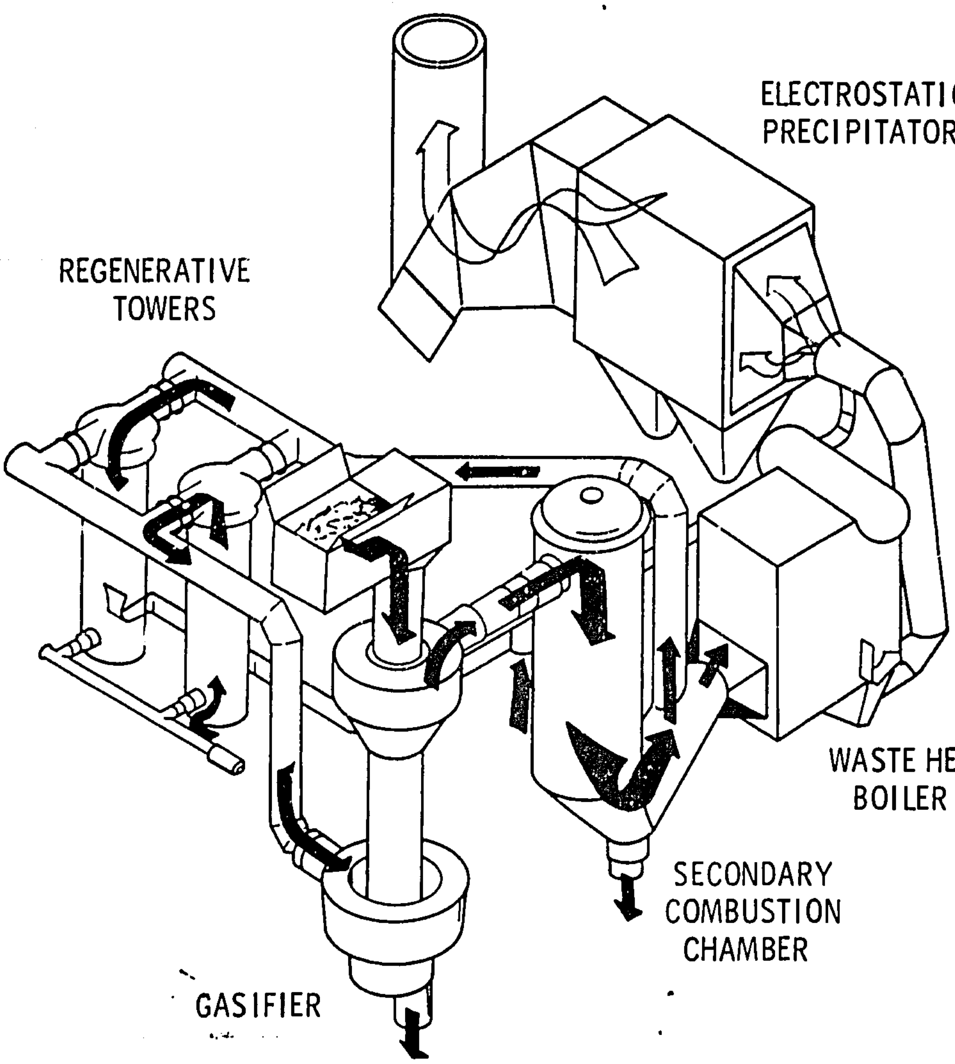


FIGURE 8. Andco-Torrax Municipal Solid Waste Gasification System (Mark 1980)

up to a 1000 tons per day unit (assuming no economy of scale) results in a cost of about $10 million. If the cost of gas treatment equipment is added the estimate agrees closely with the low estimate for the Wellman-Galusha gasifier. With current technology there is only limited economy of scale associated with biomass gasification systems as no large scale units have been built. In a study for Brazil, Davy used 24 gasifiers for a plant feeding 4500 dry tons/day (~200 dry tons/day each).

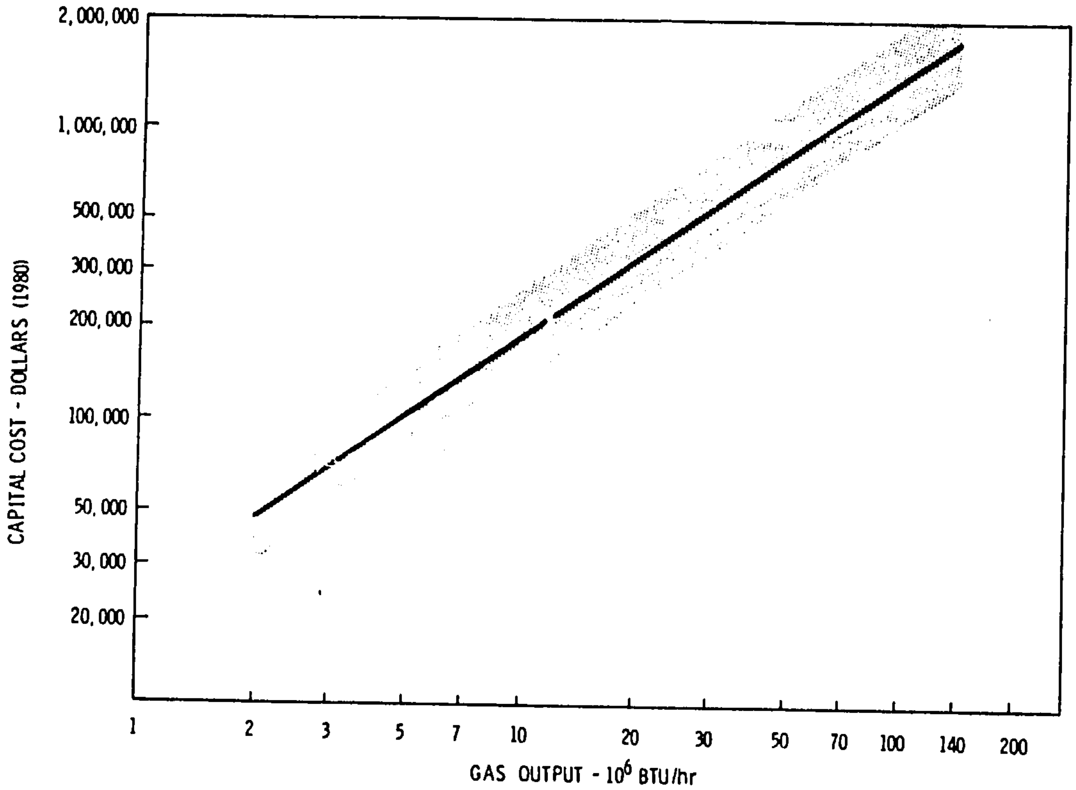


FIGURE 9. Cost of Air-Blown Biomass Gasifiers

ADVANCED GASIFICATION SYSTEMS

Most of the research on advanced gasification systems today involves production of medium or high-Btu gas, substitute natural gas, and hydrocarbon and ammonia synthesis gas. Air-blown gasifiers for the production of low-Btu gas are well developed and are being used in many commercial applications.

Medium-Btu gas produced by air-oxygen, oxygen, or steam gasification is a first step in the production of high-Btu gas or synthesis gas. Systems using oxygen operate essentially in the same manner as air blown gasifiers, only at higher temperatures and/or higher throughput. The technology is essentially the same. Biomass is more reactive than coal and has the potential for gasification at lower temperatures, perhaps without the addition of oxygen, to produce medium-Btu gas or synthesis gas. Steam gasification systems which do not use oxygen are being developed in the U.S. These projects are of interest because the elimination of an oxygen plant can make the production of synthesis gas more economical. Projects being funded currently by the Department of Energy are described in Table 8. Some advanced biomass gasification systems being developed in foreign countries are shown in Table 9. Some of the unique aspects of gasification systems under development include:

- catalytic systems
- steam gasification
- pressurized fluid bed gasifier
- entrained bed gasifier

GAS CLEANING

Fuel gas from biomass gasification may require cleaning before it is used. The degree of cleaning required depends on the intended use of the gas. Often no gas cleaning is required for boiler applications. However, extensive cleaning is desirable for internal combustion engine applications and synthesis gas compression units.

Possible contaminants in fuel gases from biomass are unreacted biomass, char, condensible tars and acids, ash, fluidizing media, and foreign matter. The feedstock and the type of gasifier are two factors which directly affect the amounts of each contaminant in the product gas. Tars and acids are the main contaminants of fixed bed updraft gasifier product gas. Gas from downdraft gasifiers contains little tar or acid, but will contain more char and ash. The product gas from fluid bed and entrained bed gasifiers will contain appreciable quantities of char, ash, and fluidizing media. When designing a gas cleaning system the operating conditions, the fuel, the gasifier, and the application must all be examined.

Early fixed bed gasifier systems designed by the Powergas Corporation and the Crossley Bros. had remarkably similar gas cleaning systems. The gas was cooled and the pyroligneous acids condensed in a spray scrubber. Tars were then removed by a "tar extractor." This was a rotary impellor which collected tars in its outside walls. A dry filter bed followed the extractor.

TABLE 8. Some Advanced Gasification Systems Underdevelopment in the U.S.

Project	Reactor Type	PDU Size	Potential Feedstocks	Product(s)	Potential Applications	Status
Pacific Northwest Laboratory Richland, WA	- Fluidized Bed - Catalytic-Various Catalysts - Pressure (1-10 atm) - No Oxygen Required	0.5 ODT/D	Wood Various others	Methane, hydrogen and synthesis gases for ammonia methanol and liquid hydrocarbons	Current PDU for catalyst screening studies - concept applicable to various gasifiers	Operational
Battelle Memorial Institute Columbus, OH	- Multisolids Fluidized Bed - Catalytic - Low Pressure - No Oxygen Required	2 ODT/D	Wood-whole tree-chips and Residues	MBG (~350 Btu/scf) or Methane	Larger units, energy farms (300-1,500 ODT/D)	PDU designed startup mid 1980
Texas Tech University Lubbock, TX	- Counter Current Fluidized Bed - Non-Catalytic (Steam-Air - Low Pressure - No Oxygen Required	0.5 ODT/D	Manure, Wood Cotton Gin Trash, Corn Stover, and Other agricultural Stalks	MBG (270-360 Btu/scf as is basis) NH_3 synthesis gas	Larger units 300-1,500 ODT/D ammonia production from feedlot wastes, other industrial uses	Operational
University of Missouri Rolla, MO	- Fluidized Bed - With or Without Catalyst - Low Pressure - No Oxygen Required	2.4 to 24 ODT/D	Sawdust, Hogged Wood Chips and others	Low Btu gas, MBG and synthesis gas	Larger units 300-1,500 ODT/D PDU will be used to verify Texas Tech projections and develop scale up data for commercial size units	Operational
Wright-Malta Corporation Ballston Spa, NY	- Rotary kiln - High Pressure - No oxygen required	3 ODT/D	Wood Chips	MBG and synthesis gas	Small industrial plants, pulp and paper mills	PDU startup in 1980

TABLE 9. Some Advanced Gasification Systems in Foreign Countries

Organization	Location	Reactor Type	Comments	Status
Forintek	Canada	fluid bed, fixed bed	Catalytic for CH_4, NH_3, CH_3OH, SNG production	bench scale, 0.2-2 T/O PDU planned
Tokyo University	Japan	dual fluid bed	For solid wastes	40 T/D POU operational
Agency for Industrial Science	Japan	dual bed	For municipal solid waste	100 T/D plant under construction
Royal Institute of Technology	Sweden	pressurized fluid bed	Steam gasification	0.5 T/D POU operational
Canadien Center for Mineral and Energy Technology	Canada	fluid bed	Air and oxygen blown for low-Btu gas and synthesis gas	100 T/D plant planned
Centre National d'Etudes et d'Experimentation de Machinisme Agricole	France	entrained bed	For light biomass materials	

Downdraft gasifiers used for vehicular applications typically used a cyclone in series with a wet scrubber or condensation scrubber. These were often followed by cloth filters. Other items that were used were small electrofilters and cork filters.

Commercial gas cleaning equipment available today may be divided into four main categories: cyclones, wet scrubbers, filters and electrostatic precipitators. Table 10 lists some prominent characteristics of these classes. Other less common devices are settling chambers and inertial separators other than cyclones.

TABLE 10. Characteristics of Particulate and Mist Removal Equipment (Wan 1979)

Equipment Type	Relative Cost	Smallest Particle Collected μ
Cyclones	1-2	10
Filters	3-20	0.1
Electrostatic Precipitators	2-30	0.1
Scrubbers (Spray tower, jet, venturi, cyclonic inertial, packed, rotating impeller)	1-10	1-10

Cyclones (see Figure 10b) are simple devices in which the gas is given a circular motion. This accelerates particles to the wall of the cyclone. The particles fall down the sides of the cyclone and gas exits through the top. Cyclones are commonly used with fluid bed and entrained bed reactors. They are also used on downdraft systems. Cyclones are relatively inexpensive with no moving parts. However they are inefficient for removal of particles smaller than 5 microns.

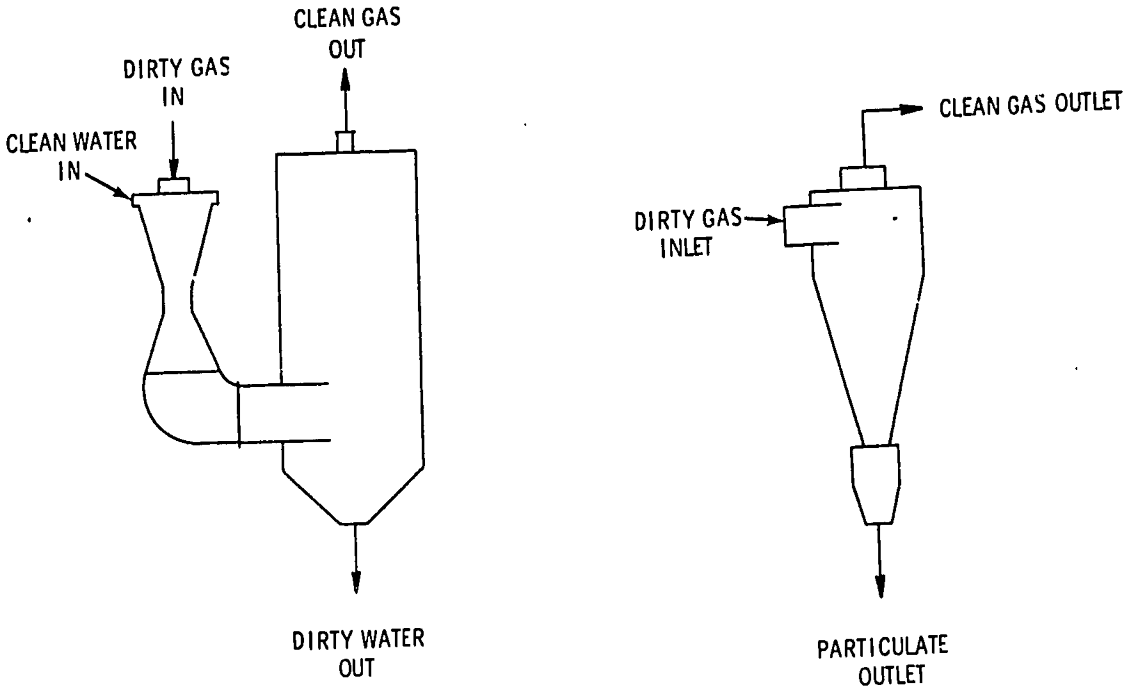
Wet scrubbers utilize a water mist dispersed in the gas stream. Both solid particulates and liquids can be removed by the units. Some types of wet scrubbers are spray columns (Figure 10c), venturi scrubbers (Figure 10a) and wet cyclones. Water effluent from a wet scrubber usually requires purification before it can be discharged to the environment.

Electrostatic precipitators operate by charging solid particles and liquid droplets in a high voltage field. The charged particle or droplet migrates to a collecting wall where it discharges and falls into a collector. Particles with high conductivity such as char may discharge so rapidly that reentrainment can occur. Sometimes precipitators are operated with wetted walls to prevent reentrainment and to continually flush collected materials from the walls.

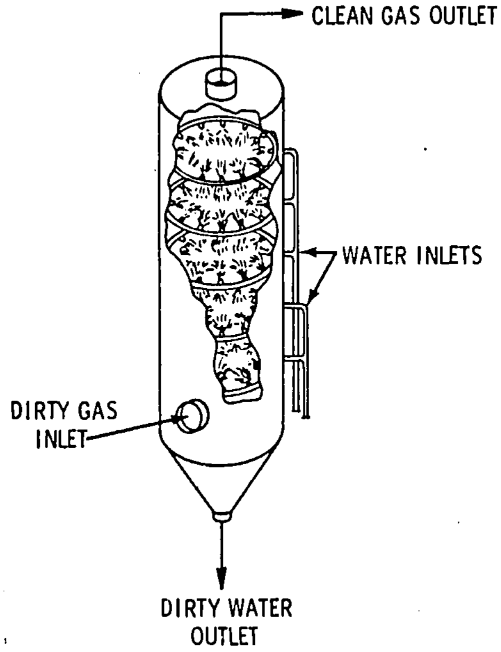
Bag filters trap particles on filter media. The filters are regenerated by reverse flow through the filter. Filters are high efficiency devices. Applications are expanding due to the development of higher temperature and corrosion resistant filter media. Filters cannot be used on streams with condensing tars or water since the filtration media will blind.

For gasifiers with low tar output, (fluid bed, entrained bed and downdraft gasifiers) a cyclone followed by an electrostatic precipitator has been suggested (Wan 1979) to clean gas for subsequent compression. Wan recommends a wet scrubber-wet precipitator for tar-laden gases from updraft gasifiers.

Product gas from DuVant Moteurs downdraft gasifiers producing gas for internal combustion engines passes through a regenerative heat exchanger to preheat the air to the gasifier and then is cleaned and cooled in a wet scrubber.



a) venturi scrubber b) cyclone



c) spray tower

FIGURE 10. Cleaning Equipment Biomass Derived Fuel Gas

A gas cleaning system consisting of a downcomer spray chamber and a baffled scrubber followed by an electrostatic precipitator for final tar recovery has been suggested for a fixed bed updraft gasifier producing synthesis gas (Rooker 1980).

UTILIZATION OF FUEL GAS FROM BIOMASS

Fuel gas produced by gasification of biomass has many potential uses. With minor equipment modifications low and medium-Btu gas can be used in many places where natural gas and oil are used. In addition medium-Btu gas can be used as a precursor for liquid fuels and chemicals. The potential uses of fuel gas from biomass are categorized below:

Low-Btu Gas

- heating in new or existing gas or oil fired equipment (boilers, kilns, driers)
- power production in new or existing gas or oil fired boilers and turbo generating units
- power production in new or existing diesel or gasoline engines
- cogeneration of heat and power in steam or gas turbine cycles

Medium-btu Gas

- synthesis gas for liquid fuels or chemical production
- heat and power applications similar to low-Btu gas
- substitute natural gas

Medium-Btu gas generally is not competitive with low-Btu gas for heat and power applications and in all further discussions of these applications emphasis will be on low-Btu gas. Production of substitute natural gas was not considered in this study.

A standard basis was used to evaluate the economics of the various applications. This basis is shown in Table 11. The economics presented in this section are for a plant located in the U.S. The next section of the report will relate these costs to costs in developing countries.

STEAM/POWER PRODUCTION

One of the most promising applications of low-Btu gas from biomass is as a fuel for new and existing oil and gas fired boilers. Packaged oil and gas

TABLE 11. Process Economic Evaluation Basis

- 20 year project life
- 5 percent/year straight line depreciation on fixed capital requirement
- 48 percent income tax
- Debt/equity ratio
  - 65/35 for utility financing
  - 0/100 for industrial financing
- 10 percent interest rate
- 15 percent discounted cash flow rate of return on equity capital
- Wood cost at $20/dry ton
- Working capital at 15 percent of fixed capital requirement
- Mid 1980 constant dollars

fired boilers have become extremely popular over the past 20 years because of their low cost and the availability of gas and oil. Packaged boilers are assembled at a manufacturers plant and have only to be set on a foundation, be piped up, and have a few appurtenaces connected before being ready for operation. Field erected boilers come in pieces or partial assemblies and must be built in the field from the ground up.

Packaged boilers are availabe in capacities ranging up to about 500,000 lb/hr of steam. A more practical upper limit is about 300,000 lb/hr (Buffington 1975). There are two basic designs: fire-tube or water tube. In a fire-tube boiler combustion takes place in a furnace under the vessel, and the hot gases flow through tubes in two to four passes (heating the water to raise steam) before being discharged to the stack. Water-tube boilers circulate water within the tubes. Heat transfer occurs from the hot combustion gases on the outside of the tubes to water on the inside. Water-tube boilers smaller than 250,000 lb/hr are the most common and they provide a large share of the process heat and power for U.S. industries (Schweiger 1977). The majority of packaged boilers built today are designed for 125-1000 psig, although pressures as high as 2000 psig are feasible. Steam temperatures generally range from 353°F (Saturation at 125 psig) to 950°F.

Small (under 300,000 lb/hr) field erected oil and gas fired boilers generally can not compete with packaged units. Most boilers of this size are generally used by small and medium size industries for heat and power. Most oil and gas fired boilers over 300,000 lb/hr are field erected. These are used by large industries and utilities.

The capacity of large scale air-blown biomass gasifiers available is a good match for the size of packaged oil/gas fired boilers. A single gasifier could supply gas to the smaller boilers while several gasifiers would be required for the large units.

Complete integrated, standard burner packages are common for use with package boilers. Existing boilers are generally equipped to burn two kinds of fuels, natural gas and No. 2 or No. 6 fuel oil. Low-Btu gas can be burned in many existing oil/gas fired packaged boilers, and a number of commercial installations have been made. Although low-Btu gas contains only one-sixth the energy on a volumetric basis that natural gas does, the stoichiometric air/fuel mixture, which establishes burner size and other requirements, increases by only about 30 percent. The flue gas volume increases by only about 20 percent.

In some instances it may be possible to use the existing burner as is, although in the long run it is probably wise to replace the burner with one specially designed for low Btu gas or modify the existing burner for low Btu gas. Boiler and burner manufacturers generally recommend a scroll type burner for low Btu gas because it permits passage of large volumes of gas and air with minimum pressure drop. Tars in the gas can be handled by providing for steam cleaning of the scrolls and by heat tracing of gas lines to prevent condensation (Schweiger 1979).

Other modifications that may be necessary when retrofitting existing oil/gas fired boilers for low Btu gas include:

- Installation of a new fuel gas piping system. The piping should be insulated to prevent condensation of tars.
- Modifications to ignition, flame-safeguard, and combustion-control equipment

- Uprating of forced and induced draft fans.

It is generally felt that with high quality biomass feedstocks, such as dry wood waste, there will be little or no change in the boiler rating. Use of wet feedstocks will result in a 10 percent or more derating. Commercial experience to date bears this out. There is, however, some disagreement on this point. One packaged boiler manufacture claims that as much as a 50 percent derating will result from use of low-Btu gas (Schweiger 1979).

Use of medium Btu gas in existing oil/gas fired boilers requires relatively little modification of the combustion equipment. The stoichiometric air/fuel mixture increases by only 5 percent over natural gas and the amount of flue gas produced is about the same. No derating of the boiler will result.

Steam produced by a boiler can be used for heating, to produce electricity or shaft work, or for cogeneration of heat and power. The thermostatic effect of the vapor pressure curve coupled with the high latent heat and density of the fluid makes steam especially attractive for heating purposes, particularly if the desired temperature is between 200-500 F (90-260 C). The condensate produced when the steam is used is returned to the boiler to complete the cycle.

Steam can be expanded through a turbine to produce electricity (turbogenerators) or drive pumps, and compressors (frequently called mechanical-drive turnes). Inlet steam pressure is usually in the range of 150 psig at zero superheat to 850 psig at 900 F (460 C). Turbines have been built to operate at as low as 5 psig with zero superheat. Pressures of 1500, 1800, and 2400 psig are common for large turbine generators.

There are two basic types of steam turbines; condensing turbines where all the steam enters the turbine at one pressure and exhausts at a pressure below atmospheric, and non-condensing turbines where the steam exhausts at a pressure equal to or greater than atmospheric. In large power stations variations on the straight condensing or non-condensing turbines are made to allow extraction of steam at one or more stages to improve the overall cycle efficiency. The extracted steam is used to preheat the feedwater (regenerative cycles) or to pass back through the boiler for additional superheat (reheat cycles).

In combined cycles high pressure steam is used to produce electricity and the low pressure exhaust steam is used for heating. Cogeneration was quite popular up until 1950; however, the low fuel prices of the 1950s and 1960s did not encourage cogeneration applications.

Applications

Table 12 shows some examples of utilization of low-Btu gas from biomass for steam generation. Some of these are prototype demonstration projects, however, many of these examples are commercial operations. Most of the applications are retrofits and do not involve additional steam generating capacity. Feedstocks range from municipal solid waste to olive pits, but wood is the most common. The maximum size of the gasifiers used to date is about 50 x 10^6 Btu/hr. The larger projects are using more than one gasifier. A majority of the installations in the U.S. and Canada have been in lumber mills and processing plants for agricultural products. In Europe utilities have made use of the technology to produce steam and electricity from municipal solid waste.

Halcyon Associates, Forest Fuels Inc., and American Fyr Feeder are particularly active in retrofitting existing boilers. In addition to supplying gasifiers each firm supplies various auxiliary equipment and interconnecting hardware (Mathur 1979, Finnie 1980). Andco-Torrax (A-T) has installed several systems in Europe for disposal of municipal solid waste. A-T supplies the complete system including a burner, boiler, electrostatic precipitator to remove particulates from the flue gas, and regenerative towers to heat the inlet air (Davidson 1978).

Process Evaluation and Economics

Figure 11 shows a block flow diagram for producing steam/electrical power from biomass via gasification. The efficiencies of the various steps are included in the blocks. Figure 11 can be misleading in that it indicates that the steam turbine is the most inefficient step in the process. However, the maximum efficiency of heat to work conversions is limited to about 40 percent by the second law of thermodynamics. The "engine efficiency" actual work/ideal work), of steam turbines is 60-80 percent, similar to the other steps in the process. The overall conversion efficiency from biomass chemical energy to

TABLE 12. Examples of Utilization of Low Btu Gas from Biomass for Steam Generation

Gasifier Suppliers	Location	Type of Facility	Size million Btu/hr gas output	Status
Halcyon	U.S.	--	--	4 commercial units in operation
	Louisiana	municipal utility	200	Under construction
	U.S.	paper mill	300	Engineering
Forest Fuels	U.S.	--	1-16	8 units in operation
Davy Powergas	Europe/Africa	--	1-15	Several units built from 1934-1965
Andco-Torrax	New York	county utility	~10	Demonstration Plant 1971-1973
	Luxemborg	municipal utility	~50	Operational
	Germany	city utility	~50	Operational
	France	city utility	~40	Operational
	France		~50	Startup 1979
Ahlstrom-Pyroflow	Finland	lumber mill	50	Operational
	Finland	city utility	28	Operational
Westwood Polygas (Moore-Canada)	B.C.	lumber mill	~70	Two prototype units installed in 1977
Mellenger-Gasodyne	Maine	lumber mill	12	Operational in 1977. Shutdown in 1978 for modifications
U.C. Davis	California	nut processing plant	6-8	Developmental unit
Energy Products of Idaho		olive processing plant	16	Engineering complete, construction to begin in 1980
Midland Ross	U.S.	tobacco manufacturer	68	Under construction

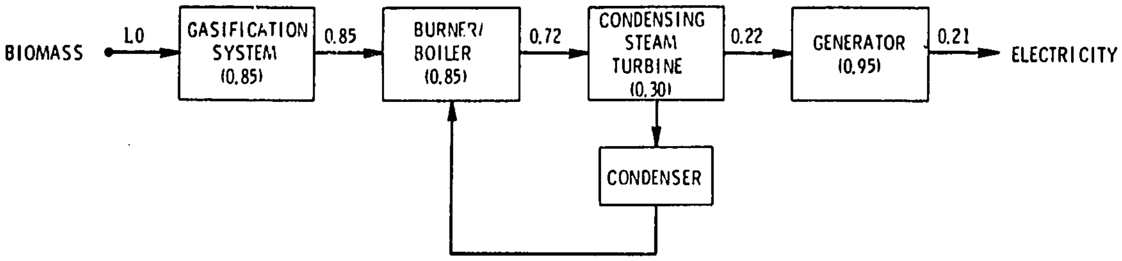


FIGURE 11. Block Flow Diagram for the Production of Steam/Power from Biomass via Gasification

electrical power is about 21 percent for high pressure, superheated steam (850 psig, 900°F) and somewhat lower for low pressure saturated steam. This is equivalent to about 0.5 kW-hr/lb of dry wood.

Cogeneration of electricity and process heat for industrial applications is shown in Figure 12. Cogeneration produces less electricity, but the overall conversion efficiency from biomass chemical energy to electrical power and steam thermal energy is about 70 percent.

For retrofitting existing boilers low-Btu gas from biomass can be produced for $2-5/million Btu depending mainly on the size of the gasifier and the cost of available biomass feedstocks. Table 13 shows a breakdown of the costs for a typical case. Feedstock cost is the most important contributor followed by capital costs.

A new 1000 kW steam generating facility can product electricity for about $0.08/kw-hr using utility financing and $0.11/kW-hr with industrial financing. For a 2920 kW facility the cost ranges from $0.06-0.09/kW-hr. Table 14 shows a breakdown of the costs. Gasification system costs were obtained from Figure 9.

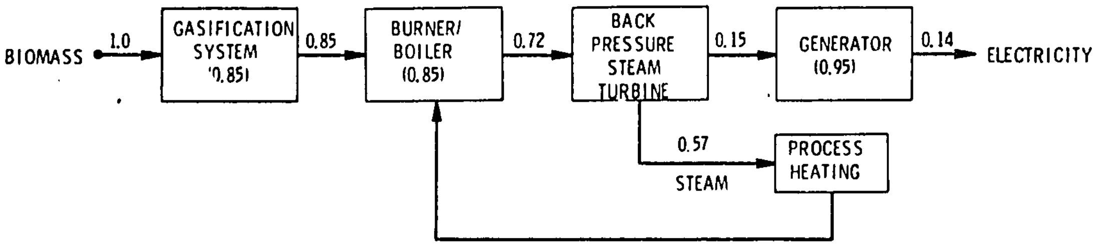


FIGURE 12. Block Flow Diagram for Cogeneration of Steam and Electricity from Low-Btu Gas from Biomass

TABLE 13. Preliminary Estimate of the Cost of Low Btu Gas from Wood for Retrofitting Oil/Gas Fired Boilers

Steam	12,000 lb/hr
Low Btu Gas	14.5 million Btu/hr
Wood	24 tons/day dry wood
Fixed Capital Investment	$400,000
Gasification System	
Burner/Combustion Chamber Modifications	
Facilities and Indirects	
Working Capital	$ 60,000
Total Capital Investment	$460,000

		Utility Financing	Industrial Financing
Capital Costs		$ 63,000	$131,000
Feedstock Costs	$20/dry ton	158,000	158,000
Operating Costs		65,000	65,000
		$286,000	$354,000
Gas Cost $/million Btu		$2.50	$3.09

Cost of facilities and indirect costs were added. Cost of the boiler and turbo generating equipment are based on published data (Guthrie 1974, Perry 1974).

For process applications which have a need for low pressure steam as well as electricity, the cost of electricity can be reduced significantly by cogeneration as shown in Table 15.

The economics of gasification of municipal solid waste (MSW) to produce steam/power are somewhat different because there is little or no cost for the feedstock and the investment and operating costs to handle MSW are significantly higher than for wood. Table 16 is a complete economic analysis of the Ando-Torrax MSW gasification system. This system is generally only economical if a credit for disposal of the waste can be taken. This is a reasonable assumption in most cases.

TABLE 14. Preliminary Estimate of the Cost of Electricity from Wood-Gasification and Steam Generation

	Case 1	Case 2
Electrical Production	1000 kW	2920 kW
Wood Feed	24 ODT/day	70 ODT/day
Capital Investment (including installation, indirect costs, and associated offsites)		
Gasification System	370,000	865,000
Boiler and Turbine Generating Units	1,400,000	3,200,000
Fixed Capital Investment	1,770,000	4,065,000
Working Capital	262,000	610,000
Total Capital Investment	$2,032,000	$4,625,000
Capital costs	$/yr	$yr
Utility Financing	275,000	638,000
Industrial Financing	575,000	1,335,000
Feedstock Costs	158,000	461,000
Operating Costs	160,000	373,000
Total Costs		
Utility Financing	593,000	1,472,000
Industrial Financing	893,000	2,169,000
Electrical Cost	$/kW-hr	$/kW-hr
Utility Financing	0.075	0.064
Industrial Financing	0.113	0.094

TABLE 15. Preliminary Estimate of Cost of Cogeneration of Steam and Electricity from Wood - Gasification and Steam Generation

Electrical Production	2000 kW
Steam Generation	28×10^3 lb/hr
Wood Feed	70 ODT/day
Capital Investment (including installation, indirect costs and associated offsites)	
Gasifier System	865,000
Boiler and Turbine Generating Units	2,800,000
Fixed Capital Investment	3,465,000
Working Capital	520,000
Total Capital Investment	$3,985,000

	Utility	Industrial
Capital Costs	$/yr	$/yr
Utility Financing/Industrial Financing	544,000	1,138,000
Feedstock Costs	461,000	461,000
Operating Costs	350,000	350,000
Total Costs		
Utility Financing/Industrial	1,355,000	1,949,000
Cost of Electricity and Steam		
Electricity $/kW-hr	0.045	0.067
Steam $/thousand lb	3.00	4.00

TABLE 16. Economics of Gasification of Municipal Solid Waste - Andco-Torrax System (Mark 1980)

	Plant Size	
	250 TPD	1000 TPD
No. of Andco-Torrax Units	1	3
Annual refuse Throughput (TPY)	82125	329000
Capital Costs ($000 omitted)		
Andco-Torrax Equipment	7500	20000
Buildings and Utilities	5800	12860
Interest During Construction	1130	2793
Start-Up Expense	740	1080
Working Capital	466	980
Total Capital Costs	15636	37713
Amortization Cost/Ton (8-1/2 interest, 20 year plant life)	$19.83	$11.94
Operating Costs ($/Ton)		
Labor and Administration	6.94	3.56
Maintenance, Power and Utilities	9.64	6.70
Total Operating Costs/Ton	16.58	10.26
Total Plant Costs/Ton	$36.41	$22.20
Credits		
Steam $3.50/1000 lb	$18.90	$18.90
Net Disposal Cost/Ton	$17.51	$3.30

OTHER OIL AND GAS FIRED EQUIPMENT

Low-Btu gas can also be used in other oil and gas fired equipment such as lumber kilns, veneer dryers, pulp dryers, grain dryers, paint dryers, lime kilns, and cement kilns. The modifications necessary to retrofit existing oil and gas fired equipment will vary depending on the type of equipment. In general they will be similar to those required for retrofitting boilers. Ball et al. ranked potential applications of low-Btu gas and identified potential problem areas (Ball 1974).

Table 17 shows some applications of low-Btu gas from biomass in fired equipment other than boilers. Lamb-Cargate has two gasifiers in operation to fire equipment in wood products industries. Pioneer and DeKalb have prototype units coupled to corn dryers. In most instances the hot dirty gases from the gasifier can be used directly. When this is possible the cost of low Btu gas for these applications will be similar to boiler applications (see Table 13).

INTERNAL COMBUSTION ENGINES FOR POWER PRODUCTION

The heat energy of low Btu gas can be converted to shaft work or electricity using internal combustion (I-C) engines. The two most common I-C engines are the Otto cycle (spark ignition) engine used in automobiles and the Diesel (compression ignition) engine. The four strokes of an Otto cycle are:

1) Intake - the fuel-air mixture flows with the cylinder,

2) Compression - the mixture is compressed, ignited and combusted,

3) Power - the high-pressure, high-temperature gases expand, and

4) Exhaust - the piston pushes the combustion gases out of the cylinder

The Diesel engine differs from the Otto engine primarily in that the temperature at the end of the compression stroke is such that combustion is initiated spontaneously. The higher temperature is obtained by continuing the compression step to a higher pressure. In general the Otto engine has a higher efficiency that the Diesel for a given compression ratio. However, the compression ratio in the Otto engine is limited by fuel quality (preignition difficulties) so that higher ratios can be used in the Diesel engine, and for that reason higher efficiencies can be obtained with Diesel engines. The measure of the fuel quality is the octane number. The higher the octane number of a fuel the less susceptible the fuel is to auto-ignition. High octane fuels are required for Otto engines and low octane fuels are necessary for diesel engines.

Low-Btu gas has a research octane of about 100 and can be used in a spark-ignited gasoline engine by replacing the carburetor with a mixing chamber. Use of low Btu-gas in a diesel engine requires that 5-10 percent diesel fuel be injected for ignition. This type of operation is referred to as dual fueling. The engine always has the potential to run solely on diesel fuel (Biomass Corporation 1980).

TABLE 17. Applications of Low Btu Gas from Biomass in Fired Equipment Other Than Boilers

Gasifier Suppliers	Location	Type of Facility	Size 10^6 Btu/hr	Status
Lamb-Cargate	Canada	lumber kiln	25	Operational
	New Zealand	pulp dryer	25	Operational
Pioneer Hi-Bred International	Iowa	Seed corn dryer	9	Prototype units have been operated. Grate is being redesigned
	Indiana	seed corn dryer	9	
DeKalb	Illinois	corn dryer	2	Prototype operated successfully Larger unit under construction

About 90 percent of all the engines in operation around the world for electrical generation, pumps, and compressors are full diesel engines. The other ten percent are dual-fueled diesel engines and spark ignition gas engines. Diesel engines are more popular principally because they are less expensive than spark ignition engines. Converting full diesel engines to dual fuel engines is relatively easy. The major modification is the addition of a second fuel injection system. When retrofitting an existing engine for low-Btu gas, there will be a loss of power. Tests have shown power reduction of 25-33 percent of the output horsepower (Horsfield 1979).

Applications

Table 18 lists some examples of utilization of low Btu gas from biomass in internal combustion engines. In the 1930's and 1940's both the Powergas Corporation and Crossley Bros. Inc. built biomass gasifiers coupled to diesel engines to produce electricity. Distibois has a gasifier fueled by wood which supplies gas to a 1000 kW generating unit in France (Horsfield 1979). Duvant Moteurs, a French firm, has been building gasifiers and dual fuel engines since 1920 and has about 30 of these units operating throughout the world (Fritz 1979). The engines range in size from 150 to 1000 horsepower (110-750 kW). A majority of these units are in West Africa, Phillipines, and Central America. Fuel for these units is typically agricultural residues such as coconut shells, coffee shells, and bamboo waste. Figure 13 is a drawing of a typical Duvant plant.

Traditionally these applications are found in remote areas where agricultural wastes were available and where low cost labor permits economic operation. Similar applications are currently being studied in the Phillipines, Alaska, Brazil, and Canada. In the Phillipines a 30 kW pilot project has been sucessfully tested using corn husks as fuel. Other fuels being tested include wood waste, rice straw, and bagasse. The pilot plant can serve the electrical needs of about 100 families. The Alaskan Village Electric Cooperative Inc. is investigating the feasibility of using a biomass gasifier to produce low Btu gas for generation of electricity with an internal combustion engine. Biomass Corporation is building a downdraft gasifier for the project. The gasifier will be coupled to a modified Cat G363 engine. In Brazil, Companhia Enegetica

TABLE 18. Examples of Utilization of Low Btu Gas From Biomass in Internal Codmbustion Engines

Suppliers	Location	Type of Facility	Size	Status
Duvant Moteurs	West Africa, Tahiti, Pakistan, Nicaragua, Phillipines	--	100-750	About 30 operational around the world. At least 7 more ordered or being negotiated
Distibois	France	--	1000	Operational
Imbert	Canada	plywood plant/ utility	75	Demonstration Plant
Davy Powergas	Europe/Africa	--	75-300	5 Built in 1934-1965. Several still operation
Halcyon	Maine	lumber company	800	Startup in 1980
Pioneer Hi-Bred	Canada	--	400	Operational
	Canada	--	40	Demonstration Plant
Biomass Corp	Alaska	electric coop	--	Construction of demonstration unit underway, Testing will begin in 1980
	Phillipines	rural electrification	30	Demonstration plant in operation
	Brazil	utility	500	Demonstration unit on line in 1979
			1000	Second larger unit is planned

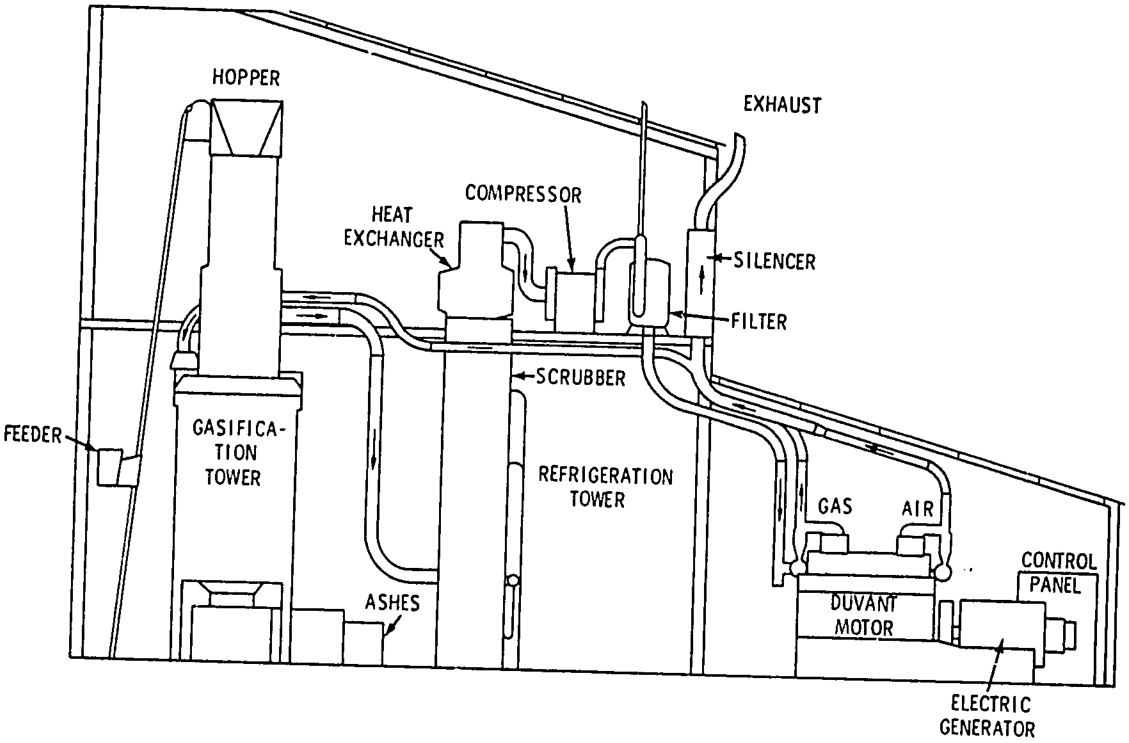


FIGURE 13. A Typical Duvant Moteurs Gasification Plant (Fritz 1979)

de Sao Paulo (CESP) has successfully powered a 900HP SKODA diesel engine coupled to 500 kW SKODA generator with low Btu gas from wood. A 1000 kW unit is now planned. Saskatchewan Power Corporation has successfully operated a 75 kW Deutz diesel engine and generator set on clean low-Btu gas from wood waste using an Imbert updraft gasifier and a Mellenger gas cleaning train (Bente 1980).

Process Evaluation and Economics

Figure 14 shows a block flow diagram for the conversion of biomass to electrical power with a gasifier and a diesel engine. The efficiencies of the various steps are included. Figure 14 is somewhat misleading in that it indicates that the engine is the most inefficient step in the process. However the maximum efficiency of heat to work conversions is limited to about 40 percent by the second law of thermodynamics. The "engine efficiency" (actual work/ideal work) is 70-80 percent, similar to the other steps in the process. The overall conversion efficiency from biomass thermal energy to electrical power is about 20 percent or approximately 0.5 kW-hr per pound of dry wood.

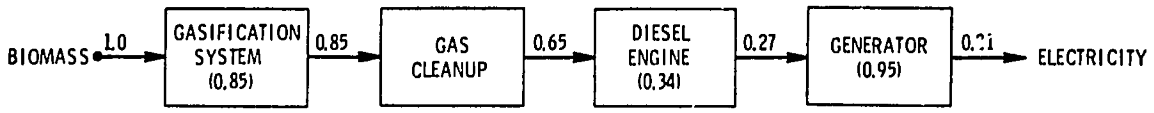


FIGURE 14. Block Flow Diagram for Conversion of Biomass to Electrical Power with a Gasifier and a Diesel Engine

The cost of electricity from early biomass gasifiers/diesel-electric sets overseas was 4-5 times as expensive as that generated by central power stations (Levelton 1978). The ratio is probably lower now. CESP has estimated that electricity can be produced from diesel-electric sets for $0.066 /kW-hr using wood at about $8 per dry ton (Bente 1980).

We estimated the cost of electricity from a 1000 kW facility and a 2900 kW facility. The results are shown in Table 19. The basic gasifier capital costs were from Figure 9 and the cost of gas cleanup equipment was added. The cost of the diesel generating equipment was obtained for published data (Bente 1980, Fritz 1979, Guthrie 1974). For the 1000 kW plant electricity can be generated for about $0.07/kW-hr using the utility financing method and $0.10/kW-hr using industrial financing. For the 2900 kW plant the cost of electricity is $0.06/kW-hr using utility financing and $0.08/kW-hr using industrial financing. The cost of electricity generated from diesel fuel in the U.S. is about $0.07/kW-hr (Bente 1980).

For retrofitting existing diesel engine-generator sets the cost of low-Btu gas from wood is $3-4 per million Btu for 1000 kW generator. Table 20 shows a breakdown of the costs. Feedstock cost is the most important contributor followed by capital and operating costs.

GAS TURBINE CYCLES

Low or medium-Btu gas can be used as fuel for combustion gas turbines to produce electricity or shaft work. A basic gas turbine system consists of a compressor, a combustion chamber, and a turbine. Components added to the system to improve efficiency include a regenerator to recover exhaust losses and preheat the air to the combustor, and intercooler between compressor stages, and an additional reheating combustion chamber between turbine stages.

TABLE 19. Preliminary Estimate of the Cost of Electricity from Wood - Gasifier and Diesel Engine Generator

Electrical Production	1000 kW	2920 kW
Wood Feed	24 ODT/day	70 ODT/day
Capital Investment (including installation, indirect costs, and offsites)		
Gasification System	400,000	1,010,000
Diesel Engine and Generator	400,000	2,010,000
Fixed Capital Investment	1,300,000	3,020,000
Working Capital	145,000	455,000
Total Capital Investment	$1,495,000	$3,475,000
	$/yr	$/yr
Capital Costs		
Utility Financing	204,000	475,000
Industrial Financing	427,000	993,000
Feedstock Cost		
90 percent wood $20/ODT	210,000	613,000
10 percent diesel $6/million Btu		
Operating Costs	140,000	340,000
Total Costs		
Utility Financing	554,000	1,428,000
Industrial Financing	777,000	1,947,000
Cost of Electricity	$/kW-hr	$/kW-hr
Utility Financing	0.070	0.062
Industrial Financing	0.099	0.085

This type of gas turbine cycle (simple cycle) uses atmospheric air as the working medium and burns relatively clean fuels such as natural gas and petroleum distallates. To date, attempts at burning dirty fuels directly in a gas turbine have met with only limited success. A major problem has been erosion and corrosion of turbine blades by particulate matter and hot gases (Pruce 1980).

TABLE 20. Preliminary Estimate of the Cost of Low-Btu Gas for Retrofitting Existing Diesel Engines

Electrical Production	1000 kW
Wood Feed	24 dry tons/day
Fixed Capital Investment	$500,000
Gasification System	
Gas Cleanup System	
Facilities and Indirects	
(Does not include any necessary diesel modifications)	
Working Capital	$ 75,000
Total Capital Investment	$575,000

	Utility	Industrial
Capital Costs	$ 78,000	$164,000
Feedstock Costs $20/dry ton	$158,000	$158,000
Operating Costs	$ 75,000	$ 75,000
	$311,000	$397,000
Gas Cost $/million Btu	$3.20	$4.08

The indirectly heated gas turbine cycle (closed or semi-closed cycles) has a significant advantage in that it can accomodate a wide variety of fuels including biomass, low-Btu gas, coal, and lignite. In the indirect cycle incoming air is compressed, heated indirectly by combustion gases using a heat exchanger and then expanded through the turbine. The exhaust air is used to combust the fuel outside of the gas turbine. The heart of the indirect fired cycle is the heat exchanger. Several different heat exchangers for gas turbine cycles are under development. Emphasis is currently on metallic and ceramic materials to protect the heat exchanger from corrosion/erosion and to meet the high temperature requirements.

With both the direct and indirect heated gas turbine the exhaust combustion gases can be used to generate steam with a waste heat boiler. The use of combined cycles increases the efficiency of the system.

Applications

We know of no current commercial applications of gas turbines fired directly or indirectly by low or medium Btu gas. Advanced Energy Applications Inc. (ADENAP) is currently developing a large scale, indirect fired gas turbine system for cogeneration of electrical power and steam or process heat. Their objective is to fuel the units with low-Btu gas from agricultural wastes. The low Btu gas will then be combusted in a down-heat cycle recuperated gas turbine. ADENAP hopes to be commercial with their system by 1981-82. Arkansas Power and Light is exploring the possibility of using low-Btu gas from wood to power a gas turbine. The heat created by the process would be used to make steam.

Process Evaluation and Economics

Figure 15 is a block flow diagram of the gas turbine cycle being developed by ADENAP. The numbers on the diagram indicate the energy flow through the process. The overall conversion efficiency from biomass thermal energy to electric power and steam thermal energy is about 58 percent.

ADENAP indicates they expect an 85 ton/day plant (including gasifier) to cost about $1.5 million plus installation and auxiliaries. Based on ADENAP's capital cost estimate the system could produce electricity at $0.04-0.06/kW-hr and low pressure steam at $2.50-3.50/thousand pounds depending on the financing method (Table 21).

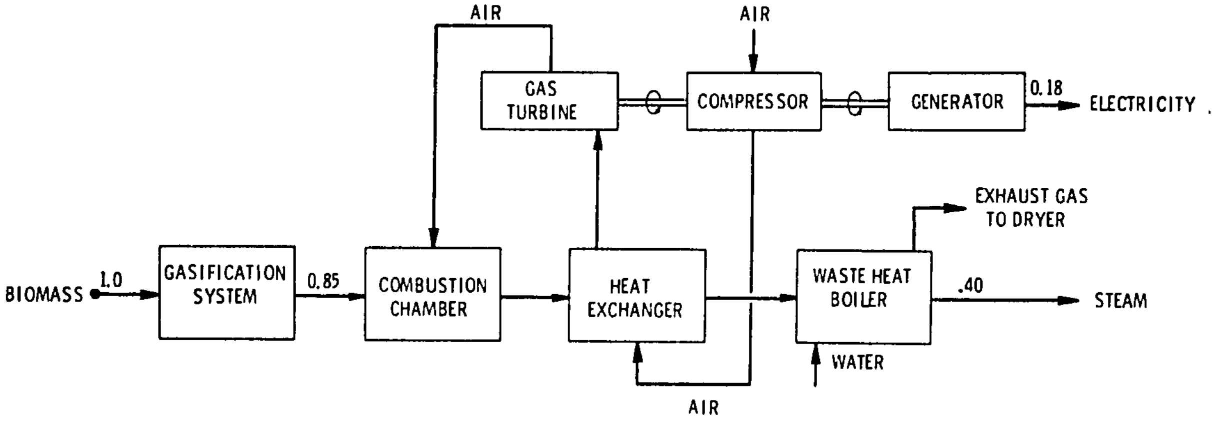


FIGURE 15. Block Flow Diagram for a Gas Turbine Cycle Based on Biomass Gasification

TABLE 21. Preliminary Estimate of the Cost of Cogeneration of Steam and Electricity - Gasification and Gas Turbine Cycle

Electrical Production	2500 kW	
Steam Generation	20 x 10^3 lb/hr	
Wood Feed	70 ODT/day	
Capital Investment		
Fixed Capital Investment	$2,475	
Working Capital	$ 370	
Total Capital Investment	$2,745	
Capital Costs	$/yr	$/yr
Utility Financing/ Industrial Financing	380,000	813,000
Feedstock Cost $20/ODT	460,000	460,000
Operating Costs	330,000	330,000
Total Costs		
Utility Financing/ Industrial Financing	1,170,000	1,630,000
Cost of Electricity and Steam		
Electricity	$0.039/kW-hr	$0.054/kW-hr
Steam	$2.50/thousand lb	$3.50/thousand lb

SYNTHESIS OF METHANOL AND OTHER LIQUID FUELS

Liquid fuels can be made from biomass indirectly by converting the biomass into a gaseous intermediate from which liquid fuels can be synthesized. Synthesis gas is a general term referring to a gaseous intermediate that is used to produce a different end product. Synthesis gas and medium Btu gas are similar in that they are both produced by oxygen-blown gasification. If the gas is to be used for SNG, a high methane (CH_4) content is desirable; however, for production of liquid fuels (synthesis gas) the gas should ideally consist of hydrogen (H_2, carbon monoxide (CO), and only small quantities of other gases. In most instances the H_2/CO ratios in the gas will have to be adjusted prior to liquid fuel synthesis. In addition inert or contaminant gases such as CO_2 and H_2S have to be removed from the synthesis gas.

There are two major processes used commercially for production of liquid fuels from CO and H_2. The most common is methanol synthesis which has been in wide commercial practice for many years. The other is the Fischer-Tropsch process practiced exclusively in South Africa for the production of gasoline, diesel, and other fuels. Other related syntheses under development include the methanol to gasoline process and processes for the production of ethanal and other higher alcohols from synthesis gas.

Synthesis Gas Modification

Various contaminants or inerts which may be in the synthesis gas from biomass are H_2S, CO_2, tars, oils, and particulates (ash and/or char). Removal of tars, oils, and particulates was discussed previously. Only the removal of gaseous constituents will be discussed here.

Typical sulfur content in wood results in a H_2S content in the synthesis gas that is marginally acceptable (1-5 ppm). This H_2S level is probably acceptable for high pressure methanol synthesis and the Fischer-Tropsch synthesis. For the copper based catalysts used in low-pressure methanol synthesis, H_2S levels of less than 1 ppm are desirable. At least some CO_2 removal will mostly likely be required to reduce the amount of purge required from the synthesis loop. Various commercial processes are available for the removal of acid gases, H_2S and CO_2 (Table 22). Most of these processes involve absorption of CO_2 and H_2S in an organic solvent and subsequent regeneration of the solvent. The ZnO process provides an attractive method of reducing small quantities of H_2S and removing the H_2S content to very low levels. For biomass gasification systems where the partial pressure of CO_2 is low, hot carbonate processes such as the Benfield process are probably the most economic (Christensen 1978).

Liquid fuel synthesis generally requires a synthesis gas with a higher H_2/CO ratio than is produced by current commercial gasifiers. The ratio is adjusted by means of the water gas shift reaction

$$CO + H_2O \rightleftharpoons CO_2 + H_2$$

The reaction is limited by thermodynamic equilibrium with lower temperatures favoring more complete conversion of CO.

TABLE 22. Summary of Commercial Acid Gas Removal Processes (Wan, 1979)

Process	Purpose	Method
ADIP	H_2S, CO_2 removal	Absorption in di-isopropanolamine solution
ALKAZIO	H_2S, CO_2 removal	Absorption in aqueous solution of alkali salts of weak amino acids
CLAUS	Convert H_2S to S	Combustion
Benfield	H_2S, CO_2 removal	Absorption in hot K_2CO_3
MDEA	H_2S removal	Absorption in methyl-diethanolamine
PURISOL	H_2S, CO_2 removal	Absorption in n-methyl-2-pyrrolidone
SCOT	H_2S, S, COS, CS_2, SO_2, and CO_2 removal	Catalytic chemical reaction and absorption in di-isopropanolamine
SELEXOL	H_2S, CO_2 removal	Absorption with di-methyl ether or proplyene glycol
STRETFORD	Converts H_2S to S	Chemical absorption
RECTISOL	H_2S, CO_2 removal	Physical absorption with methanol
SULFIBAN	H_2S removal	Absorption in mono-ethanolamine
SULFINOL	H_2S, CO_2 removal	Physical absorption with di-isopropanolamine
Activated Carbon	H_2S removal	Adsorption onto activated carbon
Iron Oxide	H_2S removal	Chemical absorption on Ferric oxide
Molecular Sieves	H_2S removal	Adsorption on Zeolite sieves
Zinc Oxide	H_2S removal	Chemical absorption on Zinc oxide

The reaction is run at 100-300 psig using metal oxides (Fe_2O_3, Cr_2O_3, etc.) for catalysts. Until recently catalyst limitations (reaction rate) have required temperatures of 370-550°C. Often a second step is included at a lower temperature to increase conversion. Recent catalyst developments may allow the use of only one stage operating at 175-300°C. Because complete conversion of CO to H_2 is not desired for synthesis gas, a single stage high temperature shift reaction is probably still preferable.

Laboratory research on catalytic wood gasification indicates that it may be feasible to shift the synthesis gas to the H_2/CO ratio in the gasifier (Weber 1980). This would eliminate the need for a separate shift reactor.

Gasifiers generally operate at low pressures, 0-300 psig, while liquid synthesis occurs at somewhat higher pressures, 200-5000 psig, so synthesis gas compression is usually required. Compression follows particulate and mist removal steps, but may precede or follow the acid gas removal and CO shift steps depending on the process.

Methanol Synthesis

The synthesis of methanol dates back to the early 1900's when methanol was a by-product of the early Fischer-Tropsch synthesis. Methanol was a minor product of this synthesis; however, over the years very selective catalysts have been developed for it. Methanol production is now a widely practiced commercial process and has been reviewed several times (Natta 1955, Strezloff 1973) including an assessment of converting biomass to methanol (Wan 1979). Only the more important aspects of methanol synthesis with respect to production of methanol from biomass in LDC's are of concern here.

Methanol is produced by the following reaction:

$$CO + 2H_2 \rightleftarrows CH_3OH$$

But carbon monoxide and hydrogen can also react to form higher alcohols, formaldehyde, methane and heavier hydrocarbons. In addition methanol can be dehydrated to form di-methyl ether. All of these reactions are undesireable when the aim of the synthesis is methanol. The key to the development of methanol synthesis was the development of highly selective, active catalysts.

Among the catalysts that have proven to give high rates of methanol formation are those containing zinc oxide and chromic oxide in various proportions with or without other metal oxides as promotors. A great amount of research was done in the early 1930's on copper oxide as a catalyst. Copper based catalysts were found to have high selectivity and a high initial activity but were sensitive to overheating and poisoning by small amounts of sulfur compounds. Therefore, until recently the straight zinc oxide-chromic oxide catalyst was used in practically all the major methanol plants in the world because of its high activity, long life, and good mechanical strength. In the 1960's ICI developed a new copper based catalyst which is much more active than the zinc oxide-chromic oxide catalysts at lower pressures. The only drawback is that the catalyst is sensitive to temperatures over 300°C and very sensitive to sulfur. The process therefore operates at temperatures somewhat below 300°C and the sulfur content of the synthesis gas is kept below the level used with zinc oxide-chromic oxide catalysts.

Methanol synthesis is highly exothermic and the heat of reaction increases with increasing temperature and pressure. In order to maintain the catalyst bed in the proper temperature range significant quantities of heat must be removed as it is generated. This can be done by placing cooling coils between the beds of catalyst. This scheme becomes uneconomical for large plants and a quench system is used. A sufficient amount of cool inlet gas mixture is injected between catalyst beds. The volume of gas is often purposely increased by using a large excess of hydrogen which serves as a coolant. The excess gas is not wasted as most of it is recycled back to the synthesis loop. Figure 16 shows a schematic of a typical methanol reactor with quench gas cooling.

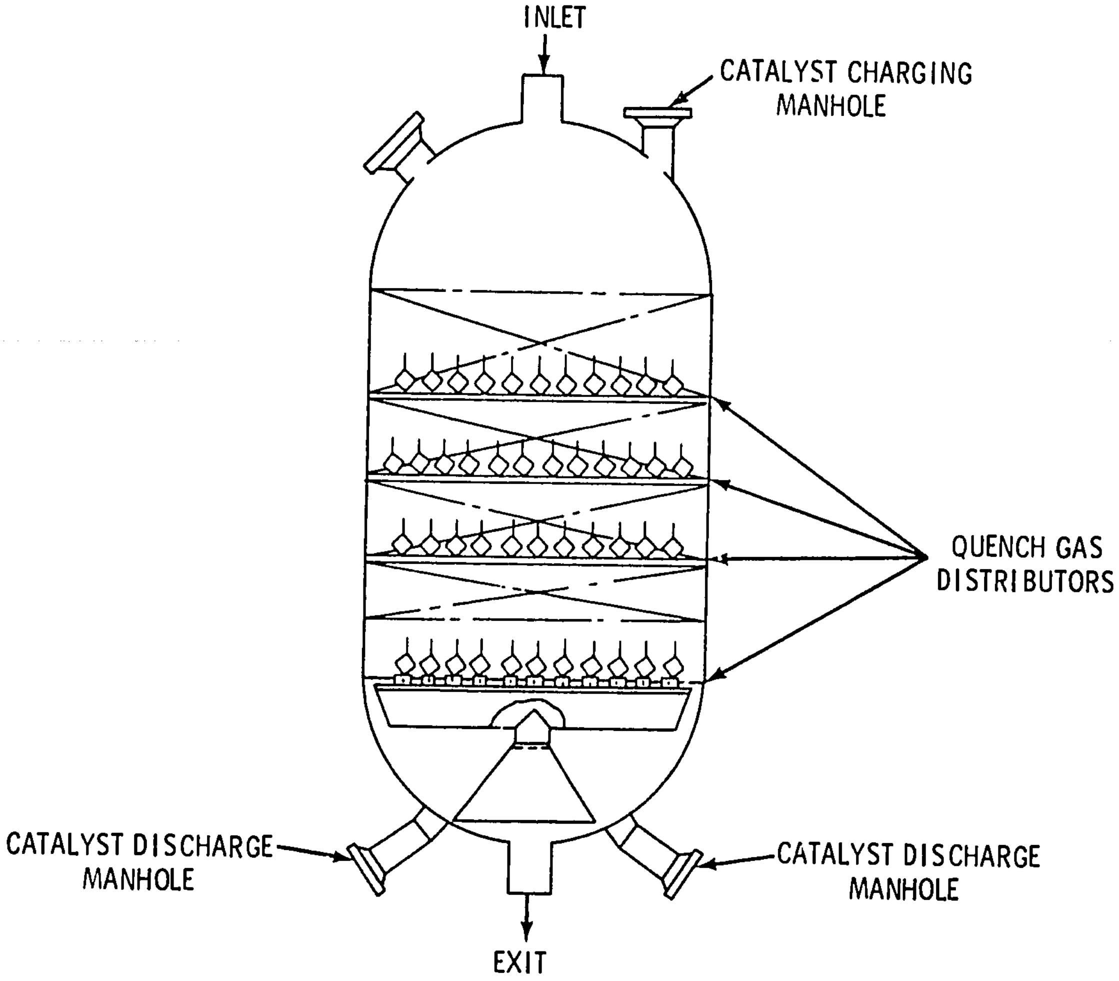


FIGURE 16. Schematic of a Typical Methanol Reactor

Processes for methanol production generally fall into three categories: 1) the high pressure process, 2) the low and medium pressure processes, and 3) a liquid phase process. The original high pressure process represents a large fraction of the methanol production capacity at the present time and was used exclusively up to 1966 when the low pressure process was introduced. The high pressure process operates at 5000 psig (340 atm) and 570-750 F (300-400 C). Synthesis gas, typically 2/1 H_2 to CO, passes through a fixed bed reactor containing a ZnO-Cr_2O_3 catalyst. The product stream is cooled to condense and separate the methanol, and the unconverted synthesis gas is recycled to the reactor. About 30 percent conversion is achieved per pass based on carbon monoxide. This results in a reactor effluent gas containing about 5 percent methanol by volume (Wan 1979, Strezloff 1973).

Imperial Chemical Industries (ICI) first introduced the low pressure process in 1966. The low pressure 50-100 atm (750-1500 pig) process was made economical by the development of more active and more selective copper based catalysts. Only 10-15 percent conversion per pass (2-3 percent methanol in the reactor effluent) is achieved with the low pressure compared to 30 percent for the high pressure process; however, both capital and operating costs are lowered because of reduced compression requirements. Other than the compression facilities and the catalyst there is very little difference between the high and low pressure process (Pinto 1977, Kenard 1973). A flow diagram for conventional methanol processes is shown in Figure 17.

A more radical methanol synthesis concept is being developed by Chemical Systems, Inc. In this process the catalyst is fluidized in an inert liquid and the synthesis gas passes through the liquid/catalyst mixture. The inert liquid is circulated between the reactor and a heat exchanger to remove the heat of reaction. Several advantages are claimed for this process including higher conversion, increased reaction rate, and reduced recycle gas rate. Initial comparison of the economics of this process with the ICI process indicate the liquid phase process may reduce costs by as much as 15 percent (Sherwin 1976). Figure 18 is a flow diagram for the three phase methanol synthesis.

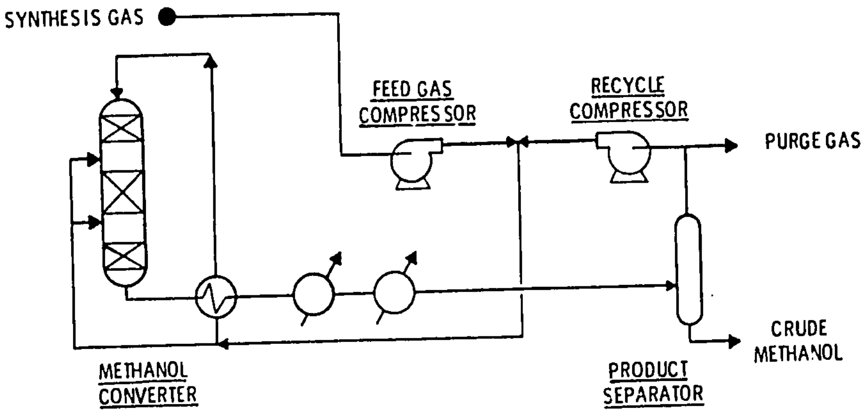


FIGURE 17. Flow Diagram for Conventional Methanol Processes

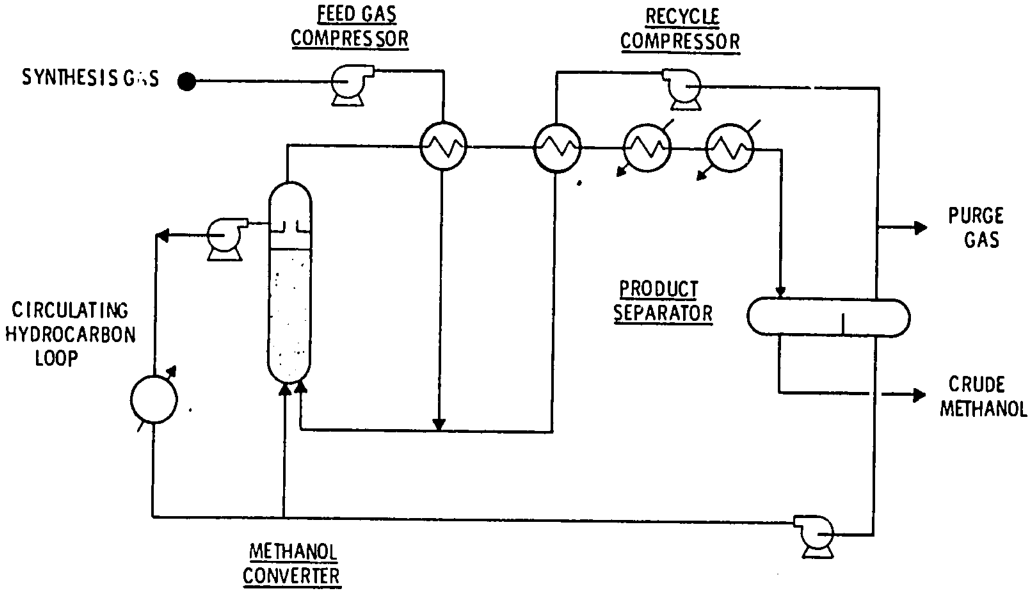


FIGURE 18. Flow Diagram for the Three-Phase Methanol Synthesis

The two major advantages of methanol synthesis for the production of liquid fuels are:

- It is a proven commercial process.
- There are no major by-products. This results in a high yield of the primary product (compared to other processes for liquid fuels production) and limited downstream separation and treating.

Disadvantages of the methanol synthesis and methanol production in general include:

- The pressure required (even for for the low pressure process) is significantly higher than the design pressure of commercial gasifiers
- Methanol is not an ideal transportation fuel

Fischer-Tropsch

Liquid fuel production from synthesis gas has been practiced on a commercial scale in South Africa for many years using the Fischer-Tropsch (F-T) synthesis. The F-T synthesis has been the subject of much research since it was discovered in the 1920's and has been reviewed several times over the past 50 years (O'Hara 1979, Vannice 1976, Anderson 1956, Storch 1951). It consists essentially of the reaction of H_2 and CO over a catalyst (usually a Group VIII metal such as iron or cobalt on a porous support) at pressures from 1-100 atm and temperatures of 400-750 F (200-400 C). The products of the synthesis are very diverse depending on the catalyst and operating conditions chosen. The overall stoichiometry of the Fischer-Tropsch synthesis of paraffinic and olefinic hydrocarbons may be represented by the following reactions:

$$nCO + (2n+1)\ H_2 \rightarrow CnH_{2n+2} + n\ H_2O$$

$$2nCO + (n+1)\ H_2 \rightarrow CnH_{2n+2} + nCO_2$$

$$nCO + 2nH_2 \rightarrow CnH_{2n} + n\ H_2O$$

$$2nCO + nH_2 \rightarrow CnH_{2n} + nCO_2$$

Two different variations of the F-T synthesis are in use at the South African Coal, Oil, and Gas corporation (SASOL) plant in South Africa. The Arge synthesis, developed in Germany, is a fixed bed process used primarily to make diesel oil and wax fractions. Figure 19 is a flow diagram of the Arge process. Synthesis gas at 480 F (250°C) and 350 psig (25 atm) enters the top of the fixed bed reactor and passes over an iron catalyst which is inside the tubes. Outside the tubes high pressure steam is produced by the exothermic heat of reaction thus maintaining the reactor at constant temperature. A typical yield breakdown for the process is shown in Table 23 (Parsons 1977, Field 1960).

The Kellogg synthesis is a fluid bed process employed to provide lighter products, mainly gasoline and fuel gas. Figure 20 is a flow diagram of the Kellogg process. Hot feed gas and powdered iron catalyst enter the bottom of the reactor and pass up through a reaction zone and then a cooling section. In the cooling section, the gas passes through tubes which are cooled on the outside by a circulating oil stream. Gas then leaves the reactor and passes through cyclone separators where entrained catalyst is removed. Catalyst from the cyclone is mixed with the feed gas just upstream of the reactor. Typical operating conditions for the Kellogg synthesis are 280 psig (20 atm), 630 F (330 C), and a gas velocity of 4-7 ft/sec. Table 23 shows the product breakdown for the Kellogg process (Garrett 1960; Field 1960; Kronseder 1976).

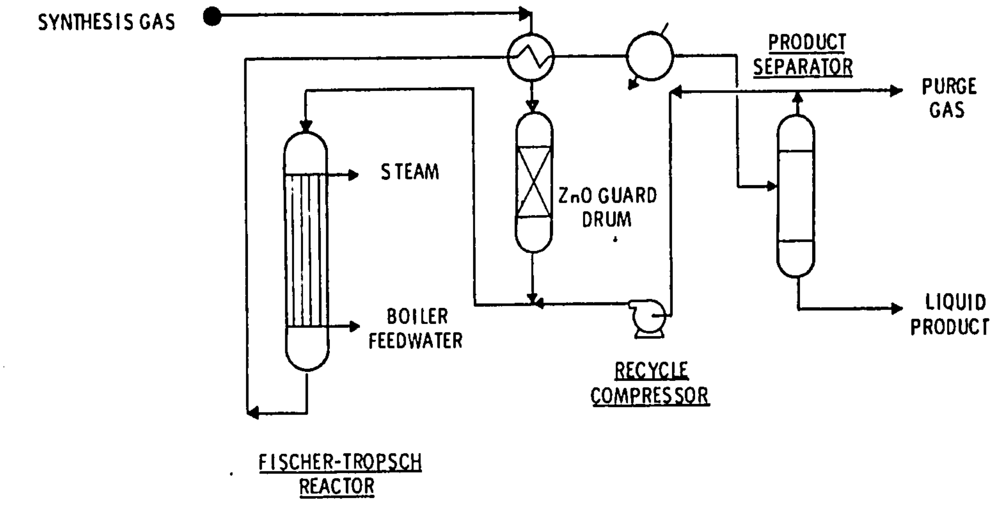


FIGURE 19. Flow Diagram for the Arge Fischer-Tropsch Synthesis

TABLE 23. Yield Breakdown for the Arge and Kellogg Synthesis (Parsons 1977, Garrett 1960, Field 1960)

	Arge (wt%)		Kellogg (wt%)
C_1-C_4	22	C_1-C_4	33
C_5-C_{11}	25	C_5-C_{11}	48
C_{12}-C_{20}	15	C_{12}-C_{20}	18
C_{20}^+	36	C_{20}^+	1
Alcohols, acids ketones	2	Alcohol, acids ketones	5
	100		100

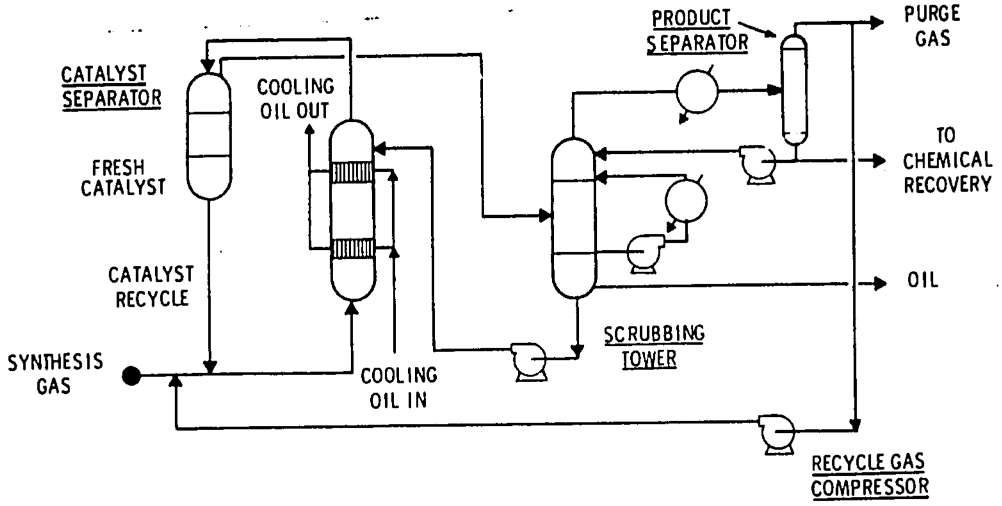


FIGURE 20. Flow Diagram for the Kellogg Fischer-Tropsch Synthesis

For both the Arge and Kellogg synthesis, the feed gas including recycle has a H_2/CO ratio of about 3/1. The ratio consumption of H_2 and CO is slightly above 2/1. In both instances, complete conversion is not obtained in one pass and the liquid product is separated from the unconverted synthesis gas which is recycled. Recycle ratio is typically 2/1 to 2.5/1. Inerts and noncondensables (primarily CH_4 and CO_2) are continually purged from the system. Overall conversion to fuels of 95 percent based on H_2 is possible (Garrett 1960; Parsons 1977).

The major advantage of the F-T synthesis is that is that it produces petroleum-like materials. A major disadvantage of the process is the wide range of products. The equivalent of a petroleum refinery is required downstream to produce specific fuels (gasoline, diesel, fuel oil, etc.). For small scale operations based on biomass (even large scale biomass projects are small by petroleum standards) the F-T process suffers severe economic penalties for product upgrading (Kam 1980).

Advances in Liquid Fuel Synthesis

Current research in alcohol synthesis technology generally falls into two areas: 1) developing active and selective catalysts for low pressure methanol synthesis, and 2) developing catalysts for the direct production of higher alcohols from synthesis gas.

Although the presently available methanol technology is well developed, owing primarily to an active, selective, and stable catalyst, there is still a strong motivation for pushing the technology to even lower pressures. Lower pressure synthesis provides for better process integration with existing gasifiers resulting in energy economies for the overall process. This is particularly true for small methanol plants where the use of reciprocating compressors (centrifugal machines can be used in large plants) significantly increases the cost of methanol production.

Recent studies at Lehigh University (Herman 1979), Union Carbide (Bhasin 1978, Poutsma 1978), and Sagami Chemical Company (Ichikawa 1978) indicate that reduction in synthesis pressure may be achieved with both the Cu/ZnO system and other catalysts containing finely dispersed precious metals and their alloys.

There is no commercial process for higher alcohol synthesis from synthesis gas; however, direct synthesis has been achieved in the laboratory (Morgan 1932, Natta 1957). When considering fuel grade alcohol where a pure product may not be necessary, the production of higher alcohols from synthesis gas is interesting in the following regards:

- Higher alcohols have a higher energy density than methanol.
- Higher alcohols are thermodynamically favored over methanol, and it may be possible to develop a more efficient synthesis by using a less selective catalyst.

An example is the process recently introduced by the Institut Francais du Petrole using a catalyst containing cobalt and copper oxides (Intelle 1979). Product of the synthesis at 270°C and 60 atmospheres was composed of 23 percent methanol, 38 percent ethanol, 22 percent i-propanol, and 17 percent n-butanol. Selectivity to alcohols was reported to exceed 95 percent. Conversion per pass was reported to be 35 percent which is considerably greater than that obtained in low pressure methanol synthesis. Such a process may not be advantageous for chemical grade alcohol production where extensive separation steps would be required. However, this process, or one like it, when fully developed may significantly reduce the production costs of fuel grade alcohols.

All the previous discussion dealt with production of methanol and other alcohols using solid heterogeneous catalysts. Recently, homogeneously catalyzed reduction of carbon monoxide to methanol and methyl formate at 1300 atm (19,000 psig) and 225 to 275 C (440-530 F) in the presence of solutions of ruthenium complexes was observed. This observation could be the forerunner of new catalytic systems for methanol manufacture (Bradley 1979).

Methanol and other alcohols can be converted to a high octane gasoline using a process developed by Mobil Oil Company. The process has been successfully tested in a 4 bbl/day process development unit, and a conceptual design of a 100 bbl/day pilot plant has been completed. Recently it was announced that New Zealand was proceeding with plans for a 12,500 bbl/day plant to convert natural gas to gasoline via methanol (Kan 1980). A flow diagram for the process using a fixed bed reactor is shown in Figure 21. Commercial development of the process is based on a fixed bed reactor. Process development studies are concentrating on a dense fluid bed reactor.

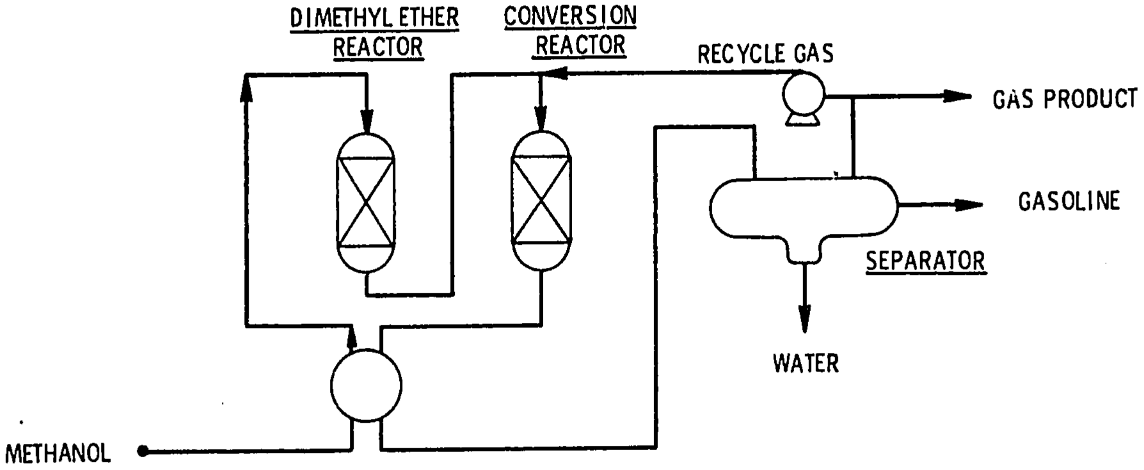


FIGURE 21. Flow Diagram for the Mobil Methanol-to-Gasoline Process

In the process, methanol vapor is contacted with a unique, shape-selective zeolite catalyst (ZSM-5) at 370-420°C (700-775°F). The size and shape of the zeolite catalyst pores result in high selectivity (88 wt percent) to high octane gasoline. Overall conversion of methanol is close to 100 percent with the by-products being light gases C_2-C_4. The hydrocarbon molecules produced include many highly branched or cyclic compounds resulting in the high octaine rating (96 research clear) (Kam 1978).

Ongoing research on the Fischer-Tropsch synthesis generally has as its ultimate goal one of the following:

1) develop a catalyst with increased activity which allows the synthesis to be run at lower temperatures thus increasing the equilibrium conversion, or

2) develop a more selective catalyst to reduce the amount of downstream refining and upgrading required.

Research dedicated toward achieving the first goal generally takes the form of studies aimed at better understanding the reaction mechanisms and kinetics. Vannice provides an excellent review of recent work in this area (Vannice 1976).

Recent research has indicated that significant improvements in product selectivity for the Fischer-Tropsch synthesis may be possible. Molecular sieve zeolites appear to have the ability to limit the molecular weight of the hydrocarbons produced. They also can apparently increase the yield of isoparaffins and aromatics (Caesar 1979, Nijs 1979). Ruthenium-alumina catalysts also show potential for limiting the size of the molecules produced (Everson 1978; Madon 1979) as do catalysts containing Cu-Ni alloys (Van Barneyeld 1978). Most of these studies have been aimed at increasing the yield of gasoline from the Fischer-Tropsch synthesis. Mobil is developing a series of catalysts which they believe can reduce the cost of gasoline from the F-T synthesis by 20 percent. These catalysts are composed of a typical F-T metal and a zeolite of the ZSM-5 class (Brennan 1978; Caesar 1979).

Applications

Currently there is no commercial production of liquid fuels from biomass by indirection liquefaction (gasification and synthesis). All methanol is made from synthesis gas from natural gas, naphtha, or heavy residual oil and Fischer-Tropsch liquids are made from synthesis gas from coal. However methanol from biomass facilities have been considered in the past and are receiving increasing interest today.

In 1944-1975 the French operated a wood to methanol pilot plant. The plant produced about 5.3 tons/day of methanol from about 17 tons/day of dry wood. An oxygen-blown De Lacotte downdraft gasifier was used along with a high pressure methanol synthesis unit (Delauney 1946).

Large scale production of methanol from wood is being considered in both Brazil and South Africa. The Brazilian project is the most advanced. Brazil is a very large territory with a warm and rather humid climate which permits a large and economical production of biomass. Wood and charcoal are already responsible for 26 percent of the total energy supply in the country. In addition the transportation system in the country has already adapted to alcohol fuels (ethanol). Since production of methanol from wood should be less expensive and more efficient than production of ethanol from wood or sugar cane, Brazil is actively pursuing this alternative.

Companhia Energetica de Sao Paulo (CESP) has been studying producing of methanol in a 1.1 ton/day methanol pilot plant. The pilot plant includes three gasifiers, gas cleaing equipment, compression facilities, shift reactor, desulfurization unit, acid gas removal unit and a methanol converter. The main objectives of the pilot facility are:

- to define operational, technical, and reliability aspects of wood and charcoal gasification;
- to develop alternative technologies for gasification and synthesis gas treatment;
- to promote alternative catalysts;
- to evaluate Brazilian capability in equipment manufacturing, design, engineering, and construction;
- to promote training of operators.

CESP believes the only major technical problem involved in production of methanol from wood is the gasification step. No wood gasifier of the size required is now available. As a result CESP is planning to build commercial scale wood gasifiers with the following designs:

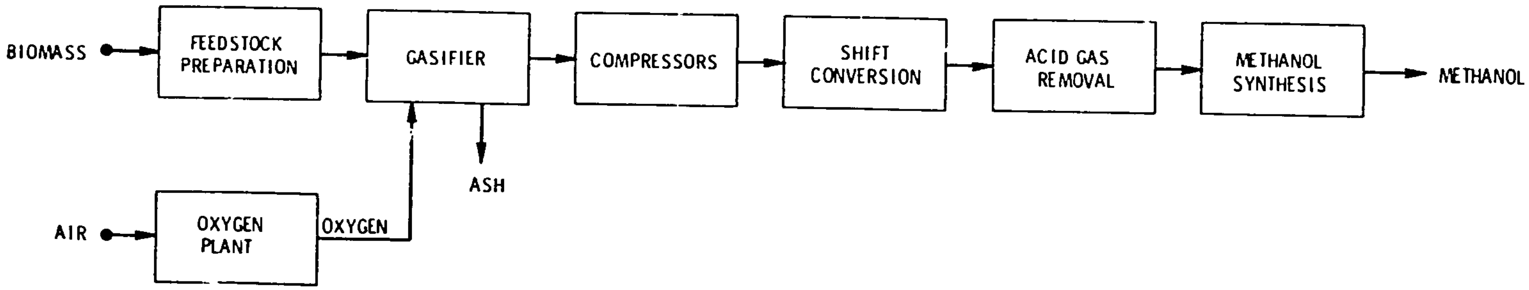
1) A fixed bed design based on CESP's pilot gasifier. The reaction heat will be supplied partly by electrical power and partly by oxygen injection.

2) A fixed bed, atmospheric, updraft gasifier which was used for several biomass facilities just after World War II. A block flow diagram for methanol production based on this gasifier is shown in Figure 22.

3) A pressurized fluid bed gasifier (Winkler) designed for lignite. This gasifier has many advantages but is only in a preliminary development stage.

Each one of these units will produce an amount of gas equivalent to a 100 ton/day methanol plant. This will require around 300 tons/day of wood for each gasifier. The engineering development for the three units is underway and is being carried on by joint ventures of Brazilian, American, and German private companies. Scheduled startup of the units is in 1982 (Filho 1980).

FIGURE 22. Block Flow Diagram for the Conversion of Biomass to Methanol



Process Evaluation and Economics

Two recent studies of production of methanol from wood have been made by SRI (Kam 1980) and Davy McKee (Rooker 1980). The SRI study was part of a larger study to compare various technologies for the production of liquid fuels from wood. The basis for this study was 2000 tons/day of green wood (525 tons/day of methanol) which is a reasonable value for the maximum amount of wood economically available at a typical site in the U.S. The Davy study was for production of methanol from eucalyptus wood in Brazil and was sized to produce 2000 metric tons/day of methanol. The major difference in the conceptual processes schemes of the two studies is the choice of gasifier, SRI selected a fluid bed gasifier operating at 500 psig. Currently there is no existing gasifier with the assumed operating conditions. However, SRI felt that such a gasifier is technically feasible and could be developed. Davy chose a proven updraft, fixed bed, atmospheric gasifier. Both chose a low pressure (500 psig) methanol synthesis. By selecting the fluid bed, pressurized gasifier SRI minimized the compression of the synthesis gas required to enter the synthesis loop, and eliminated the gas cleanup equipment necessary to remove the tars and oils generated in a fixed bed unit. The overall plant thermal efficiency is 51 percent for the Davy study and 56 percent for SRI's fluid bed system. A block flow diagram for a conceptual biomass to methanol facility is shown in Figure 22.

Table 24 presents a breakdown of the investment costs developed in the two studies. Both sets of cost data are for a U.S. location. The major contributor to the capital cost is the gasifier system followed by the methanol synthesis and the oxygen plant. The total capital investment for a biomass to methanol plant for these and three other studies are shown in Table 25. The final cost of methanol for the five studies shown in Table 25 ranges from $0.50-$1.00/gallon depending on the variations in the analysis. The major variations are the size of the facility, the type of financing used, and the cost of feedstock. The difference between utility and 100 percent equity financing is about $0.25/gallon. Increasing/decreasing the cost of wood by $10/dry ton increases/decreases the methanol selling price by about $0.07/gallon.

TABLE 24. Breakdown of Investment Costs for a Methanol from Wood Facility (U.S. location) - $ millions

	SRI (Kam 1980)	Davy McKee (Rooker 1980)
Wood handling and preparation	4.2 (4)	15.1 (4)
Gasification and gas cleanup	18.9 (17)	89.4 (26)
Shift Conversion	1.6 (1)	10.2 (3)
Acid gas removal	5.8 (5)	23.0 (7)
Compression	1.2 (1)	16.9 (5)
Methanol Synthesis	10.9 (10)	36.3 (10)
Oxygen Plant	12.9 (12)	27.0 (8)
Misc	2.0 (2)	7.0 (2)
Utilities/Facilities	37.1 (34)	50.1 (14)
Total Plant Investment	94.6 (86)	275.0 (80)
Start-up Expenses	4.7 (4)	12.5 (3)
Funds During Construction	7.2 (7)	51.3 (15)
Working Capital	3.0 (3)	7.6 (2)
Total Capital Investment	109.8 (100)	346.4 (100)
Methanol Production	525 tons/day	2200 tons/day

Gasoline can be produced from methanol using the Mobil process for about 20 percent more than the cost of methanol (on an equivalent Btu basis). This corresponds to about $1.40- 2.00/gallon (utility financing). Gasoline from Fischer-Tropsch synthesis would likely be somewhat more expensive than gasoline from the Mobil process. The cost of jet and diesel fuels the from Fischer-Tropsch synthesis would be less than the cost gasoline (Baker 1980).

TABLE 25. Estimated Cost of Methanol from Wood

Study	Gasifier Type	Methanol Production Rate tons/day	Wood Feed		Wood Cost $/dry ton	Overall Thermal Efficiency Percent	Plant Investment Cost (1979) $ million	Methanol Cost $/gallon
			Rate tons/day	Moisture Content Percent				
Davy McKee (Rooker 1980)	Fixed Bed	2,200	7,300	40	12	51	346	0.49
		2,200	7,300	40	20	51	346	0.54
		200	7,300	40	12	51	--	0.61
	Fluid Bed	2,200	7,300	40	12	--	--	0.54
		2,200	5,000	13	12	--	--	0.48
Katzen (Hokanson 1978)	Fixed Bed	2,000	6,000	50	20	38	235	0.64
		500	1,500	50	20	38	89	1.09
SRI (Kam 1980)	Fluid Bed (pressurized)	575	2,000	50	20	56	110	0.78
CESP (Filho 1980)	Fixed Bed	1,100	--	--	22	--	160	0.55
	Fluid Bed	1,100	--	--	22	--	160	0.48
	CESP	1,100	--	--	22	--	160	0.55
SAI (Wan 1979)	Entrained Bed	430	2100	52	25	50	113	0.91
	Entrained Bed	2,150	10,400	52	25	50	373	0.66
	Fixed Bed	330	2,100	52	25	38	74	0.88
	Fixed Bed	1,660	10,400	52	25	38	217	0.61
Mitre (Blake 1977)	Fixed Bed	1,340	6,800	50	20	38	235	0.64
		335	1,700	50	45	--	46	0.84

SYNTHESIS OF CHEMICALS

Various chemicals can be made from biomass by converting the biomass to a gaseous intermediate from which chemicals can be made. Chemical synthesis is similar to synthesis of liquid fuels except the synthesis gas does not necessarily consist of carbon monoxide and hydrogen. The most common chemicals that can be produced from biomass are methanol (covered under liquid fuels) and ammonia. Other chemicals that can be made from biomass via gasification include formaldehyde, acetic acid, acetic anhydride, urea, and single cell protein.

Ammonia Synthesis Processes

By the end of the nineteenth century the demand for nitrogen fertilizer began to outstrip the supply of natural fertilizers and the need for man to devise methods of fixing atmospheric nitrogen was recognized. The Haber-Bosch process for direct synthesis of ammonia from nitrogen and hydrogen was developed in Germany in between 1905 and 1913.

$$N_2 + 3\ H_2 \rightleftarrows NH_3$$

This has grown into the huge synthetic ammonia industry of today. Ammonia synthesis is in many ways similar to the methanol synthesis. Synthesis gas consisting of a 3 to 1 mixture of hydrogen and nitrogen is compressed to 100 to 800 atm, mixed with recycled, unconverted nitrogen and hydrogen, and introduced into the synthesis reactor at 400-600 C (750-1100 F). The catalyst for ammonia synthesis is a triple promoted iron oxide. The iron oxide is reduced to iron in the reactor by the nitrogen-hydrogen mixture leaving a porous iron containing promotor. The gases leaving the reactor are cooled (-10 to -20 C) to liquefy some of the ammonia. A portion of the remaining gas is purged, to prevent accumulation of diluents, and used for fuel. The remaining is recompressed and recycled. Conversion per pass is 20-22 percent and the overall yield with recycle is about 85 percent.

The Haber-Bosch-Mittasch (H-B-M) process was the first ammonia synthesis to be developed industrially and suitably modified and improved is still today the most widely used (Vancini 1971). A flowsheet of the H-B-M process is shown in Figure 23. The synthesis reactor is the heart of the process and a cross sectional view of an H-B-M reactor is pictured in Figure 24. Fresh gas passes through the exchanger shell and then enters the catalyst bed. Product gases from the catalyst bed pass through the tube side of the exchanger countercurrent to the fresh gases. A system of cold gas injections into suitable parts of the catalyst bed controls the temperature in the reactor.

Process Evaluation and Economics

In 1974 more than 80 percent of the ammonia produced was made using hydrogen from steam reforming of hydrocarbons, principally natural gas. These hydrocarbons could otherwise be used as fuel if another source of hydrogen were found.

Toward the end of World War II the Power Gas Corp. (now Davy Powergas) built a plant in India to produce ammonia synthesis gas from wood. The plant used an air-blown fixed bed gasifier to make a low-Btu producer gas. A cyclical steam-iron process was used to produce hydrogen. Producer gas was used to reduce a hot mass of iron oxide in a generator to a lower oxide and elemental iron. Steam was then introduced into the generator to oxidize the iron yielding hydrogen. To produce the nitrogen for synthesis some of the producer gas was combusted in a gas fired boiler to generate steam. The combustion gases were cooled, washed with water, and scrubbed with an ethanolamine solution to remove CO_2 (Rutherford 1949).

There have been no commercial applications of production of ammonia from biomass since the early Davy installation using the steam-iron process. However, there are several coal-to-ammonia plants in operation around the world (Waitzman 1975). Entrained bed, oxygen-blown gasifiers, particularly the Koppers-Totzek have been the gasifier of choice for synthesis gas production. Based on coal-to-ammonia plants a conceptual modern biomass-to-ammonia facility is shown in Figure 25. The major differences between this and a methanol from biomass facility are the shift converter and the nitrogen wash. In the shift reactor hydrogen production is maximized at the expense of carbon monoxide. The nitrogen wash serves two purposes: nitrogen is added for the ammonia synthesis and liquid nitrogen is used to scrub out the remaining carbon monoxide.

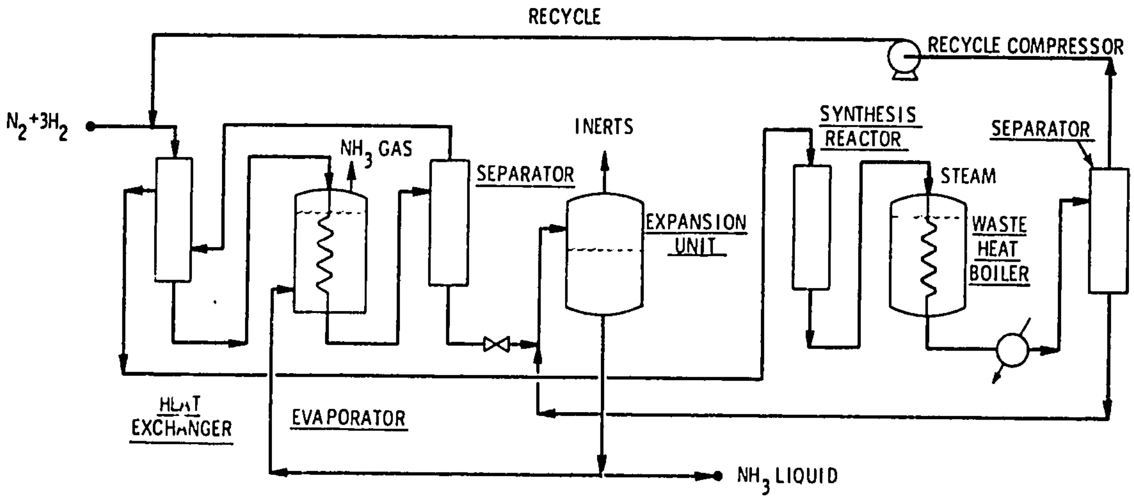


FIGURE 23. Flow Diagram for the H-B-M Ammonia Synthesis Process

Three different studies on the cost of ammonia from biomass have been completed recently. The results are shown in Table 26. The capital costs agree reasonably well although the SRI estimates are somewhat higher than the other two. The major differences in the final product cost are the wood cost and the financing method used. The values for McKee and SRI represent industrial financing methods. When all the estimates are compared using the utility financing method outlined previously the costs are quite similar. Using wood at $20 per dry ton and utility financing, the cost of ammonia from biomass is about $140-180/ton. Using industrial financing it ranges from $210-300/ton.

Other Chemicals

Some other common chemicals that can be made from biomass derived synthesis gas are shown below:

Formaldehyde	$CO + 2H_2 \rightarrow CH_3OH \xrightarrow{O_2} CH_2O + H_2O$
Acetic Acid	$CO + 2H_2 \rightarrow CH_3OH \xrightarrow{CO} CH_3COOH$
Acetic Anhydride	$2CO + 4H_2 \rightarrow 2CH_3OH \xrightarrow{2CO} 2CH_3COOH \rightarrow C_4H_6O_3 + H_2O$
Urea	$N_2 + 1.5H_2 \rightarrow NH_3 \xrightarrow{CO_2} NH_2COONH_4 \rightarrow NH_2CONH_2 + H_2O$

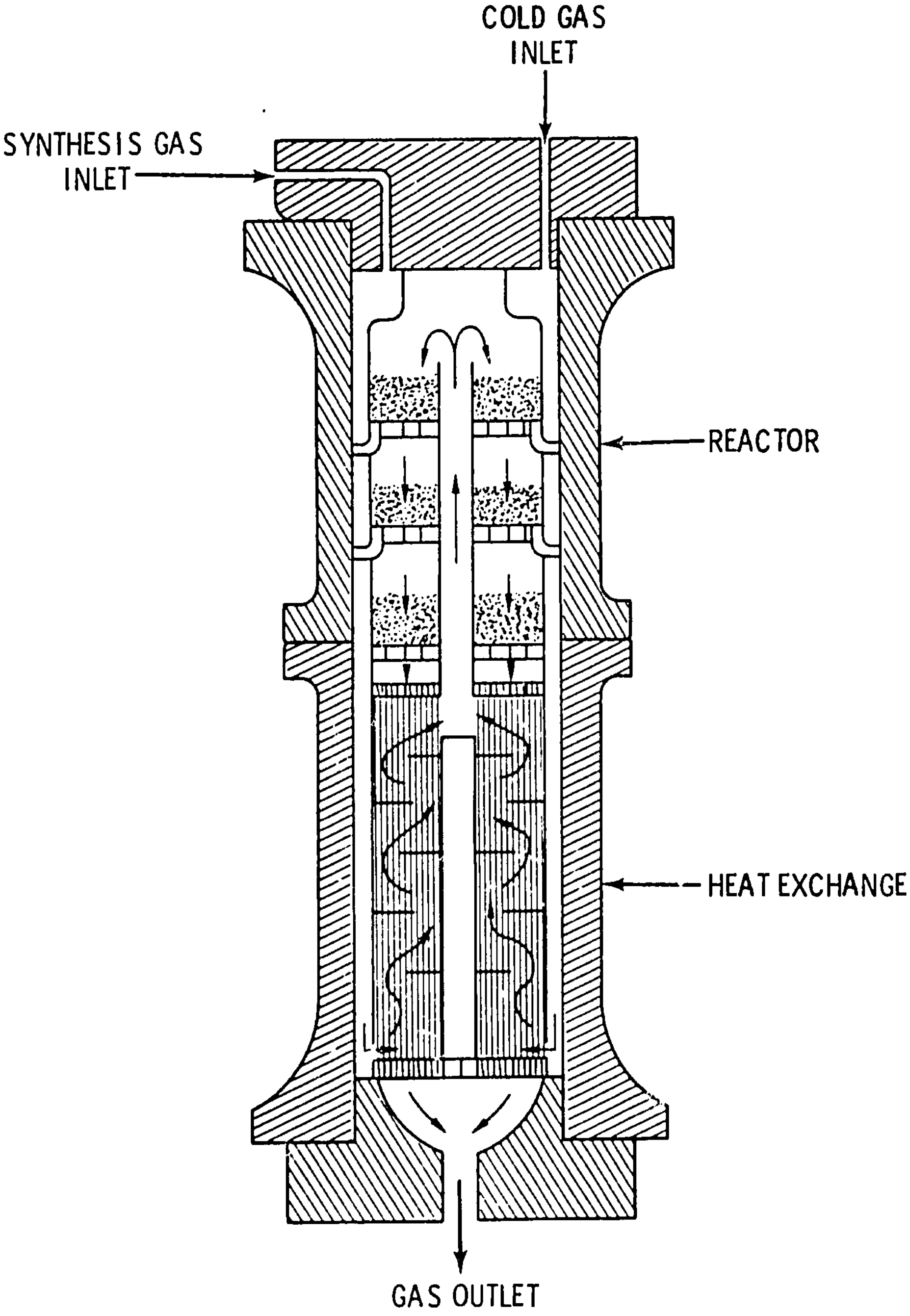


FIGURE 24. Schematic of an Ammonia Synthesis Reactor

TABLE 26. Summary of Cost Estimates for Ammonia Production from Biomass

Study	Gasifier Type	NH_3 Production Rate tons/day	Wood Feed tons/day	Wood Feed moisture	Cost Wood $/dry ton	Mass Conversion Efficiency ton NH_3/dry ton wood	Plant Investment $ million 1980	NH_3 Cost $/ton Study basis	NH_3 Cost $/ton Utility financing
Mitre (Blake 1977)	Oxygen Blown Fixed Bed	1,970 492	6,800 1,700	50 50	45 45	0.59 0.59	133 54	120 154	136 178
McKee (Dietz 1978)	Air-Blown Fluid Bed (Thermex)	400	1,270 (Bamboo)	—	20	0.31	64	213	143
SRI (Schooley 1978	Oxygen-Blown	1,542 500	6,000 2,000	50 50	19/38 19	0.50 0.50	267 110	249/287 300	147/184 182

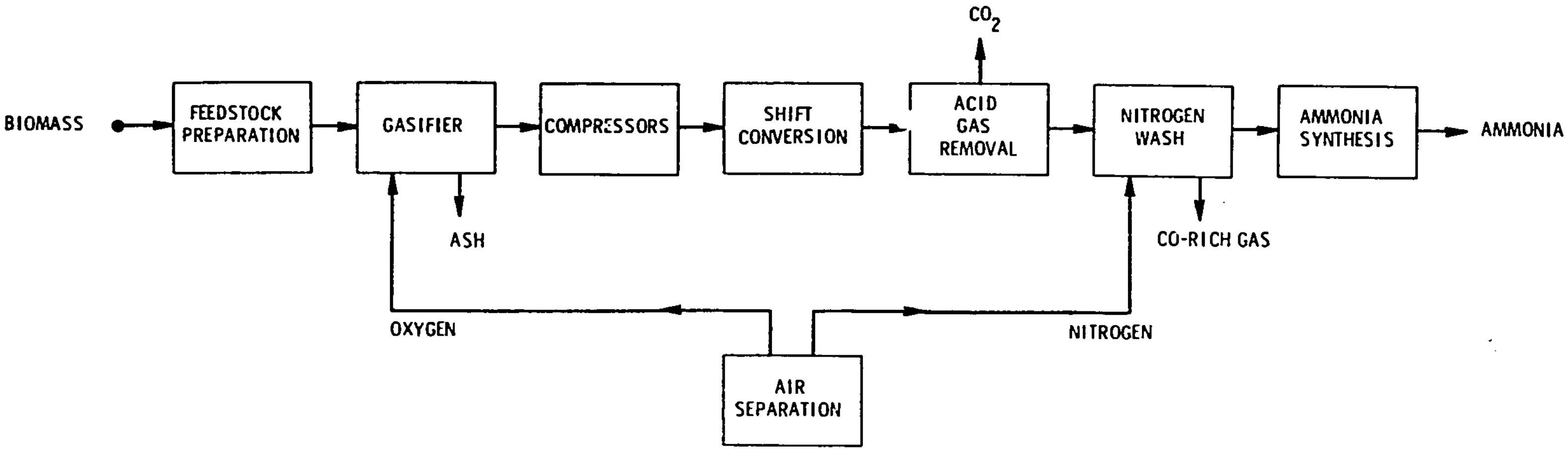
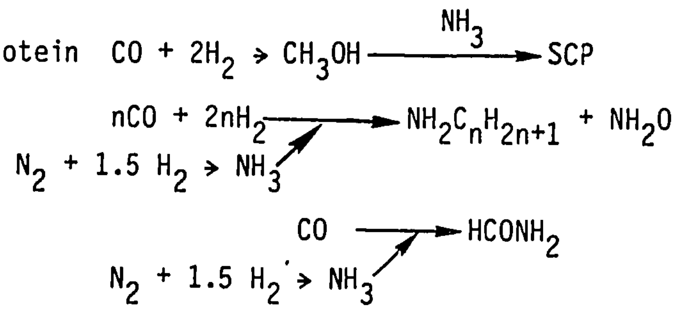


FIGURE 25. Block Flow Diagram for the Production of Ammonia from Biomass



Single Cell Protein $CO + 2H_2 \rightarrow CH_3OH \xrightarrow{NH_3} SCP$

N-Alkylamines $nCO + 2nH_2 \longrightarrow NH_2C_nH_{2n+1} + NH_2O$

$N_2 + 1.5\ H_2 \rightarrow NH_3$

Formamide $CO \longrightarrow HCONH_2$

$N_2 + 1.5\ H_2 \rightarrow NH_3$

This is by no means a complete list of potential chemicals that can be produced from biomass via gasification. In addition to being the building block for many chemicals, synthesis gas can also be used in many other chemical reactions. The economic attractiveness of producing chemicals from an integrated production system based on biomass gasification will depend on the market potential of the various products and integration and optimization of the process design.

ENVIRONMENTAL CONSIDERATIONS

Depending upon the application, up to three waste streams will be generated from biomass gasification: a solid stream containing mostly ash and some unconverted feed material (char), a waste water containing heavy liquid organics and solid particulates, and an exhaust gas stream from the combustion device using the fuel gas (boiler, engine, etc.)

Most biomass materials have a low ash content (< 1 percent); however, in the process of collecting and transporting the biomass feed materials a significant quantity of contaminants (sand, glass, metal, etc.) may be picked up. These will increase the amount of ash produced.

The granular char-ash mixture consisting of mainly fixed carbon and ash should present little or no disposed problems. The material is generally considered to be non-toxic and can be disposed of in a landfill. Another potential means of disposal is to return the char-ash mixture to the field and plow it into the soil. Preliminary tests on this disposal method show no potential problems and indicate the material may have a weak fertilizer value (Moreno 1980).

A significant quantity of heavy organics (often referred to as tar) are formed in the pyrolysis reaction. In downdraft and fluid bed gasifiers most of these heavy organics are reformed to gases prior to leaving the gasifier. However, in updraft gasifiers a large portion of the heavy organics leave the reactor with the product gas. With a relatively dry wood feed material the heavy organic liquids contain about 20-25 percent of the carbon originally in the wood (Mudge 1980). If a clean gas is necessary the tar must be removed. This is usually done by scrubbing the gas with water resulting in production of a waste water stream. Most applications of updraft biomass gasifiers in the U.S. have involved boiler retrofitting where the hot dirty gas is burned directly. No wastewater stream is produced so little attention has been given to wastewater treatment.

The organic liquids produced from biomass gasification consists of an insoluble, viscous tar (phenolics) and a soluble fraction containing acetic acid, methanol, acetone, esters, aldehydes, and furfural which collectively often referred to as pyroligneous acid.

Separation of the tar is not difficult; gravity separation or filtration is sufficient. The ultimate means of disposal of the tar is by combustion. Recovery of the heating value of the tar (by generating steam, drying the feedstock, etc.) is possible, however the viscosity of the tar will make this a difficult and expensive proposition. If heat recovery is not feasible the tar can be incinerated for disposal.

After the tar has been removed the waste water still has a high BOD content due to the soluble pyroligneous acids. Treatment of this water to meet U.S. standards has been studied and a sophisticated treatment technique outlined (Wakamiya 1980). In LDCs less complex techniques may be more appropriate. Possibilities include a simple aerator or a solar evaporating pond (the resulting sludge could be landfilled).

Disposal of scrubber waste water from downdraft and fluid bed gasifiers is much simpler as the water contains only trace quantities of heavy organics and some particulate matter (particularly for fluid beds). A solar evaporating pond would be an easy solution. Another technique that has been suggested is to pass the water stream over a filter bed of waste char. The spent char can then be recycled back to the gasifier (Biomass Corp 1980).

The product gas from all biomass gasifiers contains a significant quantity of toxic carbon monoxide gas. Even minor leaks in the plant can affect operating personnel. For this reason gasifiers should not be installed in closed buildings. In addition an after-burner or flare is necessary to handle excess gas and gas produced during startup and shutdown. Carbon monoxide monitors located throughout the plant can provide additional safety.

When the product gas from the gasifier is used, an exhaust gas stream will be generated. If the proper amount of excess air is used the gas will consist mainly of CO_2, N_2 and O_2. Small quantities of SO_x, NO_x, and particulate matter may also be present. Scrubbing the gas prior to use will greatly reduce the particulate matter. The emissions from a boiler fired by hot dirty gas from a biomass gasifier have been measured in three different tests (Hodam 1978, Mathur 1979, Finnie 1980). The emissions of SO_x, NO_x, and particulates as measured in these tests meet U.S. federal standards. In tests performed by the State of California no SO_x was detected, the NO_x was 129.7 ppm, and the particulate concentration was 0.08 gr/scf (Hodam 1978).

Other potential sources of emissions from the gasifier system are:

- dust from feed handling and ash/char handling equipment
- gas leakage out through the feed port and feed handling equipment
- gas leakage out through the ash/char removal systems

The last two will occur only if the gasifier operates at a positive pressure. All three sources of emissions should be negligible in a well designed system.

For downstream synthesis processes such as methanol or ammonia the major waste streams are flue gases from combustion equipment (furnaces, boilers, etc.) and wastewater. Emissions in flue gases can be reduced by choice of fuels (low sulfur fuels such as biomass or biomass derived gas) and proper operation of the combustion equipment. Most synthesis processes involve large integrated plants with their own water treatment facilities. These facilities would also treat the wastewater from the gasification system.

PROCESS COMPARISON

Previous sections of this report have been devoted to production of gaseous fuels from biomass and to various applications of these gaseous fuels. In this section we will try to compare the various technologies with respect to efficiency and economics. In addition plant capital and operating costs in the U.S. will be compared to costs in LDCs.

Table 27 shows the various applications of large scale biomass gasification that have been discussed. The end product costs that are presented are Battelle Northwest estimates based on processes fueled by dry (< 25 percent moisture), low-cost ($ 20/dry ton) wood. Utility financing is used. These can be considered "ideal" cases. Costs will be higher if the feedstock cost is higher, if a lower quality feedstock is used, or if industrial financing (100 percent equity) is used. The sensitivity of the end product cost to wood cost and type of financing is shown in Table 28.

Two different means of producing electricity from biomass were evaluated. The steam cycle route produces electricity at about $0.07/kW-hr for a 3 MW plant. The overall conversion efficiency is about 20 percent. This is based on a field erected high pressure boiler. For lower pressure packaged boilers the efficiency is somewhat less, but this is compensated to some degree by the reduced cost of the boiler. Diesel-electric sets can also produce electricity from biomass for about $0.07/kW-hr at around 20 percent conversion efficiency. In LDCs gasifier/diesel generator combinations have been the system of choice for small (1000 kW and less), biomass fueled, electrical generating units. Gasifier/steam cycle systems and packaged wood fired boilers would be competitive for larger systems.

The cost of electricity from small power plants fueled by low Btu gas from biomass is 3-4 times the cost of electricity from 1000 MW coal fired-central power stations (about $0.02/kW-hr) and 1 1/2-2 times the estimated cost of electricity from large (55-220 MW) wood fired power plants (Bliss 1977).

In applications where both electric power and low pressure steam for heating are required, cogeneration provides significant economies. Although

TABLE 27. Comparison of Large Scale Biomass Gasification Applications

Application	Wood Feed Dry tons/day	Conversion Efficiency Percent	End Product		Cost[(a)]	Technology[(b)] Status
			Type	Quantity		
Retrofits						
Air-Blown Gasifier/Existing Oil or Gas Fired Boiler	70	85	low Btu gas	42 x 10^6 Btu/hr	$\$ 2.20/10^6$Btu	P
Air-Blown Gasifier/Gas Cleaner/Existing Diesel Engine-Generator	70	65	low Btu gas	32 x 10^6 Btu/hr	$\$ 3.20/10^6$Btu	P
Power Production						
Air-Blown Gasifier/Boiler/Turbine-Generator	24	21	Electricity	1,000 kw	$\$ 0.075$/kw-hr	C
	70	21	Electricity	2,920 kw	$\$ 0.065$/kw-hr	
Air-Blown Gasifier/Gas Cleaner/Diesel Engine-Generator	24	21	Electricity	1,000 kw	$\$ 0.070$/kw-hr	P
	70	21	Electricity	2,920 kw	$\$ 0.062$/kw-hr	
Cogeneration						
Air-Blown Gasifier/Boiler/Back Pressure Turbine-Generator	70	72	Electricity	2,000 kw	$\$ 0.045$/kw-hr	C
			Steam	28 x 10^3 lb/hr	$\$ 3.00/10^3$ lb	
Air-Blown Gasifier/Gas Turbine-Generator/ Waste Heat Baler	70	58	Electricity	2,550 kW	$\$ 0.039$/kw-hr	D
			Steam	20 x 10^3 lb/hr	$\$ 2.50/10^3$ lb	
Methanol Production						
Oxygen-Blown Gasifier/Gas Cleaner/Acid Gas Removal/Shift Compression/Synthesis	1,000	52	Methanol	500 tons/day	$\$ 0.75$/gallon	C
	200	52	Methanol	100 tons/day	$\$ 1.05$/gallon	
Ammonia Production						
Oxygen-Blown Gasifier/Gas Cleaner/Acid Gas Removal/Shift Compression/Synthesis	1,000	50	Ammonia	500 tons/day	$\$ 160$/ton	C

(a) utility financy, wood at 20/dry ton

(b) P - Proven, commercial plants in operation; C - Commercial, process ready for commercialization, equipment commercially available; D - Developmental, significant development is necessary prior to commercialization.

TABLE 28. Sensitivity of End Product Cost to Wood Cost and Financing Method

	Change in low Btu gas $/million Btu	End Product Electricity $/kw-hr	Methanol $/gallon	Ammonia Cost $/ton
Wood Cost Increase $ 10/dry ton	0.80	0.01	0.07	20
100 percent Equity Financing vs Utility Financing	0.60	0.04	0.25	70

the ratio of electrical output to steam output can be varied, gas turbine cycles, in general, produce more electricity then steam cycles albeit at a lower overall conversion efficiency. Gas turbine cycles are still developmental for non-conventional fuels such as low-Btu gas. Cogeneration using a back-pressure steam turbine can be considered commercial, but we know of no applications using low-Btu gas from biomass.

There is a significant economy of scale for methanol production and the methanol from biomass plants currently under consideration are more than an order of magnitude larger than the power production and heating applications discussed previously. For a 500 ton/day methanol plant the cost of methanol will be about $0.75/gallon or $11/million Btu compared to the current U.S. rack price for unleaded gasoline of $7.50/million Btu. The overall thermal efficiency of the process is a little above 50 percent.

Estimating the cost of new technologies is risky at best and nearly impossible when prices are unstable and energy costs are rising rapidly. Predicting the cost in LDCs is that much more difficult. However, to evaluate large scale biomass gasification for LDCs some measure of the costs in LDCs is necessary. Construction costs and labor costs in some LDCs have been estimated relative to costs in the U.S. (Kharbanda 1979). A summary of this information is included in Table 29. Several factors affect the construction cost of process plants in LDCs. They are outlined below.

TABLE 29. Plant and Labor Costs in LDC

Location	Complete Plant Cost	Labor Wage	Labor Productivity	Labor Cost
U.S. Gulf Coast	100	100	100	100
India	90-135	15	30	50
Taiwan	> 100	10	30	30
Underdeveloped Countries	125-145	--	--	50

- If design, engineering, and equipment manufacturing is done in a developed country the plant cost will be reduced and possibly be lower than in the U.S. because of the low cost of construction labor. If a significant portion of the design, engineering, and equipment manufacturing are done in LDCs then the cost of the plant will be significantly higher than in the U.S.
- For simple construction projects such as buildings, roads, etc. the cost in LDCs will be less than in the U.S. For complex chemical plants the cost will be significantly higher than in the U.S.
- Construction projects in LDCs are more likely to overrun the projected cost and completion time than similar projects in the U.S.

Based on the preceeding discussion the cost of a large scale biomass gasification plant in a LDC will likely be somewhat more than in the U.S. However, feedstock and operating costs will be significantly lower because of the low labor costs in LDCs.

POTENTIAL IMPACT OF LARGE-SCALE BIOMASS GASIFICATION IN LESS DEVELOPED COUNTRIES

Major sections of this report summarize the technical state-of-the-art for gasification and synthesis gas processes, including a description of the degree of commercialization of various approaches, the experience in foreign sector applications, and estimates of costs of various approaches.

This essential background material forms part of a data base for assessing the probable impact of these and other alternative energy technologies on the development process in less developed countries. Each country or region represents a unique set of resources and needs, and within countries of any size, regional analyses are necessary to balance specific sectoral needs against resources and the costs of competing technical approaches.

This section of the report thus cannot do much more than provide some generalizations about needs in LDCs, and relate the potential of biomass-derived fuels to needs in such countries in a broad way.

The following general topics will be discussed:

- large-scale gasification of biomass for rural electrification
- industrial uses of biomass-derived gas
- production of methanol and other liquid fuels for transportation
- large-scale gasification of biomass for agricultural uses
- production of ammonia and other chemicals.

RURAL ELECTRIFICATION

Approximately 10 percent of the international investment in power generation has been directed toward the rural sector in third-world countries. In discussing this topic, data are drawn from a World Bank Paper, entitled Rural Electrification, dated 1975. Table 30 summarizes the extent of achieved electrification, by region, and illustrates the magnitude of unmet needs. These data, from 1971, would yield a population closer to 2 billion when adjusted for population growth rates in the intervening 9 years.

TABLE 30. Extent of Rural Electrification by Region (World Bank 1975)

	Population in 1971(1) (millions)			Village-rural(2,3) population served in 1971	
Region	Total	Village(2)	Rural(2)	Millions	Percentage
Latin America	282	140	(50)	32	23
Selected countries in Europe, Middle East, and North Africa(4)	143	87	(61)	45	15
Asia	934	700	(75)	105	15
Africa	182	165	(91)	7	4
	1,541	1,092	71	189	12

---

(1) Population figures refer to the whole region, except in the case of Europe, Middle east, and North Africa (see footnote 4).

(2) The definitions of "village" and "rural" vary between countries. Generally, villages are conglomerations of 5,000 to 10,000 inhabitants or less, rural refers to low-density populations outside the villages, often living in clusters close to large farms.

(3) Electrification data are not available for each country and the percentages should be taken as typical levels for countries in the region, about which there may be considerable variance.

(4) Algeria, Cyprus, Egypt (Arab Republic of), Iran, Morocco, Saudi Arabia, Tunisia, and Turkey.

Source: Electrification data have been compiled from miscellaneous documents and correspondence with countries, and are not official statistics. Population data are from United Nations documents.

Historically, the process of rural electrification has proceeded by weighing the costs of transmission against the losses of economies of scale involved in smaller generating systems, using the comparatively low cost of diesel fuel (prior to 1973) to justify the use of smaller, decentralized facilities located close to load centers. Operating costs for such systems are substantially tied to fuel costs. Recent large increases in the cost of oil have made the cost of generation by this approach far higher than can be covered by pricing within the means of low-income rural consumers.

This situation, wherein operating costs swamp capital investment amortization and exceed the ability of consumers to pay, can only be addressed in two ways:

1. Limiting electrification efforts to those load centers sufficiently close to large hydroelectric and thermal power plants to permit linkage to a grid system.
2. Identification of alternative fuels to permit continued operation of decentralized facilities as an initial step in extending power supplies to more remote villages and other rural populations.

Considering the second option, this report has summarized the economics of three different approaches:

1. Adaptation of existing steam generators to operation on low Btu gas from biomass.
2. Operation of diesel-electric generators in a dual-fuel mode, reducing diesel fuel requirements by 90 percent.
3. Use of gas turbines for electricity generation, or in cogeneration schemes yielding steam heat as well.

The first two of these approaches constitute well-established technology, and may be considered from the standpoint of retrofitting existing systems in LDC use, or as new capital investment opportunities. Table 31 shows the estimated cost of power for various fuels from new plants in LDCs. Power produced from biomass derived low Btu gas is competitive with imported oil for small plants in inland locations. For retrofitting existing facilities, low Btu gas from biomass can be produced for $2-5 per million Btu compared to $7-10 per million Btu for imported diesel fuel at inland locations (World Bank 1980). Biomass fuel cost assumptions in the calculations provided elsewhere are based on a figure of $20 per/dry ton for wood as the feed material. These costs, in the LDC setting, may be high where availability of agricultural wastes and wood wastes may be exploited at lower cost, while providing new sources of currency income for villagers and farmers.

TABLE 31. Comparative Costs of Power Generation Based on Various Types of Fuel Oil Importing Developing Countries

	Generator Type	Power Cost US ¢/kW-hr
Hydropower(a)	- large, high head	2.4
	- low head, mini hydro	12.7
Diesel(a)	- large, heavy oil fuel coastal location	6.7
	- small, light oil fuel in land location	13.2
Steam(a)	- large, gas-fired	2.4
	- large, coal-fired	5.2
	- large, oil-fired	7.5
	- small, heavy oil-fired inland location	11.4
	- small wood fired	10.0
Diesel(b)	- small, dual fueled low-Btu gas from wood and diesel inland location	6-10
Steam(b)	- small, low-Btu gas from wood inland location	

(a) These cost estimates were made by the World Bank and include the cost of generation and distribution (World Bank 1980).
(b) These cost estimates were made by Battelle Northwest and do not include distribution costs.

Numerous diesel generators fueled by low-Btu gas from biomass are in operation in developing countries. These units range in size from 40-1000 kW (1-25 dry tons/day of wood). Generators of this size can supply the electrical needs of 100-2500 families in a typical developing country (Bente 1980).

INDUSTRIAL USES OF BIOMASS-DERIVED GAS

Industry uses about 20-30 percent of the total energy in LDCs and much of this is in the form of imported oil. Fuel gas from biomass has been used in industrial applications and in some case was the direct means for establishing manufacturing industries in developing countries (Power Gas Corp.). The number of biomass gasifiers in operation declined steadily when low priced oil became available from the middle east, however interest in this technology for industrial energy supply has intensified recently.

The most obvious industrial application of biomass gasifiers lie in those industries which by their nature accumulate substantial amounts of waste. These include sugar processing, cotton ginning, lumber mills, and pulp and paper mills. In each case, dispersed biomass resources are collected and brought to a load center as a normal part of present operations. Gas generation from such wastes can serve needs for thermal process input and for generation of electrical power used in the plants themselves. Some similar industries in the U.S. have recently begun retrofitting oil and gas fired boilers to use low-Btu gas from biomass.

Use of biomass derived gas as a fuel in other industries may save considerable amounts of oil or gas. Some energy intensive products made in developing countries include cement, steel, bricks and ceramics, copper, aluminum, and ammonia and other chemicals. Energy requirements range widely from one barrel of oil per ton of cement to 28-36 barrels per ton of aluminum. Equipment used in these industries which can be fired by biomass derived gas include boilers, kilns, furnaces, dryers, and engines.

As many industries will be in urban sectors of developing countries the availability of forest and agricultural wastes may be limited. One potential feedstock for urban sector applications is municipal solid waste. Utilization of MSW for energy would also solve potential disposal problems in urban areas.

In broadest terms, the past experience in power generation in smaller towns and cities, as well as in rural areas, has been marked by industries which create their own power plants and sell surplus power to surrounding users for both commercial and domestic purposes. Decentralized power generation as part of a rural electrification program administered by governments has taken these industrial users into account in locating generating capacity and maximizing initial load factors. Thus, the extension of biomass-derived gas as a fuel for thermal and electrical power generation in industries share many features of the rural electrification problem discussed in the preceeding section.

PRODUCTION OF METHANOL AND OTHER LIQUID FUELS FOR TRANSPORTATION

Transportation accounts for only about 10 percent of the total energy consumption in LDC's, however it does account for a significant portion of energy imports. Road transport (cars, trucks, buses) accounts for 70-85 percent of fuel used in the transport sector.

Methanol and other liquid fuels (Fisher-Tropsch process) can be produced from biomass derived synthesis gas. Methanol is not an ideal transportation fuel and there are several constraints to widespread use of methanol for transportation. Existing engines must be modified to run on 100% methanol. In addition methanol presents several problems for commercial storage and distribution systems.

There are basically three situations where methanol can be used as a transportation fuel:

- blended, 10-15% methanol with gasoline
- neat, as a replacement for diesel or gasoline in fleet type operations where vehicle modifications can be made easily and modification of large distribution systems is not necessary
- neat, in countries that have chosen to develop transportation and distribution systems for straight alcohol fuels (i.e. Brazil)

The first two alternatives limit the amount of imported oil that can be displaced in LDCs. The third alternative requires a significant capital investment. These factors limit the potential impact of methanol from biomass in LDCs.

Methanol can be converted to gasoline using the Mobil process. This eliminates many constraints but increases the cost by about 20% on an equivalent Btu basis. Liquid fuels from the Fischer-Tropsch synthesis are ideal transportation fuels, however on the small scale of biomass based plants they will cost significantly more than methanol.

Because of the significant economy of scale associated with current liquid fuels from synthesis gas facilities they tend to be quite large (500-2000 tons per day of methanol for example). The amount of biomass required to feed such a plant is correspondingly large (2000-8000 wet tons per day). Even at this scale liquid fuels from biomass derived synthesis gas cost 20-100 percent more than imported petroleum. The potential of liquid fuel production from biomass derived synthesis gas will probably be limited by the cost and the availability of feed materials (unless "energy farms" like those planned in Brazil are considered).

AGRICULTURAL USES OF BIOMASS DERIVED GAS

Direct uses of large scale gasification in agriculture, at least in the LDC setting, are not apparent. Energy is required for tractors, water pumps, workshop machinery, mechanized mills, and drying. This energy can be supplied in many instances a biomass gasifier coupled to a diesel engine. However, these applications are small scale and are covered in a companion state-of-the-art report on small scale gasification.

Indirect uses of large scale biomass gasification in agriculture include rural electrification (electricity could be used to power much of the afore mentioned equipment) discussed previously and ammonia fertilizer production.

PRODUCTION OF AMMONIA AND OTHER CHEMICALS

Ammonia from biomass can be cost competitive with ammonia from other sources such as coal or natural gas depending on the cost and availability of the feedstock. As with methanol production ammonia plants are usually large to take advantage of economies of scale; however, in developing countries there are additional considerations of distribution and transport of relatively inexpensive bulk materials such as ammonia or urea. An infrastructure for distribution and transportation may be non-existent and the cost quite high. It has been suggested that developing countries could do well by setting up several small scale ammonia plants near various centers of consumption rather than one large centrally located plant (Kharbanda 1979). This makes even more sense for biomass based ammonia plants where location of biomass feedstocks corresponds to use centers for ammonia fertilizers.

Synthesis gas, methanol, and ammonia can serve as the building blocks for many other chemicals. However the uses of these materials in LDCs is limited and the infrastructure for transportation and distribution may be non-existent in some countries. In addition, production of specialty chemicals requires complex technology and is probably only suited to more advanced developing countries.

CONSTRAINTS AND RECOMMENDATIONS

The key to the impact of large scale biomass gasification in the developing world is availability and proximity of feed materials. Biomass fuels already account for about 35 percent of the energy consumption in LDCs. In poorer countries the percentage is even higher (50-90 percent) and shortages of these traditional fuels are not uncommon (World Bank 1980).

Availability in the rural sector must include the recognition that dung and crop residues are now distributed by long established customs and relationships between wealthier farmers who have surpluses of such materials and poorer small landholders or landless farmers who do not own enough land or cattle to meet their needs for fuel. In a broad sense, there is little "waste" per se in such agrarian cultures. Assigning a value to crop residues and dung and diverting these into some comparatively modern conversion processes may make sense from an energy efficiency standpoint, but in real life may deprive poorer agrarians of the means to cook. In addition, removal of large quantities of crop residues from the land may have serious adverse affects with respect to soil conservation.

The fuelwood supply situation is approaching crisis proportions in some LDCs. The World Bank report entitled Energy in the Developing Countries (World Bank 1980), estimates that 50 million hectares of fuelwood will need to be planted between now and the year 2000 to meet domestic demands for cooking and heating, given present methods of use and the projected growth in population. This would require a five-fold increase in the amount of tree planting worldwide, and a 15-fold increase in selected regions, such as Africa.

There are a number of ways to approach this problem, keeping a comparatively near term view. One of these is to improve the efficiency of traditional fuel uses, principally for domestic purposes by promoting the use of more efficient stoves. This conservation measure can expand effective resource availability greatly, since open fire techniques operate in the range of 10 to 20 percent efficiency. The other approach is to substantially expand firewood productivity by species substitution, incentives, regulation and creation of new institutions to manage forestry resources. Concepts of managed forests are new ideas in many LDCs and the knowledge base on tropical forestry is not well developed.

Clearly, dealing with the issue of fuel supplies will require that both production and conservation potentials be explored. The comparative amounts of biomass resources from sustainable forest yields, dung and crop residues are compared in Table 32. This table, in a crude way, indicates the most promising countries for sustained energy production from wood biomass.

While feedstock availability is the key obstacle to applications of large scale biomass gasification of biomass, other constraints also exist particularly in rural areas. Decentralized energy systems based on renewable resources have resulted in some spectacular failures (Catron 1980). To succeed, rural energy programs must be introduced with the full cooperation of the people who must use the equipment and keep it repaired. This will require use of educational services and support networks.

Fixed bed, air-blown biomas gasification systems are fairly simple and reliable and have been operated successfully in rural areas of LDCs. Most of the operating difficulties encountered with fixed bed gasifiers involve use of unsized fuels (fines, sticks, light fluffy materials, etc.) which can cause plugging and bridging in the feed system and gasifier. Periodic cleanup of the system to remove tars may be necessary. Power generators are reliable, off-the-shelf, equipment; however, proper operation and maintenance are necessary to keep them operating reliably and efficiently. Production of liquid fuels and chemicals from biomass derived synthesis gas involves somewhat more complex technologies and is probably best suited for more advanced developing countries.

Other potential constraints which are not necessarily unique to LDCs include:

- availability and cost of capital,
- regulatory constraints, and
- local manufacturing capability.

TABLE 32. Estimated Organic Resources in Less Developed Countries (Hughart 1979)

	Sustainable Forest Yield[a]	Dung[a]	Crop Residues[a]
Ethiopia	3	6	3
Kenya	1	7	4
Tanzania	54	11	3
Ghana	8	2	2
Nigeria	8	3	2
Sudan	148	18	5
South Africa	2	8	13
Algeria	3	3	1
Egypt	0	1	6
Morocco	6	5	5
Iran	22	6	7
Iraq	1	5	2
Vietnam	12	1	6
Afghanistan	6	8	7
Nepal	15	11	6
Pakistan	1	6	7
India	6	5	6
Sri Lanka	11	2	4
Bangladesh	2	4	4
Burma	82	4	6
Indonesia	63	1	6
Republic of China	n.a.	n.a.	n.a.
Republic of Korea	9	1	7
Malaysia	114	2	7
Philippines	12	3	7
Thailand	22	3	9
Chile	71	7	4
Colombia	180	16	4
Peru	245	7	2
Mexico	39	9	9
Brazil	229	15	9
Argentina	104	45	33
Venzuela	211	11	4
PR China	11	3	8
DPR Korea	24	1	13

(a) in giga-joules per capita per year

Emphasis on local manufacturing of equipment in LDCs is desirable from a balance of payments standpoint, but can significantly increase the final product cost particularly for capital intensive process such as methanol and ammonia production (Kharbanda 1979).

Based on the aforementioned constraints and.the technical considerations discussed earlier we believe the most promising applications of large scale biomass gasification in less developed countries are:

- rural electrification using medium scale gasification systems coupled with diesel generators (10-50 dry tons per day),
- retrofitting existing oil and gas fired equipment in various industries using medium scale gasifiers (10-100 dry tons per day), and
- production of ammonia based fertilizers from biomass derived synthesis gas (200-2000 dry tons per day).

The numbers in parenthesis indicate the amount of biomass required to support a typical facility.

Many small and medium scale biomass gasifiers were built in LDCs around the world in the 1930's and 1940's to produce power and electricity. At least 30 modern systems of this type are in operation today mostly in West Africa, the Phillipines, and Central America (Fritz 1979). In many instances this type of plant has made a major economic contribution to manufacturing operations and in some cases has been the direct means of establishing manufacturing industries in undeveloped countries. Low-Btu gas from biomass is currently attractive for rural electrification and for power production for rural industries particularly food processors who have a supply of waste biomass. Low Btu gas from biomass may also be attractive for urban sector industries where coal and natural gas are not available.

Production of ammonia based fertilizers from biomass derived synthesis gas to support agricultural development in LDC's should be considered (particularly where coal and natural gas are not available). The estimated cost of biomass based ammonia fertilizers is comparable to the market price of ammonia fertilizers and may even be less than the delivered cost in rural inland areas when transportation charges are added. Because of the large quantities of biomass required, managed biomass farms may be necessary to support these facilities. Production of methanol from biomass derived synthesis gas is potentially attractive, but only in more advanced developing countries who choose to develop distribution and transportation systems for alcohol fuels as has been done in Brazil. Synthesis of petroleum-like liquid fuels from biomass derived synthesis gas is significantly more costly than methanol and imported oil with current technology and is not attractive in the short term.

While we have identified what we believe are the three most promising applications of large scale biomass gasification it should be pointed out that these are based on generalizations about needs and resources in LDCs. Each country or region represents a unique set of conditions and the choice of biomass conversion technologies must be based on specific needs and resources as well as the merits of the various competing technical approaches.

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APPENDIX A

MANUFACTURERS OF BIOMASS GASIFIERS

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Applied Engineering Co.
Orangeberg, SC 29115
E. B. Rogers
(803) 534-2424

Advanced Energy Applications, Inc.
1386 Holt Avenue
Los Altos, CA 94022
F. E. Moreno
(415) 964-5429

American Fyr Feeder
Des Plaines, IL
G. V. Voss

Andco, Inc.
Buffalo, NY
S. D. Mark

Biomass Corporation
951 Live Oak Blvd.
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Bob Williams
(916) 674-7230

Century Research Inc.
16935 S. Vermont Ave
Gardena, CA 90247
Howard Amundsen
(213) 327-2405

Davy Powergas Inc.
6161 Savoy Drive
P.O. Box 36446
Houston, TX
Edgar E. Bailey
(713) 782-3440

Energy Products of Idaho
3805 Industrial Ave., South
Couer d' Alene, ID 83814
Michael L. Murphy
(208) 667-2481

ERCO, Inc.
Cambridge, MA
Herb Kosstrin
(617) 661-311

Forest Fuels, Inc.
7 Main Street
Keene, NH 03431
J. C. Calhoun/R. A. Caughey

Guaranty Performance Co., Inc.
1120 East Main, P. O. Box 748
Independence, KS 67301
John Stafford
(316) 331-0020

Halcyon
Maple Street
East Andover, NH
George Finnie
(603) 735-5356

Industrial Combustion
4465 N. Oakland Ave.
Milwaukee, WI 53211
James Fletcher
(414) 332-4100

Industrial Development & Procurement, Inc.
(Duvant Moteurs gasifier)
One Old Country Road
Carle Place, NY 11514
Jules A. Lussier
(516) 248-0880

Koppers Company, Inc.
Engineering and Construction Division
1150 Koppers Bldg
Pittsburg, PA 15219
James W. Bumbaugh

Enerco Inc.
139A Old Oxford Valley Road
Langhorne, PA 19047
Miles J. Thompson
(215) 493-6565

Environmental Energy Corporation
Route 28, P.O. Box 30
Rochester, MA 02770
Carmen Chevie
(617) 763-5117

The Vermont Wood Energy Corp.
P.O. Box 280
Stowe, VT 05672
J. P. Rich
(802) 253-7220

Pioneer Hi-Bred International, Inc.
(Gasodyne gasifier)
5700 Merle Hay Road
Johnston, IA 50131
Walter Stohlgren

Union Carbide Corp.
New York, NY
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Mutheson-Doherty
191 Beacon Street
San Francisco, CA 94080
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(415) 583-6161

McDowell-Wellman Engineering Co.
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Homestead and Willow
Belle Mead, NJ 08502
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(201) 359-8200

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Duvant Moteurs
France
(See Industrial Development & Procurement in U.S.
and Quebec Electro-Marine Diesel in Canada)

Hitachi Shipbuilding & Engineering
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Quebec Electro Marine Diesel, Inc.
(Duvant Moteurs gasifier)
Beaconsfield, Quebec
Canada
B. Labelle

Westwood Polygas Ltd
(Moore-Canada gasifier)
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