Chapter 7

THERMOCHEMICAL CONVERSION

Chapter 7.—THERMOCHEMICAL CONVERSION

TABLES

FIGURES

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THERMOCHEMICAL CONVERSION

Introduction

During the 1980's, the conversion processes with the greatest potential in terms of both the gross energy use and the largest possible displacement of oil and natural gas are the thermochemical processes, or processes involving heat-induced chemical reactions. Currently about 1.5 Quads/yr of biomass are combusted directly for process steam, electric generation (mostly cogeneration), and space heat. Intermediate-Btu gasifiers currently under development will be useful in retrofitting oil- and gas-fired boilers to biomass fuels and for crop drying and other process heat needs. Development of medium-Btu gasifiers is also underway and various processes for producing alcohols and other liquid fuels can be or are being developed. Also, methanol synthesis from wood can probably be accomplished with commercially available technology, while processes producing methanol from plant herbage can probably be demonstrated fairly rapidly. Moreover, there are good theoretical reasons for believing that the flexibility, efficiency, and usefulness of thermochemical processes can be significantly improved through basic and applied research into the thermochemistry of biomass.

Some generic aspects of biomass thermochemistry and generic reactor types are given first, followed by a discussion of the optimum size of some thermochemical conversion facilities and a more detailed consideration of select processes including densification, direct combustion, gasification, and direct and indirect liquefaction. Finally, the environmental impacts and research, development, and demonstration (RD&D) needs are presented.

Generic Aspects of Biomass Thermochemistry

Possible feedstocks for the thermochemical conversion processes include any relatively dry plant matter such as wood, grasses, and crop residues. Some conversion process designs accept a wide range of feedstocks, while others will be more suited to a specific feedstock. Although this is sometimes dependent on the chemical properties of the feedstock (e.g., manure), it more often depends on the physical properties of the material, such as its tendency to clog or bridge the reactor, the ease with which it can be reduced to a small particle size, and the materials' density.

Classification systems that provide information for assisting the designer of conversion equipment are not presently available for biomass feedstocks. Standard methods for biomass analysis or assays do not exist, although it is customary to use coal analyses (ultimate and proximate) for biomass. Some of the properties of some biomass materials using coal analyses are shown in tables 41 and 42. As a fuller understanding of biomass thermochemistry is developed, however, new classification schemes and methods of analysis are likely to be necessary.

Despite the differences in feedstocks, the generic thermochemical process consists of the following steps:

- moisture removal;
- heating the material to and through the temperature where it decomposes (about **4000** to **8000** F);
- decomposition to form gases, liquids, and solids; and
- secondary gas phase reactions.

The drying process absorbs the heat necessary to evaporate the water. This results in a decrease in the net usable heat from the feedstock as shown in figure 16. In this figure, the net heat content per pound of dry wood is

Table 41 .–Proximate Analysis Data for Selected Solid Fuels and Biomass Materials (dry basis, weight percent)

	Volatile matter	Fixed carbon	Ash	Reference
Coals				
Pittsburgh seam coal	33.9	55.8	10.3	Bituminous Coal Research 1974
Wyoming Elkol coal,	44.4	51.4	4.2	Bituminous Coal Research 1974
Lignite	43.0	46.6	10.4	Bifumirtous Coal Research 1974
Oven dry woods				
Western hemlock	84.8	15.0	0.2	Howlett and Gamache 1977
Douglas fir.	86.2	13.7	0.1	Howlett and Gamache 1977
White fir	84.4	15.1	0.5	Howlett and Gamache 1977
Ponderosa pine.	87.0	12.8	0.2	Howlett and Gamache 1977
Redwood	83.5	16.1	0.4	Howlett and Gamache 1977
Cedar	77.0	21.0	2.0	Howlett and Gamache 1977
Oven dry barks				
Western hemlock	74.3	24.0	1.7	Howlett and Gamache 1977
Douglas fir..	70.6	27.2	2.2	Hewlett and Gamache 1977
White fir	73.4	24.0	2.6	Hewlett and Gamache 1977
Ponderosa pine.	73.4	25.9	0.7	Hewlett and Gamache 1977
Redwood	71.3	27.9	0.8	Howlett and Gamache 1977
Cedar	86.7	13.1	0.2	Howlett and Gamache 1977
Mill woodwaste samples				
-4 mesh redwood shavings	76.2	23.5	0.3	Boley and Landers 1969
-4 mesh Alabama oakchips	74.7	21.9	3.3	Boley and Landers 1969
Municipal rufuse and major components				
National average waste	65.9	9.1	25.0	Klass and Ghosh 1973
Newspaper(9.4% of average waste)	86.3	12.2	1.5	Klass and Ghosh 1973
Paperboxes (23.4%)	81.7	12.9	5.4	Klass and Ghosh 1973
Magazine paper (6.8%)	69.2	7.3	23.4	Klass and Ghosh 1973
Brownpaper (5.6%).	89.1	9.8	1.1	Klass and Ghosh 1973
Pyrolysis chars				
Redwood (790°to 1,020 F)	30.0	67.7	2.3	Howlett and Gamache 1977
Redwood (800°to 1,725 F)	23.9	72.0	4.1	Howlett and Gamache 1977
Oak (820°to 1,185 F)	25.8	59.3	14.9	Howlett and Gamache 1977
Oak (1,060°F).	27.1	55.6	17.3	Howlett and Gamache 1977

SOURCE M Graboski and R Barn, ''Properties of Biomass Relevant lo Gasification, " in *A Survey of Biomass Gasification* (vol. II; Golden, Colo. Solar Energy Research Institute, July 1979), TR-33-239

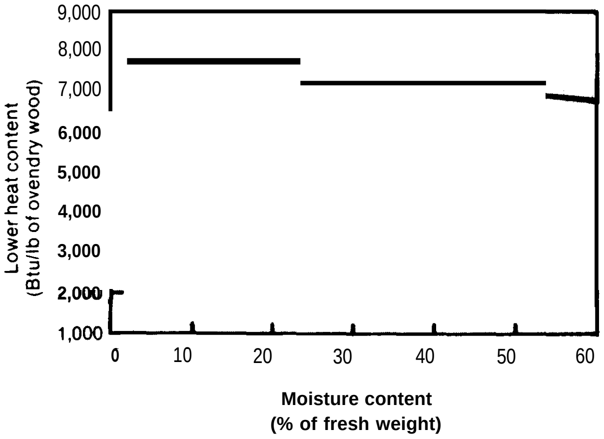
Table 42.–Ultimate Analysis Data for Selected Solid Fuels and Biomass Materials (dry basis, weight percent)

Material	C	H	N	S	O	Ash	Higher heating value (Btu/lb)	Reference
Pittsburgh seam coal .,	75.5	5.0	1,2	3.1	4.9	10.3	13,650	Tillman 1978
West Kentucky No. 11 coal	74.4	5.1	1.5	3.8	7.9	7.3	13,460	Bituminous Coal Research 1974
Utah coal	77.9	6.0	1.5	0.6	9.9	4.1	14,170	Tillman 1978
Wyoming Elkol coal	71.5	5.3	1.2	0.9	16.9	4.2	12,710	Bituminous Coal Research 1974
Lignite	64.0	4.2	0.9	1.3	19.2	10.4	10,712	Bituminous Coal Research 1974
Charcoal. ,	80.3	3.1	0.2	0.0	11.3	3.4	13,370	Tillman 1978
Douglas fir	52.3	6.3	0.1	0.0	40.5	0.8	9,050	Tillman 1978
Douglas fir bark.	56.2	5.9	0.0	0.0	36.7	1.2	9,500	Tillman 1978
Pine bark ., .,	52,3	5.8	0.2	0.0	38.8	2.9	8,780	Tillman 1978
Western hemlock.	50.4	5.8	0.1	0.1	41.4	2.2	8,620	Tillman 1978
Redwood. ... ,	53,5	5.9	0.1	0.0	40.3	0,2	9,040	Tillman 1978
Beech.	51.6	6.3	0.0	0.0	41.5	0.6	8,760	Tillman 1978
Hickory.	49.7	6.5	0.0	0.0	43.1	0.7	8,670	Tillman 1978
Maple.	50.6	6.0	0.3	0.0	41,7	1.4	8,580	Tillman 1978
Poplar.	51.6	6.3	0.0	0.0	41.5	0.6	8,920	Tillman 1978
Rice hulls	38.5	5.7	0.5	0.0	39.8	15.5	6,610	Tiliman 1978
Rice straw.	39.2	5.1	0,6	0.1	35.8	19.2	6,540	Tillman 1978
Sawdust pellets.	47.2	6.5	0.0	0.0	45.4	1.0	8,814	Wen et al. 1974
Paper.	43.4	5.8	0.3	0.2	44.3	6.0	7,572	Bowerman 1969
Redwood wastewood	53.4	6.0	0.1	39.9	0.1	0.6	9,163	Boley and Landers 1969
Alabama oak woodwaste. .,	49.5	5.7	0.2	0.0	41.3	3,3	8,266	Boley and Landers 1969
Animal waste. ,	42.7	5.5	2.4	0.3	31.3	17.8	7,380	Tillman 1978
Municipal solid waste ... ,	47.6	6.0	1.2	0.3	32.9	12.0	8,546	Sanner et al. 1970

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

SOURCE M Graboski and R Barn, “Properties of Biomass Relevant to Gasification, ” m *A Survey of Biomass* Gas/f/caf/err, (volII; Golden, Colo Solar Energy Research Institute, July 1979), TR-33-239

Figure 16.— Effect of Moisture on the Heat Content of Wood



SOURCE: Office of Technology Assessment,

shown for various moisture contents. The heat content per pound of moist material, however, decreases much more rapidly with moisture content, due to the fact that part of each pound is water and not combustible material. (Nevertheless, the price of the moist feedstock will vary with the moisture content, so that $15/ton material at 50-percent moisture content is roughly equal to $30/ton of dry material. In this report, the feedstock costs are generally expressed as dollars per ton of dry material, so that variations in cost and heat content per ton are kept at a minimum.)

There is also a secondary effect of the moisture content of the feedstock. If moist feedstocks are combusted to produce steam, the boiler efficiency will usually drop if the feedstock moisture content is not that for which the boiler was designed. Aside from the heat lost in evaporating the water in the feedstock, high-moisture feedstocks have a lower flame temperature in direct combustion, which can result in particulate and creosote emissions (which escape without being completely combusted, if considerable excess combustion air is not used). (In poorly designed wood stoves or boilers, simply feeding excess air may not be sufficient to suppress these emissions.) In principle, a reactor can be designed to accommodate this excess combustion air, vaporized moisture, and lower flame temperature without a drop in efficiency, but in practice the efficiency is likely to drop.

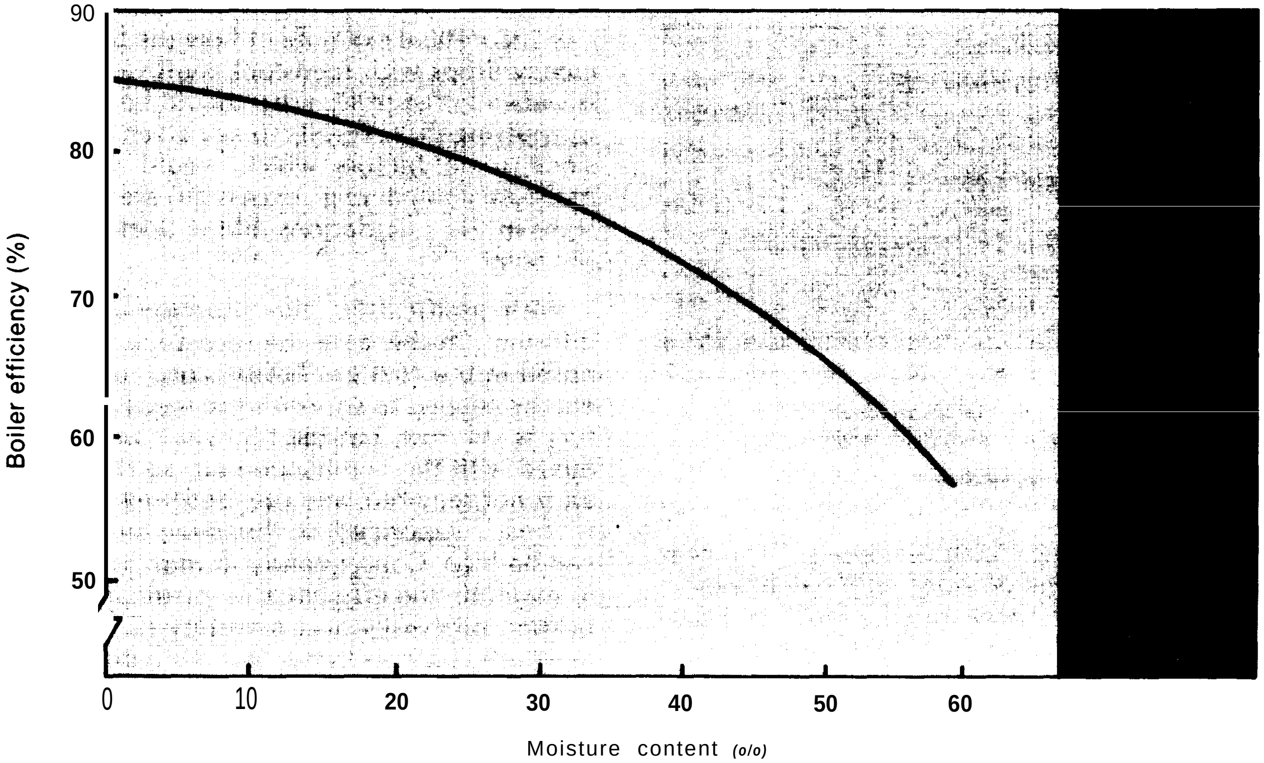
A theoretical example of how the boiler efficiency drops with feedstock moisture content is shown in figure 17. Care should be exercised in applying these results to any given situation, since some factors which would vary with moisture content (e. g., excess air) are held constant in the calculations, but it does illustrate the point.

With gasification, the situation is slightly different. In this case the feedstock is decomposed into a fuel gas before combustion. The energy needed to vaporize the feedstock moisture is still lost, but the fuel gas can easily be mixed with the combustion air, so that excess air is not required, and the feedstock moisture is already vaporized, so the flame temperature can be high. Consequently, it may be possible to maintain the efficiency of gasification-combustion processes over a variety of feedstock moisture contents better than with direct combustion. Depending on reactor design, however, it may be necessary to limit the feedstock moisture in order to produce a flammable gas, and this point needs further investigation.

The rate that the biomass is heated to and through its decomposition temperature is a critical factor in determining the products. Many reactor designs are being developed to achieve high heating rates, as described below. (The heating rate is also determined by the particle size— small particles heating faster— and moisture content.) Depending on the products desired, however, one may want this heating rate to be slower.

The details of biomass decomposition are not well understood, but one can surmise the following. As the material is heated, the large biomass molecules (cellulose, hemicellulose, and lignin) begin to break down into intermediate-sized molecules. If the material stays in the heating zone long enough, the intermediate-size molecules decompose into still smaller molecules, such as hydrogen, methane, carbon monoxide (CO), ethane, ethylene, acetylene, and other chemicals. If the heating rate is too slow relative to the time the material is in the

Figure 17.—Effect of Feedstock Moisture Content on Boiler Efficiency



SOURCE: R. A. **Arola**, "Wood Fuels – How Do They Stack Up?" ***Energy and the Wood Products Industry,*** Forests Products Research Society, Proceeding No. 76-14, **Nov.** 15-17, 1976.

heating zone, the intermediate-sized molecules will escape and later condense as oils and tar. (This may also involve some intermediate reactions that are not well understood at present.) It also appears that a slow heating rate encourages the formation of char. Thus, a slow heating rate (either by design or due to excess moisture in the feedstock) will lead to the formation of varying amounts of char, tar, oil, and gas. With rapid heating, however, virtually the entire biomass goes to a gas with only the ash remaining.

Finally, the gases and vaporized tars and oils can react in the gas phase to form a new or modified set of products. Very little is understood about these secondary gas phase reactions, but they are of considerable importance in thermochemical processes. Depending on the oxygen and moisture content, the rate the biomass was decomposed, the temperature, the pressure, and other variables not fully understood, the resultant gas can vary from almost pure carbon dioxide ($C0_2$) and water to gases with relatively high contents of materials such as hydrogen, methane, or ethylene (see ch. 12), or the gas can contain considerable quantities of particulate, various hydrocarbons, CO, and other pollutants.

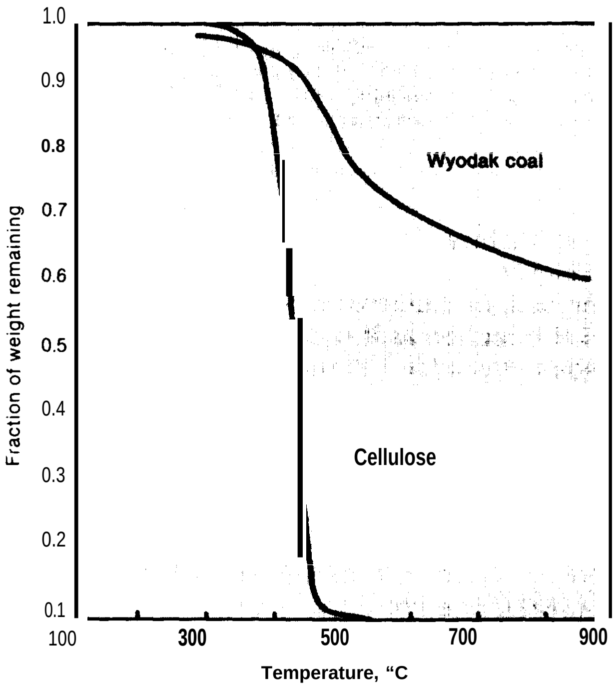
Depending on the conditions chosen and the design of the reactor, the product(s) can be heat as in direct combustion, an intermediate- or medium-Btu gas suitable for oil- or gas-fired boilers and process heat, a gas suitable for chemical synthesis, oils, and/or char. But considerable research into the thermochemistry of biomass will be needed, before engineers will have the necessary information to design reactors that can achieve the full potential for the thermochemical conversion of biomass.

Reactor Type

Most commercial biomass reactors used for direct combustion or gasification are modifications of coal technology. The reactors proposed for direct liquefaction and densification, however, do not fall into this category and are considered in the sections dealing with these topics.

Although the technology for coal combustion and gasification is considerably more advanced than for biomass, it is generally agreed that grasses, wood, and crop residues are more readily gasified than coal or char. The biomass gasifies at a lower temperature and over a narrower temperature range than does coal, as illustrated in figures 18 and 19, Both of these properties favor rapid gasification. While these advantages of biomass over coal are partially offset by biomass' higher heat capacity (the amount of heat needed to raise the material's temperature a given amount)[1] coal gasification in advanced reactors will ultimately be limited by the rate that oxygen, CO_2, steam, etc., can diffuse to and into the surface of coal particles. Biomass gasification and decomposition, on the other hand, do not require the reaction of two or more separate species. Consequently, biomass gasification probably will be limited by the rate that heat can be transferred to the biomass.

Figure 18.—A Comparison of Pyrolytic Weight Loss (on a mass fraction basis) v. Temperature for Coal and Cellulose



SOURCE: M J Antal, *Biomass Energy Enhancement—A Report to the President's Council on Environmental Quality* (Princeton, N.J Princeton University, July 1978)

In balance, these differences point to the conclusion that there is the potential for building biomass reactors that have considerably higher rates of throughput and thus lower costs than will be achieved with coal or has been achieved for either material so far. On the other hand, the most rapid heat transfer occurs when the feedstock particles are pulverized or of relatively small size. Most coals can readily be pulverized, but the fibrous nature of many types of biomass makes it difficult to reduce the particle size. Biomass densification (see below) makes it fairly easy to pulverize the biomass, but this and other pretreatments add to the costs. At present it is impossible to predict whether the difficulty and expense of reducing the biomass particle size or the inherent limitations in the rate that coal reacts will dominate the economic differences between the two types of fuel reactors. Nevertheless, it is clear that dramatic improvements in biomass reactors are possible and that achieving this full potential will require RD&D specifically aimed at addressing and exploiting the unique features of biomass. Furthermore, since biomass char is more like coal than wood, grasses, or crop residues, achieving this potential advantage of biomass will involve reactors that produce little or no char.

Generally, the biomass reactors are classified according to the way the feedstock is fed into them. Although there are numerous variations, the major types are moving grate, mov-

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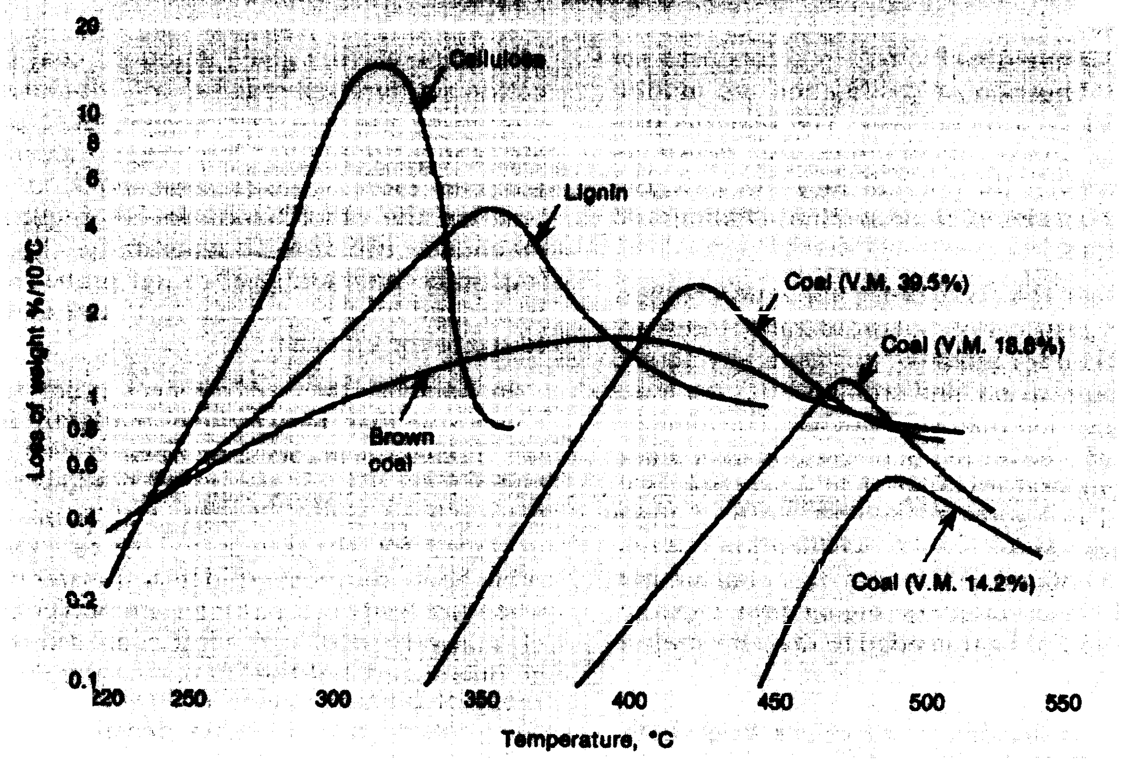
[1] M Graboski and R Bain, “Properties of Biomass Relevant to Gasification,” in *A Survey of Biomass Gasification* (v ol 11, Golden, Colo Solar Energy Research Institute, July 1979), TR-33-239

Figure 19.—Differential Loss of Weight Curves*



● **These curves represent the derivative of curves similar to those given in figure 18. They were obtained by heating a small sample of solid material at a given rate and recording fractional weight loss v. temperature. The peak of each differential weight-loss curve (i.e., for cellulose the value is 15% per 10°C at 315 "C) is indicative of the individual material's pyrolysis kinetics — a higher heating rate would displace all the curves to higher temperatures and would "sharpen" each peak. Thus the position of each peak is not related to "optimum" operating conditions. The curves simply show that biomass materials pyrolyze much more rapidly at much lower temperatures than coal.**

SOURCE: H. H. Lowry, *Chemistry of Coal Utilization Supplementary Volume* (New York: John Wiley and Sons, Inc. 1963)

ing bed, fluidized bed, and entrained flow. The rate of heat transfer generally follows the order given, with the moving-grate reactors being the slowest. (There are, however, other classification schemes which can be useful as well.)

Moving-grate reactors consist of a grate that carries or moves the biomass through the zone where it is heated and decomposes. The heat transfer is relatively inefficient and slow, so an excess of heat must be generated to sustain the reaction. Therefore this type of reactor is generally best suited to direct combustion where the biomass is completely reacted and releases virtually all of its heat in the decomposition zone.

A slightly faster rate of heat transfer is achieved with moving-bed reactors. In these the bed, or clump of biomass, moves in a vertical direction as it is decomposed. Additional biomass is added at the top, which then gradually works its way down the reactor. Two types of moving-bed reactors exist: updraft and downdraft.

The updraft moving-bed reactors have a stream of air moving up through the bed of biomass. The hottest part of the bed is at the bottom. As the hot gases move through the bed, however, they cause relatively large amounts of tars and oils to form, which can condense causing maintenance problems and which may make it more difficult to burn the resultant gas without forming particulate.

The downdraft moving-bed reactors have a stream of air moving downward through the bed of biomass. Tars and oils are formed near the middle of the bed (where the air is injected) and subsequently move through a relatively large hot zone which gives them time to further decompose. The net result is a fuel gas with fewer tars and oils, thereby making gas cleanup easier and reducing the amount of particulate that form when the gas is burned.

Another type is the fluidized-bed reactor. In this case, gas is blown through the bed of solid fuel so rapidly that the bed of biomass levitates and churns as if it were fluid. In coal-fed fluidized-bed reactors, the fluid bed may contain limestone particles to react with and remove sulfur from the coal. Since biomass usually does not contain significant levels of sulfur, sand can be used as a fluidizing medium or one can rely solely on the biomass itself, with no separate fluidizing medium. Sand has the advantage, however, of helping to retain heat in the bed, thereby increasing the rate that new pieces of fuel heat up in the bed.

Fluidized-bed reactors have a considerably faster heating rate than moving-bed *or* traveling-grate reactors. The churning in the bed, however, enables material at all stages of decomposition to be found throughout the bed. Consequently, there may be a tendency for oils and tars to escape from the heating zone before they can be fully decomposed.

The last type of reactor considered here is the suspension or entrained-flow reactor. In this type, small particles of feedstock are suspended in a stream of gas which moves rapidly into and through the decomposition zone. This type has the most rapid rate of heating, but the feedstock particles must be reduced to a relatively small size. As mentioned above, this would add to the total conversion costs and the details of this economic tradeoff are still uncertain.

Optimum Size for Thermochemical Conversion Facilities

Electric generating plants fueled with nuclear power or fossil fuels are generally quite large in order to take advantage of economies of scale. The same is true of most proposals for synthetic fuel plants. The optimum size of a biomass-fueled electric powerplant or synthetic fuels plant, on the other hand, is determined by a tradeoff between this economy of scale and the cost of transporting the feedstock to the conversion plant. Under favorable circumstances this optimum size could be several hundred megawatts electric (see app. A), and some paper-pulping mills do have wood inputs that would be sufficient for facilities of this size.[2] Under more common circumstances, however, the local availability of feedstock may limit the size of biomass conversion facilities to the equivalent of 10- to 60-MW electric or less.

The economy of scale, however, is often matched by the cost savings associated with mass producing a large number of small units. Furthermore, in many industrial applications (e. g., process heat or steam boilers) the size is determined by the needs of that industrial plant rather than a potential economy of scale for the boiler or heat needs.

Large-scale facilities are technically feasible under some circumstances, particularly where the biomass arises as a waste byproduct in a large manufacturing plant. The number of sites where large quantities of biomass are available to a single plant on a continuing basis, however, may be limited. Consequently, the fullest utilization of the biomass resource for thermochemical conversion will require the development of small-scale, mass-produced units.

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[2] Kip Hewlett, Georgia Pacific Corp , private communication, 1979

Biomass Densification

Freshly harvested biomass usually contains considerable moisture, has a relatively large volume per unit of energy (making it expensive to transport), and is fibrous (making it often difficult to reduce the particle size). These difficulties can be partially overcome by densifying the biomass.

There are several types of densification processes including pelletizing, cubing, briquetting, extrusion, and rolling-compressing. Pelletizing typifies the advantages and disadvantages of densification processes and is considered in more detail here.

Pelletization consists of drying the biomass, heating it until the lignin melts, and compressing the material into pellets. The pellets are denser than the biomass, more easily ground, and easier to handle and feed into reactors. Due to their lower moisture content, pellets usually burn more efficiently in boilers than does green biomass.

At present there are only commercial pelletization processes for wood. The lignin content in wood is generally high enough to bind the pellets so that no additional adhesives are required. Densified crop residues or grasses, however, may require the addition of adhesives to achieve the necessary binding strength to prevent the pellets from disintegrating to a powder; and the costs for this are uncertain.

The wood pelletization process has an energy efficiency* of about 90 percent if one starts with wood having 50-percent moisture content. Furthermore, wood pellets would burn in the boiler depicted in figure 17 to produce steam with an efficiency of about 83 percent as compared with an efficiency of 65 percent for woodchips with 50-percent moisture. Thus the overall efficiency (50-percent moisture woodchips to steam) is increased from 65 percent to perhaps 75 percent by including a pelletization process. This efficiency increase could also be achieved by predrying the woodchips with heat escaping out the burner's chimney. The exact numbers will vary, however, depending on the specific boiler being considered. If the boiler is designed to accept high-moisture woodchips, then there may be no efficiency improvement with wood pellets.

Wood pellet costs are shown in table 43 for various feedstock costs. While the costs are considerably higher than those for woodchips, the pellets' higher energy density allows them to be transported at a lower cost than green woodchips. This cost savings in the transportation pays for the pelletization process if the fuel is to be transported more than 50 to 150 miles depending on the transport and wood feedstock costs and the initial moisture content of the wood (see app. B for details of the calculation). However, this calculation does not include the added cost of transporting very bulky material such as plant herbage where the volume rather than the weight of the material determines the transport cost.

Table 43.–Cost of Pelletized Wood

	Wood feedstock cost (dollars/green ton)		
	$6.50	$10.00	$20,00
	Dollars/ton of pellets sold		
Wood. ... ., ...	$14.39	$22.13	$44.26
Operation and maintenance . . . . . , . .	7.95	7.95	7.95
Capital charges.	5.14	5.14	5.14
(30% Of total investment per year)			
Total	$27.48	$35.22	$57.35
Dollars/ IO" Btu. ... , . . .	$1.72	$2.20	$3.58

Input: 540 ton/d of wood (50% moisture)
Output: 244 ton/d of pellets (10% moisture) for sale and 56 ton/d of pellets used to fuel the plant.
Load 330 operating days per year

SOURCE Office of Technology Assessment, and T B Reed, et al, "Technology and Economics of Close-Coupled Gasifiers for Retrofitting Gas/Oil Combustion Units to Biomass Feedstocks , in *Retrofit '79*, Proceedings *of a Workshop on Air Gasification*, sponsored by the Solar Energy Research Institute, Seattle, Wash , Feb 2, t979

The most common and least expensive use of fuelwood, however, is likely to be in the region where it is harvested. Consequently, the use of densification processes may be limited. On the other hand, the increased ease of handling and burning pellets may make them at-

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***Efficiency is defined here as the lower heating value of the product divided by the lower heating value of the feedstock**

tractive in applications where the process has to be extremely automated such as in very small industrial applications or where the feedstock is particularly unwieldy such as with plant herbage. In each application, the user will have to decide whether the higher fuel cost is justified in terms of the labor savings. For the remainder of this chapter, it is assumed that raw biomass rather than pellets are being used.

Direct Combustion of Biomass

Biomass can be burned together with coal (termed cocombustion) to produce process steam or electricity. Currently however, the largest amounts of energy produced from biomass come from the combustion of wood and food-processing wastes such as sugarcane bagasse by themselves. Another important use of direct combustion is in home heating. Each of these applications is considered below.

Cocombustion of Biomass

Currently, outdated — and therefore unusable–seed corn is being cocombusted with coal by the Logansport, Ind., Municipal Utility. Cocombustion of wood with coal has also been successfully demonstrated by the Grand Haven, Mich., Board of Light and Power. ' And several assessments of the cocombustion of crop residues with coal concluded that it is technically feasible.[4]

Abdullah has estimated that the added costs at an electric powerplant needed to modify the boilers and handle the crop residues is $0.20 to $0.50/million Btu. [5]Consequently, for coal costing $1.50 to $2.00/million Btu ($30 to $45/ton), crop residues costing $13 to $24/ton would be economically cocombusted. Some crop residues may be available for these prices, but generally delivered crop residue prices are likely to be higher. Higher coal prices, however, will make residue cocombustion more attractive

Cocombustion can also be used to lower sulfur emissions somewhat. Since the biomass generally contains negligible amounts of sulfur, the quantity of sulfur being released in the combustion (per million Btu of heat) will decrease with the percentage of biomass, typically 20 to 30 percent. The economic savings associated with this will be highly site specific. The most advantageous situation would be where coal-fired boiler emissions are only marginally above the emissions standards without the use of sulfur removal equipment. Since the biomass costs, air pollution benefits, and feedstock availability are site specific, the economics of cocombustion will have to be determined through site-specific economic analyses. The principal determinant, however, will probably be the availability of a reliable supply of low-cost biomass feedstock.

Combustion of Biomass

Direct combustion of biomass for production of electricity or steam or for cogeneration (simultaneous production of steam and either electricity or mechanical shaft power) has commercially ready technology for wood, sugarcane bagasse, and many other feedstocks. There are also commercially available suspension burner retrofits for oil-fired boilers of 4.5 million Btu/hr or larger. The latter retrofitted boilers can return to oil if the biomass feedstock is temporarily unavailable, but they require a biomass feedstock that is quite dry (less than 15-percent moisture) and relatively small

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'Pierre Heroux, *Supplemental Wood Fuel Experiment,* report to Grand Haven Board of Light and Power (Grant Haven, Mich J B Sims Generating Stat Ion, 1978)

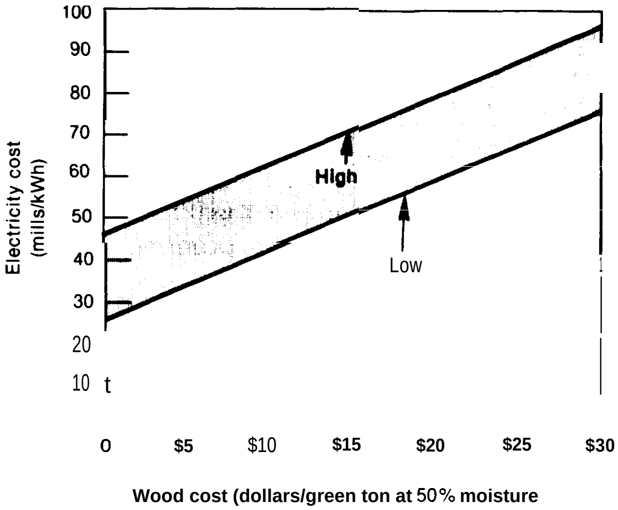
'See, e g , Wesley Buechele, *Direct Combustion of Crop Res-/dues In* Furnace *Boilers* (Ames, Iowa Agriculture and Home E conomics Experiment Stat Ion), paper No J8791

'Mohammed Abdullah, " E conomies of Corn Stover as a Coal Supplement in Steam Electric Power Plants in the North Central United States, " ph D thesis, Agricultural Economics Department, Ohio State University, Columbus, Ohio, 1978 in size (less than 1/8" x 1/2" -3/4"). [6]A few types of biomass, however, involve special problems (e.g., the high silica content in rice hulls and residues) and boilers for these are not available.

In many applications today, feedstocks with 40- to 50-percent moisture content are used, resulting in boiler efficiencies of 65 to 70 percent. (The retrofit unit mentioned above, which is restricted to low-moisture feedstock, achieves an estimated 75-percent efficiency). [7] There has been little incentive to dry the feedstock in most current applications, since they usually involve relatively inexpensive waste products. As the use of biomass for direct combustion becomes more widespread and the average feedstock costs increase, however, predrying of the feedstock is likely to be more common.

As with cocombustion, the feedstock cost and availability of a reliable supply of the feedstock are major determinants of the economics of using biomass as a fuel. While these costs vary considerably from site to site, an average feedstock cost of $30/dry ton ($1 5/green ton) results in the costs of electric generation, cogeneration, and steam production shown in table 44. (More detailed cost calculations are given in app. B.) The costs for producing only electricity or only steam are also shown for various feedstock costs in figures 20 and 21.

Figure 20.—Cost of Electricity From Wood for Various Wood Costs (field-erected generating station)



SOURCE: Office of Technology Assessment.

Obviously, where the feedstocks can be obtained inexpensively enough, biomass is competitive with coal for generating electricity and with oil for process steam. 1 n the case of electricity, the investment costs are about the same as for coal-fired powerplants; but wood-fired boilers cost about three times that of oil or natural gas boilers.[8]

Wood Stoves and Fireplaces

Wood stoves and fireplaces have long been used as a means of space heating in residences, but fireplaces are more often used today for

Table 44.–Cost of Electric Generation, Cogenerarion, and Steam Production From Wood[a]

Product	Plant size	Wood cost (dollars/ green ton, delivered at 50% moisture)	Product cost
Electricity	60 MW (field erected)	15	50-70 mill/kWh
Steam	50,000 lb/hr (package boiler)	15	***$3.50-$6.00/1 ,000*** lb
Steam and electricity	390,000 lb/hr 21,4 MW (field erected)	15	$4-$6/1 ,000 lb[b] 109-30 mills/kWh[b]

[a] See details in app B
[b] As the steam cost increases, the electric cost decreases

SOURCE Office of Technology Assessment

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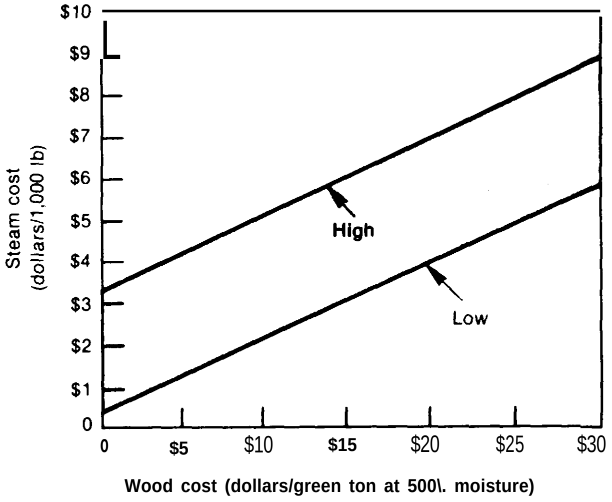
[6] **Peabody,** Gordon-Piatt, **Inc ,** Winfield, **Kan , e g , offers suspension burner retrofits to oll-fired boilers ranging from 45** million Btu/hr and up. **The retrofit cost** is slightly **higher than for** gasifiers, **but where dry, small particle** feedstock **(e g , sawdust)** is available **at low prices, the system is competitive with fuel 011** Private **communication with** Delvin Holdeman, Solid **Fuels** Marketing Division, **Peabody,** Gordon-Piatt, **November 1979**

[7] **Ibid**

[8] *A Survey of Biomass Gasification (vol* **1, Golden, Colo Solar Energy Research Institute, July 1979)**

Figure 21.—Cost of Process Steam From Wood for Various Wood Costs (package boiler)[a]



[a] Significant variations in Installation costs can occur

SOURCE: Office of Technology Assessment.

their recreational or esthetic value. Also many fireplaces are inefficient because excess air goes into the fireplace and up the chimney and this air often is drawn into the house through cracks in windows and doors. Consequently, while fireplaces do produce some local heating, the overall effect may be a net cooling of the house.

The efficiency of fireplaces can be improved (see table 45) through various methods of circulating room air past hot parts of the fireplace, through tubes being heated by the fire, or by drawing the combustion air in from outside through tubes that are heated by the fire. Depending on the complexity of the arrangement, the cost can range from as little as $10 to $30 to over $1,000.

Table 45.–Small-Scale Heating Device Efficiency

Heat unit	Net efficiency (percent)
Fireplace	
Masonry	– 10-10%
Metal prefab, noncirculating	-10-10
Insert or retrofit, circulating .,	40-50
Metal prefab, circulating	10-30
Metal. freestanding	40
Stoves	
Franklin or fireplace stove	25-45
Cast iron airtight	50-65
Metal airtight	50-65
Box	25-45
Circulator, controlled airinlet	40-55
Furnace, convertor or adder	40-60

SOURCE Auburn University Improving the Efficiency Safety and Utility of Wood Burning Units DOE contractreport DE AS05-77ET 11288 1979

Wood stoves generally have a higher efficiency than most fireplaces, due to the greater degree of air circulation around and the radiation of heat from the hot stove. In the better wood stoves, the combustion efficiency (amount of heat liberated per pound of wood) is higher than in a fireplace. Often, however, wood stoves do not completely burn the wood gases, leading to deposits of creosote in the flue. The creosote deposits can present a fire hazard and, at best, need to be regularly cleaned from the flue. There is no fundamental reason, however, why these problems cannot be solved; and research into thermochemistry and development of advanced wood stoves are likely to lead to higher efficiencies, greater flexibility of operation, and fewer safety problems.

Wood furnaces for centralized heating of a home also have significantly better efficiencies than many fireplaces. Efficiencies as high as 80 percent have been reported under certain circumstances.[9] The possibility also exists of using wood furnaces as a backup to solar-heated houses. In this case, the heat storage system of the active solar heating system could be recharged in a few hours and thereby provide space heating for several days with low solar insolation. Hill has estimated that a wood furnace (300,000 Btu/hr) with hot water storage (500 gal) would cost about $3,000 installed. This, however, should be treated as a rough estimate and additional work will be necessary to establish a more exact cost.

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[9] Laatukattila Oy, Inc , Satamakatu 4, 33201 Tampere 20, Finland, sells a YR-60 furnace capable of burning either light fuel oil or wood The Finnish Government Centre for Technical Research (Valtion Teknillinen Tutkimuskeskus) has rated this furnace at 793- and 78 8-percent efficiency at two-thirds and five-sixths full load, respectively, when using relatively dry birchwood as a fuel, according to Information supplied to OTA by Laatukattila Oy, October 1979

[10] R C Hill, University of Maine, Orono, Maine, private communication, Oct 26, 1979

In general wood stove and furnace heating require more labor than oil or natural gas heat. The fuel requires more handling, ashes must be removed, and the systems must be regularly serviced to maintain efficient and safe operation. This is less of a problem if wood pellets or well-dried wood is used or if the wood is used only as a solar backup. The use of wood heating exclusively, however, is likely to be limited to those people who consider this type of activity enjoyable or wish to use wood to achieve some degree of energy self-sufficiency. A larger number of people are likely to purchase wood stoves as insurance against oil or natural gas shortages or as a supplement to more conventional systems.

Gasification of Biomass

Gasification is the process of turning solid biomass into a gas suitable for use as a fuel or for chemical synthesis. There are several types of thermal gasification processes, or gasification induced by heat. Gases produced in blast furnaces or by the water gas process are low-Btu gases (80 to 180 Btu/stdft^3). Other gasifiers use pure oxygen and partial combustion of the feedstock to produce a medium-Btu gas (300 to 500 Btu/stdft^3) suitable for regional industrial pipelines or chemical synthesis. Still others (pyrolysis gasifiers) provide an external source of heat to produce a medium-Btu gas (e.g., dual fluidized bed gasifier described in the next section).

The gasifiers discussed in detail in this section are the airblown gasifiers. This type blows air through the feedstock to partially combust it. The heat generated is used to gasify the remaining material. The resultant gas from updraft and downdraft airblown gasifiers (termed intermediate-Btu gas) has a lower heat content (120 to 250 Btu/stdft^3) than with oxygen or pyrolysis gasification, due to the dilution effect of the nitrogen contained in the air. (Air is about 78 percent nitrogen and 21 percent oxygen.) This lower heat content makes the gas unsuitable for regional pipeline distribution, but it is not a disadvantage if the gasifier is attached directly to the boiler being fired (so-called close-coupled gasifier) or used directly for process or space heat. Gases with heat contents of 250 to 400 Btu/stdft^3, however, have been produced from an experimental fluidized-bed airblown gasifier, but the gas contains considerable tar and oil.

Close-coupled airblown gasifier systems have the potential for higher efficiencies than direct combustion when a variety of feedstocks with different moisture contents are used (see "Generic Aspects of Biomass Thermochemistry"), and can be used for process heat. Moreover, they are likely to be more efficient and less expensive, in most applications, than oxygen-blown or pyrolysis gasifiers (due to the energy loss and cost associated with the added equipment needed to produce oxygen or the external supply of heat). Nevertheless, for methanol synthesis, these gasifiers would be necessary. Moreover, there may be some circumstances where regional industrial natural gas pipelines could be converted wholly or partially to gasified biomass. Consequently, cost calculations for two medium-Btu gasifiers are included in appendix B.

Airblown (and other) gasifiers have the flexibility of being able to be used together with or as a substitute for oil or natural gas in industrial boilers for crop drying, and for process heat. This means that even where biomass feedstocks are not available in large quantities, those that are available can be used to displace oil and natural gas to the extent of their availability; and (barring regulations prohibiting it) the users could return to oil or natural gas if the biomass is temporarily unavailable or in short supply. (It should be noted that the suspension burner retrofit mentioned in the last section also has this advantage but the types of feedstocks it will accept are more restricted than for gasifies.) Furthermore, in properly designed close-coupled gasifiers, the fuel gas needs only minor cleanup (cyclone precipitator and perhaps fiberglass filter). This

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[1] 'Steven R Beck, Department of Chemical Engineering, Texas Tech University, Lubbock, Tex , private communication, 1979

together with the fact that the volume of fuel gas that needs to be cleaned is less than the volume of flue gas (from direct combustion) means that the gas cleanup is likely to be less expensive for gasifiers.

Gasifiers, however, need further development to improve their reliability (particularly with respect to materials clogging), and, in some cases, to lower the tar and char produced. Furthermore, improvements in gasifier efficiency and throughput rates can lower the effective feedstock costs and capital investment, respectively. The types of airblown gasifiers, their efficiency, and the costs are discussed below. Finally, gasifiers for internal combustion engines (ICES) are considered briefly.

Airblown Gasifier Types

The types of reactors suitable for gasification include updraft, downdraft, fluidized-bed, and entrained-flow reactors. Each of these types is depicted schematically in figure 22. The entrained-flow reactor is the fastest of these four. It has the disadvantages, however, that it requires a finely ground feedstock and the fuel gas contains considerable ash. If the ash is cleaned from the gas by wet scrubbing, then the wastewater may contain toxic compounds (e. g., phenol).[12]

Fluidized-bed reactors can take a wide range of particle sizes. In addition the material throughput is more than three times as rapid as with the updraft and downdraft gasifiers[13] and the particle stays in the gasifier only minutes[14] or fractions of a second[15] rather than hours with the slower gasifiers. Fluidized-bed reactors release some ash into the gas stream, which must be cleaned from it. Tars in the fuel gas can also be a problem.

The updraft and downdraft gasifiers are the slowest, but they also are the simplest to construct. Updraft gasifiers tend to produce more ash and tar in the fuel gas than with downdraft reactors, but their construction is the simplest of all gasifiers. Both types require relatively large feedstock particles so that the gas can flow freely through the bed of biomass.

The ideal gasifier would be simple to construct and operate, produce no ash in the fuel gas, completely gasify the feedstock (producing no char or tar), accept a wide range of feedstock sizes and moisture contents, and gasify the feedstock rapidly. The downdraft and fluidized-bed gasifiers appear to be the most favorable types, but further development of all types is required before an unambiguous choice can be made. In the end it may well be found that different gasifier types are superior for different feedstocks and applications. A partial list of gasifiers currently under development is given in appendix C.

Efficiency of Airblown Gasifiers

The heat content of the fuel gas is an important consideration in determining the overall efficiency of using a gasifier. The Electric Power Research Institute has determined the efficiency of a boiler using gases with various heat values, as shown in figure 23. Both the sensible heat (gas temperature) and the fuel value of the gas can contribute to this heating value.[16] Typical gas values range from 120 to 200 $Btu/stdft^3$ from airblown updraft and downdraft gasifiers. Some researchers claim that the energy content of the gas is increased and its burning characteristics are improved by the presence of pyrolytic oils (incompletely decomposed biomass),[17] but these oils tend to condense in fuel lines, clog valves, and in some cases may cause excessive particulate formation when combusted (thereby requiring flue gas cleanup and reducing the combustion efficiency and applicability for process heat). Determining the optimum gas composition and

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[12] Ralph Overend, "Gasification – An Overview," in *Retrofit '79, proceedings of a Workshop on Air Gasification,* sponsored by the Solar Energy Research Institute, Seattle, Wash , Feb 2, 1979

[13] Ibid

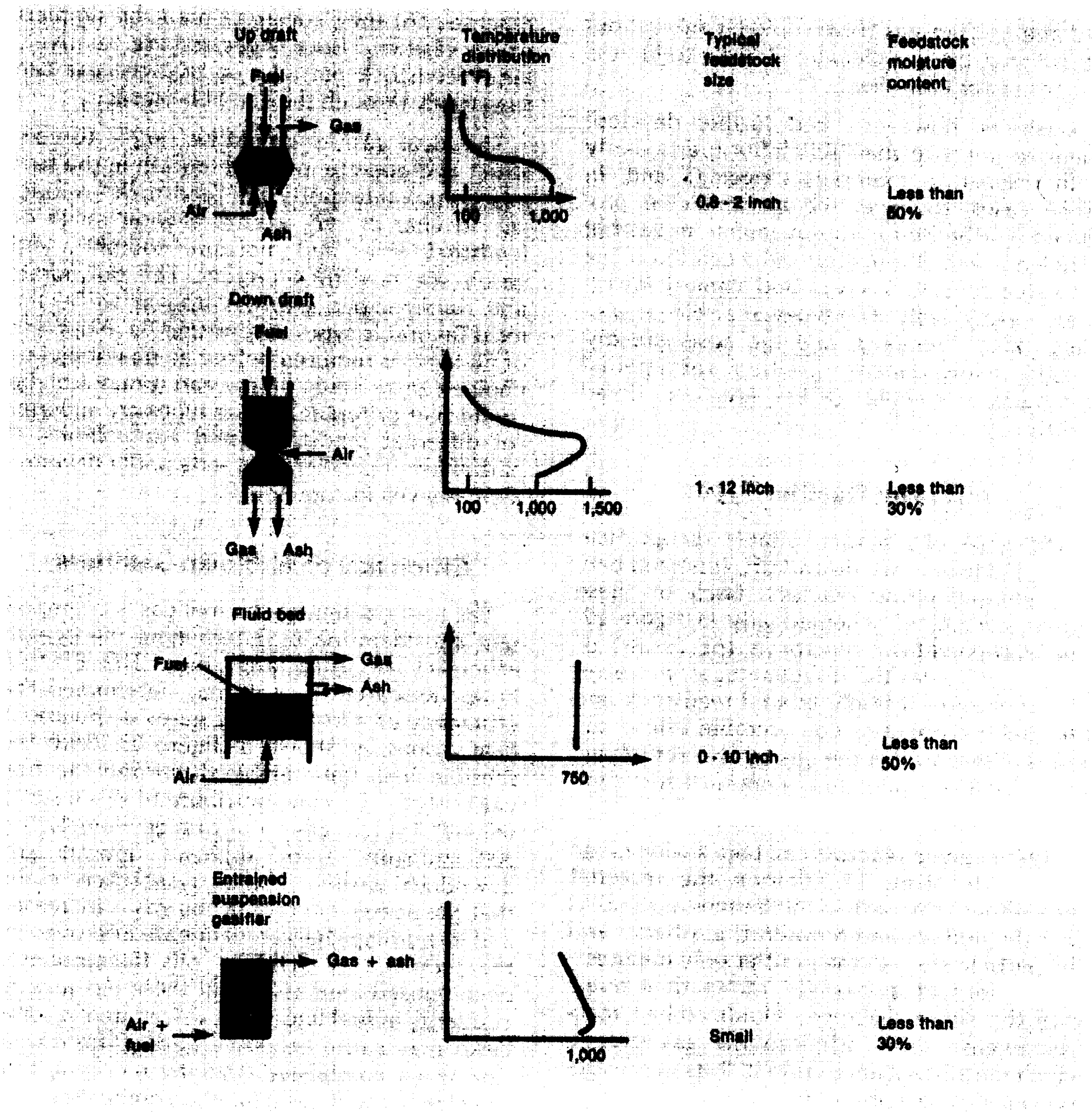
[14] Ibid

[15] Beck, op cit

[16] T B Reed, et al , "Technology and Economics of Close-Coupled Gasifiers for Retrofitting Gas/Oil Combustion Units to Biomass Feedstocks," in *Retrofit '79, proceedings of a workshop on Air Gasification,* sponsored by the Solar Energy Research Institute, Seattle, Wash , Feb 2, 1979

[17] Ibid

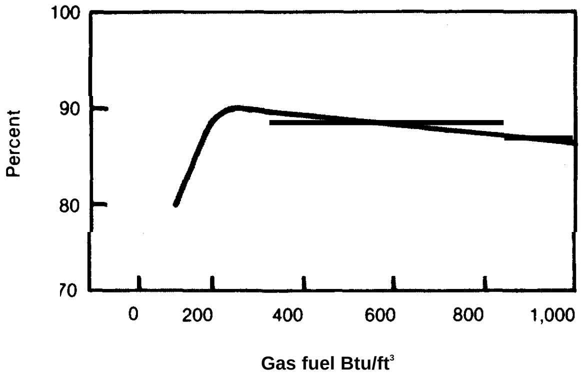
Figure 22.—Schematic Representation of Various Gasifier Types



ªNote that other schemes such as moving grate gasifier also exist

SOURCE: From R. Overend, "Gasifiation An Overview, " Retrofit 79, *Proceedings of a Workshop on Air Gasification,* Seattle, Wash., SERI/TP-49-183, Feb. 2, 1979.

Figure 23.— Boiler Efficiency as a Function of the Btu Content of the Fuel Gas



SOURCE: *Fuels From Municipal Refuse for Utilities: Technical Assessment* (Electric Power Research Institute, March 1975), EPRI report 261-1, prepared by Bechtel Corp.

how to obtain it requires further experimentation and a better understanding of biomass combustion chemistry. Nevertheless, some downdraft gasifiers have produced gases approaching 200 Btu/stdft^3 from wood with little oil formation,[18] and there appears to be no fundamental reason why the optimum energy content (see figure 23) with low tars cannot be reached with additional gasifier development,

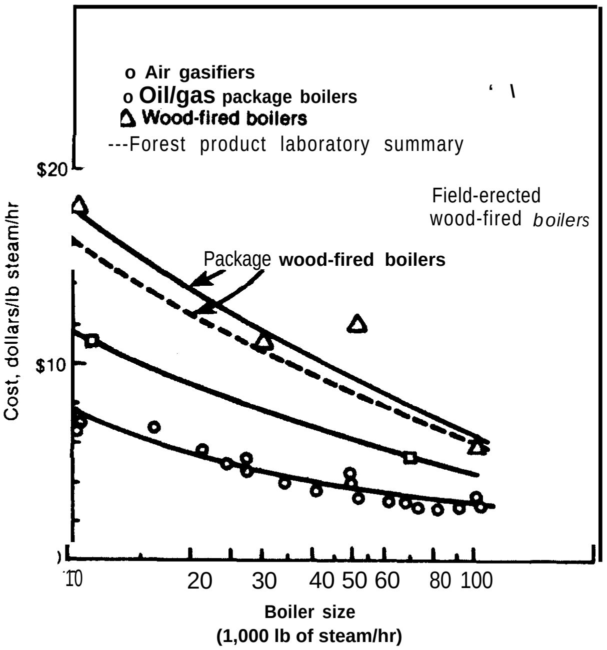
The other factor determining the overall efficiency of gasifier-boiler systems is the efficiency of the gasifier itself. Since both the sensible heat* and the chemical energy in the gas can be utilized with a close-coupled gasifier, the only gasification losses are the heat radiated from the gasifier, that lost during fuel gas cleanup, and the fuel value lost in condensed tars, oils, or char. Gasifiers have achieved efficiencies of 85 to 90 percent[19,20] and well-insulated gasifiers designed to minimize char, oil, and tar formation should be able to reach efficiencies of 90 percent or better. This would raise the overall efficiency of feedstock to steam to 85 percent or higher and provide high efficiencies for process heat needs.

Airblown Gasifier Costs

It has been estimated that oil- or gas-fired boilers can be retrofitted with mass-produced airblown biomass gasifiers for $4,000 to $9,000/ million Btu/hr ($5 to $1 2/lb of steam/h r), with gasifiers ranging from 14 million to 85 million Btu/hr.[21] Retrofit costs, however, can vary considerably depending on the difficulty of accessing the boiler and the possible need for an additional building, to house the gasifier. Voss, for example, has estimated the cost at $20,000/ million Btu/hr when new buildings and foundations are needed .22

The favorable case cost estimates are compared with the costs of new oil/gas- and wood-fired package boilers in figure 24 (similar prob-

Figure 24.—Comparison of Oil/Gas Package Boiler With Airblown Gasifier Costs



SOURCE: T B. Reed, D E Jantzen, W P Corcoran, and R Witholder, "Technology and Economics of Close. Coupled Gasifiers for Retrofitting Gas/Oil Combustion Units 10 Biomass Feedstocks," *Retrofit* '79, ***Proceedingsof a Workshop on Air Gas/~/cat/on,*** sponsored by the Solar Energy Research Institute, Seattle, Wash , Feb 2.1979

"j R Goss, **"The Downdraft** Gasifier, **" Retrofit '79,** *Proceed-/rigs of* **a** *Workshop on A/r Gasification,* **sponsored** by **the Solar Energy Research Institute,** Seattle, Wash , Feb 2,1979

'**Sensible heat** is the energy **contained** in **the gas by virtue of** its **be** ing **hot,** i e , it is the heat **that can be sensed or felt directly**

"**Goss,** op cit

"'**Reed, op** cit

"Cited in Ibid

[22] G D Voss, American Fyr-Feeder Engineers, Des Plaines, Ill , private communication, 1979

lems with installation can occur with these boilers as well). It can be seen that the capital investment for a gasifier retrofit is roughly twice that for a new oil/gas-fired boiler, but only two-thirds of that for a new wood-fired boiler. From these preliminary estimates, it appears that a new gasifier-oil/gas boiler combination costs roughly the same as a new wood package boiler but more refined data on gasifiers are needed before accurate comparisons can be made.

With costs of $4,000 to $9,000/million Btu/hr and wood fuel at $30/dry ton ($21/air dry ton, 30-percent moisture) the resultant gas is estimated to cost about $2.70 to $2.90/million Btu (see table 46). In the unfavorable case of $20,000/million Btu/hr, the cost could be $3.35/million Btu with this feedstock cost.

Table 46.–Cost Estimate for Fuel Gas From Wood Using a Mass-Produced Airblown Gasifier

Fixed investment	**$4,000-$9,000** per 10^6 Btu/hr of capacity
	Dollars/IO ^{a} Btu
Wood ($21 /ton, 30% moisture, i.e., $30/dry ton). ., ...	$2.38
Labor, electricity	0.20
Capital charge (30% of fixed investment per year)	0.150-0.34
Total ., ...	$2,73-$2,92
Estimated range ($20-$60/dry ton wood) .	$2-$6

Input: 38 to 230 tons of air-dried wood (30% moisture) per day
Output: 14 to 85 10^6 Btu/hr of intermediate-Btu gas
Load: 330 operating days per year

SOURCE: Office of Technology Assessment

Obviously from table 46, the dominant cost is the feedstock cost. If waste byproducts are used to fuel the gasifier, the gas could cost less than $1/million Btu. For the larger quantities of wood, grasses, and residues costing $20 to $60/dry ton, the gas price is estimated to range from $2 to $6/million Btu. These costs are competitive with fuel oil at $6.50/million Btu ($0.90/gal), but less so with natural gas at about $3.50/million Btu. To achieve the full potential of gasifiers, however, units in the range of 0.1 million to 10 million Btu/hr should also be developed.

Field-erected gasifiers are considerably more expensive (see app. B). They may be economic, however, in cases where very large quantities of a low-cost feedstock are available. Alternatively, package gasifiers of several hundred million Btu/hr could be developed, which, together with smaller gasifiers, would cover most situations involving biomass feedstocks.

Gasifiers for Internal Combustion Engines

Wood and charcoal gasifiers were used during the 1930's and 1940's in Europe to fuel automobile and truck engines. After some development, the gasifiers operated satisfactorily, but even under favorable circumstances, operation and maintenance required an estimated 1 hour per day of operation .23 Because of this and the 30-percent power loss associated with switching to the gas,[24] it is unlikely there would be a large market for gasifiers used in automobiles, except under cases of extreme shortages of gasoline. Gasifiers could, however, be used to fuel remote ICES for irrigation water pumping or electric generation.

The principal difference between gasifying for close-coupled boiler operation and process heat and for ICES is that the latter application requires that the gas be cooled before entering the engine and requires particularly low tar and ash content. The cooling is required to enable sufficient gas to be sucked into the cylinder to fuel the engine and to prevent misfiring. The careful gas cleanup is required to prevent fouling or excessive wear in the engine.

These problems were alleviated for charcoal and low-moisture wood by using downdraft gasifiers and various gas cooling and cleanup schemes in Europe before and during World War 11.[25] (Charcoal tended to form more ash, while wood more tar, so somewhat different systems were required.) The applicability of these gasifiers to other feedstocks, however, is uncertain.

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*[1] **Swedish Academy of Engineering,** *Generator Gas– The Swedish Experience from 7939-1945,* **Generalstabens Litografiska Anstalts Förlag, Stockholm, 1950, translated by the Solar Energy Research Institute, Golden, Colo , 1979**

[24] Ibid

[25] Ibid

Gasifiers could be used as the sole fuel for spark ignition (e. g., gasoline) engines or together with reduced quantities of diesel fuel in diesel engines (by fumigation, i.e., replacing the air intake with an air-fuel gas mixture). The energy lost in cooling the gas and removing the tar and the added cost of the cooling equipment are likely to more than double the gas costs over that for close-coupled gasifiers. (This is based on calculations by Reed,[z’] in which it is estimated that about half of the close-coupled gas energy is sensible heat. The actual value, however, will vary with the gasifier.)

With waste byproducts having no value or giving a disposal credit, the gas would be competitive with electric irrigation, gasoline, diesel fuel, and, probably, natural gas. With crop residues costing $30/dry ton, the gas cost with conventional technology is likely to be over $7/ million Btu, which is competitive with electric irrigation and will soon be competitive with gasoline and diesel fuel, but is more expensive than natural gas at present.

Gasifiers suitable for ICES could probably be manufactured immediately, but improvements in the gasifier efficiency and reliability could improve the applicability of gasifiers to ICES for crop irrigation and other uses. The development could parallel the development of other gasifiers, and improved units could probably be available in 2 to 5 years.

Liquid Fuels From Thermal Processes

Numerous liquid fuels can be made from biomass through thermal processes and chemical synthesis. The liquid fuels considered here are methanol, pyrolytic oil, and ethanol. Cost estimates for the production of these fuels are shown in table 47, with further details given in appendix B. Each of the processes is discussed below.

Methanol

Methanol (“wood alcohol”) was first produced from biomass as a minor byproduct of charcoal manufacturing. This process for methanol synthesis, however, is no longer economic. Most methanol today is produced from natural gas. The natural gas is reacted with steam and CO_2 to produce a CO-hydrogen mixture. The gas composition is then adjusted to the correct ratio of these components and the resultant gas is pressurized in the presence of a catalyst to produce methanol. Finally, the crude methanol may be distilled to produce pure methanol.

Methanol can be produced from biomass by gasifying the biomass with oxygen or through pyrolytic gasification to produce the CO-hydrogen mixture, with the remainder of the process being identical to the processes which use natural gas. The oxygen-blown gasifier systems can be built today, whereas pyrolysis gasifiers require further development.

Cost estimates for an oxygen-blown gasifier used to produce methanol are given in table 48 and a flow diagram of the process is shown in figure 25. The cost is estimated at $0.75 to

Table 47.–Summary of Cost Estimates for Various Liquid Fuels From Wood via Thermochemical Processes

Fuel	$/bbl	$/gal	$/milllon Btu	Commercial facilities could be available by.
Methanol .,	$28-$56	$0.67-$1.33	$10.50-$20.90	Now
Pyrolysis oil	**30“ 50**	**0.70-1.20**	**7 “ 12**	Mid to late 1980’s
Ethanol .,	23-68	0.55-1.62	6.50-19.10	1990’s

SOURCE Off Ice of Technology Assessment

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*’**Reed,** op cit

Table 48.–1979 Cost of Methanol From Wood Using Oxygen Gasification

Fixed investment (field erected)	$80 million
Working capital (10% of fixed investment)	8 million
Total investment	$88 million
	$/bbl
Wood ($15/green ton)	10.35
Labor, water, chemicals	1.10
Electricity (3.8 kWh/gal, $0.04 kWh)	6.40
Capital charges (15-30% of total investment per year)	$13.80-$27.60
Total	$31.65-$45.45 ($0.75-$1.08/gal)
Estimated range: ($10-$30/green ton wood)	$28-$56/bbl ($0.67-$1.33/gal) ($10.50-$20.90/10 ^{6} Btu)

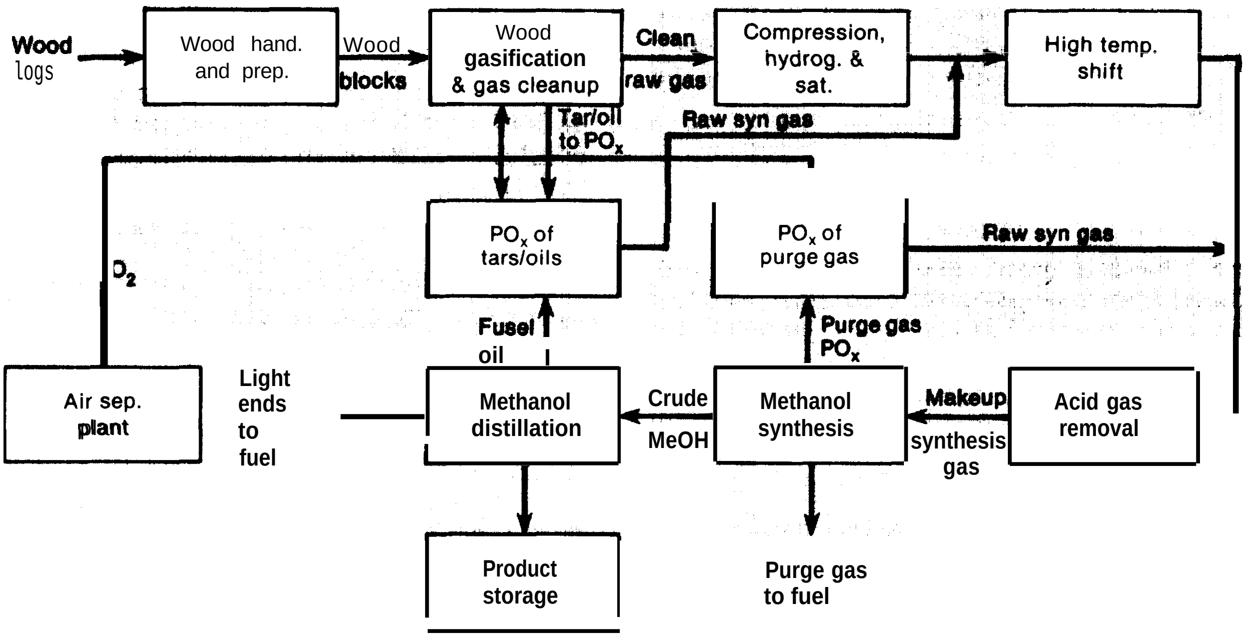
Input: 2,000 green ton/d of wood (50% moisture)
Output: 2,900 bbl/d methanol (40 million gal/yr)
Load: 330 operating days per year

SOURCE Office of Technology Assessment and based on J H Rooker, Davy McKee, Inc., Cleveland Ohio private communication May 1980 A E Hokanson and R M Rowell, Methanol From Wood Waste A Technical and Economic Study Forest Products Laboratory Forest Service. U S Department of Agriculture general technical report FPL12 June 1977 and E E Bailey manager Coal and Biomass Conversion, Davy McKee Corp Cleveland Ohio, private communication, 1979

$1.08/gal from $30/dry ton wood, and the capital investment is about $2.00 for each gallon per year of capacity, which is somewhat more expensive than grain ethanol distilleries.

Comparable cost calculations are given for a dual fluidized-bed pyrolysis gasifier in appendix B. In this gasifier, the fluidizing medium is heated in one fluidized-bed reactor which burns biomass and it is transferred to another fluidized bed where it gasifies biomass in the absence of air or oxygen, Although dual fluidized-bed gasifiers are not fully developed, the calculations in appendix B indicate that this method may produce methanol at somewhat lower costs than using oxygen-blown gasifiers, principally because it eliminates the equipment needed to produce oxygen. A more accurate comparison, however, must await development and demonstration of dual fluidized-bed and other pyrolysis gasifiers.

Figure 25.—Block Flow Diagram of Major Process Units



SOURCE: J H. Rooker, *Methanol Via Wood Gasification* (Cleveland, Ohio: Davy Mckee, Inc , 1979)

The only part of methanol synthesis, for which there is any uncertainty is the operation of and yield from the gasifier. Oxygen-blown wood gasification can probably be accomplished with commercial fixed-bed gasifiers,[27] but a large part of the gasifier cost would be associated with cleaning tars, oils, and other compounds from the gas. Consequently, the costs would be reduced somewhat by developing advanced oxygen gasifiers that maximize the CO-hydrogen yields and reduce the tar and oil formation.

With plant herbage as the feedstock, additional problems may arise from the handling of this material and possible clogging of the gasifier. These problems probably can be solved with a relatively straightforward development of suitable gasifiers.

Methanol yields from wood would vary depending on the type of wood, but have been estimated at 120 gal/dry ton in a plant that purchases its electricity.[28] If the electricity is cogenerated onsite the yield would be about 100 gal/dry ton. ” These yields correspond to conversion efficiencies of 48 and 40 percent, respectively. Yields from plant herbage are not available, but based on the above efficiencies, they may be 100 or 80 gal/ton depending on whether the electricity is purchased or generated onsite. In neither case would additional boiler fuel be needed. In theory, however, these yields can be increased significantly.

Accessing a large part of the potential biomass resource would be aided by the development of small, inexpensive package methanol plants. However, because small centrifugal compressors cannot achieve the pressures needed for methanol synthesis, plants smaller than about 3 million to 10 million gal/yr of methanol would require a different type of compressor, e.g., reciprocal compressor.[30] [31] This could increase the plant cost above that resulting from the normal diseconomy of scale, but engineering details and costs are uncertain at present.

There is little doubt that methanol can be synthesized from wood with existing technology. Since the only uncertainty is with the gasifier, the cost estimates are probably accurate to within 20 percent. This would put the cost per Btu of methanol from wood at about the same level as ethanol from grain. However, both alcohols are likely to be more expensive than methanol from coal, due primarily to the economy of scale that can be achieved by building very large coal conversion facilities.

Pyrolytic Oil

Pyrolytic oil can be produced by slowly heating biomass under pressure and in the presence of a catalyst. The pressure suppresses gas formation and the catalyst aids the formation of the oil. Other possibilities, however, such as rapid heating and cooling can also produce pyrolytic oils.

The process involving slow heating is currently under development and a pilot plant in Albany, Oreg., has produced a small quantity of oil, following earlier difficulties. The oil is about 30 percent lower in heat content (per gallon) than petroleum fuel oil and it may be corrosive but it contains negligible sulfur. The oil is said to be roughly equivalent to a low-grade fuel oil, but further testing is necessary to determine how well the oil stores and what modifications in boilers may be necessary to use this oil as a boiler fuel.

Since the pyrolytic oil is made from feedstocks that could be used in close-coupled, air gasifiers and would have some of the same uses as the gasifier fuel gas, pyrolytic oil production should be compared to close-coupled gasifiers. The pyrolytic oil is less expensive to transport than raw biomass and it is probably well suited to fully automatic boiler operation. It may also be possible to refine the oil to higher grade liquid fuels. At present, nevertheless, the costs appear to be high in relation

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[27] J H Rooker, *Methanol Via Wood Gasification* [Cleveland, Ohio Davy McKee, Inc , 1979)

[28] E E Bailey, Manager, Coal and Biomass Conversion, Davy McKee Corp , Cleveland, Ohio, private communication

[29] A E Hokanson and R M Rowell, “Methanol From Wood Waste A Technical and Economic Study,” Forest Products Laboratory, Forest Service, U S Department of Agriculture, general technical report FPL 12, June 1977

[30] Bailey, op c it

“J H Rooker, Davy McKee, Inc , Cleveland, Ohio, private communication, May 1980 to air gasifiers and the efficiency of using the biomass feedstock in this way is considerably lower than with gasification, but the oil may be comparable in cost to some other synthetic fuels. Consequently, if gasifiers become widely available, markets for the pyrolytic oils may be limited to those users who are willing to pay for complete automation of their boilers.

Various other thermal processes are possible for the production of oils from biomass (see app. C), including processes which do not try to minimize oil production during gasification and collect the oil as one of the products. These latter types produce gas, oil, and char products.

The multi product systems, while being technically easier to develop, have decreased oil yields (since part of the biomass is not converted to oil) and the management and economics are more complicated due to the need to sell each of the various products. A technical solution to these problems being studied is to slurry the char with the oil. Although the char contains ash and the oil is corrosive and may deteriorate under storage, the Department of Energy (DOE) is funding a feasibility study for burning this slurry of oil and char in gas turbines.[33] Since conventional turbines may not be able to tolerate gases with sodium and potassium the project proposes to use turbine combustion technology developed from military programs.[34]

It would seem, however, to be more technically and economically sound to develop conversion processes which produce little or no char and which produce only as much gas as can be utilized by the conversion facility. Consequently, OTA has not analyzed the multiproduct liquefaction systems in detail.

Still another type of liquefaction process would subject medium-Btu gas to pressure in the presence of a catalyst (the biomass analog of the South African SASOL process for producing gasoline from coal). The capital investment, however, appears to be quite high,[35] and further development will be needed to lower these costs.

Ethanol

Conceptually, ethanol can be produced from biomass through rapid gasification to produce ethylene. The ethylene is then separated from the other gases and converted to ethanol using commercial technology.

The critical factor in determining the economics is the ethylene yield from rapid gasification. Present experimental yields have reached 6 percent (by weight) from biomass,[36] but some researchers[37] believe that yields as high as 30 percent (by weight) may be possible. If so, then this process could produce fuel ethanol at prices considerably below those for the fermentation of lignocellulosic materials and at costs (per million Btu) comparable to those projected for methanol from coal, or roughly $0.65/gal of ethanol.

The process, however, needs considerable research to determine if and how such ethylene yields can be achieved. Even under favorable circumstances, it is unlikely that commercial processes could be available before the 1990's.

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[32] J W Birkeland and C Bendersky, "Status of Biomass Waste and Residue Fuels for Use in Directly Fired Heat Engines," presented at the *Conference on Advanced Materials for Alternate Fuel Capable Directly Fired Heat Engines*, sponsored by the Electric Power Research Institute and the Department of Energy, Maine Maritime Academy, Castine, Maine, August 1979

[33] Teledyne CAE, Toledo, Ohio, "Gas Turbine Demonstration of Pyrolysis-Derived Fuels," Department of Energy contract E778-C-03-1839

[34] Birkeland and Bendersky, op cit

[35] Dow Chemical, U S A, Freeport, "Technical, Economic, and Environmental Feasibility Study of China Lake Pyrolysis System," report to the Environmental Protection Agency, 1978

[36] S Prahacs, H C Barclay, and S P Bhada, "A Study of the Possibilities of Producing Synthetic Tonnage Chemicals From Lignocellulosid Residues," Pulp and Paper Magazine of Canada, vol 72, p 69, 1971

[37] See e g., M J Antal, *Biomass Energy Enhancement — A Report to the President's Council on Environmental Quality* (Princeton, N J Princeton University, July 1978)

Environmental Impacts of Wood and Wood Waste Combustion

The major environmental impacts of wood combustion, aside from any impacts from growing and harvesting the wood fuel, arise from the generation of air pollution in the combustion units. A variety of other impacts, including safety problems with small units, water pollution from wood storage and ash disposal, and air pollution from wood fuel distribution may be of lesser importance, although wood appliance safety could easily become an important public concern. Because the magnitude of the impacts, even on a "per ton of wood burned" basis, is quite dependent on the size of the operation, this discussion treats residential and other small-scale use separately from utility and industrial wood boilers.

Small-Scale Burning

Residential use of wood as a heating fuel is usually a low combustion efficiency, low-temperature process compared to larger industrial fossil-fueled or wood boilers. The low combustion efficiency is reflected in relatively high emissions of CO and unburned hydrocarbons (see table 49). The low temperature, coupled with extremely low fuel-bound nitrogen in wood (about 0.1 percent compared to 1.5 percent in coal, [38]) leads to levels of nitrogen oxide (NO_x) emissions well below those of fossil boilers. (Old Environmental Protection Agency (EPA) emission factors from "AP-42" showed NO_x emissions to be as high as those from coal boilers, but these factors have been demonstrated to be inaccurate.) Wood sulfur levels are equal to or less than 0.05 percent, [39] and sulfur oxide (SO_x) emissions consequently are very low.

Table 49.–Emission Factors for Residential Wood Combustion Processes

Pollutant	g/kg[a]	lb/cord[a]
Particulate[c]	5-19	20-72
Carbon monoxide”	60-130	240-520
Hydrocarbons	2-9	8-40
So_x	02	0.8
NO_x	0.3	12
Formaldehyde	1.6	6.4
Acetaldehyde	0.7	3
Phenols	1	4
Acetic acid	6.4	26
Polycyclic organic matter	0.3-4 6% of total particulate	
Elemental metals	7	30

[a] Units are grams of Species emitted per kilogram of wood burned Wood moisture is not specified in the references cited

[b] Alternate units are pounds of species emitted per cord of wood burned One cord is assumed to equal 4000 lb

[c] Particulate includes inorganic ash condensable organics and carbon char Note that other en" tries in the table e g polycyclic organic matter and elemental metals, are somewhat redundant in that they are subcomponents of particulate matter and not separate species

SOURCE J O Milliken Airborne Emissions From Wood Combustion Environmental Protection Agency /Research Triangle Park N C Feb 20 1979 with revisions based on private communication with Milliken

Particulate are an especially worrisome component of emissions from residential wood combustion. Areas with high concentrations of wood stoves are known to have particulate pollution problems, especially during winter inversion conditions. Rapid deployment of wood stoves could have significant effects on air quality in New England and the Northwest. 40

Condensable organics make up about two-thirds of the particulate matter emitted by residential wood combustion units .4’ Polycyclic organic matter (POM), species of which are known animal carcinogens, makes up as much as 4 or 5 percent of these organics and may be the most dangerous component.[42] Based on available emission data, POM emissions from wood stoves are likely to be far greater (on a "per Btu" basis) than emissions from the systems they would replace–fossil-fueled powerplants and residential oil or gas furnaces.

POM is emitted by all combustion sources and is spread throughout the environment, although usually in low concentrations. Table so shows the major sources of benzo(a)pyrene (B(a) P), which is often used as an indicator species of POM. Aerosols containing B(a)P and other species of POM can survive long enough

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"*Comparison of Wood and Fossil Fuels* (Washington, D C Environmental Protect Ion Agency, March 1976), E PA-60012-76-056

"R H Perry and C H Childton, eds , *Chemical Engineer's Handbook, 5th Edition* (McGraw Hill, 1973)

[40] M. D Yokell, et al , *Environment/ Benefits and Costs of Solar Energy*, vol I [draft), Solar Energy Research Institute report SERI/TR-52-074, September 1979

[41] J O. Milliken, Environmental Protection Agency, Research Triangle Park, N C , private communication, Oct 26, 1979

[42] Ibid

Table 50.–Estimates of Total B(a)P Emissions (metric tons/year)

Major sources	Minimum	Maximum
Burning coal refuse banks	280	310
Residential fireplaces	52	110
Forest fires	9.5	127
Coal-fired residential furnaces	0.85	740
Coke production	0.05	300

SOURCE Energy and Environmental Analysts, Inc “Prehmmary Assessment of the Sources, Control and Population Exposure to Airborne Polycyclic Organic Matter (POM) as indicated by benzo(a)pyrene [B(a) P], November 1978

to travel 60 miles (100 km) or farther from their source.4] However, sources that are far from population centers are less dangerous than urban sources both because of the dispersion that occurs with distance and because POMs eventually can be degraded to less harmful forms by photo-oxidative processes. ”

POMs are dangerous for a number of reasons. First, because of their physical nature, they are more likely than most substances to reach vulnerable human tissues. They are formed in combustion as vapors and then condense onto particles in the flue gas. The smaller particles adsorb a proportionately high amount because they have large surface/weight ratios. These smaller particles are both less likely to be captured by particulate control equipment and more likely to penetrate deep into the lungs if breathed in. Second, several of the POM compounds produced by combustion are “the same compounds that, in pure form, are known to be potent animal carcinogens. “4[5] POM is suspected as a cofactor (contributor) to the added lung cancer risk apparently run by urban residents. ” Finally, POM is suspected of causing or contributing to added incidence of chronic emphysema and asthma. 47

Because POM and other organic emissions, as well as CO, are the products of incomplete combustion, the new airtight stoves, which are beginning to take an increasing market share, will have to be evaluated carefully for their emission characteristics, especially under improper operation. Airtight stoves achieve a higher overall heating (but not necessarily combustion) efficiency by slowing down combustion, transferring more of the heat produced into the room rather than up the flue, and avoiding the establishment of an airflow from the room into the stove and up the flue. The reduction of excess air allowed into the combustion zone increases the emissions of CO and unburned hydrocarbons. Ideally, these pollutants will be burned in a secondary combustion zone fed with preheated air (air that is first routed through the primary combustion chamber). However, if the air fed into this zone is too cool, secondary combustion will not occur; under these circumstances, airtight stoves would be substantially more polluting than ordinary stoves. Also, the lower airflow and cooler exit gases of these stoves cause them to deposit more of their organic emissions– in the form of creosote—on the interior of their chimneys. Deposits of creosote from wood stoves and fireplaces have always been a fire hazard; this hazard will be increased by greater use of airtight stoves. An added safety problem associated with airtight stoves is the potential for “back-puffing” —surge back of flames–when the stove is opened. Both of these safety hazards are controllable by, respectively, having the flue cleaned regularly and increasing the intake airflow before opening the stove.

Utility and Industrial Boilers

Large wood-fired boilers should be more efficient energy converters than small units and therefore should have less problems with CO and unburned hydrocarbons. However, the potential exists to generate significant quantities of these pollutants, and some existing large boilers are fairly inefficient and thus fulfill this potential. (For example, emissions of CO from industrial boilers range from 1 to 30 g/kg of wood, compared to 60 to 130 g/kg from small

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[43] G Lunde and A Bjorjeth, “Polycyclic Aromatic Hydrocarbons in Long-Range Transported Aerosols, ” *Nature, 268, 1977,* pp *518-519*

[44] M J Svess, “The Environmental Load and Cycle of Polycyclic Aromatic Hydrocarbons, ” *The Science of the Total Environment, 6, 239, 1979*

[45] J o Milliken, “ Airborne Emissions From Wood Combustion,” presented at the *Wood Heating Seminar IV,* Portland, Oreg , sponsored by the Wood Energy Institute, Mar 22-24,1979

[46] J O Milliken and E G Bobaleck, *Polycyclic Organic Matter: Review and Analysis* (Research Triangle Park, N C Special Studies Staff, Industrial Environmental Research Laboratory, Environmental Protectlon Agency, 1979)

[47] K L Stemmer, “Clinical Problems Induced by PAH,” in *Carcinogenesis, Volume 1. Polynuclear Aromatic Hydrocarbons: Chemistry,* Metabolism, and *Carcinogenesis* (New York. Raven Press, 1976)

wood stoves.)[48] Inefficient boilers will generate the same dangerous organic compounds— including species of POM — as do small residential stoves and fireplaces. These organics are mostly “low-molecular-weight hydrocarbons and alcohols, acetone, simple aromatic compounds, and several short-chain unsaturated compounds such as olefins.[49] Some of these emissions are photochemically reactive, although the amounts in question should not contribute significantly to smog problems. As the price of wood and wood waste increases, strong incentives for greater combustion efficiency should work to minimize the organic emission problem.

Sulfur dioxide (SO_2) emissions should be minimal because of wood’s low sulfur content. An exception to this is the combustion of black liquor in the pulp and paper industry; some of these boilers should require SO_x scrubbing under Federal regulations.[50]

Although particulate emissions generated by wood-fired boilers can be high (6 g/kg, or about as high per unit of energy as a wood stove), efficient controls are available for the larger units. Available devices or combinations of devices include multi cyclones coupled with low-energy wet scrubbers, dry scrubbers, electrostatic precipitators (ESPs), or baghouses (fabric filters). Although ESPs are the most widely used control mechanism for utility boilers, they have been said to be less practical for wood-fired boilers because of the very low resistivity of both the flyash and unburned carbon particles from wood combustion.[51] However, ESPs have been successfully used on some wood-fired boilers, and the problem of low resistivity apparently can be handled with appropriate precipitator design.

Current regulations for emission control from pollution sources do not distinguish particulates by their size. Most control devices in current use suffer from a severe drop in efficiency in controlling the finer, more dangerous particles. Baghouses appear to be the only feasible control devices currently available that are capable of collecting particles below a few microns in size with 99-percent efficiency or greater. It appears quite probable that emission standards for the finer particulate eventually will be promulgated; these standards would almost certainly lead to extensive use of baghouse controls.

Current EPA emission factors show NO_x emissions from wood combustion to be comparable to emissions from coal combustion.[52] If these factors were correct, large boilers subject to Federal new source performance standards would require NO_x reductions of 40 percent. This would pose a problem in the short term, because there is virtually no experience in reducing NO_x emissions from wood-fired boilers. Techniques used for fossil fuel boilers that may be applicable to wood are:

- low excess air firing,
- staged combustion, and
- flue gas recirculation.

Recent measurements conducted by Oregon State University” and TRW[54] show actual NO_x emissions from test boilers to be one-third or less than those predicted by using the current emission factors. These measurements are much more in line with the lower combustion temperatures in wood boilers and wood’s low nitrogen content, EPA and DOE researchers are convinced that the current emission factors are in error[55] [56] and it appears likely that the factors will soon be revised.

In the past, wood boilers have never attained the size normally associated with large coal-fired boilers, Whereas coal-fired utility boilers are typically a few hundred megawatts

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[48] Milliken, “Airborne Emissions From Wood Gasification,” op cit

[49] M D Yokell, op cit

[50] *En “iron mental Readiness Document, Wood Commercialization* (Department of Energy, 1979), draft

[51] *Wood Combustion Systems An Assessment of Environmental Concerns* (Mittelhauser Corp , July 1979), draft, contractor report to Argonne National Laboratory

[52] *Compilation of Air Pollutant Emission factors Rev/seal* (Washington, D C Office of Air Programs, Environmental Protect Ion Agency, February 1972), publication No AP-42

“Memorandum from Paul A Boys, Air Surveillance and Investigation Section to George Hofer, Chief, Support and Special Projects Sect[on, U S Environmental, Protectlon Agency, ‘‘Comparison of Emissions Between Oil Fired Boilers and Woodwaste Boilers,” November 3, 1978

[54] J O Milliken, Environmental Protect Ion Agency, Research Triangle Park, N C , private communication, June 6, 1979

[55] Milliken, Oct 26, 1979, op cit

[56] J Harkness, Argonne National Laboratory, private communication, Oct 26, 1979

in generating capacity and range up to 1,000 MW, a 25- or 50-MW wood-fired boiler would be considered extremely large.

Higher capacities would require using wood suspension firing, analogous to firing with pulverized coal, or fluidized-bed combustion. Pulverizing wood to extreme fineness for suspension firing may be costly enough to offset other economic advantages of going to larger size plants, so future increases in wood boiler size may depend on further development of fluidized-bed combustion. The expense of transporting wood considerable distances has also been a constraint on boiler size in the past, but rising costs for alternative fuels may make longer distance transport of wood more attractive, increasing the effective radius of supply and the maximum practical size of the boiler.

The local impacts of utility or industrial wood-fired boilers will be moderated by their comparatively small size. However, the effects of low stacks (compared to the stacks on large coal-fired utility boilers) will be to allow less diffusion of the emissions from the plants; a higher percentage of the pollution will fall out near the plants than would normally be expected for large generating facilities or industrial boilers. Also, the high water content of wood leads to higher concentrations of water vapor in the stack gases and greater visibility of the plumes. Although not harmful except in an esthetic sense, this increased visibility may lead to added local objections to wood-fired boilers.

In general, emissions from other portions of the fuel cycle are quite low compared to emissions from combustion. The single exception is CO, which is produced in substantial quantities by harvesting, chipping, and transport equipment. Table 51 presents a comparison of the emissions at all stages of the fuel cycle for coal, oil, and wood boilers. As noted above, CO and organic emissions from wood boilers are far higher than emissions from coal. Note that the emissions of SO_2 and particulate are dependent on the level of control, and can be reduced significantly if required.

Table 51 .–"Source-to-Power" Air Emissionsfor Coal, Oil, and Wood Fuel Systems

	Emissions ton/yr (basis 50-MW plant)			
Fuel/energy system	SO_2[a]	CO	Particulate	Total organic
Low-sulfur Western coal				
Surface mining	–	—	113.1	—
Rail transport (1,800 miles), ...	**20.2**	**218.1**	**21.8**	**22.2**
Power generation. . . . ., ., . .	2,664.8	87.2	113.1	25.8
Total . . . ., ...	2,685.0	305.3	248,0	28.0
Crude oil				
Domestic oil pipeline.	25.8	0.0	***3.2***	**0.5**
New Jersey refined with desulfurization	193,8	4.8	3.2	40.4
Rail transport (300 miles)	1.5	16.3	1.6	1.7
Power generation . . ., ., ...	854.3	–	80.8	16.2
Total . . . .,	1,075.4	21.1	88.8	58.8
Wood				
Wood recovery.	6.5	48.5	3.2	8.1
Process chipping	14.5	116.3	6.5	19,4
Truck transport (60 miles).	4.4	36.3	2.1	6.0
Power generation.	119.5	398.9	339.2	398.9
Total	144.9	600.2	351.0	*432.4*

NOTE NO_x levels may be significant for wood fuel There IS Inadequate data on NO_x emission levels There are also production tradeoffs for various conversion systems

[a] SO_2 emissions from coal-fired powerplant assume no scrubbers 90% control required by new source performance standards would lower emissions from 2,6648 tons 10266 Ions

SOURCE E H Hall, et al , *Comparison of Fossil arrd Woud Fuels* (Washington, O C Environmental ProtectIon Agency, March 1976), EPA-600/2-76-056

Environmental Impacts of Cofiring Agricultural and Forest Residues With Coal

Cofiring of coal and agricultural or forest residues has been proposed both as a means of expanding energy supply and as an economical way to lower sulfur emissions (from burning local high-sulfur coal) without importing low-sulfur coal. Since wood and most crop residues have very low sulfur contents (cotton gin trash is one exception), total SO_2 emissions can be significantly lowered if the residues can replace a large fraction of the coal normally burned in the boilers. Two situations where cofiring would appear to be attractive are:

- reducing SO_2 emissions from existing coal-fired powerplants that are marginally out of compliance with their State implementation plans, and
- allowing very high-sulfur coals to be used with scrubbers in new powerplants (achievement of the current 1.2 lb/million Btu SO, standard may be difficult with some very high-sulfur coals)

There are few examples of cofiring experiments in the literature and these examples generally do not examine emission changes caused by the addition of crop and wood wastes to the coal fuel. Because SO_2 is the only pollutant whose formation generally does not vary with combustion conditions (except that sulfur may be captured in the char from a pyrolytic reaction), it is probably the only pollutant that can be predicted reliably at this time. However, general emission trends for some pollutants can be predicted. For example, hydrocarbon and CO emissions may increase slightly, because combustion temperatures are lowered and complete combustion is more difficult to achieve when residues are added to the boiler fuel. The lower combustion temperature and low fuel-bound nitrogen in the residues should cause NO_x emissions to be lowered. If dryers are used for high-moisture-content residues, their emissions must be added to those of the boiler.

Particulate emissions are difficult to predict because they are affected by several site-specific factors. However, there appears to be some potential for increased particulate emissions under certain conditions. Although biomass residues generally have lower inorganic ash contents than the coal they would replace, they tend to generate more organics in particulate form. The ability of the boiler to maintain nearly complete combustion conditions will thus strongly affect particulate emissions. In large facilities with ESPs, the lower resistivity of the particles generated from combustion of the residues may allow a higher percentage to escape control. If the biomass is fed moist into the boiler, the steam generated during combustion will increase the flow of hot combustion gases and conceivably may lead to more entrainment of bottom ash and higher particulate emissions. On the other hand, if the biomass is first artificially dried, particulate emissions from the dryer could be high unless they are carefully controlled. The significance of any of these effects is uncertain at the present time.

The importance of these emission changes depends on the original quality of the coal, the nature of the residues added, the percentage fuel mixture, the type of pollution controls on the boiler, and its operating conditions. All of these factors vary considerably from site to site. However, it seems likely that emission increases will be small except in cases where the cofiring seriously degrades the operating characteristics of the boiler (it is unlikely that cofiring would continue under such conditions unless noneconomic pressures– such as the possibility of adverse publicity and/or embarrassment of company management— prevented cessation of operations). In addition, emissions changes will be limited by constraints on the amount of biomass that can be mixed with the coal. Logging residues and high-moisture crop residues have a considerably lower energy content per unit volume than coal, Because boiler systems are sized to allow a certain volumetric flow rate of fuel feed, a high percentage of biomass volume in the feed will limit boiler output capacity. An additional limit may be presented by the additional volume of combustion gases that would be generated if the biomass is fed moist into the boiler. These constraints do not apply when the energy output required is much lower than the boiler's rated capacity, or when the system is specifically designed for cofiring. Also, the high-moisture content of the biomass may cause condensation problems in the stack unless the biomass content is limited, stack temperatures are increased (by removing less energy from the gas and thus lowering system efficiency), or the biomass is first dried (which may also lower system efficiency).

Environmental Impacts of Gasification

Gasification technologies have a number of potential air and water impacts. Because few such gasifiers are in operation, quantification of these impacts is premature. The low concentrations of trace metals and sulfur in the biomass feedstocks and the lack of extreme temperature and pressure conditions imply that impacts should be substantially less than those associated with coal gasification. However, scientists working for DOE's Fuels from Biomass Branch profess to be unsure as to whether this supposed biomass "advantage" actually exists, especially in the water effluent stream; although the hydrocarbons present in biomass gasification wastewater should be more amenable to biological treatment than coal gasification hydrocarbons (they are more oxygenated), they may be produced in greater quantities and have a higher biological oxygen demand than those of a coal system.[57] Also, the potential for proliferation of small-scale biomass gasifiers may present monitoring and enforcement problems that would not exist with a few large coal gasifiers. Therefore, biomass gasification may require as much attention and concern as coal gasification.

The quantity and mix of air pollutants produced by biomass gasification plants will depend in large part on the combustion/gasification conditions maintained as well as the environmental controls and the chemical makeup of the feedstock. For example, the concentration of hydrogen in the reaction chamber and of sulfur and nitrogen in the feedstock will influence the formation of ammonia (NH_3), hydrogen sulfide (H_2S), and hydrogen cyanide (HCN). Other products of the gasification process include carbonyl sulfide (COS) and carbon disulfide (CS_2) as well as phenols and polynuclear aromatic (PNA) compounds.[58] Gasification processes that are closer in their nature to pyrolysis and that produce considerable byproduct char will have lower nitrogen and sulfur-derived emissions; about half of the original sulfur and nitrogen in the biomass should remain in the char. 59

The gas produced will either be burned onsite (producer gas) or cleaned and upgraded to pipeline gas. Either process should eliminate or reduce most of the more toxic pollutants, with the onsite burning oxidizing them to CO_2, SO_2, NO_2, and water. Recent tests of a close-coupled gasifier/boiler combination using woodchips for fuel showed emissions of CO, particulates, and hydrocarbons–which are of major concern in wood combustion — to be well below emissions expected from a direct-fired wood boiler, although a fuel oil boiler replaced by such a gasifier would have had considerably lower particulate and hydrocarbon emissions. NO_x emissions from the gasifier/boiler combination were lower than those expected from either oil- or wood-fired boilers.[60]

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[57] Richard Doctor, Science Applications, Inc , private communication, November 1979

[58] *Solar Program Assessment: Environmental Factors, Fuels From Biomass* (Washington, D C Energy Research and Development Administration, March 1977), ERDA 77-47/7

[59] Ibid

[60] California Air Resources Board, "Source Test Report No C-G-*O(l2-C,* Source Test of Exhaust Gas From a Boiler Fired by Production Gas Generated From an Experimental Gasifier Unit Using Wood Chips for Fuel, " Stationary Source Control Division, March 1978

	Gasifier	Wood boiler	Oil boiler
Carbon monoxide (lb/hr).	*0*	*1.8-54*	0.33
Particulates (lb/hr)	070	45-135	013
Hydrocarbons (lb/hr)	0.90	63	007
Nitrogen **oxides (lb/hr)**	**039**	9	1.46

These results cannot be readily extrapolated to other situations, but they imply that the use of gasifiers *may* offer a less polluting alternative to direct combustion of biomass when a shift to renewable (from oil) is being contemplated.

Leaks of raw product gas represent a potential for significant impacts, especially on those in the immediate vicinity of the gasifier. The probability of such leakage is not known. Although impact analyses of high-pressure coal gasification technologies have identified fugitive hydrocarbon emissions as a likely problem, it is not clear that similar problems would occur with (lower pressure) biomass gasifiers.

The combustible char produced by the gasification process is another potential source of air pollution. It may be used as a fuel source elsewhere or else used to heat the bed in a fluidized-bed gasifier. In either case, its combustion will produce NO_x, flyash, and SO_x as well as trace metals either adsorbed on the flyash (potassium, magnesium, sodium, iron, boron, barium, cadmium, chromium, copper, lead, strontium, and zinc) or in gaseous form (beryllium, arsenic compounds, fluorides).[61] [62]

Because most biomass feedstocks used in gasification processes have concentrations of trace elements, ash, and sulfur that are substantially lower than concentrations found in coal, combustion of the char should emit lower concentrations of related pollutants than would coal combustion. Depending on the farming and harvesting techniques, however, the feedstock may be somewhat contaminated with pesticides, fertilizers, and soil, which should add to combustion pollutants, Also, some forms of biomass—for example, cotton trash, with 1.7 percent— have sulfur levels comparable to levels in coal.

Aside from water impacts caused by construction activities and leaching from biomass storage piles, gasification facilities will have to control potential impacts from disposal and storage of process wastes and byproducts. Water initially present in the feedstock and that formed during the combustion accompanying gasification should provide significant amounts of effluent requiring disposal (although in close-coupled systems, the moist low-Btu gas may be fed directly into the boiler). Air pollutants identified above may appear also as water contaminants: NH_3 (as ammonium hydroxide), HCN and its ionized form, phenols, and trace elements found in the ash. Leaching from byproduct chars may be a problem if the char is (incompletely carbonized) brown char although (carbonized) black char should be similar to charcoal and far less likely to be polluting. Finally, the tars produced by gasification may well be carcinogenic; as yet no data confirm this potential. These water contaminants present a potential occupational as well as ecological and public health concern, because plant operators may be exposed unless stringent "housekeeping" is enforced.

Research, Development, and Demonstration Needs

Thermochemical conversion includes the least expensive, near-term processes for using the major biomass resources — wood and plant herbage. Moreover, R&D is likely to lead to interesting new possibilities for the production of fuels and chemicals from biomass. Some of the more important areas are:

- **Thermochemistry of biomass. —** Basic and applied research into the thermochemistry of biomass, including secondary gas phase reactions, is needed to better define the possibilities for fuel synthesis and to aid engineers in designing advanced reactors. The research should include studies

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[61] *Solar Program Assessment,* **op** cit

“Doctor, op cit

of the effects of the various operating parameters on the nature and composition of products and ways to maximize the yields of various desirable products such as CO and hydrogen, ethylene, methane, and other light hydrocarbons.

- **Gasifier development and demonstration. –** Gasifiers should be developed further and demonstrated, so as to improve their reliability, efficiency, and flexibility with respect to feedstock type and moisture content. This should include airblown gasifiers for process heat, boiler retrofits, and ICES, and oxygen-blown and pyrolysis gasifiers for methanol synthesis. It should also include the demonstration of gasifiers suitable for converting plant herbage to methanol and should investigate the tradeoff between densifying herbage before gasification versus gasification of herbage directly. Each of the uses for gasifiers will have unique requirements, which probably will dictate separate development and demonstration efforts.
- **Compressor development.– One** of the major costs of producing methanol in small plants is the relativley high price of small compressors. The cost of methanol synthesis from biomass would be lowered substantially if small, inexpensive compressors suited to the process are developed.

Each of the new biomass conversion technologies will require environmental assesment to ensure the development of appropriate control technologies and incorporation of environmental considerations in system design, siting, and operation. In general, the larger scale technologies are likely to be assessed as part of normal EPA and DOE environmental programs. The smaller technologies generally will not come under Federal new source performance standards (specifications of allowable emissions), but there is growing recognition in EPA and DOE of the potential environmental dangers of small-scale technologies such as wood stoves.

Key environmental R&D areas in thermochemical conversion are:

- development of wood stove designs (or controls) that achieve complete combustion and minimize emissions of unburned hydrocarbons;
- development of combustion controls that will allow efficient — and pollutant minimizing— thermochemical reactions regardless of feedstock characteristics;
- assessment of the potential health effects of emissions from wood stoves and other biomass conversion technologies, with a focus on particulate with a high unburned hydrocarbon component;
- evaluation of toxicity and carcinogenicity of biomass gasifier/pyrolysis tars and oils; and
- design of controls for gasifier/pyrolysis effluent streams.

Appendix A.—Optimum Size for a Wood-Fired Electric Powerplant

The annual cost, C, of producing electricity in a wood-fired electric powerplant can be expressed as:

$$C = C_c + C_f + C_t \tag{1}$$

Where C_c represents the capital and other fixed charges, C_f represents the fuel and other variable costs, and C_t the cost of transporting the fuel.

Letting S represent a dimensionless scaling parameter

$$c_c = C_c^o S^{0.7} \tag{2}$$

Here C_c^o represents the fixed charges for a base case and it is assumed that these charges scale with a 0.7 scaling factor. Furthermore, the variable costs are:

$$C_f = C_f^o S \tag{3}$$

Where C_f^o represents the base case.

Assuming the fuel is collected from a circular area surrounding the powerplant, the transport costs can be expressed as:

$$C_t = C_t^o Q_o S r \tag{4}$$

Where C_t^o is the transport cost per ton-mile, Q_o is the annual quantity of wood transported in the base case, and r is the average transport distance.

For a given scaling parameter S, the quantity of wood transported is:

$$Q = Q_o S = enr^2 \tag{5}$$

where e is the average availability of fuel wood collected in dry tons per square mile year and r is the radius of the circle from which wood is collected.

If one assumes that the actual transport distance from a harvest site to the powerplant is $\sqrt{2}$ times the direct line distance,

$$\bar{r} = \sqrt{2}\ \frac{\int_o^r a^2 da}{\int_o^r a da} = \frac{(2)^{1.5}}{3} r \tag{6}$$

where the integrals represent the average straight line distance to the powerplant over the entire collection area. Substituting equation (6) and (5) into equation (4), one finds

$$\begin{aligned} C_t &= \frac{C_t^o}{3} (\varrho\pi)^{-0.5} (2Q_oS)^{1.5} \\ &= KS^{1.5} \end{aligned} \tag{7}$$

where K is defined by this equation.

Combining equations (1) through (3) and (7) results in a cost per unit output (e.g., cost per kilowatthour), which is proportional to

$$\overline{C} = \frac{C}{S} = C_c^o S^{-0.3} + C_f^o + K S^{0.5} \tag{8}$$

Taking the derivative of C with respect to S and setting it to zero (in order to find the minimum cost per kilowatthour) yields

$$S = \left(\frac{0.6C_c^o}{K}\right)^{1.25} \tag{9}$$

This represents the optimum size for the powerplant.

Evaluating the parameters for the base case given in appendix B results in:

$$S = 11.7\ \varrho^{0.625} \tag{10}$$

where ϱ is in dry tons per acre year, the base case corresponds to a 62-MW powerplant, and the transport costs are assumed to be $0.20/dry ton-mile ($0.10/green ton-mile).

As expected, the higher the density of biomass availability, e, the larger is the optimum-sized powerplant. Ironically, however, as ϱ increases, the average transport distance decreases. In other words, it is more economic to keep the powerplant size smaller than to transport large quantities of wood for greater distances.

If one assumes that $\varrho = 0.5$ dry ton/acre-yr, then the optimum powerplant size is over 500 MW and the radius of the collection circle is about 50 miles. With $\varrho = 0.05$ dry ton/acre-yr, the optimum size is 110 MW and the circle radius is 75 miles. If the transport charges double, then for these values of e, the optimum sizes are reduced to 200 and 50 MW, respectively, with collection radii of 30 and 50 miles, respectively,

In principle, then, large-scale biomass conversion facilities are not unrealistic. The values assumed for ϱ are probably less than what can be achieved in a region where the infrastructure for fuelwood harvests is fully developed. In practice, however, it is likely to be difficult to develop a mature harvest-supply infrastructure devoted to a single conversion facility. As the infrastructure is being developed, many small users are likely to compete for the fuelwood and the resultant availability to a single user may never reach the hundreds of thousands or millions of dry tons per year necessary for the larger facilities.

Clearly biomass farms dedicated to a single conversion facility would overcome these problems of obtaining a large feedstock source, It is unlikely, however, that these farms will be developed as described in the section on "Unconventional Biomass Production."

Appendix B.—Analysis of Break-Even Transport Distance for Pellitized Wood and Miscellaneous Cost Calculations

Two ways for producing 1 million Btu of steam from woodchips containing 50-percent moisture are presented in figure B-1. In the first case 389 lb of greenwood are transported to the boiler and burned directly; in the second 339 lb of greenwood are pelletized first and then transported to the boiler for burning.

In the first case the cost of the fuel needed to produce this steam is:

$$C = C_w W_w + C_t W_w d \qquad (1)$$

where C_w is the cost per ton of wood at a central yard, W_w is the weight of wood to be transported, C_t is the transport cost per ton-mile, and d is the distance from the yard to the boiler.

In the second case:

$$C = C_P W_P + C_t W_P d \qquad (2)$$

when C is the cost of the pellets at the pellet mill, W_P is the weight of pellets to be transported and the other symbols are as before (assuming the pellet mill is located at the wood yard).

Setting these two costs equal to one another and using the weights of wood and pellets as above, one finds that:

$$d = (0.65\ C_P - 1.65\ C_w) / C_t \qquad (3)$$

With transport costs of $0.10/ton mile and the wood and pellet costs given in the text, the break-even transport distance varies from 43 to 71 miles. If, however, the original wood is 40-percent moisture, only 324 lb are needed in the boiler (with the same efficiency) and the break-even transport distance becomes 123 to 134 miles. If the transport charges are lower, the break-even distance will increase. Conversely, where transport is more expensive, the break-even distance will be less. Numerous other local variables can also change the results.

Miscellaneous Cost Calculations

Following are estimates for the costs of various thermochemical conversion processes.

Figure B-1.-Two Ways to Produce 10^6 Btu Steam From Wood

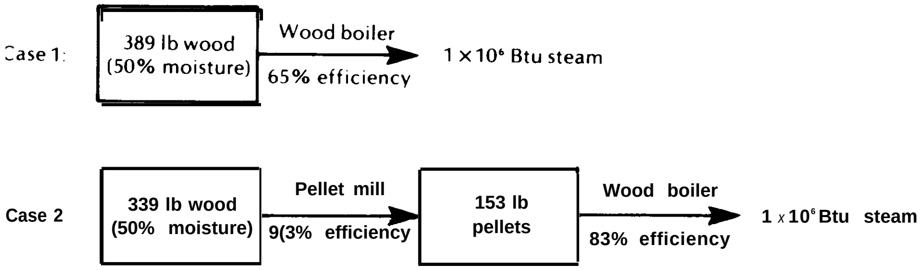

Table B-1 .-Electricity From Wood by Direct Combustion

Input	2,000 green ton/d of wood (50% moisture)	
output	62-MW electricity	
Load	300 operating days per year	
Fixed investment (field erected)	$50 million	
Working capital (10% of fixed Investment)	5 million	
Total Investment	$55 million	
	Mills/kWh	Million $/yr
Wood ($15/green ton)	20	9 0
Labor and water	9	4 0
Capital charges (15'%o of total Investment per year)	19	825
Total	48	213
Estimated range	45-70 mills/kWh	

SOURCE OTA from Steven R Beck, Department of Chemical Engineering, Texas Tech University, Lubbock, Tex , private communication, 1979

Table B-2.-Steam From Wood by Direct Combustion (package boiler)

Input:	270 green ton/d of wood (50% moisture)	
output,	50,000 lb[a] of steam/hr	
Load	330 operatin, days per year	
Fixed investment (package boiler)		$600,000
	$1,000 lb steam	
Wood ($1 5/green ton)		338
Labor ($75,000/yr)		019
Capital charges(15-30'%0 of fixed Investment per year)		O 23-0.46
Total		380-403
Estimated range:		$350-$6 00/ 1,000 lb steam ($2 'O-$4 80/10^6 Btu)

'1 ,000 lb of steam = 1 25 million Btu of steam

SOURCE OTA from *A Survey of Biomass Gas/f (car/on* (Golden, Colo Solar Energy Research Institute, July 1979)

Table B-3.–Electricity and Steam From Wood by Direct Combustion

Input	2,000 green ton/d of wood (50%. moisture)	
output	21.4-MW electricity and 390,000 lb steam[a]/hr	
Load	300 operating days per year	
Fixed Investment (field erected)		$40 million
Working capital (10% of fixed Investment)		4 million
Total Investment		$44 million
		Million $/yr
Wood ($15/green ton)		109
Labor and water		4
Capital charges (15’XO of total Investment per year)		66-132
Total		215-281
Product costs	Steam (assumed cost) $/1,000 lb	Electricity (derived) mills/kWh
	4	67-109
	5	48-91
	6	30-73

[a] 1 000 lb of steam = 1 25 million Btu of steam

SOURCE OTA from Steven R Beck Department of Chemical Engineering Texas Tech University Lubbock Tex private communication 1979

Table B-4.–Medium-Btu Gas From Wood in a Dual Fluidized-Bed Field Erected Gasifier

Input	2,000 green ton/d of wood (50%. moisture)	
output	460 10^6 Btu/hr medium-Btu gas	
Load	330 operating days per year	
Fixed investment (field erected)		$43 million
Working capital (10% of fixed Investment)		43 million
Total Investment		$473 million
		$ 10^6 Btu gas
Wood ($15/green ton)		326
Labor and water		O 82
Capital charges(15% of total Investment per year)		$195-$390
Total		$6.03-$7.98
Estimated range		$550-$9.00/10^6 Btu

SOURCE OTA from Steven R Beck Department of Chemical Engineering Texas Tech University Lubbock Tex private communication 1979

Table B-5.–Medium-Btu Gas From Manure in a Fluidized-Bed Gasifier

Input	1,000 dry tend of manure	
output	400 10’ Btu/hr medium-Btu gas	
Load	330 operating days per year	
Fixed investment (field erected)		$36 million
Working capital (10% of fixed Investment)		36 million
Total Investment		$396 million
		$/$10^6$Btu of gas
Manure ($3/dry ton)		031
Labor, water, chemicals, ash disposal, electricity		164
Capital charges (15Y0 of total Investment per year)		$188-$375
Total		$383-570
Estimated range		$350-$7 00/10’ Btu

SOURCE OTA from Steven R Beck Department of Chemical Engineering Texas Tech University Lubbock Tex private communication 1979

Table B-6.-Methanol From Wood Through Gasification in a Dual Fluidized-Bed Gasifier

Input,	2,000 green ton/d of wood (50%. moisture)	
output	3,150 bbl methanol/d (44 million gal/yr)	
Load	330 operating days per year	
Fixed Investment (field erected)		$64 million
Working capital (10% of fixed Investment)		64 million
Total Investment		$704 million
		$/bbl
Wood ($1 S/green ton)		952
Labor, water, and chemical		491
Capital charges (15-30~0 of total Investment per year)		10.16-2032
Total		$2459-$3475 ($0 58-$0 83/gal)
Estimated range		$22-$40/bbl ($0 52-$0 95/gal) ($8 20-14 96/$10^6$Btu)

SOURCE OTA from Steven R Beck, Department of Chemical Engineering, Texas Tech University Lubbock Tex private communication, 1979

Table B-7.-Pyrolysis Oil From Wood by Catalytic Direct Liquefaction

Input	2,000 green ton/d of wood (50%. moisture)	
output	2,500 bbl/d of pyrolytic oil (4 2 10^6Btu/bbl)	
Load	330 operating days per year	
Fixed Investment (field erected)		$50 million
Working capital (10% of fixed Investment)		5 million
Total Investment		$55 million
		$/bbl
Wood ($1 S/green ton)		1200
Labor, water, and chemicals		7.27
Capital charges (15-30% of total Investment per year)		1000-20.00
Total		$29.27-$39.37
Estimated range		$30-$50/bbl (.$7-$1 2/10^6Btu)

SOURCE OTA from Steven R Beck Department of Chemical Engineering, Texas Tech University Lubbock Tex private communication, 1979

Table B-8.-Ethanol From Wood via Gasification in a Dual Fluidized-Bed Gasifier

Input	2,000 green ton/d of wood (50% moisture)	
output	1,620 bbl/d of ethanol (assuming 14 wt. %. yield of ethylene from dry wood)	
Load.	330 operating days per year	
Fixed Investment (field erected)		$60 million
Working capital (10% of fixed Investment)		6 million
Total Investment		$66 million
		$/bbl
Wood ($15/green ton)		1827
Labor, water, chemicals, and electricity		1253
Capital charges (15-30% of total Investment per year)		1852-3704
Total		$49.32-$67.84 ($1 17-$1 62/gal) ($13.90-$19.20/10^6Btu)
With ethylene yield of 30 wt %		$23-$32/bbl ($0 55-$0 76/gal) (.%6 50-$9 00/$10^6$Btu)

SOURCE OTA from Steven R Beck Department of Chemical Engineering, Texas Tech University Lubbock Tex private communication 1979

Appendix C.—Survey of Gasifier Research, Development, and Manufacture

Organization	Gasifier type: Input	Gasifier type: Contact mode	Fuel products	Operating units	Size Btu/hr
Air gasification of biomass					
Alberta Industrial Dev. , Edmonton, Alb , Can	A	Fl	LEG	1	30 M
Applied Engineering Co , Orangeburge, S C 29115	A	u	LEG	1	5 M
Battelle-Northwest, Richland, Wash 99352. , .,	A	u	LEG	I-D	—
Century Research, Inc., Cardena, Calif. 90247	A	u	LEG	1	80 M
Davy Powergas, Inc., Houston, Tex. 77036	A	u	LEG-Syngas	20	—
Deere & Co., Moline, Ill. 61265	A	D	LEG	1	100kw
Eco-Research Ltd. , Willodale, Ont. N2N 558	A	Fl	LEG	1	16 M
Forest Fuels, Inc., Keene, N H 03431.	A	u	LEG	4	15-3.0 M
Foster Wheeler Energy Corp., Livingston, N H 07309	A	u	LEG	1	—
Fuel Conversion Project, Yuba City, Calif. 95991	A	D	LEG	1	2 M
Halcyon Assoc. Inc., East Andover, N.Y. 03231	A	u	LEG	4	6-50 M
Industrial Development & Procurement, Inc., Carie Place, N.Y. 11514 ., .,	A	D	LEG	Many	100-750 k W
Pulp & Paper Research Inst.,[b]Pointe Claire, Quebec H9R 3J9	A	D	LEG	—	—
Agricultural Engr. Dept., Purdue University, W. Lafayette, Ind. 47907	A	D	LEG	1	O 25 M
Dept. of Chem. Engr., Texas Tech University, Lubbock, Tex. 79409.	A	Fl	LEG	1	0.4M
Dept. of Chem. Engr., Texas Tech University, Lubbock, Tex, 79409	A	u	LEG	1	—
Vermont Wood Energy Corp., Stowe, Vt. 05672	A	D	LEG	1	008 M
Dept. of Ag. Engr., Univ. of Calif., Davis, Calif. 95616 .,	A	D	LEG	1	64,000
Dept. of Ag. Engr., Univ. of Calif., Davis, Calif. 95616	A	D	LEG	1	6 M
Westwood Polygas (Moore)	A	u	LEG	1	
Bio-Solar Researc & Development Corp., Eugene, Oreg. 97401 .,	A	u	LEG	1	—
Oxygen gasification of biomass					
Environmental En Eng., Morgantown, W V	O	D	MEG	1P	0 5
IGT-Renugas	0, s	Fl	MEG		
Pyrolysis gasification of biomass					
Wright-Malta, Ballston Spa, N.Y.[c]	PG	O	MEG (C)	1 R, 1 P	4
Coors/U. of MO.	P	Fl		1P	
U. of Arkansas	P	o	MEG (C)	1R	
A & G Corp., Jonesboro, Ark, ., ...	P	0	MEG (C)	1C	
ERCO, Cambridge, Mass,	P	Fl	PO,C	1P, (1C)	16, (20)
EN ERCO, Langham, Pa.	P		MEG, PO, C	1P, 1 c	
Garrett Energy Research ...	MH		MEG	1P	
Tech Air Corp., Atlanta, Ga. 30341. ...	P	u	MEG, PO, C	4P, 1C	33
M. Antal, Princeton Univ., NS ., .,	PG	o	MEG, C	1R	—
M Rensfeit, Sweden .	PG	0	MEG, C	1R	
Texas Tech, Lubbock, Tex..	PG	Fl	MEG	1P	
Battelle-Columbus, Columbus, Ohio					
Air gasification solid muncipal waste (SMW)					
Andco-Torrax,[a] Buffalo, N. Y.. . . . ., ...	A	u	LEG	4C	100 M
Battelle-Northwest, Richland, Wash. 99352,					

Table Notation (by columns)

Input	A = air gasifier; O = *oxygen* gasifier; P = pyrolysis process, PC = pyrolysis gasifier; S = steam, C = char combustion
Contact mode	U = updraft, D = downdraft, O = other (sloping bed, moving grate), Fl = fluidized bed, S = suspended flow, MS = molten salt, MH = multiple hearth
Fuel products	LEG = low energy gas (-150-200 Btu/SCF) produced in air gasification; MEG = medium energy gas produced in oxygen and pyrolysis gasification (350500 Btu/SCF; PO = pyrolysis 011, typically 12,000 Btu/lb; C = char, typically 12,(x)0 Btu/lb
Operating units	R = research, P = pilot, C = commercial size, Cl = commercial Installation, D = demonstration
Size	Gasifiers are rated m a variety of units Listed here are Btu/h derived from feedstock throughput on the basis of biomass containing 16 MBtu/ton or 8,000 Btu/lb, SMW with 9 MBtu/ton ( ) indicate planned or under construction

[a] Unless noted otherwise, the gasifiers listed here produce dry ash (T > 1,100” C) and operate at 1 atm pressure (Coal gasifiers and future biomass gasifiers may operate at much higher pressures)

[b] Operates at 1-3 atm pressure

[c] Operates at 10 atm pressure

[d] These gasifiers produce slagging (T > 1,300° C) instead of dry ash

SOURCE *A Survey of Biomass Gas/f ication* (Golden, Colo Solar Energy Research Institute, July 1979)

Organization	Gasifier type Input	 Contact mode	Fuel products	Operating units	Size Btu/hr
Oxygen gasification of SMW					
Union Carbide (Linde), Tonowanda, N.Y.[d]	O	u	MEG	1	100 M
Catorican, Murray Hills, NS	O	u			9 M
Pyrolysis gasification of SMW					
Monsanto, Landgard, Enviro-chem	P, c	K	LEG, O, C	I D	20 (375)
Envirotech, Concord, Calif.	P	MH	LEG	1P	
Occidental Res. Corp., El Cajon, Calif.	P	Fl	PO, C, MEG	1C	
Garrett En. Res. & Eng., Hanford, Calif.	P	MH	MEG	1P	
Michigan Tech., Houghton, Mich.	P	ML	MEG		
U. of W. Va. -Wheelebrator, Morgantown, W. Va.	P, G, c	Fl	MEG	1P	
Pyrex, Japan	P, c, c	Fl	MEG	1C	
Nichols Engineering	P		MEG, C		
ERCO, Cambridge, Mass	P	Fl	MEG	1P	16
Rockwell International, Canoga Park, Calif.	P	MS	MEG, C	1P	16
M.J. Antal, Princeton, NS	P	o	MEG, C	2R	—

Table Notation (by columns)

Input A = air gasifier; O = oxygen gasifier; P = pyrolysis process, PG = pyrolysis gasifier; S = steam, C = char combustion

Contact mode U = updraft, D = downdraft O = other (sloping bed, moving grate), Fl = fluidized bed, S = suspended flow, MS = molten salt; MH = multiple hearth

Fuel products LEG = low energy gas (-150-200 Btu/SCF) produced in air gasification; MEG = medium energy gas produced in oxygen and pyrolysis gasification (350-500 Btu/SCF; PO = pyrolysis oil, typically 12,000 Btu lb, C = char, typically 12,000 Btu/lb

Operating units R = research, P = pilot, C = commercial size C I = commercial installation; D = demonstration

Size Gasifiers are rated in a variety of units listed here are Btu h derived from feedstock throughput on the basis of biomass containing 16 MBtu ton or 8,000 Btu, lb, SMW with 9 MBtu ton ( ) indic ate planned or under construction

[a] Unless noted otherwise, the gasifiers listed here produce dry ash [T 1 1 ()()0 C) and operate at 1 atm pressure (Coal gasifiers and future biomass gasifiers may operate at muc h