DEVELOPMENT OF BIOMASS GASIFICATION SYSTEMS FOR GAS TURBINE POWER GENERATION

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ABSTRACT

Gas turbines are of interest for biomass applications because, unlike steam turbines, they have relatively high efficiencies and low unit capital costs in the small sizes appropriate for biomass installations. Gasification is a simple and efficient way to make biomass usable in gas turbines. We evaluate here the technical requirements for gas turbine power generation with biomass gas and the status of pressurized biomass gasification and hot gas cleanup systems. We also discuss the economics of gasifier-gas turbine cycles and make some comparisons with competing technologies. Our analysis indicates that biomass gasifiers fueling advanced gas turbines are promising for cost-competitive cogeneration and central station power generation. Gasifier-gas turbine systems are not available commercially, but could probably be developed in 3 to 5 years. Extensive past work related to coal gasification and pressurized combustion of solid fuels for gas turbines would be relevant in this effort, as would work on pressurized biomass gasification for methanol synthesis. Companion papers presented at this conference discuss applications of gasifier gas-turbine cogeneration in the cane sugar industry, where cane residues would be used for fuel, and for large-scale power generation in Sweden, where significant amounts of new electricity supply will be needed before 2010 as existing nuclear generating capacity is phased out.

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INTRODUCTION

Increasing the thermodynamic efficiency of the conversion and end-use of biomass is important if biomass is to play a larger role than at present in the global energy balance, because the low efficiency of photosynthesis will ultimately lead to land use constraints on the level of bioenergy use. Biomass is widely used in developing countries today, but it is used very inefficiently, primarily for cooking. In some industrialized countries it accounts for a measurable portion of primary energy supply, but in these regions it is predominantly converted into heat or steam, not higher quality electricity.

Thermochemical gasification is one of the simplest and most energy-efficient means for upgrading biomass into an energy carrier that can be used very efficiently in a wide range of applications. Biomass gasification has been used with varying degrees of success with industrial furnaces and boilers, internal combustion engine-generators, and methanol synthesis plants. While gasification is conceptually simple, practical systems must be tailored to the end-use of the gas. This paper considers biomass gasification for electric power generation using gas turbines.

Gas turbines are increasingly playing larger roles in power generation as a result of recent advances that make the technology much more efficient and less capital intensive than traditional steam turbine technologies (42). The idea of biomass-gasifier/gas turbine power generation has received little attention in the past, although there is considerable interest and ongoing development work in coal gasification for gas turbines (27,28,42). In principal, gas turbines are well-suited for biomass applications because of their relatively high efficiency and low capital cost in the small sizes--1 to 100 MW_e-- required for biomass facilities by cost constraints on fuel transport. Steam-injected gas turbines are of particular interest (18).

To better understand the prospects and timeframe for commercialization of biomass-gasifier/gas turbine systems, we evaluate here the technical requirements and status of biomass gasification and hot gas cleanup for gas turbines and discuss the economics of biomass-gasifer/gas turbine power generation. Two companion papers are also presented at this conference. One discusses applications of biomass-gasifier/gas-turbine systems in the cane sugar industry, where residues from the grinding of the sugarcane are used as fuel (19). The other (38) discusses potential applications for power generation in Sweden, where a $155 million, 5-10 year program was launched by the Swedish State Power Board in August of 1989 to develop technologies that would provide the option of making biomass a major fuel source for electric power generation in that country.

GAS TURBINE SYSTEMS FOR BIOMASS-GAS APPLICATIONS

In a biomass-gasifier gas turbine system, the feedstock would be gasified in a pressurized air-blown reactor and the products cleaned of contaminants at elevated temperature before being burned in the gas turbine combustor. Hot gas cleanup is required to avoid cost and efficiency penalties that would reduce economic attractiveness. Pressurized gasification is required to avoid losses associated with compressing the fuel gas after gasification. Air gasification is

dictated by the high cost of oxygen plants at the small scale required for biomass installations.

Candidate gas turbine systems that could be coupled to a gasification system include the simple-cycle gas turbine, steam-injected gas turbine (STIG), gas-turbine/steam-turbine combined cycle, intercooled steam-injected gas turbine (ISTIG), and others. Of these, the combined cycle is the least likely to be of interest with biomass, because a relatively large size (> 200 MW_e) plant is required to capture the scale economies associated with the steam turbine bottoming cycle. Most biomass facilities would be far smaller than this. The most interesting of the cycles are the STIG and ISTIG, both of which are discussed later in this paper. The STIG is commercially available for natural gas firing in cogeneration and central-station power generation. The natural gas-fired ISTIG requires a 4-5 year development effort to commercialize (42). One possible layout of a biomass integrated-gasifier/steam-injected gas turbine (BIG/STIG) cycle is shown in Fig. 1.

GASIFIER DESIGN AND EDEVELOPMENTAL STATUS FOR GAS TURBINES

Gasification of biomass has been successfully used previously in a variety of applications, including production of industrial process heat, internal combustion (IC) engines, and methanol synthesis. The technical specifications for gas derived from biomass are quite different for gas turbine applications than for these end-uses, however, so a gasification development effort focussed on gas turbine applications is needed. With gas

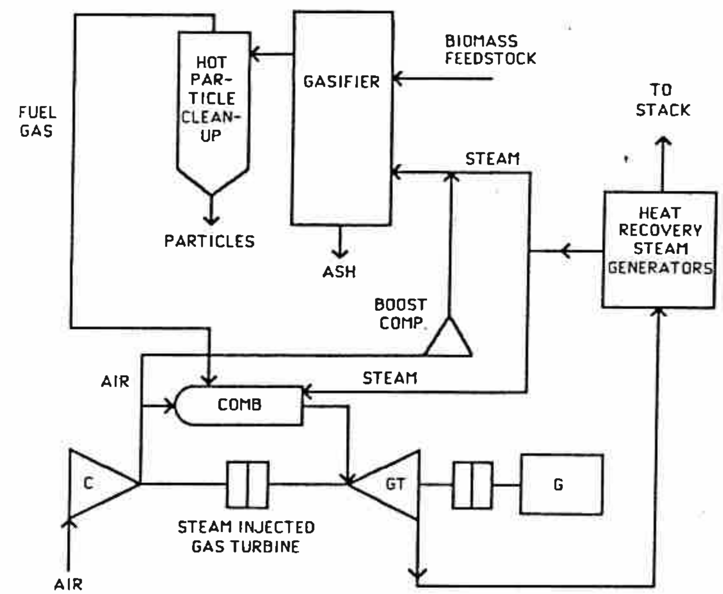

Fig. 1. One possible configuration of a biomass integrated-gasifier/steam-injected gas turbine (BIG/STIG) cycle, which includes a pressurized gasifier, hot-gas cleanup, and a steam-injected gas turbine.

turbines, particulate cleanup requirements would be much stricter than for heating applications and comparable to those for IC engines and methanol synthesis. However, with hot gas cleanup, neither gas cooling nor tar removal would be required, as for IC engine and methanol synthesis applications. Furthermore, there would be no strict requirements on gas composition (unlike methanol synthesis), providing fuel flammability limits are met and the heating value of the fuel is above 4 MJ/Nm^3.

There have been no previous significant development efforts focussed on biomass gasification for gas turbine applications. However, considerable efforts have been devoted to coal gasification for gas turbines in the USA, West Germany, and elsewhere (27,28,42). While much of the coal work is also relevant for biomass, key differences between coal and biomass necessitate a focussed development effort on biomass. Biomass has a higher volatile content (75-85% versus 30-40%), making it much easier to gasify (17): complete carbon conversion to gas is typically achieved, unlike the case with coal. Biomass is typically less dense, which affects handling, feeding, and gasification. And it contains little or no sulfur, which eliminates the need for the development of hot sulfur removal technology, the commercial viability of which is a major uncertainty hindering the development of efficient coal-gasifier/gas turbine systems.

Gasifier designs that are of potential interest for biomass-gas turbine applications include the fixed-bed updraft gasifier and the fluidized-bed gasifier.

Fixed-bed gasifiers

In a fixed-bed updraft gasifier, combustion of biomass char occurs on a grate near the bottom of the reactor, where air is injected (Fig. 2a). Temperatures are highest at this point in the reactor (1000-1200°C), where steam is also injected to keep ash from melting. The combustion product gases cool as they travel up through the fuel bed. The fuel is pyrolyzed as it travels in counterflow to the gas, arriving as char at the grate.

The product gas would be extracted from the reactor at 500-600°C to insure that its large tar/oil component is in vapor form. With hot gas cleanup and "close-coupling" of the gasifier and gas turbine combustor, tars and oils, which condense between 150 and 500°C (2), would not have an opportunity to condense, thus avoiding potential problems associated with tar condensation. Close-coupled arrangements have been incorporated into designs for advanced coal-gasifier gas turbine systems (3,7).

The gas exits from a fixed-bed gasifier with relatively low particulate concentrations because of low exit velocities and the filtering effect of the fuel bed. Hot gas efficiency,[1] the efficiency measure of interest for close-coupled gasifier-gas turbine cycles, is typically high (90-95%) because of the high peak temperatures, the volatility of biomass, and the efficient (counter-current) heat transfer from the gas to the fuel bed.

Feedstock considerations. For fixed-bed gasifiers, relatively large, dense, and uniformly-sized feedstocks are preferable to help prevent bridging, reduce feed losses, and reduce carryover (Table 1). Some designs have rotating agitators to assist the fuel flow. Feedstocks with as high as 50% mc (moisture content)[2] can be gasified, but the minimum acceptable gas heating value for gas turbines--about 4 MJ/Nm^3 (7)--sets an upper limit of about 30% on the acceptable feedstock moisture content. This will usually mean some pre-drying of the fuel would be needed. Most agricultural residues would also require some densification.

[1] Hot gas efficiency is defined as the chemical plus sensible energy in the raw gas divided by the total energy input (chemical plus sensible) to the gasifier.

[2] Moisture contents are given on a wet basis in this paper.

Fluidized-bed gasifiers

In a fluidized-bed gasifier, the feedstock is "fluidized" with an inert heat-distributing material, e.g. sand, by air injected from below. The bubbling bed (Fig. 2b) was the first fluidized-bed design developed. The circulating fluidized bed (CFB) (Fig. 2b, lower) has been developed more recently. Control of air injection rates and excellent mixing in

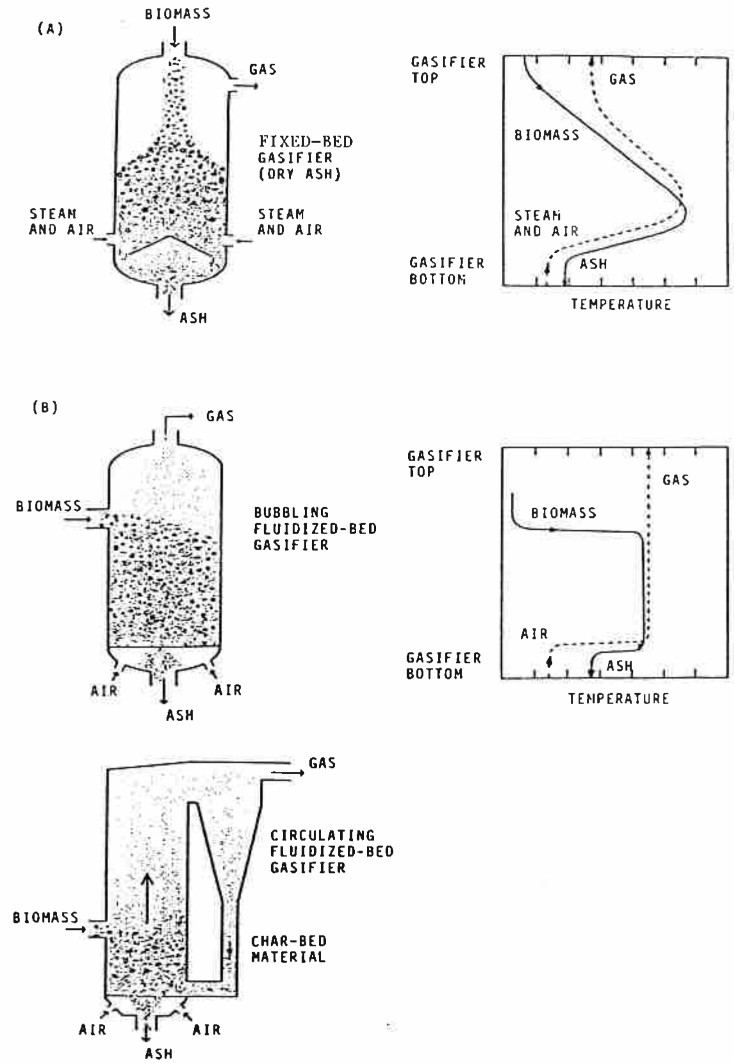

Fig. 2. Operating principles and temperature profiles for (a) fixed-bed and (b) bubbling fluidized-bed gasifiers. Also shown is a circulating fluidized-bed (CFB) gasifier.

Table 1. Required biomass feedstock characteristics for alternative gasifier designs and properties of actual biomass feedstocks.(a)

GASIFIER FEEDSTOCK REQUIREMENTS	Fixed-bed	Fluidized-bed	
	Updraft	Bubbling	Circulating
Length (mm)	13-75	0-50	0-100
Max. thickness (mm)	6-13	0-3	0-50
Size variability	small	large	larger
Moisture (wt%) (b)	< 30%	< 30%	< 30%
Bulk density (kg/m^3)	> 240	(c)	(c)

ACTUAL FEEDSTOCK PROPERTIES	Length (mm)	Thickness (mm)	Bulk density(d) (kg/m^3)
Wood chips			
Hardwood	16-22	1.5-3	280-480
Softwood	16-22	3-6	200-340
Sawmill residues	max. size < 50 mm		290-400
Biomass pellets	6-19	6-19 (diam.)	610
Non-woody biomass			
Pits (cherry, olive, etc.)			360
Straw (baled)			160-300
Bagasse			160
Rice hulls			130
Shells (walnut, coconut, etc.)			64

(a) From (17).

(b) Fuel moisture level to produce raw gas of suitable quality for gas turbines. The moisture level at which gasification can be sustained is about 50%.

(c) The minimum acceptable bulk density for stable operation of fluid beds is much lower than for fixed beds. Fuel handling and feeding considerations are likely to set the lower limit.

(d) Bulk densities vary with moisture content. For wood chips, the range given here is for 15 to 50% mc. Bulk densities for mill wastes (hog fuels) vary widely. The indicated range is for 50% mc samples. Pellets and non-woody biomass have 10-15% mc, except the figure for bagasse, which is for 50% mc. The baled straw range is for standard and "double compressed" bales.

fluidized-bed gasifiers leads to uniform temperatures throughout the bed (Fig. 2b) and faster reactions than in fixed beds. Fuel throughput capabilities per unit volume are, therefore, much higher for fluidized-beds than for fixed-beds, leading to lower unit costs for fluid-bed reactors. Peak reaction temperatures are relatively low (700-800°C), which prevents ash melting with little or no need for the cooling steam required with a fixed-bed. Higher average temperatures than in a fixed-bed (Fig. 2) contribute to less production of tars and oils. Hot gas efficiency is comparable to that for a fixed-bed. Particulate loading in the raw gas is one to two orders of magnitude greater.

Feedstock considerations. The fundamentally different operating principle of fluidized-bed gasifiers leads to distinctly different feedstock requirements compared to those for fixed-beds. Since most biomass feedstocks are similar in chemical composition (17), differences in feedstock specifications relate primarily to physical characteristics. Fluidized-bed gasifiers can accept much smaller, less dense, and less uniformly-sized feedstocks than fixed-beds (Table 1). The minimum acceptable bulk density for fluid beds is much lower than for fixed-beds, though is not well established (23). Requirements for fuel handling and feeding will most likely set the lower limit. Fuel moisture considerations are the same as those for fixed-beds. The range of acceptable feedstock characteristics is greater with circulating fluidized beds than with bubbling beds (Table 1). Most of the feedstocks listed

in Table 1, including minimally processed agricultural residues, would probably be acceptable fuels after drying.

Status of gasifier technologies

The major research, development, demonstration, and commercial activities worldwide relating to pressurized biomass gasification are summarized in Table 2. The table also describes three particularly noteworthy commercialized atmospheric-pressure gasifiers.

Because of their simplicity and high efficiency updraft gasifiers are widely used commercially with both coal (pressurized and unpressurized units) and biomass (atmospheric-pressure units). The pressurized Lurgi dry-ash gasifier has the longest commercial operating experience (dating to the 1930s) of any pressurized gasifier with coal and has been considered for coal-gasifier STIG and ISTIG systems (7). The Lurgi-type gasifier also appears to be a good candidate for biomass applications. Successful, but limited, pilot-scale testing of a pressurized Lurgi-type unit has been carried out by the General Electric Company (GE) using biomass pellets (10) and RDF/coal briquettes (35) (Table 2). More extensive testing is required to fully demonstrate the feasibility of fixed-bed biomass gasification for gas turbine applications.

Fluidized-beds also appear to be good candidates for gas turbine applications. A planned major coal-gasifier gas turbine demonstration project in the United States was to utilize a KRW fluidized-bed gasifier (3), and a similar project for the city of Berlin that would utilize a circulating fluidized-bed gasifier is under study by the Lurgi Corporation (12). A 25-bar, coal-fueled Rheinbraun-Uhde HTW pilot plant for gas turbine applications was scheduled for start up in West Germany in late 1989 (16). Development of fluid-beds for biomass-gas turbines could build on such efforts and on the extensive previous development efforts on large-scale pressurized biomass gasification for methanol synthesis (17). Of the units described in Table 2, the most extensive development and testing has been done with the Rheinbraun/Uhde HTW, Biosyn, IGT and MINO units. Of these, only the Rheinbraun/Uhde unit has significant commercial operating experience: a 13.5-bar, peat-fueled unit began commercial operation in May 1988 at an ammonia production plant in Finland.

Also noteworthy is the commercial availability of three atmospheric-pressure CFB gasifiers (Table 2). One manufacturer of CFB gasifiers, Ahlstrom, has recently started up a 10 MW_{fuel} pressurized CFB combustor to demonstrate the feasibility of CFB combustion plus hot-gas cleanup for direct firing of gas turbines with solid fuels (1,15). Since CFB gasifiers are similar to CFB combustors in many respects, if this demonstration is successful, it would be an important step toward development of a CFB gasifier/gas cleanup system for gas turbines.

PROSPECTS FOR COMMERCIAL DEVELOPMENT OF BIG/STIG TECHNOLOGY

Because much of the previous coal and biomass-related hardware development efforts are also relevant to biomass gasifier-gas turbine systems, the near term development of the latter type of systems for commercial applications is a distinct possibility. In fact, only a relatively modest development-demonstration effort would probably be sufficient to resolve technical and economic unknowns. The most important of these relate to hot gas cleanup, expected capital costs, and expected overall cycle efficiency.

Hot gas cleanup

Cleaning of raw gas from the gasifier would be required to avoid damage to turbine blades and to meet emissions regulations in many countries. Pilot-scale testing with biomass feedstocks would be needed to determine the levels of cleanup required and appropriate cleanup technologies. The most effective cleaning systems would involve cold wet scrubbing, but this adds cost and complexity to a plant and reduces efficiency. Thus, the focus in this paper is on hot gas cleanup. A limited amount of work has already been done on pressurized hot cleanup of biomass gas, for methanol production (34) and for direct firing of gas turbines using pressurized combustion (40). Extensive work has been done on hot cleanup for coal-gasifier gas-turbines (4,5,8,25) and for directly-fired gas turbines using

Table 2. Gasifiers that have operated with biomass feedstocks.(a)

	Status(b)	*Capacity (t/h)*	*Pressure (bars)*	*Blast* (b)	*Tested feedstocks*
PRESSURIZED FIXED-BED					
Lurgi-type (USA)	P(c)	2	21	A/S	Wood pellets, RDF briquettes
Syn-Gas Downdraft (USA)	P	2	10	A,O	Wood chips, wood pellets, corn cobs, peat pellets
Wright-Malta Kiln (USA)	P	0.2	21	S	Wood chips, municipal solid waste
PRESSURIZED FLUIDIZED-BED					
Rheinbraun -Uhde HTW (FRG)	D C	3 27	10 13.5	A/S O/S	Wood chips, peat Peat
ASCAB (France)	D	5	25	O/S	Wood chips
Biosyn (Canada)	C D	6 10	8 14	A A,O	Wood chips Bark, sawdust, wood pellets
IGT Renugas (USA)	P	1	34	A/S, O/S	Wood chips, corn stover, pulp mill wastes
MINO (Sweden)	P	0.5	28	O/S	Wood chips, peat, lignite
Tech. Res. Center (Finland)	L	0.09	10	A	Peat pellets
COMMERCIAL ATMOSPHERIC-PRESSURE FLUIDIZED-BED					
Lurgi CFB (FRG)	C	16	1	A	Bark, wood wastes
Gotaverken CFB (Sweden)	C	8	1	A	Bark, sawdust, wood wastes
Ahlstrom CFB (Finland)	C	8	1	A	Wood waste, peat

(a) See (17) for additional details.

(b) C = commercial, D = demonstration, P = pilot, L = laboratory, A = air, O = oxygen, S = steam.

(c) Large-scale pressurized Lurgi gasifiers for coal have been in commercial operation since the 1930s. Only pilot-scale testing has been done with biomass, however.

pressurized-fluidized-bed combustors (PFBC) (15,43). Much of the coal-based work is relevant for biomass, but cleaning biomass gases is simpler, since most biomass gas does not require sulfur removal.

Alkalai compounds. Alkalai compounds in biomass gas form primarily from potassium and sodium in the feedstock. They are of concern because they can accelerate hot corrosion and cause cementing of particulate deposits on turbine blades (32). The limit for alkalais in coal-derived fuel gas for a gas turbine has been given as 0.1 to 0.2 ppm by weight (14,32). Limits for biomass-derived gas are probably similarly stringent.

Because of the relatively recent interest in hot-gas cleanup for gas turbines and the difficulty of measuring hot-gas alkalai concentrations, the extent of alkalai production and required removal are not well understood. Some work has been done with coal. None has been done with biomass.

Based on the coal-related work, it appears that the gasifier exit temperature plays a key role in determining whether alkalai compounds would be in the condensed or vapor phase. Vapor-phase removal would be considerably more difficult than condensed-phase removal. Thermodynamic calculations suggest that for pressurized coal gasification at 800-900°C--the upper end of the temperature range for fluidized-bed biomass gasification--raw-gas concentrations of alkalai would be well in excess of gas turbine limits and largely in vapor form (24,32). At temperatures in the range of 500-650°C, however, alkalai compounds appear as a condensed phase on entrained particulates, so that acceptable alkalai concentrations can be achieved in the fuel gas by particulate cleanup at these temperatures (7,13,25). This lower temperature range corresponds to the outlet temperatures of fixed-bed gasifiers. With fluidized-bed gasifiers, some cooling of the gas would be required, which would probably result in a slight loss of efficiency.[3]

Because no work has been done looking at alkalai concentrations in biomass-gas, this area should receive careful attention in the development of gasification systems for gas turbines.

Particulates. Particulate cleanup would also require attention in a gasifier development effort. Estimated permissible particulate loadings for gas turbines vary widely (Table 3), as do particle size distributions. Table 3 gives one size distribution specification developed by General Electric (GE) in the 1970s. More recently, the Electric Power Research Institute (EPRI) has proposed a specification which takes account of the greater damage done by larger particles (22):

Particle size (micron)	>20	10-20	4-10
Maximum ppm (weight)	0.1	1	10

The size and quantity of particulates would vary substantially with the type of biomass feedstock and design of gasifer, but some particulate cleanup would be required in any case. The relatively little published data available on particulates from biomass gasifiers indicates that updraft units produce two orders of magnitude less particulate matter than fluidized-beds, but also much smaller particles (Table 3).

Cyclones or barrier filters are usually considered for hot particulate removal. Cyclones are commercially proven and relatively inexpensive. In pilot-scale tests using GE's pressurized Lurgi-type fixed-bed gasifier cyclones provided adequate cleanup of coal-derived gas to meet the GE specification shown in Table 3 (Fig. 3). The data in Table 3 on fixed-bed (atmospheric-pressure) biomass gasification (2) indicate production of a larger fraction of submicron particles than with coal gasification, suggesting that the GE specification could

[3] The efficiency loss could be minimized if heat is recovered as steam for use elsewhere in the system, e.g., for gasifier bed cooling, for injection into the gas turbine, or for process use in a cogeneration system.

Table 3. Particle loadings and size distributions from updraft and fluidized-bed biomass and coal gasifiers and specifications for gas turbine operation. (a)

	Particulates in raw fuel gas			Suggested turbine inlet requirements
	Biomass(b) *Updraft*	*Biomass*(b) *Fluid-bed*	*Coal*(c) *Updraft*	
Loading (*g/Nm*^{3})(d)	0.1 - 1	10 - 100	0.5 - 0.94	0.002 - 0.02(e) 0.1 - 0.2(f)
Distribution (wt% less than)				
500 microns			98	
250			82	
100			50	
50		99	13	
30		97	10	
20	99+	87	9	98(g)
10	97	38	8	83
5	96	17	3	45
2	95	2	2+	7
1	89		2	0.3
0.5	81			

(a) The particulates in the raw fuel gas are at the gasifier exit, while the gas turbine specifications are for the gas entering the turbine expander, i.e., after combustion and dilution with cooling air. Cooling air would dilute the fuel gas particulate concentration by about a factor of six.

(b) From (2) for atmospheric pressure gasification.

(c) The updraft results are based on operation of a pilot-scale pressurized Lurgi-type gasifier (14). Data for fluidized-bed coal gasification were not found in the literature.

(d) 1 g/Nm^3 is approximately 1000 ppm by weight.

(e) From (2).

(f) From (11).

(g) The size distribution is from (8) and was developed by General Electric in the late 1970s as part of a US Department of Energy supported program in pressurized fluidized-bed coal combustion for locomotive gas turbine applications.

not be met using cyclones in this case. However, cyclones may be sufficient to meet the EPRI specification given above. Testing with a pressurized fixed-bed biomass gasifier is needed to determine whether cyclones would provide adequate particulate removal. Such testing could be undertaken in the GE gasifier or a comparable existing facility.

The larger number of particles from fluidized-bed biomass gasifiers would probably require the use of more efficient particle removal technology. Barrier filters provide more complete filtration than cyclones, but have not yet been commercially proven for gas turbines. For coal-gas cleanup, the emphasis has been on silicon-carbide candle filters (30), which would also work with biomass. Sintered metal-alloy filters also appear promising for biomass (34). The key technical issues to resolve in a demonstration effort would be the ability of such filters to withstand thermal and mechanical shock and to maintain effective seals in gas turbine systems. A demonstration project using ceramic candle-type filters in Finland is addressing these issues, among others (15).

Nitrogen Oxides. Nitrogen oxides (NO_x) can be produced in a gas turbine combustor from nitrogen originating in the fuel (fuel-bound NO_x--$FBNO_x$) or by dissociation of the nitrogen in the combustion air (thermal NO_x). The peak combustion temperatures of coal or biomass-gas are relatively low because of their low heating value, so that thermal NO_x levels would be relatively low (14). In any case, thermal NO_x can be controlled to a large

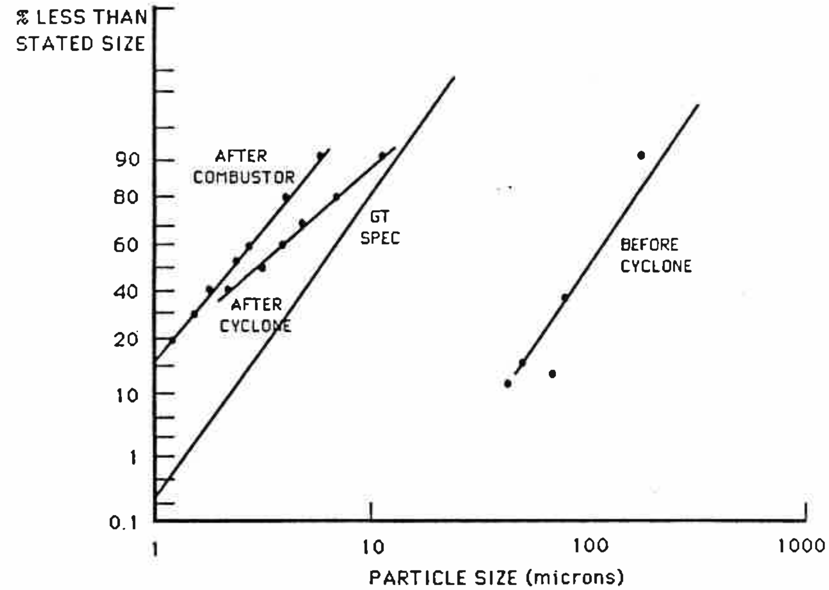

Fig. 3. Measured particulate size distribution in tests with pilot-scale fixed-bed coal gasification (8). The data are for the raw gas at the gasifier exit, after the cyclone, and after a simulated gas turbine combustor. They are compared to a set of recommended gas turbine specifications (see Table 3, note g).

extent by the use of low-NO_x combustion technologies, of which steam-injection is the least costly and most widely used today. As NO_x regulations tighten in the future, the development of dry low-NO_x combustors is anticipated using staged or catalytic combustion (33).

$FBNO_x$ is produced primarily from ammonia which forms during gasification. In the gas-turbine combustion of gas derived from bituminous coal, $FBNO_x$ has been estimated to be produced at a rate of about 0.3 grams per MJ of fuel burned (14). $FBNO_x$ from the combustion of biomass gas has been measured to be significantly less than this (20), which would be consistent with the lower fraction of nitrogen in most biomass compared to coal (17). With either coal or biomass, however, the $FBNO_x$ levels would probably exceed most emissions regulations, and would therefore need to be reduced. Staged or catalytic combustion technologies are under development to limit $FBNO_x$ in coal-gasifier gas turbine systems (25,39). In addition, selective catalytic reduction (SCR) techniques, although not ideal because of added cost, can also be used. In any case, NO_x reduction with biomass might be simpler because of the lower fuel-bound nitrogen levels.

Capital Costs

A detailed engineering/cost study, followed by a commercial-scale (20-MW) demonstration would be required to accurately determine the captial cost of biomass gasifier-gas turbine systems. However, estimates of likely capital costs can be obtained from detailed engineering/cost studies of coal gasifier-gas turbine systems. Table 4 gives capital cost estimates for a 100-MW coal integrated-gasifier/steam-injected gas turbine

Table 4. Capital cost estimates (1987 $/kW$_e$) for coal-gasifier STIG and ISTIG power plants based on General Electric LM-5000 gas turbines and either Lurgi fixed-bed or KRW fluidized-bed gasifiers.(a)

	Lurgi/STIG(b)	*Lurgi/ISTIG*(b)	*KRW/ISTIG*(c)
Coal handling/preparation	41.5	38.4	
Blast air system	14.0	10.1	
Gasification plant	168.5	87.0	
Raw gas physical cleanup	9.1	8.0	
Raw gas chemical cleanup	183.3	158.0	
Gas turbine/HRSG	308.3	268.5	
Balance of plant			
Mechanical	42.0	34.6	
Electrical	68.1	50.7	
Civil	68.6	63.6	
SUBTOTAL, PROCESS CAPITAL	**903.4**	**718.9**	**698**
Engineering home office	90.2	71.9	
Process contingency	56.0	44.4	
Project contingency	157.4	125.2	
SUBTOTAL, PLANT COST	**1207.6**	**960.4**	**932**
AFDC cost(d)	21.8	17.3	
SUBTOTAL, PLANT INVESTMENT	**1229.4**	**977.7**	**949**
Preproduction costs	33.7	27.5	
Inventory capital	32.8	27.7	
Initial chemicals	2.6	2.4	
Land	1.5	1.4	
TOTAL CAPITAL REQUIREMENT	**1300.0**	**1036.7**	**1007**

(a) The United States' gross national product deflator has been used to convert all costs to mid-1987 dollars. All cost estimates shown here were prepared using consistent costing procedures developed by the Electric Power Research Institute (29).

(b) The Lurgi/STIG and Lurgi/ISTIG plant sizes are 2x50-MW$_e$ and 1x109-MW$_e$ capacity, respectively. Each involves use of a single gasifier. From (7).

(c) The KRW/ISTIG cost was developed for a nominal 100-MW$_e$ unit using the ISTIG and a single KRW gasifier (26). A more detailed cost breakdown was not publically available at the time of this writing. See also (25).

(d) AFDC is allowance for funds during construction.

(CIG/STIG) of $1300/kW and a 109-MW CIG/ISTIG of $1040/kW, both of which would use fixed-bed Lurgi-type gasifiers, cyclones for hot particulate removal, and hot sulfur-removal systems. A 100-MW coal-fired fluidized-bed gasifier-ISTIG, based on a KRW gasifier with in-bed sulfur removal and ceramic candle filters for particulate cleanup, has been estimated to have roughly the same installed cost as the fixed-bed ISTIG--$1010/kW (Table 4).

With biomass, sulfur removal would not be required, which would eliminate 15-20% of the capital cost from that for a fixed-bed coal system. Also, the greater ease with which biomass can be gasified means less harsh reactor conditions are required than with coal, which would further reduce costs. Thus, for a 53-MW fixed-bed BIG/STIG, the installed capital cost would probably be in the range of $1000-$1100/kW. For a 20-MW$_e$ plant, the cost is estimated to be about $1300/kW (19), reflecting the relatively weak scale economies inherent in gas turbine technology. Based on the coal fixed-bed/fluid-bed cost comparison (Table 4), a biomass fluid-bed gasifier/STIG plant would probably have a capital cost comparable to that for a biomass fixed-bed gasifier/STIG.

Overall cycle efficiency

A demonstration of gasifier/steam-injected gas turbine technology would be required to determine actual system performance that could be expected in commercial plants. A parameter that would affect economic performance is overall cycle efficiency. The net biomass-to-busbar electricity production efficiency has been estimated elsewhere for a 53-MW BIG/STIG (based on the GE LM-5000 STIG) producing power only to be 32.5% (18) and 38.4% for a 110-MW BIG/ISTIG (17).[4] These estimates were derived from calculations by research engineers at GE which were made based on very limited test data using biomass pellets in a pilot-scale fixed-bed gasifier (9,10). The data were used in a detailed computer model of the LM-5000 STIG fired with low-btu gas which was used previously for analysis of coal gasifier/STIG systems (CIG/STIG) (7).

The limited biomass testing that was done suggested roughly a 10% lower gasifier hot-gas efficiency with biomass compared to the much better documented value with coal (18). However, there is no obvious reason that biomass gasification efficiency, and hence overall cycle efficiency, would not be as high as with coal. In fact, because of the greater ease with which biomass is gasified (17), the gasification efficiency might be even higher than with coal. The well-documented estimates for CIG/STIG and CIG/ISTIG systems are 35.6% and 42.1%, respectively (7).[5]

Where relatively inexpensive biomass fuels are available, e.g. as industrial byproducts of the cane sugar industry (19), the economics of BIG/STIG power generation would not be terribly sensitive to a 10% difference in cycle efficiency. However, the efficiency difference would be more important in situations where BIG/STIG and/or BIG/ISTIG systems were fueled by biomass from dedicated energy plantations, which would need to be utilized if biomass is to play a truly major role in electric power generation. Biomass from plantations would in general be more costly than industrial residues (Table 5), so high conversion efficiency would be important. Higher conversion efficiency would also mean correspondingly lower land area requirements per unit of electricity produced.

POTENTIAL MARKETS FOR BIG/STIG AND BIG/ISTIG SYSTEMS

Promising initial markets for BIG/STIG systems would be in cogeneration applications at industrial sites that produce biomass as byproducts. For example, the favorable economics of BIG/STIG cogeneration at cane sugar factories are discussed in detail in (19). Globally, an estimated 50,000 MW of BIG/STIG capacity could be supported using for fuel the sugar cane processing residues that are currently produced. There are also large potential markets in applications where other biomass processing residues are available (Table 6).

The role of biomass in electricity production could be expanded considerably in the longer term if dedicated energy plantations are developed to provide fuel. The potential for this in Sweden is discussed in a companion paper (38). With the fuel costs given in Table 5, and assuming the capital cost and efficiency estimates discussed above are realized in practice, 50-MW BIG/STIG and 100-MW BIG/ISTIG central station power plants would be competitive on a lifecycle cost basis with much larger coal-fired plants, including conventional steam-electric plants and advanced combined-cycles based on gasification (IGCC) or pressurized-fluidized bed combustion (PFBC). Figure 4 shows calculated total lifecycle electricity production costs for fuel costs ranging from $1.8/GJ to $3.6/GJ, which covers a range of possible future coal and biomass costs. For comparably sized power plants, the biomass-fired systems would provide less costly power, even if biomass were

[4] Efficiencies are on a higher heating value basis and assume the input biomass fuel has a 15% moisture content.

[5] The more conservative efficiency estimates are used for the BIG/STIG in (19) and for the BIG/STIG and BIG/ISTIG in (38).

Table 5. Estimated costs of delivered, air-dry biomass chips from plantations.

Region	*Species*	*Cost (1987$/GJ)*
Industrialized Countries		
Sweden	Salix, Populus	2.9-3.9(a)
Finland	Birch	3.6(b)
United States(c)		
Northeast	Hybrid Poplar	2.7-3.2 (4.6)
Lake States	Hybrid Poplar	2.7-3.4 (4.9)
Great Plains	Black Locust	2.5-3.1 (4.0)
Southeast	Sycamore	2.5-3.1 (4.9)
Pacific Northwest	Bl. Cottonwood	2.2-2.5 (3.8)
South Florida	Eucalyptus	2.5-2.8 (3.9)
Developing Countries(d)		
Brazil, Sao Francisco	Eucalyptus	3.0(e)
Brazil, Minas Gerais	Eucalyptus saligna	2.4
Brazil, Minas Gerais	Eucalyptus	2.3(f)
India, Uttar Pradesh	Eucalyptus, Acacia, others	2.8
India, West Bengal	Eucalyptus	2.6
India, Gujarat	Albizia, Acacia	2.3
Thailand	Pine, Eucalyptus, Casuarina	2.6-2.8
Haiti	Leucaena, Albizia, Cassia, others	2.3
Philippines	Leucaena, Albizia	1.9

(a) From Table 7 in (17) for dedicated energy plantations. Cost includes 30-km transport and $0.5/GJ for drying.

(b) From (21) for birch pulpwood--the lowest cost pulpwood in Finland--delivered to the mill plus $0.5/GJ for drying.

(c) From (41) based on the USDOE Short Rotation Woody Crops (SRWC) Program. The costs include 40 km transport, chipping, and drying. The costs shown in parenthesis have been achieved on existing plots. The range of costs are from conservative to optimistic targets for the SRWC Program for the year 2000.

(d) Cost data are from World Bank projects (except where otherwise noted) involving fuelwood production from dedicated or multi-purpose plantations (36). Additional costs of $0.5/GJ have been added for chipping, $0.5/GJ for transport (120 km), and $0.5/GJ for drying.

(e) From (37) for eucalyptus pulpwood, including 120 km transport, chipping, and drying.

(f) Based on detailed yield data and establishment, maintenance and harvesting costs for dedicated energy plantations owned by Acesita Energetica (31), to which $0.5/GJ added for chipping, $0.5/GJ for transport (120 km), and $0.5/GJ for drying. Acesita Energetica produces charcoal from the wood for use in its steel mills.

more costly than coal and even with the more conservative efficiency estimates. The development of the BIG/ISTIG technology would be particularly important for regions with higher plantation fuelwood costs (Table 5), but even with relatively high biomass costs (> $3/GJ), the BIG/ISTIG technology would be cost competitive with much larger coal-fired power plants (Fig. 4).

In addition to cost-competitive electricity, gas turbine electricity from plantation fuelwood would provide other benefits as well, including no net emissions of carbon dioxide to the atmosphere. In industrialized countries surplus agricultural land could be used for wood plantations, providing an opportunity to reduce or eliminate the government subsidies that are responsible for the agricultural surpluses (41). And in developing countries, such units would be located in rural areas, where they could help alleviate problems of unemployment and urban drift both directly and by supplying electricity at reasonable cost to help spur agricultural development and rural industrialization.

Table 6. Estimated potential biomass integrated-gasifier/steam-injected gas turbine (BIG/STIG) generating capacity (in 1000s of MW) that could be supported with the 1985 levels of residue production in biomass-processing industries worldwide.(a)

Residue Source	*Asia*	*Africa*	*Latin America*	*Industrial Market Economies*	*World*
Forest products	37.1	1.5	7.7	91.3	101.6
Saw mills	32.0	1.2	4.8	44.1	82.1
Pulp mills	5.1	0.3	2.9	47.2	19.5
Sugar cane	13.9	4.9	27.9	4.8	51.5
Corn stover	10.9	2.7	4.5	30.7	48.8
Rice husks	18.0	0.3	0.5	0.3	19.1
TOTAL	**79.9**	**9.4**	**40.6**	**127.1**	**257.0**

(a) From (17), assuming 33% conversion of residues to electricity and a 75% capacity factor.

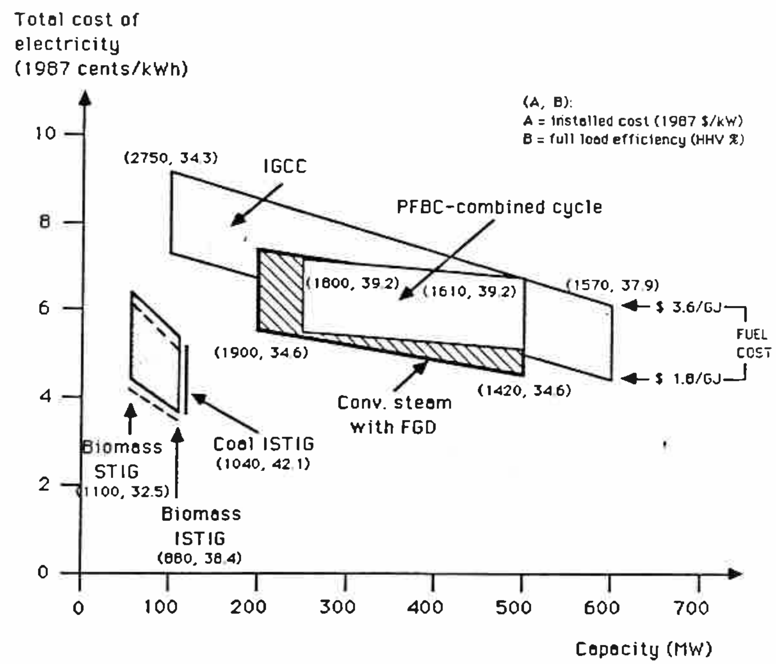

Fig. 4. Calculated levelized lifecycle costs (including capital and operating costs) for generating electricity with coal and biomass as a function of plant size. A 6% discount rate, 30-year life and 70% capacity factor are used. No taxes or tax incentives are included. For simplification, linear relationships between the costs for the largest and smallest units of each technology are assumed. The cost range for each technology at a fixed size assumes a fuel cost of $1.8/GJ to $3.6/GJ. Performance and cost estimates for the coal-fired PFBC, IGCC, and conventional steam plants are from (29). Performance and cost estimates for the biomass-gasifier/STIG (BIG/STIG) and biomass-gasifier/ISTIG (BIG/ISTIG) are discussed in the text. Two sets of cost ranges are shown for each: the shaded range represents the costs of power using conservative efficiency estimates (32.5% for BIG/STIG, 38.4% for BIG/ISTIG). The dashed lines indicate the costs if efficiencies are assumed to be the same as those expected for the coal-fired versions of the technologies (35.6% and 42.1%, respectively). As discussed in the text, there appears to be no reason biomass-based systems should be any less efficient than coal-based systems.

CONCLUSIONS

The analysis in this paper suggests the following conclusions regarding the development of biomass gasification systems for gas turbine power generation:

1. The gasification of biomass for gas turbine applications should be simpler and probably less costly on a unit basis than for IC-engine or methanol synthesis applications; restrictions on gas quality would be easier to meet, and pressurization leading to higher specific throughputs would help reduce unit capital costs.

2. Fixed-bed and fluidized-bed gasifiers are both candidates for gas turbine applications. Advantages of fixed-bed units include their simpler operation, extensive commercial experience operating at high pressure (with coal), and potentially simpler gas cleanup (i.e., cyclones may be sufficient). The main disadvantage would be the added cost required to pre-process some types of feedstocks. Pressurized fluidized-beds have less commercial operating experience, are more complex, and may present more challenging gas cleanup (i.e., barrier filters are likely to be required), but could handle a wide range of feedstocks with little or no pre-processing. Unit costs for fluid-bed reactors would be lower because of higher specific throughput capabilities.

3. With either type of gasifier, hot-gas cleanup of particulate and alkalai compounds to levels acceptable to gas turbines has not been adequately demonstrated with biomass. Pilot-scale demonstration would probably be sufficient to resolve these uncertainties.

4. A demonstration would also be required to determine expected capital costs and cycle efficiencies for commercial units. However, the economics of cogeneration or central-station power generation would be favorable compared to alternative sources of electricity in many situations even if capital costs turn out to be at the higher end and/or efficiencies turn out to be at the lower end of current estimates.

5. It appears that only a relatively modest, 3 to 5-year effort would be required to develop and demonstrate biomass-gasifier gas turbine systems, since the effort could build on extensive previous development work on coal-gasification systems for gas turbines and pressurizied biomass gasification for methanol production. The development could focus on BIG/STIG technology, since the STIG is already commercialized for natural gas applications. If this effort were carried out in parallel with efforts to commercialize natual gas ISTIG technology, subsequently the two technologies could be combined into BIG/ISTIG systems.

6. Because of the potential operational advantages of fixed-bed systems, the development of the BIG/STIG should probably focus initially on this option. Low-cost pilot-scale testing could be undertaken in the GE Lurgi-type gasifier or at a comparable existing facility to explore feedstock processing requirements and gas cleanup issues. Following this phase, the development work could proceed directly to a demonstration, perhaps at the 20-MW_e scale, to prove commercial viability. Such a demonstration effort would probably cost $40-50 million (6). No significant scale-up work would be required beyond this, since 20-MW_e represents a commercial size for many biomass applications.

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