Biomass Gasification for Gas Turbine Power Generation

by Eric D. Larson[1], Per Svenningsson[2], Ingemar Bjerle[3]

Reprinted from

Electricity

Efficient End-Use and New Generation Technologies, and Their Planning Implications

Editors: Thomas B. Johansson, Birgit Bodlund and Robert H. Williams

19578

Lund University Press
Box 141, S-221 00 Lund, Sweden
Art nr 20090
ISBN 91-7966-065-7

Chartwell-Bratt
Old Orchard, Bickley Road,
Bromley, Kent BR1 2 NE, England
ISBN 0-86238-208-4

[1] Visiting Research Engineer, Department of Environmental and Energy Systems Studies, University of Lund, Gerdagatan 13, S-223 62 Lund, Sweden
[2] Research Associate, Department of Environmental and Energy Systems Studies, University of Lund, Gerdagatan 13, S-223 62 Lund, Sweden
[3] Professor, Department of Chemical Engineering II, University of Lund, Box 124, S-221 00 Lund, Sweden

Biomass Gasification for Gas Turbine Power Generation

Eric D. Larson, Per Svenningsson, Ingemar Bjerle

Abstract

This chapter evaluates the technical requirements and status of biomass gasification and hot gas cleanup for gas turbine power generation. The economics of gasifier-gas turbine systems are also discussed. Gas turbine technologies, including combined and steam-injected cycles, are of interest because they have relatively high efficiencies and low unit capital costs in the small sizes appropriate for biomass installations. Gasifier-gas turbine systems are not available commercially, but they could probably be developed in a few 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. Biomass-gasifier gas turbine systems, if they are developed, could play important roles in the future supply of electricity in both industrialized and developing countries. In Sweden, electricity could be cogenerated at gas turbine district-heating plants at costs estimated to be competitive with new fossil-fuel central station plants. One quarter or more of the current national electricity production could be cogenerated from biofuels in the long term. The potential electricity generation is also very large in many developing countries, where the economics would be even more attractive due to lower biomass production costs.

1 Introduction

Biomass has attractive characteristics as an energy resource. It can be recovered as a byproduct or produced specifically for energy. The climate and soil in tropical countries are especially well suited for its production, but it can also be grown in temperate climates such as in Sweden. The production and use of biomass can be structured to cause only minor environmental impacts compared to the exploitation of fossil resources. Most biomass contains much less sulfur than coal or oil. Its use results in no net addition of heavy metals and other toxic elements to the biosphere, as is the case with most fossil fuels. And, if produced and used renewably, biomass would make no net contribution to atmospheric carbon dioxide.

Biomass is already an important energy source in many developing countries, but it is used very inefficiently. And, in industrialized countries such as Sweden and Denmark, it accounts for a significant portion of primary energy supply, but is predominantly converted to heat or steam in boilers. The low efficiency of photosynthesis will ultimately lead to land use constraints on the level of bioenergy use. However, this constraint can be relaxed if emphasis is given to energy efficiency in bioenergy conversion processes and end uses.

Thermochemical gasification is one of the simplest and most energy-efficient means for upgrading biomass. While gasification is conceptually simple, practical systems must be tailored to the end-use of the gas. Biomass gasification has been used with varying degrees of success with industrial furnaces and boilers, internal combustion engine-generators, and methanol synthesis plants. This paper considers biomass gasification for electric power generation using gas turbines. This application has received little attention, although there is considerable interest and ongoing development work in coal gasification for gas turbines (1,2,3).

Gas turbines appear well-suited for biomass applications because their natural scale is small (5–100 MW_e), as required for biomass facilities by cost constraints on fuel transport. Efficient gas turbine technologies, including combined cycles and steam-injected cycles, are discussed briefly in this chapter and in greater detail elsewhere (3).

In Section 2, we review the technical requirements and status of biomass gasification and hot gas cleanup technology for gas turbine applications. In Section 3, we present some preliminary performance and cost estimates for biomass-gasifier gas-turbine systems. In Section 4, some energy and economic implications of the widespread use of biomass-gasifier gas turbine systems are considered for Sweden and other regions of the world where biomass can be grown.

2 Biomass Gasification Systems for Gas Turbines

2.1 Background

In a biomass-gasifier gas turbine system, the feedstock would be gasified in a pressurized air-blown reactor and the products cleaned of particulates 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.

A representative biomass-gasifier gas turbine cycle, based on a steam-injected gas turbine (STIG), is shown in Figure 1. The basic components of the gasification system would be unchanged even if an alternative gas turbine technology were used in place of the STIG, e.g., a simple cycle, a combined cycle or an intercooled steam-injected gas turbine (ISTIG).

Past applications of gasification have related to industrial heating, internal combustion (IC) engines, and methanol synthesis. Gasifiers feeding industrial boilers, which have been successful in North America (4), Brazil (5), and elsewhere (6), typically operate with air at atmospheric pressure in "close-coupled" arrangements where gas cleanup is generally not a major concern.

Air-blown-gasifier/IC engines, which were widely used for vehicles during World War II in Europe (7) and are receiving renewed attention today (8,9), include extensive gas cleaning (to remove troublesome particulates and tars) and cooling for proper engine operation.

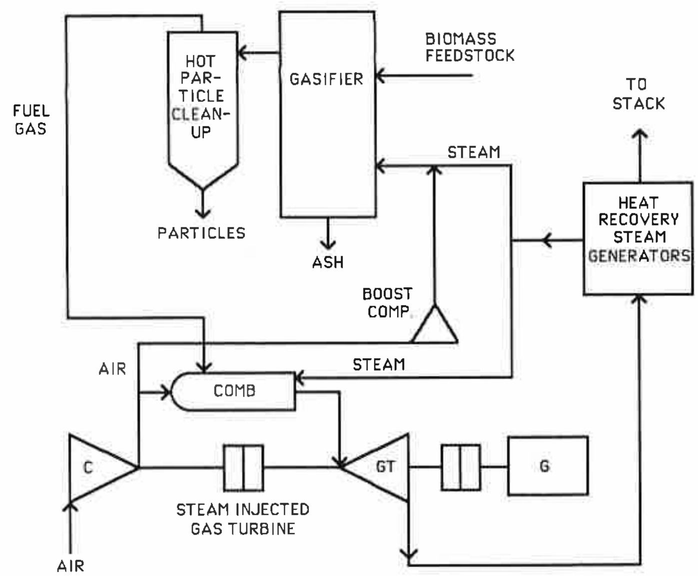


Figure 1. A biomass-gasifer gas turbine cycle. For illustration a steam-injected gas turbine is shown. An alternative gas turbine technology, e.g., a simple-cycle, a combined cycle, or an intercooled steam-injected unit could be considered as well.

A methanol synthesis plant typically includes: a pressurized oxygen-blown gasifier, necessitating large-scale operation to exploit scale economies; cleaning to eliminate all particulates and condensibles; a shift reactor to obtain the desired gas composition for methanol synthesis (2:1, H_2:CO); and a still higher-pressure catalytic reactor for the final conversion to methanol.

The technical requirements of gasification for gas turbines are quite different from those for previous applications. Particulate cleanup requirements are much stricter than for heating applications and comparable to those for IC engines and methanol synthesis. However, with hot cleanup, neither gas cooling nor tar removal are required. Furthermore, there are no strict requirements on gas composition (as with methanol synthesis), providing fuel flammability limits are met and the heating value of the fuel is above 4 MJ/Nm^3.[1] Overall, the requirements for gasification for gas turbines are less stringent than for other non-heating applications, which suggests that supplying fuel gas to gas turbines may in many ways be simpler and, perhaps, less costly.

2.2 Gasification Fundamentals

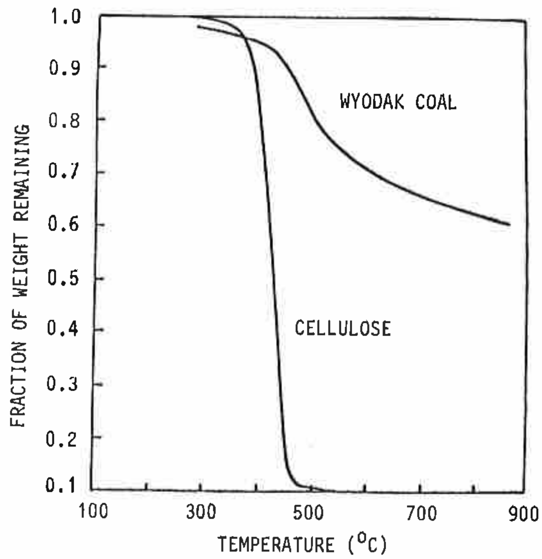
Gasification consists of two basic sets of reactions. Pyrolysis refers to a complex set of reactions during which the volatile components of the feedstock vaporize at temperatures below about 600°C and leave behind fixed carbon (char) and ash (10,11). Biomass consists of 75–85% volatile matter compared to half or less this level with coal (Table 1), so pyrolysis plays a larger role in biomass gasification. In addition, biomass generally pyrolyzes at lower temperatures than coal (Figure 2a).

Products of pyrolysis include water vapor and heavy hydrocarbon compounds (tars and oils) that condense at relatively high temperatures. In some gasifiers, the tars and oils constitute an important energy component of the raw gas. In other cases, gas-phase reactions occur in higher temperature regions of the gasifier, converting most of the primary pyrolysis products into lower-molecular-weight permanent gases.

Char conversion refers to the gasification and/or combustion of the fixed carbon that remains after pyrolysis. With biomass, a relatively small amount of char remains after pyrolysis due to the low fixed carbon fraction (Table 1). Much of the char burns to provide heat for pyrolysis and to gasify any remaining char. Biomass chars gasify much more easily than coal chars, because they are 10–30 times more reactive (12). Thus, biomass gasifiers can typically operate at lower temperatures than coal gasifiers to achieve the same char conversion (Figure 2b).

[1] One Nm^3 (normal cubic meter) is one cubic meter at standard temperature and pressure.

(A)



(B)

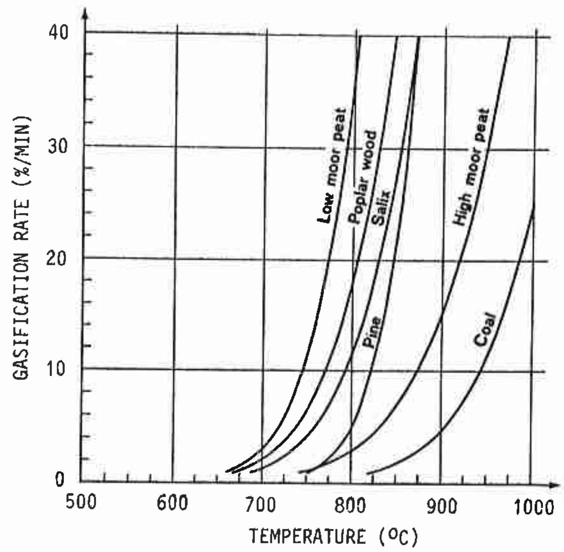


Figure 2. *(a)* Weight loss as a function of pyrolysis temperature for coal and cellulose (a major component of biomass) (83) and *(b)* Gasification rates in steam of chars from different feedstocks (84).

Table 1. Typical proximate and ultimate analyses of gasification feedstocks (weight percent, dry basis).

Proximate analysis	Volatiles	Fixed Carbon	Ash	*Ultimate analysis* C	H	N	S	O	Ash	Heating Value (MJ/kg)[d]
Biomass[a]										
Douglas Fir										
Wood	86.2	13.7	0.1	52.3	6.3	0.1[c]	0.0	40.5	0.8	21.0
Bark	70.6	27.2	2.2	56.2	5.9	0.0	0.0	36.7	1.2	22.0
Sawmill waste										
Redwood shavings	76.2	23.5	0.3	53.4	6.0	0.1	0.1	39.9	0.6	21.3
Oak chips	74.7	21.9	3.3	49.5	5.7	0.2	0.0	41.3	3.3	19.2
Other										
Sugar cane bagasse	74.0	23.0	3.0	45.0	6.0	0.2	0.0	46.0	3.0	19.1
Municipal solid waste (USA, 1970)	65.9	9.1	25.0	47.6	6.0	1.2	0.3	32.9	12.0	19.8
Coals[b]										
Texas Lignite	38.9	44.5	16.6	65.1	4.8	1.1	1.2	16.9	10.8	24.3
Illinois No. 6	35.7	54.3	10.0	68.0	5.2	1.2	3.8	9.8	12.0	29.6

a From (49a), except for sugar cane bagasse (49).
b From (49b).
c Nitrogen content of biomass can vary substantially and could be as high as 0.5% in some cases.
d Higher heating value, moisture free basis.

The chemistry and practical operational aspects of gasification are influenced by four main parameters: type of oxidant, temperature, pressure, and presence of moisture.

Oxygen or air is the oxidant in most gasifiers, and steam is sometimes used as an additional reactant. Using oxygen produces a gas with a heating value of typically about 11 MJ/Nm^3 (compared to 38 MJ/Nm^3 for natural gas). Air gasification produces gas with about half this energy content, due to the diluting effect of the nitrogen, but this is still sufficient for gas turbine combustion.

Temperature affects gasification rates and, more importantly, reactor design. Operating temperatures influence the design of ash removal systems. Both slagging and dry-ash gasifiers have been developed for coal. Biomass and coal ash have comparable melting temperatures (typically 1100–1200°C), but since biomass can be gasified at lower temperatures (Figure 2b), most biomass gasifiers utilize dry ash removal systems. Ash removal from biomass gasifiers is further simplified by a much lower ash content than for coal (Table 1).

Pressure has a modest effect on gasification chemistry, but an important effect on system design and cost. Higher pressure permits higher processing rates for a given reactor size.[2] The ability to use smaller reactors leads to savings in material and in field construction costs. Drawbacks of higher pressure operation are the increased complications of feeding and the increased risk of clinker formation in hot spots within the oxidation zone of the gasifier.

Moisture plays a role in char gasification. In some gasifiers, steam is injected to provide some of the required moisture,[3] since water in the feedstock is driven off during pyrolysis and is thus unavailable for reaction. In some gasifiers, additional steam is used to maintain the reacting bed below a specified temperature, typically that of ash melting.

Excess moisture acts to dilute the heating value of the raw gas. The lower limit on the heating value of gas for stable gas turbine combustion appears to be about 3.9 MJ/Nm^3 (13). This sets an upper limit on the acceptable moisture content of the feedstock of 25–30%.[4]

[2] In a fluidized-bed gasifier, throughput (tonnes per hour) increases from m_0 to m as pressure increases from p_0 to p, approximately according to $m/m_0 = (p/p_0)^{0.6}$. Thus, for example, fuel throughput would be seven to eight times as large when operating a reactor at 30 bars instead of atmospheric pressure.

[3] Because of the inherently higher moisture content and reactivity of most biomass feedstocks compared to coal, external steam requirements are generally lower for biomass gasification than for coal.

[4] Unless explicitly indicated otherwise, feedstock moisture contents are expressed on a wet weight basis (percentage of the total wet feedstock weight).

2.3 Gasifier Designs

Three gasifier designs have traditionally been considered for coal: entrained-bed, fixed-bed and fluidized-bed. Several entrained-bed gasification systems have been brought to advanced stages of development for coal-gasifier combined-cycle applications, but appear ill-suited for biomass-gas turbine applications.[5] Air-blown fixed-bed and fluidized-bed gasifiers appear to be more promising candidates in terms of performance and near-term commercial viability. Table 2 gives some comparative performance characteristics based primarily on pilot-scale measurements.

2.3.1 Fixed-bed gasifiers

Performance

The most interesting of several fixed-bed (also called moving-bed) gasifiers for gas turbine applications is the updraft or counter-current design, in which the feedstock successively undergoes drying, pyrolysis, char gasification and char combustion (Figure 3a).[6] The blast air is largely consumed at the grate during combustion, leading to peak temperatures at this point in the bed. Blast air requirements are relatively low (Table 2). Steam is used to maintain the bed below the ash melting temperature and to a lesser extent to facilitate char conversion. The combustion products and steam drive char gasification reactions just above the grate. The gas cools as it travels up through the bed, pyrolyzing the incoming feedstock.

The product gas exits near the top with relatively low temperature and laden with tars and oils (in vapor form). The gas exits with relatively low particulate concentrations because of low exit velocities and the filtering effect of the fuel bed. The raw gas heating value is high due to the tars and oils. Good carbon conversion (99%) is achievable because of the high peak temperatures and the efficient (counter-current) heat transfer from the gas to the fuel bed.[7] Hot-gas efficiency can also be high (90–95%), but cold-gas efficiency is typically low (65–75%) because tars and oils are excluded from this measure.

5 One drawback is the relatively low heating value of raw gas from an air-blown entrained-bed unit.

6 Other types of fixed-bed gasifires include downdraft (co-current) and rotary kiln gasifiers.

7 See Table 2, note (g) for definition of efficiencies.

Table 2. Operating characteristics of fixed and fluidized bed gasifiers with biomass feedstocks.[a]

	Fixed-bed (updraft)[b]	Fluidized-Bed[c]
Solids residence time (s)	300–900	5–120
Throughput (dry tonne/m^2-hr)	2.1	7.0
Typical blast (kg/$kg_{dry\ feed}$)		
Air	0.8	1.3
Steam	0.3	0[d]
Peak temperature	1100	827
Raw-gas		
Exit temperature (°C)	550	800
Yield (kg/$kg_{dry\ feed}$)	2.7	2.9
Typical Composition (Vol.%) (w/15% feedstock moisture content (mc))		
CO	13.0	8.1
H_2	17.1	6.9
CH_4	5.1	4.8
C_2H_4	–	0.2
C_2H_6	–	0.3
C_6H_6	–	0.5
CO_2	13.1	14.1
N_2	29.5	36.3
H_2O	28.0	30.0
Tars/oils (wt %)	3.3	0.8
Particulates (g/Nm^3)[e]	1	100
Higher heating value (MJ/Nm^3)		
Wet gas	5.0	4.6
Dry-gas	6.9	6.5
Efficiencies[f,g]		
Carbon conversion (%)	99	98
Hot efficiency (%)	93	95
Cold efficiency (%)	67	81

[a] The performance described here is based primarily on pilot-scale testing. Gasifiers can be operated over a wide range of parameters, and performance can vary accordingly.

[b] Unless otherwise noted, these are preliminary results for gasification of 14.9% mc wood pellets at 21.4 bar in a gasifier designed for gasification of 24 t/day of coal (14). The carbon conversion efficiency is that estimated for oxygen gasification of coal at the same pressure (44).

[c] Unless otherwise noted, these are for gasification of 14.5% mc whole-tree hardwood chips at 21.8 bar, 827°C in air and steam in the IGT 12 tonnes/day bubbling fluidized-bed gasifier without char recycle (17).

[d] Based on (50).

[e] Estimates range over an order of magnitude or more. The upper-end value is given here (30).

[f] Efficiencies for the fluidized-bed unit are for 9.1% mc whole-tree chip gasification in enriched air and steam at 911°C, 21.6 bar in the IGT gasifier without char recycle (17).

[g] Carbon conversion is the fraction of input carbon converted to gas. Hot efficiency is the chemical and sensible energy in the raw gas divided by the total energy input (chemical plus sensible). Cold efficiency is the chemical energy in the gas excluding condensibles (tars/oils), divided by the total input.

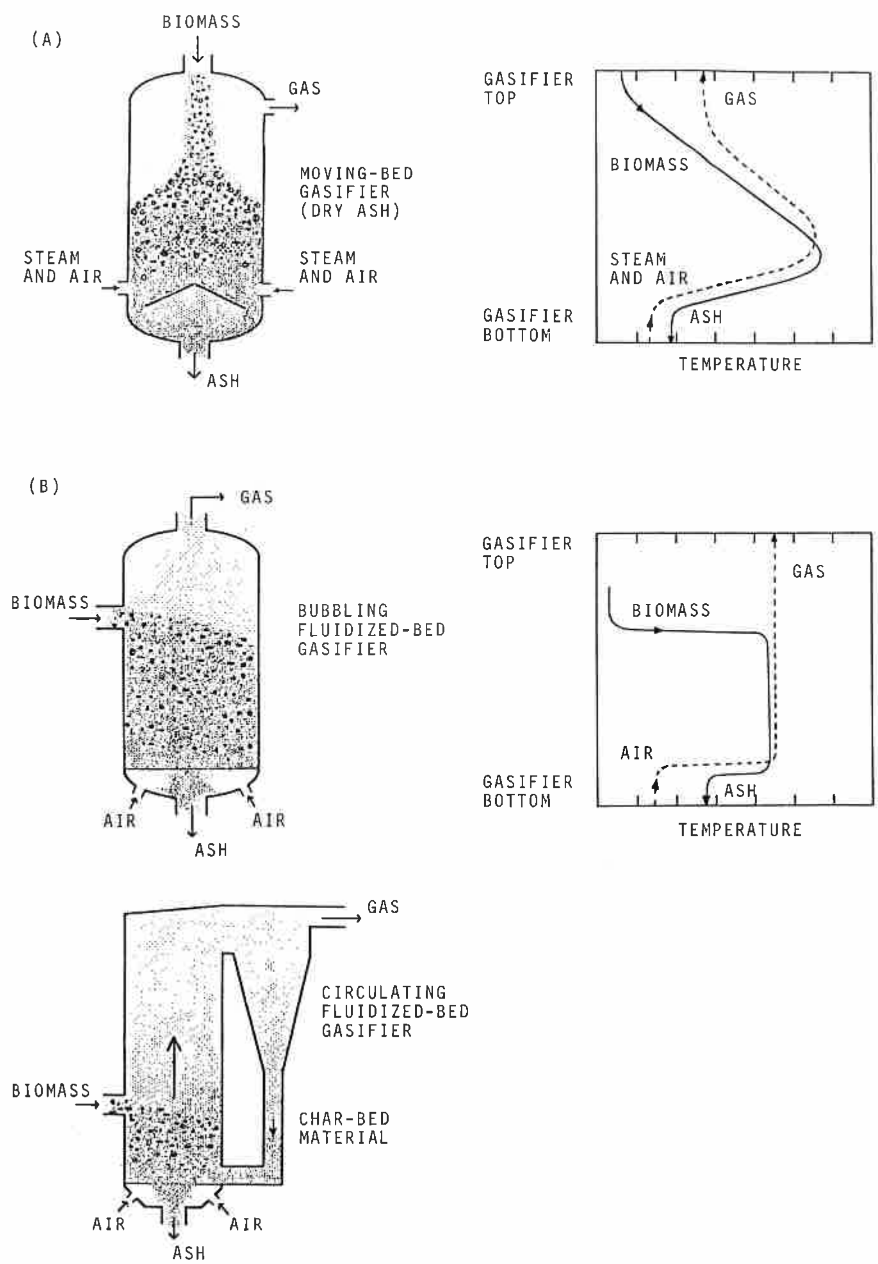


Figure 3. Operating principles and temperature profiles for (*a*) fixed-bed and (*b*) bubbling fluidized-bed gasifiers. Also shown is the operating principle of a circulating fluidized-bed gasifier.

Feedstock requirements

Relatively large, dense, and uniformly-sized feedstocks are preferable for fixed-bed gasifiers to help prevent bridging, reduce feed losses, and reduce carryover (Table 3). Some designs have rotating agitators to assist the fuel flow. Feedstocks with as high as 50% mc (moisture content) can be gasified, but the moisture will dilute the heating value of the raw gas as discussed earlier. Suitable fuels appear to be wood chips and mill residues (Table 3), though some size screening of the residues would probably be required. Most agricultural residues would require densification for use in fixed-bed reactors, which would increase fuel costs.

Status

Because of their simplicity and high efficiency, updraft gasifiers are widely used commercially with both coal and biomass. The pressurized Lurgi dry-ash gasifier, which has the most commercial operating experience of any gasifier with coal and which has been considered for coal-gasifier STIG, ISTIG, and combined-cycle systems (13), appears to also be a good candidate for biomass applications. Successful, but limited, pilot-scale testing of a Lurgi-type unit has been carried out by the General Electric Company (GE) using biomass pellets (14) and RDF/coal briquettes (15) (Table 4). More extensive testing would be required to demonstrate the feasibility of operating on various feedstocks, e.g., wood chips and densified agricultural residues, and of removing particulates at elevated temperatures (see below). Such testing might be undertaken at low incremental cost using the GE pilot gasifier or a comparable existing facility.

2.3.2 Fluidized-bed gasifiers

Performance

In a fluidized-bed gasifier, the feedstock is typically fed continuously and is "fluidized", together with an inert heat-distributing material, e.g., sand, by oxidant and/or steam injected from below. The bubbling bed (Figure 3b) was the first fluidized-bed design developed. A variation of this, the circulating fluidized bed (CFB) (Figure 3b, lower), has been developed more recently. In any fluidized bed, pyrolysis and char conversion occur throughout the bed. The excellent heat and mass transfer leads to relatively uniform temperatures throughout the bed, better fuel-moisture utilization, and faster reactions than in fixed beds. The latter leads to much higher throughput capabilities per unit volume for fluidized beds (Table 2).

Table 3. Required biomass feedstock characteristics for alternative gasifier designs and properties of actual biomass feedstocks.

Gasifier feedstock requirements:	Fixed-Bed Updraft	Fluidized-Bed Bubbling	Fluidized-Bed Circulating[a]
Length (mm)[b]	13–75	0–50	0–100
Max. thickness (mm)[b]	6–13	0–3	0–50
Size variability	small	large	larger
Moisture (wt%)[c]	< 30%	< 30%	<30%
Bulk density (kg/m^3)	> 240	(d)	(d)

Actual properties:	Length (mm)	Thickness (mm)	Bulk Density[e] (kg/m^3)
Wood chips			
Hardwood	16–22	1.5–3	280–480
Softwood	16–22	3–6	200–340
Mill Residues	maximum 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 (50).

[b] For fixed and bubbling fluidized-bed, see (51).

[c] 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%.

[d] 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.

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

Reaction temperatures are kept relatively low (to prevent ash melting) by control of blast air rates and good mixing of the bed. As a result, little or no steam is needed for cooling, unlike with a fixed bed. While peak temperatures are lower than in a fixed-bed, average temperatures are higher (Figure 3b), leading to conversion of a significant amount of tars and oils into permanent gases.

Carbon conversion when gasifying coal appears to have a practical maximum of about 96% (for lignite when char carried out of the reactor with the gas is recycled to the bed (16)). With the more reactive biomass, however, conversion in excess of 98%–comparable to that in fixed-beds–has been achieved in pilot-scale tests without char recycle (17). Hot-gas efficiencies are also comparable to those for the fixed-bed, but cold efficiencies are higher (80–85%) because of the low tar/oil production (Table 2).

The particulate loading in the raw gas is one to two orders of magnitude greater than with fixed beds (Table 2).

Feedstock requirements

Fluidized-bed gasifiers can accept much smaller, less dense, and less uniform feedstocks than fixed-beds (Table 3). The minimum acceptable bulk density for fluid beds is much lower than for fixed-beds. Requirements for fuel handling and feeding, which is more difficult the less dense the fuel, will most likely set the acceptable 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 3). Most of the feedstocks listed in Table 3, including minimally processed agricultural residues, appear to be acceptable fuels.

Status

The major advantages of fluidized-bed gasifiers over fixed-bed units are their greater fuel flexibility and higher throughput capability. The higher throughput capability leads to lower unit capital costs than fixed-beds in most of the size range of interest for gas turbines–greater than 15 MW_{fuel} (18).[8] The main drawback of fluidized beds appears to be higher levels of particulates in the raw gas, which makes gas cleanup more challenging (see below).

[8] Fixed-beds have a capital cost advantage below about 10 MW_{fuel} because of the relatively high cost at this small scale of the blowers, continuous feed systems, control systems and other instrumentation associated with fluidized beds.

Table 4. Gasifiers that have operated with biomass feedstocks.

	Status[a]	Capacity (t/h)	Pressure (bars)	Blast[a]	Tested Feedstocks
Fixed-bed					
Lurgi Updraft (Dry Ash)[b]	P	2	21	A/S	Wood pellets/RDF briquettes
Syn-Gas Downdraft[c]	P	2	10	A,O	Wood chips/Wood pellets/Corn cobs/ Peat pellets
Wright-Malta Kiln[d]	P	0.2	21	S	Wood chips/MSW
Fluidized-bed					
Rheinbraun- Uhde HTW[e]	D	3	10	A/S	Wood chips/Peat
	C	27	13.5	O/S	Peat
ASCAB[f]	D	5	25	O/S	Wood chips
Biosyn[g]	C	6	8	A	Wood chips
	D	10	14	A,O	Bark/Sawdust/ Wood Pellets
IGT Renugas[h]	P	1	34	A/S,O/S	Wood chips/Corn stover/Pulp mill wastes
MINO[i]	P	0.5	28	O/S	Wood chips/Peat/ Lignite
TRC Finland[j]	L	0.09	10	A	Peat pellets
Lurgi CFB[k]	C	16	1	A	Bark/Wood wastes
Götaverken CFB[l]	C	8	1	A	Bark/Sawdust/Wood wastes
Ahlström CFB[m]	C	8	1	A	Wood waste/Peat

[a] C=commercial, D=demonstration, P=pilot, L=laboratory, A=air, O=oxygen, S=steam.

[b] The pilot facility is at the General Electric Corporate Research Center, Schenectady, New York.

[c] From (52).

[d] In the Wright-Malta rotary kiln gasifier, external heating provides most of the energy for gasification. High moisture feedstocks are used (40–50%), with a residence time of 1 hour. The gasifier is being developed by Wright-Malta with Zurn Engineering (Erie, Pennsylvania) to drive a gas turbine, the exhaust heat from which would drive the gasifier. Commercial availability is anticipated in 1991 (53).

[e] The pilot plant, which is located at the Rheinisch-Westfalische Technische Hochschule in Aachen, FRG, has been operated primarily with lignite, though some tests have been made with biomass as well (54). The commercial unit has recently started operation at an ammonia production plant in Oulu, Finland (55).

———>

Fluidized-beds appear to be good candidates for gas turbine applications. A major coal-gasifier gas turbine demonstration project in the USA will utilize a fluidized-bed gasifier (19). Development of fluid-beds for biomass-gas turbines could build on such efforts and on the extensive previous development efforts on large-scale pressurized gasification for methanol-from-biomass (Table 4). Of the units described in Table 4, 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 is currently being actively developed (for coal applications), with a 25 bar pilot plant (for combined-cycle applications) scheduled for start up in late 1989 (20). As with the fixed-bed, additional development work to tailor biomass-fueled fluidized-beds to gas turbines could be undertaken at low incremental cost in one of the existing units.

Also noteworthy is the commercial availability of three atmospheric-pressure CFB gasifiers (Table 4). One manufacturer of CFB gasifiers, Ahlström, has recently announced plans to startup a 10 MW_{fuel} pressurized CFB combustor in the spring of 1989 (21). The Ahlström project is intended to demonstrate the feasibility of CFB combustion for direct firing of gas turbines with solid fuels, including the use of ceramic hot gas filters (22). Since CFB gasifiers are similar to CFB combustors in many respects, successful demonstration of a pressurized CFB combustor/hot filter would be a major step toward successful demonstration of a pressurized CFB gasification system for gas turbines.

[f] The unit, located in Clamecy, France, has undergone only limited testing to date (50). It was originally designed for methanol production.

[g] The demonstration facility is located in St. Juste de la Breteniere, in southern Quebec Province, Canada (56). The commercial unit, which supplies gas to a 6.7 MW diesel engine in Cayenne, French Guyana, was scheduled for startup in early 1987 (57).

[h] The facility is located at the IGT research center in Chicago, Illinois (17,58).

[i] Testing, including some with hot gas filtering, was undertaken between 1983 and 1986 at the pilot plant facility at Studsvik AB, Nyköping, Sweden (23,50).

[j] The unit is located at the Technical Research Center of Finland, Espoo, Finland. Related work is ongoing on gasifier feeding systems, gas cleaning, and gas turbines fired with gasified peat (59).

[k] This circulating fluidized-bed (CFB) supplies fuel gas to a lime kiln at a pulp mill in Pols, Austria (60).

[l] The Götaverken unit supplies fuel gas for operations at a pulp mill in Värö, Sweden (18).

[m] Ahlström units are operating in Finland, Sweden, and Portugal (22).

2.4 Gas Cleanup

Cleaning raw gas is required to avoid damage to turbine blades and to meet emissions regulations. The main gas contaminants of concern from biomass gasifiers are tars/oils, alkalai compounds, nitrogen (as a component of various chemical compounds), and particulates. The most effective cleaning systems involve cold wet scrubbing, which complicates a plant and reduces efficiency. Thus, only processes for cleaning gas at elevated temperature are considered here. A limited amount of work has been done on pressurized hot cleanup of biomass gas, for methanol production (23) and more recently for direct firing of gas turbines using pressurized combustion (22,24). Extensive work has been done on hot cleanup for coal-gasifier gas-turbine systems and for directly-fired systems using pressurized-fluidized-bed combustors (PFBC) (25–29). The coal-based work is relevant for biomass, but cleaning biomass gases is simpler, because most biomass gas does not require sulfur removal (Table 1).

2.4.1 Tars and oils

Tars and oils are a problem only if the temperature of the gas falls below their dew point, which ranges from 150°C to 500°C for biomass tars (30). In condensed form, tars and oils foul surfaces, leading to increased maintenance costs and performance degradation. Tar and oil condensation is of greatest concern with updraft gasifiers, which produce the largest quantities and at the lowest gasifier exit temperatures (Table 2). Tar condensation can be avoided, however, by keeping the gas temperature above the tar/oil dew point until it reaches the gas turbine combustor. Such close-coupled arrangements have been incorporated into designs for advanced coal-gasifier gas turbine systems (13,31).

2.4.2 Alkalai compounds

Alkalai compounds in fuel gas, which form from potassium and sodium in the feedstock, are a concern because they can accelerate hot corrosion and cementing of particulate deposits on turbine blades (32). The limit for alkalai metal in coal-derived gaseous fuel for a gas turbine has been given as 0.1 to 0.2 ppm by weight (32,33). Limits for biomass-derived gas are probably similar to those for coal-derived gas. Thermodynamic calculations suggest that for pressurized gasification at 800–900°C, raw-gas concentrations of alkalai would be well in excess of the suggested limits and largely in vapor form, making their removal more difficult (32,34).[9]

Alkalai compounds in coal gas appear to condense on entrained particulates at temperatures of 500–650°C and, therefore, can be reduced to acceptable levels by particulate cleanup at these temperatures (13,29,31). Measurements are required to determine whether this would be the case for alkalais in biomass-derived gas as well. If alkalai removal by this mechanism is insufficient, then the use of an inorganic sorbent (e.g. aluminosilicates) after the particulate removal system might be feasible to collect ("getter") much of the remaining alkalai (32). Additional work is needed to fully understand alkalai production and removal.

2.4.3 Nitrogen oxides

Nitrogen oxides (NO_x) can be produced in the gas turbine combustor from nitrogen in the fuel (fuel-bound NO_x) or 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 (produced by dissociation of N_2) would be relatively low (33). In any case, thermal NO_x can be controlled to a large extent by the use of low-NO_x combustion technologies, of which steam-injection is the 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 (35).

Fuel-bound NO_x ($FBNO_x$) is produced from nitrogen compounds, primarily ammonia, which form 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 (33). $FBNO_x$ from the combustion of biomass gas has been measured to be significantly less than this (36), which would appear consistent with the lower fraction of nitrogen in most biomass compared to coal (Table 1). 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 (29,37). Such technologies for biomass might be simpler because of the lower fuel-bound nitrogen levels.

9 This is in contrast to the calculations assuming oxidation conditions, which would be representative of pressurized fluidized-bed combustion (PFBC). At temperatures below about 950°C, the alkalai are present as condensed sulphates, which can probably be removed with the particulates (32). At higher temperatures, the alkalais would be present in vapor form.

2.4.4 Particulates

Cleanup of particulates is required to prevent erosion of gas turbine blades, although the extent of required cleanup appears uncertain. Updraft biomass gasifiers produce two orders of magnitude less particulate matter than fluidized-beds, but also much smaller particles (Table 5). Estimated permissible particulate loadings for gas turbines vary widely (Table 5), as do particle size distributions. Table 5 gives one size distribution specification developed by General Electric (GE). More recently, the Electric Power Research Institute (EPRI) in the USA has proposed a particulate specification which takes account of the greater damage done by the larger particles (38):[10]

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

Two technologies are usually considered for hot particulate removal. The most common and least costly is the cyclone. A high efficiency cyclone will remove most particles larger than 5–10 microns, but is ineffective for smaller particles. Because of relatively large particle sizes in gas from an updraft *coal* gasifier (Table 5), cyclones have been shown in pilot scale tests to provide adequate cleanup to meet the particle size specification developed at GE (Figure 4). For biomass applications, cyclones would appear not to be sufficient to meet the GE specification because of the large fraction of submicron particles (Table 5). They may be sufficient, though, to meet the criteria proposed by EPRI. Particles from fluidized-bed biomass gasifiers are larger but much greater in number than from fixed-bed gasifiers, and therefore may require the use of more efficient particle removal technology.

Barrier filters provide more complete filtration than cyclones, but have not been commercially proven for gas turbine applications. They are typically constructed of either sintered metal alloys, e.g. inconel or hastalloy, which can operate at 700–900°C, or of ceramic materials, e.g. silicon carbide, which can operate at still higher temperatures. A variety of filter designs have been developed, most of which operate by initially trapping large particles within a fine mesh (0.5–100 micron pore sizes), but then quickly begin trapping much smaller particles as a layer of dust builds up. When the pressure drop across the filter reaches a specified level, the filters are cleaned by a reverse jet blast.

For hot cleanup of biomass gas, sintered metal filters appear promising, based on previous pilot-scale work in Sweden (23). For coal-gas cleanup, the

10 Smaller particles will tend to follow streamlines around the turbine blade. They will do little damage even if they hit the blade, since the angle of impact will be shallow and their velocity will be slowed in passing through the fluid boundary layer around the turbine.

Table 5. 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[c] Updraft	Biomass[c] Fluid-Bed	Coal[d] Updraft	
Load (g/Nm^3)[b]	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 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] 1 g/Nm^3 is approximately 1000 ppm by weight.

[c] From (30) for atmospheric-pressure gasification.

[d] The updraft results are based on operation of a pilot-scale pressurized Lurgi-type gasifier (33). Data for fluidized-bed coal gasification were not available.

[e] From (30).

[f] From (61).

[g] The size distribution is from (25) 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.

emphasis has been on silicon-carbide candle filters (39). The collection efficiencies with either metal or ceramic filters would be high. In pilot-scale tests with coal-gas from the KRW fluidized-bed gasifier, collection efficiencies well in excess of 99% have been reported, using commercially available silicon-carbide candle filters (26). Similar efficiencies have been reported for removal of simulated gasifier char (4.5–5.5 micron size), using a silicon-carbide/Nicalon filter developed at the Oak Ridge National Laboratory (40). Since collection efficiency appears well established, how rapidly ceramic barrier filters reach commercial readiness will probably depend more on the demonstration of their ability to withstand thermal and mechanical shock and

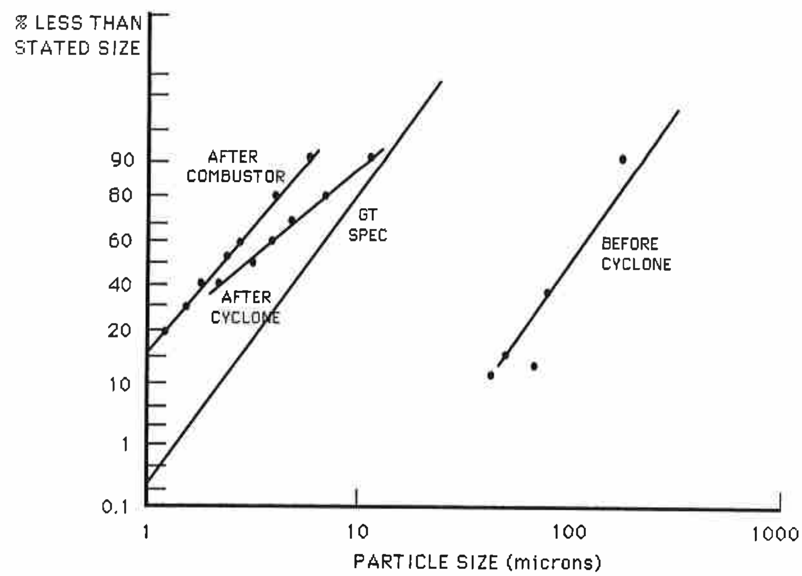


Figure 4. Measured particulate size distribution in tests with a pilot-scale fixed-bed dry-ash coal gasifier (25). The data are for the raw gas at the gasifier exit, after the cyclone, and after a simulated gas turbine combustor. Also shown are recommended gas turbine specifications (see Table 5, note g).

to maintain effective seals in gas turbine systems. Pilot projects in the USA (19) and Finland (22) are intended in part to demonstrate the thermal and mechanical integrity of ceramic candle filters for such applications.

The cost of barrier filters for gas turbines would be high compared to cyclones, but would still represent a small part of the total plant capital cost.[11] Operating costs, for pulse cleaning and periodic replacement, may be of greater concern.

A number of other cleanup technologies for hot applications are at various early stages of development (41), including ceramic cross-flow filters, granular bed filters, and various electrostatic precipitators.

[11] In one design study for a 100-MW coal-gasifier steam-injected gas turbine, cyclones were estimated to cost $10/kW out of a total installed plant cost of $1290/kW (13).

2.5 Summary

Five main conclusions can be drawn from the above discussion:

1. The gasification of biomass for gas turbines should be simpler and probably less costly on a unit basis than for most other applications; restrictions on gas quality are less severe, and pressurization leading to higher specific throughputs would help reduce unit capital costs.
2. Biomass gasification is easier in many respects than coal gasification: lower temperatures yield comparable gasification rates, ash levels are much lower, and sulfur removal would not be required.
3. Fixed and fluidized-beds are both interesting candidate gasification technologies for biomass-gas turbines. Fixed-beds offer greater simplicity and less challenging particulate cleanup, while fluidized-beds offer greater fuel flexibility, higher throughput rates, and lower unit capital costs in the size range of interest with gas turbines.
4. Particulate and alkalai cleanup have not been adequately demonstrated for biomass-gasifier gas turbine systems. Pilot-scale demonstration would probably resolve these uncertainties.
5. The development of biomass gasification systems for gas turbines would be facilitated by "piggy-backing" on: existing coal-gasifier gas-turbine work, past work on pressurized biomass gasification/hot gas cleanup for methanol synthesis, and ongoing work on solid fuel PFBC gas turbine/gas cleanup systems.

3 Applications for Power Production

Gas turbines can operate with significantly higher peak temperatures than steam turbines and, thus, have the potential for producing power more efficiently from solid fuels. Gasification would permit the full efficiency benefit of higher temperatures to be realized both in today's gas turbines and in future units with even higher firing temperatures.[12] Both central station and cogeneration applications are of potential interest.

[12] Gas turbines could also be fired directly with biomass, e.g. using pressurized fluidized-bed combustors (PFBC). The limit for turbine inlet temperatures used in PFBC systems today is about 900°C, which is well below the rating for the best commercial gas turbines – about 1200°C. At combustion temperatures higher than about 900°C, cleanup problems associated with ash melting and alkali release would become more serious. Unless these problems can be overcome, therefore, the full efficiency potential of gas turbines cannot be realized with direct combustion.

3.1 Central Station Power

For central station power generation, the most interesting gas turbine technologies are combined cycles and steam-injected cycles (3). Efficiencies for advanced gasifier-fueled versions of these cycles would probably be comparable. However, unit capital costs are likely to be higher for combined cycles in plant sizes less than about 200-MW_e, because of the high cost of smaller-scale steam turbines. Since most biomass applications will probably be smaller than this, we limit the discussion here to steam-injected cycles.

Biomass-gasifier steam-injected gas turbines (STIG) and intercooled steam-injected gas turbines (ISTIG) would be similar in many respects to the coal-gasifier STIG and ISTIG systems which have been proposed for baseload electricity generation in the USA.[13] In a detailed design study, capital costs for 100-MW coal-fired STIG and ISTIG plants that would use Lurgi fixed-bed gasifiers and General Electric LM-5000 gas turbines have been estimated to be \$1290/kW and \$1040/kW,[14] respectively, with efficiencies of 35.6% and 42.1% (higher heating value basis)[15] (13).

Detailed capital cost estimates have not been made for biomass-gasifier STIG or ISTIG plants, but costs are likely to be lower than those estimated for the above coal STIG and ISTIG systems for several reasons. Hot sulfur removal equipment, which accounts for 15–20% of the estimated capital cost of the coal-fired systems, would not be required. In addition, the less harsh reactor conditions required for biomass gasification would contribute to lower costs. Furthermore, substituting a fluidized-bed gasifier for the fixed-bed would lead to some cost reduction.

Thus, a reasonable capital cost estimate for a biomass-gasifier STIG based on the LM-5000 gas turbine would be in the range of \$1100/kW. Such a system would produce about 53 MW of electricity, and an estimate of its efficiency is 32.5%. This efficiency estimate was made by research engineers at the General Electric Corporate Research Center (Schenectady, New York) based on limited experimental data from pilot-scale fixed-bed biomass gasification, which indicated lower gasification efficiency than with coal.

13 STIG units are commercially available with natural gas firing in sizes from 1.8 to 51 MW. ISTIG units have yet to be commercialized. See (3).

14 Costs in this paper are expressed in constant 1987 US\$. The US gross national product deflator has been used to convert costs originally given in other-than-1987 dollars. Costs in Swedish kronor have been converted at 6.5 SEK/\$.

15 Higher heating values (HHV) are used for fuels in this paper. For natural gas, the HHV is approximately 10% greater than the lower heating value (LHV). For coal the difference is about 3%. The HHV of biomass on a dry matter basis is independent of its moisture content (mc), unlike the LHV. For biomass with 0%, 15%, 30%, and 50% mc, the HHV is greater than the LHV by approximately 5%, 11%, 18%, and 25%, respectively.

However, there is no obvious reason biomass gasification efficiency, and hence overall cycle efficiency, would not be at least as high as for coal. Thus, the efficiency estimate here can be considered conservative.[16]

A similarly conservative estimate for the efficiency of a 110-MW biomass-gasifier ISTIG is 38.4%. Its estimated capital cost is \$880/kW.[17]

If these cost and conservative performance estimates are realized in practice, 50–100 MW central station biomass gas turbine 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 5 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. (Costs of biomass are discussed further in Section 4.) In many cases, the biomass option would be less costly even if biomass fuel cost more than coal.

3.2 Cogeneration

In a biomass-gasifier gas-turbine cogeneration system, the high-temperature exhaust from the turbine would be used to raise steam, which could be (*a*) used directly for heat (simple cycle), (*b*) used to drive an absorption heat pump, while low-temperature heat in the gas turbine exhaust after the waste heat boiler provides the pump with a heat source, or (*c*) passed through a steam turbine first (combined cycle). Because of scale economy considerations, combined cycles are likely to be of interest only in relatively large sizes, unlike the other options. Option (*b*) might be of particular interest where only low-grade heat is required, e.g., as for hot-water district heating. With this option, latent heat in the exhaust (arising from the relatively high moisture content in fuel gas from biomass) could provide a significant heat source for the heat pump.

All three gas turbine systems could be designed with a flexibility to boost electricity production and electrical conversion efficiency when heat demand falls. In cases (*a*) and (*b*), this would require a steam-injected gas turbine

16 The efficiency estimate assumes an input biomass moisture content of 15%. For additional discussion, see (42).

17 Consistent estimates for biomass-gasifier combined cycle systems have not been made. One design study indicates a capital cost of \$1270/kW for a 205-MW unit based on a system using a fluidized-bed gasifier and ASEA-STAL GT-200 gas turbine (43). Based on the scale-sensitivity of coal-gasifier combined cycle systems discussed in (44), a 100-MW biomass-gasifier combined cycle would cost about \$1530/kW.

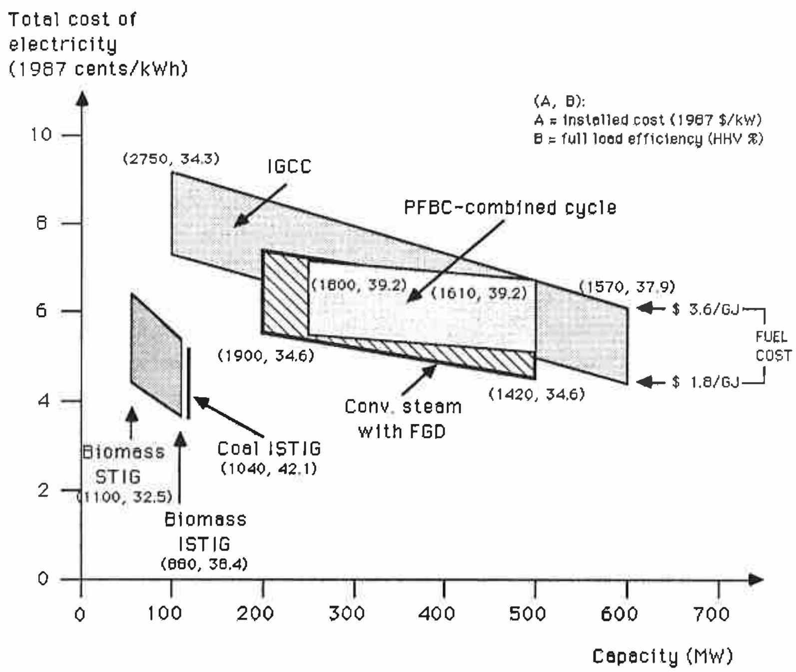


Figure 5. Calculated levelized lifecycle cost (including capital, operating and maintenance, and fuel) of electricity generation with coal and biomass as a function of plant size. A 6% discount rate, 30-year life and 70% capacity factor are used. No taxes or tax incentives are included. For simplification, linear relationships between the costs for the largest and smallest units are assumed. The cost range for each technology at a fixed size assumes a fuel cost of $1.8/GJ to $3.6/GJ. The lower fuel cost is the average utility coal price projected for the USA in 1995 by the US Department of Energy (85).

Performance and cost estimates for the conventional steam plant, the PFBC-combined cycle, and the IGCC are from the Electric Power Research Institute (86). The conventional steam plant uses wet flue gas desulfurization. The PFBC-CC has a gas-turbine inlet temperature of 843°C and steam conditions of 163 bar, 538°C. The IGCC utilizes oxygen-blown Texaco gasification with cold gas cleanup and gas-turbine inlet temperatures of 1093°C and 1204°C for the 100-MW and 600-MW units, respectively.

Performance and cost estimates for the coal-ISTIG, utilizing an air-blown dry-ash Lurgi gasifier, hot sulfur and particulate cleanup, and an intercooled steam-injected LM-5000 gas turbine, are from (13).

Performance and cost estimates for the biomass-STIG and ISTIG are discussed in the text.

The PFBC and IGCC have undergone successful technology demonstrations. The STIG-based systems have not.

(STIG) to be substituted for the simple-cycle gas turbine. With a STIG, steam not needed for heating is instead injected into the gas turbine combustor and/or expander to raise electrical output and efficiency. For example, a gasifier-gas turbine system based on the General Electric LM-5000 would produce an estimated 53 MW_e at 32.5% efficiency with full steam injection (42), compared to 39 MW_e at 28.6% efficiency with no injection (Table 6). The added flexibility with steam injection may be advantageous in the many potential biomass applications where heat demands vary widely, e.g., crop-processing facilities or district heating plants that operate seasonally, and where excess electricity can be marketed, e.g., sold to a utility.

Table 6 shows performance estimates for two sizes of simple cycles and one simple/heat pump cycle compared with those for two different sized conventional back-pressure steam turbines.[18] The gas turbine based systems would have higher electrical efficiencies than steam turbines. Their electricity-to-heat production ratio (E/H) would also be higher, which means they would produce more electricity while supplying a given amount of heat. The simple-cycle option without the heat pump would have a relatively low total efficiency compared to the other options.

The economic viability of alternative cogeneration options would depend on relative biomass, heat, and electricity prices. Gas turbines would tend to be favored on a capital cost basis, particularly in smaller sizes. For example, estimated installed unit costs for biomass-gasifier systems based on steam-injected gas turbines are lower and less sensitive to scale than those for steam turbines (Figure 6). The lower sensitivity to scale is particularly important since there are potentially many small biomass applications.

4 Implications for Regions with Biomass Resources

4.1 Sweden

In the decades ahead, Sweden will be seeking alternative fuels and electricity-generating technologies to replace existing nuclear capacity. Sweden has no indigeneous fossil fuel resources and limited unexploited hydroelectric

[18] Consistent estimates for combined cycles are not available. However, see (43) for some discussion of biomass-gasifier combined cycle cogeneration.

Table 6. Estimated full-load output and efficiencies of biomass-fired cogeneration systems (higher heating value basis).

	Electricity		Heat		Electricity-to-heat ratio	Total Efficiency (%)
	MW	Eff. (%)	MW	Eff. (%)		
Simple-cycle[a,b]						
LM-5000	39	28.6	37	27.3	1.05	56
LM-1600	15	27.1	17	30.7	0.88	58
SC + Heat pump[c]						
LM-5000	39	28.6	55	40.0	0.71	69
Steam turbine[d]						
Back-pressure	18	25.9	36	51.8	0.50	78
Back-pressure	4.3	20.4	12	57.1	0.36	78

[a] From (42) for systems using Lurgi-type fixed-bed gasifiers with 15% moisture content biomass fuel. The heat would be generated as steam at 20 bar, 316°C in a heat recovery boiler. The full steam production would be about 20% greater than indicated, but some of the steam would be used for cooling in the gasifier. With a fluidized-bed gasifier more steam would be available for heating since the gasifier would not require any.

[b] These are aeroderivative turbines made by General Electric for natural gas applications. The LM-5000 is available with steam injection. The turbine inlet temperature and compression ratio are approximately 1200°C and 25:1, respectively, in both machines.

[c] This system would be a modification of the simple cycle LM-5000. Some steam produced in the heat recovery boiler would be used to drive absorption heat pumps with an assumed coefficient of performance of 1.7. The heat source for the heat pump would be water at about 55°C generated by recovery of the sensible and latent heat in the gas turbine exhaust between 80°C and 35°C (using a direct-contact condensing heat exchanger.) (A small amount of steam would also be used to reheat the cool, dry exhaust before it leaves the stack.) The total heat production of 55 MW is the sum of the output of the heat pump (31 MW), the sensible energy recovered from the turbine exhaust (after the waste heat boiler) between 140°C and 80°C (8 MW), and the portion of the steam not used to drive the heat pump or heat the stack gas (16 MW). In a district heating system, the 55 MW of heat would raise water from typical return temperatures of 55-60°C to delivery temperatures of 85–90°C.

[d] Estimated for new plants in Sweden using 15% moisture content wood chips, based on (62).

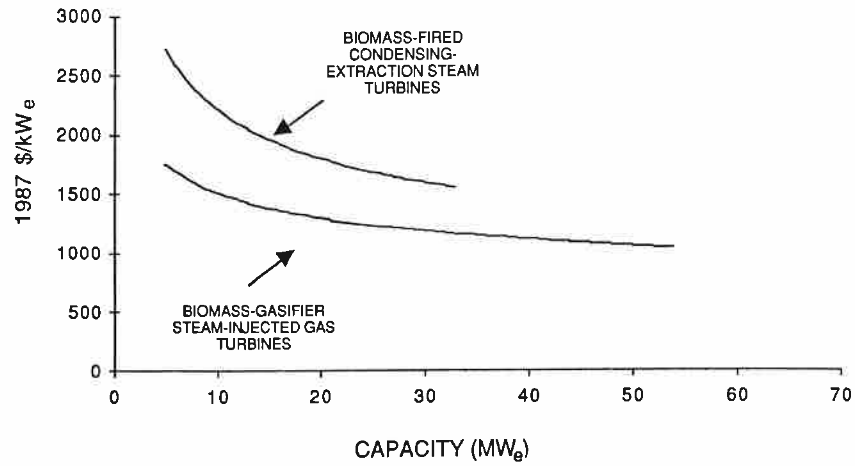


Figure 6. Estimated installed capital costs (1987 $\$/kW_e$) for biomass-gasifier steam-injected gas turbine and condensing-extraction steam turbine cogeneration systems (42).

potential. And increasingly stringent environmental regulations will decrease the attractiveness of using coal.[19] Imported natural gas will likely be available, but costs are uncertain. Wind might supply some electricity, though the economics are also uncertain.

Sweden has significant biomass resources which might be used with gas turbines to generate some of its future electricity needs. Biomass fuels are already used to a significant extent today for heat supply, but generate less than 2% of Sweden's electricity. The potential production of electricity from biomass gas turbine central station or cogeneration units would depend on the commercial readiness of the technology and on the availability and cost of biomass.

4.1.1 Biomass supply and cost

Sweden's potential sustainable production of biomass energy is estimated to be some 730 PJ per year, about three times its current use (Table 7). Some 360

[19] In the spring of 1988, the Swedish Parliament passed a recommendation that in the future net carbon dioxide emissions should not exceed the present level. In addition, most new electricity and/or heat producing plants must comply with very stringent sulfur dioxide and nitrogen oxide emission regulations: allowed emissions of sulfur and nitrogen are half (or less) of those allowed by the New Source Performance Standards in the USA.

Table 7. Current use of biomass fuels in Sweden and estimated long-term potential supplies and costs.

	Used in 1987[a]		Long-Term Potential Supplies		Costs
	(PJ)	(TWh)	(PJ)	(TWh)	($/GJ)[b]
Forest-industry residues	*212*	*59*	*356*	*99*	
Forest residues[c]	54	15	198	55	2.0–2.6[d]
Pulping liquors[e]	104	29	104	29	0
Other byproducts[f]	54	15	54	15	0–1.7
Plantation fuelwood[g]	*0*	*0*	*302*	*84*	2.4–3.4
Other	*14*	*4*	*68*	*19*	
Refuse-Derived Fuel[h]	14	4	14	4	0
Straw[i]	0	0	54	15	?
Total	*234*	*65*	*726*	*202*	

[a] From (63).

[b] Higher heating value basis for 50% mc chips, including 30-km transport for plantation fuelwood and 50-km transport for forest residues. [For comparison, $3.4/GJ (HHV basis) is SEK 0.1/kWh (LHV basis).] For drying to 15% mc, the extra cost would be $0.5 to $0.6/GJ (64).

[c] Forest residues include mainly tops and branches from Norwegian Spruce, Scots Pine, and birch, and whole trees from thinning. The long-term potential reflects limits imposed by environmental considerations: *no important irreversible effects and no deterioration of the long-term soil productivity* (65). The potential accounts for ecological reductions following recommendations in (66). Thus, the actual volume of tops and branches produced is about 70% greater than the estimated recoverable volume. In addition, no removal of stumps is assumed.

[d] Production costs assume integrated recovery of energy and industrial feedstocks using the tree-section method (67). Total costs are fairly sensitive to transport costs: the cost is increased by 18% for 100-km vs. 50-km transport.

[e] Byproduct of the pulp and paper industry, currently used for steam and electricity production. The long-term potential is assumed to be today's use. Zero cost is assumed since it now has no important alternative uses.

[f] Currently approximately 9 TWh are used in the pulp and paper industry (mostly bark and other moist products) and 6 TWh in sawmills (bark and relatively dry sawdust) (63). The long-term potential is assumed to be the same as today's use. The upper cost limit is the current market price for off-site use (68). Zero cost is assumed for on-site use.

[g] Intensively cultivated Salix or Populus on agricultural land with an assumed average yield of 17 tonnes dry matter per hectare per year (45). The indicated potential assumes the use of some 1 million hectares of surplus agricultural land. Currently, some 300,000 hectares could be considered surplus. Some 500,000 hectares could be available by 1990 (69). Continued agricultural productivity growth would result in 1 million hectares by 2000 (70). Costs are based on (45,71).

[h] Current use is in district heating (63). The total long-term potential is assumed to be today's use.

[i] Potential is what would be available after reduction for soil humus preservation, cattle stable use, etc (70).

PJ/year are generated today as forest residues or industrial byproducts, 60% of which are currently used. Short-rotation energy plantations of willow and poplar trees, which are currently under development (45), could provide an additional 300 PJ/year. The development of this potential must be seen in the perspective of decades, however, because it requires a major restructuring of the use of agricultural land.

The costs of producing biomass in Scandinavia are generally higher than in many regions of the world (see Section 4.2). The present market price for wood chips from forest residues in Sweden, about \$3.4/GJ,[20] reflects the current costs of recovering the residues separately from other forest-industry feedstocks. Integrating the recovery processes would lower the cost for such chips to \$2.0–2.6/GJ (Table 7). The cost of industrial byproducts (bark and sawdust) would be for handling and transport, implying essentially zero cost for onsite use. Chips from short-rotation fuelwood plantations are estimated to cost \$2.4–3.4/GJ.

4.1.2 Biomass-based electricity production

Biomass-based gas turbine electricity generation could be considered for Sweden. A commitment to large-scale use of biomass would probably be accompanied by a shift in forestry practices toward more economically efficient integrated residue recovery and a concerted effort to develop energy plantations. A reasonable long-run cost of biomass would therefore be in the neighborhood of \$2.5/GJ–at the upper end of estimated costs for integrated recovery of residues and the lower end of estimated costs for plantation fuelwood (Table 7). Drying the fuel, as required for gasification, would raise this cost to about \$3/GJ. (See Table 7, note (b).)

Central-station power

With biomass costing \$3/GJ, and based on the cost and performance estimates for 50–100 MW steam-injected gas turbine systems given in Section 3.1, central station plants would produce power at a cost in the range of 4.8 ¢/kWh to 5.7 ¢/kWh (Figure 5). With lower-cost forest residues (\$2.5/GJ), the busbar cost range would be 4.3–5.2 ¢/kWh.[21] With these costs, biomass power plants

20 Note that higher heating values are used for fuels in this paper. (See footnote 15.) The \$3.4/GJ is for wood chips with 50% moisture content.

21 Larger combined cycles (> 200-MW_e) may produce electricity at comparable, but not lower costs.

would be competitive with much larger condensing coal-steam plants and advanced coal-fired PFBC and IGCC systems (Figure 5). The biomass option would clearly have the advantage if a cost were assigned to the net emissions of CO_2 from coal-fired plants.

Cogeneration

Gas turbine cogeneration might also be considered as part of a biomass-based electricity supply strategy in Sweden. The higher electricity-to-heat production ratios compared to steam turbines would permit larger quantities of electricity to be cogenerated while meeting a given heat demand. Potentially important applications include those in the pulp and paper industry, a well-established user of bioenergy, and in district heating (DH). DH applications are considered here. Some DH plants use biomass for fuel today, but more widespread biomass-based DH could be considered since most communities are surrounded by actively managed forests or agricultural land that could be used to produce biomass.

District heating (DH) systems today produce about 40 TWh/yr of heat,[22] primarily from plants providing heat only. A typical load duration curve for heat production in a DH system includes a temperature-dependent component superimposed on a relatively constant component (domestic hot water supply) (Figure 7). A mix of individual plants is operated to provide the required heat while minimizing operating costs. Heat that is produced with the lowest operating cost typically comes from refuse-derived-fuel incinerators, industrial waste heat, or sewage-water heat pumps. The next increment is typically supplied by baseload plants (including cogeneration units in some cases) sized to operate for about 5000 equivalent full-load heating hours per year.[23] Such plants would annually provide about 3/4 of the heat required in the system (shaded area in Figure 7). Oil or, in some cases, natural gas-fired boilers with minimal capital costs are typically used to supply peak demand.

If a biomass-gasifier combined-cycle or STIG-heat pump cycle were designed as a baseload DH plant, it would follow heat demand and could increase electricity production when heat demand falls. To estimate a cost

22 Total demand for district heat is not expected to rise significantly in the future. Increases in district heating demand due to growth in the number of connected buildings are likely to be offset by increases in building energy efficiencies. Efficiency improvements could even lead to a reduction in total heat demand.

23 The output of an individual DH plant varies over the year, depending on heat demand. A unit operating for 5000 equivalent full-load heating hours produces cumulatively as much heat in 8760 hours (one year) as the same plant would produce if operated at full heat output for 5000 hours.

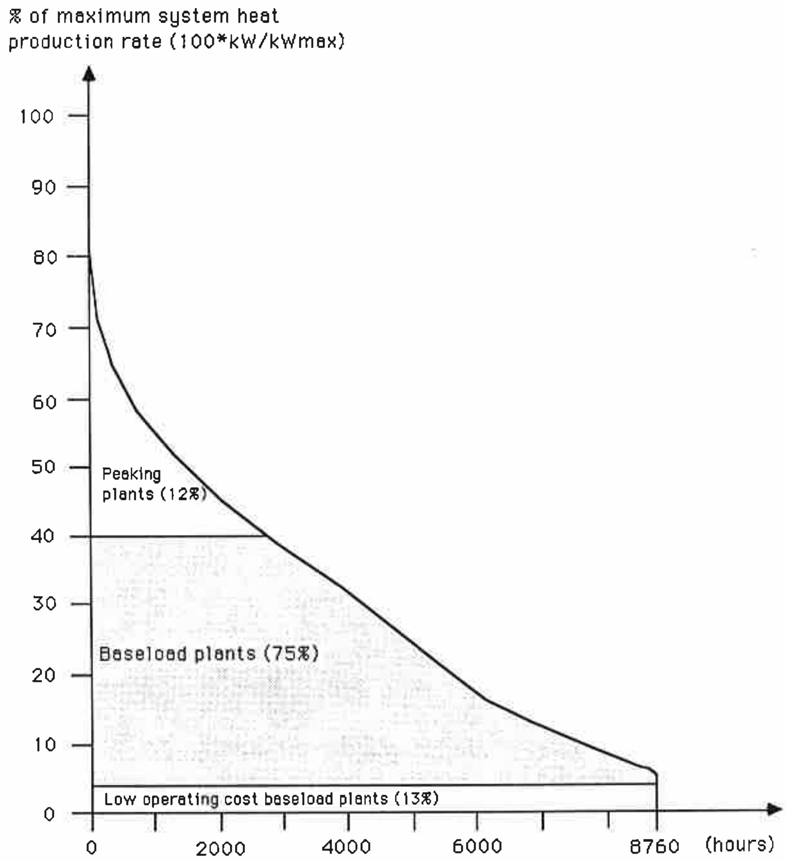


Figure 7. Typical load duration curve for heat production in a Swedish district heating system, representing the combined output of a number of individual plants. The fraction of the system's maximum heat production rate is shown versus the number of hours per year that production reaches this level or higher. The lowest operating-cost plants, e.g. refuse-derived-fuel incinerators, industrial waste-heat recovery, and sewage-water heat pumps, typically supply the first increment of baseload heat, in this case 13% of total annual heat production. Other baseload plants provide most of the heat (75% in this case), as indicated by the shaded area, which corresponds to operation of the baseload plants for 5000 equivalent full-load heating hours (see footnote 23). Higher operating-cost units, e.g., oil or natural gas-fired boilers, produce heat during peak demand periods.

range for the electricity that would be cogenerated, we consider a STIG-heat pump DH plant with the characteristics described in Table 6, the heat production of which is assumed to match the shaded area in Figure 7. The plant would produce heat at its maximum rate of 55 MW for approximately 2700 hours per year. Excess heat would be available as steam during the rest of the year. The excess steam could be injected to raise electricity output from 39 MW_e (Table 6) up to a maximum of 53 MW_e (if no steam at all were used for heating). If all steam not needed during the year for heating were used to boost electricity output, the resulting annual electricity-to-heat production ratio (E/H) for the system would be 1.4.[24] If only one-third the potential electricity output were generated during the three summer months, when electricity demand is lowest in Sweden, the annual E/H would be 1.1.

For this latter operating scenario, the cost of cogenerating electricity with the gas-turbine systems would range from 4.5–5.6 ¢/kWh (3.9–5.0 ¢/kWh), with biomass costing \$3/GJ (\$2.5/GJ) and assuming a credit for heat based on an avoided fuel cost of \$2.0–5.0/GJ (Figure 8). (Higher avoided fuel costs lead to larger credits for heat and, thus, lower costs of power.) The lower displaced fuel cost would be representative of heavy fuel-oil (at \$20/bbl for crude), while the higher prices might be representative of future natural gas prices. These electricity costs would be competitive with efficient central station power based on natural gas for a gas price higher than about \$4.5/GJ (with biomass at \$3/GJ) or higher than \$4/GJ (with biomass at \$2.5/GJ) (Figure 8). (For comparison, Sweden's National Energy Administration indicates that gas prices for perhaps the next decade may range from \$3.5/GJ to \$5.0/GJ (46).) Even assuming low gas prices, the cogenerated power would be less costly than that from new, large coal-fired central station power plants (Figure 5).

4.1.3 Overall potential

On a per-capita basis Sweden's biomass resources are large relative to those of most other industrialized countries. Sweden is therefore in an enviable position of having the option to use some of these resources to meet future energy needs. This option may become increasingly attractive as the use of fossil fuels grows increasingly troublesome due to rising costs and environmental problems such as the global greenhouse warming. The biomass resource is limited, however, so using it efficiently would be extremely important.

24 If the plant were to operate with full heat output year-round, the E/H would be 0.71 (Table 6). The E/H of 1.4 assumes the heat output varies as shown in Figure 7 and that electricity output increases linearly as the heat output is decreased. (Zero heat output would correspond to 53 MW_e.)

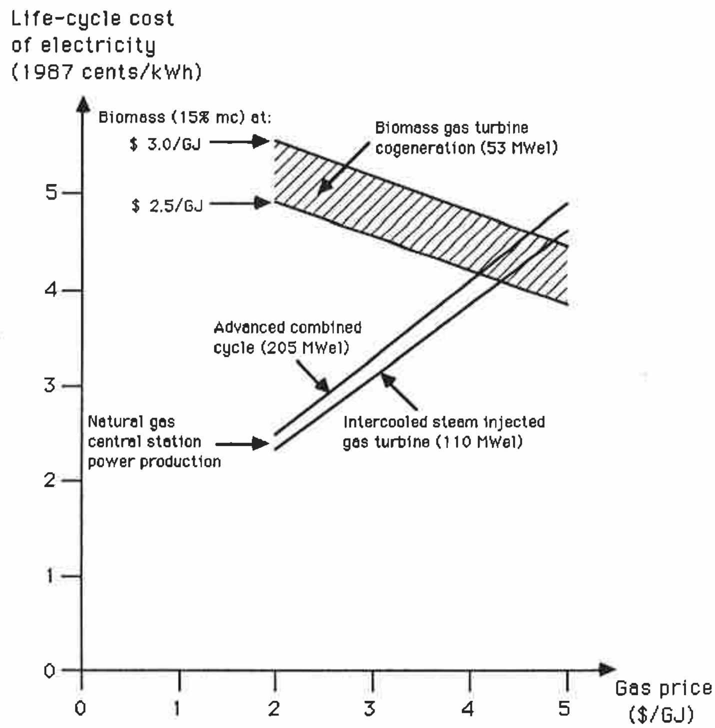


Figure 8. Calculated lifecycle electricity production costs with biomass-gasifier gas turbine district-heating cogeneration compared with the costs of efficient natural-gas fired central station power as a function of the assumed gas price.

The cogeneration system is based on a STIG-heat pump system (Table 6, note c), the heat production of which follows Figure 7, with a total of 5000 equivalent full-load heating hours (see footnote 23). With full heat production, the system performance would be as in Table 6. When producing no heat, the system would produce 53 MW at 32.5% efficiency by steam injection. Electricity production is assumed to increase linearly with decreasing heat production. As discussed in Section 4.1.2, the assumed system operating strategy yields an annual electricity-to-heat production ratio of 1.1 (and an electrical capacity factor of 62%).

The total estimated installed capital cost for the cogeneration unit is $67 million ($1100/peak kW_e for the STIG (Figure 6) plus $280/$kW_{th}$ for 31 MW_{th} of absorption heat pump.) Based on (43), fixed annual maintenance costs are assumed to be 3% of capital costs, variable costs are 2 mills/kWh_e, and labor costs are $0.65 million per year. The calculations assume a 6% discount rate, 30-year life, and 90% equipment availability.

The credit for heat is the cost to produce the same amount of heat in a stand-alone natural gas boiler with a capital cost of $77/$kW_{th}$, non-fuel operating costs of $3.1/$kW_{th}$-yr, and a higher heating value efficiency of 84% (92% LHV).

The assumed installed capital costs (efficiency) for the natural gas central station power plants are $420/kW (47%) and $510/kW (45%) for the ISTIG and advanced combined cycle, respectively, and operating and maintenance costs are 0.3 ¢/kWh (3). A 6% discount rate, 30 year life, and 70% capacity factor are used.

To illustrate the potential contribution of biomass-gasifier gas turbine systems in the long term, we consider the use for electricity production of the potentially available biomass resources in Sweden that are not currently utilized, i.e., a biomass fuel use of up to 500 PJ (Table 7).

A biomass cogeneration strategy might be considered, e.g., based on gas turbine district heating systems. An estimate of the potential electricity cogeneration in Sweden can be made by assuming Figure 7 to represent the DH profile for all of Sweden, with the shaded portion (75%) supplied by gas turbines with the operating characteristics of STIG-heat pump systems. In this case, the annual E/H of 1.1 discussed in Section 4.1.2 would apply to Sweden as a whole. For an assumed total district heat demand of 40 TWh, therefore, some 33 TWh of electricity would be cogenerated (0.75*40*1.1 = 33), which would require about 400 PJ of fuel.[25] The approximate monthly distribution of electricity production with such a strategy would be as shown in Figure 9 superimposed on the 1986 Swedish electricity production. Figure 9 reflects the cogeneration operating scheme discussed in Section 4.1.2, but a variety of other strategies are conceivable, since the overall electricity-to-heat ratio for gas turbine systems could be varied over a wide range.

Alternatively, with a central station strategy, e.g., based on biomass-gasifier ISTIG technology with an efficiency of 38%, the 500 PJ of fuel could produce some 53 TWh of electricity.

The potential 33–53 TWh of electricity from biomass would represent 25–40% of current total generation, or 50–80% of nuclear production. Thus, *in the long term, if electricity demand were reduced through end-use efficiency improvements (47), hydro and biomass sources combined could provide all of Sweden's electricity needs.*

How rapidly biomass-gas turbine electricity production could be introduced would depend firstly on the successful commercial development of the technology. It would also depend on the availability of feedstocks and the extent to which they are committed to power generation. (If a cogeneration strategy were pursued, the rate of capital stock turnover would also be important.) Forest industry residues are an attractive initial fuel source. Some 160 PJ are currently recoverable but unused (Table 7), which alone would

[25] An alternative cogeneration strategy based on back-pressure steam turbines could also be used to meet the district heating demand and would produce electricity at lower cost than the gas turbine strategy considered here. However, because of the much lower electricity-to-heat ratio of steam turbines (0.3–0.5), these would need to be augmented by other electricity sources to produce the same amount of power as with the gas turbines. To maintain overall biomass-based electricity costs and resource use comparable to those with the gas turbine cogeneration strategy, efficient central station power would be required, e.g. based on gasifier-ISTIG or combined cycle technology.

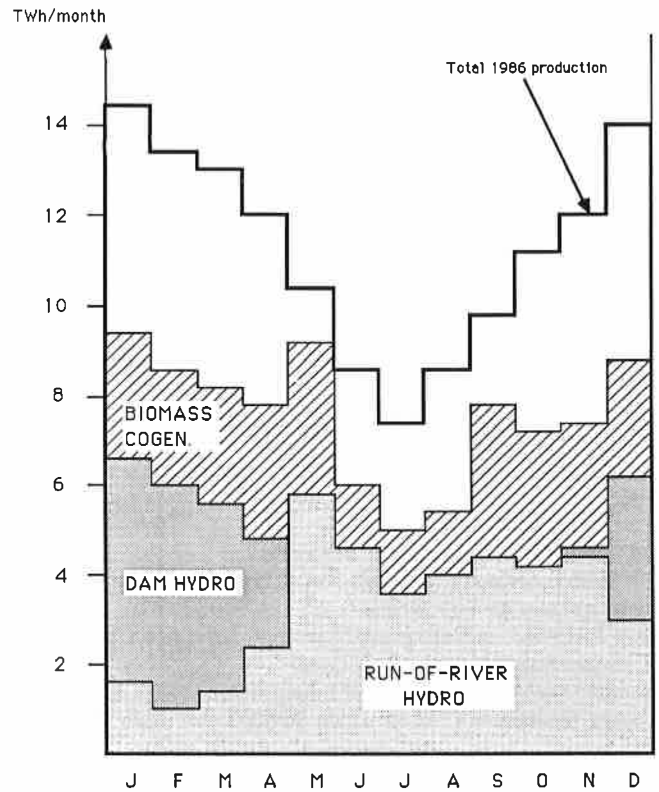


Figure 9. The potential electricity supply in Sweden from biomass-fueled gas turbine district heating cogeneration plants is shown superimposed on the total 1986 Swedish electricity production. Nearly all non-hydroelectricity was supplied by nuclear plants in 1986. The distribution of the hydroelectric supply can vary to some extent from year to year depending on rainfall variations and the operating strategy chosen.

support the production of some 14 TWh of cogenerated electricity. This initial use of residues would provide time to fully develop fuelwood plantations.

4.2 Worldwide

Biomass-based gas turbine power generation would be even more economically attractive in the many regions of the world where better climate and lower labor rates lead to lower biomass production costs, e.g., in many developing countries (Table 8).

Table 8. Estimated cost of producing biomass chips from fuelwood plantations.[a]

Region	Species	Cost (1987$/GJ)
Sweden	Salix, Populus	2.4–3.4[b]
Finland	Birch	3.1[c]
USA, Hawaii	Eucalyptus	1.4–2.0[d]
India, Uttar Pradesh	Eucalyptus, Acacia, others	1.9
Thailand	Pine, Eucaplytus, Casuarina	1.7–1.9
India, West Bengal	Ecalyptus	1.7
Brazil, Minas Gerais	Eucalyptus saligna	1.5
Brazil, Minas Gerais	Eucalyptus	1.4[e]
Haiti	Leucaena, Albizia, Cassia, others	1.4
India, Gujarat	Albizia, Acacia	1.4
Philippines	Leucaena, Albizia	1.0

[a] Production cost from (72) (except where otherwise noted) for fuelwood from dedicated or multi-purpose plantations, with $0.30/GJ added for chipping and $0.30/GJ added for transport.

[b] For fuelwood from dedicated plantations. See Table 7.

[c] From (73) for birch pulpwood (the lowest cost pulpwood in Finland) delivered to the mill. Delivered forest residues are estimated to cost $1.7/GJ to $2.6/GJ.

[d] For plantation fuelwood, including establishment, harvesting, and chipping. Based on ongoing 300-hectare trial on the island of Hawaii (74).

[e] Based on detailed yield data and establishment, maintenance and harvesting costs for dedicated energy plantations (75), to which $0.60/GJ has been added for chipping and transport.

With biomass costs of less than $2/GJ, central station steam-injected gas turbine plants would be economically competitive power producers (Figure 5). In addition, in many developing countries, the small scale of the steam-injected units would be well-matched to small utility grids which cannot accommodate large (500–1000 MW) new power plants (48). Maintenance characteristics of the technology are also attractive (3). Its low capital intensity is an added attribute, as is its requirement for local rather than imported fuels.

Gas turbines might also be operated as cogenerators fueled by biomass made available as an industrial byproduct. Of course, some of these byproducts would be used for other purposes, as they are today. A detailed analysis of gas turbine cogeneration in the cane sugar industry (49) shows, however, that although bagasse, a byproduct from the crushing of cane, is often fully utilized at present in meeting the on-site energy needs of the sugar factory, it is typically used very inefficiently. Thus, it would be economical for the typical sugar producer to improve process energy efficiency and install a steam-injected gas turbine fired with gasified cane residues. For one Jamaican sugar

Table 9. Estimated potential gas turbine generating capacity (in 1000s of MW) supportable with current biomass residue production.[a]

Residue Source	Asia[b]	Africa	Latin America	Industrial Market Economies	World
Saw mills[c]	32.0	1.2	4.8	44.1	82.1
Sugar cane[d]	13.9	4.9	27.9	4.8	51.5
Pulp mills[e]	1.8	0.1	1.0	16.6	19.5
Corn Stover[f]	10.9	2.7	4.5	30.7	48.8
Rice husks[g]	18.0	0.3	0.5	0.3	19.1
Total	76.6	9.2	38.7	96.5	221.0

[a] Assuming 33% conversion of residues to electricity and a 75% capacity factor.

[b] Includes the Soviet Union.

[c] For the 1983 level of sawnwood production (76), assuming 0.7 bone-dry tonnes of residue per m^3 of sawnwood (77) and 20 GJ/tonne.

[d] For 1985 level of cane production. Residues include bagasse and approximately half the cane trash (tops and leaves) (49).

[e] For the 1983 level of chemical pulp production (76), assuming from each tonne of pulp 3.1 GJ of bark and 13.1 GJ of black liquor are derived (78).

[f] For the 1985 level of corn production (79), assuming each tonne of corn produces 0.5 tonnes of stover (15 GJ/tonne). About 0.75 tonnes of stover are actually produced, but only 2/3 of this can be removed without damaging soil productivity (80).

[g] For the 1983 level of rice production (81), assuming 0.2 tonnes of rice husks (15 GJ/tonne) are produced from each tonne of rice (82).

factory, it has been estimated that electricity output could thereby be increased more than 20-fold while still meeting onsite energy needs. For the local electric utility, buying the excess electricity would be more economical than building a new central station coal-fired plant. The total amount of cane-based excess electricity that could be produced in Jamaica is estimated to be about two-thirds of that nation's present utility production.

Such cogeneration possibilities appear to exist in many countries. The potential gas turbine electricity generating capacity that could be supported worldwide by the residues of sugar cane, corn and rice, sawmills, and the pulp and paper industry is about 220 GW at current rates of residue production (Table 9).[26] This is equivalent to about 10% of the installed electric generating capacity in the world in 1984 and would represent a total investment of about $300 billion.

[26] This estimate does not include a large fraction of the forestry residues that are currently unutilized, which may be a significant resource in some countries, such as in Sweden.

5 Conclusions

The biomass-gasifier gas turbine would be an attractive technology for efficiently utilizing biomass resources for energy, but the technology is not commercially available today. The assessment here of the state of gasification technology and required developments for gas turbine applications indicates, however, that it could probably be developed in a few years, given an appropriate level of effort. Such a short time is conceivable because previous and ongoing work on coal-gasifier gas-turbine systems, PFBC systems for coal and biomass, and pressurized gasification of biomass for methanol production provide a headstart in the development process. In addition, biomass gas turbine systems would not require the commercial demonstration of any fundamentally new technology. In particular, hot sulfur removal, the commercial-scale viability of which has not been proven for coal-gasifier gas-turbine systems, would not be required with biomass. The overall development time would be further reduced since the scale of a demonstration plant would be comparable to that of a commercial plant, eliminating the need for significant scale-up work.

The unique work required for the development of the biomass gas turbine technology would be the demonstration of gasification and hot gas cleanup systems with biomass feedstocks and gas turbines. We have identified some of the key technical considerations that would need to be addressed in such a demonstration project, as well as some potential candidate gasification systems. Sweden might be a promising setting for such a demonstration because of its extensive experience in the development of biomass gasification systems, including pressurized units, and the design, installation and operation of gas turbines.

Acknowledgements

The authors thank Mattias Lundberg for assistance in calculating energy balances for gas turbine/heat pump cogeneration systems.

Partial financial support in the preparation of this paper is gratefully acknowledged by EDL from the Office of Energy of the US Agency for International Development, Washington, DC and by PS from the Swedish Energy Research Commission (Efn).

References

1. Peters, W. 1989. Coal gasification technologies for combined cycle power generation. This volume.
2. Penner, S. S., et al. 1987. Coal gasification: direct applications and synthesis of chemicals and fuels. *Energy.* 12(8/9).
3. Williams, R.H., Larson, E.D. 1989. Expanding roles for gas turbines in power generation. This volume.
4. Hodam, R., Williams, R., Lesser, M. 1982. *Engineering and economic characteristics of commercial wood gasifiers in North America.* Golden, Colorado: Solar Energy Res. Inst.
5. Furtado, P., Antunes, R.C. 1985. *Commercial applications of biomass gasifiers in Brazil.* Presented at 2nd Intl. Producer Gas Conf., Bandung, Indonesia.
6. Baker, E.G., Mitchell, D.H., Williford, J.F. 1980. *Assessment of large scale biomass gasification systems for less developed countries.* Richland, Washington: Battelle Pacific NW Lab.
7. National Res. Council. 1983. *Producer Gas: Another Fuel for Motor Transport.* Wash., DC: Natl. Academy Press.
8. Rensfelt, E. 1987. *Cogeneration using gasification and diesel engines.* Nyköping, Sweden: Studsvik Energy AB.
9. Reed T.B., Das, A. 1988. *Handbook of Biomass Downdraft Gasifier Engine Systems (SERI/SP-271–3022).* Golden, Colorado: Solar Energy Res. Inst.
10. Antal, Jr., M.J. 1983. Biomass pyrolysis: a review of the literature, part 2: lignocellulose pyrolysis. *Advances in Solar Energy.* 2:175–255.
11. Milne, T. 1979. Pyrolysis: the thermal behavior of biomass below 600°C. In *Survey of Biomass Gasification,* II:95–131. Golden, Colorado: Solar Energy Res. Inst.
12. Graboski, M.S. 1982. Comparison of coal and wood as feedstocks for methanol manufacture. *Proc. Biomass-to-Methanol Specialists' Workshop (SERI/CP-234–1590),* ed. T.B. Reed, M. Graboski, 41–59. Golden, Colorado: Solar Energy Res. Inst.
13. Corman, J.C. 1986. *System analysis of simplified IGCC plants.* Schenectady, New York: General Elec. Corp. Res. Center (for US Dept. of Energy).
14. Furman, A.H. 1987. personal communication. Schenectady, New York: General Elec. Corp. Res. Center.
15. Smith, D.P. 1982. *Feasibility investigation: gasification of simplex briquettes.* Schenectady, New York: Mechanical Technology, Inc. and General Elec. Corp. Res. Center (for New York State Energy Res. and Dev. Authority).
16. Teggers H., Nitschke, E. 1986. *The Rheinbraun high-temperature Winkler (HTW) process and its application for the production of synthesis gas and town gas.* Presented at 4th Adv. Coal Gasification Symp., Suzhou, China.
17. Evans, R.J., Knight, R.A., Onischak, M., Babu, S.P. 1988. *Development of biomass gasification to produce substitute fuels (PNL-6518).* Richland, Washington: Battelle Pacific NW Lab.
18. Lindman, N. October 1988. personal communication. Göteborg, Sweden: Götaverken Energy AB.
19. Buckman, J.W., Cover, A.E. 1988. The Appalachian project. *Proc. 8th Annual Gasification and Gas Stream Cleanup Systems Contractors Review Meeting, 1988 (DOE/METC-88/6092),* 1–10. Morgantown, West Virginia: USDOE Morgantown Energy Technology Center.
20. Keller, J. July 1988. personal communication. Dortmund, FRG: Udhe GmbH.
21. A. Ahlström, Inc. Nov. 16, 1988. press release. Karhula, Finland: R&D Center.

22. Viel Lamare, C. Nov. 1988. personal communication. Stockholm: Ahlström Boilers.
23. Sinclair A., Waldheim, L. 1985. *MINO feasibility study, concluding report (Studsvik Arbetsrapport-Technical Note).* Nyköping, Sweden: Studsvik Energiteknik AB.
24. Webb, P.R. 1987. *Wood-fired turbine emissions measurements.* Columbus, Ohio: Battelle Columbus Lab.
25. Corman, J.C., Horner, M.W. 1986. Hot gas clean-up for a moving bed gasifier. *Proc. 5th Annual Contractors' Conf. on Coal Gasification (AP-4680),* ch. 14. Palo Alto, Calif: Elec. Power Res. Inst.
26. Cherish, P., Holmgren, J.D. 1988. *Hot gas cleanup process demonstration of ceramic filters for IGCC power generation.* Presented at Elec. Power Res. Inst. Seminar on Fluidized-Bed Combustion Technology for Utility Applications, Palo Alto, Calif.
27. Wright, I. G., Stringer, J. 1986. *Erosion and corrosion considerations for PFBC gas turbine expanders (86-GT-217).* Presented at Am. Soc. Mech. Engineers' Intl. Gas Turb. Conf., Dusseldorf, FRG.
28. Westinghouse Elec. Co. 1986. *Alternative combustion turbine designs and cleanup systems for pressurized fluidized-bed combustion power plants (CS-4860).* Palo Alto, Calif: Elec. Power Res. Inst.
29. Notestein, J. 1988. *Update on Department of Energy hot gas cleanup programs.* Presented at 8th Elec. Power Res. Inst. Coal Gasification Conf., Palo Alto, Calif.
30. Brown, M.G., Baker, E.G., Mudge, L.K. 1987. Evaluation of processes for removal of particulates, tars, and oils from biomass gasifier product gases. In *Energy from biomass and wastes X*, ed. D.L. Klass, 655–77. London and Chicago: Elsevier Appl. Sci. and Inst. of Gas Technology.
31. Holmgren, J.D. 1986. *The KRW hot gas cleanup coal gasification process.* Presented at 4th Adv. Coal Gasification Symp., Suzhou, China.
32. Scandrett, L.A., Clift, R., 1984. The thermodynamics of alkalai removal from coal-derived gases. *J. of the Inst. of Energy.* Dec:391–97.
33. Horner, M.W. 1985. *Simplified IGCC with hot fuel gas combustion (85-JPGC-GT-13).* Presented at Jt. ASME/IEEE Power Generation Conf., Milwaukee, Wisconsin.
34. Mojtahedi, W., Backman, R. 1988. *Alkali metals volatilization in pressurized fluidized-bed combustion and gasification of peat.* Presented at 4th Intl. Fluidized Combustion Conf., London.
35. Sidebotham, G.S., Williams, R.H. 1989. *Technology of NO_x control for stationary gas turbines.* Princeton, New Jersey: Center for Energy and Environ. Studies, Princeton Univ.
36. Leppalahti, J., Stahlberg, P., Simell, P. 1988. Nitrogen compounds in peat and wood gasification and combustion. *Proc. Res. in Thermochemical Biomass Conversion.* London: Elsevier Appl. Sci.
37. Unnasch, S., Chang, R. 1988. Ammonia removal in coal gasification processes using integrated systems approach. *Proc. 8th Annual Gasification and Gas Stream Cleanup Systems Contractors Review Meeting, 1988 (DOE/METC-88/6092),* 1–10. Morgantown, West Virginia: USDOE Morgantown Energy Technology Center.
38. Meadowcroft, D.B., Stringer, J. 1987. Corrosion in coal-fired gas turbines. *Materials Sci. and Tech.* 3:562-70.
39. Reed, G.P. 1985. Filtration of high temperature fuel gases from a fluidised bed gasifier. *Filtration and Separation.* March/April:106–09.
40. Stinton, D.P., Lowden, R.A., Chang, R. 1987. Fiber-reinforced composite hot gas filters (ORNL/FMP-87/4). *Proc. Fossil Energy Materials Program,* 156–67. Oak Ridge, Tennessee: Oak Ridge National Lab.

41. Clift, R. 1988. Hot gas cleanup: the state-of-the-art and prospects for the future. *Proc. VTT Symp. 83: Pressurized Fluidized Bed Combustion and Gasification Power Systems,* 213–35. Espoo, Finland: Technical Res. Center of Finland.
42. Larson E.D., Williams, R.H. 1988. Biomass-fired steam-injected gas turbine cogeneration. *Proc. 2nd Intl. Symp. on Turbomachinery, Combined-Cycle Technologies and Cogeneration,* 57–66. New York: Am. Soc. Mech. Engineers.
43. Rensfelt E., Waldheim, L. 1986. *Vedbaserad elproduktion med förgasning och kombinerad cykel (Wood-based electricity production with gasification and combined cycle) (BF-86/8).* Stockholm: National Energy Admin. (In Swedish)
44. Synthetic Fuels Assoc. 1983. *Coal gasification systems: A guide to status, applications, and economics (AP-3109).* Palo Alto, Calif: Elec. Power Res. Inst.
45. *Energiskog (Energy plantations) (1985:9).* 1985. Stockholm: National Energy Admin. (In Swedish)
46. *El- och värmeproduktion med naturgas (Electricity and heat production with natural gas) (1987:R5).* 1987. Stockholm: National Energy Admin. (In Swedish)
47. Bodlund, B., Mills, E., Karlsson, T., Johansson, T.B. 1989. The challenge of choices: technology options for the Swedish electricity sector. This volume.
48. *The energy transition in developing countries.* 1983. Wash., DC: World Bank.
49. Larson, E.D., Ogden, J.M., Williams, R.H. 1987. *Steam-injected gas turbine cogeneration for the cane sugar industry: optimization through improvements in sugar-processing efficiencies (PU/CEES 217).* Princeton, New Jersey: Center for Energy and Environ. Studies, Princeton Univ.
49a. Graboski, M., Bain, R. 1979. Properties of biomass relevant to gasification. In *Survey of Biomass Gasification,* II:21–65. Golden, Colorado: Solar Energy Res. Inst.
49b. Fluor Engineers, Inc. 1985. *Cost and perfomance of Kellog Rust Westinghouse-based gasification-combined-cycle plants (AP-4018).* Palo Alto, Calif: Elec. Power Res. Inst.
50. Rensfelt, E. Nov. 1988. personal communication. Nyköping, Sweden: Studsvik Energy AB.
51. Miles T.R., Miles, Jr., T.R. 1988. Reliable feed systems for thermochemical conversion. *Proc. Res. in Thermochemical Biomass Conversion.* London: Elsevier Appl. Sci.
52. Reed, T.B., Levie, B., Graboski, M.S. 1987. *Fundamentals, development and scaleup of the air-oxygen stratified downdraft gasifier.* Golden, Colorado: Solar Energy Res. Inst.
53. Coffman, J. A. April 1988. personal communication. Ballston Spa, New York: Wright-Malta Corp.
54. Teggers, H., Scharf, H.J., Schrader, L. 1985. Gasification of biomasses by HTW-gasification process. *Proc. 3rd Intl. Conf. on Energy from Biomass,* ed. W. Palz, J. Coombs, D.O. Hall. London: Elsevier Appl. Sci.
55. Sipila, K. May 1988. personal communication. Espoo, Finland: Technical Res. Center of Finland.
56. Gravel, G., Chamberland, A. 1987. Testing and evaluation of a pressurized 10 t/h fluid-bed wood gasifier. In *Energy from biomass and wastes X,* ed. D.L. Klass. London and Chicago: Elsevier Appl. Sci. and Inst. of Gas Technology.
57. Drouin, G., Bechard, L., Du Chouchet, P. 1987. Electricity generated by a diesel engine running on lean gas produced from a biomass pressurized fluid-bed gasifier. In *Energy from biomass and wastes X,* ed. D.L. Klass. London and Chicago: Elsevier Appl. Sci. and Inst. of Gas Technology.

58. Onischak, M., Lynch, P.A., Babu, S. 1988. *Process and economic considerations for the gasification of pulp mill wastes using the Renugas process.* Presented at Conf. on Energy from Biomass and Wastes XII, New Orleans, Louisiana.
59. *The Otaniemi pressurized fluidized bed combustion and gasification research project.* 1988. Espoo, Finland: Technical Res. Center of Finland.
60. Herbert, P.K., Baguss, I., Loeffler, J.C. 1988. *Low-btu gas from bark and waste via CFB gasification.* Presented at Conf. on Energy from Biomass and Wastes XII, New Orleans, Louisiana.
61. Haldipur, G.B., Cherish, P., Lewandowski, D.A., Pavel, J. 1986. Hot gas cleanup using the KRW gasifier. *Proc. 5th Annual EPRI Contractors' Conf. on Coal Gasification (AP-4680)*, ch. 11. Palo Alto, Calif: Elec. Power Res. Inst.
62. *Småskalig kraftvärme (Small-scale cogeneration) (1986:1).* 1986. Stockholm: National Energy Admin. (In Swedish)
63. *Energiläget i Siffror (Energy in Sweden: facts and figures).* 1988. Stockholm: National Energy Admin. (In Swedish)
64. Munter, C. Sept. 1988. personal communication. Göteborg, Sweden: Svensk Exergiteknik AB.
65. Parikka, M. 1987. Hur mycket trädbränsle finns det? (How much wood fuel is there?). *Skogsfakta Konferens 10: Proc. Conf. on Forestry in Energy Supply.* Uppsala: Swedish Univ. of Agric. Sci. (In Swedish)
66. *General recommendations on limitations of recovery of tree sections in excess of stemwood on forest land (memorandum).* Dec. 2, 1985. Jönköping, Sweden: National Forestry Board (In Swedish)
67. Hildeman, A., Rutegård, G., Tibblin, G. 1986. *Träddelsmetoden-integrerad produktion av skogsbränsle och massaråvara (The tree-section method–integrated production of wood fuel and pulp feedstock) (Forest-Industry-Market Study No. 19).* Uppsala: Swedish Univ. of Agric. Sci. (In Swedish)
68. Lönner, G. Sept. 1988. personal communication. Uppsala: Forest-Industry-Market Studies, Swedish Univ. of Agric. Sci.
69. 1983 års livsmedelskommitte (1983 government committee on food production). 1984. *Slutbetänkande (final report).* Stockholm: Ministry of Agric. (In Swedish)
70. Stjernquist, I. et al. 1986. *Miljö och energi – framtida möjligheter och begränsningar (Environment and energy – future possibilities and limitations) (Rpt. 3238).* Stockholm: Swedish National Environ. Protection Board.
71. Parikka, M. 1988. *Ekonomisk analys av energiskogsodling (Economical analysis of short rotation forestry).* Uppsala: Forest-Industry-Market Studies, Swedish Univ. of Agric. Sci. (In Swedish)
72. Spears, J. (World Bank Forestry Div.). 1985. *Summary of World Bank supported projects with fuelwood components.* Presented at World Resources Inst. Conf. on Biomass Energy: Building Blocks for a Sustainable Agric., Airlie House, Virginia.
73. Marjokorpi T., Leppa, K. 1983. Northern European approach to wood energy. In *Industrial Wood Energy Forum '82, Vol. II*, 363–67. Madison, Wisconsin: Forest Products Res. Society.
74. Crabb T. (Bioenergy Dev. Corp.). 1987. Presentation at 2nd Pacific Basin Biofuel Workshop, Kauai, Hawaii.
75. Rodrigues de Almeida, M. 1987. personal communication. Belo Horizonte, Brazil: Charcoal, Technical Subproducts Department, Acesita Energetica.
76. Food and Agric. Org. 1985. *Yearbook of Forest Products.* Rome: United Nations.

77. Bergvall, J.A., Bullington, D.C., Gee, L., Koss, W. 1978. *Wood waste for energy study*. Olympia, Washington: Wash. State Dept. of Natural Resources.
78. Fors, J., Nord, B. 1980. Energianvändingen inom massa- och pappersindustrin, SCA-Nordliner i Munksund (Energy use in the pulp and paper industry, SCA-Nordliner factory in Munksund (STU 174–1980). Stockholm: Swedsh Board for Technical Development. (In Swedish)
79. US Dept. of Agric. 1986. *Agricultural Statistics 1986*. Wash., DC: US Govt. Print. Office.
80. Kresovich, S., McClure, T., Scantland, D. 1979. Field crop feedstock as renewable resources for energy production. *Proc. EPRI/GRI Workshop on Biomass Resources and Conversion,* 6–12. Palo Alto, Calif: Elec. Power Res. Inst.
81. US Dept. of Commerce. 1986. *Statistical Abstract of the United States*. Wash., DC: US Govt. Print. Office.
82. Beagle, E.C. 1978. *Rice-husk conversion to energy (Agric. Services Bull. No. 31)*. Rome: Food and Agric. Org., United Nations.
83. Antal, M.J. 1978. *Biomass energy enhancement*. Princeton, New Jersey: Dept. Mech. and Aerospace Engineering, Princeton Univ.
84. Waldheim, L., Rensfelt, E. 1982. Methanol from wood and peat. *Proc. Biomass-to-Methanol Specialists' Workshop (SERI/CP-234–1590)*. ed. T.B. Reed, M. Graboski, 239–59. Golden, Colorado: Solar Energy Res. Inst.
85. Energy Inform. Admin. 1987. *Annual energy outlook 1986, with projections to 2000 [DOE/EIA-0383(86)]*. Wash., DC: US Govt. Print. Office.
86. Planning and Evaluation Div. 1986. *Technical assessment guide, vol. 1: electricity supply–1986 (P-4463-SR)*. Palo Alto, Calif: Elec. Power Res. Inst.