POTENTIAL IMPACT OF BIOMASS-GASIFIER GAS TURBINES ON SWEDEN'S POWER SYSTEM

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ABSTRACT

Over the next decades new electricity supplies will be needed in Sweden, as the nuclear generating capacity of about 10 GW is phased out. Options include central station power generation as well as cogeneration of heat and power. For the latter, district heating systems and industrial process heat demands represent suitable heat sinks (10's to 100's of megawatts). Sweden has considerable biomass resources (forest residues, wood from energy plantations, straw, etc.) which might be used in the nuclear phase-out effort.

Gasification of biomass feedstocks provides an opportunity to use biomass efficiently in advanced gas turbine systems. An overview of Swedish biomass resources is given, followed by a technical and economic analysis of the potential impact on the Swedish power system of the widespread use of biomass-gasifier gas turbine power production. A large portion of the electricity produced today in the nuclear plants could be cost-effectively replaced using biomass-gasifier gas turbine systems, thus eliminating the need for a major expansion of fossil fuel use. The relatively modest development effort required to commercialize the gasifier-gas turbine technology is discussed in a companion paper.

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INTRODUCTION

Over the next decades new electricity production capacity will be needed in Sweden, as the nuclear generating capacity of about 10 GW is phased out. Biomass-based electricity production is an attractive option for many reasons: an indigenous source of energy and environmentally benign. Rapid developments with energy conversion technologies have brought about possibilities to produce electricity efficiently (both technically and economically) from this feedstock. The aim of this paper is to examine to what extent biomass-based gas turbine systems could contribute to the production of electricity in the Swedish context in the time frame of some 20-30 years. For a more detailed discussion of biomass-fired steam-injected gas turbines, see (13,14). The particular development of biomass gasification systems is treated in a companion paper (11).

Prospects for the development and future use of biomass-based electricity production in Sweden are good, in part because of serious efforts that have been and continue to be made to develop biomass for energy. The most important activity in this regard is a $155 million, 5-10 year development program focussed on electricity-from-biomass announced in August of 1989 by the Swedish State Power Board. This represents a major committment of development funds -- on a per-capita basis, the annual expenditures for this program alone are 15-30 times larger (depending on whether it is a 10 or 5 year program) than for all bioenergy development programs combined in the USA.

In this paper, we identify the potential biomass resources in Sweden and explore how they could be utilized effectiviely for power generation. The first section treats the availability and costs of biomass resources. The second section covers biomass conversion to electricity in biomass-gasifier gas turbine systems in central station and cogeneration applications, including district heating cogeneration. In the final section we discuss the total potential of biomass-based electricity production in Sweden.

Throughout the paper costs are expressed in constant 1987 US$. Costs in Swedish kronor (SEK) have been converted at 6.5 SEK/$. Also, 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.

BACKGROUND: SUPPLY AND USE OF ELECTRICITY IN SWEDEN

Swedish electricity supply and use are in a period of transition. On the supply side, the existing nuclear capacity, which accounts for about half of all electricity generated in Sweden (Table 1), will be phased out by 2010 as required by a national referendum passed in 1980, and later confirmed by the parliament. Sweden has no indigenous resources of fossil fuels, and several other constraints limit options for replacing the nuclear capacity: major hydropower expansions are outlawed, the use of fossil fuels are constrained by parliament decisions not to increase emissions of gases that would contribute to the global greenhouse warming and to reduce other pollutant emissions (most new electricity and/or heat producing plants must comply with very stringent sulfur dioxide and nitrogen oxides emission regulations: allowed emissions of sulfur and nitrogen are half or less of those allowed by the New Source Performance Standard in the USA).

National energy policy calls explicitly for greater use of indigenous and renewable sources of energy. Available primary energy sources in this category are mainly windpower and biomass. The economic costs of windpower are still unçertain. Biomass conversion to electricity is discussed below.

Electricity use has increased greatly during the 1980s, the major part of which consists of electricity for resistance heating -- currently more than 20% of total electricity use (4). Electricity for domestic purposes has been fairly constant, with increasing efficiencies allowing for steady growth in electricity services. Industrial electricity use has grown slowly with a small increase in electricity use per value added. During the same period oil use was decreased radically, both in industry and for low temperature heating (4).

It has been shown that the use of electricity on an overall basis could be made much more efficient, thus making an increase in electricity services possible while decreasing total electricity use (1). In Sweden, with a total per-capita electricity use twice that of the OECD average and 50% greater than that of the USA (10), resistance heating also offers an opportunity for electricity substitution. The widespread use of resistance heating brings about a very uneven annual power distribution, with a marked winter peak. Sweden's per-capita GDP was slightly greater than that of the OECD average in 1987, and some 30% smaller than that of the USA (10).

Table 1. Distribution of electricity use and supply in Sweden 1987 (TWh/year) (22).

Supply of electricity:	
Hydropower (a)	70.9
Nuclear power	64.3
Conventional thermal power	6.5
Imports	2.2
	143.7
Electricity use by sector:	
Agriculture, forestry	3.5 (3%)
Industry	51.7 (41%)
Transport	2.6 (2%)
Commercial/services	34.2 (27%)
Households	35.4 (28%)
Total final use of electricity	127.4
Distribution losses	10.0
Exports	6.3
	143.7

(a) Average hydro production based on 30-years precipitation data is approximately 65 TWh/year

The current electricity production system is based almost exclusively on hydropower and nuclear power (about 50% each). Cogeneration of heat and electricity plays a minor part in the national balance, although currently installed capacity could produce about 10 TWh/year of electricity.

BIOMASS RESOURCES

Current and Potential Production of Biomass Feedstocks

Sweden's potential sustainable production of biomass energy is estimated to be some 730 PJ/year, about three times its current use (Table 2). Some 360 PJ/year are generated today as forest residues or industrial byproducts, 60% of which are currently used for energy. Short-rotation energy plantations of willow and poplar trees, which are currently under development (5), 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 dominating potential biomass resource is wood, either as a byproduct from conventional forestry (residues from clear-cuttings or thinnings) or from short rotation energy plantations (willow or poplar trees). In addition, straw and other agricultural byproducts are available, but in smaller quantities. Large scale recovery and use of wood as an energy resource has taken place for decades. An infrastructure exists, which consists of machinery for recovery and chipping/drying of forest products, transportation systems and combustion facilities (up to approximately 100 MW).

Costs of Biomass Fuels

The costs of producing biomass in Scandinavia are generally higher than in many other regions of the world (11). The present market price for wood chips from forestry residues in Sweden, about $3.4/GJ, reflects the current costs of recovering the residues separately from other forest-industry feedstocks (pulpwood and lumber). Integrating the recovery processes would lower the cost for such chips to $2.0-2.6/GJ (Table 2). The cost of industrial byproducts (bark and sawdust) would be for handling and transport, implying essentially zero costs for on-site use. Wood chips from short-rotation fuelwood plantations are estimated to cost $2.4-3.4/GJ.

Table 2. 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 (4).
(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 (16).
(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 (18). The potential accounts for ecological reductions following recommendations in (8). 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 (9). 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 electrcitity 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) (4). 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 (15). 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 (5). 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 (26). Continued agricultural productivity growth would result in 1 million hectares by 2000 (23). Costs are based on (5,17).
(h) Current use is in district heating (4). 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 (23).

Local Availability and Area Requirements

Biomass resources are located in most parts of Sweden. More than half of Sweden is actively managed forest, and densely populated areas are situated either close to the forest or are surrounded by agricultural land. In both cases biomass for energy could be produced locally. Both the low energy density of biomass and the typical as-harvested moisture content of 50% place limits on the range of transportation. What production areas and what average transportation distances will be needed given the power output of different power production facilities?

The case of central station power generation implies power ratings of more than 50 MW. Were forestry residues to be used for fuel they would have to be transported up to 25 km at this plant size (7 km for short-rotation forestry; see Table 3), if the plant is situated in the center of the production area. Modern forestry includes normally long distance transports to large terminals at the pulp mills. With an integrated recovery of pulpwood and biomass-for-energy these transports and terminals could be used for biomass as well. Large scale long distance transport to power plants could be efficiently performed by rail or boat. Most Swedish pulp mills as well as central station power plants are situated at the sea and have harbours.

For a cogeneration plant the electricity-to-heat (E/H) ratio (i.e. how much heat will be produced along with the electricity) and the total efficiency ((heat + electricity output)/fuel input) define total fuel use. Because gas turbine cogeneration has a generally higher E/H characteristic than steam turbines, there can be greater electricity production per hectare with gas turbines while meeting the same heat demand. Table 3 shows biomass production area requirements and transport distances for a cogeneration plant, based on efficiency assumptions for biomass-gasifier steam-injected gas turbine technology.

Table 3. Biomass production area requirements and implied transportation ranges for electricity production from renewable fuels (forest residues, straw and energy plantations (Salix, short-rotation forest)).

Feedstock	Assumed harvest (MWh/ha,yr)/ (MW/km^2)	Area required for 50 MW_{el} (km^2)/ max. transport range (km) (f)	
		Central station BIG/ISTIG (d)	Cogeneration BIG/STIG (e)
Short rot. forest (a)	75/.86	150/6.9	200/8.0
Forest residues (b)	6/.07	1910/25	2530/28
Straw (c)	17/.19	670/15	890/17

(a) This corresponds to a yield of 15 tdm/ha,year (tonnes dry matter per hectare per year), which has been achieved in large scale demonstration projects. It is conservative for long term yields on agricultural land.

(b) For southern Sweden (Götaland). Assumes a rotation time of 80 years during which 470 MWh/ha in branches and tops is produced along with industry feedstock.

(c) Corresponds to a straw yield of 5 tdm/ha,year, and assuming that 20% of the straw is plowed back in the soil to preserve the humus content.

(d) A biomass-gasifer intercooled steam-injected gas turbine plant with a fuel-to-electricity efficiency of 38.4% assuming 15% moisture content fuel (12).

(e) A biomass-gasifer steam-injected gas turbine cogeneration plant with a total effciency of 69% and an E/H ratio of 0.71 (see Table 4). Total area requirements for electricity and heat production is shown.

(f) With the simplifying assumption that the plant is situated in the centre of a circle with the area given.

Cost estimates of Table 2 include 30-km transport for plantation fuelwood and a 50-km transport for forest residues. From Table 3 it can be concluded that for a 50 MW cogeneration plant transport distances are well below these limits (with the simplifying assumption that all available land within a given radius is utilized for biomass production). It is clear that at least small to medium sized cities (up to, say, 50,000 inhabitants) would have no important resource constraints to base a district heating cogeneration plant on biomass fuels (assuming that the district heat load gives the opportunity to cogenerate some 2 kW_e/inhabitant, yielding a 100-MW_e cogeneration plant). Some 40% of the total Swedish population lives in towns/cities with 5,000 to 80,000 inhabitants (7).

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 towards 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 2). Drying the fuel, as required for gasification, would raise this cost to about $3/GJ (see Table 2, note (b)).

Central-station power generation

With biomass costing $3/GJ, and based on the cost and conservative performance estimates for 50-100 MW steam-injected gas turbine systems discussed in (11), central station power plants would produce power at a cost in the range of 4.8 c/kWh to 5.7 c/kWh (Figure 1). With lower-cost forestry residues ($2.5/GJ), the busbar cost range would be 4.3 - 5.2 c/kWh. With these costs, biomass power plants would be competitive with much larger condensing coal-steam plants and advanced coal-fired PFBC and IGCC systems (Figure 1). The biomass option would clearly have the advantage if a cost were assigned to the net emissions of CO_2 from coal-fired plants. A CO_2 tax is currently being discussed in Sweden.

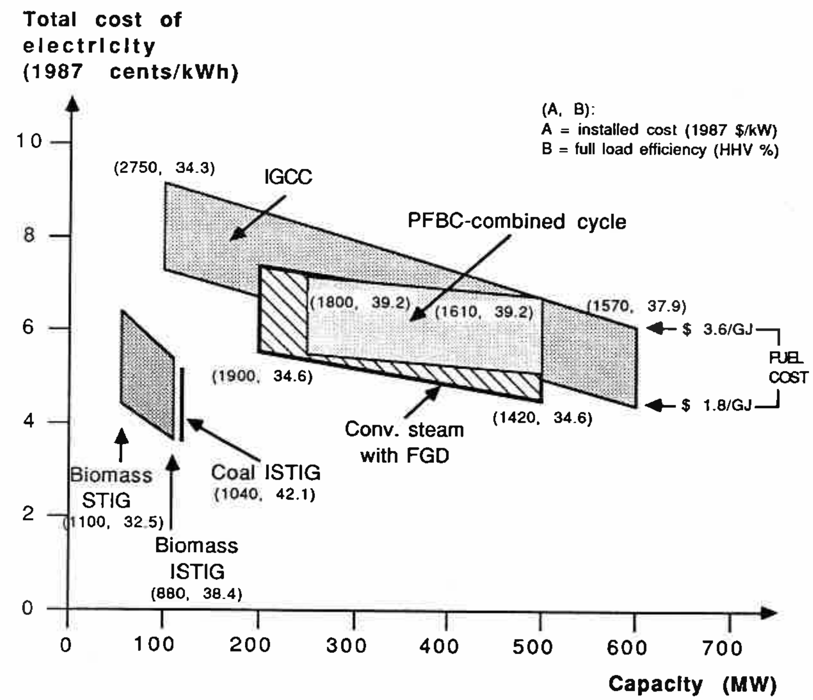

Figure 1: Calculated levelized lifecycle cost (including capital, operating and maintenance, and fuel) of electricity generation with coal and biomass as a function of plant size. A 6% discount rate, 30-year life and 70% capacity factor are used. No taxes or tax incentives are included. For simplification, 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 (6).

Performance and cost estimates for the conventional steam plant, the PFBC-combined cycle, and the IGCC are from the Electric Power Research Institute (19). 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 (intercooled steam-injected gas turbine), utilizing an air-blown dry-ash Lurgi gasifier, hot sulfur and particulate cleanup, and an intercooled steam-injected LM-5000 gas turbine, are from (2). For a further discussion of the biomass-STIG (steam-injected gas turbine) and ISTIG, see (12,25).

The PFBC and IGCC have undergone successful technology demonstration, which is not yet the case for the STIG-based systems.

Cogeneration of Heat and Power.

Cogeneration of heat and power would be an important part of a biomass-based electricity supply strategy for Sweden. Cogeneration gives an opportunity to produce electricity with less fuel input than that of central station power generation, and with lower marginal investment costs for power production. Biomass is particularly well suited for cogeneration applications, since its natural scale is relatively small (up to approximately 100 MW).

Gas turbine systems offers higher electricity-to-heat (E/H) ratios than conventional steam turbines and would permit larger quantities of electricity to be produced while meeting a given heat demand. Potentially important applications include those in the process industry (particularly the paper and pulp industry), and in district heating (DH). DH applications are considered in the following. Many DH systems use biomass for fuel today, but almost exclusively for heat production only.

Cogeneration in District Heating Plants. Heat loads in DH systems follow a characteristic annual pattern with an outdoor temperature-dependent component superimposed on a fairly constant component (domestic hot water supply). The annual variation in heat production rate will, however, be flatter if industries with relatively constant heat loads are connected. In the following we will presume a "normal" annual distribution, as described by a load duration curve (Figure 2). Such a "normal" distribution will have a sharp peak, representing the coldest days of the year.

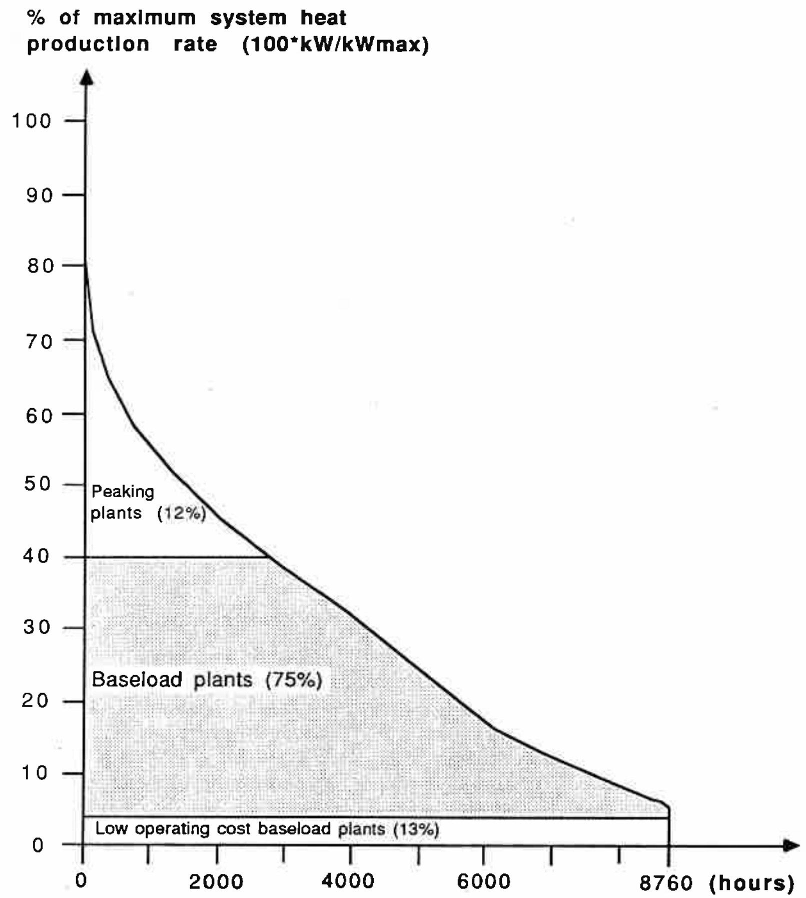

Figure 2: Typical load duration curve for heat production in a Swedish district heating system, representing the combined output of a number of individual plants. The fraction of the system's maximum heat production rate is shown versus the number of hours per year that production reaches this level 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. (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.) Higher operating-cost units, e.g. oil- or natural gas-fired boiler, produce heat during peak demand periods.

In a DH system a mix of individual plants (boilers, heat pumps, cogeneration plants, etc.) is operated to provide the required heat while minimizing total operating costs. Heat that is produced with the lowest operating cost comes from refuse-derived-fuel incinerators, industrial waste heat, or sewage-water heat pumps (extreme baseload). The next increment is typically supplied by baseload plants, sized to operate for about 5000 equivalent full-load heating hours per year (see caption of Figure 2 for definition). Cogeneration plants are normally considered baseload units, having relatively high investment costs but low variable heat production costs (being credited for electricity production). Such plants would annually provide about 3/4 of the heat required in the system (shaded area in Figure 2). Oil- or natural gas-fired boilers with minimal capital costs are typically used to supply peak demand.

Biomass-Based Gas Turbine District Heating 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 the scale-sensitivity of the steam turbine bottoming cycle in a combined cycle, this option is likely to be of interest only in relatively large sizes, unlike the other two options. Option (b) would be of particular interest for district heating, since only relatively low-grade heat is required. With this option, latent heat in the exhaust (arising in part from the relatively high moisture content in the fuel gas from biomass) could provide a significant heat source for the heat pump.

All three gas turbine systems could be designed with the flexibility to boost electricity production and electrical conversion efficiency when heat demand falls, which would be desirable for district heating applications. With options (a) and (b), this flexibility could be achieved using a steam-injected gas turbine (STIG). In 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 (13), compared to 39 MW_e at 28.6% efficiency with no injection (Table 4).

Table 4 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. The gas turbine based systems would have higher electrical efficiencies than steam turbines. Their electricity-to-heat (E/H) production ratios would also be higher, which means they could produce more electricity while supplying a given heat demand. The simple cycle option without the heat pump would have a relatively low total efficiency compared to the other options. Gas turbines would have the flexibility to trade-off heat and electricity production using steam injection, which would not be the case for back-pressure steam turbines.

Table 4. Estimated full-load output and efficiencies of biomass-fired cogeneration systems (higher heating value basis)

	Electricity MW	Electricity Eff.(%)	Heat MW	Heat Eff.(%)	Electricity-to-heat ratio	Total 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 (13) 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 aeroderiviative 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 (21).

<u>Economics of Biomass-Based District Heating Cogeneration.</u> If a biomass-gasifier STIG-heat pump cycle (see note (c) of Table 4) 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 range for the electricity that would be cogenerated, we consider a STIG-heat pump DH plant with the characteristics described in Table 4, the heat production of which is assumed to match the shaded area in Figure 2.

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 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 (E/H) production ratio for the system would be 1.4. (If the plant were to operate with full heat output year-round, the E/H ratio would be 0.71 (Table 4). The E/H ratio of 1.4 assumes the heat output varies as shown in Figure 2.) 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 ratio would be 1.1.

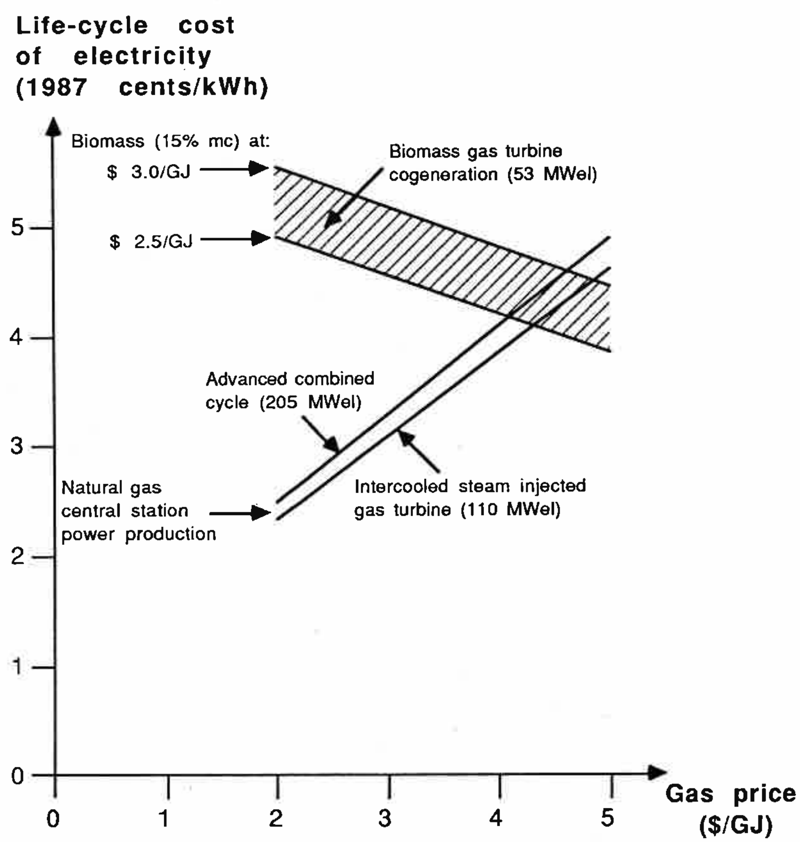

Figure 3: Calculated lifecycle electricity production costs with biomass-gasifier gas turbine district-heating cogeneration compared with the costs of efficient natural-gas fired central station power as a function of the assumed gas price.

The cogeneration system is based on a STIG-heat pump system (Table 4, note (c)), the heat production of which follows Figure 2, with a total of 5000 equivalent full-load heating hours. With full heat production, the system per-

formance would be as in Table 4. 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 the text, the assumed system operating strategy yields an annual electricity-to-heat production ratio of 1.1 (and an electrical capacity factor of 65%).

The total estimated installed capital cost for the cogeneration unit is $67 million ($1100/peak kW_e for the STIG (13) plus $280/$kW_{th}$ for 31 MW_{th} of absorption heat pump.) Based on (20), 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 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 c/kWh (99). A 6% discount rate, 30 year life, and 70% capacity factor are used.

For this latter operating scenario, the cost of cogenerating electricity with the gas-turbine systems would range from 4.5-5.6 c/kWh (3.9-5.0 c/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 3). (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 per barrel for crude) while the higher price 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 3). (For comparison, Sweden's National Energy Administration indicates that natural gas prices for perhaps the next decade may range from $3.5/GJ to $5.0/GJ (3) independent of any fuel tax that may be placed on carbon emissions.) Even assuming low gas prices, the cogenerated power would be less costly than that from new, large coal-fired central station power plants (compare Figure 3 and Figure 1).

POTENTIAL IMPACT ON THE SWEDISH POWER SYSTEM

On a per-capita basis Sweden's biomass resources are large relative to those of most other industrialized countries. Sweden is in the position of having the option to use some of these resources to meet future energy needs, without interfering with the resource base of the conventional biomass processors: forestry and agriculture. This option may become increasingly attractive as the use of fossil fuels grows increasingly troublesome due to rising costs and environmental problems such as greenhouse warming. A further economic incentive for substituting fossil fuels with biomass may result from a CO_2 tax currently being discussed in Sweden. Since the biomass resource is limited, using it efficiently will be extremely important.

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 up to 500 PJ/year (see Table 2). A variety of biomass-gas turbine electricity supply strategies, or a mix thereof, are conceivable, including central station power generation and cogeneration. Cogeneration could be based in the energy-intensive branches of Swedish industry, e.g. pulp and paper, iron and steel, and the chemical industry, all of which need process heat in large quantities. District heating cogeneration is also possible and is discussed here.

A very large part of the total low temperature heat demand in Sweden is supplied via district heating (DH) systems. About 40 TWh/year of heat is supplied by DH systems ranging from a few MW up to several 100:s of MW (heat). Table 5 shows the distribution and sizes of the existing DH systems, along with installed cogeneration capacity and produced electricity (the full potential for electricity production is currently not utilized). Conventional steam turbines are common practice with the exception of a few diesel engines running on conventional diesel fuel.

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

Table 5. Heat production and installed cogeneration capacity in Swedish district heating systems 1987 (24).

	Heat prod. capacity (MW)	Delivered heat (GWh)	Installed cogen. cap. (MW)	Produced electricity (GWh)
Heat load 0-20 MW	544	1053	0	0
Heat load 21-100 MW	2927	5925	44	31
Heat load 101-200 MW	2290	4463	41	48
Heat load 201- MW	12952	26745	2037	2613
Total	18772	37841	2127	2692

In addition to conventional DH systems there exists a great number of small heating plants (up to approximately 5 MW), which supply typically a few apartment buildings or hospitals/schools with heat. These are not considered here, but could also be candidates for the installation of cogeneration plants.

An estimate of the potential gas turbine-based electricity cogeneration in Swedish DH systems can be made assuming Figure 2 to represent the DH profile for all of Sweden, with the shaded portion (75%) supplied by gas turbines with operating characteristics of STIG-heat pump systems described in Table 4. In this case, the annual E/H ratio of 1.1 discussed earlier would apply to Sweden as a whole. For an assumed total district heating demand of 40 TWh/year, therefore, some 33 TWh/year of electricity would be cogenerated (0.75*40*1.1 = 33), which would require about 400 PJ/year of fuel. The approximate monthly distribution of electricity production with such a strategy might be as shown in Figure 4 superimposed on the 1986 Swedish utility electricity production. Figure 4 reflects the cogeneration operating scheme discussed earlier, 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.

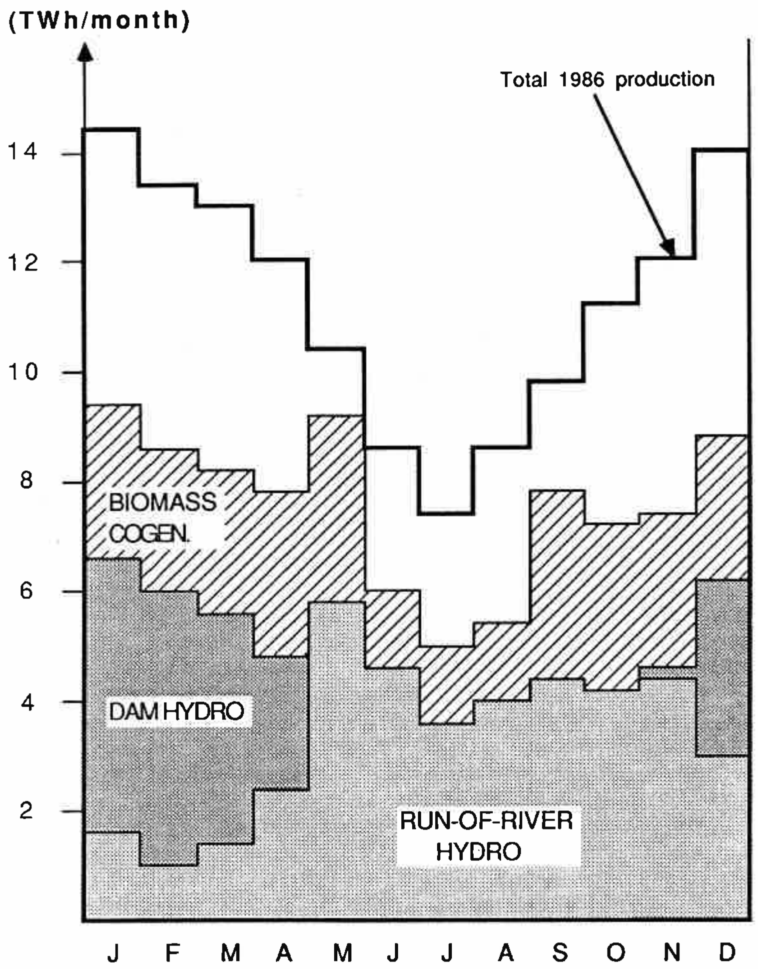

Figure 4: The potential electricity supply in Sweden from biomass-fueled gas turbine district heating cogeneration plants is shown superimposed on the total 1986 Swedish electricity production. Nearly all non-hydroelectricity was supplied by nuclear plants in 1986. The distribution of the hydroelectric supply can vary to some extent from year to year depending on rainfall variations and the operating strategy chosen.

An alternative DH cogeneration strategy based on back-pressure steam turbines could also be used to meet the district heating demand, and would produce electricity at lower costs than the gas turbine strategy considered here. However, because of the much lower E/H ratio of steam turbines (0.3-0.5, for the power ratings discussed here), 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.

If a central station, rather than cogeneration, strategy were chosen, e.g. based on biomass-gasifier ISTIG technology with an efficiency of 38%, the 500 PJ/year of potential biomass fuel could produce some 53 TWh/year of electricity.

SUMMARY

The potential 33-53 TWh/year of electricity from biomass-based gas turbine systems 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 (1) and/or substitution of e.g. resistance heating, 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 appears that biomass-gasifier STIG systems could be brought to commercial readiness in 3 to 5 years with a serious development effort (11). 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/year are currently recoverable but unused (Table 2), which alone would support the production of some 14 TWh/year of cogenerated electricity. This initial use of residues would provide time to fully develop fuelwood plantations.

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