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BIOMASS-GASIFIER GAS TURBINE POWER GENERATING TECHNOLOGY*

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Abstract

Integrating gasifiers with gas turbines, aeroderivative gas turbines in particular, makes it possible to achieve high efficiencies and low unit capital costs in modest-scale biomass power generating facilities. Electricity produced with biomass-integrated gasifier/gas turbine (BIG/GT) power systems would be competitive with electricity produced from coal and nuclear energy under a wide range of circumstances. Biomass also offers major environmental benefits. Initial applications will be with biomass residues generated in agro- and forest-product industries. Eventually, biomass grown for energy purposes on dedicated energy farms will also be used to fuel these gas turbine systems. Continuing improvements in jet engine and biomass gasification technologies will lead to further gains in the performance of BIG/GT systems over the next couple of decades.

Introduction

Power generation is a route to the modernization of biomass for energy offering opportunities for substantial industrial development before the turn of the century. Already in the United States, installed biomass-electric generating capacity is more than 8,000 megawatts-electric (MW_e) [2] (see Table 1). Much of this capacity was installed as a result of incentives provided by the Public Utility Regulatory Policies Act of 1978 (PURPA). There is not yet much biomass power generating capacity in the rest of the world, where PURPA-type incentives have not been available.

* This article is based largely on [1].

Steam-Turbine Cycle Technology

Essentially all biomass power plants today operate on a steam–Rankine cycle, a technology which was initially introduced into commercial use a century ago. Biomass-steam turbine systems are less efficient than modern electric-utility coal-fired systems in large part due to more modest steam conditions. The majority of the 94 biomass plants in California (see Table 1) operate with a steam pressure and temperature of about 6 megapascals and 480°C [3], compared to typical steam pressures of 10 to 24 megapascals and temperatures of 510 to 540°C in modern utility-scale coal plants [4].

The modest steam conditions in biomass plants arise primarily because of the strong scale-dependence of the unit capital cost ($ per kW) of steam turbine systems—the main reason coal and nuclear steam-electric plants are built big. Biomass plants are usually of modest scale (less than about 100 MW_e) because of the dispersed nature of biomass supplies, which must be gathered from the countryside and transported to the power plant. If bio-electric plants were as large as coal or nuclear power stations (500 to 1,000 MW_e), the cost of delivering the fuel to the plant would often be prohibitive. To help minimize the dependence of unit cost on scale, vendors use lower grade steels in the boiler tubes of small-scale steam-electric plants and make other modifications that reduce capital cost, but also require more modest steam temperatures and pressures, thereby leading to reduced efficiency. Plants operating in California have efficiencies of 14 to 18 percent [3], compared with 35 percent for a modern coal plant.[1] The best biomass steam-electric plants have efficiencies of 20–25 percent.

Such low efficiencies explain the reliance of the biomass power industry in the United States on low-, zero-, or negative-cost biomass feedstocks (primarily residues of agro- and forest product–industry operations and urban refuse). Largely as a result of the growth in biomass-based power generation, the supply of such feedstocks is dwindling in some parts of the United States today, although in some areas there are still significant unused or underused supplies of such feedstocks locally. Once such low-cost feedstocks are fully used, continued expansion of biomass power will require the use of higher cost feedstocks, such as residues that are hard to recover and biomass that is grown for energy on dedicated energy farms. In order to make higher cost biomass resources economically interesting for power generation, it is necessary to have technologies that offer higher efficiency and lower unit capital cost at modest scale.

One technological initiative aimed at improving the economics and efficiency of utility-scale steam cycle systems would use whole trees as fuel rather than more costly forms of biomass (e.g., woodchips). The whole-tree burner concept, developed by Energy Performance Systems, Inc., of Minnesota, has yet to be commercially demonstrated. A recent assessment of the technology for the Electric Power Research Institute (EPRI) [5] projects an efficiency and installed capital cost for a 100 MW_e plant employing a reheat-steam cycle of 34 percent and $1,365 per kilowatt-electric (kW_e).[2] The size was selected

1. In this paper, efficiencies and fuel heating values are presented on a higher heating value basis.

2. In this paper, costs and prices are presented in 1989 U.S. dollars.

as a likely initial size for central station utility applications. The reheat-steam cycle is a more sophisticated cycle than is typically found in existing biomass power plants, nearly all of which are substantially smaller than 100 MW_e. Scale economy gains at the 100 MW_e size may permit economical use of the more complex cycle.

In comparing the whole-tree technology to a conventional 100 MW_e biomass reheat-steam system burning wet wood chips (assuming low-cost wood recovered from natural forests in the United States in both cases), the report estimated a 10 to 30 percent lower electricity production cost for the whole-tree technology, because of the higher efficiency, lower capital cost, and lower fuel cost.

The higher efficiency of the whole-tree approach compared with conventional biomass-power technology would make the use of higher cost biomass feedstocks more economical at the 100 MW_e scale. The biomass power market for installations at the relatively large scales needed for whole-tree burner technology may be quite limited, however. The requirement of whole trees restricts the technology largely to markets that can be served by wood recovered from existing forests—a biomass supply source that is likely to be limited by environmental concerns [6]. Also, the technology is not likely to improve much over time beyond what has been proposed, since the steam-turbine cycle is a mature technology for power generation. The efficiency of modern fossil fuel–fired, steam-electric power plants has not increased since the late 1950s (see Figure 1), when peak steam temperatures of the order of 540°C were reached. While it is technically feasible to increase the peak steam temperatures further, doing so is probably not worthwhile because of the higher capital costs involved [7].

Gas-Turbine Cycle Technology

A promising alternative to the steam-turbine cycle for biomass power generation is a set of biomass-integrated gasifier/gas turbine technologies. These technologies involve marrying advanced Brayton cycle (gas turbine) power-generating or cogenerating cycles, which have already been developed for natural gas and clean liquid fuel applications, to closely coupled biomass gasifiers, which can be based to a large extent on gasifiers already developed for using coal in gas-turbine power cycles.

The unit capital costs of gas-turbine systems are relatively low and insensitive to scale. Thus, from a capital cost perspective, the gas turbine is an interesting candidate for biomass-based power generation. The gas turbine is also a good candidate for achieving higher thermodynamic efficiency because the peak cycle temperature of modern gas turbines (about 1,260°C for the best gas turbine for stationary power applications on the market) is far higher than that for steam turbines (about 540°C), providing an inherent thermodynamic advantage for the gas turbine. Moreover, unlike the situation with steam turbines (see Figure 1), gas turbines are being steadily improved. There have been continual advances in turbine blade materials and turbine cooling technologies for jet engines, and, as a result, there has been a 20°C average annual increase in the state-of-the-art turbine inlet temperature for jet engines and a continual increase in engine efficiency since the end of World War II, a trend that is expected to continue (see Figure

2) [8, 9]. Such improvements are largely a result of U.S. Department of Defense support for research and development (R&D) on jet engines for military aircraft applications, which has averaged about $0.5 billion per year over the past decade.

There are two general classes of gas turbines that are used for power generation: heavy-duty industrial turbines designed specifically for power generation and lightweight, compact, aeroderivative gas turbines. While eventually ongoing improvements in jet engine technology will be incorporated into industrial turbines, these advances are automatically incorporated into aeroderivative machines. Thus emphasis on aeroderivative turbines provides a direct, low-cost way to exploit advances in aircraft engines for stationary power applications.

Cycles based on aeroderivative turbines also offer the advantages of high efficiency (see Figure 3) and low unit capital costs at the modest scales (< 100 MW_e) that will characterize much of the biomass energy market. Moreover, the compact, modular nature of aeroderivative turbines facilitates maintenance. When an aeroderivative engine fails, it can be replaced quickly by a spare trucked or flown in from a centralized lease-pool maintenance facility, at which the failed engine would be repaired.

Efficient Gas-Turbine Cycle Options

Although no gas-turbine cycle is commercially available for biomass applications, several cycles of interest are commercially available or are under development for applications involving high-quality fluid fuels. These cycles use the hot exhaust of the gas turbine in various ways to achieve high efficiencies.

Steam-Injected Gas Turbine

One commercially available aeroderivative turbine cycle is the steam-injected gas turbine (STIG) (see Figure 4). As in the simple-cycle gas turbine used for the cogeneration of electricity and steam for process use, steam is produced in a STIG cycle from the gas turbine exhaust heat using an HRSG. But in this case steam not needed for process use is injected back into the gas turbine combustor (and at further points along the gas flow path), where it is heated to the turbine inlet temperature and then passed through the turbine. With steam injection, the gas turbine produces more power at higher electrical efficiency. STIG technology makes it possible (if the extra electricity produced when the steam load decreases can be used) to overcome the problem of poor part-load performance that has limited the use of simple-cycle gas turbines to cogeneration applications involving constant steam loads [10].

More than 30 STIG units in the U.S. burning high-quality gaseous and liquid fuels are either operating, under construction, or on order [7]. The largest STIG unit commercially available is based on the General Electric (GE) LM-5000 turbine (derived from the jet engine used in the Boeing 747, the DC-10 Series 30, and the Airbus 300). As a simple cycle, it produces 33 MW_e at 33 percent efficiency operated on natural gas fuel.

With full steam injection, this engine produces 51 MW_e at 40 percent efficiency. Turnkey STIG units of this capacity packaged on a skid and without a building are commercially offered for about $700 per kW_e [11].

Intercooled Steam-Injected Gas Turbine

An advanced version of the STIG is the intercooled steam-injected gas turbine (ISTIG) (see Figure 5). The installed cost of a 47 percent efficient, natural gas–fired 114 MW_e ISTIG (essentially the 51 MW_e STIG unit described above, but modified with compressor intercooling) would be about $500 per kW_e [11]. Although ISTIG is not commercially available, it could be brought to market in 3 to 5 years, if there were sufficient commercial interest [12].

Combined Cycle

The combined-cycle (see Figure 6) is the most energy-efficient power-generating cycle on the market today and is the generating technology of choice in many utility and independent power markets with natural gas firing.

Most combined cycles are based on heavy-duty industrial rather than on aeroderivative turbines. An important distinction between the two turbine types is that the combustors of the latter operate at much higher pressures (25 atmospheres or more, compared with 12 to 16 atmospheres for heavy-duty industrial turbines). High pressures are needed to optimize the performance of jet engines at today's high turbine inlet temperatures. Heavy-duty industrial turbines are usually designed instead for optimal performance in the combined-cycle mode. For a given turbine inlet temperature, the turbine exhaust of heavy-duty industrial turbines is hotter and capable of producing more steam than is possible with aeroderivatives. Typically, the steam turbine bottoming cycle provides about one third of the total output of these combined cycles. In light of the strong scale economies of steam-turbine cycles, combined cycles based on heavy-duty industrial turbines are not the best candidate engines for applications at the modest scales needed for biomass.

Ordinarily, the relatively low turbine exhaust temperatures of the aeroderivatives makes them poor candidates for combined-cycle configurations, suggesting that the various steam-injected cycles would offer more favorable economics at the modest scales needed for biomass. This situation may change, however, with a new generation of aeroderivatives coming onto the market in the 1990s [13].

For example, the GE LM-6000, which entered commercial service in 1992, produces 42.4 MW_e at a simple-cycle efficiency greater than 36 percent on natural gas and has an estimated equipment price of $250 per kW_e [14],[3] which is much less than the $400 per kW_e price for the most efficient (33 percent) aeroderivative on the market today [15]. Combined cycles based on the LM-6000 are expected to produce 53.3 MW_e at an efficiency of 48 percent, making them as efficient as the most efficient combined cycle on the market [16]. The LM-6000 combined cycle might be economically competitive with much larger combined cycles based on heavy-duty industrial turbines, despite the scale-economy problem of the steam turbine bottoming cycle, not only because the cost of the gas turbine is so low, but also because the steam turbine accounts for such a modest fraction (one-fifth) of the total output.

The air bottoming cycle (ABC) (see Figure 7) is an alternative promising way to recover exhaust heat. In the ABC the air working fluid is heated via a heat exchanger with exhaust heat from the gas turbine topping cycle. While not quite as efficient as a gas turbine/steam turbine combined cycle, a combined cycle involving the ABC would be much simpler (e.g., it requires no boiler) and more rugged, and it is expected to be much less costly to build, operate, and maintain [17]. Because it involves no advanced technology, the ABC could be developed and commercialized quickly.

Prospects for Continuing Improvements in Gas Turbine Technology

The performance of gas turbines is expected to improve considerably in the decades ahead, both because of continuing improvements in jet engine technology (see Figure 2) and because there are many untapped opportunities for improving the performance of stationary turbines that are not relevant for jet engines.

Besides adapting aircraft engine blade cooling advances to stationary power applications, replacing air as the turbine blade coolant with steam would offer several advantages. One is that steam, having a higher heat-carrying capacity per unit mass, is a more effective coolant than air. Also, steam provides the flexibility to choose higher pressures for cooling, thus making it feasible to achieve higher coolant velocities and therefore to provide more intensive heat removal from the components being cooled. In addition, the temperature of the steam used for cooling might be lower than that of air. And finally, when air is replaced by steam, the compression work requirements for the coolant become negligible. Despite such advantages, little progress has been made in steam cooling to date, in large part because steam cooling is not relevant to aircraft engines, because it is not practical to carry large quantities of water aboard airplanes.

Other possible cycle modifications could lead to improved performance over what can be achieved with combined cycles and ISTIG. One such modification would be to add a "reheat" combustor ahead of the final expansion stage in the turbine. Adding reheat increases not only turbine output but also efficiency, because with reheat there is an increase in the average temperature at which heat is added to the cycle through fuel combustion. The Pacific Gas & Electric Company has estimated that adding a reheat combustor to the ISTIG unit described above would increase output and efficiency on natural gas fuel from 114 MW_e and 47 percent to 185 MW_e and 49 percent [18].

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3. In converting a jet engine to an aeroderivative gas turbine, the fan is removed, and, ordinarily, the thrust-producing nozzle is replaced by a power turbine, so that the system produces net power instead of thrust. The extraordinarily low expected price for the LM-6000 arises because this engine is derived from a high- bypass ratio jet engine, in which the final expansion of combustion products is through a turbine instead of a thrust-generating nozzle. In the jet engine configuration, the output of the turbine drives the compressor and bypass fan. But when the fan is removed for stationary power applications, the unit produces net power without the addition of a costly power turbine.

Firing Gas Turbines with Biomass-Derived Gas

Gas turbines cannot be fired directly with biomass, because the biomass combustion products would damage the turbine blades. However, by first gasifying the biomass and cleaning the gas before combustion, it is feasible to operate gas turbines with biomass fuels.

While little attention has been given to biomass use in gas turbines, many hundreds of millions of dollars of public and private-sector investment funds have been committed in the United States, Europe, and Japan to R&D efforts aimed at marrying the gas turbine to coal, through the use of coal-integrated gasifier/gas turbine (CIG/GT) systems. These efforts have been motivated in part by the large thermodynamic advantages offered by the gas turbine for power generation and the desire to exploit these advantages with coal (which is much more abundant than oil and natural gas), and in part by the prospect that the burning of coal can be accomplished with much less environmental damage through gasification than with alternative approaches.

CIG/GT development has focused largely on systems using oxygen-blown gasifiers (e.g., Cool Water [19]). These are not a good model for biomass-based systems because oxygen production is particularly costly at the modest scales needed for biomass plants.

Coal gasifier/gas turbine systems based on airblown gasifiers would eliminate the need for oxygen. The capital costs for such systems would, accordingly, be much less sensitive to scale [1, 20]. However, CIG/GT systems using airblown gasifiers are not as well developed as systems involving oxygen-blown gasifiers, because the required technology for removing the sulfur from the hot gases exiting the gasifier is not proven at a commercial scale. But hot-gas sulfur cleanup technology would not usually be needed for biomass, because most biomass contains negligible sulfur. Furthermore, the higher reactivity of biomass compared with coal makes it easier to gasify (see Figure 8). These considerations imply that it should be feasible to commercialize biomass versions of airblown gasifier/gas turbine systems more quickly and with less technological effort than the coal versions.

Figure 9 is a schematic representation of a biomass-integrated gasifier/gas turbine combined cycle, a leading first-generation candidate for BIG/GT systems. The principal generic gasifier design options for BIG/GT applications are fixed-bed updraft and fluidized-bed gasifiers (see Figure 10).

Gasifier Options

Fixed-Bed Gasifiers. The fixed-bed, updraft gasifier (see Figure 10, left) is a simple, efficient system suitable for biomass feedstocks having high bulk density (e.g., woodchips or densified biomass). The pressurized fixed-bed Lurgi Mark IV dry-ash gasifier is a mature system with extensive coal experience whose adaptation to CIG/GT applications has been extensively evaluated [21].

Hot-gas cleanup is perhaps the most important system-development issue for all airblown gasification systems (for both coal and biomass feedstocks). A high degree of removal is required for alkali compounds (formed primarily from potassium and sodium in the feedstock) and particulates. The estimated tolerable concentration of alkali vapors in fuel gas for gas-turbine applications is very low—100 to 200 parts per billion or less at the gasifier exit [22, 23], with corresponding several-fold lower concentrations at the turbine inlet. The extent of alkali production and required removal from biomass gas is not well documented. Based on coal-related work, however, the gasifier exit temperature appears to be the most important controlling parameter. At sufficiently low temperatures the alkalis appear to condense on particulate matter and can be controlled by controlling particulates. At the relatively low temperatures of the fuel gas exiting the fixed-bed gasifier (500 to 600°C), most of the alkalis appear to condense on particulates and can thus be controlled by controlling particulates.

While a high rate of tar formation has long been a concern for fixed-bed gasifiers in other applications, this may not be a concern for BIG/GT applications, because the temperatures of the fuel gas exiting the gasifier should be high enough that the tars would be in the vapor phase. By close-coupling the gasifier and gas turbine, the tars can be burned (without condensation problems) in the gas turbine combustor. Tars are desirable, in fact, to boost the heating value of the gas. Thus, for fixed-bed gasifiers there appears to be a practically realizable exit-gas temperature window of 500 to 600°C, within which problems with both condensed tars and vaporized alkalis may be avoided. This temperature window also coincides with material limits for valves that would be used to control gas flow to the turbine [21].

While there has been no focused effort to develop fixed-bed gasifier technology for biomass feedstocks, limited pilot-scale testing was carried out in 1991 by GE with wood chips and sugarcane bagasse pellets as fuel. A gas with adequate heating value was generated, but the tests indicated that development work is needed on pressurized feeding and on gas cleanup [24].

Fluidized-Bed Gasifiers. Fluidized-bed gasifiers have higher throughput capabilities and greater fuel flexibility than fixed-beds, including the ability to handle low-density feedstocks like undensified crop residues or sawdust [25]. Their ability to handle a wide range of biomass fuels with minimal preprocessing may ultimately make fluidized-bed gasifiers the technology of choice for many biomass applications, because of the diversity of biomass feedstocks.

For fluidized-bed gasifiers, gas quality control may be somewhat more problematic than for fixed-bed gasifiers, for two reasons. First, at the high temperatures of the fuel gas exiting the gasifier (800 to 900°C), alkalis will be in the vapor phase. Dealing with this problem will probably require fuel gas cooling to condense the alkalis, with attendant efficiency and capital cost penalties. (Some gas cooling would be needed in any case to meet control-valve material constraints.) Second, there is much more particulate carryover with a fluidized-bed gasifier, so that control of particulates may be more difficult. Ceramic or sintered-metal barrier filters, neither of which is fully proven commercially, will probably be needed. A number of such filters are being developed in Finland [26], the United States [20], and elsewhere.

Several candidate fluidized-bed systems for BIG/GT applications are in various states of development. The bubbling bed (see Figure 10, center) was the first fluidized-bed design developed. The Rheinbraun–Uhde (Germany) HTW (High Temperature Winkler) is a commercially mature, pressurized bubbling fluidized-bed technology using coal. It has operated successfully with biomass, though not extensively. The world's only commercial pressurized gasifier operating on a feedstock other than coal is a peat-fired HTW unit in Finland. Additional testing is needed to fully demonstrate the HTW performance on biomass and its ability to meet gas turbine fuel gas specifications. Like all fluidized-beds discussed here, it has no actual or simulated operating experience coupled to a gas turbine.

The Institute of Gas Technology (IGT) Renugas system (United States) is another bubbling bed that has perhaps more experience operating at elevated pressure with biomass than any other gasifier. It has been operated only at pilot scale, however, so a successful scaleup effort is needed before the technology can be considered mature. Its capability to meet gas turbine fuel gas specifications must also be demonstrated.

Circulating fluidized beds (CFBs), (see Figure 10, right) allow for more complete carbon conversion and permit higher specific throughputs than bubbling beds. Ahlstrom (Finland), Lurgi (Germany), and TPS/Studsvik (Sweden) have commercially operating biomass-fired, atmospheric-pressure CFBs. There are no pressurized CFBs operating on any feedstock (including coal). Ahlstrom is developing a pressurized CFB for biomass applications that would have gas cooling for alkali control and ceramic-filter particulate cleanup. Also, a hybrid HTW/Lurgi-CFB is under development for CIG/GT combined cycle applications.

System Performance and Cost

Initial applications of BIG/GT technologies are likely to be in industries where biomass residues of industrial activities can be used as fuel for the cogeneration of electricity and steam for on-site use. Cogeneration system performance parameters are shown in Table 2, along with associated capital costs, 1) for various BIG/GT systems that involve coupling a fixed-bed gasifier to various steam-injected gas turbine systems,[4] and, for reference, 2) a double-extraction/condensing steam turbine (CEST) cogeneration system. From Table 2 it is seen that in the maximum steam-producing mode, all systems convert about 60 percent of the energy of the biomass fuel into steam and electricity, but

4. The BIG/STIG performance and cost estimates presented in Table 2 can be compared to the estimated performance and cost for a 37 MW_e BIG/combined cycle plant designed in a feasibility study carried out at the Shell International Petroleum Company. The Shell design consists of an Ahlstrom circulating fluidized-bed gasifier with ceramic-filter gas cleanup, feeding a Rolls Royce RB-211 aeroderivative gas turbine, which would provide 27 MW_e of the plant's total output. Overall efficiency on biomass fuel with 15 percent moisture content was estimated to be 39 percent. The total installed cost was estimated to be $1,200 to $1,300 per kW_e for commercial plants and $1,600 to $1,700 per kW_e for the first demonstration plant [27]. (In the present analysis a 37 MW_e BIG/STIG unit is estimated to have an efficiency of about 34 percent and an installed cost of about $1,200 per kW_e.)

the fraction of fuel energy converted to the more valuable electricity is three or more times as large for gas turbines as for the steam turbine. In the maximum electricity-producing mode, the BIG/GT systems produce from 1.6 to 2.1 times as much electricity per unit of biomass energy as the CEST system. BIG/GT systems are also expected to be less capital-intensive, and their capital costs less sensitive to scale, than CEST systems (see Table 2 and Figure 11).

In areas where biomass residues are in short supply, BIG/GT systems could be fired with biomass grown on plantations dedicated to biomass production. Such applications will involve the production of only electricity in central-station power plants, as well as cogeneration. Biomass fuel delivered from plantations will often be more costly than biomass residues. The average delivered cost of dried wood chips grown on *Eucalyptus* plantations in Brazil is estimated to be from \$2.2 to \$2.4 per gigajoule (see Table 3). Costs for delivered dry wood chips from short-rotation, intensive-culture poplar plantations on good quality agricultural land in the United States are projected to be from \$3.0 to \$3.8 per gigajoule (see Table 3).

In both Brazil and the United States, plantation wood costs are higher than projected long-run costs of coal (\$1.8 per gigajoule) delivered to coal-fired power plants in most regions of the world. However, because of their higher efficiency and lower unit capital cost, BIG/GT systems could compete with conventional coal-fired, steam-electric plants with biomass that is much more expensive than coal. Specifically, with coal priced at \$1.8 per gigajoule, BIG/ISTIG plants could compete at biomass prices that are up to double the coal price (see Table 4). If advanced coal-based systems like the coal integrated-gasifier/intercooled steam-injected gas turbine [21], should eventually be commercialized, the competition from coal would be much tougher. However, BIG/ISTIG could still compete at biomass prices as much as 20 to 30 percent higher than coal prices owing to the lower capital cost of BIG/ISTIG (see Table 4).

Commercialization Prospects

At least six initiatives bearing on the commercial development of BIG/GT technology are underway or have recently been announced.

In the fall of 1991, Bioflow, a joint venture between Sydkraft, the second largest electric utility in Sweden, and Ahlstrom, a Finnish gasifier manufacturer, began construction of a 6 MW_e BIG/GT combined cycle cogeneration demonstration plant in Varnamo, in southern Sweden. Ahlstrom is providing a pressurized circulating fluidized-bed gasifier and a gas cooling and cleaning system that includes ceramic filters for particulate removal. Preliminary tests by Bioflow have indicated that wood fuels can be gasified at pressure and the gas filtered at elevated temperature to specifications for gas turbines. Gas production at the demonstration site is scheduled to begin in March 1993, and full-plant startup is set for May or June of 1993.

In Brazil, the Companhia Hidro Elétrica do São Francisco (CHESF), a major electric utility in the northeast, has an ongoing R&D program aimed at developing biomass from planted forests as a major fuel source for power generation, with conversion to electricity using BIG/GT units [28]. CHESF is leading the development of a BIG/GT demonstration project in Brazil, an effort that includes the participation of Eletrobrás (the Brazilian federal electric utility), the Shell International Petroleum Company and its affiliate Shell Brasil, Companhia Vale do Rio Doce (a major Brazilian forest products company), and Fundação de Ciência e Tecnologia (a Brazilian gasification research institute). Initial grant funding of $7 million has been provided by the Global Environment Facility (GEF) for a two year engineering design and development effort to be completed in 1994. During this phase, candidate gasifier and gas cleanup systems are being developed by TPS/Studsvik and by Bioflow. General Electric is developing a modified LM2500 for the project. The GEF will commit an additional $23 million at the end of a successful two year engineering effort. The project will demonstrate an LM2500-combined cycle of 25 MW_e output using wood chips supplied from a standing plantation in the northeast of Brazil [28].

In the United States, the DOE announced in late 1990 a major new initiative to carry out R&D on BIG/GT technology [29]. The U.S. DOE also recently selected the IGT pressurized, bubbling fluidized-bed Renugas gasifier for a large-scale biomass gasification demonstration [30]. A pressurized pilot-scale Renugas unit has extensive operating experience on a variety of biomass feedstocks [31]. The scaled-up unit will be built in Hawaii and run initially on sugarcane bagasse (50 tonnes per day capacity). Construction of the gasifier is scheduled to start in 1993, with a gas turbine to be added at a later time.

Vattenfall, Sweden's largest utility, is also supporting pressurized biomass gasifier development, by the Finnish Tampella company. Vattenfall's longer-term objective is to demonstrate at commerical scale a BIG/GT system. Tampella's development work is focussed on the U-gas fluidized-bed gasification system orignally developed for coal at IGT and now licensed to Tampella.

In the United States, the Vermont Department of Public Service, in cooperation with in-state electric utilities, is exploring possibilities for a commercial demonstration of BIG/GT technology fueled by wood chips derived from forest management operations. In preparation for this demonstration project, the U.S. DOE, the U.S. Environmental Protection Agency, and the U.S. Agency for International Development jointly supported gasification tests of wood chips and alternative biomass fuels at the pilot-scale fixed-bed gasifier at the General Electric Corporate Research and Development Center, Schenectady, New York (see earlier discussion).

The Finnish electric utility, Imatran Voima Oy (IVO), has begun development of a modified BIG/STIG cycle designed to take advantage of the moisture in wet feedstocks [32]. In the "IVOSDIG" cycle, wet fuel is first dried in a pressurized dryer, so that the moisture evaporated from the feedstock can be recovered as high-pressure steam. The recovered steam is then injected into the gas turbine, as in a conventional STIG, while the dried biomass is fed to the gasifier. IVO is targeting initial development of the IVOSDIG process for peat, which would have an initial moisture content of 60 to 75 percent before being dried to 10 to 30 percent for gasification. A 92 MW_e IVOSDIG cycle is estimated to have an efficiency of 35 percent, starting with 70 percent moisture content peat. IVO is developing the fuel supply and drying systems, which they plan to couple to gasifier and gas turbine systems developed elsewhere. Commercialization of the cycle is targeted for the late 1990s.

Advanced BIG/GT Technologies and Beyond

BIG/ISTIG as described earlier does not represent the ultimate in performance for biomass power-generating technologies. Improvements in turbine blade materials and advances in blade cooling technology that will permit gas turbine operation at higher turbine inlet temperatures, as well as cycle modifications such as the addition of reheat combustors, will lead to overall system efficiency improvements in future BIG/GT systems. Also costs and performance will be improved with advances in biomass gasification and biomass feedstock preparation—e.g., as circulating fluidized-bed gasifiers and pressurized biomass drying technologies become well established. In the longer term, fuel cells operated on gasified biomass may offer even higher performance and better economics at scales similar to or smaller than BIG/GT systems [1].

It is desirable to pursue such opportunities for future improvements in biomass power-generating technologies in R&D programs, because as the biomass power industry grows, it will be necessary to exploit higher cost biomass feedstocks, as low-cost biomass supplies become exhausted and land use constraints on biomass production are approached. Such improvements in conversion technology would make it feasible to extend the roles for biomass in power generation.

Public Policy Issues

With proper management of biomass production, biomass-based power offers major local and global environmental benefits compared with fossil fuel–based power [1]. Also it is likely that biomass power would be competitive with power from conventional sources in a wide range of circumstances.

The first priority in launching a major biomass-based power industry is to demonstrate BIG/GT systems based on present technology. It appears that this will happen over the course of the next several years.

But just demonstrating the technology will not be sufficient to launch a major biomass power industry. In addition, consideration must be given to the institutional reforms needed to create a hospitable environment for the industry. In light of the fact that BIG/GT power-generating units will generally be much smaller than conventional central-station power-generating units, a regulatory environment is needed that is conducive to power generation at modest scale—e.g., by independent power producers. In most parts of the world, utilities, whether privately owned or government owned, have tended to focus their investments on large, central-station systems and have discouraged decentralized power generation by independent power producers or otherwise. In the United States this problem has been successfully addressed with the passage of the PURPA legislation. PURPA-like reforms or alternative measures that would serve to encourage power generation at modest scales are needed in other parts of the world as well.

PURPA-like reforms should be complemented by regulatory or tax measures that would attract investment not just to biomass power but to biomass power based on new technologies like the BIG/GT. Incentives are needed to reward those investors willing to risk trying new technologies—incentives that would be operative for a few years and then phased out as the new technologies become well established.

Consideration should also be given to industrial structural issues that relate to the fact that biomass is an unusual fuel and often is not readily available for long-term contracts, as is the case for coal or natural gas. Accordingly, prospective biomass power producers may sometimes want to produce not just electricity but also biomass, in order to secure fuel supplies for the life of the plant investments. Or they may wish to form joint ventures with firms in the forest product or agricultural industries to increase biomass supply security. In some instances, institutional reforms might be needed to facilitate such joint ventures between utilities or independent power producers and various possible producers of biomass.

It is also important to support research and development on promising advanced biomass power-generating technologies, and to promote a continuing flow of innovations to market, so that as the biomass power industry develops and the use of biomass for power increases, there are improvements in the conversion technology that will enable biomass power to remain competitive as biomass costs rise.

Finally, achieving the high levels of biomass production that would be needed globally to support a major biomass power industry would be a significant undertaking. Great care will need to be taken to ensure that it is done in ecologically sound ways—paying close attention to considerations of sustainability, biological diversity, and other environmental issues [6, 33, 34].

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Table 1: Electricity generating plants burning biomass fuels in the United States as of 1989[a]

State	Number of facilities		Installed capacity MW_e		
	Stand-alone	*Cogeneration*	*Stand-alone*	*Cogeneration*	*Total*
Alabama	0	15	0	375	375
Arizona	2	0	45	0	45
Arkansas	1	4	2.4	10	12
California	64	30	736	255	991
Connecticut	4	3	155	14	169
Delaware	1	0	13	0	13
Florida	12	15	314	474	788
Georgia	0	5	0	36	36
Hawaii	2	13	70	129	199
Idaho	1	6	0.2	116	116
Illinois	0	1	0	2	2
Indiana	0	7	0	36	36
Iowa	2	1	11	2.2	13
Kentucky	1	1	1	1	2
Louisiana	1	12	11	300	311
Maine	4	22	88	704	792
Maryland	2	2	214	94	308
Massachusetts	2	9	38	252	290
Michigan	3	13	78	247	325
Minnesota	3	23	63	161	224
Mississippi	0	10	0	230	230
Missouri	0	2	0	60	60
Montana	2	17	18	340	358
New Hampshire	3	5	15	65	80
New Jersey	2	0	14	0	14
New York	11	17	154	425	579
North Carolina	3	27	60	351	411
Ohio	1	6	17	90	107
Oklahoma	2	1	8	17	25
Oregon	3	24	69	185	254
Pennsylvania	0	9	0	144	144
South Carolina	1	13	49	46	95
Tennessee	2	12	6	43	49
Texas	1	9	2	146	148
Utah	0	1	0	20	20
Vermont	5	3	80	218	298
Virginia	0	9	0	136	136
Washington	3	11	72	120	192
Wisconsin	5	9	55	117	172
U.S. TOTAL	149	367	2,459	5,962	8,421

a. Based on [35]. The total here is an underestimate because the cited reference is incomplete.

Table 2: Performance and capital cost estimates of biomass cogeneration systems

	Cogeneration performance				Performance for maximum electric power		Installed capital costs[a]
	Electricity		Maximum process steam				
	MW_e	Effic., %	kg/hour	Effic., %	MW_e	Effic., %	$\$/kW_e$
15 percent moisture content fuel[b]							
BIG/ISTIG							
LM-8000	97	37.9	76,200	25.4	111.2	42.9	870
BIG/STIG							
LM-5000	39	31.3	47,700	30.0	51.5	35.6	1,120
LM-1600	15	29.8	21,800	33.8	20	33.0	1,380
LM-38	4	29.1	5,700	32.4	5.4	33.1	1,840
50 percent moisture content fuel[b]							
BIG/STIG[c]	38.3	29.5	47,700	28.9	50.8	33.5	1,220[d]
CEST[e]	37	10.0	319,000	52.1	77	20.9	1,520

a. Unit installed costs for BIG/ISTIG, BIG/STIG, and CEST scale with capacity according to: $(\$ \text{ per } kW_e)_{ISTIG} = 2{,}463\ (MW_e)^{-0.22}$, $(\$ \text{ per } kW_e)_{STIG} = 2{,}669\ (MW_e)^{-0.22}$, and $(\$ \text{ per } kW_e)_{CEST} = 6{,}100\ (MW_e)^{-0.32}$

b. The indicated fuel moisture content (mc) is the percentage of the wet weight of the biomass.

c. For the LM-5000. The lower efficiencies and slightly lower electricity production compared to the case with 15 percent mc fuel reflect the estimated energy use associated with drying the fuel to 15 to 20 percent mc.

d. Includes \$84 per kW_e for a steam-based drier. Drying is accomplished using a commercial system (private communication from C. Muenter, Stork Friesland Scandinavia AB, Gothenberg, Sweden, September 1990) that condenses 15-bar saturated steam to provide heat for a dryer that evolves 2/3 as much 3-bar saturated steam from the wood chips during drying, for process use in the plant.

e. This is a double-extraction/condensing steam turbine, with assumed boiler efficiency 68 percent, feedwater temperature 182°C, turbine inlet steam conditions 6.2 megapascals, 400°C. Maximum process steam corresponds to operation with minimum flow to the condenser. Saturated process steam conditions are 12.9 bar (119 tonnes per hour) and 4.4 bar (300 tonnes per hour). Maximum electricity corresponds to minimum required extraction of 72 tonnes per hour of saturated steam at 4.4 bar.

Table 3: Estimated costs ($ per oven dry tonne) of plantation wood: commercial *Eucalyptus* in Brazil today and year 2000 projection for short-rotation, intensive-culture poplar in the United States

	Brazil[a]	United States[b]
Production cost[c] *(6 percent discount rate)*		
Establishment	5.17[d]	5.74[e]
Land rent[f]	0.99	7.95
Maintenance[g]		
Management	0.29	2.72
Land taxes	na	0.99
Research	0.58	na
Cultivation	1.55	
Insecticides/fungicides	na	0.93
Fertilizer	na	1.09
Subtotal	8.58	19.42
Harvesting[h,i]		
Harvester, tractor	na	4.58
Baler	na	3.87
Subtotal	na	8.45
Transport[h]		
Loader/unloader	na	4.46
Tractor/trailer[j]	na	5.15
Subtotal	na	9.61
Harvest/transport[k]		
Subtotal	14.09	na
Chipper/conveyor[h]		
Subtotal	3.15	3.15
Storage/drying[h]		
Storage[l]	6.77	6.77
Drying[m]	11.08	11.08
Subtotal	17.85	17.85
Total *$ per oven dry tonne*	**43.6**	**58.5**
$ per GJ	**2.2**[n]	**3.0**[o]
$ per GJ, 12 percent discount rate	**2.4**	**3.8**

a. Average of high and low estimates given in [28] for eucalyptus plantations currently operated by various forest-products and charcoal industries. (na indicates not applicable)

b. For short-rotation poplars on good-quality agricultural land. Based on the use of a production model incorporating findings from the U.S. DOE Short-Rotation Woody-Crop Program [36]. (na indicates not applicable)

c. The levelized production cost is given by $[\mathrm{CRF}(i,N) \times E + i \times L + M] / Y_L$, where i = discount rate = 0.06; N = plantation life; $\mathrm{CRF}(i,N)$ = capital recovery factor = $i/[1-(1+i)^{-N}]$; t = rotation period; L = land price; E = plantation establishment cost; M = annualized maintenance cost; Y_L = levelized yield = $\mathrm{CRF}(i,N) \cdot \Sigma_t Y_t \cdot (1+i)^{-t}$; Y_t = yield at each harvest. For Brazil, N = 18 years; t = 6 years, L = $208 per hectare, E = $707 per hectare; M = $30.5 per hectare. The total yield is estimated to be 97.3, 87.6, and 70.0 dry tonnes per hectare at the first, second, and third cuttings, respectively, corresponding to a levelized yield of 12.6 tonnes per hectare per year. This corresponds to an actual average yield of 14.1 tonnes per hectare per year. Carpentieri [28] estimates average yields to be 12.3 per hectare per year in the northeast of Brazil and 15.3 tonnes per hectare per year in the state of Minas Gerais, which contains most existing plantations in Brazil today. (In experimental plantations, yields as high as triple today's averages have been achieved in the northeast of Brazil, where soil and climate are not as well suited to tree production as in the southeast and south regions.). For the United States, N = 12 years; t = 6 years; L = $1,800 per hectare; E = $654 per hectare; M = $78.5 per hectare. The total yield over two equal-yield cuttings is assumed to be 190 dry tonnes, corresponding to a levelized yield of 13.6 tonnes per hectare per year (15.8 tonnes per hectare per year actual average yield).

d. Includes nursery production of seedlings and planting.

e. Includes mowing/brushing, plowing, herbicides, liming, fertilization, planting.

f. The land rent is $(i \cdot L)$ (see note c). The Brazil land price of $208 per hectare is the average of high and low land prices as reported in [28]. The U.S. land price is typical for a good corn production site.

g. For Brazil, the maintenance costs include: 1) start-up management costs of $19.6 per hectare and $1.9 per hectare per year in years 1 to 18; 2) cultivation costs of $19.5 per hectare per year in years 1 to 18; and 3) research costs (to improve future productivity) of $7.3 per hectare per year in years 1 to 18. For the United States, the maintenance costs include: 1) insecticides, fungicides applied every other year beginning in year 2 at a cost of $26 per hectare per application; 2) fertilizers applied every other year beginning in year 3 at a cost of $37 per application; 3) management at $37 per hectare per year; and 4) land taxes at 0.75 percent of the land price per year ($13.5 per hectare per year).

h. [37].

i. For a harvesting strategy in which trees are cut, crushed, field-dried, and baled before loading and transport to the storage/conversion site. (It has been found that for bolts of crushed wood averaging 10 centimeters in diameter, moisture contents (wet basis) have dropped from 50 percent to 20 to 30 percent after 6 days in the field [38]. Crushing tree-length stems with diameters up to 18 centimeters at a rate of 14 meters per minute requires only modest amounts of energy—some 0.88 kWh per tonne [39]).

j. Round-trip truck transport costs for a conversion facility located 40 kilometers from the harvesting site.

k. For Brazil, harvesting costs are $1,316 per hectare for the first rotation, $1,185 per hectare for the second rotation, and $950 per hectare for the final harvest. The harvested wood air dries to about 33 percent moisture before it reaches the user. Transport costs assume a 70 kilometer haul.

l. For 6 months of storage, with the wood covered by heavy polyethylene film.

m. Drying with unheated, forced-air system, based on a study by Frea [40].

n. Eucalyptus is assumed to have a higher heating value of 20 gigajoules per oven dry tonne.

o. Poplar has a heating value of 19.38 gigajoules per tonne (HHV basis).

Table 4: Busbar costs (cents per kWh) for alternative power technologies

	CS[a]	BS[b]	CIG/STIG[c]	BIG/STIG[d]	CIG/ISTIG[c]	BIG/ISTIG[d]
Fuel[e]	$1.061 \cdot P_c$	$1.536 \cdot P_b$	$1.011 \cdot P_c$	$0.992 \cdot P_b$	$0.855 \cdot P_c$	$0.839 \cdot P_b$
Labor[f]			0.30	0.20	0.28	0.19
Maintenance[g]			0.42	0.32	0.33	0.24
Administration			0.14	0.10	0.12	0.09
Total fixed O&M	**0.35**	**0.80**	**0.86**	**0.62**	**0.73**	**0.52**
Water requirements[i]			0.028	0.028	0.026	0.026
Catalysts/binder[j]			0.018	–	0.016	–
Solids disposal[k]			0.071	0.069	0.060	0.059
H_2SO_4 by-product credit[l]			–0.273	–	–0.231	–
Total variable O&M	**0.59**	**0.50**	**–0.16**	**0.10**	**–0.13**	**0.09**
Capital[m]						
6 percent discount rate	1.71	2.27	1.66	1.32	1.32	1.03
12 percent discount rate	3.19	3.99	2.85	2.26	2.26	1.76
Total	**$1.061 \cdot P_c +$**	**$1.536 \cdot P_b +$**	**$1.011 \cdot P_c +$**	**$0.992 \cdot P_b +$**	**$0.855 \cdot P_c +$**	**$0.839 \cdot P_b +$**
6 percent discount rate	**2.65**	**3.57**	**2.36**	**2.04**	**1.92**	**1.64**
12 percent discount rate	**4.13**	**5.29**	**3.55**	**2.98**	**2.86**	**2.37**
			Examples (total busbar cost):			
For P_c = \$1.8 per GJ[n]						
6 percent discount rate	4.56		4.18		3.46	
12 percent discount rate	6.04		5.37		4.40	
For P_b = \$3,0 per GJ[o]						
6 percent discount rate		8.18		5.02		4.16
12 percent discount rate		9.90		5.96		4.89

a. CS = a subcritical, coal-fired steam-electric plant (two 500 MW_e units) with flue gas desulfurization, east or west central U.S. siting. EPRI estimates for heat rate (10.61 megajoules per kWh), overnight construction cost (\$1,217 per kW_e), other capital (\$78 per kW_e), O&M costs (\$23.1 per kilowatt per year fixed; \$0.0059 per kilowatt variable), and the idealized plant construction time (5 years) [41]. Including AFDC, the total capital cost amounts to \$1,450 per kW_e (\$1,624 per kW_e) for a 6 percent (12 percent) discount rate.

b. BS = a 27.6 MW_e biomass-fired steam-electric plant. Based on an EPRI design for a 24 MW_e condensing/extraction cogeneration plant producing 20,430 kilograms per hour of steam at 11.2 bar for process [41]. Here it is assumed that this steam is instead condensed, thus producing an additional 3.6 MW_e; the heat rate is 15.36 megajoules per kWh (corresponding to steam conditions of 86 bar and 510°C at the turbine inlet and a turbine efficiency of 80 percent). EPRI estimates for the overnight construction cost (\$1,693 per kW_e), other capital (\$127 per kW_e), and idealized construction period (3 years). Including AFDC, the total capital cost amounts to \$1,924 per kW_e (\$2,031 per kW_e) for a 6 percent (12 percent) discount rate.

c. CIG/STIG = a coal-integrated gasifier/steam-injected gas turbine and CIG/ISTIG = a coal-integrated gasifier/intercooled steam-injected gas turbine. The total estimated capital cost for a 6 percent (12 percent) discount rate is \$1,411 per kW_e (\$1,449 per kW_e) for CIG/STIG and \$1,122 per kW_e (\$1,153 per kW_e) for CIG/ISTIG [21].

d. BIG/STIG = a biomass-integrated gasifier/steam-injected gas turbine and BIG/ISTIG = a biomass-integrated gasifier/intercooled steam-injected gas turbine. The total estimated capital cost for a 6 percent (12 percent) discount rate for BIG/STIG is \$1,121 per kW_e (\$1,152 per kW_e) and for BIG/ISTIG is \$874 per kW_e (\$898 per kW_e). These costs were derived from CIG/STIG and CIG/ISTIG cost estimates by subtracting out costs that would be needed for coal plants (e.g., sulfur removal), but not for biomass plants. See [1].

e. P_c = coal price, and P_b = biomass price, in \$ per gigajoule (HHV basis).

f. The coal-based systems require three operators for the gasification system, four for the hot-gas cleanup, and three for the power plant. At \$22.55 per hour, operating labor costs for the coal systems are \$1.977 million per year. Because hot-gas desulfurization is not needed for the biomass systems, it is assumed that seven operators are needed for the biomass systems—four fewer because hot-gas desulfurization is not needed and one more because of increased fuel handling requirements. Thus annual operating labor costs would be \$1.384 million.

g. Annual maintenance costs (40 percent labor and 60 percent materials) are estimated to be \$2.812 million for CIG/STIG (including \$0.634 million for chemical hot-gas cleanup) and \$2.342 million for CIG/ISTIG (including \$0.591 million for chemical hot-gas cleanup). The corresponding values for BIG/STIG and BIG/ISTIG, without chemical hot-gas cleanup, are \$2.178 million and \$1.751 million, respectively.

h. Annual administrative costs, assumed to be 30 percent of O&M labor, are \$0.930 million for CIG/STIG, \$0.874 million for CIG/ISTIG, \$0.677 million for BIG/STIG, and \$0.625 million for BIG/ISTIG.

i. Raw water costs are \$0.189 million per year for all systems.

j. Annual catalysts and binder costs are \$0.121 million (\$0.113 million) for CIG/STIG (CIG/ISTIG) and zero for BIG/GT systems.

k. Annual costs for solids disposal are \$0.469 million (\$0.428 million) for CIG/STIG (CIG/ISTIG) and are assumed to be the same for the corresponding BIG/GT systems.

l. Annual H_2SO_4 by-product credits are \$1.815 million for CIG/STIG, \$1.659 million for CIG/ISTIG, and zero for BIG/GT systems.

m. The capital charge rate includes the capital recovery factor for an assumed 30-year plant life [0.0726 (0.1241) for a 6 percent (12 percent) discount rate] plus an insurance charge rate of 0.5 percent of the initial capital cost per year. The capacity factor is assumed to be 75 percent. Corporate income and property taxes are not included.

n. The levelized price of coal, 2000–2030, delivered to utilities in the west/north central United States, as projected by the U.S. Department of Energy.

o. Delivered cost of wood chips from short-rotation, poplar crops in the United States, including the costs of 40 kilometers transport, drying, and 6-month storage, for a 6 percent discount rate (see Table 3).

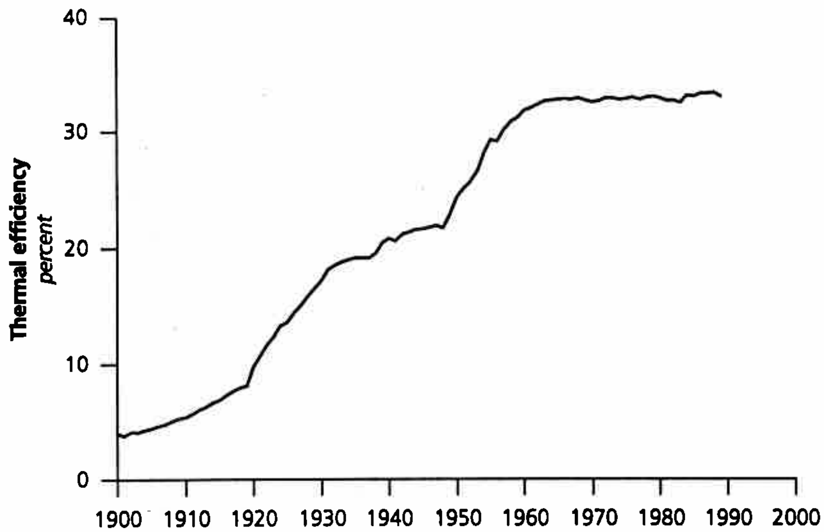


FIGURE 1: Historical trend in the average efficiency of electricity generation in central-station thermal power plants in the United States [5].

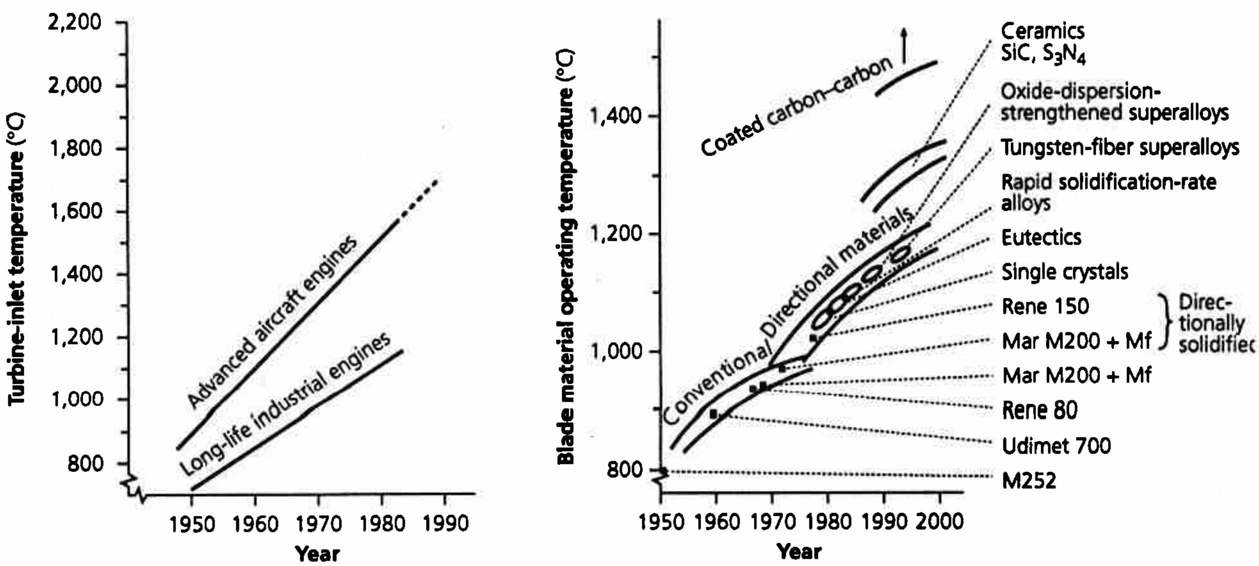


FIGURE 2: The trend in turbine-inlet temperatures for advanced aircraft jet engines and long-life industrial turbines (left) and turbine blade material operating temperatures (right) [7]. Note: When an aircraft engine is modified for stationary applications, the rated turbine-inlet temperature is reduced about 110 °C to promote long-life operation.

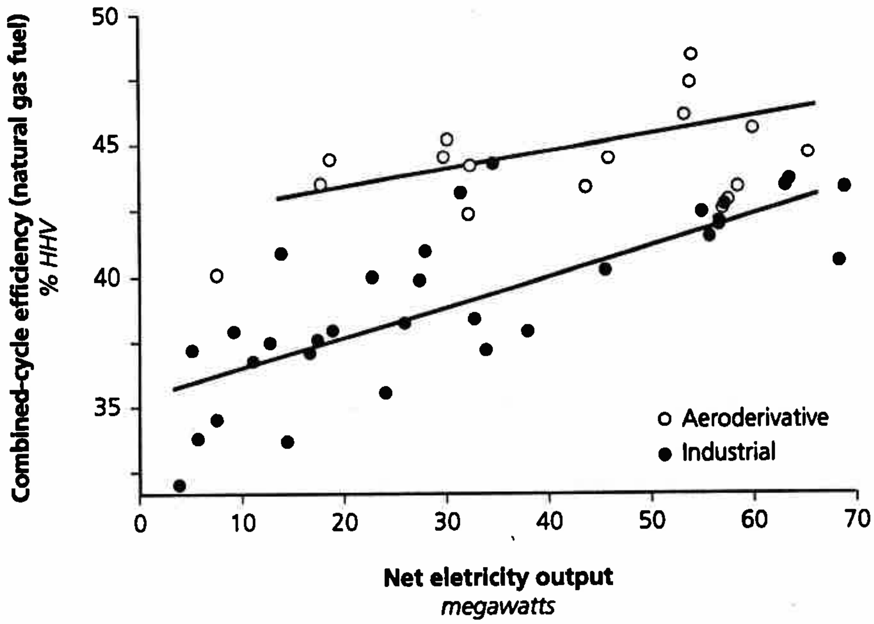


FIGURE 3: This figure includes all combined-cycle power plants with a net electrical output less than 70 MW_e and listed in the 1991 Gas Turbine World Handbook *[42]. Each point represents a specific, commerically offered combined-cycle package based on aeroderivative or industrial gas turbines. Note that the aeroderivative-based cycles have efficiencies that are several percentage points higher than cycles based on industrial turbines.*

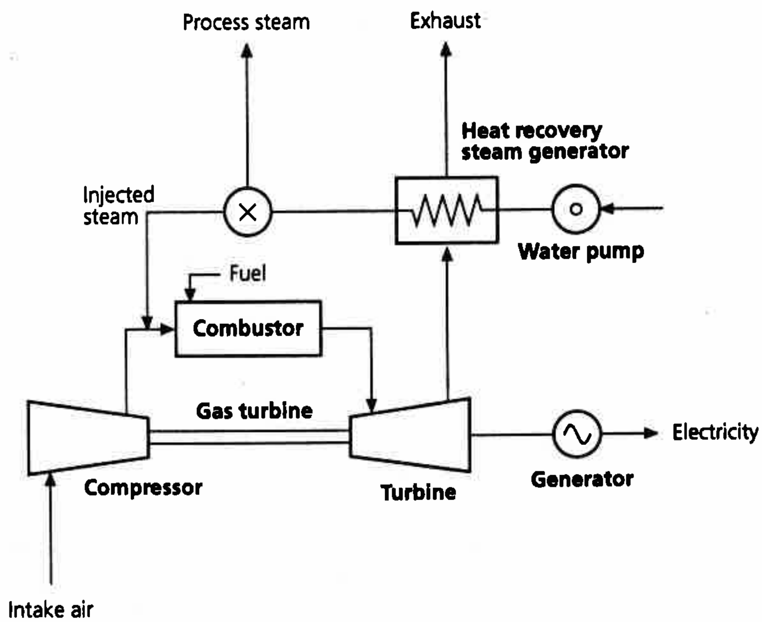


FIGURE 4: Steam-injected gas turbine (STIG). Similar to the simple-cycle gas turbine used for cogeneration, except that steam not needed for process use is injected into the combustor and at points further down the flow path for increased power output and higher electrical efficiency.

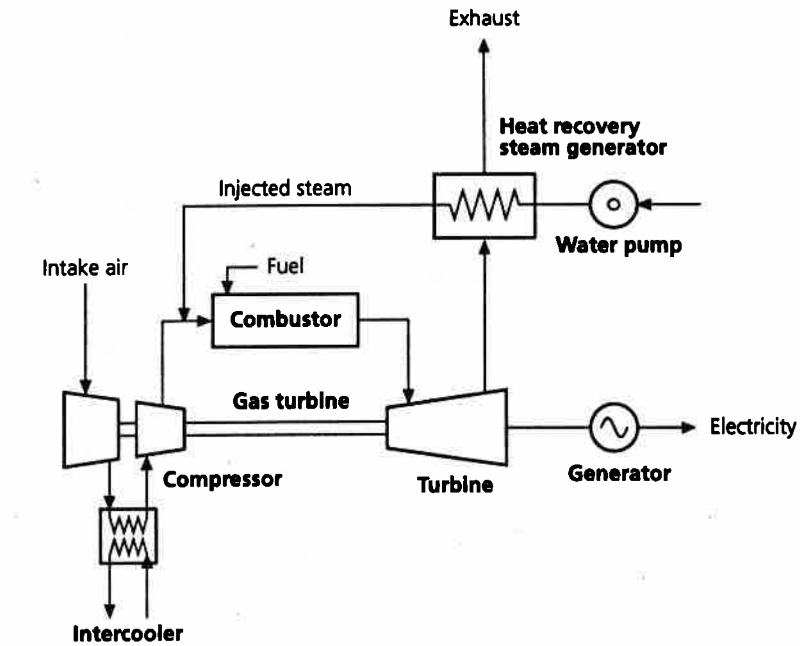


FIGURE 5: Intercooled steam-injected gas turbine (ISTIG). Similar to STIG, except that an intercooler between compressor stages leads to much higher efficiency and much larger electrical output, because less compressor work is required and the turbine can operate at a higher turbine-inlet temperature owing to improved cooling of the turbine blades with air bled from the compressor.

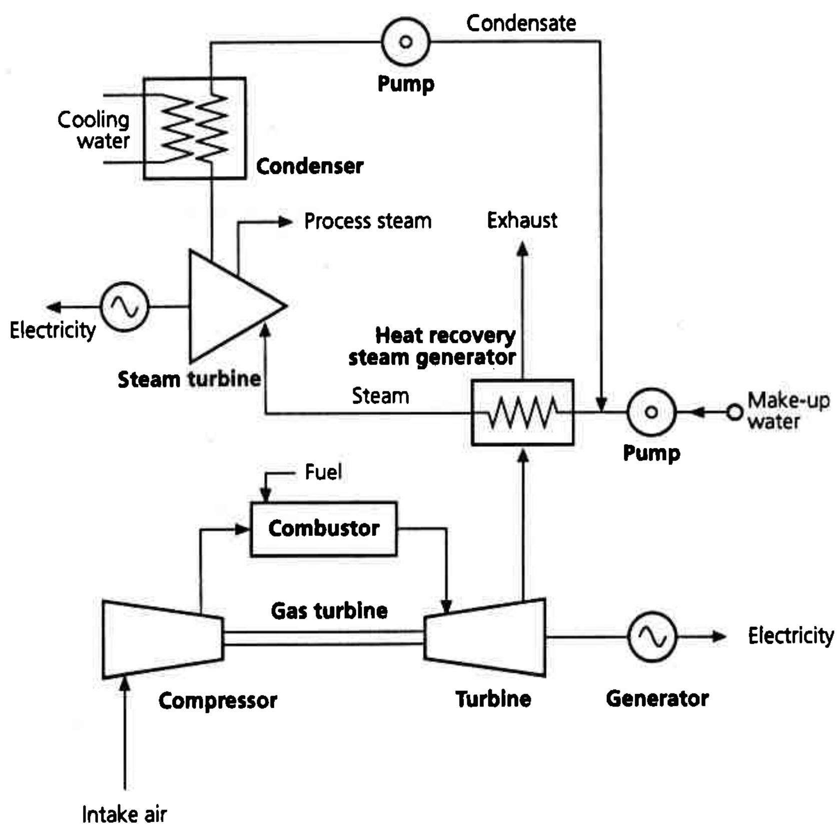


FIGURE 6: Gas turbine/steam turbine combined cycle (CC). Similar to the simple cycle gas turbine used for cogeneration, except that steam from the HRSG is used to produce extra power in a condensing steam turbine, from which some steam might be bled for process applications.

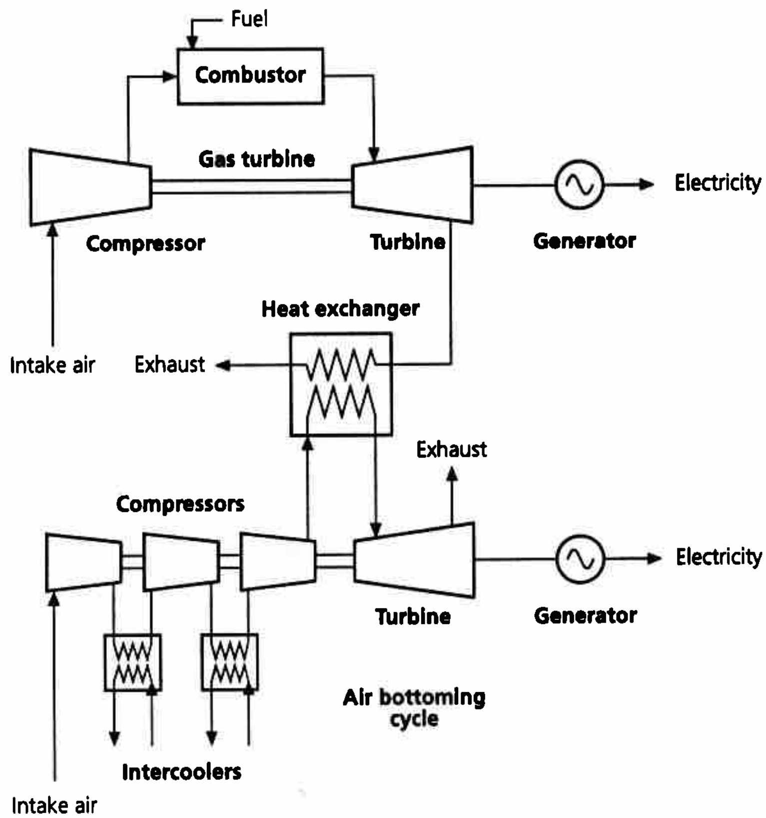
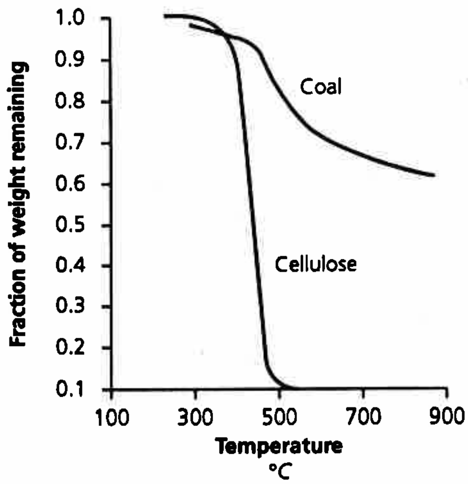


FIGURE 7: Air bottoming cycle (ABC). Similar to the gas turbine/steam turbine combined cycle, except that the exhaust heat from the gas turbine topping cycle is recovered not as steam but by heat transfer via a heat exchanger to the air working fluid of an indirectly heated air bottoming cycle. [17].



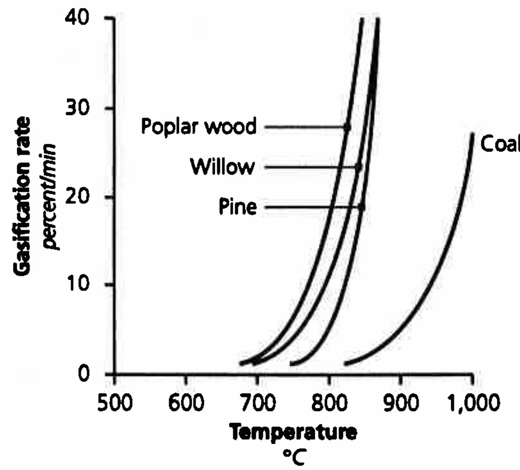


FIGURE 8: Comparison of the gasification characteristics of biomass and coal. The left figure [43] shows the rate at which Wyodak coal and cellulose (which accounts for typically half the weight of biomass) lose weight, or devolatilize, as they are pyrolyzed, i.e., heated in the absence of air. Pyrolysis is one of the main processes involved in converting solid fuels into combustible gases. Nearly complete devolatilization of cellulose occurs at under 500 °C. In contrast, only about 40% of coal is devolatilized and only after heating to close to 900 °C. The slower weight loss with coal reflects its inherently lower thermochemical reactivity. The much higher fraction of weight remaining even after heating to 900 °C reflects the much lower content of volatile components in coal compared to cellulose.

The right figure [44] shows the rate at which solid carbon that remains after pyrolysis (char) is converted into carbonaceous gases in the presence of steam. Char gasification is another of the major processes involved in converting solid fuels into combustible gases. Because of the higher reactivity of biomass chars, these gasify much more rapidly and at lower temperatures than coal chars. Thus, lower temperatures can be used in biomass gasifiers compared to coal gasifiers to achieve the same level of char conversion to gas.

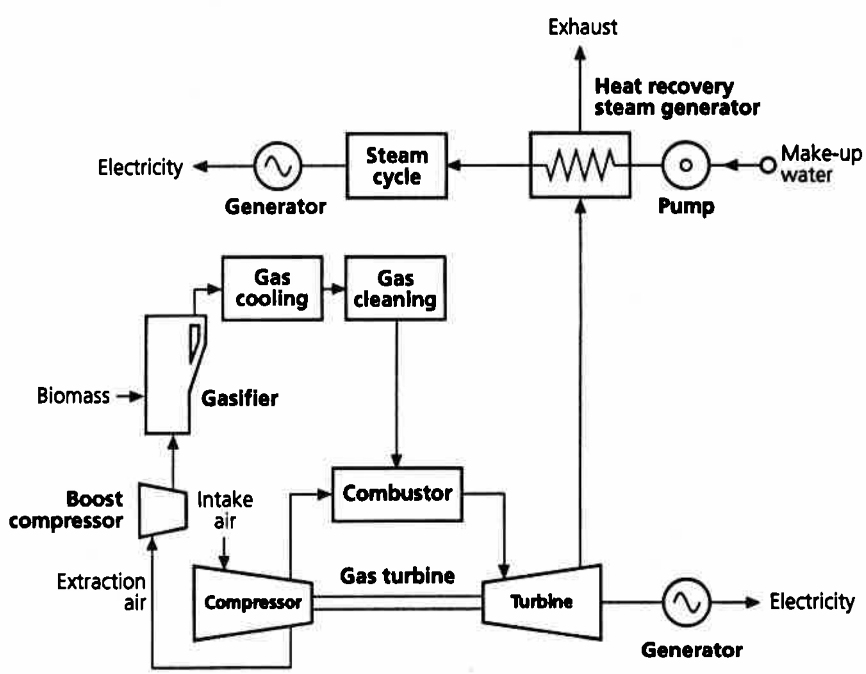


FIGURE 9: A biomass-gasifier/gas turbine combined cycle.

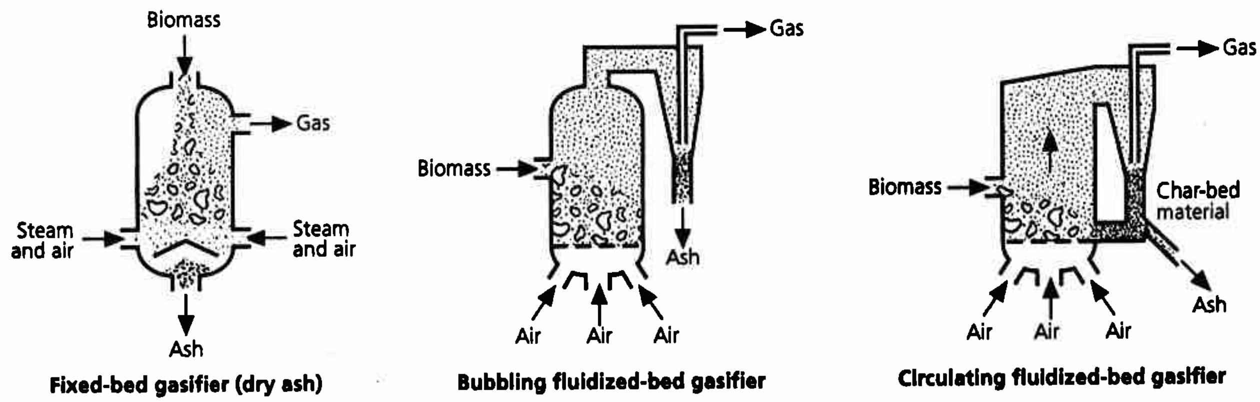


FIGURE 10: Alternative biomass gasifier designs.

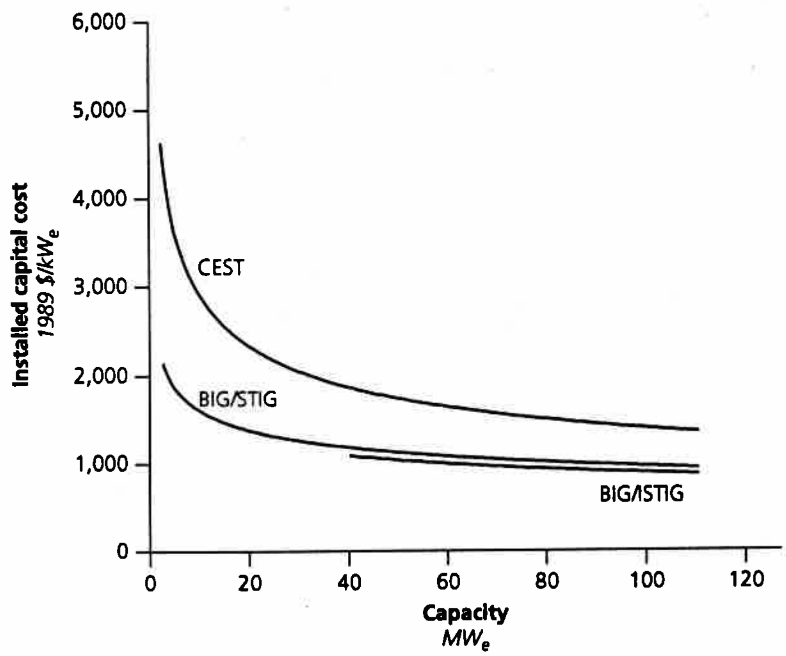


FIGURE 11: Installed capital cost estimates for alternative biomass cogeneration technologies versus scale (table 2, note a).