STEAM-INJECTED GAS-TURBINE COGENERATION FOR THE CANE SUGAR INDUSTRY

Optimization Through Improvements in Sugar-Processing Efficiencies*

Eric D. Larson
Joan M. Ogden
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PU/CEES Report No. 217

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EXECUTIVE SUMMARY

This study was undertaken to assess the technical and economic feasibility of gas-turbine cogeneration in cane-sugar factories, using sugar cane residues as the primary fuel. The study has found that some 50,000 MW of gas turbines fired with sugar cane residues could be supported globally with the 1985 level of cane production (Table I). In the 70 developing countries that grow sugar cane (Figure I), gas turbines could produce some 300 billion (10^9) kWh of electricity annually (Table II), representing over 25% of the current electric utility generation and about as much electricity as is currently generated with oil in these countries. The cost of generating this electricity would be lower than that for most central-station alternatives.

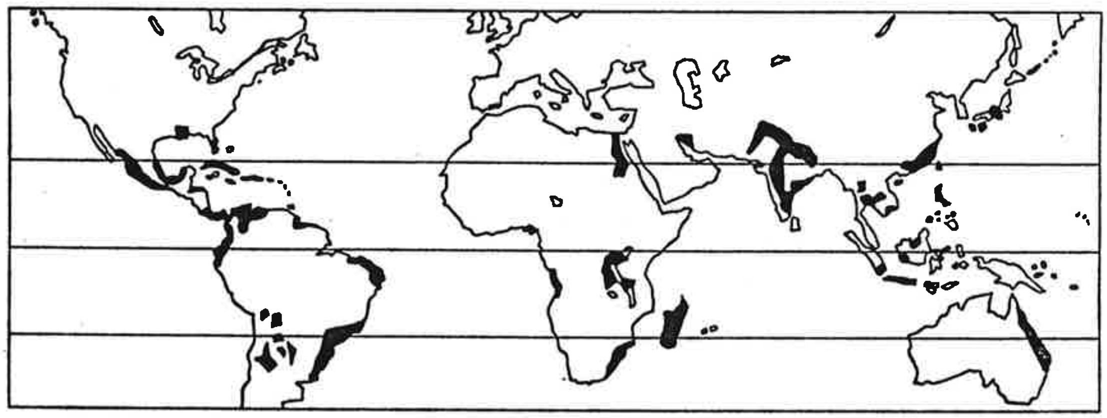

Figure I. The major sugar cane growing regions of the world are indicated by the darkened areas on this map. From (I. Sangster, Sugar and Jamaica, Thomas Nelson & Sons, London, 1973).

Table I. Estimated potential worldwide gas turbine generating capacity at sugar factories with the 1985 level of sugar cane production.[a]

Region	Potential Electrical Capacity (MW)
SOUTH AMERICA	17,800
ASIA	14,000
CENTRAL AMERICA	10,100
AFRICA	4,900
OCEANIA	2,700
UNITED STATES	1,900
EUROPE	200
TOTAL	51,600

[a] See Table 17 in text for sources and explanatory notes.

Table II. Gas turbine electricity generating potential from sugar cane, based on the 1985 cane production level, (A), and the actual total electric utility generation in 1982, (B), in developing countries (10^9 kWh).[a]

	A	B		A	B	A	B
ASIA						89	599
India	31.6	129.5	Iran	0.90	17.5		
China	19.0	327.7	Vietnam	0.81	1.69		
Thailand	10.8	16.2	Burma	0.45	1.52		
Indonesia	7.6	11.9	Bangladesh	0.42	2.98		
Philippines	7.4	17.4	Malaysia	0.32	11.1		
Pakistan	6.4	14.9	Nepal	0.12	0.284		
Taiwan	3.4	45.0	Sri Lanka	0.07	2.07		
CENTRAL AMERICA						65	100
Cuba	35.5	10.8	Jamaica	0.94	1.30		
Mexico	15.7	73.2	Panama	0.72	2.71		
Dominican Rep.	4.2	2.38	Belize	0.49	0.065		
Guatemala	2.3	1.42	Barbados	0.45	0.339		
El Salvador	1.2	1.45	Trinidad & Tob.	0.36	2.30		
Nicaragua	1.1	0.945	Haiti	0.23	0.352		
Honduras	1.0	1.04	St.Chris.-Nevis	0.12	na		
Costa Rica	1.0	2.42					
SOUTH AMERICA						116	257
Brazil	95.0	143.6	Guyana	1.1	0.255		
Colombia	6.1	21.3	Bolivia	0.78	1.40		
Argentina	5.5	36.2	Paraguay	0.36	0.569		
Peru	3.3	7.25	Uruguay	0.23	3.47		
Venezuela	2.1	39.0	Suriname	0.05	0.175		
Ecuador	1.3	3.09					
AFRICA						32	167
South Africa	11.4	109.0	Mozambique	0.26	3.25		
Egypt	3.7	17.2	Somalia	0.24	0.075		
Mauritius	3.1	0.320	Nigeria	0.23	7.45		
Zimbabwe	2.1	4.16	Angola	0.23	1.46		
Sudan	2.0	0.910	Uganda	0.15	0.569		
Swaziland	1.8	0.075	Congo	0.11	0.195		
Kenya	1.6	1.73	Mali	0.09	0.080		
Ethiopia	0.87	0.618	Gabon	0.05	0.530		
Malawi	0.69	0.410	Burkina Faso	0.05	0.123		
Zambia	0.64	10.3	Chad	0.04	0.065		
Ivory Coast	0.57	1.94	Guinea	0.02	0.143		
Tanzania	0.47	0.720	Sierra Leone	0.02	0.136		
Madagascar	0.45	0.342	Benin	0.02	0.016		
Cameroon	0.32	2.15	Liberia	0.01	0.389		
Zaire	0.30	1.48	Rwanda	0.01	0.066		
Senegal	0.30	0.631					
OCEANIA						2	1
Fiji	1.6	0.241	Pap. N. Guinea	0.13	0.441		
ALL SUGAR-PRODUCING DEVELOPING COUNTRIES						304	1,124

[a] See Table 18 in text for sources and explanatory notes.

Such a major role for cane-sugar producers in power generation is feasible despite the fact that at present all the bagasse, the fibrous residue of cane milling, is typically burned as fuel in small steam-turbine cogeneration systems to meet the modest steam, mechanical power, and electricity demands of sugar factories. With the same amount of bagasse much more electricity can be produced than at present if more efficient modern cogeneration systems are employed. A few factories in Hawaii and elsewhere have recently installed larger, more efficient steam-turbine cogeneration systems that export some electricity to the grid, and a number of other installations are being considered.

This study was motivated by recent significant developments in gas turbine technology in the US, which could lead to the near-term commercialization of biomass-fired gas turbine cogeneration systems that would be much more efficient and more economical than steam turbine cogeneration systems. Major improvements in the performance of gas turbines have come in the last decade largely from advances in jet engine technology. Jet engine improvements have been made in response to market pressures of high fuel costs for commercial airlines and as a result of more than $400 million of annual expenditures by the US Department of Defense on R&D for jet engines for military aircraft. The transfer of these improvements to stationary gas turbines has been stimulated largely by the surge in gas-turbine sales for cogeneration applications in the US that followed the passage of legislation in 1978, the Public Utilities Regulatory Policies Act, which strongly encouraged cogeneration.

Steam injection for power and efficiency augmentation is one significant modification of aircraft-derivative gas turbines that has been commercialized recently for natural gas-fired applications (Figure II). Originally developed for cogeneration applications, the steam-injected gas turbine has become a serious candidate for central station baseload power

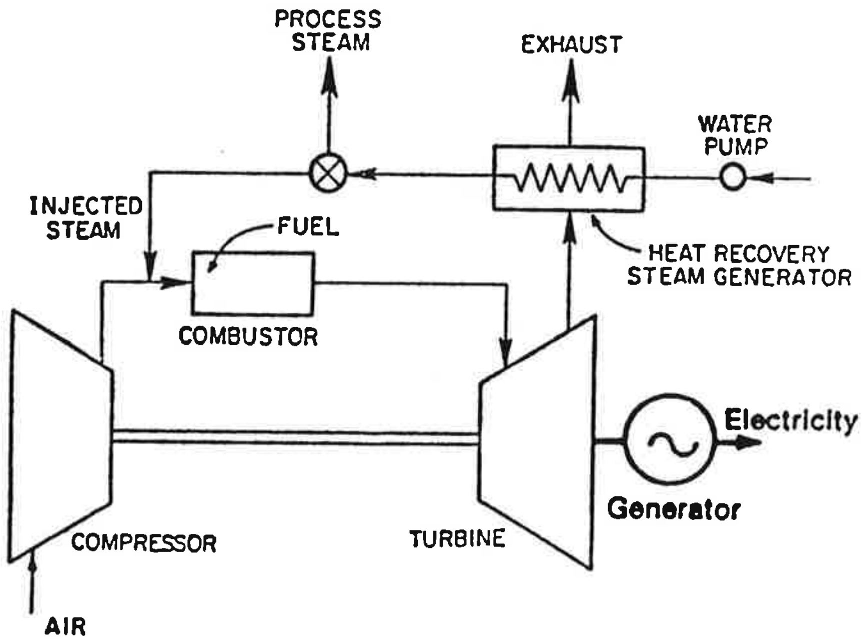

Figure II. In a steam-injected gas turbine cogeneration system fired with a clean fuel (natural gas or distillate oil). steam generated with the hot turbine exhaust gases, if not required for process, can be injected at the exit of the compressor to boost the electrical efficiency and output of the system.

generation as well, because of its high efficiency, low capital cost, and small size.

Gas turbines have traditionally operated only on clean fuels (natural gas or distillate oil), but technologies for firing with solid fuels are nearing commercial readiness. Three biomass-fired steam-injected gas turbine cogeneration systems were reviewed for this study: a gas turbine fired directly with biomass (sawdust), which is under development at a test facility in Red Boiling Springs, Tennessee; a gas turbine fired indirectly with biomass [employing a heat exchanger between the atmospheric-pressure combustor and the pressurized working fluid (air)]; and a gas turbine fired with gasified biomass. Of the three, the biomass-gasifier steam-injected gas turbine (GSTIG) was found to be overall the most promising in terms of efficiency, capital cost, and commercial readiness.

Although the biomass-GSTIG is the most technologically advanced of the three systems reviewed here, it could be commercialized relatively quickly because of recent developments relating to coal-GSTIG systems in the US. The technical feasibility of operating a gas turbine on coal-gas from an oxygen-blown gasifier has been commercially demonstrated at the 100-MW Cool Water central station power plant in California. In a recent analysis done for the US Department of Energy (USDOE), the General Electric Company (GE) has identified the steam-injected gas turbine coupled to an air-blown gasifier with hot-gas sulfur removal as an alternative to the Cool Water technology that would have higher efficiency and lower capital cost. As of the time of this writing, an agreement between the USDOE and GE to continue this $156 million "clean coal" program had not been reached. Should the program proceed, GE would plan to conduct a commercial demonstration of the hot-gas sulfur removal technology required for coal-firing (the only system component unproven at commercial scale) within one year, followed by startup of a 5-MW pilot plant within 3 years and a 50-MW commercial demonstration within 6 years. Much of this technology can be readily adapted to biomass feedstocks. In fact, gasifying biomass should be easier than gasifying coal, and no sulfur removal technology would be required, since biomass contains virtually no sulfur.

The technical performance of alternative cogeneration systems in a raw sugar factory can be specified in terms of the amount of electricity that can be generated for each tonne of cane crushed (kWh/tc), while meeting the on-site process steam demand. A typical cogeneration system at an existing factory today produces about 20 kWh/tc during the milling season--enough for on-site needs. A modern condensing-extraction steam turbine (CEST) would produce about 100 kWh/tc. About 25% more power could be produced if steam-conserving process technologies (e.g. condensate juice heaters and falling film evaporators) now widely used in oil-dependent industries such as beet sugar and dairy were adopted in cane sugar factories. Moreover, if an auxiliary fuel were used in the the off-season, the CEST could produce over 240 kWh/tc. (Three off-season fuel alternatives are considered in this study: barbojo, the tops and leaves of the cane; fuelwood grown on plantations; and oil). A GSTIG system installed at the same steam-conserving factory would produce (with year-round operation) over 460 kWh/tc--nearly twice the level of the CEST, or 23 times as much electricity as is generated at a typical factory today (Figure III).

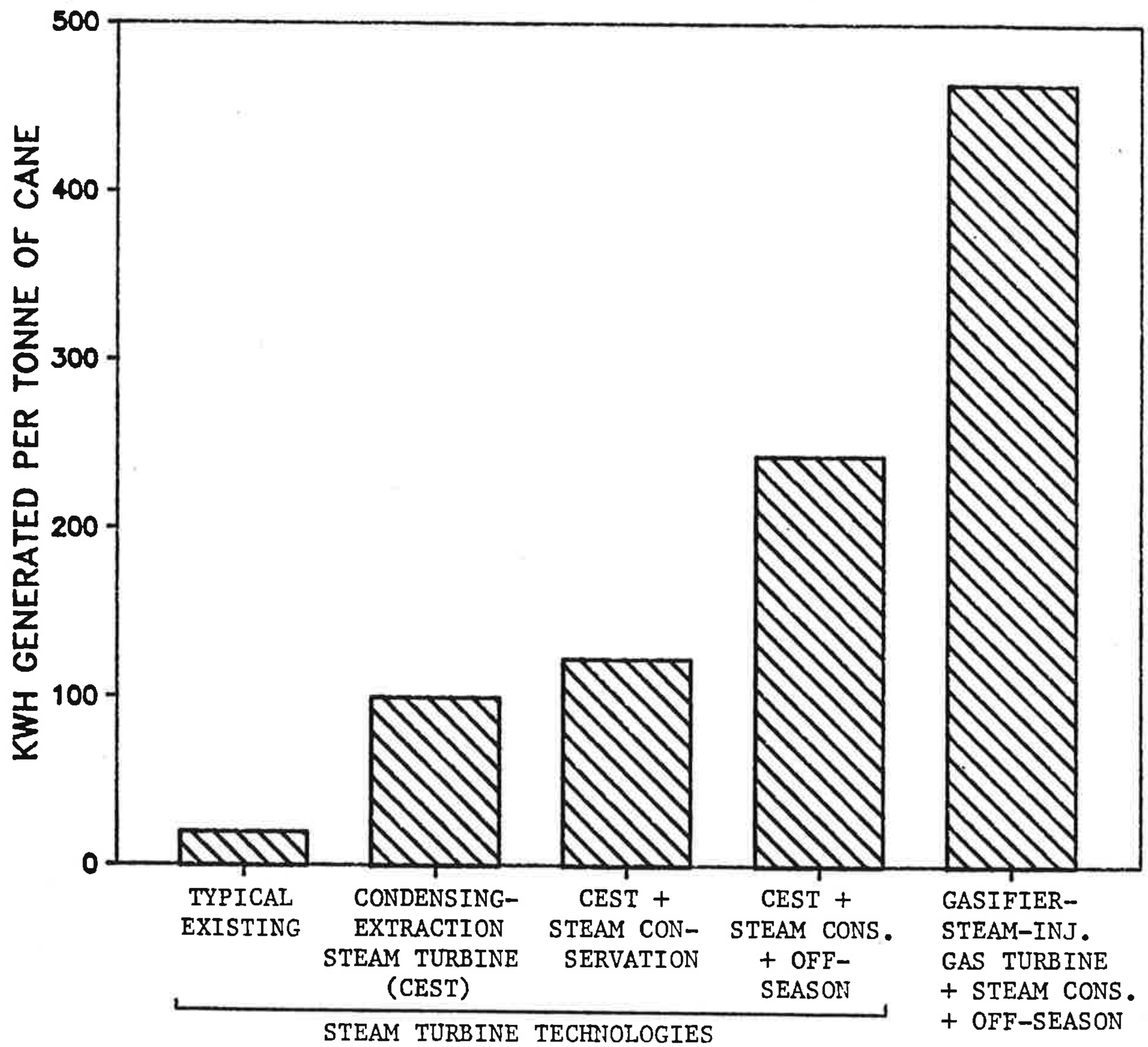

Figure III. Electricity generating potential of cane-residue-fired condensing-extraction steam-turbine and gasifier steam-injected gas turbine cogeneration systems. The two right-most bars include the effects of reduced process steam demand and off-season operation with an auxiliary fuel.

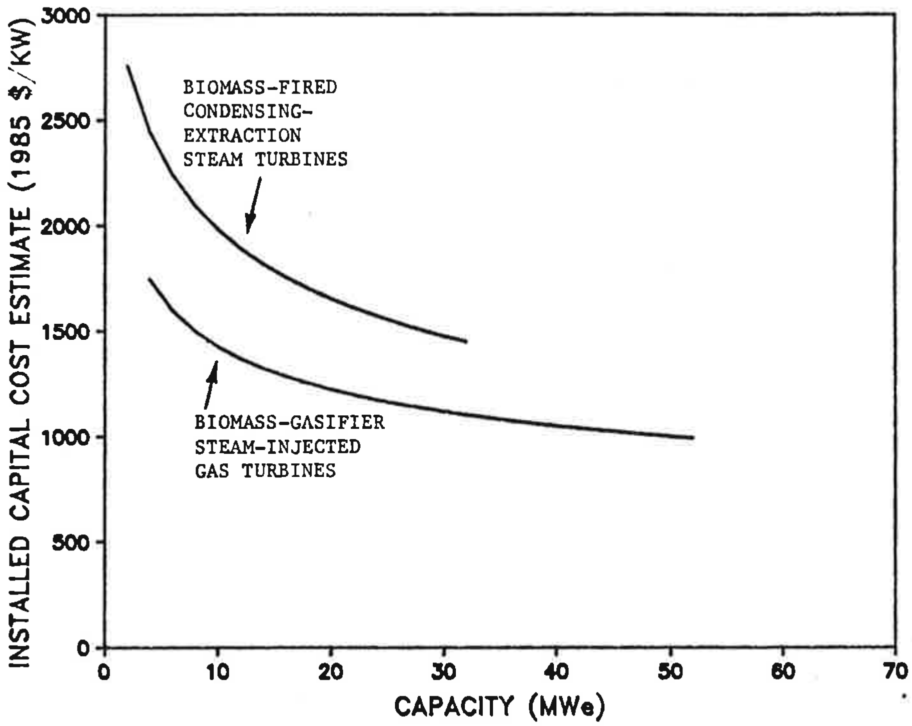

Figure IV. Estimated unit capital costs for biomass-fired steam turbine and gas turbine cogeneration systems.

Besides being more energy efficient, GSTIG systems would have lower unit capital costs than CEST systems, and scale economies for the GSTIG would be weaker (Figure IV). Thus, the economics of power generation with the GSTIG would be more favorable at the small scales (5-50 MW) most relevant for biomass-fueled applications.

For the case study considered here--a Jamaican raw-sugar factory processing 175 tonnes of cane per hour--investments in cogeneration systems, together with investments in steam-conserving end-use equipment, were analyzed. Because the GSTIG would produce more electricity and less process steam per unit of fuel consumed than a CEST, the sugar factory would need to reduce its steam consumption from about 400 kg per tonne of cane processed (typical of existing factories) to about 300 kg/tc in order to be able to use the GSTIG. The bagasse produced at the 175 tc/hr factory could support either a 27-MW CEST or a 53-MW GSTIG. The 27-MW CEST would provide a real (inflation-corrected) rate of return of 13-16%, depending on the assumed price paid for exported electricity ($0.050-$0.058/kWh) and the level of steam savings implemented. A 53-MW GSTIG system would provide a return of 18-23% and produce about twice as much exportable electricity as the CEST. The annual electricity revenues generated (at $0.05/kWh) per tonne of cane with the GSTIG would equal sugar revenues when sugar sells for $0.23 per kilogram. Electricity revenues with the CEST would be half as large.

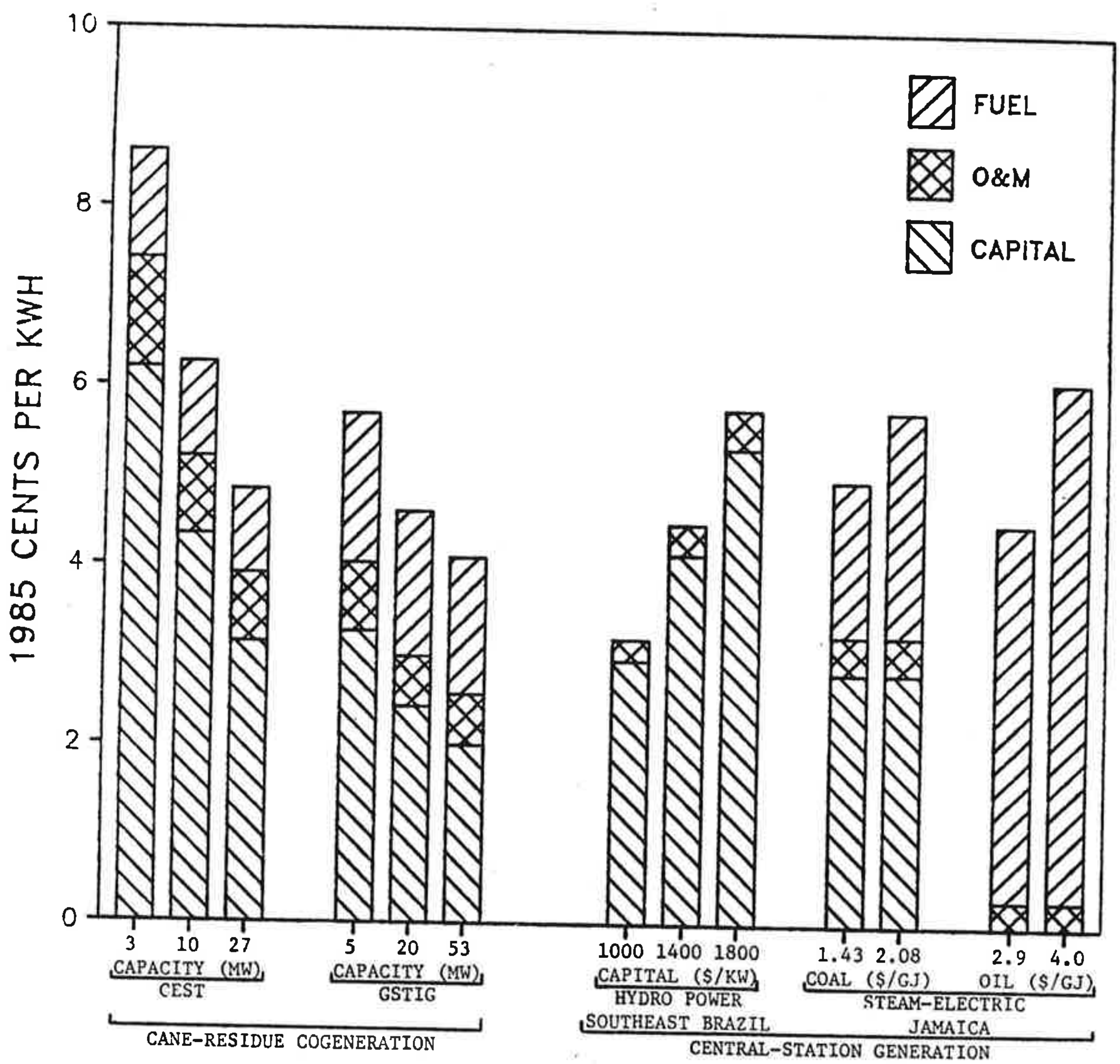

Figure V. Estimated levelized costs of generating exportable electricity with steam turbine and gas turbine cogeneration systems at sugar factories compared with least-cost central station alternatives.

GSTIG systems may be of interest to electric utilities, since they would generate electricity at lower cost than most alternatives. In Jamaica the generating cost for a large- (53-MW) or medium- (20-MW) sized GSTIG would be lower than the cost for power from a new 61-MW coal-steam plant burning imported coal, which has been identified as a least-cost generating option for the 1990s (Figure V) in that country. It would also be competitive with the operating cost for existing oil-fired steam plants burning residual oil in Jamaica, even with oil costing a relatively low $2.90/GJ ($19 per barrel). Only the largest CEST (27-MW) could produce power competitively with coal-fired plants and with oil-fired plants when the oil price is higher than $3.2/GJ (Figure V). GSTIGs would also be competitive with most new hydro-electric plants in cane-growing countries where this is a least-cost option, e.g. Brazil (Figure V).

Some engineering development work and a pilot demonstration remain to be carried out to bring biomass-GSTIG cogeneration systems to commercial readiness. How rapidly this technology is commercialized in the cane-sugar industry will probably depend more on how quickly institutional thinking patterns change than on technological constraints. The introduction of GSTIG units would be facilitated by a willingness of the sugar industry to view itself as a purveyor of sugar and electricity, as well as by the willingness of electric utilities to consider gas turbines burning cane residues as a candidate least-cost generating option.

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I. INTRODUCTION

World-market sugar prices have fluctuated widely over the past two decades and have been relatively low for the past several years (Figure 1), reflecting the mercurial nature of commodity markets and the depressed state of the industry today. Growth in world markets for raw sugar will be slow, due largely to permanent inroads that artificial and corn sweeteners have made into traditional cane sugar markets.[1] As a result, the industry is beginning to seek alternative products from sugarcane, including energy.[2] The conversion of raw sugar juice into fuel alcohol has enjoyed considerable success in Brazil,[3] and a number of other countries are considering the production of ethanol from sugar.

Alternative uses of bagasse have not received as much attention as sugar, since bagasse has generally been considered a waste product. In fact, sugar factories have traditionally been designed to consume all their bagasse to meet plant steam and electricity demands, thereby avoiding bagasse disposal costs.[4] If bagasse is instead regarded as a valuable energy resource, it may be desirable to reoptimize the processing of sugar and/or alcohol with the production of exportable electricity from bagasse. With a redesigned cane processing plant and the use of more efficient technologies for the cogeneration of process steam and electricity, quantities of electricity far in excess of on-site needs could be generated for export to national electrical grids.

Cogeneration has been used for many decades by the world's sugar industry. These systems, based on small steam turbines, have typically been designed to meet all of a factory's steam and electricity demands and leave no excess bagasse. In the past decade or so, some factories have installed larger steam turbines which satisfy all of the on-site steam and electricity demands and, because of their higher electrical efficiency, export a substantial quantity of electricity into the utility grid.[a] Interest is growing worldwide in adopting this commercially-proven technology.[5,6,7]

This study was undertaken to assess the feasibility of using gas-turbine cogeneration in cane sugar factories, with bagasse from the crushing of the cane as the primary fuel. Since the introduction of gas turbines would represent a fundamental change for the industry involving technological and financial risks, the expected technical and economic performances of gas turbines must far exceed those of the steam turbine before the sugar industry would seriously consider gas turbines for cogeneration. This study was motivated by preliminary analyses suggesting that indeed gas turbines may significantly out-perform steam turbines in cogeneration applications where biomass is used as fuel.

While to date gas turbines have required oil or natural gas for fuel, the development of gas turbines operating on solid fuels, particularly coal, has been progressing rapidly in the United States. The implications of these developments for biomass-fired gas turbine cogeneration in the sugar industry are considered in the present study.

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[a] On the Hawaiian islands of Kauai, Hawaii, and Maui, sugar factories generated 150, 431, and 521 GWh, respectively, in 1985, corresponding to 58%, 32%, and 32% of all electricity generated on those islands (C. Kinoshita, Head, Sugar Technology and Engineering Department, Hawaiian Sugar Planter's Association, unpublished data, 1987). In Mauritius, sugar cane factories supplied 30.6 GWh, or 8.4% of the country's electricity generation in 1981 (Central Electricity Board, 29th Annual Report and Accounts, Curepipe, Mauritius, 1982). A recently completed plant at the Beaufonds factory in Reunion is anticipated to be able to supply 37 GWh annually to the national grid during the milling season (Directorate-General of Information and Market Innovation, "24.65 MW Bagasse-FIred Steam Power Plant Demonstration Project," EUR 10390 EN/FR, Commission of the European Communities, Brussels, 1986).

The study is focussed on the Monymusk sugar factory in Jamaica, for which an extensive technical database has been developed in a feasibility study of the installation of a condensing-extraction steam-turbine cogeneration system.[8] For the present study, the data for Monymusk permits a case-study of the prospects for gas turbine cogeneration in sugar factories and a comparison with steam-turbine systems of the type proposed for Monymusk.

2. RECENT DEVELOPMENTS IN STATIONARY GAS TURBINE TECHNOLOGY

2.1 History

Until recently, the main attractions of gas turbines for central station power generation have been their simplicity and low capital cost, which has lead to their wide use for peaking service by the electric utilities. Because of their low efficiencies, however, utility gas turbines have historically not been used for base-load power generation where they would compete with large steam-turbine units.

In contrast, gas turbines in cogeneration applications have long been thermodynamically efficient prime movers, since large quantities of process heat could be recovered from the hot (500-600^{o}C) turbine exhaust gases. In addition, because of their high electricity-to-process heat output ratios, gas turbines in many applications generate electricity far in excess of that required onsite.[9] Furthermore, unit capital costs are lower and scale economies are weaker for gas turbines relative to comparably sized steam turbines (Figure 2), so that the economics of gas turbine cogeneration are often favorable at small scales (a few up to a few tens of megawatts)--the most relevant sizes for biomass applications.

Interest in gas turbines for cogeneration applications grew rapidly after passage of the Public Utilities Regulatory Policy Act (PURPA) in the United States in 1978 and the Supreme Court decisions of 1982 and 1983 upholding key provisions of the legislation. PURPA requires a utility to pay cogenerators a price for their electricity equal to the cost the utility can avoid by not having to build a new power plant or otherwise supply that electricity. In addition, the utility is required to provide backup power to cogenerators at a reasonable price. PURPA has led to a boom in cogeneration. Some 40,000 MW of capacity were certified by the Federal Energy Regulatory Commission from 1980 through the end of 1986,[10,11] and certifications of gas-turbine-based capacity have accounted for a larger and larger fraction of the annual totals (Figure 3).[12]

The boom in gas turbine sales for cogeneration applications has led gas turbine vendors to make significant improvements in the technology. Many of these have been borrowed from advances in aircraft-engine technology, which has seen major improvements during the past 10-15 years due to: the development of more efficient gas turbines for commercial airliners (motivated by rising fuel costs, which accounted for 20-30% of airline operating costs in the mid-1970s[13]); and the expenditure of over $400 million annually over the last decade by the US government for R&D on gas turbines for military aircraft.[14]

2.2 Steam-Injected Gas Turbines

One significant modification which has recently been commercialized for stationary gas turbines is the use of steam injection for power and efficiency augmentation. The steam-injected gas turbine (STIG) cycle involves a variation on the simple gas turbine cycle, in which steam recovered in a turbine exhaust heat recovery steam generator is injected into the combustor (Figure 4). Steam injection increases both power output and electrical efficiency.[b] Aircraft-derivative units are chosen for steam injection, because they are designed to accommodate turbine flows considerably in excess of their nominal ratings.

Steam-injected gas turbines were introduced initially in a 5.5-MW_e natural-gas fired unit called the "Cheng Cycle" by International Power Technology, Inc.,[15] a small company in California whose founder holds patents related to the technology. The General Electric Company has since introduced 28 and 47 MW_e units.[16,17]

The STIG was developed originally as a means of coping with the most troublesome problem for simple-cycle gas turbines in cogeneration -- their poor part-load performance, which restricted them largely to applications with nearly constant process-heat loads. With a STIG unit, steam not needed for process use can be injected into the combustor to produce more power; under PURPA in the US, this extra electricity can be sold to the utility, thus often extending the financial viability of gas turbine cogeneration to a wide range of variable load applications.[18]

Steam-injection technology has made the gas turbine a serious candidate for central station power generation as well. Because of their high efficiency and low unit capital cost, advanced steam-injected units burning

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[b] With steam injection, the higher mass flow through the turbine expander creates more power output. Higher efficiency is achieved largely because only a negligible amount of additional work input is required to pump the boiler feedwater to boiler pressure, avoiding the large amount of compressor work required to compress a gaseous working fluid (E.D. Larson and R.H. Williams, "Steam-Injected Gas Turbines," <u>ASME Journal of Engineering for Gas Turbines and Power</u>, Vol. 109, No. 1, January 1987).

expensive natural gas or distillate oil (which could be commercialized in a few years)[c] could produce base-load electricity in small plants at costs competitive with most other sources of power, including large new coal or nuclear plants. In addition, the small scale and short construction times for such systems make them ideal for electric utilities faced with slow but uncertain electricity demand growth.[19,20]

Further advances in stationary gas turbines are likely in the future;[21] from improvements already made in jet engines but not yet applied to stationary gas turbines, from further cycle modifications appropriate for stationary applications but not jet engines, and from turbine material improvements that will allow still higher turbine inlet temperatures.

3. STEAM-INJECTED GAS TURBINES BURNING SOLID FUELS

To circumvent dependence on costly high quality fuels, coal and biomass are now being seriously considered for use with gas turbines. Three basic solid-fired gas turbine cycles are currently under development: gas turbines fired (a) directly with solid fuels, (b) indirectly with solid fuels, and

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[c] An advanced steam-injected gas turbine, the intercooled STIG or ISTIG, would produce about 110 MW of electricity at an efficiency of 47% (higher heating value) burning natural gas and would cost about $400/kW. This ISTIG unit is based on the LM-5000, a GE aircraft-derivative turbine which, in simple-cycle operation, has an output of 33 MW and an efficiency of 33%. Modified for steam injection alone the LM-5000 would have an output of 47 MW and an efficiency of 38%. The much higher efficiency achievable with the ISTIG is due largely to the much higher turbine inlet temperature made possible through better cooling of the turbine blades with air bled from the compressor. (With intercooling the compressor air flow is cooled between the two stages of the compressor.) (See E.D. Larson and R.H. Williams, "Steam-Injected Gas Turbines," ASME Journal of Engineering for Gas Turbines and Power, Vol. 109, No. 1, 1987.)

(c) directly with gasified solid fuels.[d]

3.1 Directly-Fired Gas Turbines

Gas turbines fired directly with biomass operate in much the same way as conventional gas turbines, but they require much larger combustors. With direct firing, air exiting the compressor is ducted to a high-pressure combustor where it acts as the combustion air for the burning of the biomass (Figure 5). After passing through a particulate removing cyclone, the hot gases are ducted back to the turbine. The hot turbine exhaust gases are used to raise steam in a heat recovery steam generator (HRSG).

A modest development effort is ongoing for gas turbines fired directly with biomass.[22] A 3-MW sawdust-fired unit is presently undergoing trial operation in Red Boiling Springs, Tennessee, in part to determine the extent of clean-up of the hot combustion products required to insure adequate turbine life, and in part to refine the system for feeding solid fuel into the pressurized combustor. To date, the system has operated successfully only at relatively low turbine inlet temperatures (less than 790^{o}C), which translates into relatively low efficiency.

If successfully developed, this system would be attractive because it is likely to have relatively low unit capital costs[23] and be simpler in construction than other biomass-fired gas turbine options. However, a verdict on its commercial viability appears several years away, given the modest success achieved to date and the low level of R&D support it is currently receiving. Because of this uncertainty, the directly-fired

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[d] In addition to the discussion in this section, the latter two cycles are described in greater detail in Appendix A.

biomass gas turbine was not considered for detailed assessment in the present study.

3.2 Indirectly-Fired Gas Turbines

The indirectly-fired gas turbine (IFGT) is a candidate for near term applications, since the technology is commercially ready: no systems have been operated commercially, but several vendors offer the major system components. Most development work on indirectly-fired gas turbine systems has been targeted at coal applications,[24] but there are no apparent difficulties in using biomass.

In the IFGT cycle, the biomass is burned in an atmospheric-pressure combustor, and heat is transferred through a high temperature heat exchanger (air heater) to the air exiting the compressor, which subsequently expands through the turbine (Figure 6).[25] The clean hot air exiting the turbine at about 350-400^oC can be used directly for process needs and/or to raise steam in a HRSG. Additional process steam can be generated using the combustion exhaust gases, which typically leave the air-heater section of the combustor at 350-400^oC.[e] For indirectly-fired units based on aircraft-derivative turbines, steam not needed for process can be injected into the cycle working fluid at the exit of the compressor to raise electrical output and efficiency.

The gas turbines needed for indirectly-fired systems are commercially proven and available from several vendors. (See Appendix A.) While the

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[e] This relatively high temperature results because the temperature of the air entering the air heater from the compressor is at 300-350^oC. (See Appendix A.)

combustor/heat exchanger has not been commercialized, several vendors[f] offer variations of the most promising candidate technology, an atmospheric fluidized-bed combustor (AFBC) containing air heater tubes. In the AFBC (Figure 7), jets of rising air "fluidize" a bed consisting of over 95% non-combustible material, such as sand, which stores heat and acts as a heat transfer medium.[26] The thorough mixing of the hot inert material with the burning fuel yields a relatively uniform temperature throughout the combustion zone and a very high combustion efficiency, typically 98-99%. AFBCs with steam heater tubes are already well-established using coal and high-moisture biomass fuels,[27] but there are no commercially operating AFBC-IFGT systems. However, prototype AFBCs with air heaters for gas turbine applications have been tested by a number of manufacturers,[28] and a 10-MW petroleum-coke-burning commercial demonstration plant has been operating for approximately 2000 hours in Torrence, California.[29]

Because of their commercial readiness, IFGT systems are considered in this study for near-term cogeneration applications in the sugar industry. However, two characteristics of these systems limit their attractiveness:

- o The heat exchanger required for indirect firing leads to significantly higher unit capital costs than for systems that can be fired directly.
- o The efficiency of indirectly-fired systems is limited because the peak temperature allowable in the heat exchangers (about 815°C with the best available alloys) is much lower than the turbine inlet temperatures of state-of-the-art commercial gas turbines--1200°C and higher. As gas turbine advances permit higher and higher turbine inlet temperatures,

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[f] These include Struthers-Wells, Fluidyne, and Wormser Engineering in the United States.

the efficiency gap between indirectly- and directly-fired systems will widen.[g]

3.3 Gas Turbines Fired Directly with Gasified Biomass

In a gas turbine fired directly with gasified biomass, some air from the gas turbine compressor would be used to gasify the biomass in a pressurized gasifier, the gas from which would pass through a particulate removal device before entering the combustor, where it would burn with the balance of the compressor air (Figure 8). The hot turbine exhaust gases would raise steam in the HRSG, some of which would be required to operate the gasifier, and the rest of which could be used for process or for injection into the combustor.

The cycle efficiency constraint imposed by the heat exchanger in IFGT systems would be eliminated in the gasifier-gas turbine units, since gasification losses would be more than compensated for by the efficiency gains arising from the much higher turbine inlet temperature possible with direct firing. The cost of the AFBC and heat exchanger would also be eliminated, although these savings would be partially offset by the added cost of a gasifier.

The technical feasibility of operating gas turbines on gas derived from sulfur-bearing coal has been commercially demonstrated at the 100-MW Cool

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[g] One way to increase the turbine inlet temperature further would be to burn a small amount of clean fuel (e.g. distillate fuel oil) in a simple, inexpensive "topping" combustor between the AFBC air heater exit and the gas turbine inlet (C.L. Marksberry and B.C. Lindahl, "Industrial AFB-Fired Gas Turbine Systems with Topping Combustors," American Society of Mechanical Engineers, Paper No. 80-GT-163, 1980). Higher overall efficiency and greater electricity production could thus be obtained, although fuel costs would be higher.

Water central-station power plant in California.[30] In that system, gas produced from coal in an oxygen-blown gasifier is cooled and scrubbed to remove sulfur before it is injected into the gas-turbine combustor, and the steam raised in the HRSG is passed through a steam turbine (rather than being injected into the gas-turbine combustor) to generate additional power. The Cool Water project was designed to demonstrate the attractive operational and emissions characteristics of coal-based gas turbine power generation. In this it has been successful.[h] However, a commercial scale Cool Water plant (600 MW) based on state-of-the-art combined cycle technology would be no less costly on a lifecycle cost basis than a conventional coal-fired steam plant with stack-gas scrubbers in the US (Table 1).

Recently, the US Department of Energy (USDOE) solicited an analysis by the General Electric Company (GE) to identify technological strategies that could lead to higher efficiencies and lower capital costs for coal gasification-gas turbine systems. The GE analysis concluded that the most promising ways to improve upon Cool Water technology would involve:[31]

- o Replacing the oxygen-blown gasifier with an air-blown gasifier, thereby eliminating the oxygen plant and reducing overall capital costs.
- o Replacing the gas turbine/steam turbine combined cycle with a steam-injected gas turbine (STIG) or an intercooled STIG. So doing would reduce unit capital requirements (because there would be no need for a steam turbine, condenser, cooling tower, etc.) and thereby also reduce

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[h] For example, measured emissions of sulfur dioxide, nitrogen oxides, and particulates at Cool Water are all an order of magnitude below the US Environmental Protection Agency's New Source Performance Standards (P.F. Curran, "Clean Power at Cool Water," Mechanical Engineering, August 1987).

the sensitivity of the unit cost to scale.

- Introducing a hot-gas sulfur removal system which GE analysts believe is commercially ready, thereby achieving a significant efficiency gain over the system of cooling and scrubbing the gasifier exhaust used in the Cool Water demonstration.

As of the time of this writing, an agreement between the USDOE and GE to continue this $156 million "clean coal" program had not been reached. Should the program continue, GE would plan a commercial-scale demonstration of the hot-gas sulfur-removal technology within one year, followed within 3 years by the startup of a 5-MW coal-gasifier-steam-injected gas turbine (coal-GSTIG) pilot plant and within 6 years by the startup of a 50-MW commercial demonstration plant (Table 2).[32] The primary interest in these demonstrations will be in proving the performance and cost-effectiveness of commercial-scale hot-gas sulfur removal technology.

The coal-GSTIG technology is largely transferable to systems based on biomass.[i] In fact, the higher volatility of biomass makes it inherently easier to gasify than coal.[33] Furthermore, most biomass contains virtually no sulfur, obviating the need for, and additional cost of, the sulfur removal equipment. Thus, no new technology must be proven to use biomass in GSTIG systems.[34] In fact, by "piggy-backing" onto the work on the coal-GSTIG, the commercialization of the biomass-GSTIG could be accomplished in about 3 years.[35]

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[i] GE researchers have focussed on coal-powered systems, but have also recently conducted trial gasification tests on biomass and biomass-coal composites and have carried out some systems analysis of gas turbines burning gasified biomass (D.P. Smith, Manager, Process Operations Program, Engineering Systems Laboratory, Corporate Research and Development, General Electric Company, Schenectady, New York, USA, personal communication, March 1987).

4. PERFORMANCE AND COSTS OF COGENERATION SYSTEMS FOR SUGAR FACTORIES

4.1 Performance Characteristics

4.1.1 In-Season Performance

In a sugar factory, the crushing of one tonne of cane yields about 300 kg of 50% moisture bagasse fuel (with a heating value of about 9,530 kJ/kg).[j] The amounts of steam and electricity required to process the cane into sugar varies with the type of processing equipment used. For the Monymusk plant in Jamaica, which is assumed to be a conventional raw-sugar factory, it is estimated that about 20 kWh of electricity and 380 kg of process steam would be required to process one tonne of cane when the cane throughput rate is 175 tonnes per hour.[k]

In conventional sugar factories in most parts of the world today, small steam turbine cogeneration systems operating with electrical efficiencies of perhaps 5%[36] produce just enough electricity and steam to meet onsite demands. More efficient systems can produce excess electricity while satisfying the process steam demand. Figure 9 summarizes the estimated production characteristics--process steam (kg/tc) vs. electricity (kWh/tc)--for alternative cogeneration systems operating on bagasse during the milling

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[j] Higher heating values are used for fuels in this report. The value of 9,530 kJ/kg is calculated from the Pritzlewitx van der Horst formula:

$$HHV\ (kJ/kg) = 19{,}050 - 4{,}190*s - 18{,}840*w,$$

where s is the ash or impurity fraction and w is the moisture fraction on a wet basis (N. Magasiner, "Boiler Plant as an Integral Part of a Cane Sugar Factory," Proceedings of the Meeting of the International Society of Sugar Cane Technologists, 1974, p. 1661).

[k] Sugar-processing energy demands are discussed in detail in Section 5 and Appendix G.

season.[l]

A 27 MW, high pressure (6 MPa), condensing-extraction steam turbine (CEST), similar to the type proposed for installation at the Monymusk plant in Jamaica,[37] can produce about 100 kWh/tc while supplying a conventional factory's steam needs.[m]

Two IFGT systems, one based on the 3.2-MW Detroit Diesel Allison 501-K aircraft-derivative engine and one on the 21.4-MW ASEA-STAL GT-35C, can produce up to 25% more electricity than the CEST while producing the same amount of process steam.

Larger quantities of electricity could be generated if the factory steam demand were reduced through steam-conserving investments. (Section 5 describes strategies for reducing steam consumption using commercially available process equipment.) For CEST systems, this would allow condensing a greater fraction of the steam to boost electricity output. For the IFGT systems, it would make more electricity available through steam injection.

The bagasse-fired GSTIG systems assessed in this study cannot be used in conventional sugar factories because these more efficient units do not produce enough steam to meet onsite needs. However, if the process steam demand were reduced to about 300 kg/tc, GSTIG systems could be used (Figure

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[l]Details of the calculations of cogeneration performance on biomass fuels are given in Appendices A, B, and C. Listings of computer programs used for some of these calculations are provided in Appendix I.

[m] A conventional factory's steam demand is defined to include steam which drives small steam-turbine generator sets that produce the factory's electricity needs. Whether these small turbo-generators would be used in practice (rather than having the CEST supply the on-site electricity) will depend largely on the relationship/contract between the sugar producer and the owner of the cogeneration plant.

9).[n] These would produce about twice as much electricity per tonne of cane as a CEST, or over 10 times the electricity produced in most existing sugar factories today. Figure 9 shows the estimated performance for three different sized GSTIG systems, all based on gas turbines manufactured by GE. The LM-5000 and LM-1600 are in widespread use with clean fuels today, and the GE-38 (an improved version of the existing LM-500) will be introduced in the early 1990s. All three are aircraft-derivative engines.[o]

4.1.2 Year-Round Performance

Most sugar factories operate only during the harvest season, which varies in length depending on regional agricultural practices. In Jamaica the season can last up to 7 months. Where the milling season is less than twelve months long, the capacity utilization and kWh generation of a new cogeneration plant would be improved if an auxiliary fuel were available in the off-season. (Potential off-season fuels are discussed in detail in Section 6.) Figure 10 summarizes the potential electrical generation (kWh per tonne of cane crushed) at a sugar factory in Jamaica with a range of

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[n] The total steam production in the HRSG of the biomass-GSTIG would be higher than 300 kg/tc. It is estimated, however, that the Lurgi-type gasifier considered here, which GE is planning to use in its coal-GSTIG system, would require about 20% of the total steam production when operating with biomass, primarily for cooling of the bed. (See Appendix A.) An alternative gasifier, e.g., a pressurized fluidized-bed unit such as the Rheinbraun High-Temperature Winkler system, may require virtually no steam, since its normal operating temperature without steam would be relatively low (A. Bellin, H-J. Scharf, L. Schrader, and H. Tegger, "Application of the Rheinbraun-HTW Gasification Process to Biomass Feedstocks," Bioenergy 84 (III), Elsevier, London, 1985.

[o] Aircraft which use a flight version of the LM-5000 (the CF6-xx) include commercial airliners: the Boeing 747 and 767, the McDonnell Douglas DC-10, the Airbus A300 and A310, and military aircraft: the US Air Force's KC-10A tanker/cargo plane. The LM-1600 is derived from the F-404 aircraft engine, which is used on a number of U.S. military aircraft, including the Northrup F-20, the McDonnell Douglas F/A-18, and the Grumman Aerospace A-6F attack planes.

cogeneration technologies and includes the effect of reducing process steam and operating in the off-season.

As noted earlier, a typical existing system operates only during the milling season and produces about 20 kWh/tc. Some larger steam turbines, such as the one recently installed at the Beaufond Factory in Reunion, produce 50-60 kWh/tc during the milling season.[38] In Hawaii, where an auxiliary fuel is used in some factories during the off-season, the average electricity production from steam turbine systems is about 90 kWh/tc.[39] A CEST of the type proposed for Monymusk would generate about 100 kWh/tc in a conventional factory during the milling season. In a "steam conserving" factory (discussed in Section 5.2), this system would produce about 25% more electricity. Adding off-season operation would raise this to about 240 kWh/tc. For the same conditions (steam-conserving factory with off-season operation), an IFGT system would produce about 300 kWh/tc. The electricity production of a GSTIG system based on the LM-5000 would be over 460 kWh/tc, or 23 times the elecricity generated in most sugar factories today.

4.2 Cost Characteristics

4.2.1 Capital Costs

For the present study, installed unit capital costs ($/kW) were estimated for several sizes of steam turbine and gas turbine cogeneration plants based on detailed engineering design studies, engineering scoping studies, other technical studies presented in the literature, and discussions with industry experts, as described in detail in Appendix D. Figure 11 shows the estimated costs over a range of plant capacities.

The strong scale economies associated with condensing steam-turbine systems are evident in the figure: A 30 MW CEST is estimated to cost about \$1510/kW; a 3 MW system about \$3010/kW.[p]

There are probably no significant scale economies associated with IFGT power plants: the fuel handling and combustion equipment for larger-capacity units would generally require field fabrication rather than shop fabrication, which adds cost, while smaller systems would suffer some penalty in efficiency. To a rough approximation, therefore, the unit installed capital costs for IFGTs can be assumed invariant with size.[40] A 3.2-MW steam-injected Detroit Diesel Allison 501-K gas turbine and a 20.7-MW ASEA-STAL GT-35C STIG are both estimated to cost about \$1900/kW.

Unit capital costs would be lower for the GSTIG systems, because of their substantially higher efficiency and reduced materials requirements. In addition, the scale economies associated with these units are much weaker than for steam turbines. Even in the larger plants it is expected that shop fabrication could be utilized extensively,[41] since pressurization of the gasifiers keeps their physical size relatively small. A 53-MW GSTIG plant based on the LM-5000 gas turbine is estimated to cost about \$990/kW; a 5-MW plant based on the GE-38 about \$1650/kW.

A cost estimate for a 61-MW coal-fired central-station powerplant, which is discussed below, is also shown in Figure 11. In a least-cost expansion study for the Jamaican electric utility,[42] the unit capital cost was estimated to be about \$1315/kW, which includes a 61 MW plant's share of a coal-handling infrastructure.

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[p] The GNP deflator has been used to express all costs in this report in constant 1985 US dollars.

4.2.2 Maintenance Issues

Maintenance costs are a key consideration for gas turbine cogeneration systems. Gas turbines represent "jet-age" technology, with which many developing countries may have had relatively little experience.[q] Even in industrialized countries, gas turbine maintenance costs are widely believed to be high relative to those for steam turbines. Maintenance costs for aircraft-derivative gas turbines, compared to heavy-duty industrial units, are thought to be higher still. However, experience indicates that these perceptions are generally incorrect for the baseload applications relevant to the present analysis.

The perception of high maintenance costs is a result primarily of the electric utility experience with peaking gas turbines. For peaking duty, capacity factors are very low (typically 10% or less[43,44]) and when units are operated, they generally run at "full throttle," causing considerable stress on the machine. The result is that maintenance costs per kWh can be quite high. For example, the Jersey Central Power and Light (JCP&L) utility in the US has incurred average maintenance costs of $0.010-$0.015/kWh for their oil-fired peaking gas turbines over the last 15 years.[45] However, with the proper maintenance programs that accompany most gas turbine units operating with higher capacity factors these costs are much lower. For example, JCP&L has also operated a combined cycle burning distillate fuel oil since about 1980 in intermediate-cycle duty (capacity factor of 30-40%),

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[q] While the gas turbines considered here represent "high technology," they involve modest steam pressures. The small steam-turbine systems used in most sugar factories today operate with peak steam pressures of 1-2 MPa. Larger, more efficient steam turbines such as some in Hawaii, Reunion, and Mauritius operate with steam pressures of 5-8 MPa. (The plant proposed for Monymusk would operate at 6 MPa.) By contrast, the peak pressures in the gas turbine systems considered here range from about 1.5 to 3.5 MPa.

with maintenance costs of $0.0035/kWh.[46] All of the JCP&L units are industrial gas turbines.

In many US industrial cogeneration applications, where gas turbines continuously supply baseload electricity and process heat, maintenance costs have been comparable or lower, even for aircraft-derivative units, due primarily to well-structured maintenance programs. For example, the Dow Chemical Company has operated several natural-gas-fired Pratt and Whitney FT-4 aircraft-derivative gas turbines (15-20 MW_e output each) in cogeneration plants in the San Francisco area for some 20 years, with maintenance costs averaging $0.002 to $0.003/kWh.[47] Discussions with other cogeneration plant operators have confirmed this cost range for natural gas-fired systems in the US, and there has been similar industrial experience worldwide. One gas turbine manufacturer (General Electric) has installed over 230 aircraft-derivative gas turbines for power production and cogeneration in 23 countries. Figure 12 shows the worldwide locations of one GE gas turbine, the LM-2500.

The general perception that aircraft-derivative gas turbines are more expensive to maintain than heavy-duty industrial units is based largely on the fact that the materials used in these units, and their construction in general, are typically more sophisticated than for industrial machines. Higher costs for replacement parts, however, are offset to some extent by the shorter time required to remove and replace parts. (The modular construction of aircraft-derivative units which permits this was originally developed to minimize down time for aircraft.) For example, a complete inspection (part of a routine maintenance program, including any necessary replacement of parts) of the hot section of a General Electric LM-2500 aero-derivative turbine (21 MW capacity) requires a crew of five working 100 person-hours,[48] compared to a similar procedure on a comparable-output industrial turbine, which requires a six-person crew working 480 person-hours.[49]

Major maintenance on aircraft-derivative engines is typically done off-site, while a replacement engine continues to produce power. With larger heavy-duty industrial turbines, repairs must be made on-site, requiring complete shutdown of the plant, often for extended periods. With aircraft-derivative units, replacement engines are typically leased or purchased from manufacturers as part of a service contract. In other cases, manufacturers provide innovative service contracts which guarantee delivery (anywhere in the world) and installation of a replacement engine within a specified period (e.g. 48 hours) of a major engine failure,[50] which is made possible by the compact nature of aero-derivative machines (Figure 13).

4.2.3 Operation and Maintenance Costs

For the present study, fixed maintenance costs for steam turbine and gas turbine systems are estimated to be $24.6/kW-yr (see Appendix D). Variable maintenance costs are estimated to be $0.001/kWh for the GSTIG systems, and $0.003/kWh for the CEST and IFGT systems. The higher variable cost for the latter two systems is attributed primarily to the maintenance required on heat exchangers that must operate in direct contact with burning solid fuel.

The operating labor requirements for both steam-turbine and gas-turbine cogeneration systems are comparable, since both utilize a thermochemical conversion unit, a turbine/generator, and a pressurized boiler. Based on detailed engineering design studies and discussions with cogeneration plant operators in the United States, the estimated minimum labor required to operate and maintain a biomass-fueled cogeneration plant would be approximately 20 employees. (See Appendix D). In the US, this would cover a range of plant sizes from about 10 to 50 MW. The number of employees required in other countries is likely to vary, depending on prevailing employment practices and operating and safety standards. The cost of labor will also depend strongly on location. For the present study, estimates for the number of employees and average wage per worker in Jamaican central-station power plants are used:[51] 50 MW and 30 MW plants require 53 and 27 employees, respectively, and the annual average total cost per employee is $5400. (See Appendix D).

5. OPPORTUNITIES FOR IMPROVING SUGAR-PROCESSING EFFICIENCIES

Regardless of the type of cogeneration technology installed, process-steam conservation appears worth considering because of the additional export of electricity this permits. To use the GSTIG technology steam consumption would have to be reduced from about 400 kg/tc typically achievable at existing raw-sugar factories to about 300 kg/tc, a level that is probably readily achievable with commercially available technologies.[52]

Additional export electricity could also be made available if factory electricity demands could be decreased, e.g. through the use of more efficient electric motors and variable speed motor drives. Industrial experience with such equipment is growing (see Appendix H), although virtually no experience exists with such equipment in cane-sugar factories. However, given the extensive use of motors, pumps, and fans in the typical sugar factory (Table 3), the potential savings may be substantial. As part of the present study an assessment of this potential is being undertaken, including on-site measurements of motor and motor-system performance in typical sugar factories. (See Appendix H.)

To explore the costs and benefits of factory energy conservation, three end-use scenarios with decreasing levels of steam consumption, described below,[r] are used as the basis for subsequent financial analyses. No new technologies for reducing electricity demand are considered, pending completion of the motors assessment described above. For all end-use scenarios, the design cane throughput is nominally 175 tonnes per hour.

5.1 Energy Demand in Conventional Factories

5.1.1 Factory Operation

In a conventional factory (Figure 14) steam raised in boilers at 1.5-2 MPa is used to drive back-pressure steam-turbine mills, which crush the cane and produce dilute sugar juice and bagasse, and back-pressure and condensing steam turbo-generators, which produce electricity for the factory (Figure 15a). Steam exhausted from the back-pressure turbines at 0.2-0.3 MPa is utilized in juice heaters (in which the juice is heated, clarified and reheated), evaporators (which concentrate the juice), and vacuum pans (in which further concentration and crystallization occurs). A cardinal rule of sugar factory design is to balance the high and low pressure steam demands, so as to take full advantage of the heat in the exhaust steam. The cascading use of steam is reflected in Table 4, which shows for a conventional raw-sugar factory the steam use at each factory station per

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[r] See Appendix G for detailed descriptions of energy-saving technologies and their integration into these, and several additional, end-use scenarios.

tonne of cane crushed.[s]

In a growing number of factories in Hawaii and elsewhere, where the aim is the production of both sugar and export electricity, larger condensing-extraction steam turbine (CEST) cogeneration systems, which produce significant amounts of excess electricity, have been introduced. In these systems, all of the steam is first used to produce electricity in the steam turbine. Some steam extracted at 0.2-0.3 MPa goes to process use (Figure 15b). That extracted at 1.5-2 MPa is used to drive the cane mills through back-pressure steam turbines, the exhaust from which (at 0.2-0.3 MPa) is also used for process.[t]

5.1.2 Costs and Paybacks

The result of calculations for a CEST and an IFGT operating during the milling season only in a conventional raw-sugar factory processing 175 tc/hr are shown in Table 5. A 27-MW CEST would be able to export about 100 kWh/tc during the milling season.[53] The $42 million investment would give a simple payback of about 6 years, assuming the cogeneration plant produces power during both the milling- and off-season. An IFGT installed in a conventional factory would export more electricity (127 kWh/tc during the season), but the higher capital requirement ($72 million) would lead to a 20% longer payback time. The GSTIG would produce insufficient process steam for a conventional factory.

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[s] The estimates in Table 4 are based on calculations using performance specifications of equipment at the Monymusk Factory supplied by John Blanchard (J. Blanchard, Development Engineer, Jamaica Sugar Holdings, Monymusk Factory, Jamaica, personal communication, Oct. 1986 and Mar. 1987.)

[t] Alternatively, a larger fraction of the steam could be extracted at the higher pressure to provide enough steam to operate small, previously existing back-pressure turbo-generators, the exhaust from which would then be used for process.

5.2 Energy Demand in a Steam-Conserving Factory

By reducing the process steam demand, more electricity could be exported from a CEST or IFGT. In addition, the GSTIG system could be utilized. For the present study, a "steam-conserving factory" is defined as one that uses condensate juice heaters, falling film evaporators, and single-effect continuous vacuum pans to reduce the low-pressure process steam demand to that which can be supplied by the exhaust from the cane-mill turbines alone. (See Figure 16 and Table 6).

5.2.1 Juice Heating with Condensates

The condensates leaving the evaporators at 70-110°C and vacuum pans at 90°C contain a considerable amount of low-grade energy. In some factories, some of this energy is recovered by using some of the condensate as boiler feedwater. More often, the heat is not recovered. If the condensate were used in a heat exchanger to heat juice, the overall steam demand could be reduced by perhaps 10%.

5.2.2 Falling Film Evaporators

In contrast to the conventional natural-circulation short-tube evaporator, which is the main steam user in all cane sugar factories today (Table 4), the falling film evaporator (FFE) (Figure 17) would use much less steam. Its higher efficiency arises because of its better heat transfer characteristics: higher juice velocities lead to higher heat transfer rates and shorter juice residence times, which allows higher operating temperatures (without heat damage to the juice). While the use of FFEs (which would probably require some hardware modifications to existing FFE designs[54]) would represent a signficant change for the cane sugar industry, the FFE is the evaporator of choice for the beet-sugar and dairy industries, which rely on purchased fuels. In addition, since oil prices jumped in the 1970s, nearly all new pulp and paper plants have installed falling film evaporators in preference to the previous industry standard.[55] A few cane-sugar producers have installed FFEs, including the Imperial Sugar Refinery in Texas[56] in the US and a small experimental facility operated by the Sugar Industry Research Institute in Jamaica.[57]

5.2.3 Continuous Vacuum Pans

Steam use in the vacuum pans can be reduced by perhaps 25% via continuous rather than batch operation. The first single-effect continuous vacuum pan to be installed in a cane sugar factory has been operating for several years at the Beaufonds factory in Reunion.[58] Multiple-effect continuous vacuum pans, which have only been used experimentally to date,[59] would further reduce the steam use.

5.2.4 Costs and Paybacks

The cost of retrofits required for the "steam-conserving" factory are estimated to be about $3.12 million (Table 7). The revenue from the extra electricity exported would yield payback times of 7 and 11 milling seasons at factories with CEST and IFGT systems, respectively (Table 5). A GSTIG system, which could also be used in a steam-conserving factory, would require an investment of $52.5 million in addition to that for the conservation retrofits, and would payback in 5 seasons (Table 5).

5.3 Energy Demand in an Electrified Factory

The process-steam demand of a raw-sugar factory could be reduced even further in an "electrified" factory with three additional retrofits to the steam-conserving factory: mechanical vapor recompression on the FFE, electric motor drives on the mills, and triple-effect continuous vacuum pans.

5.3.1 Mechanical Vapor Recompression

Mechanical vapor recompression (MVR) systems can reduce the steam demand for evaporation. The vapor evolved from the sugar juice in the evaporator is compressed and introduced into the steam side of the FFE, boiling away additional water from the juice (Figure 18). Some externally generated steam would be needed to start the evaporators and to compensate for any vapor bled from the evaporators for use elsewhere. While MVR would greatly reduce evaporator steam demand, it would increase factory electricity demand. Falling film evaporators with MVR are used in a variety of process plants, including the Imperial Sugar Refinery in Texas.

5.3.2 Electrified Mills

The higher-pressure process steam demand can be eliminated completely by using electric motors to drive the cane mills. Electric mills are relatively uncommon today in cane-processing factories, although they are found in a few plants.[60] Their use would entail higher factory electricity demand. Aside from energy considerations, electrically driven mills should be simpler to operate and less costly to maintain than conventional steam-turbine drives.

5.3.3 Costs and Paybacks

Steam demand at an electrified factory would fall to about 94 kg/tc of low-pressure steam (Figure 19). At the same time, the overall factory electricity demand would increase from 13 to about 28 kWh/tc (Table 8).[u]

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[u] This assumes that conventional motor technologies are used in the electrified plant. Electricity demand might be reduced still further by the introduction of more efficient motors and motor-systems, but this is not

The investments to electrify the factory (Table 7), would payback in 4 and 2 seasons with the CEST and IFGT systems, respectively (Table 5). With the GSTIG, the additional power output would be more than offset by the extra electricity demand at the factory. Reducing factory electricity demand by the use of more efficient electric motors and variable-speed motor drives (see Appendix H), may improve the economics of the GSTIG case.

6. CASE STUDY BASED ON THE MONYMUSK FACTORY

6.1 Assumptions

To explore the financial feasibility of exporting electricity from sugar factories, internal rates of return have been calculated for CEST, IFGT, and GSTIG cogeneration plants installed in a raw-sugar factory like the Monymusk factory in Jamaica. A significant database on the operation of this factory was previously available as a result of a proposal developed for the installation of a steam-turbine cogeneration plant there.[61] In addition, two site visits were made in the course of this study to gather data and discuss factory performance with plant personel. (See Appendix F.)

6.1.1 Factory Operation

The Monymusk facility has a rated cane crushing capacity of 5000 tonnes/day (208 tc/hr)[62] but has been running at an average rate of 150-160 tc/hr for the last several years, primarily because of deterioration in processing equipment.[63] With World-Bank supported rehabilitations to field irrigation systems, as well as the processing plant, plans are to raise the throughput to 200 tc/hr by 1990. A nominal processing rate of 175 tc/hr was chosen as the basis for the plant energy consumption calculations in this

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considered in the present analysis. (See Appendix H).

study, based on discussions with engineers at Monymusk.[64] To assess the impact of steam-conservation, the analysis includes a conventional plant (based on Monymusk performance) and the two additional end-use scenarios described in Section 5 (Tables 4, 6, and 8).

6.1.2 Price for Exported Electricity

The price paid by utilities for exported electricity should, in principle, reflect the cost the utility avoids by not having to supply that electricity itself. The construction of new capacity might be avoided, or fuel and operating costs for existing plants might be avoided if new capacity is not needed.

In the former case, the full avoided cost (including capital, fuel, and O&M charges) in Jamaica is estimated to be $0.050/kWh (1985 US$), based on a least-cost generating option identified in a recent study done for the Jamaica Public Service (JPS) electric utility: a 61 MW steam-electric plant burning imported coal.[65] (See Figure 11 and Appendix E.) This corresponds to a coal price of $1.43/GJ ($40/tonne), the most recent projection for JPS to the year 2000.[66] With an earlier projected coal price of $2.08/GJ ($58/tonne),[67] the avoided cost would be $0.058/kWh.[v,w]

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[v] The total installed cost of the coal plant was estimated to be $72.9 million ($1,195/kW) (Montreal Engineering Company, "Least-Cost Expansion Study" prepared for the Jamaica Public Service Company, Kingston, 1985), to which has been added $7.4 million ($121/kW) to cover 1/6 of the cost estimated by Monenco of a new coal port facility (assuming the coal transportation infrastructure costs would be shared by 6 plants in all). The total cost ($1,316/kW) is lower than those for new coal plants with flue gas desulfurization in the US, some $1,340/kW @ 500 MW and $1795/kW @ 200 MW (Electric Power Research Institute, "Technical Assessment Guide," Palo Alto, California, 1987). Extrapolating to 61 MW, US costs would be $2,620/kW, some 2.2 times the cost estimated in the Monenco study. With this higher capital cost, the busbar cost would be $0.080/kWh with coal at $1.43/GJ and $0.088/kWh with coal at $2.08/GJ. The lower Monenco study estimate is due in part to the neglect of the costs of flue gas desulfurization. In addition, labor and other construction costs may be lower in Jamaica than in

Avoided O&M and fuel costs for oil-fired plants in Jamaica would range from \$0.045/kWh with residual oil at \$2.9/GJ to \$0.061/kWh with oil at \$4.0/GJ.[x] The lower oil price is that currently used in JPS projections to 2000[68] and has, therefore, been used for most of the analysis in this study, although it probably underestimates future prices.[y]

6.1.3 Off-Season Operation

If the cogeneration facility is to be credited with the cost of avoiding the construction of a new central station plant, the cogenerator must be able to supply base-load electricity, which means it must operate essentially year-round. Four scenarios are considered for supplying fuel during the off-season, when no cane is crushed.

6.1.3.1 Barbojo

For the base case, barbojo, the tops and leaves of the cane plant (see Figure 20), is assumed to be the off-season fuel. In most regions of the world today, the barbojo is burned off the cane before harvesting to

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the US. The Monenco report may also have underestimated the cost of the coal plant.

[w] Avoided costs estimated in the detailed feasibility study of a steam-turbine cogeneration plant for Monymusk (Ronco Consulting Corporation and Bechtel National, Inc., "Jamaica Cane/Energy Project Feasibility Study," funded by the US Agency for International Development and the Trade and Development Program, Washington, DC, 1986) are \$0.066/kWh for electricity from a new oil-fired steam-electric plant, \$0.087/kWh for electricity from a new oil-fired gas turbine plant, and \$0.083/kWh for a new coal-fired steam-electric plant.

[x] For an average oil-steam plant heat rate of 14,500 kJ/kWh and O&M costs of \$0.0030 per kWh. (See Appendix E.)

[y] With expectations of a tightening world oil market, the US Department of Energy has recently (Energy Information Administration, Annual Energy Outlook, US Department of Energy, Washington, DC, February 1987) projected that residual fuel oil for US utilities will cost \$4.3/GJ to \$6.4/GJ in the year 2000.

facilitate cutting. In the Dominican Republic, hand-harvesting of barbojo plus mechanized chopping and recovery has been practiced since 1982 for use in furfural production at one sugar factory.[69] Hand harvesting and delivery of barbojo as a supplemental boiler fuel have been carried out for one season at a sugar factory in the Philippines, in large part to help increase local employment.[70] The program is being expanded for the 1987-1988 crop year, with mechanical barbojo collection planned.[z,71]

The harvesting and storage of barbojo for energy has not been done on a large commercial scale. However, small-scale field trials have been conducted in Florida,[72] and more extensive field trials with three varieties of cane have been carried out in Puerto Rico.[73] In the latter studies it was found that on average, 660 kg of (50% wet) barbojo were produced with each tonne of cane, or more than twice as much barbojo as bagasse. Left on the field after cutting, the barbojo dried from 50% to about 35% moisture within 6 days. Longer-term studies were recommended to fully assess the agronomic effects of barbojo removal, but the initial trials indicated that increased weed growth and decreased soil moisture retention were not serious problems. Where ratooning is practiced (as in much of Puerto Rico and Jamaica), a major concern appears to be with potential damage to the emerging crop during mechanical collection of barbojo. To avoid damaging the new growth, it has been recommended that the barbojo be recovered within one week after harvesting.[74,75] Another concern is soil compaction that may occur with the use of heavy machinery, particularly on wet soils, which can

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[z] A mechanical baler (Holland Model 311) will be used to collect the barbojo, which will be mixed with bagasse and used in the existing boilers shortly after it is collected. Excess bagasse will be stored for use in the off-season.

reduce ratoon yields.[76,77,78]

Only rough estimates of the costs of barbojo are available. It has been estimated that the labor cost alone in green cutting cane and separating the barbojo from the millable cane on the fields in Jamaica would be about 60% higher than the cost of traditional cutting of burnt cane.[79] (Barbojo recovery would create more jobs, but the labor requirements would probably remain highly seasonal, as in the sugar industry today.) In the Dominican Republic, where barbojo is hand-harvested and machine collected in chopped form (without storage), the cost of 30% wet barbojo delivered to the factory is estimated to be \$7.06/tonne[80] (\$0.53/GJ). The feasibility study of steam turbine power generation for Monymusk[81] estimated a cost of \$12/tonne of 35% wet barbojo (\$0.97/GJ), including cutting, baling, transportation, and storage.

6.1.3.2 Plantation Fuelwood

Since barbojo recovery has yet to be proven commercially viable, alternative off-season fuels are also considered here. One possibility is plantation fuelwood. Primary considerations with this fuel include the cost of production and the land requirements, both of which are dependent on annual yields. Reported yields from managed short-rotation forests in tropical regions range from 10 cubic meters per hectare per year (m^3/ha/yr) to 100 m^3/ha/yr, the latter in Brazil, where plantations of clonal varieties of Eucalyptus have been perhaps more successful than in any other region (Table 9).[aa] The land area needed will also depend on the cogeneration

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[aa] One company in Brazil (Aracruz Cellulose, S.A.) has been developing its Eucalyptus plantations for the pulp and paper industry since the 1960s, when it grew trees from seed, which typically produced 35 m^3/ha/yr. In the late 1970s, clonal propagation was adopted, with impressive results: a typical yield today is 90 m^3/ha/yr. The company now uses 17 different traits to

technology chosen, with the more efficient systems requiring much less wood per kWh produced, but somewhat more wood per tonne of harvested cane. Plantations may provide significant full-time employment opportunities: in Brazil, it has been estimated that one temporary job is created in establishing each 5[82] to 7[83] hectares of plantation, and one permanent job is created in maintaining each 5[84] to 15[85] hectares.

Experience in tropical regions indicates that the total costs for plantation establishment, harvesting, and chipping of fuelwood is in the range of $1.00 to $1.50/GJ (Table 10).

6.1.3.3 Oil

Since the recovery and storage of barbojo has yet to be fully commercialized, and since new plantations require a minimum of several years to establish, a third scenario considered here involves using oil as the off-season fuel for the first 5 years of operation, followed by a switch to a biofuel. Steam turbine systems would burn residual fuel oil, and gas turbine systems would be fired directly with distillate fuel oil.

6.1.3.4 Excess Bagasse

In the fourth scenario, the cogeneration system is undersized relative to the in-season fuel supply and excess bagasse is stored for use during the off-season (after processing to permit longer-term storage), thus avoiding altogether the use of an auxiliary biofuel as well as of oil. The cogeneration system must still meet the factory steam requirements. For the electrically more efficient gas turbine systems, this requires process-

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select trees to be cloned and over 100 different clones to help protect against some diseases (R. Osgood, Hawaiian Sugar Planters' Association, reported at the Second Pacific Basin Biofuel Workshop, Kauai, Hawaii, April 1987).

equipment retrofits to reduce the steam demand per tonne of cane to the level of the "electrified" factory described in the previous section.

6.1.4 Fuel Costs

The fuel costs assumed for all of the scenarios are given in Table 11. For the CEST and IFGT systems, no cost is charged for bagasse used during the milling season, and the minimum cost of \$0.97/GJ is charged for barbojo used in the off-season. If bagasse is used in the off-season, a cost of \$0.78/GJ (for baling and storage) is charged. For the GSTIG system, it is currently unkown what level of processing of bagasse and barbojo will be required. The five levels shown in Table 11 are considered in the analysis below. Briquetting is chosen for the base case,[bb] making processed bagasse and barbojo about as costly as plantation fuelwood.

Fossil fuel price assumptions are also shown in Table 11. In the off-season scenarios where oil is used, the low oil prices are assumed to apply during the first five years of plant operation. The oil and coal prices have been used to calculate avoided costs, as discussed earlier.

6.2 Results

6.2.1 Baseline Comparisons

The impact of the choice of technology and the utility electricity buyback rate on the financial return on a cogeneration investment at a raw-sugar factory is illustrated in lefthand side of Figure 21. The results shown here are for the base-case, in which the off-season fuel is barbojo.

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bb The Lurgi dry-ash gasifier, which is considered for the GSTIG systems analyzed here, was originally designed to gasify chunks of coal. It is likely that the biomass fuel, therefore, would need to be in a form similar to coal chunks.

With conventional sugar-processing technology, the choice of cogeneration system is limited to CEST and IFGT. the internal rates of return (ROR) for which are 13-16% and 14-15% respectively. The higher capital cost of the IFGT compared to the CEST (Table 5) is partially offset by the extra revenues from the export of nearly 20% more electricity (Figure 21, right).

With steam-conserving retrofits, the RORs for the CEST and IFGT systems do not change significantly, but for the GSTIG system, the ROR would be 18-32%. In addition, the GSTIG plant would export about 60% more electricity than the IFGT plant and about twice as much as the CEST plant. Conserving more steam by electrifying the factory would improve the ROR slightly in all cases, and lead to a small increase in export electricity production.

Since the IFGT system would produce no clear benefits over the well-established steam turbine, further analysis of gas turbines will be limited here to the GSTIG.

6.2.2 Additional Comparisons Between CEST and GSTIG

In the baseline comparison, minimal fuel processing was assumed for the CEST, and briquetting of both bagasse and barbojo were assumed for the GSTIG. If less extensive processing than briquetting is required for the GSTIG, the ROR would increase to the range of 24-29%, while if pelletizing were required, the ROR would fall to the range of 11-16% (Figure 22).

If plantation fuelwood were used as the off-season fuel, the RORs for both the CEST and GSTIG would be comparable to those for the base case (Figure 23), since the off-season fuel costs would be comparable. For a plantation yield of 40 m^3/ha/yr, an apparently readily achievable yield in Brazil (see Table 9), the total fuelwood plantation area required would represent 30-40% of the sugarcane land area (assuming an average Jamaican cane yield of 62 tonnes per hectare). More productive use of the plantation land would result by using the GSTIG, since it would export about twice as much electricity per hectare as the steam turbine (Table 12). In both cases, permanent employment (associated with maintainence of the plantations) would increase by 30%, and 50% more temporary jobs would be created in establishing the plantations.[cc]

For the scenarios in which oil is burned in the off-season during the first 5 years, the RORs for both the GSTIG and CEST systems would fall relative to the base case (Figure 23). The ROR for the GSTIG would fall further relative to the base case than for the CEST, because the GSTIG unit would have to use more costly distillate oil, while the CEST would use residual fuel oil.)

The final off-season scenario considered, that of undersizing the cogeneration plant, would result in the production of about half as much electricity as the base case and a ROR of 10-13% for the CEST and 14-18% for the GSTIG (Figure 24).[dd]

In summary, for the Monymusk-based case study of a 175 tc/hr factory,

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[cc] Of the roughly 11,000 workers directly employed in the sugar industry in Jamaica today, the direct employment generated by operation of the Monymusk Factory is estimated to be about 1400, based on the fraction of total Jamaican sugar produced at Monymusk. Assuming 1 permanent job is created for each 10 hectares of fuelwood plantation and 1 temporary job is created in establishing each 6 hectares (see Section 6.1.3.2), 400-500 permanent and 700-800 temporary jobs would be created in supplying off-season fuelwood (from plantations yielding 40 m^3/ha/yr) for a GSTIG or CEST operating at a sugar factory processing 175 tc/hr.

[dd] In this scenario, the CEST is a 15-MW unit with a capital cost (including factory electrification retrofits) of $2110/kW. The CEST burns unprocessed ("free") bagasse during the milling season, but dried bagasse (costing $0.78/GJ) during the off-season. The GSTIG system consists of one 20-MW LM-1600 ($1227/kW) and one 5.4-MW GE-38 ($1650/kW), for a total cost (with factory retrofits) of $1470/kW. This system would use briquetted bagasse (costing $1.16/GJ) year-round.

the biomass-GSTIG system would provide significantly higher financial returns than a CEST unit, assuming the systems could operate entirely on biofuels, and, in any case, it would produce more than twice as much electricity for export.

For an electricity buyback rate of $0.05/kWh, up to $23of electricity revenue would be generated per tonne of cane crushed, if GSTIG cogeneration were used. The revenue from sugar would be comparable for a sugar price of $0.23/kg, or about double the world-market sugar price in 1986. Electricity revenue with steam turbine systems would be comparable to those for sugar when the sugar price is $0.11/kg.[ee]

7. SCALE COMPARISONS

The average cane-processing capacity of sugar factories in Jamaica and many other developing countries is lower than the 175 tc/hr assumed for the Monymusk-based case study (Table 13). Because of the scale economies associated with power generation (see Figures 2 and 11), some calculations are presented here to indicate the relative economics of cogeneration investments at three differently-sized sugar factories.

Hypothetical factories have been considered with the same end-use steam and electricity demands per tonne of cane as for the "steam-conserving"

[ee] Advanced cogeneration systems could also be installed at ethanol-from-sugar-cane distilleries. Because in-house steam and electricity demands per tonne of cane would be comparable at modern distilleries to those at a steam-conserving sugar factory (Electrobras, "Aproveitamento Energetico dos Residuos da Agroindustria da Cana-de-Acucar," Ministry of Industry and Commerce, Brasilia, 1981), such distilleries could export comparable amounts of electricity per tonne of cane. The producer price of alcohol would need to be $0.32 to $0.37 per liter (60-85% higher than the price in Brazil today) for the revenue from alcohol to equal that from electricity, if a GSTIG cogeneration system were used, assuming an alcohol yield of 70 liters per tonne of cane.

sugar factory (Table 6). The cane throughputs for each factory were set to match the (bagasse) consumption of different sized CEST and GSTIG cogeneration plants. A performance and cost estimate for each system is shown in Table 14.

The ROR and exportable electricity production per tonne of cane decrease with decreasing cane throughput for both the CEST and GSTIG (Figure 25).[ff] In all three cases, the GSTIG shows a much higher return and produces more than twice as much electricity as the steam turbine. Moreover, because of its weaker scale economy, the financial advantage of the GSTIG relative to the CEST increases with decreasing factory size.

8. A UTILITY PERSPECTIVE ON SUGAR-INDUSTRY COGENERATION

8.1 Jamaican Context

8.1.1 Generating Costs

While the GSTIG would provide more attractive rates of return to a sugar producer than would a CEST, the capital involved (Table 5) would be large compared to investments to which sugar producers may be accustomed. In contrast, the investments in a GSTIG unit would typically be less than what an electric utility might invest in building a comparable amount of new central station capacity (Fig. 11). In addition, the capacity increment of a single GSTIG would be smaller than a typical new central station power plant, allowing a utility to better track evolving electricity supply and demand.

For a utility, cogenerated electricity would be of interest if it cost

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[ff] This assumes barbojo is used as the off-season fuel and is briquetted for use in the GSTIG.

less than other utility sources. Fueled by briquetted cane residues at a "steam-conserving" factory, the GSTIG would produce exportable electricity for about \$0.041/kWh, and the CEST would produce about half as much electricity for about \$0.048/kWh. If plantation fuelwood were the off-season fuel, generating costs would be \$0.040/kWh for the GSTIG and \$0.051/kWh for the CEST. In the scenarios involving oil the costs would be about \$0.052/kWh for the GSTIG and \$0.054/kWh for the CEST. These cogeneration costs are compared in Fig. 26 to the cost of power from a new 61-MW coal-fired power plant, which is being considered by JPS as a least-cost expansion option. It would produce electricity for an estimated total cost of 5.0-5.8¢/kWh (see footnote [w] in Section 6.1.2 and Appendix E). In all cases shown in Fig. 26, the GSTIG plant would provide comparable- or lower-cost electricity than the new coal-fired option, even with a low price for coal.

The cost of cogenerated electricity is also compared in Fig. 26 to the operating cost of existing oil-fired power plants, which would range from \$0.045 to \$0.061/kWh (see Appendix E). For all cases where biomass is the sole fuel, the GSTIG facility would produce electricity at a lower cost, even with oil at \$2.9/GJ. Under these conditions, it would be economically worthwhile to scrap existing oil-fired plants and replace them with new GSTIG facilities.

8.1.2 Potential Electricity Generation

A typical 1980s cane harvest in Jamaica (2.2 million tonnes) would support up to 80 MW of CEST units that could export about 500 GWh of electricity per year, or over 150 MW of GSTIG units that could export 1000 GWh annually (Figure 27). For comparison, JPS generated 1437 GWh in 1985.[86]

A return to the mid-1970s level of cane production (3.6 million tonnes) would permit substantially more electricity to be exported (Figure 27).

8.1.3 Foreign Exchange Savings

Cogeneration at sugar factories could lead to large foreign exchange savings for Jamaica. If the full steam turbine potential were exploited at the 1980s level of cane production in order to avoid constructing new coal-fired capacity, Jamaica would save \$50-\$90 million dollars in foreign exchange over the 30-year life of the plants (depending on the price of coal). For the cogenerated electricity to displace existing oil-fired capacity, the price of residual oil would have to be \$3.2/GJ or higher. With oil at \$4/GJ, Jamaica would save about \$100 million by backing out oil (Table 15).

Using the same biofuel resource, the GSTIG systems could generate some 1000 GWh, which would save \$200-270 million by avoiding the building of new coal-fired plants. Backing out oil would save over \$300 million, if the price of residual oil were \$4/GJ. Per kWh generated, the savings with GSTIG would be 50-90% higher than with CEST (Table 15).

8.2 Southeast Brazilian Context

Southeast Brazil, where most of Brazil's sugar cane grows and which includes the heavily industrialized state of Sao Paulo, provides an interesting contrast to Jamaica, because it is a cane-producing region which relies heavily on hydropower, a much less costly electricity source than most alternatives. With electricity demand in Sao Paulo growing at 8-10% per year,[87] the installation of new hydro capacity is under consideration. Since all of the economical hydro potential has already been exploited in the South, however, new plants would be built in the Amazon, with transmission lines connecting them to Sao Paulo.[88] Electricity from such facilities would cost from \$0.032 to \$0.058/kWh, depending primarily on the siting of the facility (Table 16).

Large (50 MW) GSTIG cogeneration plants operating year-round on briquetted biofuels at sugar factories in Sao Paulo could supply electricity at a cost in the mid-range of those estimated for new hydro supplies, and small GSTIG units would be competitive with the higher-cost hydro supplies. By contrast, only the larger CEST cogeneration plants would be competitive and then only with higher-cost hydro (Table 16).

Given the shortage of capital in Brazil (as in many other developing countries), the capital charges alone for electricity may be as important as the total cost of generation, in which case GSTIGs would have a significant advantage. For example, the capital charges for GSTIG power would be 50-80% of those for hydro capacity costing \$1400/kW. (See Figure 28.) For CEST, only a modest capital advantage would be gained, and only for the largest units.

Even if GSTIG units were operated only during the milling season, the produced power would be attractive to the electric utilities if hydro and bagasse-fired gas-turbine generating options were considered together. Since the sugar cane milling season coincides with the dry-season, cogeneration at sugar processing facilities could help fill in the hydropower "trough," (see Figure 29), thus making greater use of the installed hydroelectric capacity. Futhermore, since the GSTIGs would have the capability to operate on oil in the off-season, a larger risk of a rainfall-short year could be designed into new hydro facilities,[gg] resulting in still lower capital charges for hydropower.

9. GLOBAL POTENTIAL FOR GAS-TURBINE COGENERATION AT SUGAR FACTORIES

Biomass-GSTIG cogeneration systems appear to have significant technical and economic advantages over CEST units. The introduction of GSTIGs worldwide could have a significant impact on the more than 70 developing countries that produce sugar. Based on an extrapolation of the results for Jamaica, the total potential gas-turbine power generating capacity that could be supported by the 1985 global level of sugar cane production is over 50,000 MW, most of which would be in developing countries in Asia and Latin America (Table 17).[hh] In all sugar-producing developing countries some 300 billion (10^9) kWh of electricity could be produced at the 1985 level of cane production (Table 18).[ii] This is more than 1/4 of the electricity generated by utilities in these countries in 1980, and is comparable to the level of electricity generated with oil. In some countries, the cane-electricity potential is significantly greater than the current total utility generation (Table 18). Thus, GSTIG cogeneration at sugar factories could help reduce the dependence many developing countries have on imported oil (Table 19).

[gg] Hydropower systems in Brazil are typically designed assuming a 5% probability of a "dry" year (J. Moreira, University of Sao Paulo, Sao Paulo, Brazil, personal communication, April 1987).

[hh] This includes about 8,900 MW of capacity that would be supported by sugar cane used for alcohol production in Brazil.

[ii] This includes about 57,000 GWh from sugar cane used to produce alcohol in Brazil.

10. INSTITUTIONAL ISSUES

10.1 Challenges in Implementation

The analysis in this report indicates that biomass-GSTIG cogeneration would be technically and financially attractive. For the sugar industry, these systems offer the prospect of attractive returns. From a societal perspective, GSTIG systems offer the prospect of lower electricity prices for utility customers and foreign exchange savings for many countries. However, realizing the potential of GSTIG cogeneration on a wide scale presents a number of technical, financial, and institutional challenges.

Technical challenges for the sugar industry include reoptimizing and operating cane processing plants for both sugar production and electricity generation. In the factory, this will require adopting steam-conserving process technologies commonly found in other industries. It will also require operating as a utility power plant, reliably supplying power essentially year-round. (With many interconnected cogenerators, the utility would need to be concerned about dispatchability of the power and maintaining the integrity of their grid.)[89] To supply fuel for the off-season, it would be desirable to develop barbojo recovery systems or fuelwood plantations.

Implementing GSTIG cogeneration will also present some financial challenges. The investments in a cogeneration plant would typically dwarf traditional capital investments made by the sugar industry. In contrast, investments required for GSTIG would typically be less than what a utility would otherwise invest in a comparable amount of generating capacity. Thus, it may be desirable to explore creative financing and ownership schemes to insure the availability of capital and repayment of foreign debts.

The most important factor in determining how rapidly GSTIG cogeneration can be implemented may be how quickly institutional thinking patterns adapt to these opportunities. The introduction of these systems would be facilitated if the sugar industry were to consider itself a purveyor of electricity as well as sugar. It would also be facilitated if electric utilities were to consider cane power as a candidate least-cost power-generating option. Successful grid-interconnected cogeneration plants (based on steam turbines) at sugar factories in Hawaii, Mauritius, and Reunion, and additional systems being considered for Jamaica, the Dominican Republic and elsewhere, attest to the fact that new thinking is indeed emerging.

10.2 Facilitating Development of the Biomass-GSTIG

The potential benefits of widespread implementation of GSTIG systems appear to be worth the risk of developing this technology for commercial application.[jj] The potential markets appear large enough to justify the development effort that would be required by the gas turbine suppliers, and the projected growth of the sugar industry would insure secure markets in the future. The World Bank projects that the stagnation in demand for sugar in the industrialized countries will be more than offset by growth in demand in the developing world, leading to a global growth of some 1.5% annually through at least the mid-1990s.[90]

The demand for GSTIG technology in the cane sugar industry may be considerably greater than these numbers suggest if sugar cane-based fuel

[jj] The IFGT technology, while being more electrically efficient than the CEST, does not appear to offer advantages sufficiently compelling to motivate its commercialization for this application.

alcohol comes into wide use. Our preliminary calculations indicate that GSTIG cogeneration technology would be well-suited for the production of electricity at alcohol distilleries and may lead to revenues even larger than those for alcohol (see footnote [ee]). Although the fuel alcohol industry is developed on a large scale today only in Brazil, this situation may change over the next decade, if, as expected (see footnote [y]), oil prices rise considerably in this period. In light of the very favorable projected economics for GSTIG, this co-product strategy could make alcohol production economically attractive at lower oil prices than otherwise, a possibility that warrants a detailed assessment. A sensible multiple-product strategy might involve producing electricity plus a mix of alcohol and sugar that depends on the relative market prices of sugar and petroleum at any time. There are in fact many sugar cane processing facilities in Brazil that now have the flexibility to vary the mix of output between sugar and alcohol. If such facilities also produced electricity with GSTIG the overall economics should improve, because a smaller fraction of the total capital investment would be idle when the sugar/alcohol mix is varied.[kk]

Bringing GSTIG cogeneration systems to commercial readiness within the

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[kk] For example, for a facility processing 140 tc/hr, the capital costs are estimated to be about (in million $):

with:	GSTIG		Low-Pressure Steam-Turbine	
Cogeneration plant	49		10	
Cane crushing mills	10		10	
Sugar production equipment	13	(15% of total)	13	(27%)
Ethanol production equipment	15	(17% of total)	15	(31%)
TOTAL	87		48	

The GSTIG estimate is based on a system with 2 LM-1600 gas turbines (see Table D-4). The estimate for the ethanol distillery is from (J. Goldemberg, J.R. Moreira, P.U.M. dos Santos, and G.E. Serra, "Ethanol Fuel: A Use of Biomass Energy in Brazil," Ambio, Vol. XIV, No. 4-5, 1985). Other estimates are from Steve Clark (S. Clark, Audoban Sugar Institute, Louisiana State Univ., Baton Rouge, Louisiana, personal communication, Sept. 1987).

next few years will require some engineering development work and a successful commercial demonstration in the field. The investment required would be relatively modest because development work could piggy-back on work already underway (with much larger expenditures) on coal-GSTIG systems.[91] Furthermore, small (5-20 MW) demonstrations would be sufficient to prove the technology, since this represents a commercial size range for many biomass applications and since there are essentially no uncertainties involved in scaling up to the largest plants (50 MW) that might be considered for biomass applications.

As highlighted in this report, key engineering development work required before a demonstration could be undertaken should focus on the gasification system. In particular, the level of processing of bagasse required for gasification needs to be determined.

Subsequently, a small (5 MW) pilot project would be required to work out technical bugs and could also serve as a training facility for future plant operators. In identifying candidate sites, several criteria should be considered:

- To minimize risk, it would be important for the pilot project to focus exclusively on demonstrating the GSTIG concept with biofuel and not on proving other new concepts as well, e.g. barbojo recovery or radically new sugar processing technologies.
- Excess bagasse already being produced at a large, relatively-efficient sugar processing facility might be sufficient to fuel a 5-MW GSTIG. In this case, the sugar processing facility would not have to rely on the pilot plant for any of its process energy needs.
- A good technical infrastructure (experience with bagasse processing,

cogeneration, etc.) would facilitate implementation of the project.

- Although the cost of a pilot plant would be modest in relation to the cost of pilot efforts for most other new energy supply technologies, the ability to finance the project may ultimately be the most important factor in determining where it would be sited.

As a final step toward commercialization, a larger (20 MW) commercially-oriented demonstration project would be required to prove the financial feasibility of biomass-GSTIGs. Such a project would provide a testing ground for innovative financing schemes and ownership arrangements, and also would allow the development of new institutional relationships and regulatory initiatives that may be required for wider-scale implementation of the technology. Since most of the potential markets for the technology are in developing countries, it would probably be desirable to site the commercial demonstration in a developing country.

11. CONCLUSIONS

The analysis presented in this study indicates that the potential for cost-effectively generating exportable electricity using cane residues is large. Condensing-extraction steam turbine cogeneration systems operating year-round could produce up to 10 times as much electricity as is generated in a typical factory today. Indirectly-fired gas turbines would produce up to 60% more electricity than steam turbines, but would have an overall economic performance only comparable to that for the steam turbines. Gasifier-gas turbine systems are the most attractive of the technologies considered in this study at any scale. They would produce up to 25 times as much electricity as is generated at a typical factory today at much less cost than either the steam turbine or indirectly-fired gas turbine.

The modern jet-engine technology on which GSTIG cogeneration in the sugar industry would be based would be appropriate technology for firing with biomass (the most primitive of fuels) in developing countries for a number of reasons:

- o The natural, economical scale of the technology is small (5-50 MW), which is well-suited for use with a diffuse energy source like biomass.
- o Its size should make it attractive from an electric utility's perspective, because the capacity additions would typically be small in relation to the size of the utility grid in most developing countries, making it easier to keep evolving demand and supply in balance.
- o Because of its low unit capital cost, high efficiency, and low fuel cost, GSTIG adoption could lead to lower average electricity prices in many countries. (In hydro-dependent countries, it could help lower electricity costs even if it operated only during the cane milling season by filling in the hydro-electricity supply "trough.")
- o Because GSTIG is based on aircraft-derivative turbines, a sophisticated local maintenance capability is not required as a prerequisite for introducing the technology. Instead, replacement engines can be flown into a region or country from centralized facilities. Systems could be operating in a country while wide-spread technical expertise is developed, e.g. through training programs in other countries.
- o Because it can utilize indigenous, renewable resources, it could reduce dependence on imported energy supplies, leading to savings in foreign exchange for many countries.
- o For GSTIG suppliers, large, secure markets exist for the technology at sugar factories. The 1985 level of cane production could support some 50,000 GW of capacity, and the World Bank projects global sugar demand will grow by 1.5% annually through the mid-1990s.
- o GSTIG units may provide favorable economics at fuel-alcohol

distilleries, even with today's oil prices. (A detailed assessment of this prospect should be undertaken.) The sugar cane processing plant of the future may be one which produces electricity from a GSTIG system as its primary product, with sugar and alcohol as co-products.

- o Introduced for initial operation on the biomass already available in the sugar cane-processing industries, these systems might motivate subsequent wider applications using other biomass forms, including fuelwood from "energy plantations."
- o The higher efficiency and lower capital cost of GSTIG relative to CEST would make fuelwood more valuable for power generation than at present, making fuelwood plantations a more attractive investment opportunity than at present.
- o GSTG systems would be used largely in rural areas, where they might help generate greater employment opportunities by increasing the value of the agricultural products, and hence the level of investment in the agricultural sector.

The application of biomass-GSTIG cogeneration systems would represent a fundamental technological change for the sugar industry and electric utilities worldwide. In the longer term, the technology might find widespread use with other biomass feedstocks, including wood and other agricultural residues. Commercializing the GSTIG will involve some risk, as is true with any new technology, but the potential long-term benefits relative to the commercially-established steam turbine appear to be well worth taking.

Table 1. Comparison of electricity generating costs in the US with coal and nuclear steam-electric plants and oxygen-gasifier gas-turbine combined cycle plants.

STEAM-ELECTRIC PLANTS

Type	Coal[a]	Coal[a]	Coal[a]	LWR[b]
Unit Size (MW)	2x500	500	200	1100
Effic. (% coal-busbar)	33.9	33.9	33.6	32.4
Capital Cost ($/kW)	1300	1360	1820	2960
Levelized Busbar Cost ($/kWh)				
Capital[c]	0.0146	0.0152	0.0176	0.0331
Fuel[d]	0.0171	0.0171	0.0173	0.0089
O&M	0.0084	0.0094	0.0129	0.0057
TOTAL	0.0401	0.0417	0.0478	0.0477

COMBINED-CYCLE/OXYGEN-BLOWN COAL GASIFICATION WITH COLD-GAS CLEANUP[e]

Gasifier	Texaco	Texaco	Texaco	Texaco
Prime Mover Technology	Cur CC	Cur CC	Cur CC	Adv CC
Unit Size (MW)	500	250	100	600
Effic. (% coal-busbar)	34.9	34.7	33.3	36.8
Capital Cost ($/kW)	1630	1940	2630	1500
Levelized Busbar Cost ($/kWh)				
Capital[c]	0.0182	0.0217	0.0294	0.0167
Fuel[d]	0.0166	0.0167	0.0174	0.0158
O&M	0.0083	0.0111	0.0197	0.0075
TOTAL	0.0431	0.0495	0.0665	0.0400

[a]For a conventional coal-fired subcritical steam plant with wet limestone flue gas desulfurization, for bituminous coal, East/West Central Regions. Unit capital costs, efficiencies, O&M costs, and other plant characteristics are from an analysis by the Electric Power Research Institute (EPRI).[92]

[b]Unit capital costs, efficiencies, O&M costs, and other Light Water Reactor plant characteristics are from EPRI.[93]

[c]For a 6.1% real discount rate,[94] 30-year plant life, and a 75% capacity factor. No taxes or tax incentives are included. Thus, the annual capital charge rate is the capital recovery factor = 0.0734.

[d]For a delivered coal price of $1.61/GJ -- the average price in the East North Central, West North Central, East South Central, and West South Central regions of the US in April 1986. For a nuclear fuel cycle cost of$0.81/GJ, the estimated cost in 1990.[95] These values are assumed to remain constant over the lifecycles of the plants.

[e]Unit capital costs, efficiencies, O&M costs, and other plant characteristics are from EPRI.[96] The Texaco gasifier was used in the Cool Water demonstration. Combined cycle units with performance comparable to the "advanced combined cycle" have recently become commercially available.

Table 2. Program and schedule for development and demonstration of coal gasifier steam-injected gas turbine systems by the General Electric Company.[a]

Elapsed Time (Years)	Task
0.5	Complete construction of hot-gas sulfur clean-up pilot facility at Corporate R&D Center, Schenectady, New York.
1.5	Complete testing of the pilot hot-gas sulfur clean-up system.
3.0	Start-up of a 5-MW pilot plant at Dunkirk, New York, in the Niagra-Mohawk Utility grid.
2.0	Begin construction of a 50-MW commercial demonstration plant.
6.0	Start-up of 50-MW commercial demonstration plant.

[a]Source: Corman.[97]

Table 3. Inventory of electric motors at the Bernard Lodge Sugar Factory in Jamaica.[a]

END-USE	ALL UNITS Number	ALL UNITS Total kW	UNITS > 7.5 kW Number	UNITS > 7.5 kW Total kW	UNITS > 37 kW Number	UNITS > 37 kW Total kW
Mixers & Crystallizers	17	52	2	30	0	0
Auto-Cane Drive	3	97	3	97	1	37
Compressors & Vacuum Pumps	5	138	4	134	2	86
Boiler fans	15	455	15	455	5	269
Transport & Misc Drive	32	522	24	496	3	175
Centrifuges	17	619	17	619	15	560
Pumps	102	2182	62	2096	20	1414
TOTAL	191	4065	127	3927	46	2541
Currently steam-driven[b]						
Cane Knives		858				
Cane Mills		2425				

[a]Source: Hylton.[98]

[b]Retrofit of electrically-driven knives is under consideration.[99]

Table 4. Estimated process steam and electricity demands for a typical conventional raw-sugar factory.[a]

"LIVE" STEAM at 1.4 MPa, 250ºC		
Demand for:		
Cane mills		209 kg/tc
Steam turbo-generators[b]		268
Back-pressure	211	
Condensing	57	
Total Generated		477
Total exhaust steam available		374[c]
EXHAUST STEAM, Saturated at 120ºC		
Demand for:		
Evaporator		337
Bled for vacuum pans	98	
Bled for juice heaters	90	
Vacuum pans (used directly)		37
Total exhaust steam demand		374
ELECTRICITY		
Total Factory Demand		13.0 kWh/tc[d]

[a]Based on the Jamaican Monymusk Factory processing 175 tc/hr. Installed equipment includes steam-driven cane mills, a quadruple effect Calandria evaporator, and steam turbo-generators for electricity production. (See Figure 14 and Appendix G.)

[b]If a new cogeneration system were installed the steam demand for the turbo-generators would be eliminated.

[c]Steam used in the condensing turbo-generator and an additional 46 kg/tc lost in the turbo-generators are unavailable for cascaded use as low pressure steam.

[d]When a new cogeneration system is installed at a sugar factory, the old boiler system (including fans, pumps, and other electrical ancilliaries) would be shut down. The boiler section of a sugar factory consumes approximately 1/3 of the electrical consumption of the entire factory. (See Appendix H for discussion of measurements made at the Bernard Lodge Factory in Jamaica.) The 13 kWh/tc is the electrical demand with a new cogeneration facility. Note that the electrical output of the new cogeneration systems considered in this report are specified as net of the cogeneration plant.

Table 5. Estimated incremental costs of cogeneration systems and steam-conserving equipment, extra exportable electricity generated per tonne of cane during the season, and number of seasons for investments to be paid back at a raw-sugar factory crushing (nominally)[a] 175 tonnes of cane per hour.

	FACTORY DESIGN[b]		
	Conventional	Steam-Conserving	Electrified
INCREMENTAL COST	(MILLION 1985 DOLLARS)		
CEST	42.01[d]	3.12	0.794
IFGT	71.06[d]	3.12	0.794
GSTIG[c]	---	55.6[e]	0.794
EXTRA EXPORT ELECTRICITY GENERATED IN-SEASON	(KWH PER TONNE OF CANE CRUSHED)		
CEST	100[f]	10	4.7
IFGT	127[f]	7	9.5
GSTIG[c]	---	222[f]	-2
SIMPLE PAYBACK TIME[g]	(NUMBER OF MILLING SEASONS)		
CEST	6.1	7.4	4.0
IFGT	7.3	10.8	2.0
GSTIG[c]	---	5.4	-

[a]The actual assumed cane throughput varied slightly in each case, depending on the exact fuel requirements for the cogeneration system. For example, the factory with a condensing-extraction steam turbine (CEST) would process 173 tc/hr.

[b]See Tables 5, 8, and 9 for energy demands for each of these factories.

[c]Gasifier-gas turbine plants would produce a maximum of about 310 kg of process steam per tonne of cane (see Figure 7), which is insufficient to operate a typical conventional sugar factory today.

[d]Installed cost of the cogeneration plant.

[e]Installed cost of the cogeneration plant plus steam-economy retrofits.

[f]Exportable electricity made available by installation of a new cogeneration plant.

[g]Assuming an electricity selling price of $0.058/kWh.

Table 6. Estimated process steam and electricity demands for a "steam-conserving" raw-sugar factory.[a]

<u>"LIVE" STEAM at 1.4 MPa, 250ºC</u>		
Demand for:		
Cane mills		209 kg/tc
Total Generated		209
Total exhaust steam available		209
<u>EXHAUST STEAM, Saturated at 120º</u>C		
Demand for:		
Evaporator		209
Bled for vacuum pans	141	
Bled for juice heaters	21	
Total exhaust steam demand		209
<u>ELECTRICITY</u>		
Total Factory Demand[b]		13.0 kWh/tc

[a]For a cane processing rate of 175 tc/hr. The "steam-conserving" factory (see Figure 16 and Appendix G) has steam-driven cane mills, a quadruple effect falling film evaporator, and juice heating with condensate from the evaporator.

[b]See note (d) in Table 4.

Table 7. Estimated costs of equipment retrofits (1985$) for a steam conserving and electrified raw-sugar factory.[a]

Retrofit Equipment	FACTORY DESIGN Steam-Conserving	Electrified
Plate & Gasket Juice Heater	$ 101,400	$ 45,700
Falling Film Evaporator	2,400,000	2,400,000
Mechanical Vapor Recompressor	na	350,000
Continuous Vacuum Pan	622,000	622,000
Electric-Motor Drive for Mill	na	500,000
TOTAL	$ 3,123,400	$ 3,917,700

[a]For a plant processing rate of 175 tc/hr. See Appendix G.

Table 8. Estimated process steam and electricity demands for an "electrified" raw-sugar factory.[a]

"LIVE" STEAM at 1.4 MPa, 250ºC		
Total Demand		0 kg/tc
EXHAUST STEAM, Saturated at 120ºC		
Demand for:		
Evaporator		94
Bled for vacuum pans	47	
Bled for juice heaters	21	
Total exhaust steam demand		94
ELECTRICITY		
Demand for:		
Electric mills		9.0 kWh/tc
MVR Compressor		5.7
Pumps, fans, conveyors, etc.		13.0[b]
Total Factory Demand		27.7[c]

[a]For a cane processing rate of 175 tc/hr. The "electrified" factory (Figure 19 and Appendix G) has electrically-driven cane mills, a single effect falling film evaporator with mechanical vapor recompression, juice heating with condensate from the evaporator, and a triple-effect continuous vacuum pan.

[b]See note (d) in Table 4.

[c]Assumes use of conventional, commercially available motor technologies.

Table 9. Reported yields from managed short-rotation fuelwood plantations in tropical areas.[a]

Region	Primary Species	Annual Increment (m^3/ha/yr)
Highland Ethiopia	Eucalyptus globulus	10-30
Mindanao, Philippines	Albizia falcataria	20-35
Pangasinan, Philippines	Leucaena leucocephala	20-35
Indonesia (various areas)	Calliandra calothrysus	35-60
Brazil	Eucalyptus	43[b]
Hawaii, island of	Brazilian Eucalyptus	~ 50[c]
Southwestern Brazil	Eucalyptus (various)	50-100

[a]Except where otherwise noted, data are from Brewbaker.[100]

[b]Yield of eucalyptus plantations operated by Acesita Energetica for charcoal production in Minas Gerais.[101]

[c]Projected from an ongoing 300-ha trial.[102]

Table 10. Reported costs of plantation fuelwood in some tropical areas.[a]

Region	Species	(1985$/GJ)
Philippines	Leucaena, Albizia	0.60
Haiti	Leuc.,Alb., Cassia, others	1.00
Brazil, Minas Gerais	Eucalyptus	0.80[b]
Brazil, Minas Gerais	Eucalyptus saligna	1.10
Thailand	Pine, Euc., Casuarina	1.30[c]
India, West Bengal	Eucalyptus	1.30
India, Gujarat	Albizia, Acacia	1.30
India, Uttar Pradesh	Euc., Acacia, others	1.50
Hawaii, island of	Eucalyptus	1.00-1.60[d]

[a]Except where otherwise noted, the total costs include establishment and harvesting[103] plus $0.30/GJ for chipping.[104]

[b]Based on detailed yield data and establishment, maintenance and harvesting costs,[105] to which $0.30/GJ has been added for chipping.[106]

[c]Range of $1.20-1.40 reported.

[d]For plantation establishment, harvesting, and chipping. Based on an ongoing 300-hectare trial with eucaplyptus varieties on the island of Hawaii.[107]

Table 11. Levelized fuel prices in Jamaica assumed for the Monymusk-based case study.

FUEL	PRICE (1985$/GJ)
BAGASSE	
As delivered from mills, 50% moisture	0.00
Dried to 25% moisture[a]	0.58
Baled, dried to 25% moisture and stored[a]	0.78
Briquetted (12% moisture)[a]	1.16
Pelletized (15% moisture)[a]	2.02
BARBOJO	
Baled, dried to 25% moisture, transported and stored[b]	0.97
Briquetted, transported, and stored (12% moisture)[c]	1.35
Pelletized, transported, and stored (15% moisture)[c]	2.21
PLANTATION FUELWOOD	1.00-1.50[d]
RESIDUAL FUEL OIL	
Low	2.90[e]
High	4.00
DISTILLATE FUEL OIL	
Low	5.40[e]
High	7.50
IMPORTED COAL	
Low	1.43[f]
High	2.08[g]

[a]Source: Eletrobras.[108]

[b]Estimated by Ronco.[109]

cCalculated as the cost of baled barbojo ($0.97/GJ, which includes transport and storage costs) plus the difference in cost between baling and either briquetting or pelletizing bagasse.

[d]See Table 10.

[e]The low prices are those used by the Jamaica Public Service Utility for their projections to the year 2000.[110]

[f]Coal price being used by the Jamaica Public Service Utility for projections to the year 2000.[111]

[g]Estimated for Jamaica to the year 2000 in a 1985 study.[112]

Table 12. Land requirements, and productivity of land in terms of electricity generation, for a fuelwood plantation to provide off-season fuel for a GSTIG or a CEST cogeneration plant located adjacent a 175 tc/hr steam-conserving sugar factory.

PLANTATION YIELD (m^3/ha/yr)[a]	PLANTATION AREA REQUIRED (hectares)[b]		ELECTRICAL PRODUCTIVITY (MWh sold/ha/yr)	
	GSTIG	CEST	GSTIG	CEST
20	10,110	8,430	35.5	20.8
30	6,750	5,620	53.3	31.3
40	5,060	4,210	71.1	41.6
50	4,050	3,370	88.9	52.6
60	3,370	2,810	107	62.5

[a]A cubic meter of wood is assumed to contain 10 GJ of energy.

[b]For comparison, the total cane growing area required to supply the factory processing 175 tc/hr, assuming a yield of 62 tc/ha,[113] would be about 12,600 hectares.

Table 13. Number and average rated cane processing capacity of sugar factories in some developing countries[a] and the capacity of the GSTIG or CEST cogeneration system that the averaged-size factory could support.[b]

COUNTRY	Average Rated Capacity (tc/hr)	Number of Plants	Capacity (MW) at average factory GSTIG	CEST
China	20	150	5.2	3.1
India	73[c]	296	19	11
Tanzania	73	5	19	11
Pakistan	80	38	21	12
Indonesia	98	64	25	15
Kenya	100	6	26	15
Brazil	110[d]	450	28	17
Jamaica[e]	126	9	33	20
Guatemala	147	14	38	23
Argentina	174	25	45	27
Mexico	188	84	49	29
Philippines	191	43	49	30
Thailand	217	39	56	34
Panama	224	6	58	35

[a]Source: Ruspam Communications.[114]

[b]The capacities shown are calculated based on "efficiencies" of 156 kWh per tonne of cane for a CEST and 259 kWh/tc for a GSTIG, which correspond to operation as power-only plants, i.e., at factories with no process steam demand. (See Fig. 9.)

[c]Average for the (alphabetically) first 100 factories.

[d]Estimate for all cane processing plants producing sugar and/or alcohol.[115]

[e]The operating factories in Jamaica and their nominal capacities (in tc/hr) are: Frome (271), Monymusk (208), Bernard Lodge (167), New Yarmouth (92), Long Pond (88), Appleton (70), Hampden (63), Worthy Park (50). See note (a).

Table 14. Cost and performance estimates for cogeneration plants at "steam-conserving" factories of three different sizes.

	Fuel Used[a] (tc/hr)	Capacity (MW_e)	Peak Efficiency[b] (Percent)	Unit cost[c] (1985$/kW)
<u>LARGE</u>				
CEST	173	27	20.3	1670
GSTIG[d]	180	53	32.5	1050
<u>MEDIUM</u>				
CEST	71	10	17.8	2222
GSTIG[e]	70	20	30.8	1290
<u>SMALL</u>				
CEST	24	3.0	15.7	3150
GSTIG[f]	19	5.4	30.1	1710

[a]Equivalent cane throughput required during the milling season to provide bagasse fuel for the cogeneration plant.

[b]See Appendices A, B, and C for discussion of the efficiency calculations.

[c]Installed capital cost for the cogeneration plant plus the cost of steam conservation retrofits.

[d]Based on a General Electric LM-5000 steam-injected gas turbine.

[e]Based on a General Electric LM-1600 gas turbine with steam injection.

[f]Based on the General Electric GE-38 steam-injected gas turbine.

Table 15. Potential foreign exchange savings to Jamaica with alternative cogeneration systems (based on the 1985 level of cane production) by avoiding construction of new coal-fired capacity or by displacing existing oil-fired capacity.[a]

Generating Technology	Potential New Capacity (MW)	Required Capital Investment (Million $)	Lifecycle Foreign Exchange For Fuel (Million $)[b]	Present value of Lifecycle FOREIGN EXCHANGE SAVINGS WITH COGENERATION over Coal or Oil Firing[c] (Million $)	($/MWh)
1. CEST COGEN[d]	79	132	0		
vs. New Coal-Steam[e]					
Coal @ $1.43/GJ	88	116	70	54	3.54
Coal @ $2.08/GJ	88	116	102	86	5.64
vs. Existing Oil-Steam[f]					
Oil @ $2.9/GJ	0	0	172	not applicable[g]	
Oil @ $3.2/GJ	0	0	190	58	3.81
Oil @ $4.0/GJ	0	0	237	92	6.89
2. GSTIG COGEN[h]	153	160	0		
vs. New Coal-Steam[e]					
Coal @ $1.43/GJ	172	226	138	204	6.84
Coal @ $2.08/GJ	172	226	200	266	8.92
vs. Existing Oil-Steam[f]					
Oil @ $2.9/GJ	0	0	337	177	5.94
Oil @ $3.2/GJ	0	0	372	212	7.11
Oil @ $4.0/GJ	0	0	464	304	10.2

[a]For a cane production of 2.2 million tonnes per year, and CEST and GSTIG export electricity production of 231 and 452 kWh/tc, respectively. Thus, the CEST and GSTIG systems would produce 500 and 1000 GWh/year, respectively.

[b]For a 12% discount rate and a 30-year lifecycle.

[c]For this analysis, all of the capital is assumed to be foreign exchange.

[d]Assuming all of the capacity is installed at a cost of $1671/kW, which includes factory retrofits for a "steam-conserving" factory, and a calculated capacity factor of 73%.

[e]See footnote 8 for assumptions associated with the cost of electricity from the coal-steam plant.

[f]See footnote 10 for assumptions associated with the cost of electricity from the oil-steam plant.

[g]CEST power would not displace oil-fired power unless the price of oil is at least $3.2/GJ, where the fuel plus operating cost for the oil-fired plants would equal the total generating cost for the CEST ($0.049/kWh).

[h]Assuming all of the capacity is installed at a cost of $1048/kW, which includes factory retrofits for a "steam-conserving" factory, and a calculated capacity factor of 74%.

Table 16. Comparison of the estimated cost of generating exportable electricity at sugar processing facilities in Southeast Brazil and that delivered from new hydro-electric plants in the Amazon to Southeast Brazil.[a]

	ELECTRICITY COSTS ($ PER KWH)								
Cost Component	Hydro-electricity[b] Costing ($/kW) 1000	1400	1800	GSTIG (MW)[c,d] 5	20	50	CEST (MW)[c,e] 3	10	27
Capital	0.0296	0.0414	0.0532	0.0327	0.0243	0.0200	0.0620	0.0434	0.0320
Fuel	0	0	0	0.0166	0.0161	0.0152	0.0121	0.0106	0.0094
O&M	0.0024	0.0034	0.0044	0.0076	0.0056	0.0057	0.0122	0.0086	0.0077
TOTAL	0.032	0.045	0.058	0.057	0.046	0.041	0.086	0.063	0.049

[a]Economical hydro resources in the South of Brazil have already been essentially fully exploited.[116]

[b]Capital costs in the Amazon region of Brazil are $400-1200/kW, transmission costs to Sao Paulo state are $600/kW, transmission losses are 7%, and annual O&M costs are 1% of the capital cost.[117] Because of the seasonal availability of water and year-to-year variations in rainfall, a capacity utilization factor of 50% is used.[118] A 50-year equipment life and a 12% discount rate are used.

[c]The three installed capacities correspond to sugar factories processing about 19, 70, and 180 tonnes of cane per hour, respectively. See Table 14.

[d]Assuming briquetting of fuel, barbojo use in the off-season, a discount rate of 12%, and a 30-year equipment life. The calculated capacity factor is about 75% in all three cases.

[e]Assuming no cost for bagasse, barbojo use in the off-season, a discount rate of 12%, and a 30-year equipment life. The calculated capacity factor is about 73% in all three cases.

Table 17. Estimated potential worldwide GSTIG generating capacity at sugar factories with the 1985 level of sugar cane production.[a,b]

Region	Potential Electrical Capacity (MW)
SOUTH AMERICA	17,800[c]
ASIA	14,000
CENTRAL AMERICA	10,100
AFRICA	4,900
OCEANIA	2,700
UNITED STATES	1,900
EUROPE	200
TOTAL	51,600

[a]Sugar cane production, assuming ten tonnes of cane are required to produce one tonne of sugar. Sugar production data are from the International Sugar Organization.[119]

[b]Assuming a 206 day season, 24 hour/day operation, 90% plant availability, and a GSTIG fuel requirement corresponding to 180 tonnes of cane per hour for a 53 MW unit.

[c]Includes capacity that would be installed at alcohol production facilities in Brazil. (See note c in Table 18.)

Table 18. GSTIG electricity generating potential using the 1985 level of cane production, (A),[a] and the actual total electric utility generation in 1982, (B),[b] in developing countries. Numbers are given in 10^9 kWh.

	A	B		A	B	A	B
ASIA						89	599
India	31.6	129.5	Iran	0.90	17.5		
China	19.0	327.7	Vietnam	0.81	1.69		
Thailand	10.8	16.2	Burma	0.45	1.52		
Indonesia	7.6	11.9	Bangladesh	0.42	2.98		
Philippines	7.4	17.4	Malaysia	0.32	11.1		
Pakistan	6.4	14.9	Nepal	0.12	0.284		
Taiwan	3.4	45.0	Sri Lanka	0.07	2.07		
CENTRAL AMERICA						65	100
Cuba	35.5	10.8	Jamaica	0.94	1.30		
Mexico	15.7	73.2	Panama	0.72	2.71		
Dominican Rep.	4.2	2.38	Belize	0.49	0.065		
Guatemala	2.3	1.42	Barbados	0.45	0.339		
El Salvador	1.2	1.45	Trinidad & Tob.	0.36	2.30		
Nicaragua	1.1	0.945	Haiti	0.23	0.352		
Honduras	1.0	1.04	St.Chris.-Nevis	0.12	na		
Costa Rica	1.0	2.42					
SOUTH AMERICA						59	257
Brazil	38.0[c]	143.6	Guyana	1.1	0.255		
Colombia	6.1	21.3	Bolivia	0.78	1.40		
Argentina	5.5	36.2	Paraguay	0.36	0.569		
Peru	3.3	7.25	Uruguay	0.23	3.47		
Venezuela	2.1	39.0	Suriname	0.05	0.175		
Ecuador	1.3	3.09					
AFRICA						32	167
South Africa	11.4	109.0	Mozambique	0.26	3.25		
Egypt	3.7	17.2	Somalia	0.24	0.075		
Mauritius	3.1	0.320	Nigeria	0.23	7.45		
Zimbabwe	2.1	4.16	Angola	0.23	1.46		
Sudan	2.0	0.910	Uganda	0.15	0.569		
Swaziland	1.8	0.075	Congo	0.11	0.195		
Kenya	1.6	1.73	Mali	0.09	0.080		
Ethiopia	0.87	0.618	Gabon	0.05	0.530		
Malawi	0.69	0.410	Burkina Faso	0.05	0.123		
Zambia	0.64	10.3	Chad	0.04	0.065		
Ivory Coast	0.57	1.94	Guinea	0.02	0.143		
Tanzania	0.47	0.720	Sierra Leone	0.02	0.136		
Madagascar	0.45	0.342	Benin	0.02	0.016		
Cameroon	0.32	2.15	Liberia	0.01	0.389		
Zaire	0.30	1.48	Rwanda	0.01	0.066		
Senegal	0.30	0.631					
OCEANIA						2	1
Fiji	1.6	0.241	Pap. N. Guinea	0.13	0.441		
ALL SUGAR-PRODUCING DEVELOPING COUNTRIES						247	1,124

Notes for Table 18.

[a]For the 1985 levels of sugar production,[120] assuming 100 kg of sugar is produced, on average, from each tonne of cane.

[b]World Bank data,[121] except Taiwan, Iran, South Africa, Cuba, Trinidad & Tobago, and Venezuela, which are from US Bureau of the Census.[122]

[c]Based on cane used for sugar production only, which accounted for about 40% of all cane harvested in 1985.[123] GSTIG systems could also be installed at ethanol-from-sugar-cane distilleries, because in-house steam and electricity demands per tonne of cane crushed would be comparable at modern distilleries to those at steam-conserving sugar factories.[124] Such distilleries could export an amount of electricity comparable to that from a steam conserving sugar factory. Including the cane used for ethanol production, the total electricity potential from cane in Brazil is about 95 billion kWh.

Table 19. Fuel oil dependence of some sugar-producing developing countries.

Country	Energy Imports as a Percentage of Merchandise Exports[a]	Fraction of Electricity Generated Using Liquid Fuels[b]
ASIA		
India	30	2
Pakistan	52	1
Bangladesh	41	25
Philippines	44	59
Sri Lanka	33	11
Thailand	33	78
Indonesia	12	73
China	not available	17
CENTRAL AMERICA		
Panama	not available	58
Dominican Republic	71	96
Jamaica[c]	65	95
El Salvador	not available	2
Nicaragua	21	54
Costa Rica	14	4
Mexico	1	50
Guatemala	17	81
SOUTH AMERICA		
Brazil	37	7
Colombia	14	3
Argentina	6	36
Peru	4	31
Venezuela	1	25
AFRICA		
Kenya	not available	40
Mauritius	23	75
Egypt	10	26
Sudan	51	36

[a]Data are for 1985 from the World Bank.[125]

[b]Data are for 1980 from the World Bank,[126] except for Mauritius, which is from the Central Electricity Board,[127] and Jamaica (see note c).

[c]Data are for 1985 from the Planning Institute of Jamaica[128] for exports and from Jamaica Public Service[129] for the liquid fuel fraction.

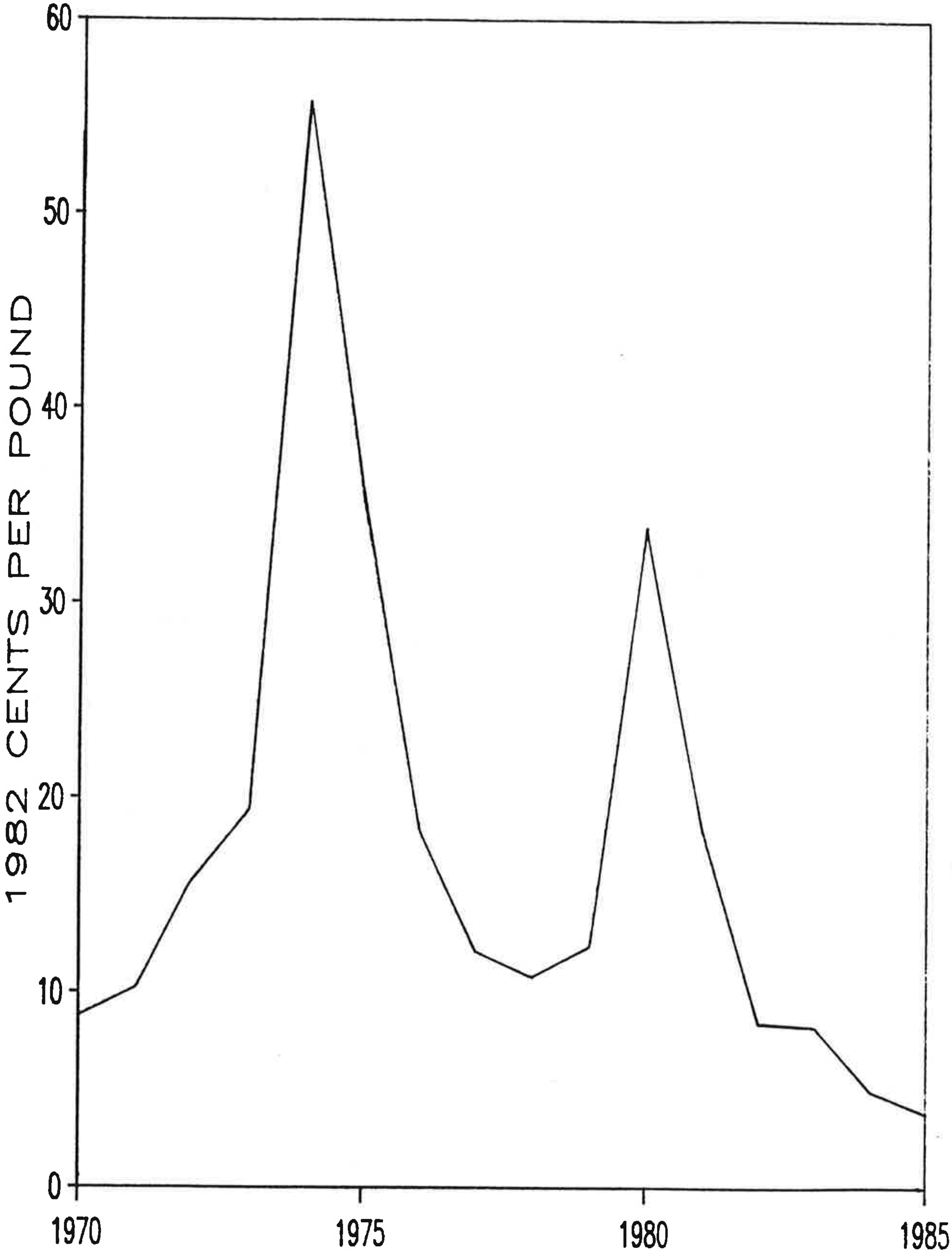


Figure 1. The world-market price of sugar, 1970-1985. Current-dollar prices from (International Sugar Organization, Sugar Yearbook, London, annual) have been expressed in constant 1982 dollars using the GNP deflator.

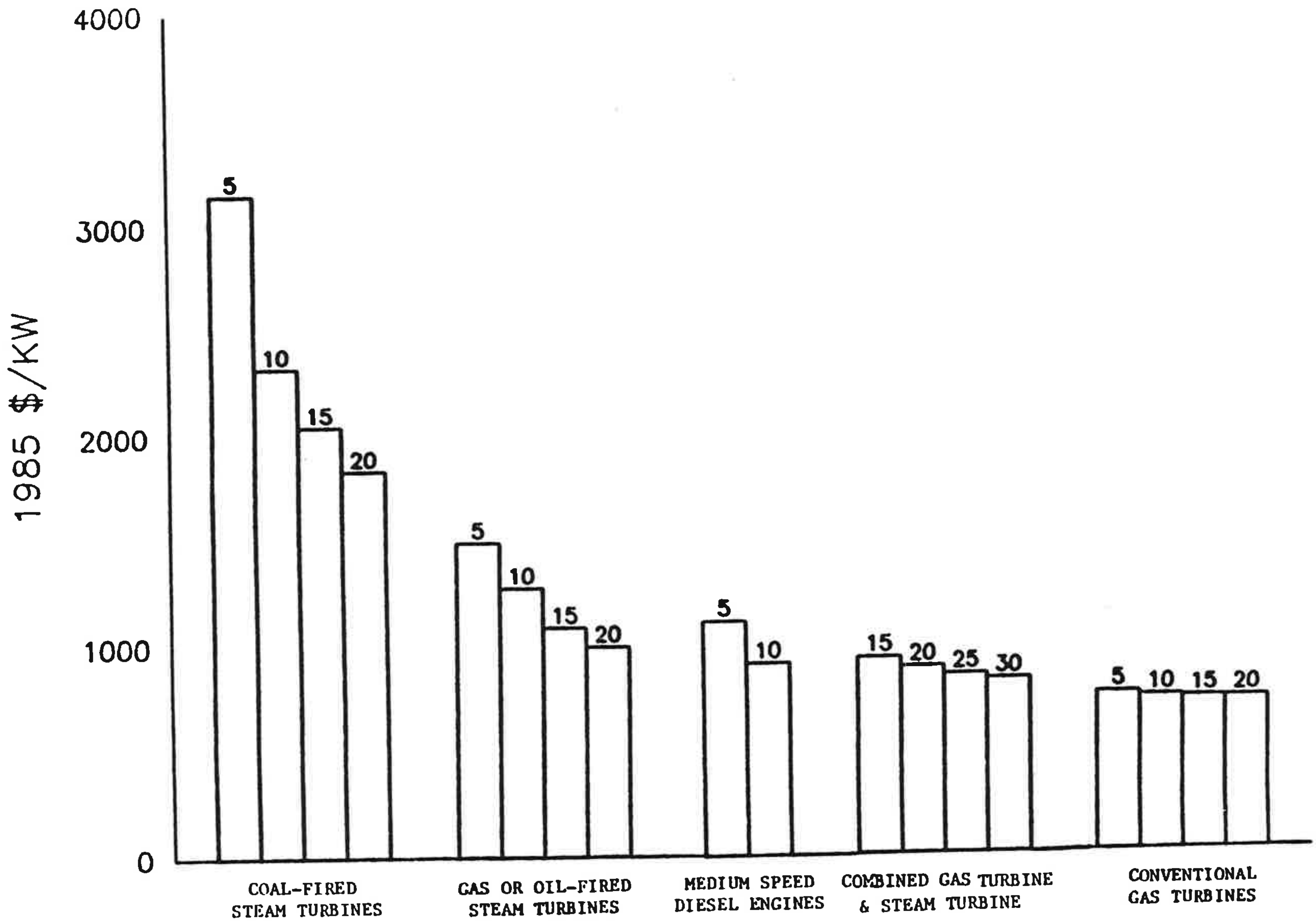


Figure 2. Unit installed capital costs for small cogeneration systems. The numbers at the tops of the bars are the installed electrical generating capacity in MW. From (Office of Industrial Programs, Industrial Cogeneration Potential, 1980-2000, for Application of Four Commercially Available Prime Movers at the Plant Site, US Department of Energy, Washington, DC, 1984).

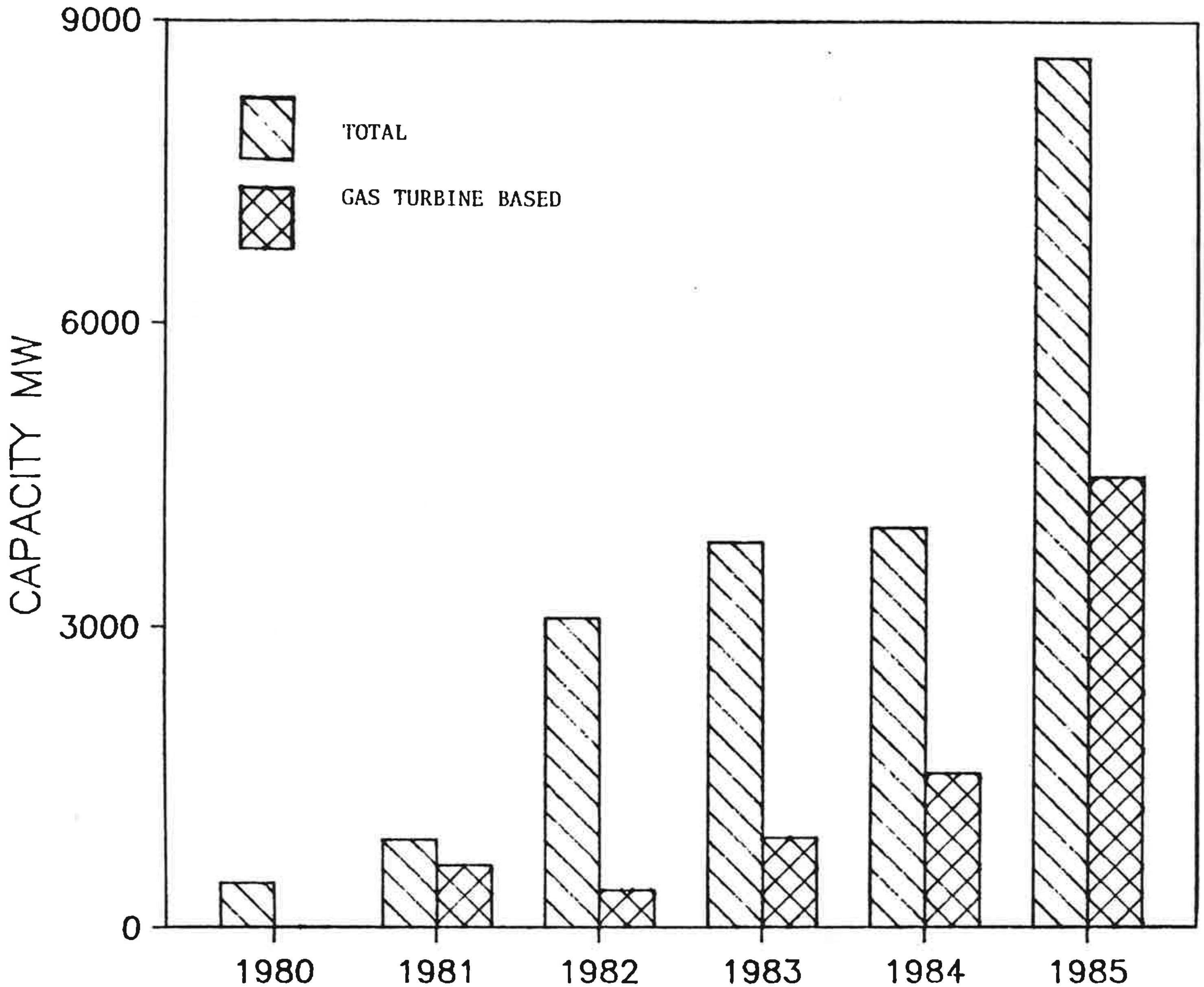


Figure 3. Total and gas turbine-based cogeneration capacity certified in the U.S. versus year of certification by the Federal Energy Regulatory Commission. From (Office of Electric Power Regulation, The Qualifying Facilities Report, (FERC-0118) Federal Energy Regulatory Commission, Washington, DC, 1986).

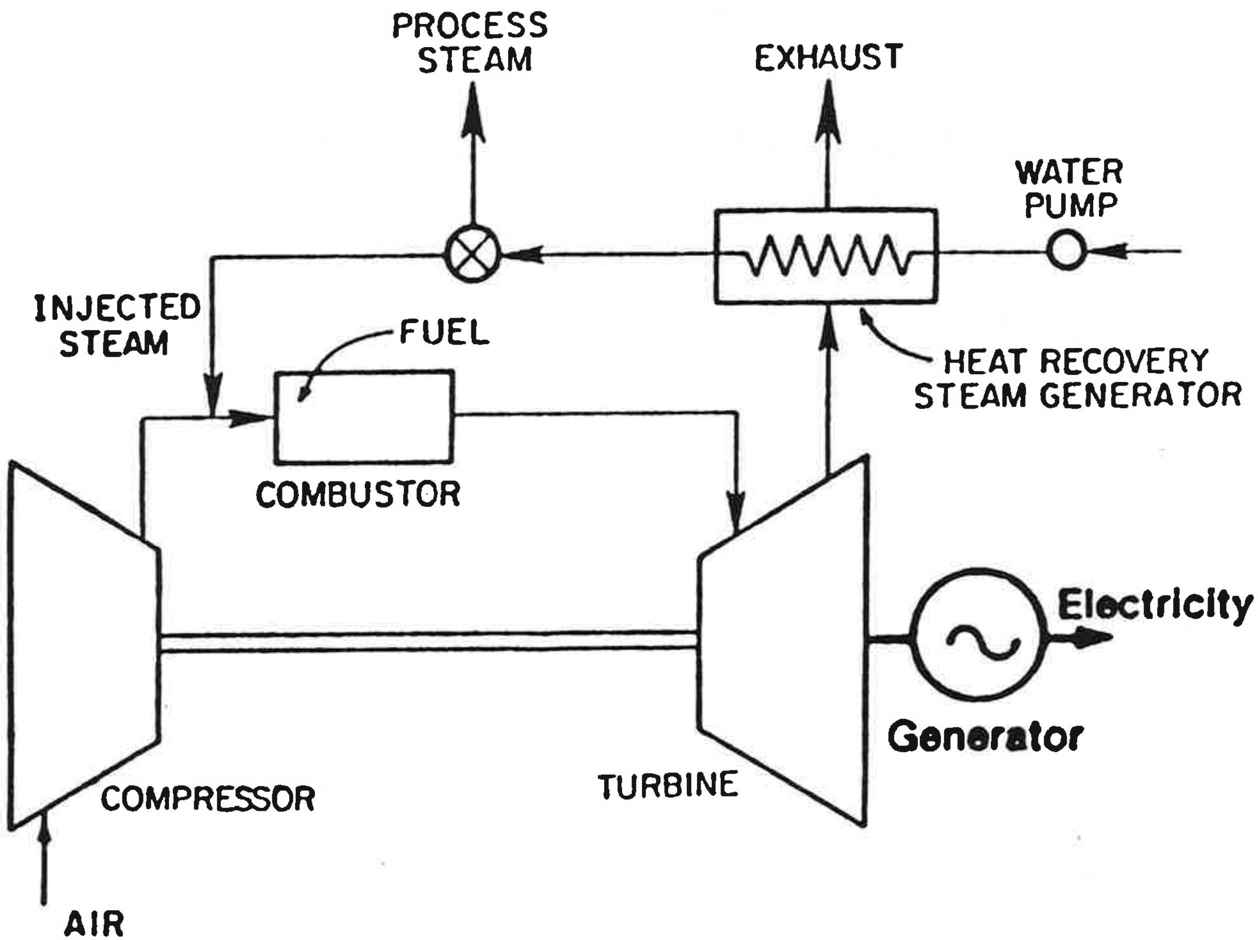


Figure 4. Steam-injected gas turbine cogeneration cycle.

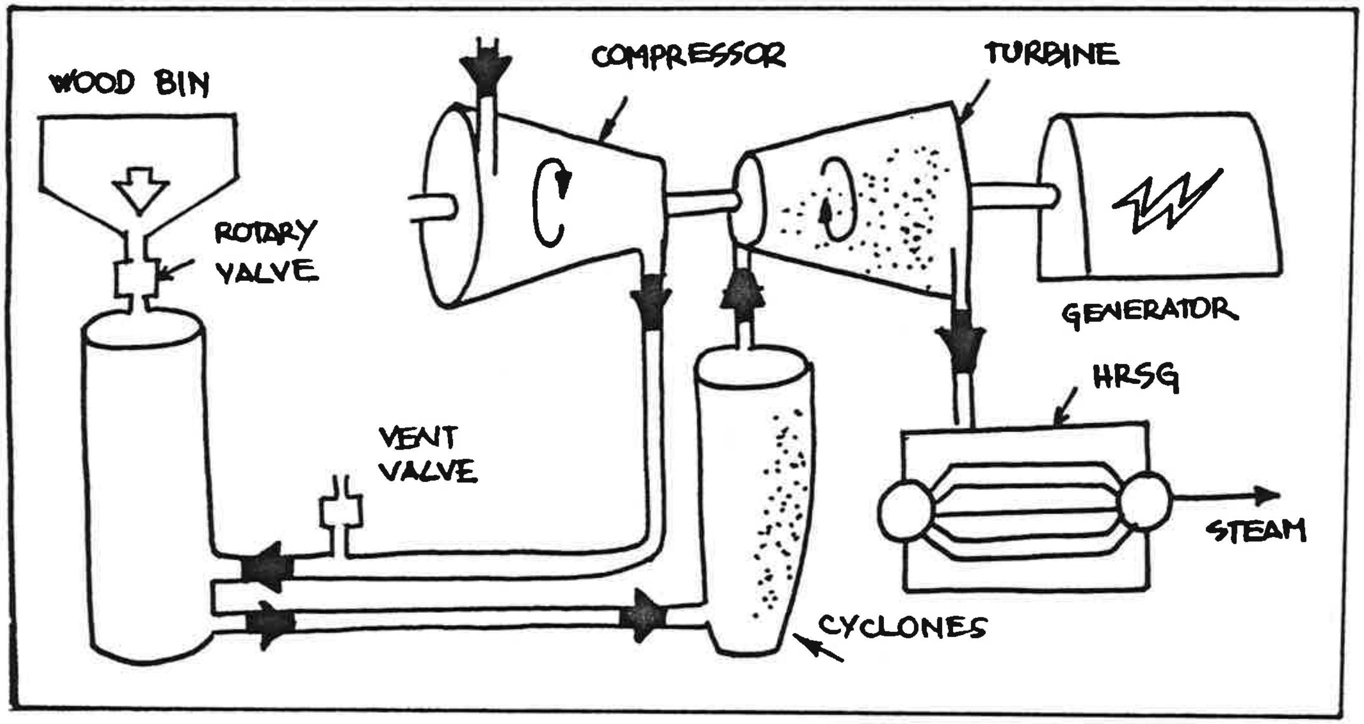


Figure 5. Gas turbine cogeneration cycle with direct firing of biomass.

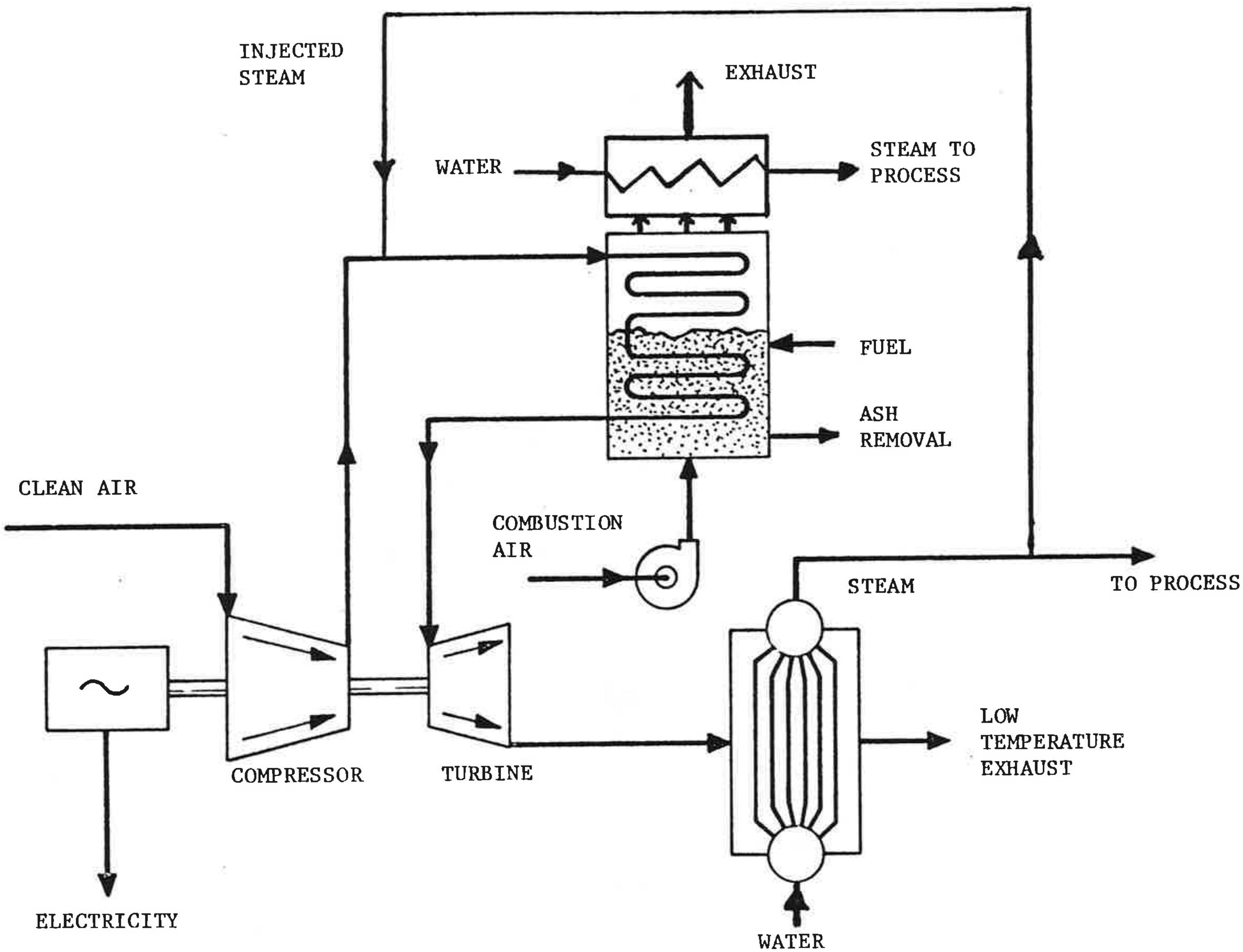


Figure 6. Steam-injected gas turbine cogeneration cycle with indirect firing of biomass in an atmospheric-pressure fluidized-bed combustor.

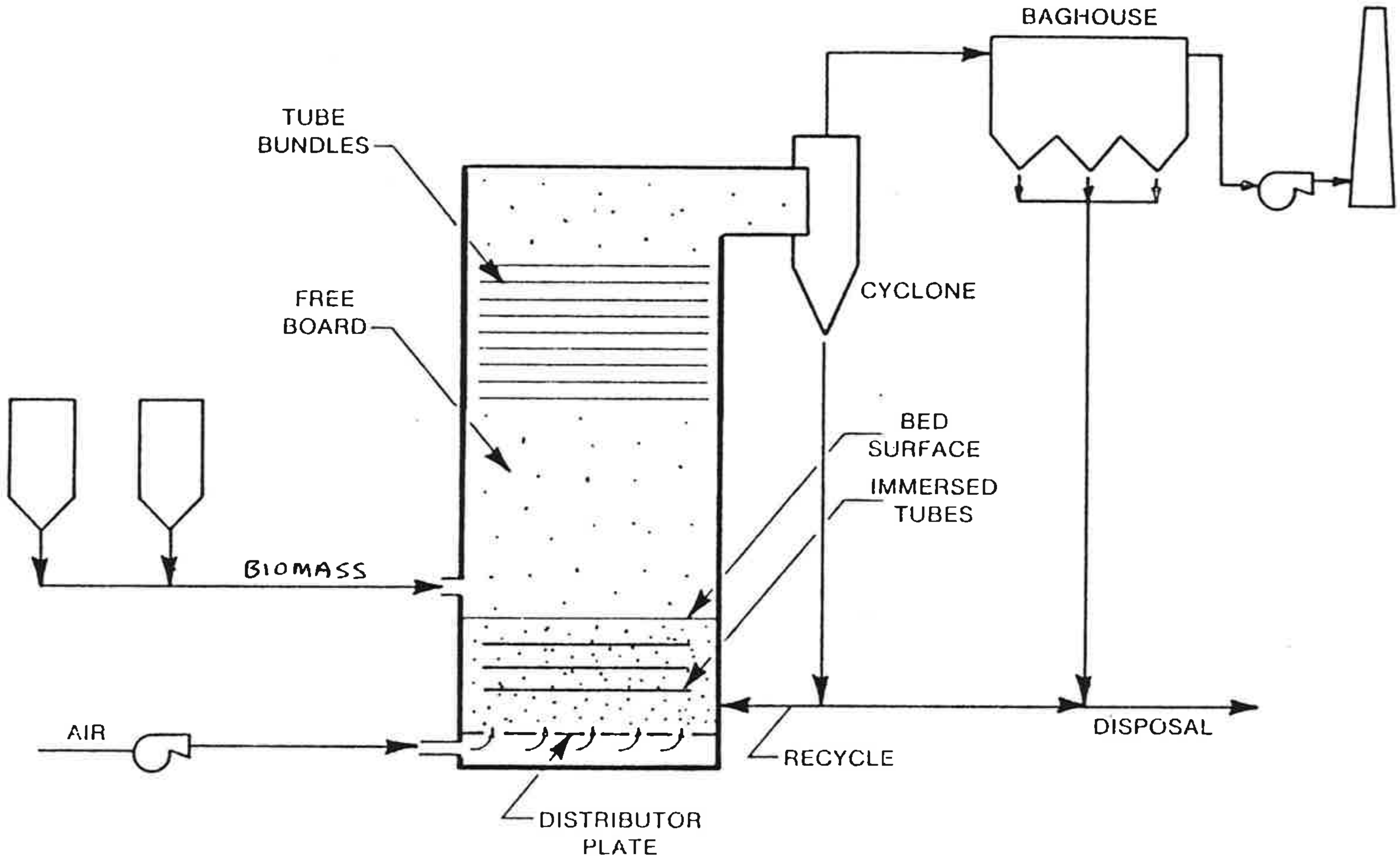


Figure 7. Schematic of one type of atmospheric-pressure fluidized-bed combustor. The design shown, the first AFBC design to be widely commercialized, is called a bubbling-bed because of the appearance of the bed during operation.

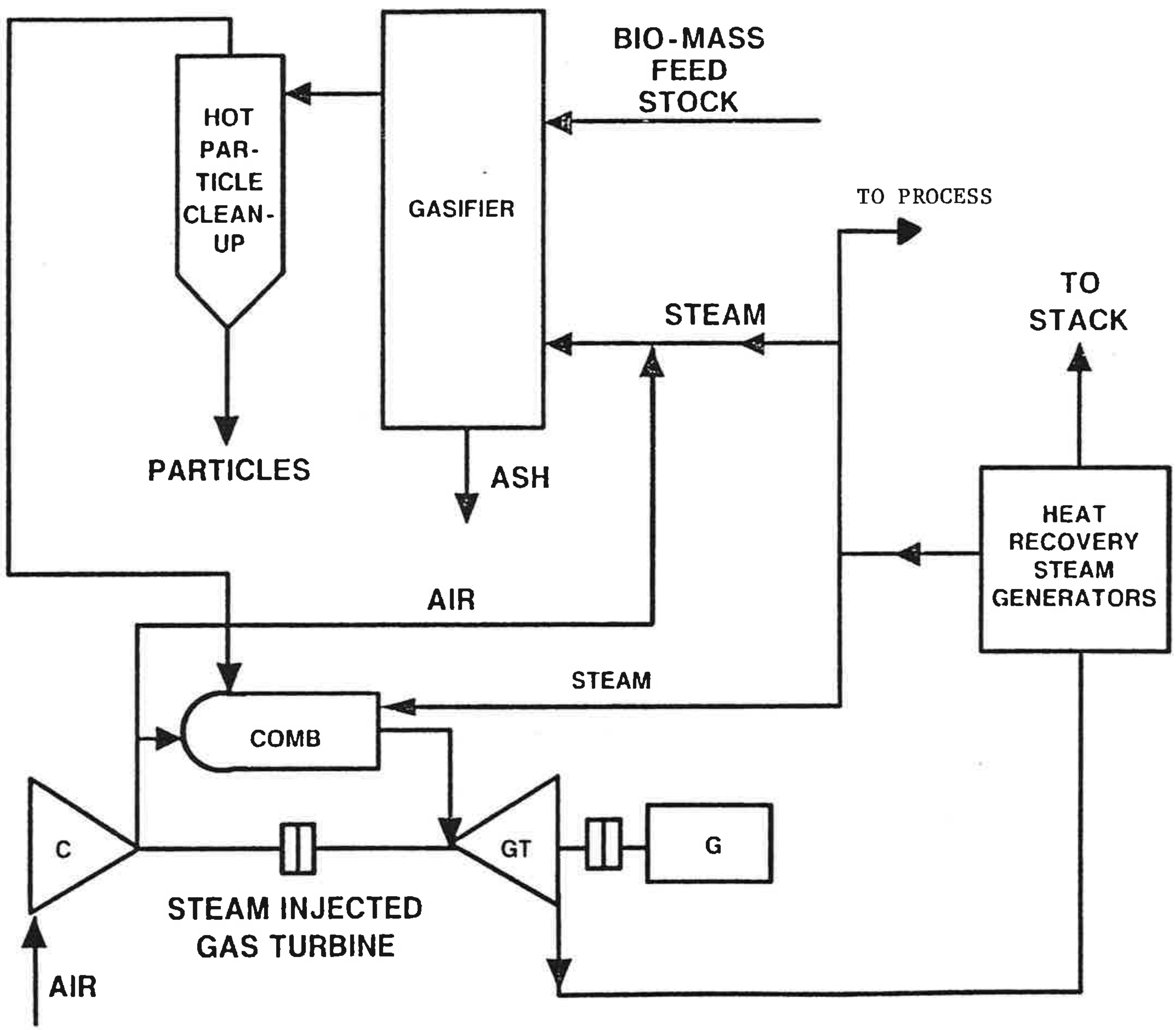


Figure 8. Biomass-gasifier steam-injected gas turbine (biomass-GSTIG) cogeneration cycle.

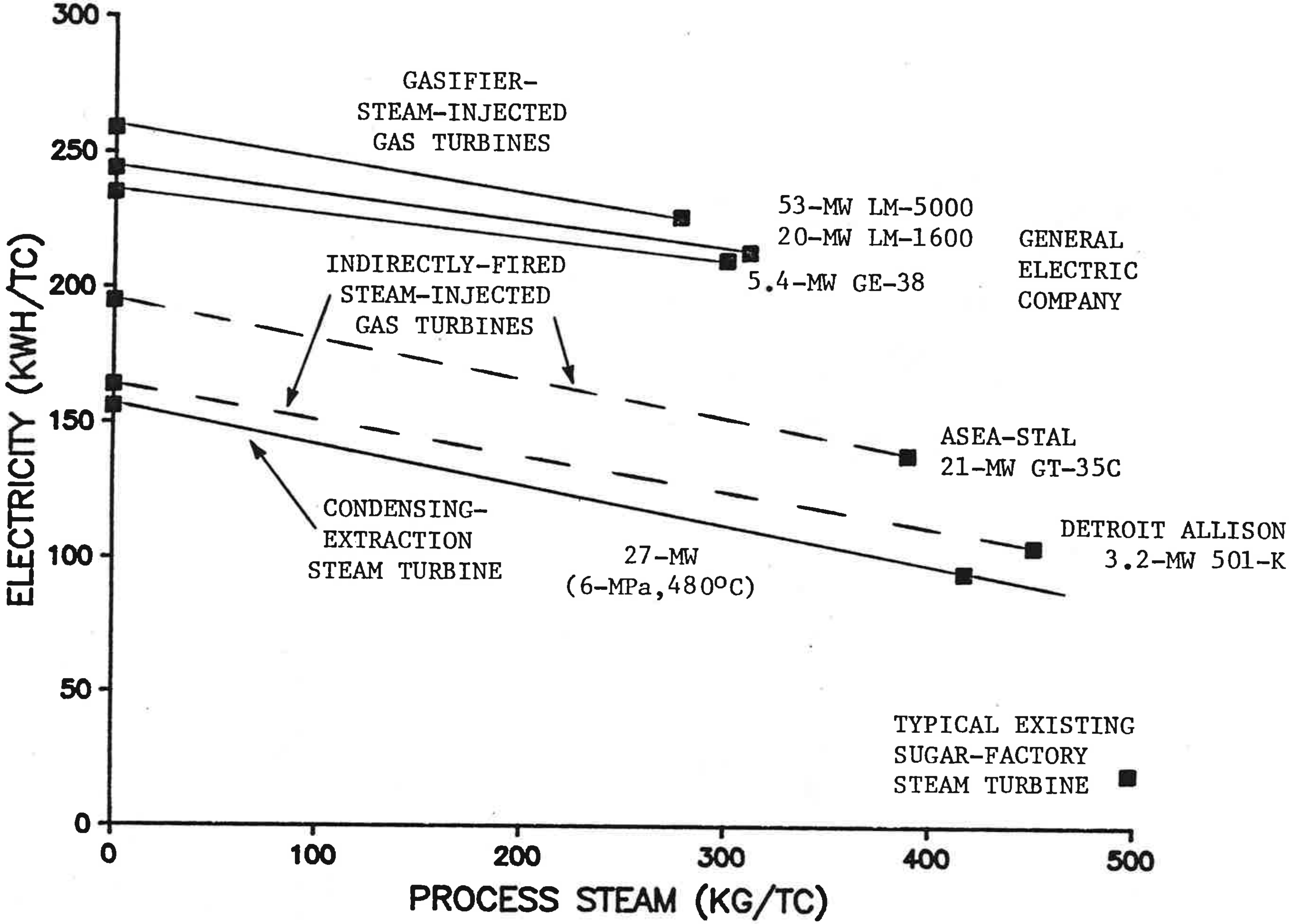


Figure 9. Steam and electricity production estimates for cogeneration systems operating at sugar factories during the milling season with bagasse as fuel. See Appendices A and B for details.

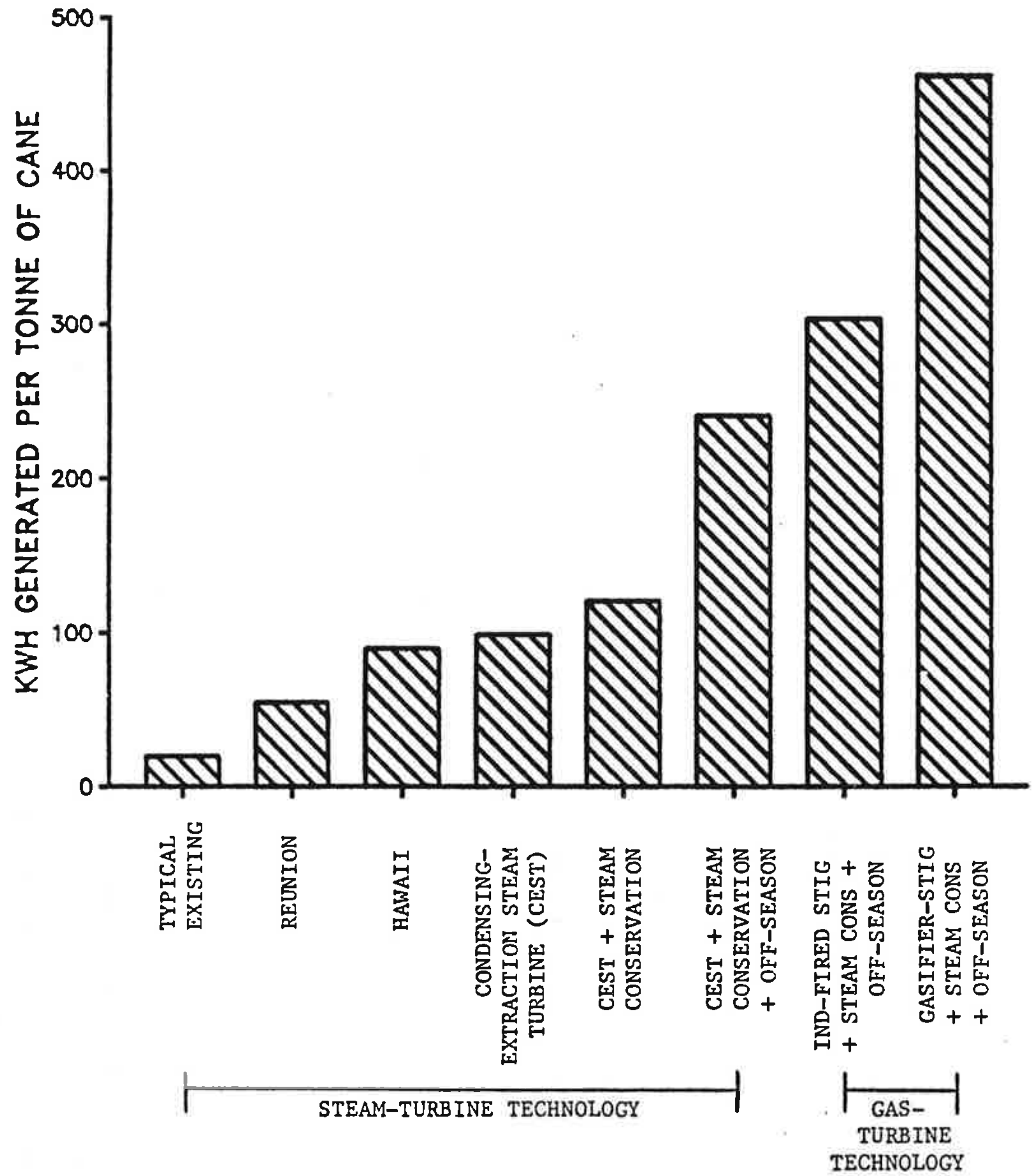


Figure 10. Electricity generating potential from sugar cane residues at a raw-sugar factory per tonne of cane crushed.

The four left-hand bars represent cogeneration systems installed in existing conventional factories: TYPICAL EXISTING is based on the existing equipment at the Monymusk factory in Jamaica (see Appendix G); REUNION is based on the 1984 performance of a recently-installed condensing-extraction steam turbine in Reunion (Directorate General of Information and Innovation, "24.65 MW Bagasse-Fired Steam Power Plant Demonstration Project," EUR 10390 EN/FR, Commission of the European Communities, Brussels, 1986); HAWAII is the average for all sugar-factory cogeneration systems in that state, some of which operate with an auxiliary fuel in the off-season (C. Kinoshita, Hawaiian Sugar Planters' Association, unpublished data, 1987); CONDENSING-EXTRACTION STEAM TURBINE (CEST) is based on the unit proposed for the Monymusk plant (Ronco Consulting Corp. and Bechtel National, Inc., "Jamaica Cane/Energy Project Feasibility Study," funded by the US Agency for Int'l Development and the Trade and Development Program, Wash., DC, 1986).

The four right-hand bars represent systems in "steam-conserving" factories (see Section 5.2). In addition, the last three bars include operating during the off-season with an auxiliary fuel. The two right-most bars represent gas turbine technologies.

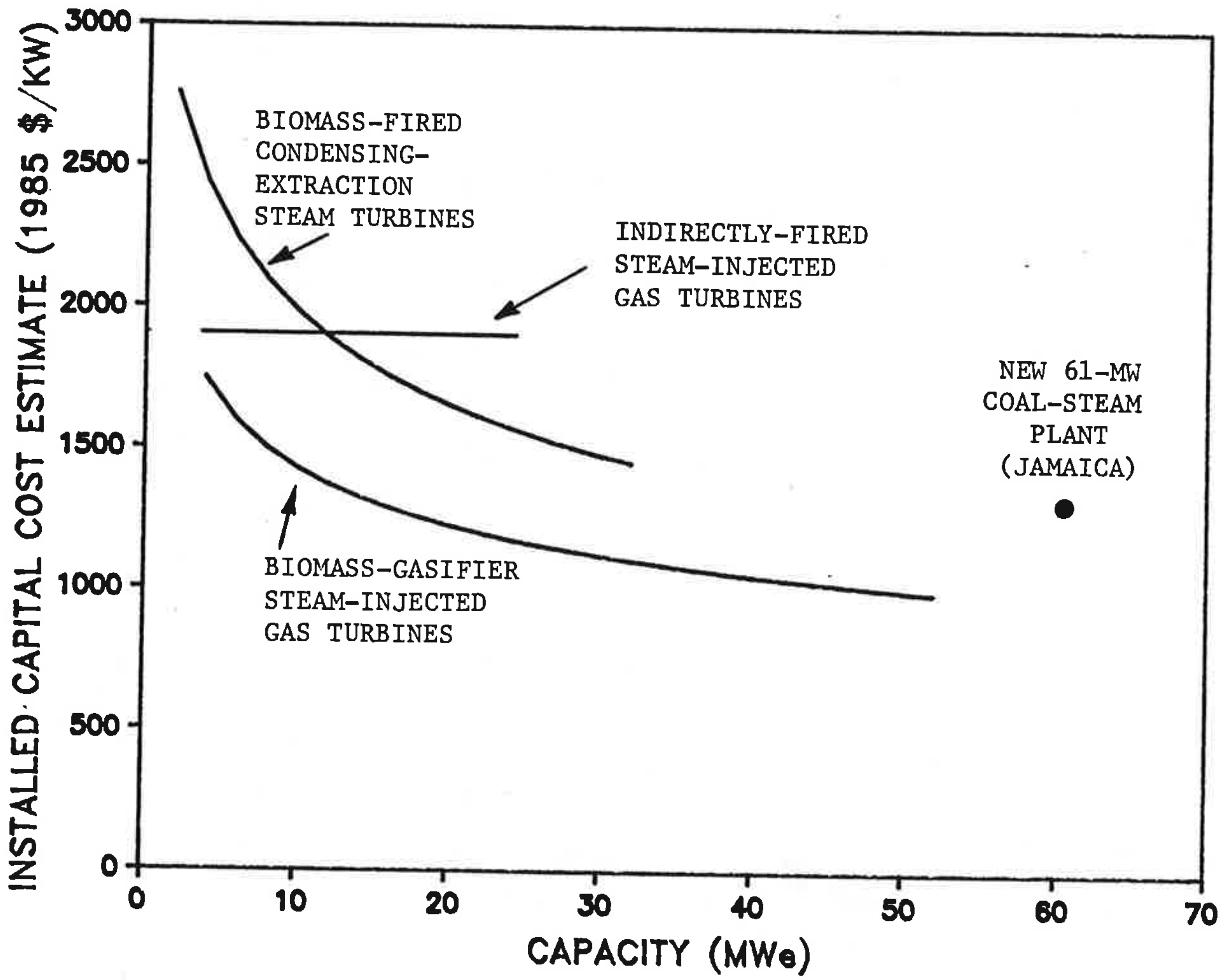


Figure 11. Estimated installed capital costs for condensing extraction steam turbine (CEST), indirectly-fired steam-injected gas turbine (IFGT), and gasifier-steam-injected gas turbine (GSTIG) powerplants fired with biomass. (See Appendix D for details.) Also shown is a cost estimate for a 61-MW coal-steam plant in Jamaica (Montreal Engineering Company, "Least-Cost Expansion Study," for the Jamaica Public Service Co., Ltd., Kingston, Jamaica, 1985).

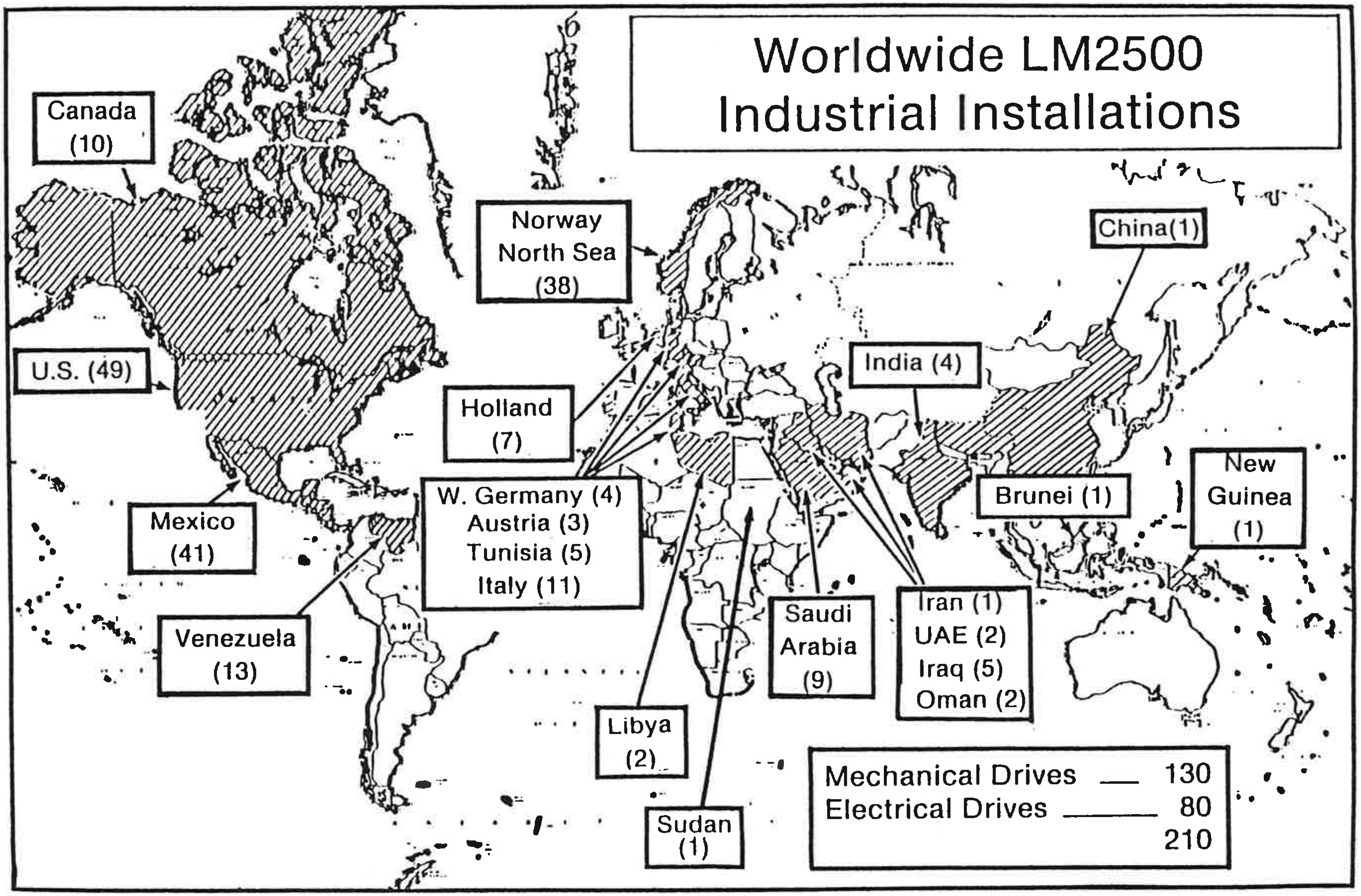
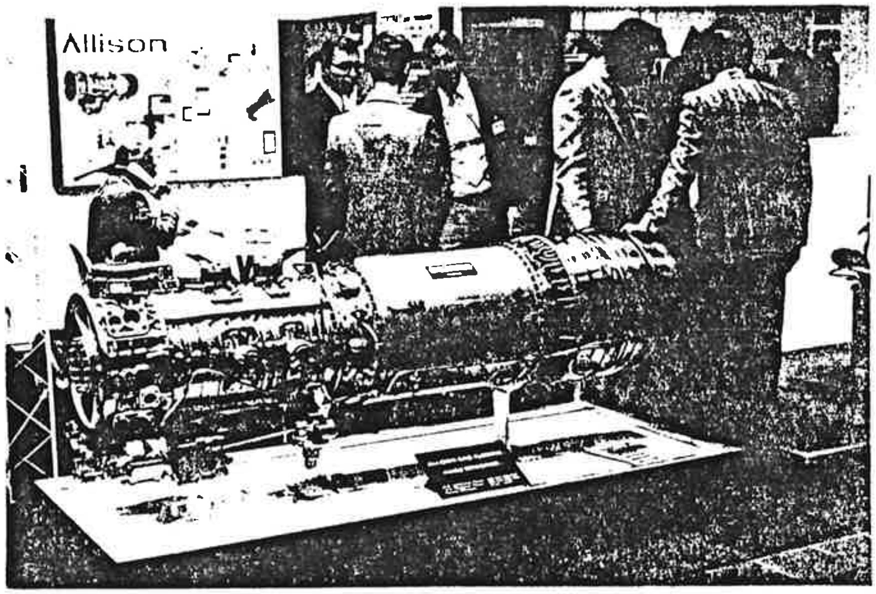


Figure 12. Worldwide industrial installations of the General Electric LM-2500 aircraft-derivative gas turbine (L. Gelfand, Manager of Advanced Programs and Ventures, General Electric Co., Cincinnati, Ohio, personal communication, February 1987).



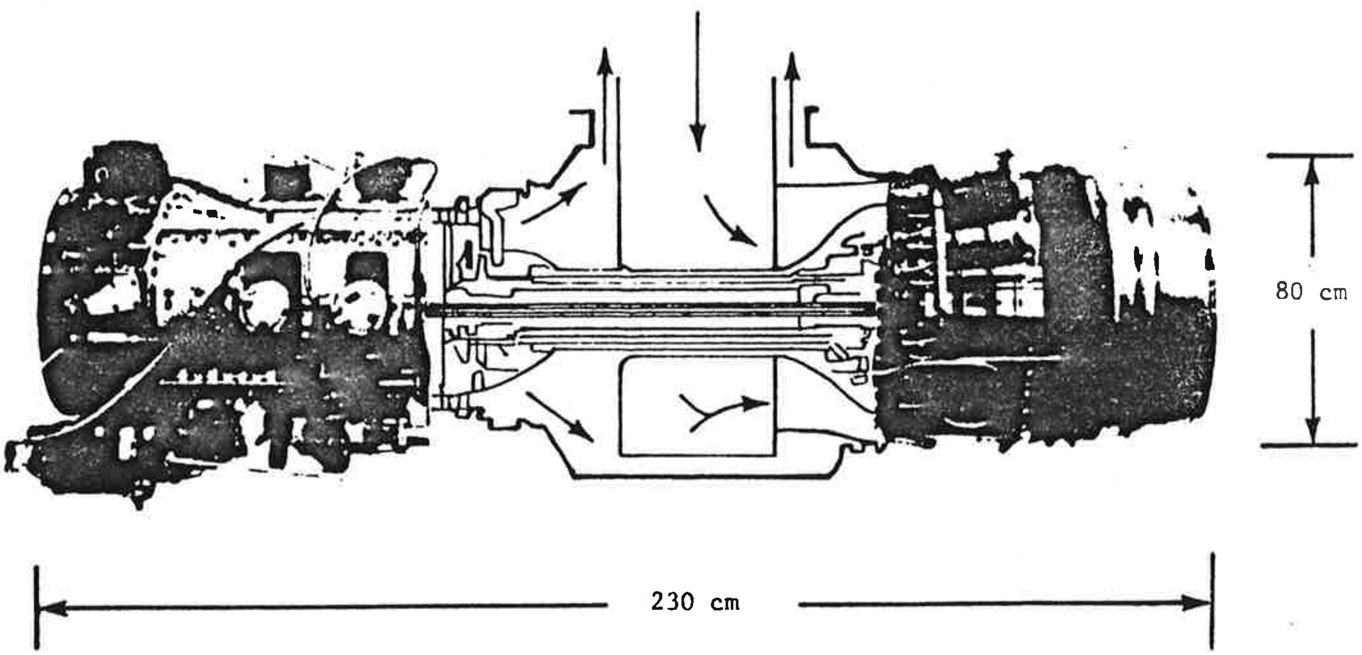


Figure 13. The upper figure shows the Detroit Diesel Allison 501-K aircraft-derivative gas turbine on display at the 1986 International Gas Turbine Conference (Dusseldorf, Germany). The lower figure shows the same engine modified for indirect firing with biomass. The engine weighs approximately 580 kilograms. Operating with steam-injection on natural gas, it can produce 5.5 MW of power.

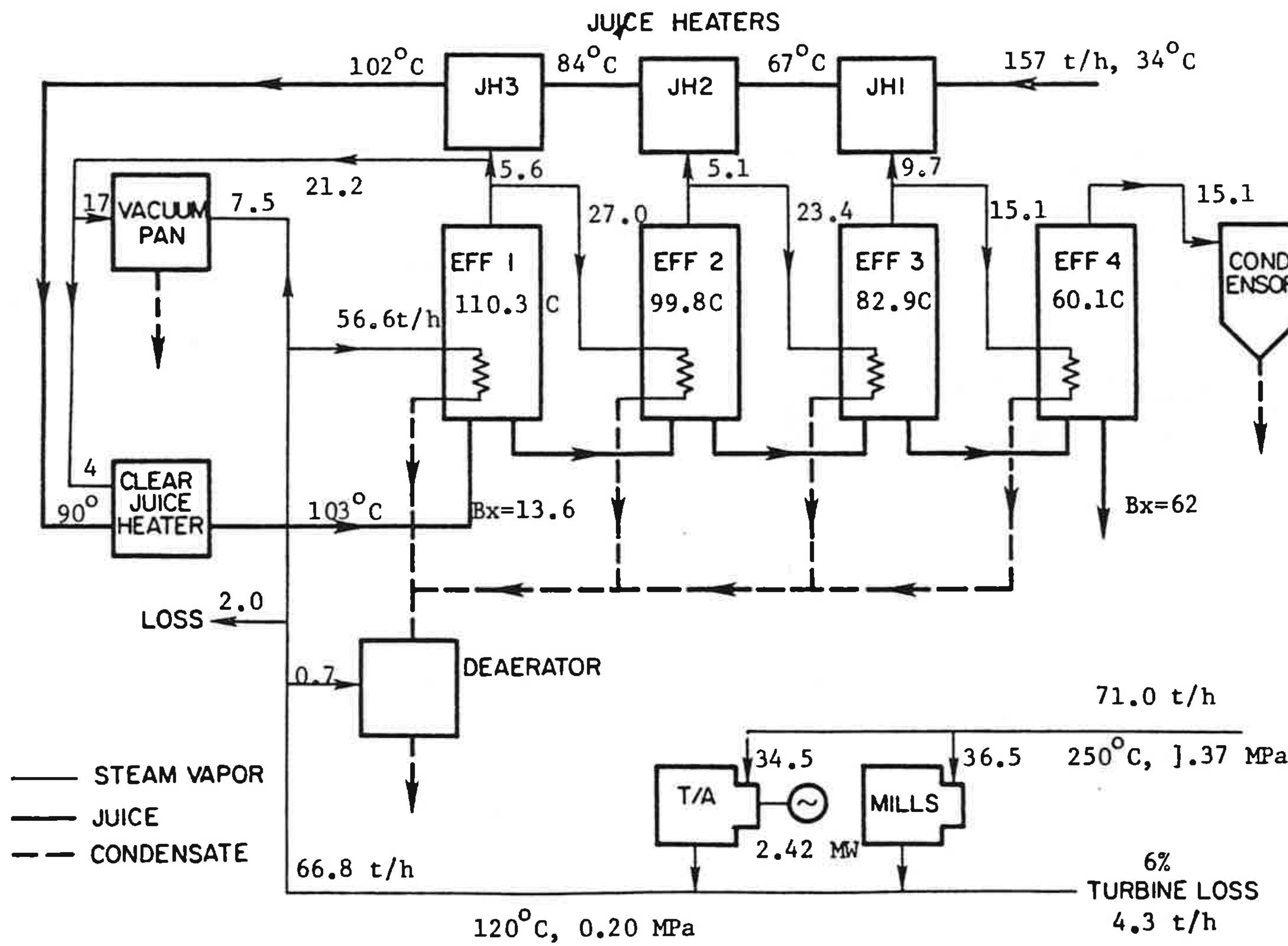
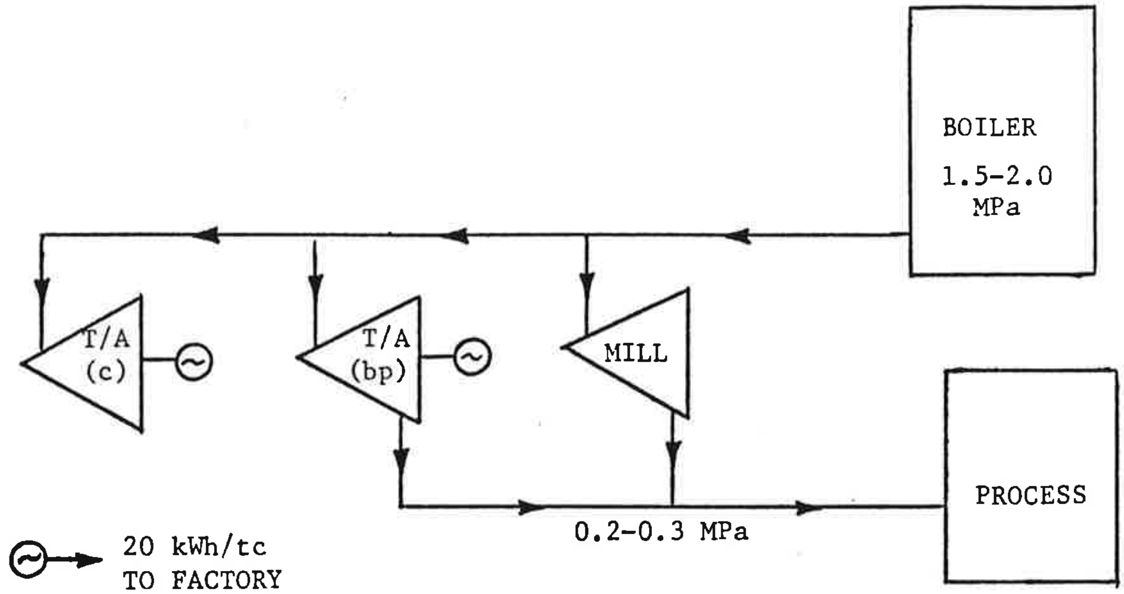
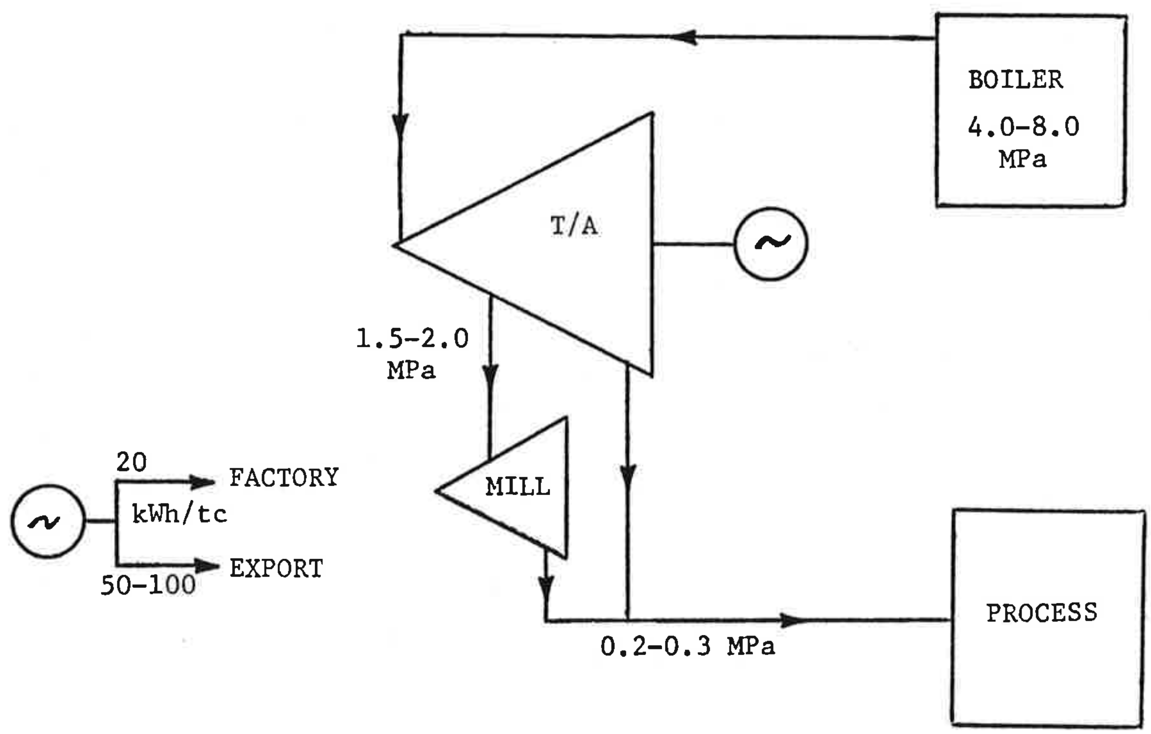


Figure 14. Steam and material flows in a typical conventional raw-sugar factory processing 175 tonnes of cane per hour. (See Table 4 and Appendix G.)



(a)



(b)

Figure 15. (a) Typical steam-turbine cogeneration system existing in many sugar factories today to supply on-site steam and electricity demands (based on the Monymusk Factory in Jamaica) and (b) a larger condensing-extraction steam turbine (CEST) of the type installed in a few factories (e.g. in Hawaii and Reunion), which can export some electricity to the grid.

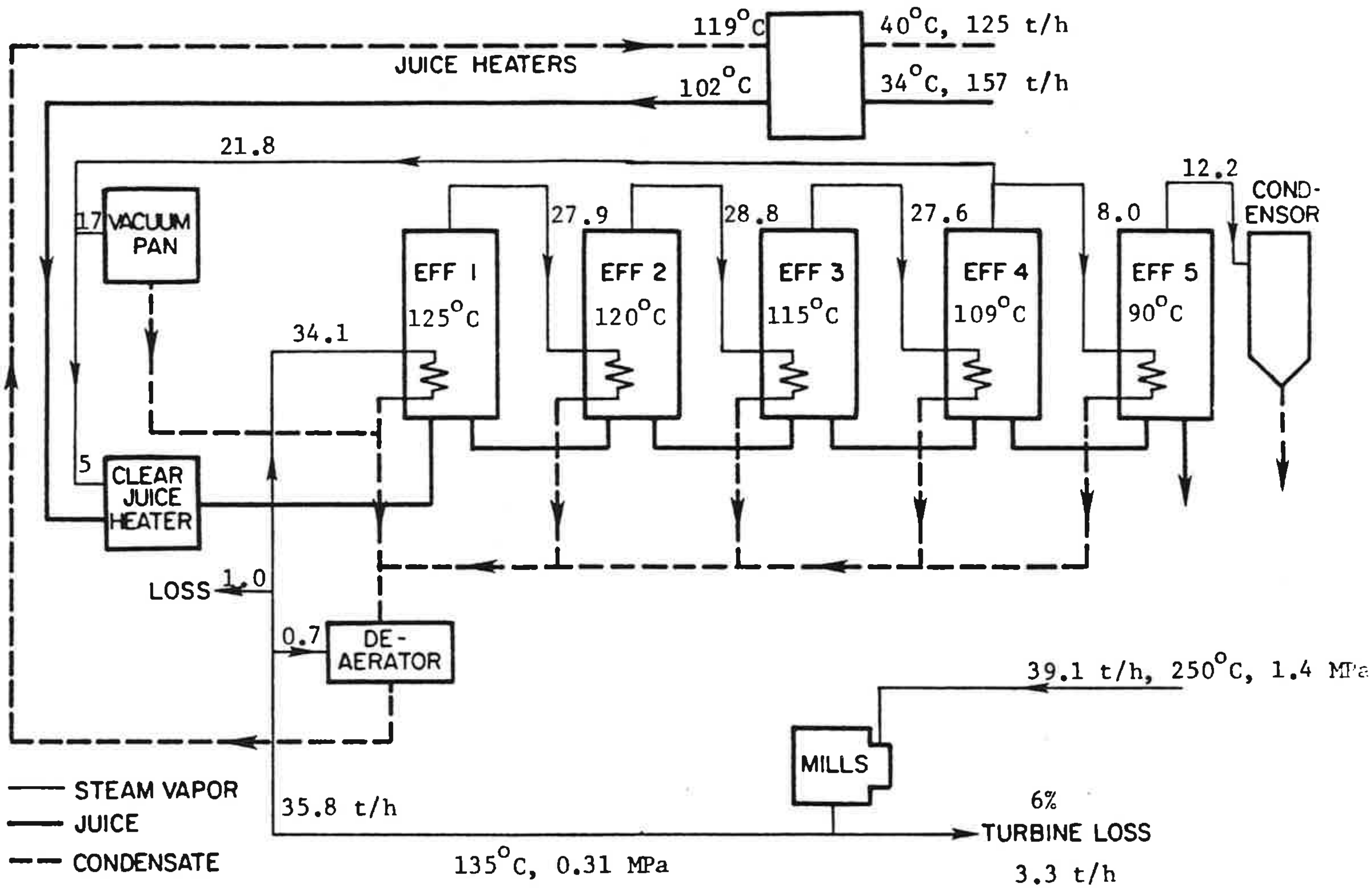


Figure 16. Steam and material flows in a "steam-conserving" raw-sugar factory processing 175 tonnes of cane per hour. (See Table 6 and Appendix G.)

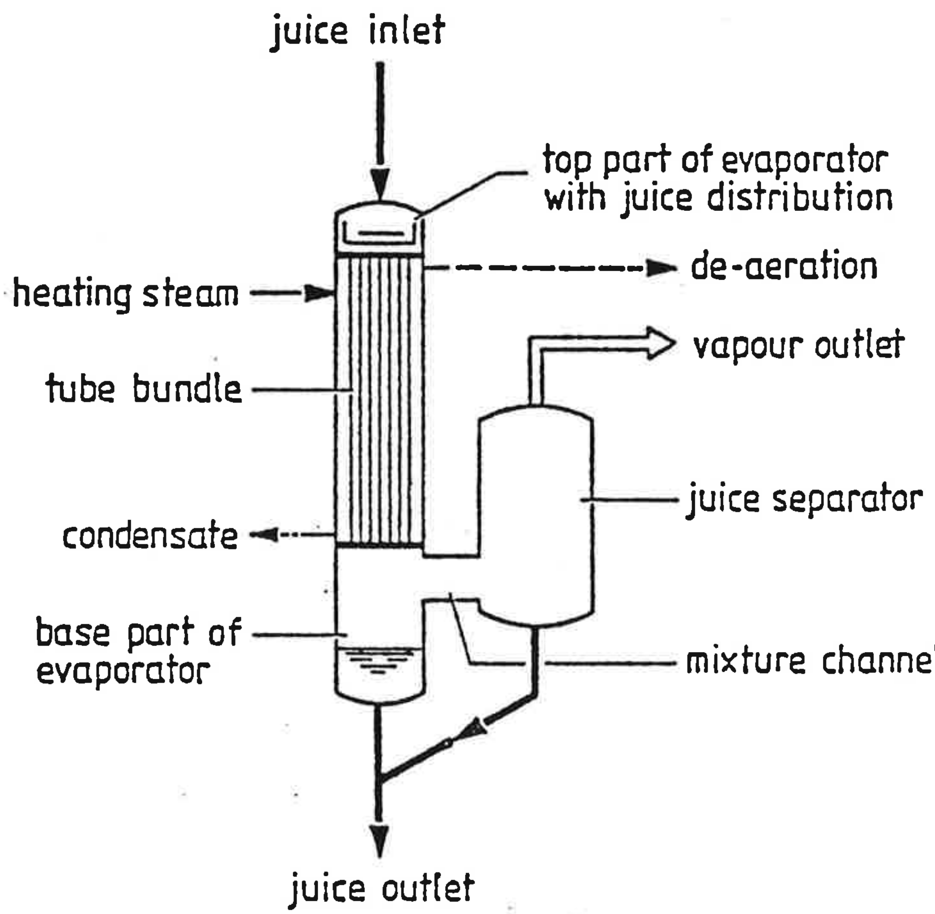


Figure 17. A single effect of a falling-film evaporator.

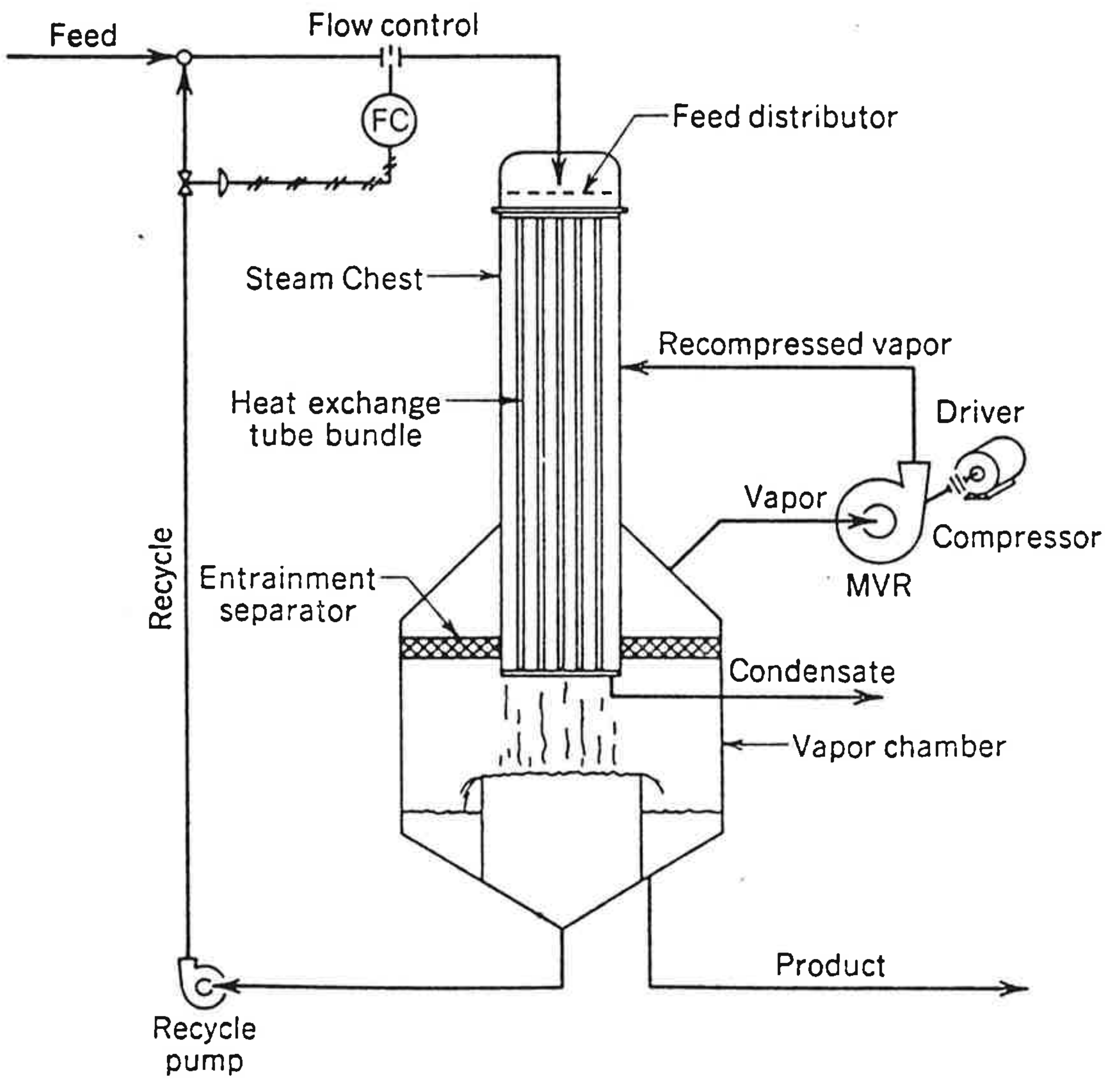


Figure 18. A single-effect falling-film evaporator with mechanical vapor recompression.

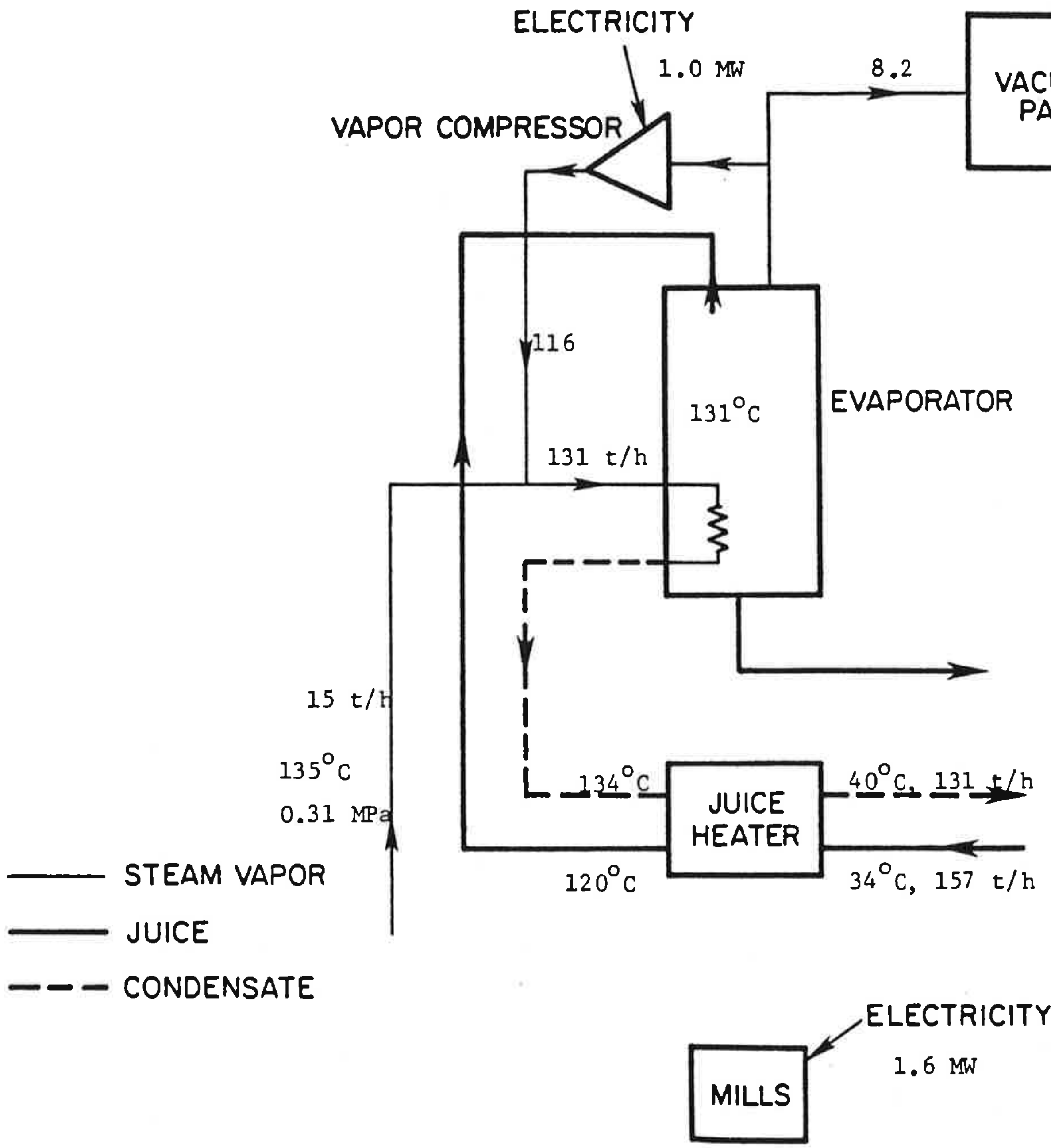


Figure 19. Steam and material flows in an "electrified" raw-sugar factory processing 175 tonnes of cane per hour. (See Table 8 and Appendix G.)

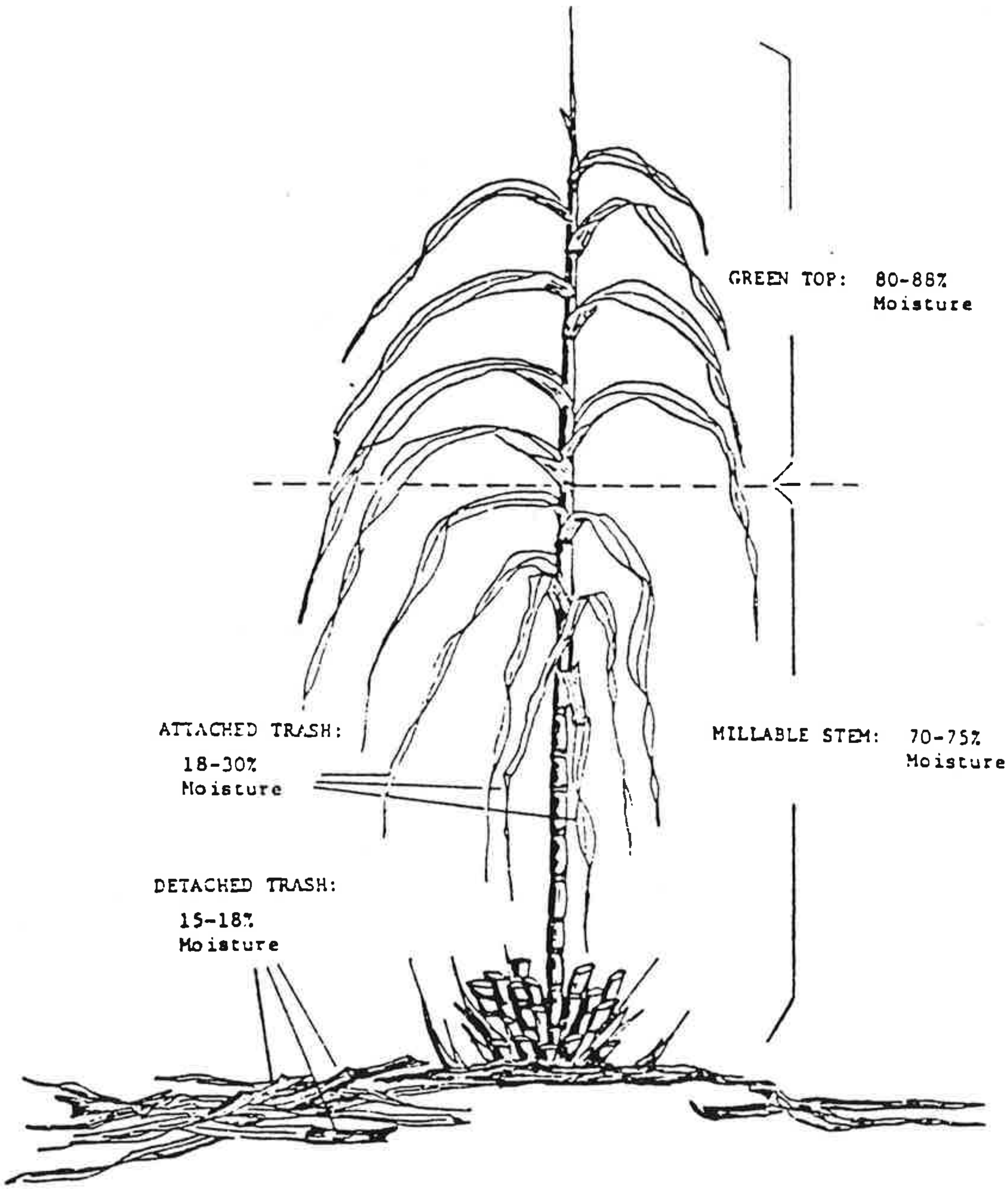


Figure 20. The above-ground components of a ratooned sugar cane plant. Barbojo consists of the green top and all attached and detached trash. From (A.G. Alexander, The Energy Cane Alternative, Elsevier, Amsterdam, 1985).

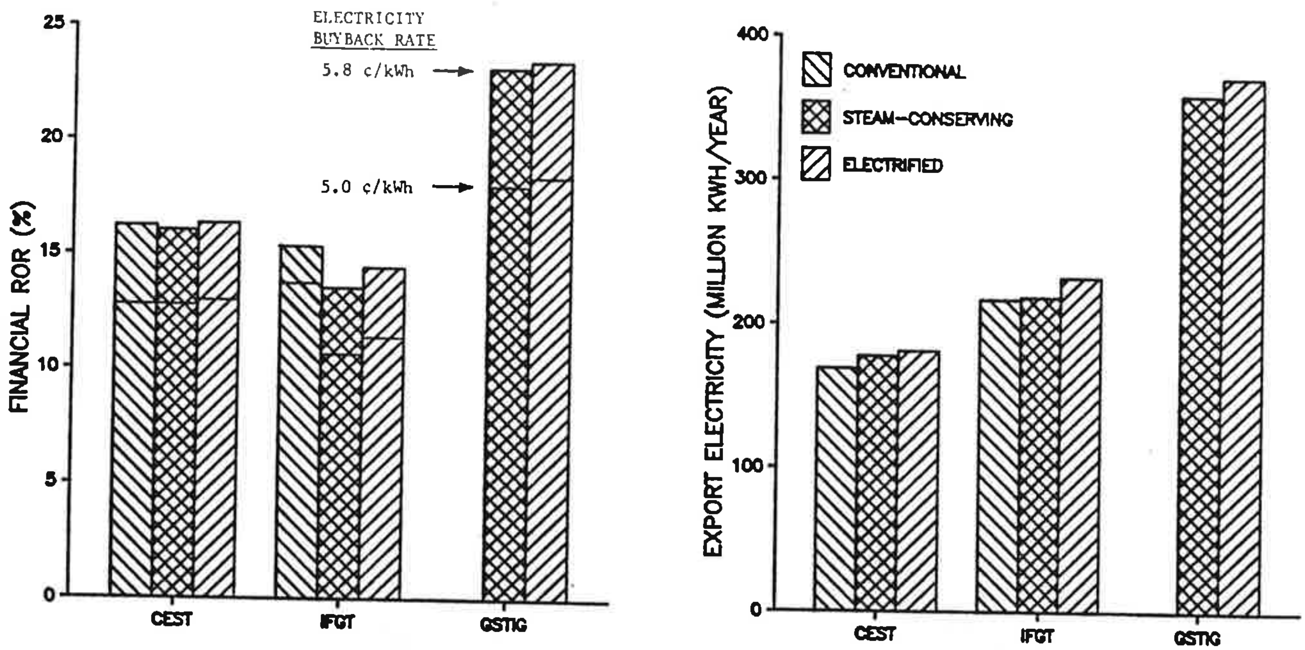


Figure 21. Financial rates of return and annual electricity exports for cogeneration and process-equipment investments at "conventional," "steam-conserving," and "electrified" factories crushing (nominally) 175 tonnes of cane per hour, 206 days/year, with 90% availability. Section 5 describes the factory energy demands and Table 7 gives process-equipment costs. Maintenance and labor costs for the cogeneration plants are given in Table D.4. A thirty-year economic life is assumed for all calculations.

The CEST is a single 27-MW condensing-extraction steam turbine which operates in a plant processing 173 tc/hr. Its installed capital cost is \$42.01 million. It burns no-cost bagasse during the milling season and baled, dried barbojo (\$0.97/GJ) during the off-season. During the milling season, it exports 100, 110, and 115 kWh/tc in conventional, steam-conserving, and electrified factories, respectively.

For the conventional factory, the IFGT consists of one 21.4-MW ASEA-STAL GT-35C and five 3.2-MW Allison 501-K indirectly-fired steam-injected gas turbines. To fuel the 37.4-MW system requires the processing of 173 tc/hr. It exports 127 kWh/tc during the milling season and costs \$71.06 million. For the steam-conserving factory, one less 501-K machine is required. Total capacity is 34.2 MW, the processing rate is 169 tc/hr, the in-season export electricity is 134 kWh/tc, and the investment cost is \$68.10 million. The electrified factory would also use one less 501-K than the conventional factory, would process 180 tc/hr, and would export 144 kWh/tc. In all cases, fuel costs are the same as with the CEST.

The GSTIG is a single LM-5000 (53-MW) gasifier steam-injected gas turbine. It costs \$52.5 million and operates in steam-conserving and electrified factories processing 180 and 194 tc/hr and exporting 222 and 220 kWh/tc, respectively. During the season it burns briquetted bagasse (\$1.16/GJ), and in the off-season it burns briquetted barbojo (\$1.35/GJ).

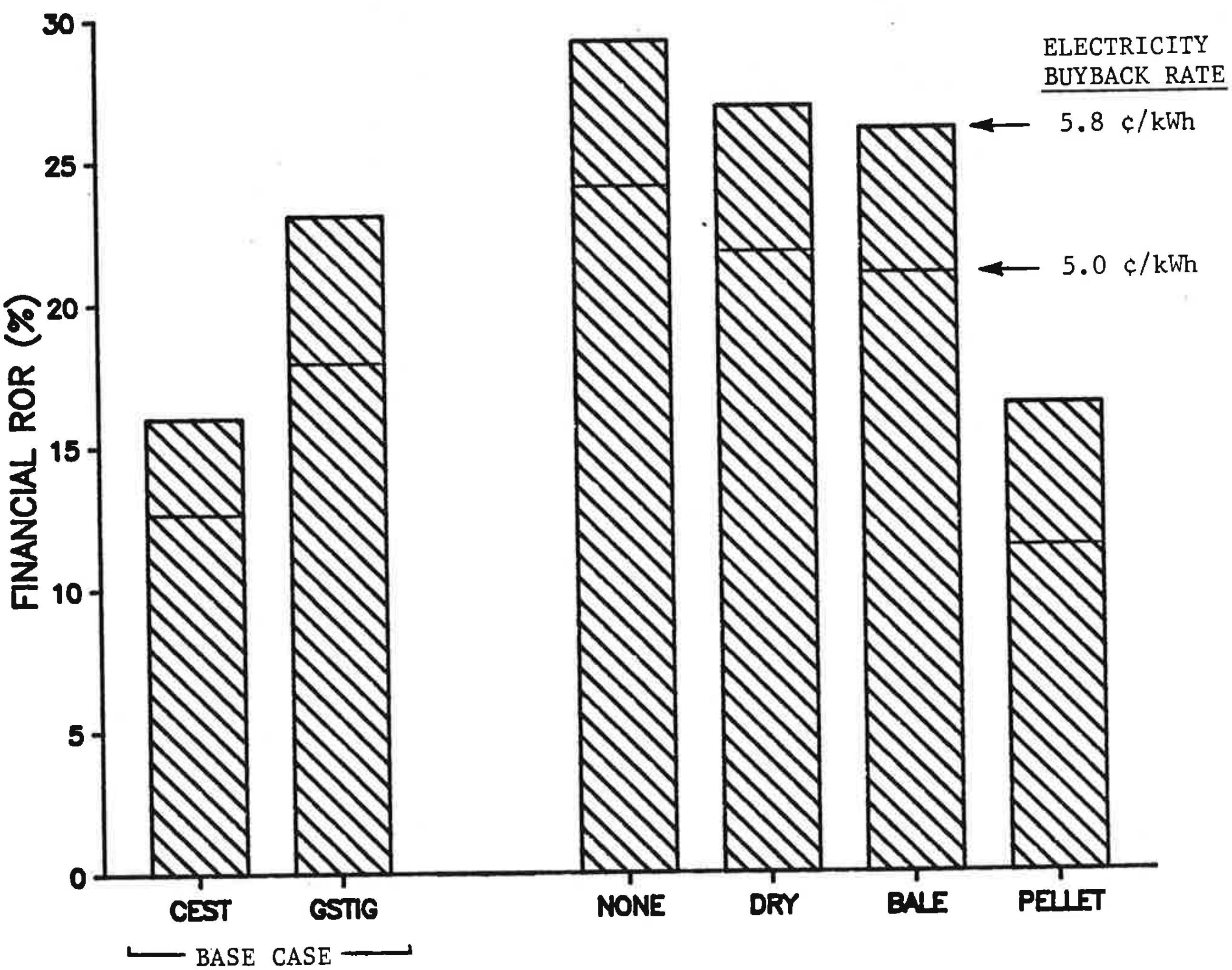


Figure 22. Effect of fuel processing cost on the internal rate of return on an investment in a GSTIG cogeneration plant at a steam-conserving factory.

For the base case, the CEST uses "free" bagasse during the milling season and baled, dried barbojo ($0.97/GJ) during the off-season; the GSTIG uses briquetted bagasse ($1.16/GJ) during the milling season and briquetted barbojo ($1.35/GJ) during the off-season. Costs for alternative levels of processing bagasse and barbojo are given in Table 11.

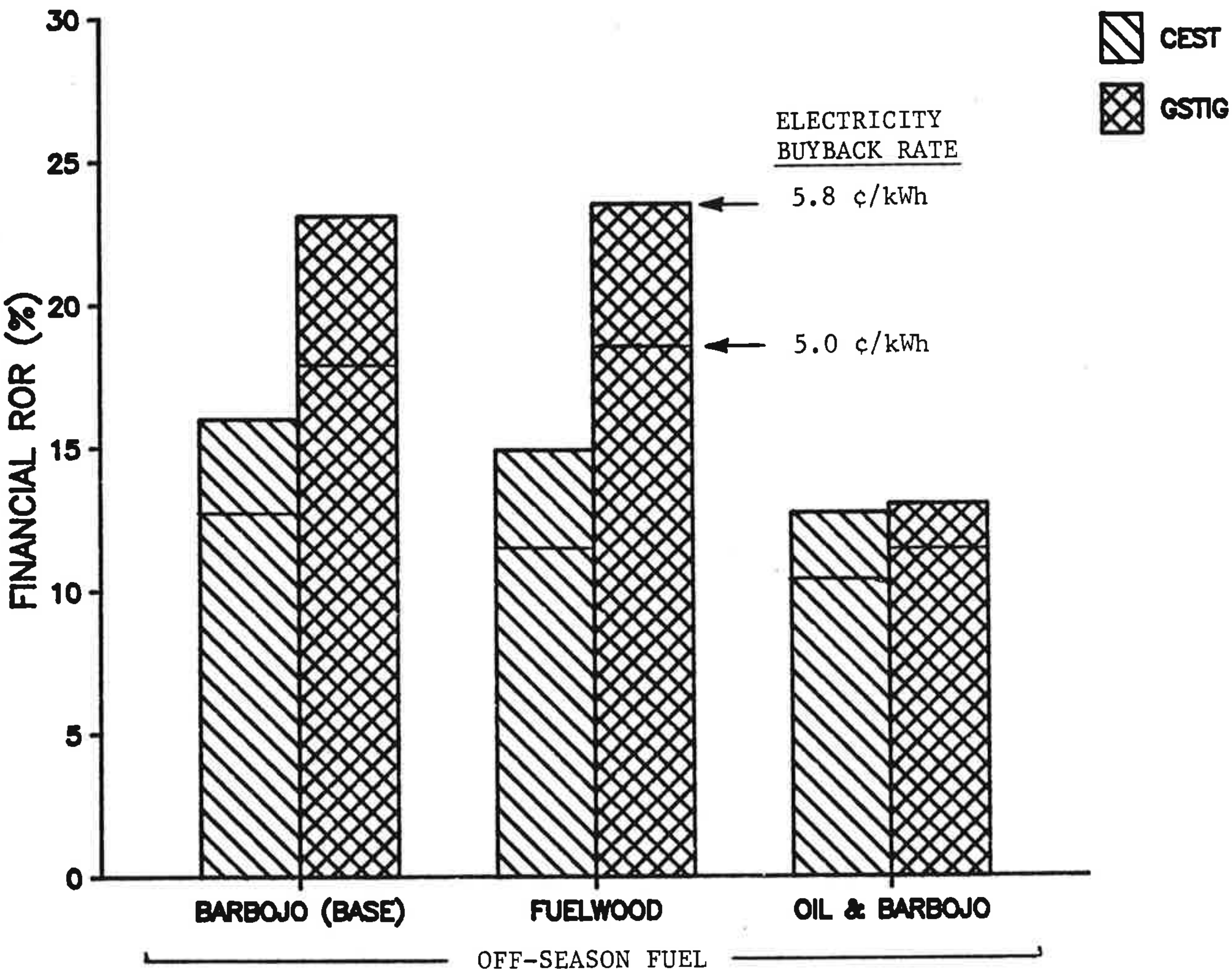


Figure 23. Internal rates of return for steam turbine (CEST) and gasifier-gas turbine (GSTIG) cogeneration plants under alternative off-season fuel scenarios.

The base case corresponds to that shown in Figure 22. FUELWOOD corresponds to the use of plantation fuelwood ($1.25/GJ) during the off-season. OIL & BARBOJO refers to the use of oil during the off-season for the first five years of operation, after which barbojo (processed as in the base case) is used. For the CEST, residual oil costs $2.9/GJ. For the GSTIG, distillate fuel oil costs $5.4/GJ.

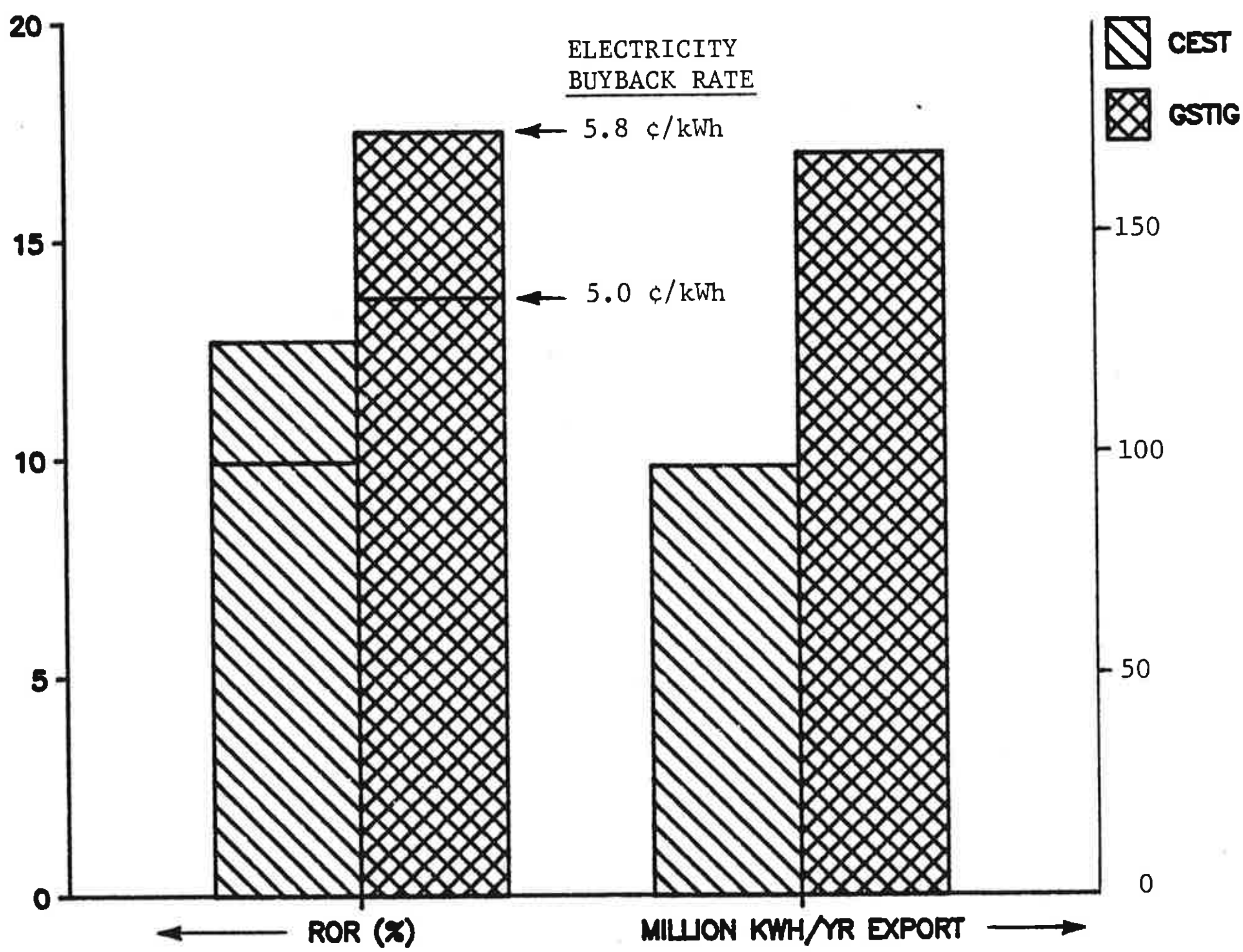


Figure 24. Internal rates of return and annual electricity exports for CEST and GSTIG cogeneration plants undersized relative to the in-season bagasse supply at an electrified factory and operated off-season with stored bagasse. See footnote (dd).

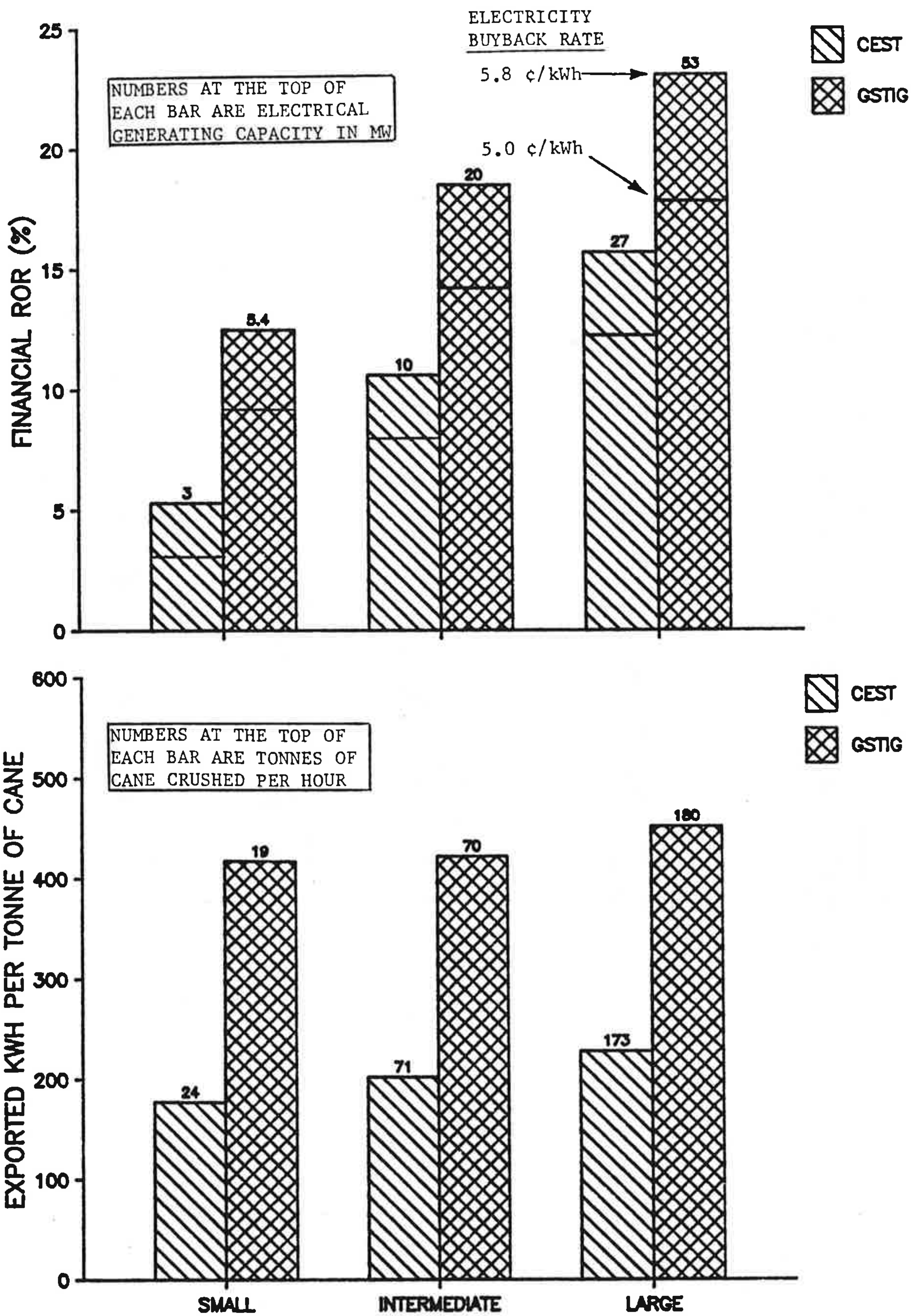


Figure 25. Scale comparisons between CEST and GSTIG cogeneration systems at steam-conserving factories using barbojo (briquetted for the GSTIG) as the off-season fuel. (See Table 14.)

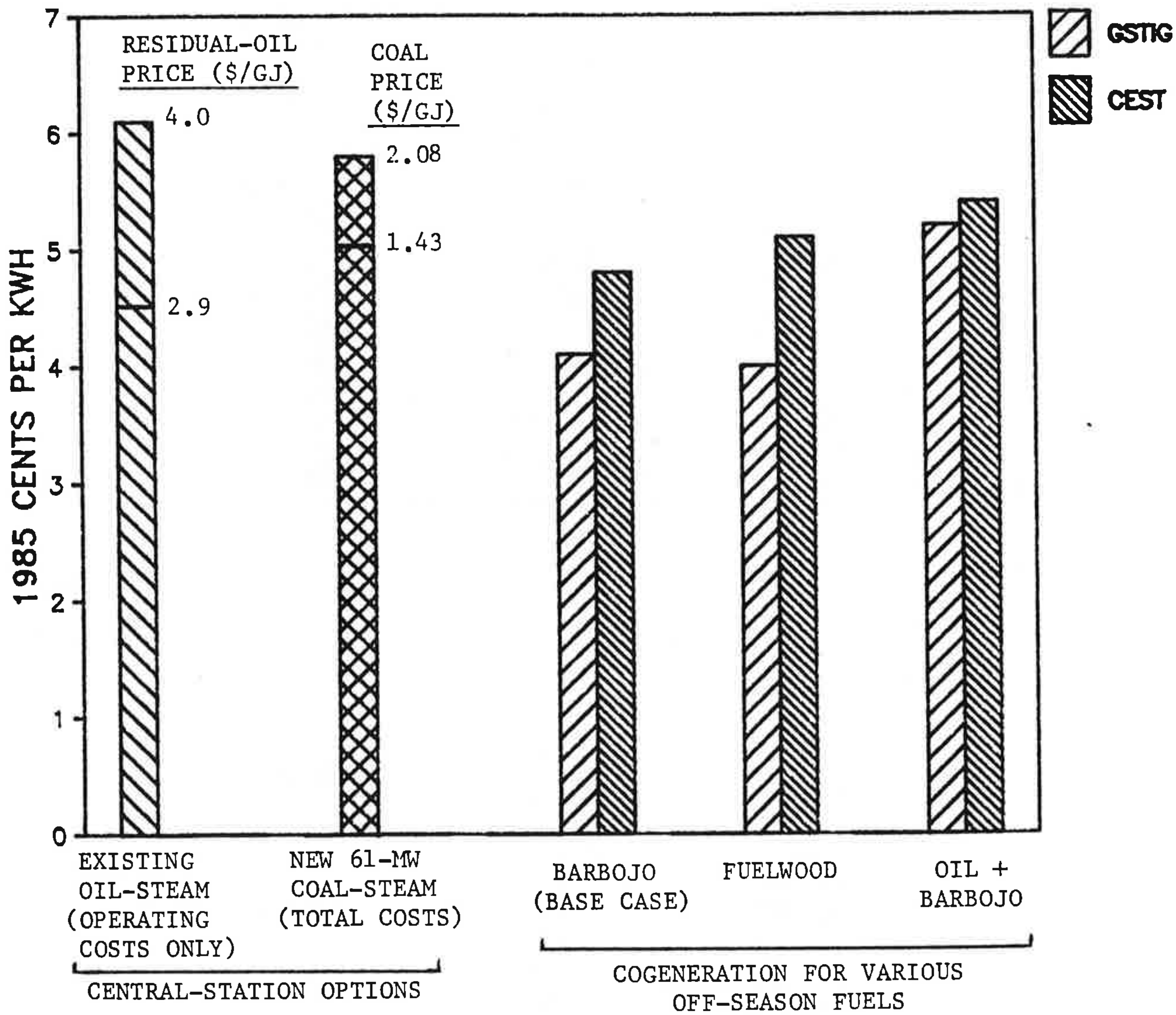


Figure 26. Levelized cost of generating exportable electricity with CEST and GSTIG cogeneration systems at a sugar factory and for two central-station fossil-fuel alternatives in Jamaica: an existing oil-fired steam plant (for which only fuel and O&M costs are shown) and a new 61-MW coal-fired steam plant, identified in the Monenco Study (Montreal Engineering Company, "Least-Cost Expansion Study," for Jamaica Public Service, Ltd., Kingston, 1985) as a least-cost new generating option for Jamaica. The coal prices correspond to coal at $40 and $58 per tonne. The oil prices correspond to oil at $19 and $27 per barrel. A thirty-year economic life and 12% discount rate are used. See Appendix E for details of the fossil-fueled generating cost estimates.

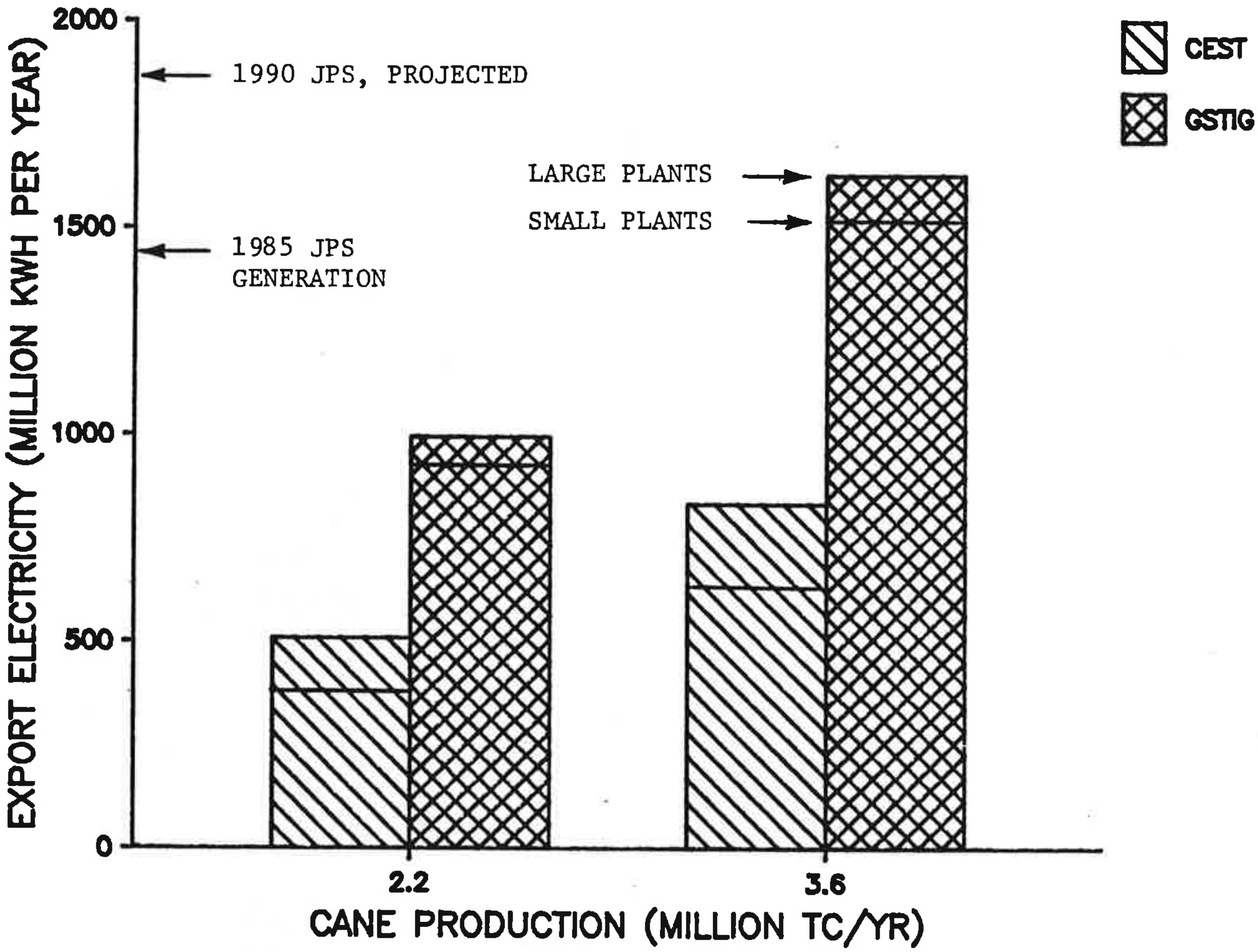


Figure 27. Potential electricity export from sugar factories in Jamaica with CEST and GSTIG cogeneration technologies.

The lower cane production represents a typical 1980s level. The higher level was typical of the mid-1970s. LARGE PLANTS and SMALL PLANTS correspond to the potential generation based on the efficiencies of large and small cogeneration units, respectively, as described in Table 14.

Also shown are the electricity generated in 1985 by the Jamaica Public Service (JPS) electric utility (JPS, Annual Report 1985, Kingston, 1986) and a projection for 1990 (Montreal Engineering Company, "Least-Cost Expansion Study," for JPS, Kingston, Jamaica, 1985).

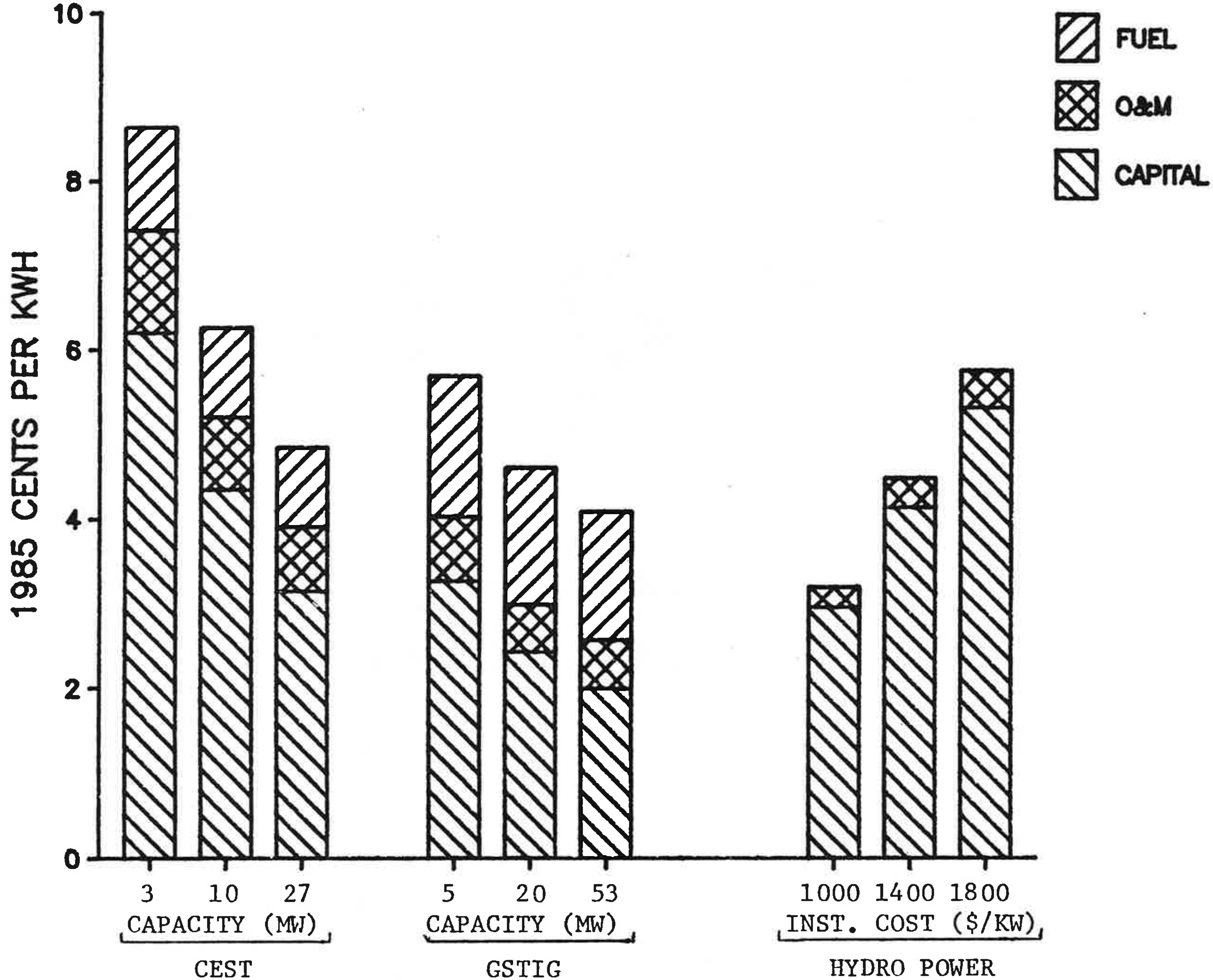


Figure 28 Levelized busbar cost estimates for CEST and GSTIG cogeneration systems in a hypothetical Brazilian sugar factory and for new hydro plants in the Amazon providing electricity to the state of Sao Paulo. (See Table 16.)

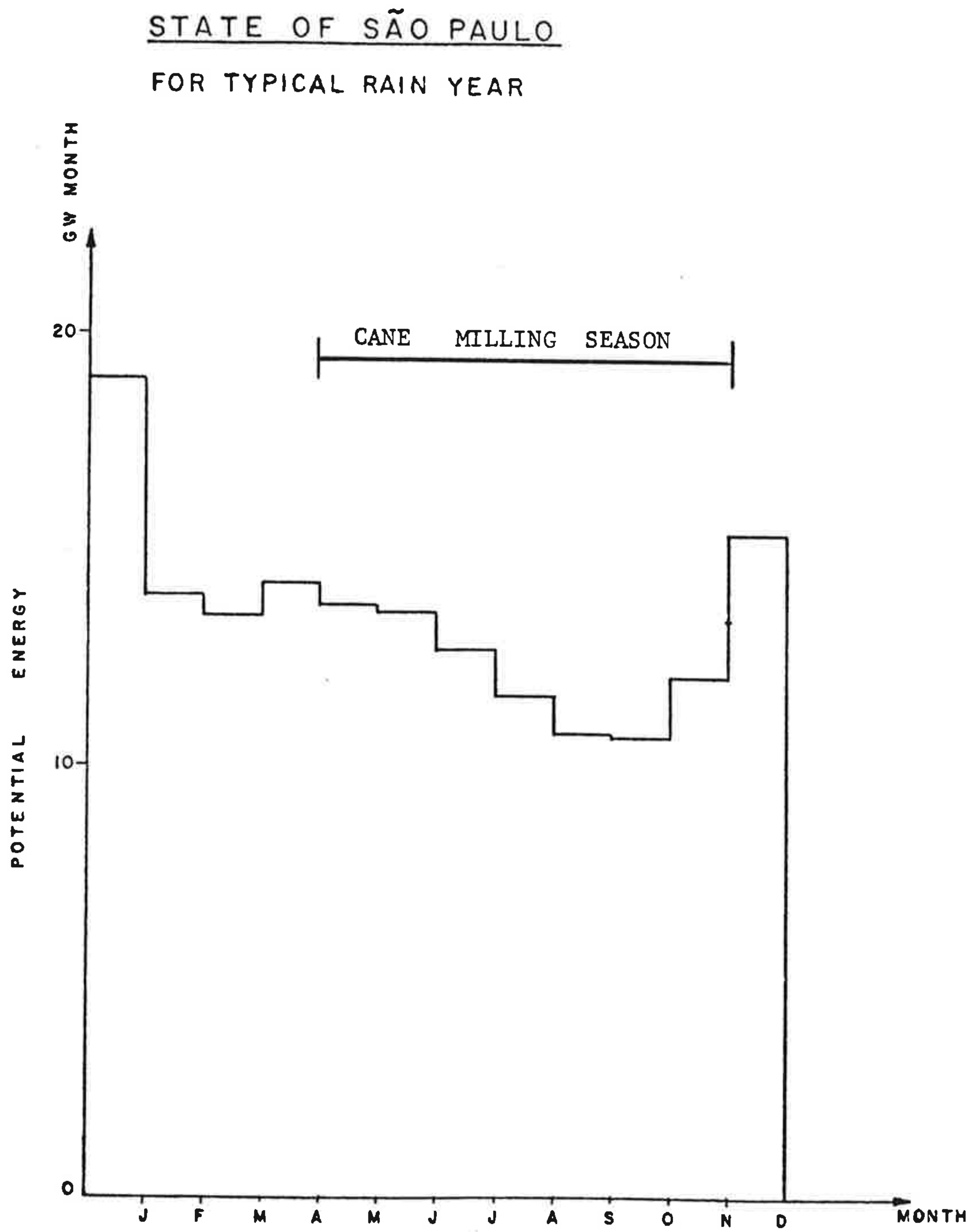


Figure 29 The current hydro-electricity supply "trough" and the sugar cane milling season in the state of Sao Paulo, Brazil (J. Goldemberg, et al., "Country Study--Brazil," Workshop on End-Use Oriented Global Energy Strategies, São Paulo, Brazil, June 1984).

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Appendix A

PERFORMANCE ESTIMATES OF GAS TURBINE SYSTEMS

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Technical performance estimates for indirectly-fired gas turbine cogeneration systems and for systems fired directly with gasified biomass are given in this appendix. Many of the results presented here are based on the application of computer software developed specifically for the present study, as described in Appendix C.

INDIRECTLY-FIRED GAS TURBINE CYCLES

MAJOR CYCLE COMPONENTS

Gas Turbines/Heat Recovery Steam Generators

The engines used in indirectly-fired gas turbine systems today are conventional direct-fired units for which it is possible to replace the combustors with simple ducting (see Figure 13 in the main text) to permit the compressed air to travel through a heat exchanger before returning to the engine and expanding through the turbine. A number of manufacturers offer gas turbines in the relatively small size range appropriate for biomass applications that can be operated with indirect firing (Table A.1). Two engines were chosen for detailed study: The Detroit Diesel Allison (DDA) 501-K and the ASEA-STAL GT-35C.

The Allison 501-K made by the General Motors Company is the ground-based version of the engine used on commercial and military aircraft worldwide (the T-56). It is a compact machine with a very high power-to-weight ratio typical of aircraft-derivative gas turbines. In part because of its small size, and in part because its original design dates back 2-3 decades, the efficiency of the 501-K operating in the simple cycle mode on natural gas is relatively low, about 24%. Table A.2 provides estimated operating characteristics used to calculate the performance of this machine with indirect firing.

The ASEA-STAL GT-35C is designed to operate on a clean fuel at a turbine inlet temperature of 825°C with an efficiency of about 28.7%, making it one of the most efficient engines in the class of engines with a turbine inlet temperature below 850°C. It is an ideal engine to consider for indirect firing, since its design turbine inlet temperature is close to the temperature limit imposed by the heat exchanger material constraints in the indirectly-fired cycle. Table A.2 gives important operating characteristics of this machine with indirect firing which were assumed for purposes of calculation.

Fluidized Bed Combustor-Heat Exchangers

Three basic configurations of atmospheric-fluidized bed combustors are commercially available today: bubbling beds (BFBC), circulating beds (CFBC), and multiple beds (MBFBC). The specific requirements of a given application would determine the system configuration used.

In the bubbling bed, the first type of AFBC developed, uniformly distributed jets of air fluidize the bed, in which are immersed tubes to carry away heat (Figure A.1). The rate of heat removal can be controlled to regulate the bed temperature, allowing operation at low enough temperatures that production of the pollutant NO_x would be largely eliminated. The "free-board" area just above the bed serves as a disengagement zone for most of the entrained material and as a secondary combustion zone for volatile matter evolved near the top of the bed. For boiler applications, a water-wall typically lines the bed and free-board regions to capture radiant energy from the burning material. Above the free-board region are additional tubes to which heat is transferred by convection from the hot combustion product gases.

In a circulating fluidized bed system, combustion occurs in a bed much as in the BFBC, but the velocity of the fluidizing air is high enough that it carries the heated inert material into a second chamber, a cyclone, which separates the particles from the hot combustion products (Figure A.2). The particles are then circulated back into the combustion bed, while the hot gases pass into a convective tube-heating region. For boiler applications, a water-wall lines much of the system. In the CFBC, the heat production rate can be changed by varying the circulation rate of the hot solids. A typical "turndown ratio" for a CFBC is 3:1, which provides a significant advantage over the BFBC in applications where variable output is required.

The multiple-bed design is a hybrid of the BFBC and CFBC. Combustion occurs in a bubbling bed of sand and fuel, from which heat is carried by cooling tubes. The heat output of the bed is regulated by draining hot sand out of the bed and into a storage area as necessary (Figure A.3). The hot combustion products then enter a second bed, designed primarily for sulfur removal. Desulfurization is important when burning coal, but is not required when burning biomass. Exiting the upper bed, the hot gases pass into a convective tube-heating region.

Air temperatures exiting a heat exchanger embedded in an AFBC are limited to about 815^{o}C because of material properties of the metallic heat exchangers. Development and testing of higher-temperature alloys is continuing [1]. Development work is also being done on high-performance ceramics [2], although this option appears a decade or more from pilot-scale testing. Two primary obstacles currently limit the viability of ceramics technology. An adequate system for joining ceramic to metal has not been developed: The different coefficients of expansion of the two materials leads to problems when operating under widely varying temperature conditions. Ceramic heat exchangers have been operated in atmospheric pressure applications, but ceramics of strength adequate to operate in pressurized systems, as required for gas turbines, have not been developed.

In the present analysis, the combustion system in all cases is modeled as a simple bubbling AFBC with some of the air heat exchanger tubes immersed in the bed (in-bed tubes), and some located above the bed (freeboard tubes). See Appendix C for discussion of the computer models developed for this study.

PERFORMANCE CALCULATIONS

A number of candidate cycle configurations considered for sugar factory application have been evaluated. Systems without and with steam injection and/or evaporative cooling are considered, as well as alternative fuels: 50% wet bagasse, dried bagasse, Bagatex-20, and barbojo. Auxiliary equipment items that have been modeled include bagasse driers and condensing heat exchangers, both operating off hot exhaust flows in the system. Many of the more complex cycle configurations were excluded from the detailed financial analysis in the text, based on rough calculations suggesting that they would provide relatively small benefits over simpler systems.

Simple Cycles

Reference Configuration: The calculated performance of a simple-cycle system based on the ASEA GT-35C is described in Figure A.4. In this, as in all calculations for indirectly-fired systems, blow-down from the HRSG has been neglected to simplify the calculations.[1] In ths simple cycle, the exhaust gases from the atmospheric fluidized bed combustor (AFBC) are hot enough (> 400°C) to generate steam to augment that produced in the turbine heat recovery steam generator (HRSG). With 50% wet bagasse as fuel, this cycle would produce about 12.7 MW of electricity, while consuming the bagasse available at a cane milling rate of about 91 tc/hr. The system would convert about 17.5% of the energy in the fuel to electricity, or would produce about 139 kWh per tonne of cane. About 38% of the fuel energy would be converted to steam: superheated high-pressure steam from the turbine HRSG (216 kg/tc) and either saturated low-pressure steam (173 kg/tc) or superheated high-pressure steam (155 kg/tc) from the AFBC steam generator.

The DDA 501-K is a less efficient electricity producer than the ASEA GT-35C and is consequently a better "steamer." In a simple cycle system (Figure A.5), it would produce about 1.7 MW, while consuming about 16 tc/hr. It would convert about 13.3% of the fuel energy to electricity (105 kWh/tc) and about 47% to steam.

With Bagasse Drying: Bagasse with 50% moisture can be burned with little problem in fluidized-bed boilers. However, the latent heat loss associated with the moisture in the combustion products is substantial. One means of improving overall system efficiency would be to utilize some of the AFBC exhaust gases to dry the bagasse before it is burned in the combustor. This process has been modeled in some of the present analysis, assuming direct contact between the gases and the wet bagasse (Table A.3). This relatively efficient mode of heat transfer is used in actual systems operating in sugar mills (e.g. at the Hilo Coast Processing and Hamakua Haina factories in Hawaii).

External Bagasse Treatments: Rather than drying bagasse using exhaust gases from the AFBC, an external drying system could be used. The Bagatex-

[1] The blow-down is typically 2-5% of the HRSG steam flow, so neglecting it here will not introduce significant inaccuracies in these calculations.

20 process [3] is considered in the present analysis. In this process, raw bagasse (typically 50% wet) is baled and sheltered from the weather under a structure designed to produce a natural ventilation flow that will carry away water vapor driven from the bagasse by spontaneous heating (up to about 60-70°C) in the bale cores. After 20 days, the bales reach about 20% moisture and can be stored for extended periods of time. The bales are shredded immediately before they are burned. A Bagatex-20 system, producing 20% wet bagasse at a rate of about 31,000 tonnes per year, has been operating at the Santa Lydia sugar processing plant in the state of Sao Paulo, Brazil for 4 years, and another has operated for 3 years at the San Martino plant in the state of Parana, Brazil.

Table A.4 shows the results of calculations assuming Bagatex at several moisture values is used to fuel reference simple-cycle systems. As in the case of burning bagasse dried with AFBC exhaust gases, the electricity production per tonne of cane increases as the moisture in the fuel is decreased. The rate of improvement slows as the moisture level decreases. In contrast to the case with AFBC-exhaust bagasse drying, (compare Tables A.3 and A.4), steam production per tonne of cane increases when using progressively drier Bagatex.

<u>With Condensing Heat Exchangers</u>: Some exhaust flows in the gas turbine cycles that will be considered carry significant quantities of latent energy in the form of water vapor. Some of this energy can be recovered for low temperature applications, e.g., boiler feedwater or combustion air preheating, through the use of condensing heat exchangers. In addition, condensing heat exchangers can also be effective in reducing pollutant emissions. In fact, this has been the predominant application to date for such units in the United States [4]. Because of the higher temperatures to which air or water can be heated in indirect-contact (compared to direct-contact) condensing heat exchangers [5], a model of these has been used in the present analysis.

When burning 50% wet bagasse, the low-grade energy carried out of the AFBC as latent energy of vaporization in the combustion gases represents a substantial fraction of the input fuel higher heating value (about 24% for the cycle shown in Figure A.4). If a condensing heat exchanger is used to recover some of this energy to preheat either boiler feedwater or combustion air, modest improvements in overall cycle efficiency can be obtained. Since the latent heat is available only at a relatively low temperature (perhaps 70°C), however, the improvement in cycle efficiency would be quite modest. If large quantities of hot water can be utilized in the process, however, condensing heat exchangers may prove more useful.

<u>With Evaporative Cooling</u>: If a lower level of process steam is required, an evaporative cooler can be added to the reference simple-cycle to improve its electrical performance. In an evaporatively-cooled system, water sprayed into the working fluid between the compressor and the AFBC air-heater evaporates, cooling the working fluid, and is carried through the rest of the system. This leads to significantly greater electricity production primarily by two mechanisms: (1) a greater fraction of the heat generated in the AFBC is transferred to the gas turbine cycle working fluid,

since the working fluid enters the AFBC heat exchanger tubes at a lower temperature than in the reference simple cycle, and (2) the water which is evaporated increases the total mass flow of the working fluid through the turbine, boosting the power output, which is a strong function of the turbine mass flow.

Adding evaporative cooling to the ASEA GT-35C reference simple-cycle would increase its electrical output by nearly 70% to 21.4 MW and the fuel consumption rate would increase from 91 to 145 tc/hr (Figure A.6). The net result would be an increase in electrical efficiency from 17.5% to 18.6%. The fraction of fuel energy converted to high pressure process steam, which is limited to that from the turbine HRSG, would decrease from about 38% to 17%.

For the DDA 501-K, the power output would increase from 1.7 MW to about 2.7 MW and the fuel consumption would increase from 16 to about 23 tc/hr (Figure A.7). About 117 kWh/tc of electricity and 242 kg/tc of high pressure steam would be produced.

With Topping Combustors: A topping combustor burning a clean fuel (e.g., distillate fuel oil or natural gas) can be utilized between the exit of the fluidized bed/air heater and the inlet of the turbine to boost the turbine inlet temperature beyond the limit imposed by the AFBC heat exchanger materials. By permitting an engine to run at its rated turbine inlet temperature, the use of topping fuel can lead to substantial increases in power output and an overall increase in efficiency. Figure A.8 shows the estimated performance characteristics of the reference simple-cycle DDA 501-K gas turbine system operating with distillate fuel oil topping. (Compare with Figure A.5.)

Steam-Injected Cycles

The DDA 501-K and the ASEA GT-35C gas turbines can operate with steam injection during periods when process-steam demands fall below the total steam production capability of the cogeneration system. In the off-season, all of the steam generated can be injected, assuming fuel is available to run the system.

Base Case: In the base-case indirectly-fired steam injected gas turbine (STIG), all of the steam generated in the turbine HRSG would be injected into the turbine to increase power production and raise the electrical efficiency. As shown in Figure A.9, an ASEA GT-35C STIG would produce about 17.4 MW of electricity while consuming about 101 tc/hr, corresponding to an electrical efficiency of 21.6% (171 kWh/tc). It would still produce some process steam in the AFBC steam generator, some 143 kg/tc of superheated high-pressure steam or 178 kg/tc of saturated low-pressure steam.

The DDA 501-K STIG would produce about 2.7 MW and require 18.6 tc/hr for fuel (Figure A.10). The corresponding electrical efficiency would be 18.6% (147 kWh/tc), and either 128 kg/tc of superheated steam or 159 kg/tc of saturated steam could be produced in the AFBC steam generator.

With Bagasse Drying: As in the simple-cycle, some or all of the hot AFBC gases can be diverted for drying bagasse, which results in an increase in electrical efficiency (by over 20% in going from 50-20% wet bagasse), but a decrease in process steam production, as described in Table A.5. The changes in performance with decreasing bagasse moisture parallel those of the simple-cycles. (Compare with Table A.3.)

With Bagatex: Also, as in the simple cycle, process-steam production can be maintained by using external drying of the bagasse, e.g., the Bagatex process. As in the case with AFBC-exhaust bagasse drying, the improvements in electrical performance track those of the simple cycle, while process-steam production remains essentially constant (See Table A.6).

With Extra Injection or Evaporative Cooling: If the process steam demand drops to zero during the milling season, two cycle options could be utilized to boost electrical production. In one case, the steam generated using the AFBC exhaust gases could be injected into the STIG -- the extra-injection case (Figure A.11 for the ASEA GT-35C) -- increasing the total amount of steam injected by about 50%, leading to an increase of about 23% in electricity production in the ASEA GT-35C cycle and an increase of about 13% in electrical efficiency compared to the base case STIG cycle (Table A.7). The performance improvement in the DDA 501-K cycle would be somewhat less (Figure A.12).

Alternatively, an evaporative cooler could be used. In this case, the steam injection into the working fluid would occur at an intermediate point inside the heat exchanger so as to take advantage of the cooling effect in the initial section of the heat exchanger, which allows for recovery of the lower temperature heat in the AFBC flue gases. Figure A.13 gives the energy and material balances for a STIG system based on the DDA 501-K with evaporative cooling. Table A.7 compares the performance of the STIG-evaporative cooling cycles to those of the base case STIG and the STIG with extra injection.

Off-Season Operation

During the off-season, the most efficient electricity-producing cycle could be utilized: the STIG with extra steam injection. The high efficiency of this cycle would be augmented if barbojo were the fuel, because it would be relatively dry -- approximately 25% moisture content. Under these conditions, the ASEA GT-35C cycle would produce about 20.7 MW of power at an efficiency of 28.7%, and the DDA 501-K would produce about 3.1 MW at an efficiency of about 23.9% (Table A.8).

STEAM-INJECTED GAS TURBINES FIRED WITH GASIFIED BIOMASS

BACKGROUND

The gasifier steam-injected gas turbines described in the text are based on aircraft-derivative gas turbines manufactured by General Electric (GE). All of GE's aircraft-derivative LM series engines -- LM-5000, LM-

2500, LM-1600, and GE-38 (the GE-38 will be introduced as a replacement to the currently available LM-500 in the early 1990s) -- have the potential to be operated with steam injection. The LM-5000 and LM-2500 fired with natural gas are sold by GE today either as simple-cycle or steam-injected machines. Steam-injected models of the LM-1600 and GE-38 have yet to be commercialized. Table A.9 shows the estimated performance of all four engines in simple-cycle and STIG (steam-injected gas turbine) modes when using natural gas as fuel.

COAL-GSTIG

For the past several years General Electric has been developing systems for firing STIGs with gasified coal. Their work has focussed on a power plant which involves coupling of a commercially-available pressurized Lurgi Mark IV gasifier to the LM-5000 STIG. A system of two coal gasifiers coupled to two LM-5000 STIGs is projected by GE to produce 101 MW_e (net of plant) with an efficiency of 35.6% [6].[2]

Figure A.14 shows the detailed energy and mass balances projected for this system. The LM-5000 STIG portion of the plant consists of a low- and a high-pressure compressor, a combustor, low- and intermediate-pressure turbines (which drive the compressors), and a power turbine (which drives the generator). All exhaust from the power turbine goes to the heat recovery steam generator (HRSG) where steam is raised at two pressure levels for injecting into the STIG and the gasifier. The gasifier blast-steam joins compressed air from a boost compressor before it mixes with coal in the gasifier. The fuel gas from the gasifier passes through a cyclone, a hot sulfur cleanup unit, and a second cyclone before burning in the combustor. A performance summary based on Fig. A.14 for a single coal-gasifier-LM5000 STIG unit is provided in Table A.10.

BAGASSE-GSTIG

The physical configuration of a biomass-GSTIG system would be similar to that of the coal system shown in Fig. A.14, expect that no sulfur removal component would be required. (A simplified diagram of a biomass-GSTIG is shown in Fig. 8 in the text.) Details of the heat and mass flows in the STIG/HRSG portion of the system, which has been modeled by GE engineers [7], are shown in Fig. A.15. No gasification tests have been conducted with bagasse, so the fuel gas composition (and the performance of the gasification plant--not shown in Fig. A.15) were estimated by GE engineers based on a set of limited tests conducted at the GE gasification facility on wood pellets. Testing with bagasse would be required to verify the accuracy of the preliminary estimate given here.

In Fig. A.15, the HRSG thermal input stream labelled "process heating"

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2 A plant based on a single ISTIG (intercooled STIG--see footnote c in the main text) is projected to produce 109 MW_e with an efficiency of 42.1% (Corman, 1986). Since the ISTIG is not yet commercially available, the present analysis is restricted to systems that would be based on STIGs.

represents an estimate of the feedwater preheating that would result from recovery of heat in the air cooler which precedes the boost compressor (not shown) and in the gasifier cooling jacket (not shown). In addition, the gross generator output is shown, which does not account for balance of plant requirements. The major BOP power requirements would include that for the feedwater pump and the boost compressor for the gasifier blast air. The total BOP requirement would be about 2 MW. As with the coal system (Fig. A.14), steam generated at two pressure levels would be injected in both the combustor and exit of the high-pressure turbine, and a significant quantity would be blast steam required by the gasifier. Since only limited biomass gasification tests have been run, the blast steam requirements have been estimated by GE engineers.

A comparison of Tables A.10 and A.11 indicates that the STIG/HRSG portion of the bagasse-based plant would have a performance comparable to that for the coal plant. However, the overall system efficiency with coal (35.6%) would be about 10% higher than that estimated with bagasse (32.5%). The difference is due to the lower estimated gasification efficiency for bagasse, 77%, compared to the value of 85% for coal. Since no empirical determination of the bagasse gasification efficiency has been made, the efficiency estimate used here for biomass was made by GE engineers based on a conservative analysis of very limited data from a short set of gasification experiments they conducted on wood pellets. There would appear to be no inherent reason why the efficiency of gasifying bagasse should not be as high as that for coal. If this were the case, the overall system efficiency for the bagasse system would be over 35%.

For the analysis in the text, overall system efficiency for a 53-MW LM-5000 biomass-GSTIG was assumed to be 32.5%. When process steam is required, both efficiency and power output would drop. Figure A.16 shows the heat and mass flows for an LM-5000 GSTIG system producing 47,700 kg/hr of process steam in the cogeneration mode. In this case, the net power output is estimated to be about 39 MW and overall system efficiency is estimated to be 28.6%.

Table A.12 summarizes the performance estimates used in the present analysis in the text for the LM-5000 operating at a sugar factory, as well as estimates for systems based on the LM-1600 and GE-38. The latter estimates were obtained by comparing the performance of the LM-5000 on natural gas to that on bagasse and applying the percentage differences in output and efficiency to the performances of the LM-1600 and GE-38 on natural gas (as shown in Table A.9).

SUGAR CANE BAGASSE AS A FEEDSTOCK FOR GASIFIERS

Composition: The primary fuel for the biomass-GSTIG system would be bagasse, the composition of which varies by geographic region, by cane variety, and by local agronomic practice. A range of important characteristics of bagasse and bagasse ash are given in Table A.12 and Table A.13, respectively.

Pre-Treatment: Since little work has been done on the pressurized gasification of biomass, it is unclear what pretreatment of the bagasse would be required to make it an acceptable gasifier feedstock. Bagasse-gasification studies at atmospheric pressure indicate that pellets would be the most desirable fuel form [8], primarily because of ease in feeding. But the reduction of fiber size may be the most important effect of pelletization for atmospheric-pressure gasification [9].

The bagasse processing levels considered in the financial analysis in the main text include drying, baling and drying (as in the Bagatex-20 process [10] which is in use at several sugar-processing facilities in Brazil), briquetting, and pelletizing (as in the Woodex process [11] which has been used at the Hamakua Haina Sugar Factory in Hawaii). Bagasse drying and the Bagatex process are described above. Briquetting requires some mechanical power (about 70 kWh per tonne of 12% moisture briquetts, which translates to about 12 kWh per tonne of cane crushed) and low-grade heat. For pelletization, higher pressures (greater than 30 MPa) and more moderate temperatures (150-200^{o}C) are required to melt the waxes and lignin in the bagasse, which act as a glue to hold the pellet together. The final product has a moisture content of 15-18%, and the process requires some 100-120 kWh per tonne of pellet produced or about 19 kWh/tc [12].

Table A.1. Some gas turbines that can be used (or modified for use) in indirectly-fired systems burning biomass.

Manufacturer	Model	Nominal output with direct firing of natural gas (MWe)
Solar Turbines, USA	Saturn	0.8
Solar Turbines, USA	Centaur	2.5
General Motors Co., USA	DDA 501-K	3.3
Nuovo Pignone, Italy	MS-1002	4.5
Mitsui, Japan	SB-30	5.1
Nuovo Pignone, Italy	PG-10	10.4
Mitsui, Japan	SB-60	12.3
ASEA-STAL, Sweden	GT-35C	15.5
Westinghouse Electric Co., USA	W-191	16

Table A.2. Characteristics of the General Motors Detroit Diesel Allison 501-K and the ASEA-STAL GT-35C gas turbines assumed for calculating performance in indirectly-fired cycles.

	DDA 501-K	ASEA STAL GT-35C
Turbine inlet temperature (^{o}C)	815	815
Simple-cycle compression ratio[a]	9.3	12.5
Compressor inlet air mass flow (kg/s)[b]	14.7	90.3
Average compressor adiabatic efficiency	0.83	0.84
Average turbine adiabatic efficiency	0.87	0.945
Average gear box/generator efficiency	0.93	0.93

[a]When steam or water is injected at the compressor exit, as is considered in some cases, the compression ratio will increase due to increased back-pressuring of the compressor [13], which is accounted for in the modeling of the gas turbines.

[b]For modeling purposes, this is assumed constant through the entire engine. In a conventional DDA 501-K operating with a turbine inlet temperature of about 1000^{o}C, some air is bled from the compressor to cool the turbine blades. In the indirectly-fired systems this would probably not be necessary due to the lower turbine inlet temperature.

Table A.3. Calculated performance characteristics of indirectly-fired simple-cycle incorporating bagasse drying to four different levels. The 50% moisture case represents the reference simple cycle.

	ASEA-STAL GT-35C				ALLISON 501-K			
Bagasse (% wet) ===>	20	30	40	50	20	30	40	50
Power Output (MW_e)	12.7	12.7	12.7	12.7	1.68	1.68	1.68	1.68
Fuel (tc/hr)	75.7	78.9	83.6	91.2	13.4	13.9	14.7	15.9
Electricity								
% HHV of fuel	21.2	20.3	19.1	17.5	15.9	15.3	14.4	13.3
kWh/tc	167	160	151	139	125	120	114	105
Steam								
High Pressure[a]								
% HHV of fuel	27	38	39	38	37	46	47	45
kg/tc	261	373	380	371	363	446	453	437
OR								
High Pressure[a]								
% HHV of fuel	27	26	24	22	37	36	34	31
kg/tc	261	250	236	216	363	349	331	305
Low Pressure[b]								
% HHV of fuel	0	13	15	16	0	10	12	14
kg/tc	0	133	159	173	0	107	130	146

[a]Steam conditions: 1.3 MPa, 330°C.

[b]Steam conditions: 0.2 MPa, saturated.

Table A.4. Calculated performance characteristics of indirectly-fired simple-cycle using Bagatex pre-treatment of bagasse. The 50% moisture case represents the reference cycle.

	ASEA-STAL GT-35C				ALLISON 501-K			
Bagatex (% wet) ===>	20	30	40	50	20	30	40	50
Power Output (MW_e)	12.7	12.7	12.7	12.7	1.68	1.68	1.68	1.68
Fuel (tc/hr)	75.7	78.9	83.6	91.2	13.4	13.9	14.7	15.9
Electricity[a]								
% HHV	21.2	20.3	19.1	17.5	15.9	15.3	14.4	13.3
kWh/tc	167	160	151	139	125	120	114	105
Steam								
High Pressure[b]								
% HHV	42	41	40	38	50	49	47	45
kg/tc	409	401	389	371	484	475	460	437
OR								
High Pressure[b]								
% HHV	27	26	24	22	37	36	34	31
kg/tc	261	250	236	216	363	349	331	305
Low Pressure[c]								
% HHV	15	16	16	16	13	13	14	14
kg/tc	161	165	169	173	136	139	143	146

[a]Plant electricity production, which does not include the approximately 1.2 kWh/tc consumed in converting 50% wet bagasse to 20% wet Bagatex.

[b]Steam conditions: 1.3 MPa, 330°C.

[c]Steam conditions: 0.2 MPa, saturated.

Table A.5. Calculated performance characteristics of indirectly-fired steam-injected gas turbine cycle incorporating bagasse drying to four different levels. The 50% moisture level represents the base case cycle.

	ASEA-STAL GT-35C				ALLISON 501-K			
Bagasse (% wet) ===>	20	30	40	50	20	30	40	50
Power Output (MW_e)	17.4	17.4	17.4	17.4	2.75	2.75	2.75	2.75
Fuel (tc/hr)	84.0	87.6	92.9	101.4	15.6	16.2	17.1	18.6
Electricity								
% HHV	26.3	25.1	23.6	21.6	22.4	21.5	20.3	18.6
kWh/tc	207	198	187	171	176	170	160	147
Steam								
High Pressure[a]								
% HHV	0	12	15	15	0	10	12	13
kg/tc	0	116	144	143	0	99	121	128
OR								
High Pressure[a]								
% HHV	0	0	0	0	0	0	0	0
kg/tc	0	0	0	0	0	0	0	0
Low Pressure[b]								
% HHV	0	14	18	18	0	12	15	16
kg/tc	0	138	174	178	0	118	147	159

[a]Steam conditions: 1.3 MPa, 330°C.

[b]Steam conditions: 0.2 MPa, saturated.

Table A.6. Estimated performance characteristics of indirectly-fired steam-injected gas turbine cycle using Bagatex pre-treatment of bagasse. The 50% moisture case represents the base case.

	ASEA-STAL GT-35C				ALLISON 501-K			
Bagatex (% wet) ⟹	20	30	40	50	20	30	40	50
Power Output (MW_e)	17.4	17.4	17.4	17.4	2.75	2.75	2.75	2.75
Fuel (tc/hr)	84.0	87.6	92.9	101.4	15.6	16.2	17.1	18.6
Electricity[a]								
% HHV	26.3	25.1	23.6	21.6	22.4	21.5	20.3	18.6
kWh/tc	207	198	187	171	176	170	160	147
Steam								
High Pressure[b]								
% HHV	15	15	15	15	13	13	13	13
kg/tc	141	143	144	143	129	128	129	128
OR								
High Pressure[b]								
% HHV	0	0	0	0	0	0	0	0
kg/tc	0	0	0	0	0	0	0	0
Low Pressure[c]								
% HHV	16	16	16	17	14	14	15	16
kg/tc	166	170	174	178	149	152	156	159

[a]Plant electricity production, which does not include the approximately 1.2 kWh/tc consumed in converting 50% wet bagasse to 20% wet Bagatex.

[b]Steam conditions: 1.3 MPa, 330°C.

[c]Steam conditions: 0.2 MPa, saturated.

Table A.7. Estimated performance of three indirectly-fired steam-injected gas turbine cycles: base-case, modified for extra steam injection, and modified for evaporative cooling.

Engine ==>	ASEA-STAL GT-35C				DDA 501-K			
		Elec	Electrical			Elec	Electrical	
	Fuel	Prod	Efficiency		Fuel	Prod	Efficiency	
Cycle	tc/hr	MW	%	kWh/tc	tc/hr	MW	%	kWh/tc
Base case	101.4	17.4	21.6	171	18.6	2.75	18.6	147
w/Extra Inj.	109.9	21.4	24.5	195	19.8	3.24	20.6	164
w/Evap. Cool.	158.8	27.6	21.9	174	26.2	4.06	19.5	155

Table A.8. Estimated off-season performance of indirectly-fired steam-injected gas turbine cycles with extra injection, using 25% moisture barbojo for fuel.

Engine	Electricty MW	Barbojo tonnes/hr	Efficiency Percent
ASEA-STAL GT-35C	20.7	17.5	28.7
DDA 501-K	3.1	2.2	23.9

Table A.9. Estimated performance of General Electric LM-series gas turbines in simple and steam-injected cogeneration cycles operating on natural gas.

	----- SIMPLE CYCLE -----			---- STEAM-INJECTED CYCLE ----		
	Electricity		Process Steam	Electricity		Process Steam
Engine	(MW)	(%HHV)	(kg/hr)[g]	(MW)	(%HHV)	(kg/hr)
LM-5000[a,b]	33.1	33.0	47,700	51.4	40.0	0
LM-2500[a,c]	21.2	33.0	34,500	26.3	36.0	0
LM-1600[a,d]	12.8	31.3	21,800	17.8	36.5	0
GE-38[e,f]	3.4	30.6	5,700	5.3	37.1	0

[a]For operation at 15°C ambient temperature at sea level pressure, based on [14].

[b]The LM-5000 operates with a nominal turbine inlet temperature of 1211°C and simple-cycle pressure ratio of 25.3.

[c]The LM-2500 operates with a nominal turbine inlet temperature of 1211°C and simple-cycle pressure ratio of 18.5.

[d]The LM-1600 operates with a nominal turbine inlet temperature of 1241°C and simple-cycle pressure ratio of 22.5.

[e]The GE-38 will be introduced commercially in the early 1990s to take the place of the less efficient and more costly (but currently available) LM-500. The GE-38 is projected to operate with a nominal turbine inlet temperature 1204°C and simple-cycle pressure ratio of 23. For comparison the LM-500 simple-cycle cogeneration system operates with a nominal turbine inlet temperature of 1116°C and simple-cycle pressure ratio of 14.2. Firing natural gas, it produces about 3.7 MW at 26.6% efficiency and about 8,200 kg/hr of process steam.

[f]Simple-cycle performance is based on [15]. The performance improvement with steam-injection is assumed to be the same as with the LM-5000, since both are high pressure ratio machines with similar turbine inlet temperatures.

[g]Steam at 2 MPa, 316°C.

Table A.10. Performance projected by General Electric for a coal-GSTIG unit based on the LM-5000 gas turbine and a Lurgi Mark-IV gasifier.[a]

GASIFIER (Lurgi Mark-IV)			
Feedstock			
	Coal type		Illinois #6
	Higher heating value (kJ/kg)		25,011
	Flow rate (tonnes/hr)		20.4
Gas Production			
	Composition (Mole %)	N_2	31.39
		CO_2	14.25
		Ar	0.37
		CO	4.81
		H_2	18.62
		CH_4	3.22
		H_2O	27.10
		NH_3	0.20
		T/O/P	0.04
		H_2S	10 ppmV
	Higher heating value (kJ/kg)		4,565
	Lower heating value (kJ/kg)		4,055
	Temperature (°C)		640
	Flow rate (tonnes/hr)		94.9
Gasification Efficiency (HHV)			
	Chemical energy out / Feedstock energy in		0.849
STEAM-INJECTED GAS TURBINE/HRSG (LM-5000 STIG)			
Fuel Input			
	Higher heating value (kJ/kg)		4,565
	Lower heating value (kJ/kg)		4,055
	Flow rate (tonnes/hr)		94.9
Electrical Output			
	Gross output (MW)		52.41
	Balance of plant demand (MW)		1.917
	Net output (MW)		50.49
STIG/HRSG Efficiency (HHV)			
	Net electricity out / Chemical energy in gasified coal		0.419
OVERALL EFFICIENCY (HHV)			0.356
NET ELECTRICAL OUTPUT (MW)			50.49

[a] From [16].

Table A.11. Preliminary performance estimates for a 53-MW bagasse-fired GSTIG.[a]

GASIFIER		
Feedstock		
Briquetted bagasse (15% moisture)[b]		
Higher heating value (kJ/kg)		16,166
Flow rate (tonnes/hr)		36.4
Gas Production		
Composition (Mole %)[c]	N_2	27.13
	CO_2	12.05
	CO	15.72
	H_2	11.90
	CH_4	4.65
	H_2O	27.81
(surrogate for tars)	C_2H_4	7.10
	H_2S	0.0003
Higher heating value (kJ/kg)		5,522
Lower heating value (kJ/kg)		5,099
Temperature (^oC)		600
Flow rate (tonnes/hr)		82.3
Gasification Efficiency	(HHV)	
$\frac{\text{Chemical energy out}}{\text{Feedstock energy in}}$		0.772
STEAM-INJECTED GAS TURBINE/HRSG		
Fuel Input		
Higher heating value (kJ/kg)		5,522
Lower heating value (kJ/kg)		5,099
Flow rate (tonnes/hr)		82.3
Electrical Output		
Gross output (MW)		55.1
Balance of plant demand (MW)		2.0
Net output (MW)		53.1
STIG/HRSG Efficiency	(HHV)	
$\frac{\text{Net electricity out}}{\text{Chemical energy in gasified bagasse}}$		0.421
OVERALL EFFICIENCY (HHV)		0.325
NET ELECTRICAL OUTPUT (MW)		53.1

[a]From [17] unless otherwise noted.

[b]Assuming the typical bagasse composition given in Table A.13.

[c]Estimated based on results of trial wood-pellet gasification tests performed at the GE gasification test facility [18].

Table A.12. Estimated performance of the General Electric LM-Series gas turbines when fired with gasified bagasse in simple-cycle and steam-injected modes.

Engine	Fuel Consumption[a] (tc/hr)	Fuel Consumption[a] (MW)	Net Electricty Prod. (MW)	Net Electricty Prod. (%HHV)[b]	Net Electricty Prod. (kWh/tc)	Process Steam (kg/hr)[c]	Process Steam (kg/tc)
SIMPLE CYCLE							
LM-5000	172	137	39[d]	28.6[d]	227	47,700[c]	277
LM-1600	70	55	15	27.1	214	21,800	311
GE-38	19	15	4.0	26.5	211	5,700	300
STEAM-INJECTED CYCLE							
LM-5000	205	163	53[d]	32.5[d]	259	0	0
LM-1600	82	65	20	30.8	244	0	0
GE-38	23	18	5.4	30.1	235	0	0

[a]Assuming each tonne of cane crushed provides 176 kg of bagasse fuel [15% moisture, 16,166 kJ/kg (HHV)]

[b]This efficiency is defined as net electricity produced divided by the higher heating value of the raw bagasse fuel.

[c]Steam at 2 MPa, 316°C.

[d]Based on [19].

Table A.13. Characteristics of milled-sugar-cane bagasse.[a]

Physical Composition (%, wet basis)	Minimum	Maximum	Typical
Moisture	46	52	50.0
Fiber	43	52	47.0
Sugar	2	6	1.5
Ash	1	7	1.5
Proximate Analysis (%, dry basis)			
Volatiles	65	83	74.0
Fixed carbon	13	24	23.0
Ash	2	13	3.0
Ultimate Analysis (% dry basis)			
Carbon	43	47	45.0
Oxygen	37	47	46.0
Hydrogen	5	7	6.0
Nitrogen	0.1	0.3	-
Sulfur (ppm)	-	300	-
Higher Heating Value (MJ/kg)			
Dry	18.0	19.5	19.1
Wet[b]			
Apparent Density (kg/m^3)			
Stacked	160	240	-
Loose	80	120	-

[a]Based on [20,21,22,23].

[b]A number of formulas have been developed to calculate the heating value of wet bagasse [24], e.g. Hessey's formula for the higher heating value of raw bagasse in MJ/kg is HHV = 19.378 - 5.140*s - 19.020*w), where s is the percent sugar fraction (wet basis) and w is the percent moisture fraction (wet basis).

Table A.14. Composition of sugar-cane bagasse ash.[a]

Component (% by weight)	Minimum	Maximum	Typical[b]
SiO_2	56.1	82.5	71.4
K_2O	4.6	13.4	11.0
CaO	3.0	8.2	4.3
MgO	0.3	5.1	3.8
P_2O_5	1.7	3.4	3.4
Fe_2O_3	0.9	7.8	1.9
Al_2O_3	0.5	7.6	1.6
Na_2O	0.8	3.4	0.8
MnO	0.1	0.3	-
Fusion Temperature (^oC)	1210	1350	

[a]From [25].

[b]For Mauritius [26].

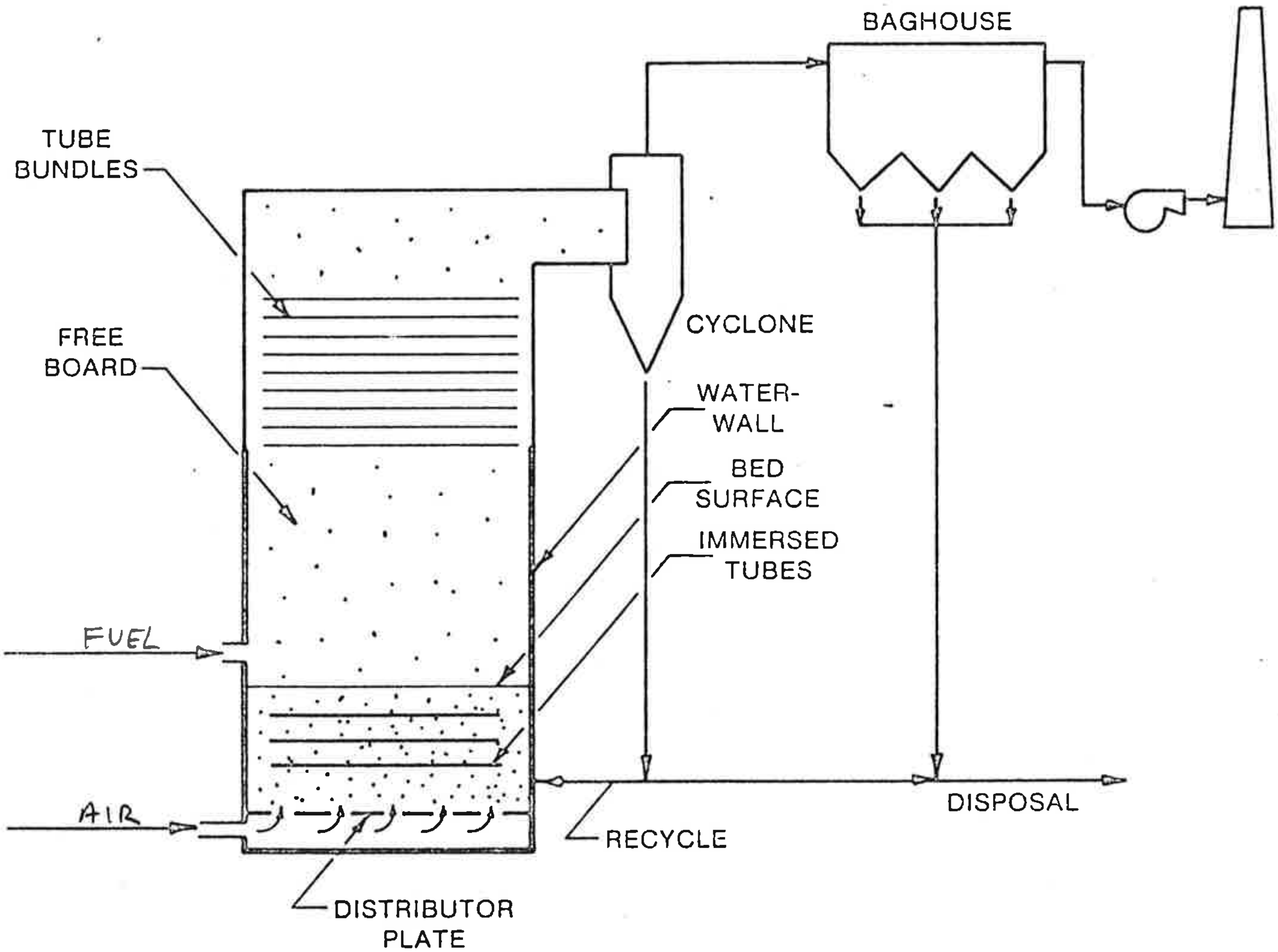


Figure A.1. Bubbling fluidized bed combustor (boiler application).

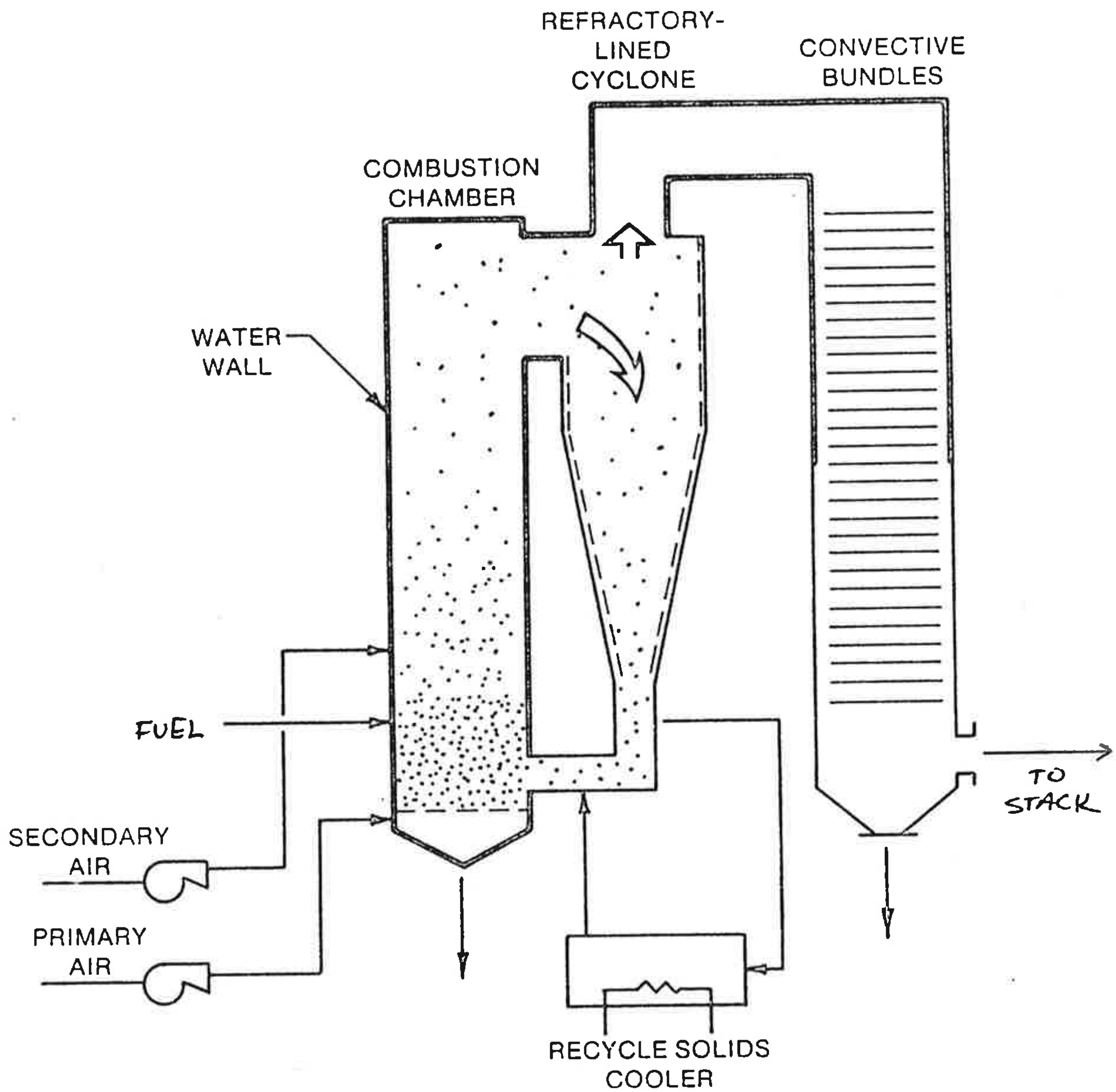


Figure A.2. Circulating fluidized bed combustor
(boiler application)

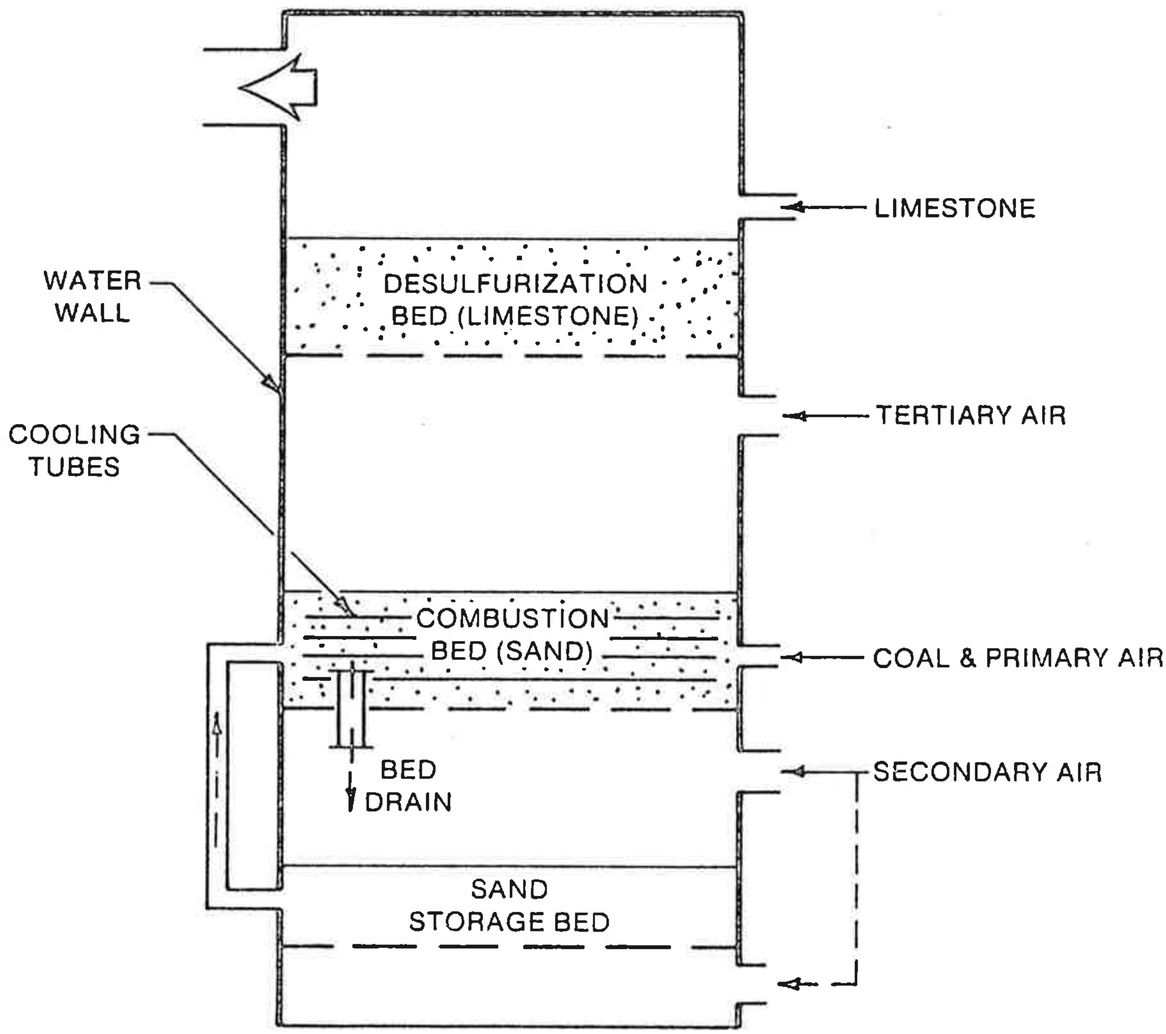


Figure A.3. Multiple-bed fluidized bed combustor (boiler application).

FIGURE A.4

SIMPLE GAS TURBINE CYCLE
Full-Load Performance Characteristics
(Based on the ASEA-STAL GT-35C engine)

Electrical output : 12651 kW
Bagasse consumption (@ 50% moisture) : 27.4 tonnes/hour
Cane consumption (@ 15% fiber) : 91.2 tc/hr
Per tonne of cane production:
    Electricity : 139 kWh/tc
    Process Steam : 354 kg/tc @ 1.3 MPa, 330°C
    OR
    216 kg/tc @ 1.3 MPa, 330°C
    173 kg/tc @ 0.2 MPa, Sat.
Percent of fuel higher heating value converted to
    Electricity : 17.5%
    Steam : 38.4%
Consumptive water requirements per tonne of cane : 0 kg/tc

State	Temperature (°C)	Pressure (MPa)	Flow (kg/s)	Moisture (kgH2O/kgDRY)	Notes
1	25	0.101	90.3	0	air
2	392	1.266	90.3	0	air
3	815	1.178	90.3	0	air
4	337	0.105	90.3	0	air
5	174	0.101	90.3	0	air
6	70	1.30	5.51	---	feedwater
7	330	1.30	5.51	---	process steam
8	25	0.101	7.89	1.0	50% wet bagasse
9	25	0.101	24.5	0	combustion air
10	150	0.101	32.3	0.235	combustion products
11	70	1.30	3.88	---	feedwater
12	330	1.30	2.04	---	process steam

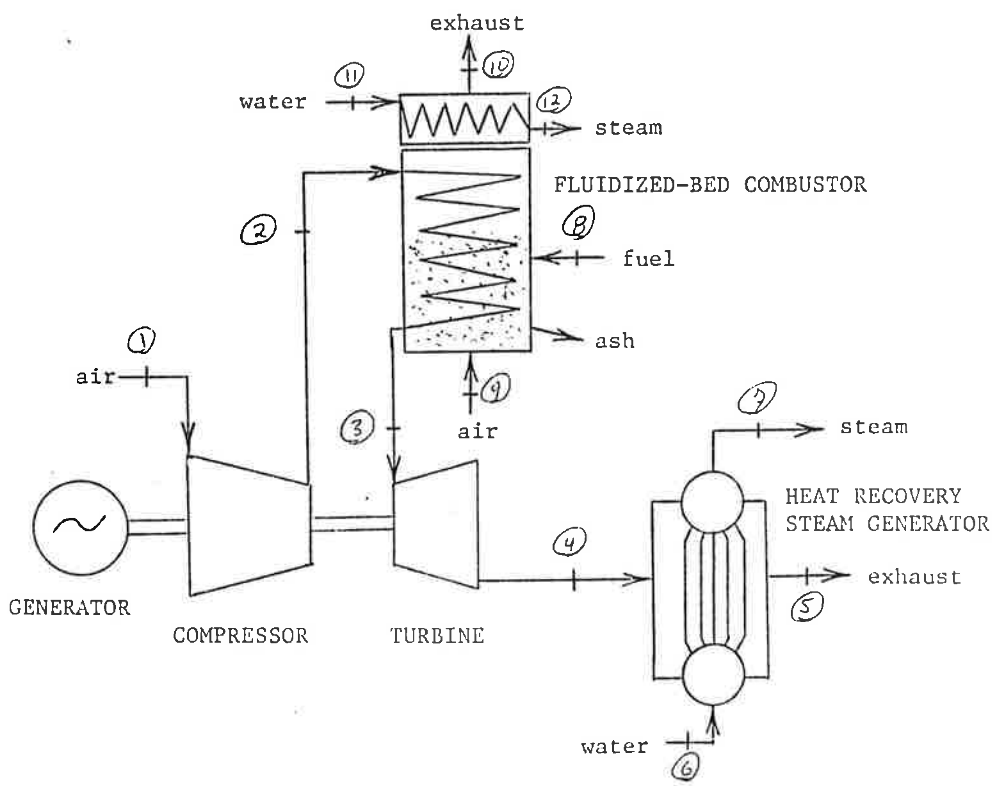


FIGURE A.5

SIMPLE GAS TURBINE CYCLE
Full-Load Performance Characteristics
(Based on the Detroit Diesel Allison 501-K engine)

Electrical output : 1,678 kW
Bagasse consumption (@ 50% moisture) : 4.77 tonnes/hour
Cane consumption (@ 15% fiber) : 15.9 tc/hr
Per tonne of cane production:
  Electricity : 105 kWh/tc
  Process Steam : 437 kg/tc @ 1.3 MPa, 330°C
  OR
  305 kg/tc @ 1.3 MPa, 330°C
  146 kg/tc @ 0.2 MPa, Sat.
Percent of fuel higher heating value converted to
  Electricity : 13.3%
  Steam : 47.4%
Consumptive water requirements per tonne of cane : 0 kg/tc

State	Temperature (°C)	Pressure (MPa)	Flow (kg/s)	Moisture (kgH2O/kgDRY)	Notes
1	25	0.101	14.7	0	air
2	337	0.942	14.7	0	air
3	815	0.876	14.7	0	air
4	418	0.105	14.7	0	air
5	159	0.101	14.7	0	air
6	70	1.30	1.35	---	feedwater
7	330	1.30	1.35	---	process steam
8	25	0.101	1.33	1.0	50% wet bagasse
9	25	0.101	4.12	0	combustion air
10	152	0.101	5.45	0.235	combustion products
11	70	1.30	0.59	---	feedwater
12	330	1.30	0.59	---	process steam

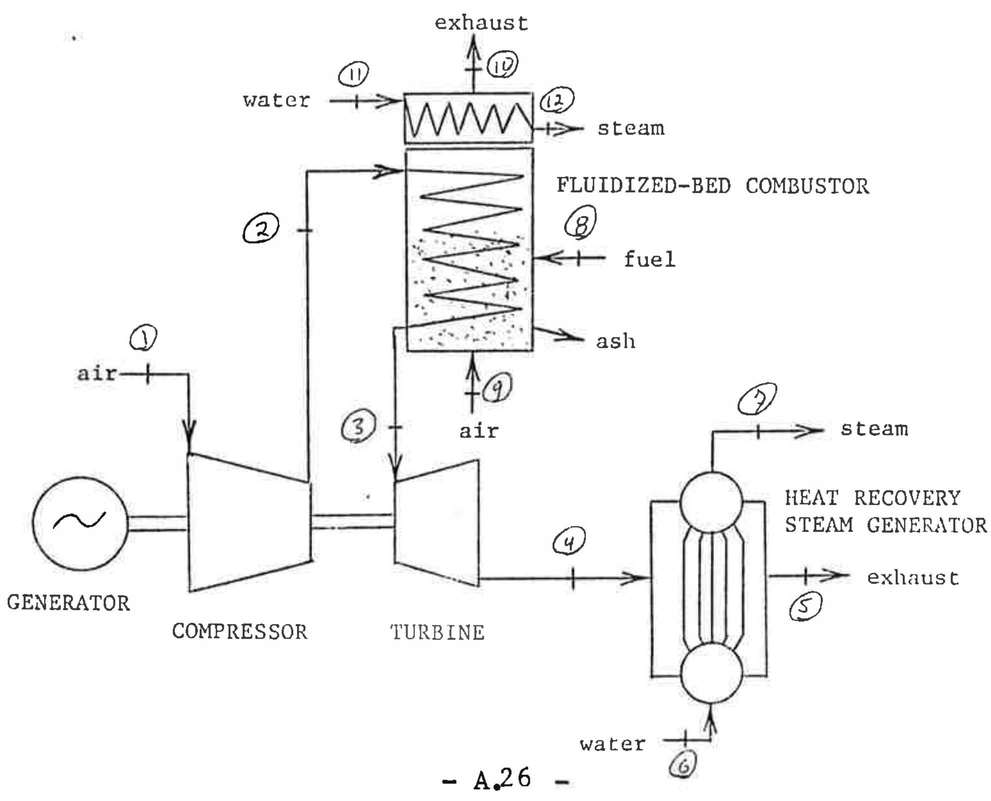


FIGURE A.6

SIMPLE GAS TURBINE CYCLE WITH EVAPORATIVE COOLER
Full-Load Performance Characteristics
(Based on the ASEA-STAL GT-35C engine)

Electrical output : 21397 kW
Bagasse consumption (@ 50% moisture) : 43.4 tonnes/hour
Cane consumption (@ 15% fiber) : 144.6 tc/hr
Per tonne of cane production:
  Electricity : 148 kWh/tc
  Process Steam : 156 kg/tc @ 1.3 MPa, 330°C
Percent of fuel higher heating value converted to:
  Electricity : 18.6%
  Steam : 16.9%
Consumptive water requirements per tonne of cane : 268 kg/tc

State	Temperature (°C)	Pressure (MPa)	Flow (kg/s)	Moisture (kgH2O/kgDRY)	Notes
1	25	0.101	90.3	0	air
2	424	1.485	90.3	0	air
3	126	1.485	101	0.119	air/saturated steam
4	815	1.381	101	0.119	air/steam
5	327	0.105	101	0.119	air/steam
6	166	0.101	101	0.119	air/steam
7	25	1.30	6.23	---	feedwater
8	330	1.30	6.23	---	process steam
9	25	0.101	12.1	1.0	50% wet bagasse
10	25	0.101	37.4	0	combustion air
11	175	0.101	49.4	0.235	combustion products
12	25	1.485	10.7	---	injection water

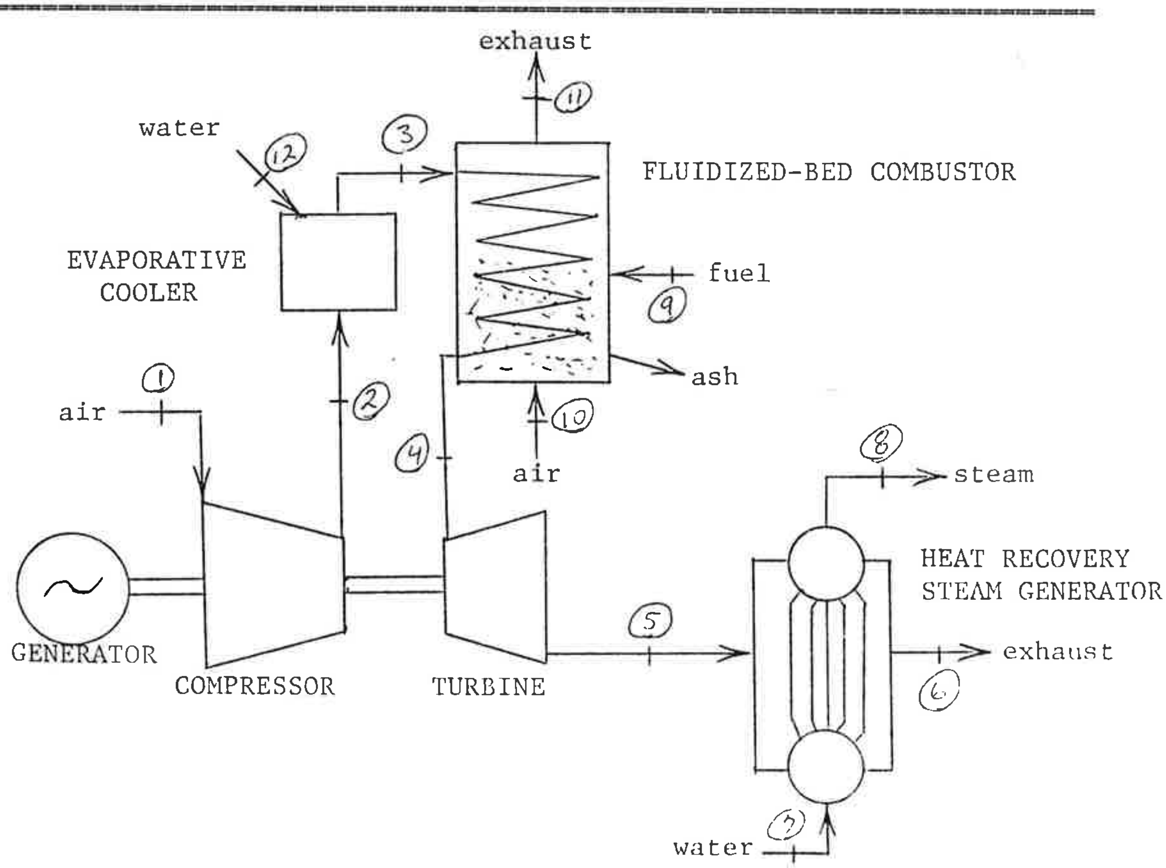


FIGURE A.7

SIMPLE GAS TURBINE CYCLE WITH EVAPORATIVE COOLER
Full-Load Performance Characteristics
(Based on the Detroit Diesel Allison 501-K engine)

Electrical output : 2690 kW
Bagasse consumption (@ 50% moisture) : 6.90 tonnes/hour
Cane consumption (@ 15% fiber) : 23.0 tc/hr
Per tonne of cane production:
    Electricity : 117 kWh/tc
    Process Steam : 242 kg/tc @ 1.3 MPa, 330°C
Percent of fuel higher heating value converted to:
    Electricity : 14.7%
    Steam : 26.2
Consumptive water requirements per tonne of cane : 232 kg/tc

State	Temperature (°C)	Pressure (MPa)	Flow (kg/s)	Moisture (kgH2O/kgDRY)	Notes
1	25	0.101	14.7	0	air
2	363	1.079	14.7	0	air
3	111	1.079	16.2	0.101	air/saturated steam
4	815	1.004	16.2	0.101	air/steam
5	409	0.105	16.2	0.101	air/steam
6	146	0.101	16.2	0.101	air/steam
7	25	1.30	1.54	---	feedwater
8	330	1.30	1.54	---	process steam
9	25	0.101	1.92	1.0	50% wet bagasse
10	25	0.101	5.95	0	combustion air
11	160	0.101	7.87	0.235	combustion products
12	25	1.079	1.48	---	injection water

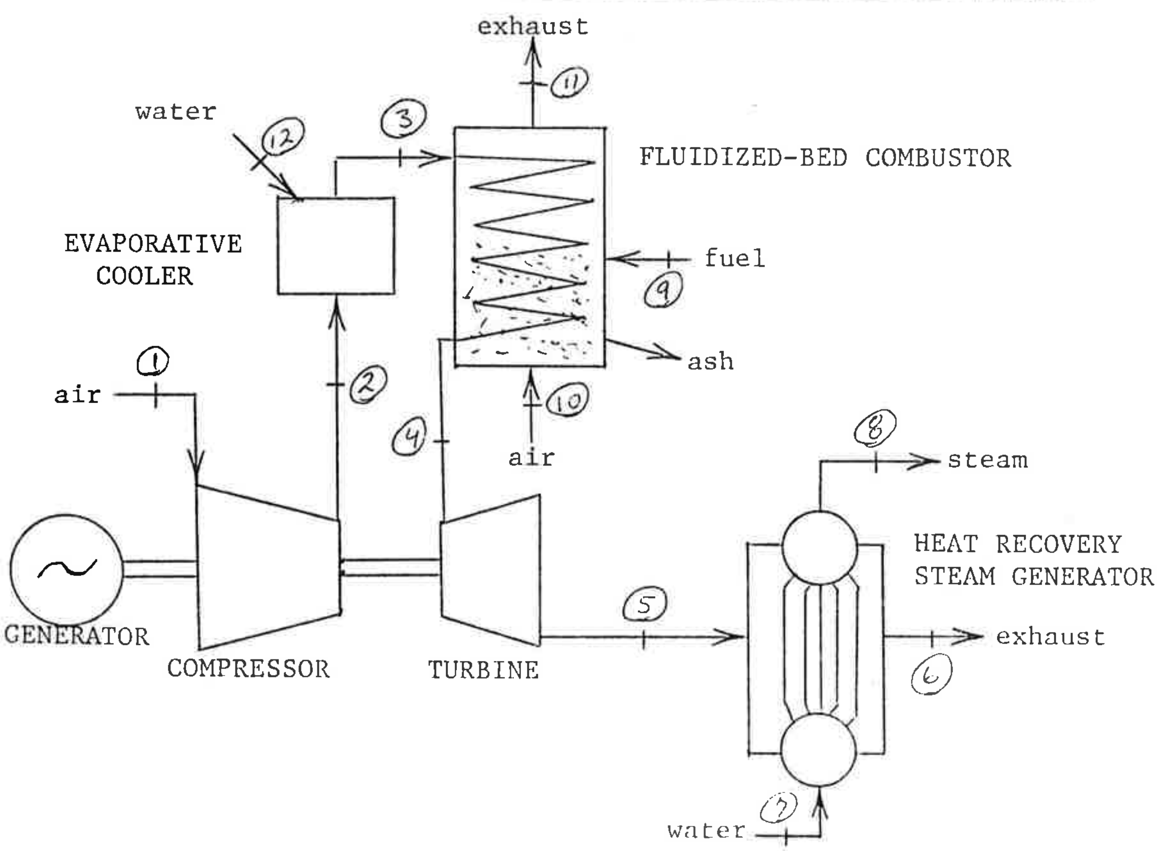


FIGURE A.8

SIMPLE GAS TURBINE CYCLE WITH TOPPING COMBUSTOR
Full-Load Performance Characteristics
(Based on the Detroit Diesel Allison 501-K engine)

Electrical output : 2690 kW
Bagasse consumption (@ 50% moisture) : 6.90 tonnes/hour
Cane consumption (@ 15% fiber) : 23.0 tc/hr
Distillate oil consumption: 3582 kW
Per tonne of cane production:
  Electricity : 180 kWh/tc
  Process Steam : 549 kg/tc @ 1.3 MPa, 330°C
OR
417 kg/tc @ 1.3 MPa, 330°C
156 kg/tc @ 0.2 MPa, Sat.
Percent of total fuel higher heating value converted to:
  Electricity : 17.7%
  Steam : 50.6%
Consumptive water requirements per tonne of cane : 0 kg/tc

State	Temperature (°C)	Pressure (MPa)	Flow (kg/s)	Moisture (kgH2O/kgDRY)	Notes
1	25	0.101	14.7	0	air
2	337	0.942	14.7	0	air
3	815	0.876	14.7	0	air
4	982	0.876	14.7	0.006	air/comb. prods.
5	518	0.105	14.7	0.006	air/comb. prods.
6	144	0.101	14.7	0.006	air/comb. prods.
7	70	1.30	1.85	---	feedwater
8	330	1.30	1.85	---	process steam
9	25	0.101	1.33	1.0	50% wet bagasse
10	25	0.101	4.12	0	combustion air
11	150	0.101	5.45	0.235	combustion products
12	70	1.30	0.59	---	feedwater
13	330	1.30	0.59	---	process steam

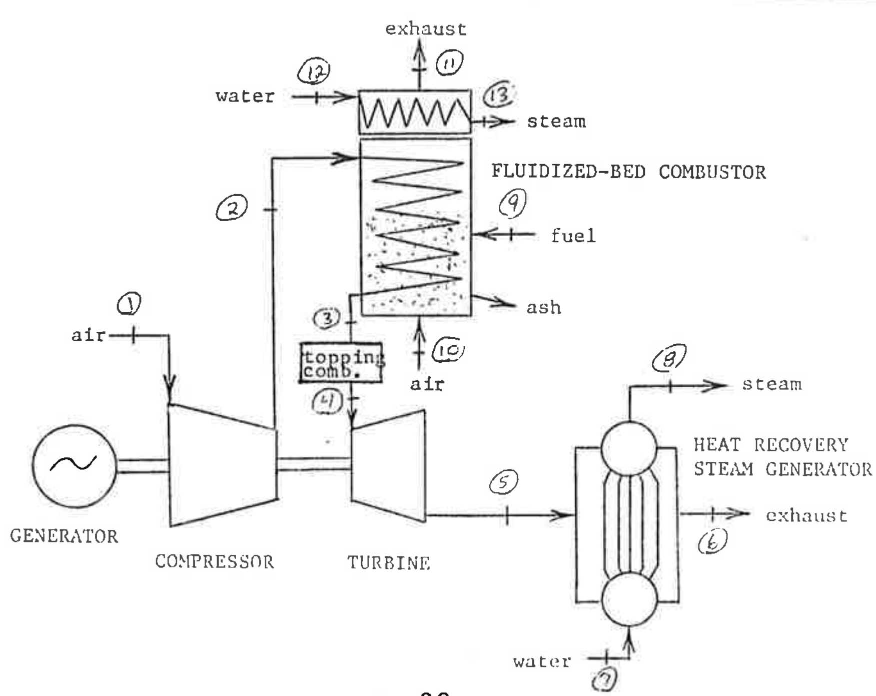


FIGURE A.9

STEAM-INJECTED GAS TURBINE CYCLE
Full-Load Performance Characteristics
(Based on the ASEA-STAL GT-35C engine)

Electrical output : 17371 kW
Bagasse consumption (@ 50% moisture) : 30.4 tonnes/hour
Cane consumption (@ 15% fiber) : 101 tc/hr
Per tonne of cane production:
    Electricity : 171 kWh/tc
    Process Steam : 143 kg/tc @ 1.3 MPa, 330°C
        OR
    178 kg/tc @ 0.2 MPa, Sat.
Percent of fuel higher heating value converted to:
    Electricity : 21.6
    Steam : 15.1
Consumptive water requirements per tonne of cane : 212 kg/tc

State	Temperature (°C)	Pressure (MPa)	Flow (kg/s)	Moisture (kgH2O/kgDRY)	Notes
1	25	0.101	90.3	0	air
2	410	1.387	90.3	0	air
3	403	1.387	96.3	0.066	air/steam
4	815	1.289	96.3	0.066	air/steam
5	332	0.105	96.3	0.066	air/steam
6	165	0.101	96.3	0.066	air/steam
7	25	1.30	5.96	---	feedwater
8	302	1.30	5.96	---	injection steam
10	25	0.101	8.45	1.0	50% wet bagasse
11	25	0.101	26.2	0	combustion air
12	150	0.101	34.6	0.235	combustion products
13	25	1.30	4.06	---	feedwater
14	330	1.30	4.06	---	process steam

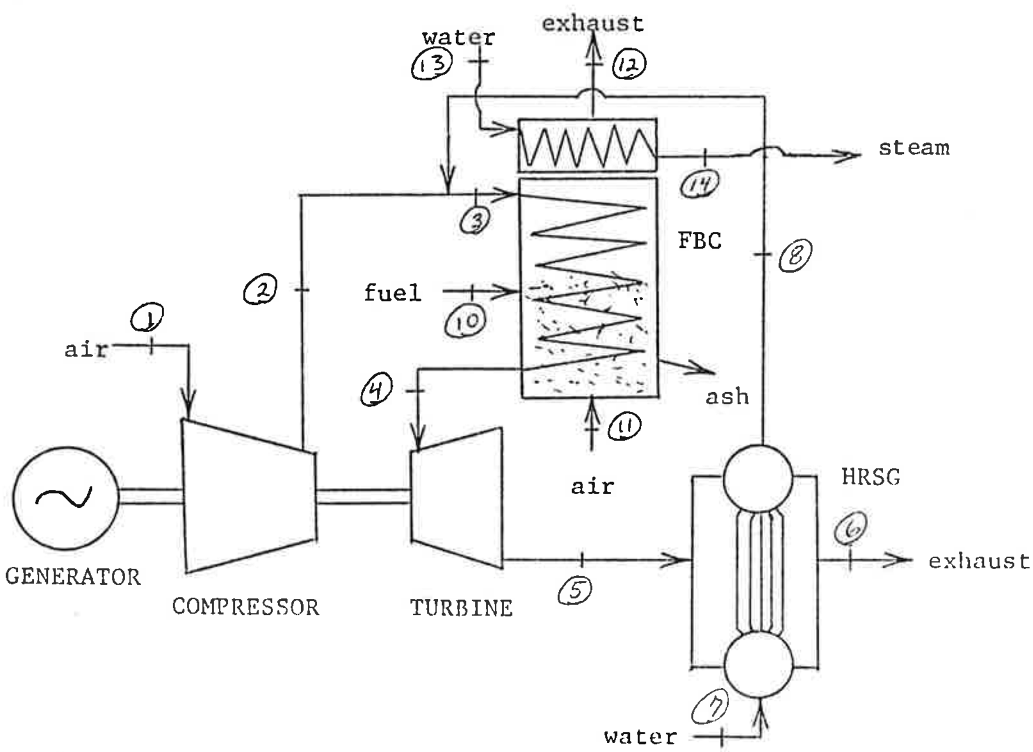


FIGURE A.10

STEAM-INJECTED GAS TURBINE CYCLE
Full-Load Performance Characteristics
(Based on the Detroit Diesel Allison 501-K engine)

Electrical output : 2747 kW
Bagasse consumption (@ 50% moisture) : 5.58 tonnes/hour
Cane consumption (@ 15% fiber) : 18.6 tc/hr
Per tonne of cane production:
    Electricity : 147 kWh/tc
    Process Steam : 128 kg/tc @ 1.3 MPa, 330^{o}C
    OR
    159 kg/tc @ 0.2 MPa, Sat.
Percent of fuel higher heating value converted to:
    Electricity : 18.6%
    Steam : 13.9%
Consumptive water requirements per tonne of cane : 302 kg/tc

State	Temperature (^{o}C)	Pressure (MPa)	Flow (kg/s)	Moisture (kgH2O/kgDRY)	Notes
1	25	0.101	14.7	0	air
2	364	1.087	14.7	0	air
3	365	1.087	16.3	0.106	air/steam
4	815	1.011	16.3	0.106	air/steam
5	408	0.105	16.3	0.106	air/steam
6	146	0.101	16.3	0.106	air/steam
7	25	1.30	1.56	---	feedwater
8	378	1.30	1.56	---	injection steam
10	25	0.101	0.64	1.0	50% wet bagasse
11	25	0.101	2.00	0	combustion air
12	152	0.101	34.6	0.235	combustion products
13	25	1.30	0.48	---	feedwater
14	330	1.30	0.48	---	process steam

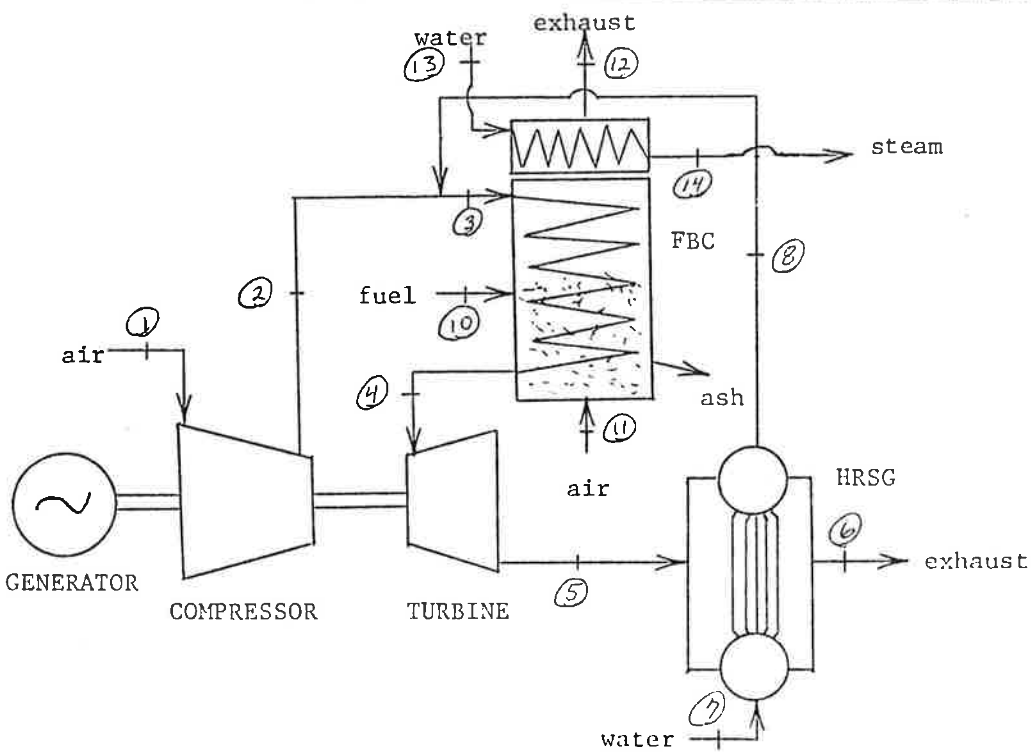


FIGURE A.11

STEAM-INJECTED GAS TURBINE CYCLE WITH EXTRA STEAM INJECTION
Full-Load Performance Characteristics
(Based on the ASEA-STAL GT-35C engine)

Electrical output : 21387 kW
Bagasse consumption (@ 50% moisture) : 30.6 tonnes/hour
Cane consumption (@ 15% fiber) : 110 tc/hr
Per tonne of cane production:
Electricity : 195 kWh/tc
Steam : 0
Percent of fuel higher heating value converted to
Electricity : 24.5%
Steam : 0
Consumptive water requirements per tonne of cane : 352 kg/tc

State	Temperature (^oC)	Pressure (MPa)	Flow (kg/s)	Moisture (kgH2O/kgDRY)	Notes
1	25	0.101	90.3	0	air
2	424	1.485	90.3	0	air
3	412	1.485	90.3	0.119	air/steam
4	815	1.381	90.3	0.119	air/steam
5	327	0.105	101	0.119	air/steam
6	157	0.101	101	0.119	air/steam
7	25	1.30	6.23	---	feedwater
8	297	1.30	6.23	---	primary inj. steam
9	311	1.30	10.7	---	total inj. steam
10	25	0.101	9.16	1.0	50% wet bagasse
11	25	0.101	28.4	0	combustion air
12	152	0.101	37.5	0.235	combustion products
13	25	1.30	4.51	---	feedwater
14	330	1.30	4.51	---	secondary inj. steam

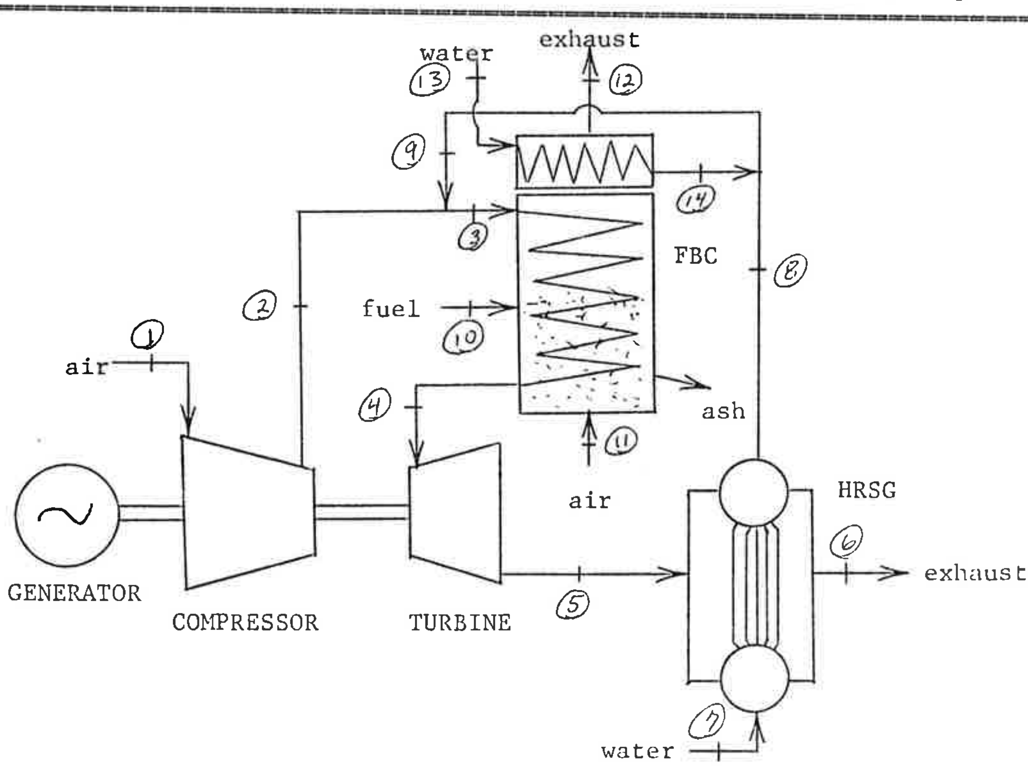


FIGURE A.12

STEAM-INJECTED GAS TURBINE CYCLE WITH EXTRA STEAM INJECTION
Full-Load Performance Characteristics
(Based on the Detroit Diesel Allison 501-K engine)

Electrical output : 3242 kW
Bagasse consumption (@ 50% moisture) : 5.94 tonnes/hour
Cane consumption (@ 15% fiber) : 19.8 tc/hr
Per tonne of cane production:
    Electricity : 164 kWh/tc
    Steam : 0
Percent of fuel higher heating value converted to
    Electricity : 20.6%
    Steam : 0
Consumptive water requirements per tonne of cane : 409 kg/tc

State	Temperature (°C)	Pressure (MPa)	Flow (kg/s)	Moisture (kgH2O/kgDRY)	Notes
1	25	0.101	14.7	0	air
2	375	1.150	14.7	0	air
3	373	1.150	16.9	0.153	air/steam
4	815	1.070	16.9	0.153	air/steam
5	404	0.105	16.9	0.153	air/steam
6	150	0.101	16.9	0.153	air/steam
7	25	1.30	1.53	---	feedwater
8	374	1.30	1.53	---	primary inj. steam
9	370	1.30	2.25	---	total inj. steam
10	25	0.101	1.65	1.0	50% wet bagasse
11	25	0.101	5.12	0	combustion air
12	150	0.101	6.77	0.235	combustion products
13	25	1.30	0.72	---	feedwater
14	360	1.30	0.72	---	secondary inj. steam

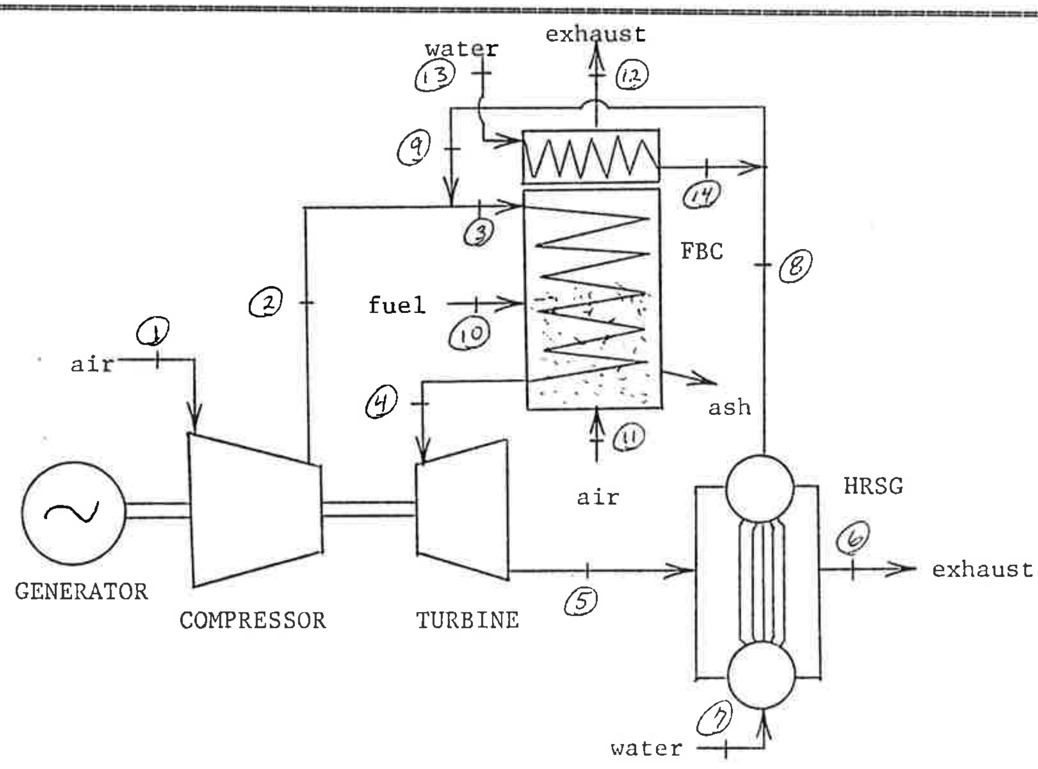
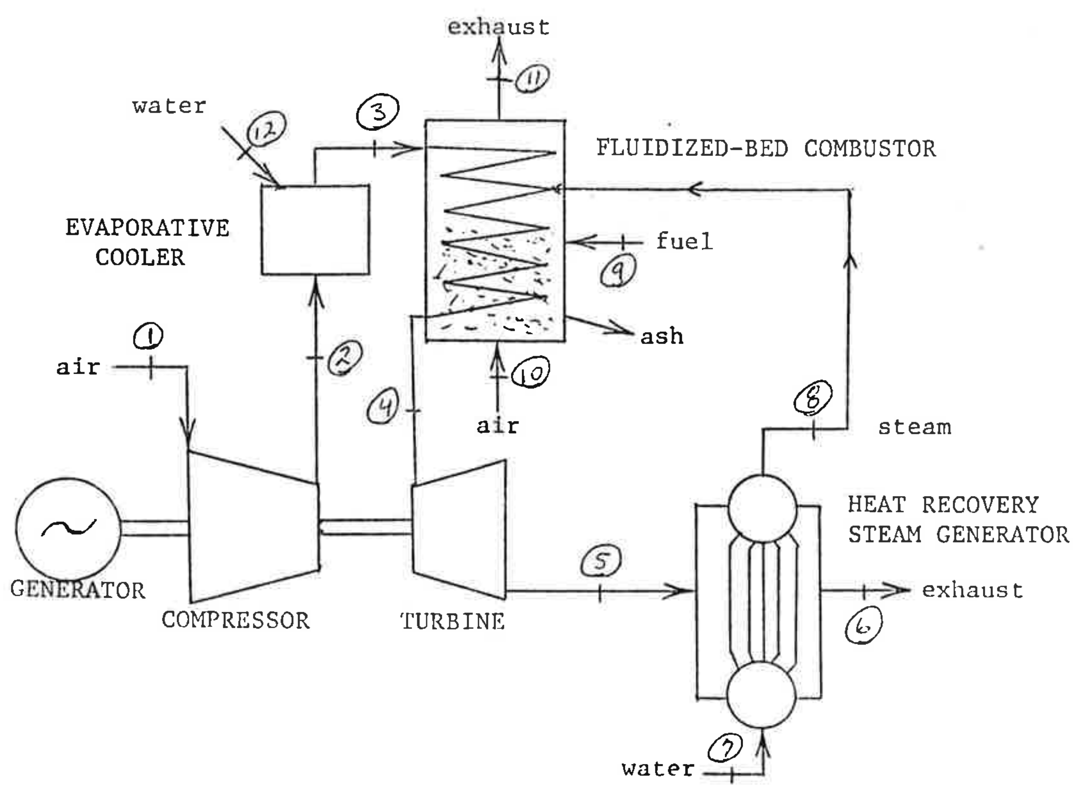


FIGURE A.13

STIG CYCLE WITH EVAPORATIVE COOLING AND EXTRA STEAM INJECTION
Full-Load Performance Characteristics
(Based on the Detroit Diesel Allison 501-K engine)

Electrical output : 4064 kW
Bagasse consumption (@ 50% moisture) : 7.86 tonnes/hour
Cane consumption (@ 15% fiber) : 26.2 tc/hr
Per tonne of cane production:
    Electricity : 155 kWh/tc
    Steam : 0
Percent of fuel higher heating value converted to
    Electricity : 19.5
    Steam : 0
Consumptive water requirements per tonne of cane : 459 kg/tc

State	Temperature (°C)	Pressure (MPa)	Flow (kg/s)	Moisture (kgH2O/kgDRY)	Notes
1	25	0.101	14.7	0	air
2	391	1.252	14.7	0	air
3	118	1.252	16.3	0.109	air/steam
4	815	1.164	18.0	0.227	air/steam
5	397	0.105	18.0	0.227	air/steam
6	145	0.101	18.0	0.227	air/steam
7	25	1.30	1.73	---	feedwater
8	367	1.30	1.73	---	injection steam
9	25	0.101	2.19	1.0	50% wet bagasse
10	25	0.101	6.78	0	combustion air
11	180	0.101	8.99	0.235	combustion products
12	25	1.30	1.60	---	injection water



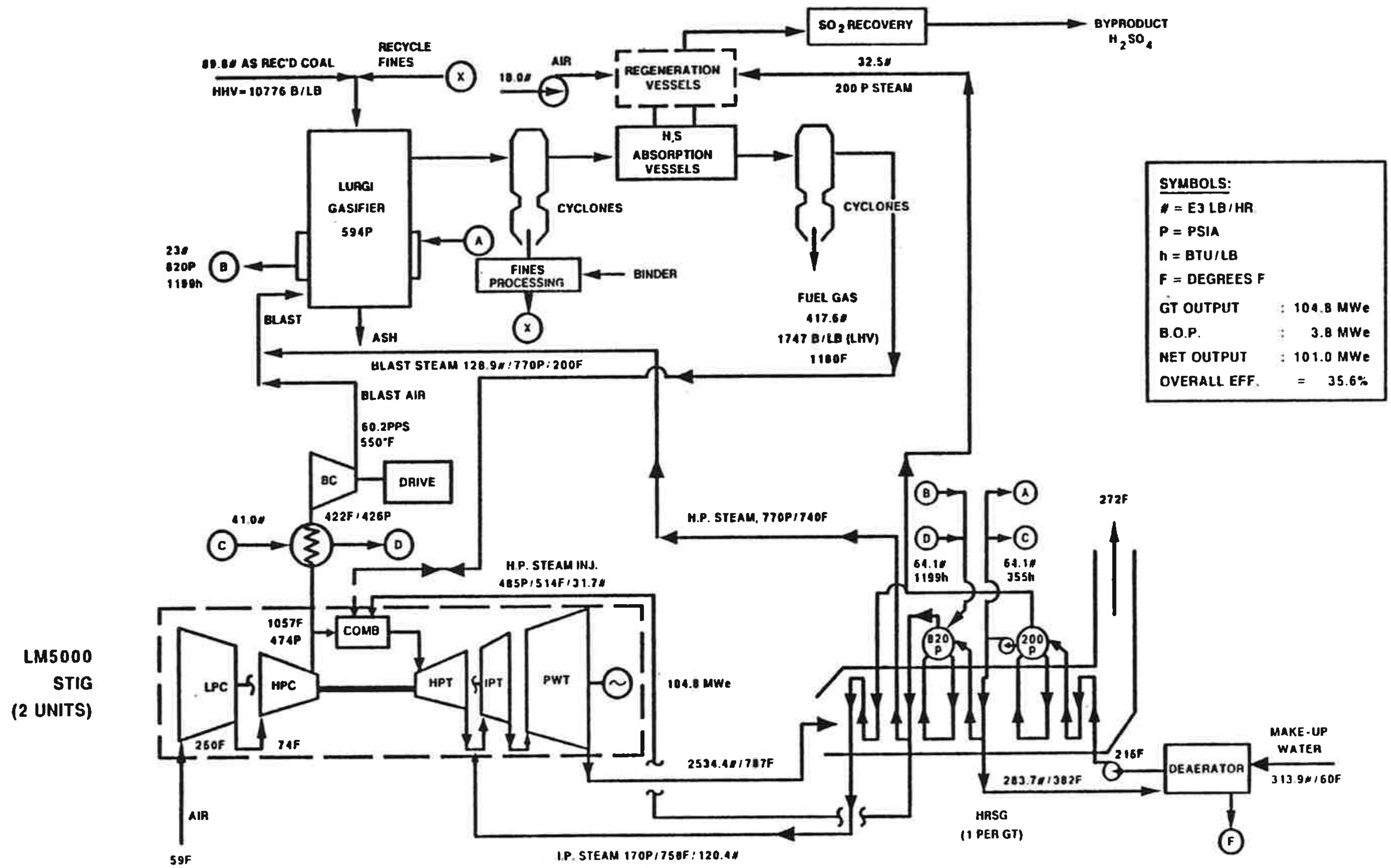


Figure A.14. Energy and mass balances for a coal-gasifier STIG system based on two STIG/LM5000 units integrated with two air-blown fixed-bed Lurgi Mark IV gasifiers [6].

Bagasse-Fired IG-STIG without Cogeneration

Case: BAGASS8

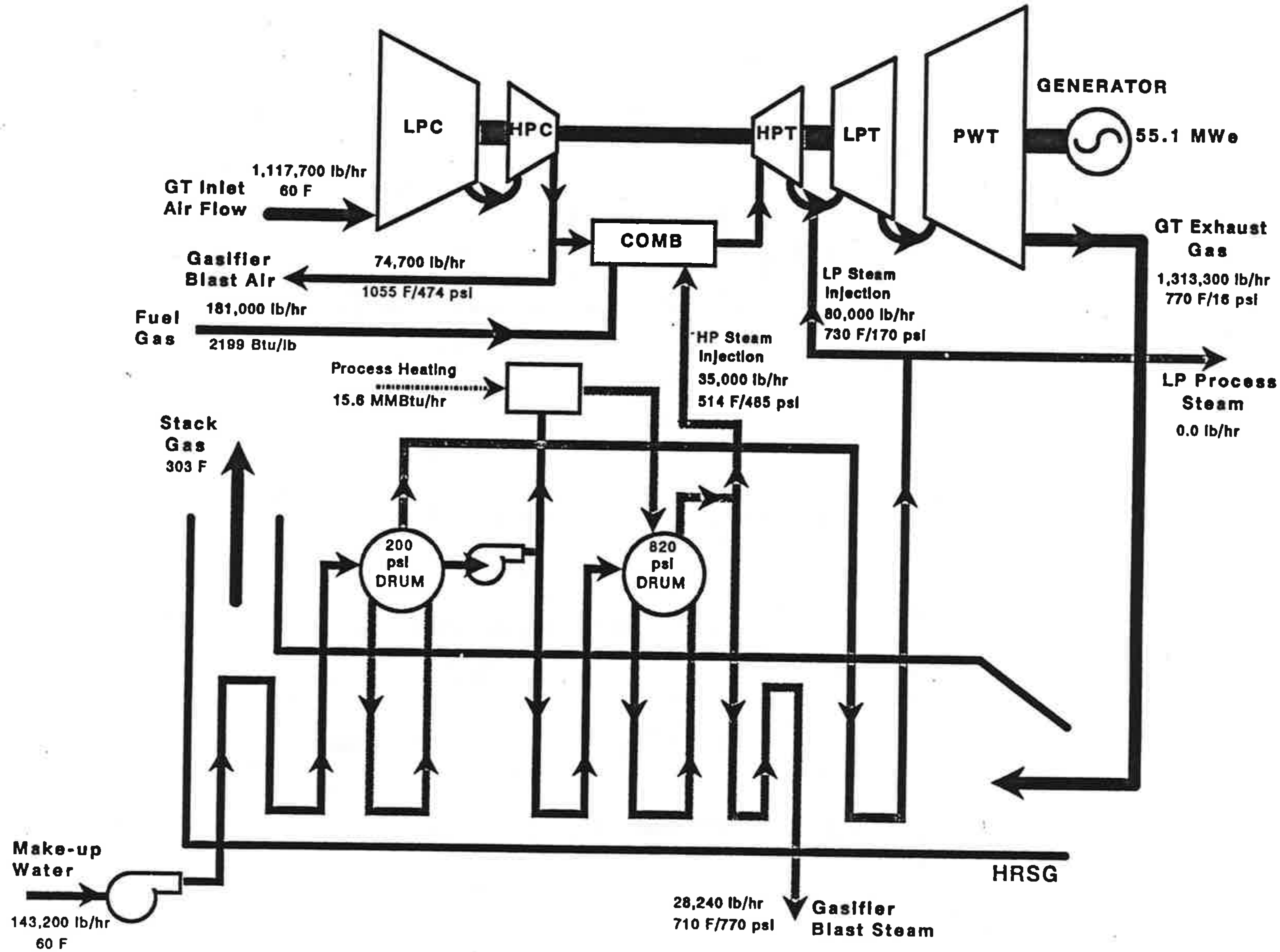


Figure A.15. Estimated energy and mass balances for the gas turbine/HRSG portion of a bagasse-GSTIG system based on a single STIG/LM-5000 fueled by gasified bagasse producing power only [7].

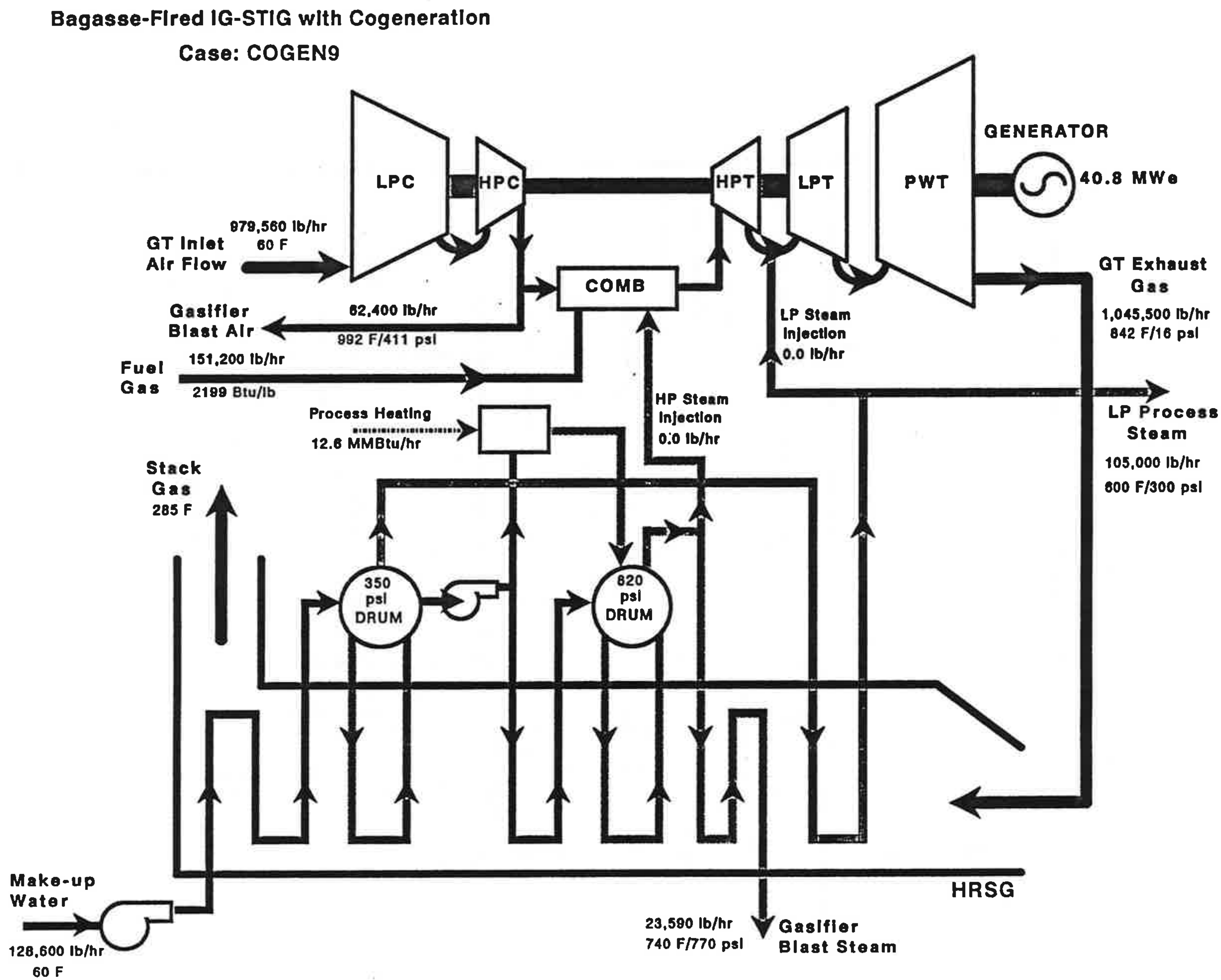


Figure A.16. Estimated energy and mass balances for the gas turbine/HRSG portion of a bagasse-GSTIG based on a single STIG/LM5000 fueled by gasified bagasse operating in the cogeneration mode [7].

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Appendix B

PERFORMANCE ESTIMATES OF STEAM TURBINE SYSTEMS

Angel Abbud-Madrid
Eric D. Larson

CONTENTS:

Basis for Analysis in Main Text B.1

Computer Model of a Steam-Turbine Cogeneration Plant B.1

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This appendix describes the technical performance of steam-turbine cogeneration systems less than 35 MW in size, which was estimated based on previous engineering design studies and used for the analysis in the main text. In addition, the development of a computer model of a steam-turbine cogeneration plant, based on the plant proposed for the Monymusk sugar factory is described. The model was used to help assess the performance of cogeneration plants at raw-sugar factories with different levels of process steam demand.

BASIS FOR ANALYSIS IN MAIN TEXT

For the base-case analysis presented in the main text, the electrical efficiency of steam turbine system was based on [1], in which a 32.25 MW capacity condensing-extraction steam turbine is estimated to operate with an electrical efficiency of 20.3% in the full condensing mode when burning 50% wet bagasse (requiring the crushing of some 207 tc/hr). This corresponds approximately to a production of 156 kWh per tonne of cane crushed (see Fig. 9 in main text). For the case-study factory analyzed in the main text, the fuel available from the processing of 175 tc/hr was estimated to be sufficient to fuel a (156x175=) 27-MW unit.

When supplying process steam to a "conventional" raw-sugar factory (374 kg/tc -- see Table 4 in main text), the cogeneration plant's electricity production was estimated (from Fig. 9) to be 100 kWh/tc. Including the electricity produced in the existing steam turbo-alternators to meet onsite demand, the total electricity production would be about 113 kWh/tc.

When supplying a "steam-conserving" factory (where the existing turbo-alternators would not be used), the total electricity production was estimated (from Fig. 9) to be 126 kWh/tc, and in an "electrified" factory it was 141 kWh/tc.

For the scale comparisons in the main text, the efficiencies of 3 and 10 MW capacity systems were calculated from

$$EFF = 13.93 \times (MW)^{0.107},$$

where EFF is the plant electrical efficiency in percent and MW is the generating capacity in megawatts, which was developed based on [2] and [3]. In the latter study, a 7.6 MW plant is estimated to have an efficiency of 17.3% when burning 50% wet wood.

COMPUTER MODEL OF A STEAM-TURBINE COGENERATION PLANT

The steam power plant model used for the present analysis is based upon a regenerative Rankine steam cycle consisting of a biomass-fired steam generating unit with a double extraction steam turbine. The process flowsheet of the steam cycle is shown in Figure B.1.

The superheated steam leaves the steam generator unit (1) and is

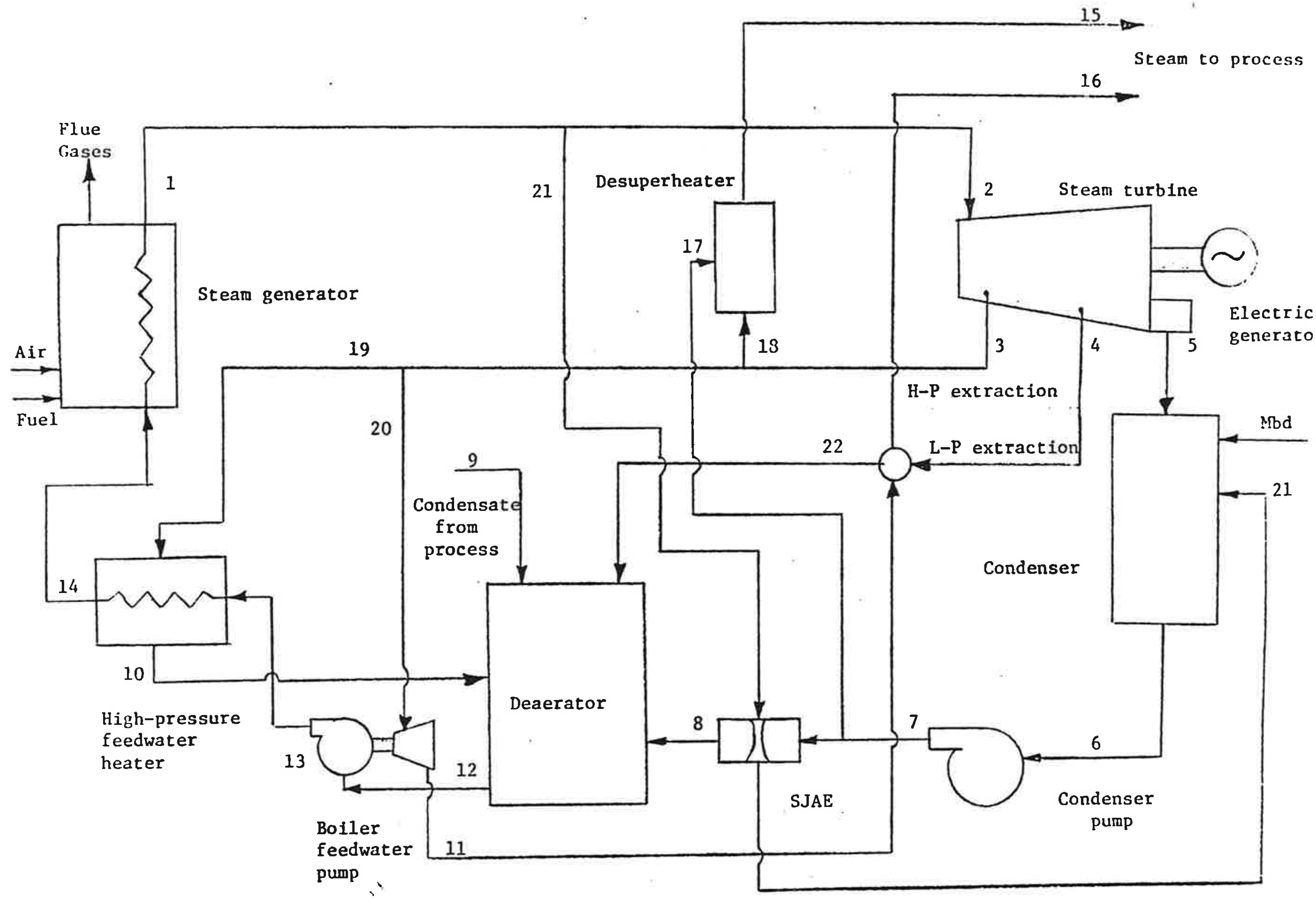


Figure B.1. Regenerative Rankine steam cycle model directed through a manifold to the steam turbine inlet (2). Some steam is extracted before the turbine for the steam jet air ejector (21), the purpose of which is to drain the noncondensable gases coming out of the condenser.

The steam turbine has two extractions: one controlled extraction at high pressure (3) and one uncontrolled extraction at low pressure (4). The high pressure steam extraction provides steam for process (after going through a desuperheater to reduce its temperature) (15), for the turbines driving the boiler feedwater pump (20) and for the high pressure closed feedwater heater (19). The low pressure steam extraction provides steam for process (16) and for the deaerator (22).

The two stages of feedwater preheating consist of one low pressure deaerator and one closed, high-pressure feedwater heater; the deaerator also acts as a noncondensable gases remover. Two stages of feedwater pumping are provided. A motor-driven condensate pump pumps the feedwater from the condenser hotwell (6) to the deaerator (8) after passing through the SJAE (7), and sends some condensate to the desuperheating station (17). The second pumping stage, which consists of a turbine-driven pump, increases the feedwater pressure from its value at the exit of the deaerator (12) to the steam generator inlet pressure (13). The feedwater is then heated in the high-pressure feedwater heater (14), before it passes to the steam generator.

THE STEAM PROGRAM

The mass and energy balances and the performance evaluation of the steam power plant are executed by the STEAM computer program, which includes (Figure B.2):

- Main program
- Data input and output procedures
- Simulation of the steam cycle components with mass, energy and combustion calculations
- Evaluation of the thermodynamic properties for each chemical component or mixture considered in the total process

The main program organizes the sequence of the various calculations involved. It calls first the input procedure to receive all the necessary process parameters. These are the following:

- Steam flow conditions at the boiler inlet and outlet
- Fuel and combustion air conditions
- Temperature of combustion gases leaving the stack
- Steam extraction pressures
- Turbines, pumps and generator efficiencies
- Pressure drops between main components
- Process steam conditions
- Discharge pressure of pumps
- Design mass flow through turbines, steam jet air ejector and boiler blowdown
- Closed feedwater heater characteristics (TTD, TD)

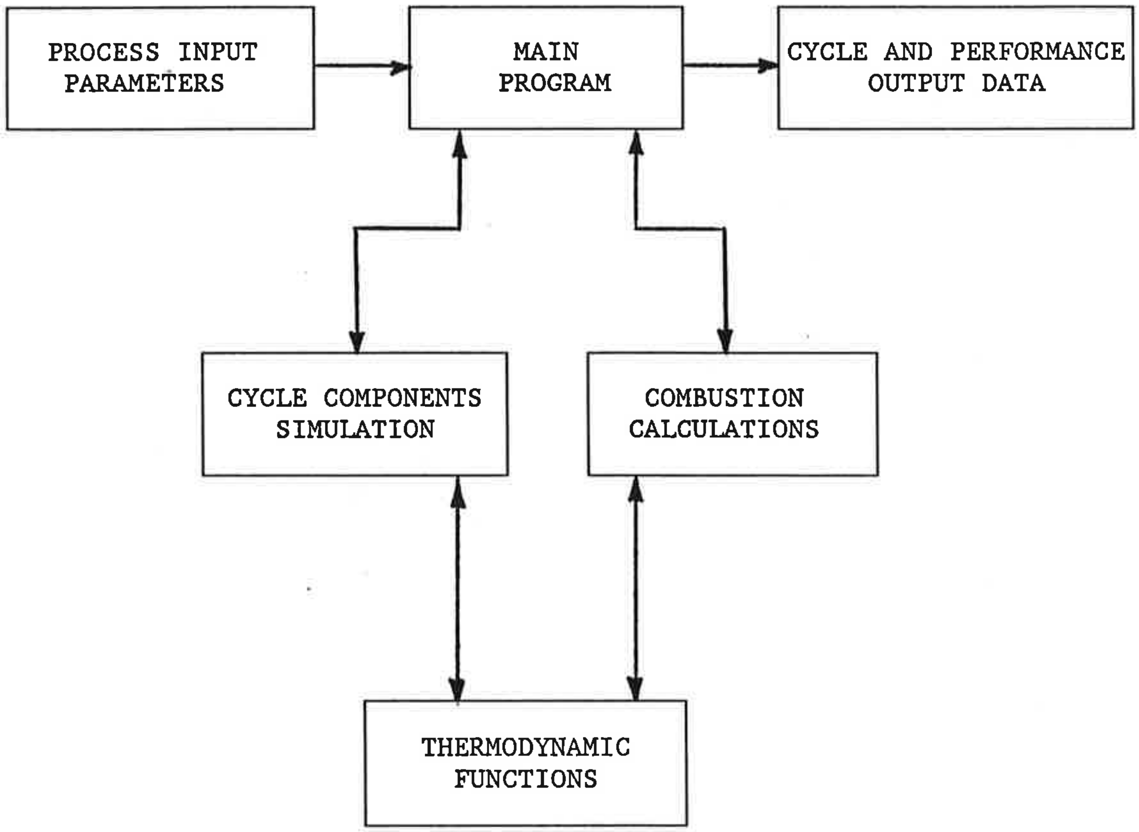


Figure B.2. STEAM program structure

Next, mass and energy balances for each component of the cycle are solved for the unknown quantities. This consists of the calculation of:

- Pressure
- Temperature
- Enthalpy
- Entropy
- Specific volume
- Steam quality
- Mass flows
- Work

Following the cycle procedure, the combustion calculations are performed giving as a result:

- Total heat input

P19 = High pressure heater steam inlet
P22 = Deaerator
dP = Pressure drop from boiler to turbine (%)
dPext1 = Pressure drop from turbine to h-p feedwater heater (%)
dPext2 = Pressure drop from turbine to deaerator (%)

Temperature variables (^{o}C)

T1 = Boiler outlet
T3 = Turbine first steam extraction
T3S = Turbine first section isentropic expansion temperature T3
Tsat3 = Saturation temperature at first extraction
T4 = Turbine second steam extraction
T4S = Turbine second section isentropic expansion temperature
Tsat4 = Saturation temperature at second extraction
T5 = Turbine exhaust
T5S = Turbine third section isentropic expansion temperature
Tsat5 = Saturation temperature at turbine exhaust
T6 = Condenser outlet
T7 = Condenser pump discharge
T10 = Condensate from h-p feedwater heater to deaerator
T11 = Feedwater pump turbine exhaust
T12 = Deaerator outlet
T13 = Feedwater pump discharge
T14 = Boiler inlet
T15 = High pressure steam to process
T16 = Low pressure steam to process
TTD19 = H-P feedwater heater terminal temp. difference (high temp. side)
TD10 = H-P feedwater heater terminal temp. difference (low temp. side)

Mass flow variables (Kg/hr)

M1 = Boiler outlet
M2 = Turbine inlet
M3 = Turbine first steam extraction
M4 = Turbine second steam extraction
M5 = Turbine exhaust
M6 = Condenser outlet
M8 = Condenser pump discharge
M9 = Condensate from process
M10 = Condensate from h-p feedwater heater to deaerator
M12 = Deaerator outlet
M15 = High pressure steam to process
M16 = Low pressure steam to process
M17 = Condensate to desuperheater
M18 = Steam to desuperheater
M19 = H-P feedwater heater steam inlet
M20 = Feedwater pump turbine inlet
M21 = Steam jet air ejector inlet flow
Mbd = Boiler blowdown flow

- Flue gases heat loss
- Heat available for steam production
- Boiler efficiency
- Amount of fuel required
- Fraction of fuel converted to electricity

Both the cycle and combustion procedures require the evaluation of thermodynamic properties of the several chemical components involved. This work is performed by the thermodynamic functions which calculate the following values:

- Saturation temperature of water (H_2O) as a function of pressure
- Enthalpy and entropy of saturated liquid and steam as a function of temperature
- Latent heat of vaporization of H_2O as a function of temperature
- Enthalpy and entropy of superheated steam as a function of temperature and pressure
- Specific volume of saturated liquid as a function of temperature
- Temperature of superheated steam as a function of pressure and enthalpy or of pressure and entropy
- Sensible enthalpy changes between two temperatures for CO_2, N_2, O_2, fuel and air
- Specific heats for air and fuel as a.function of temperature

The last operation of the main program is the output of the results obtained by the calculations. The results consist in a description of the thermodynamic state of each stage in the steam cycle (pressure, temperature, mass flow and enthalpy) and the performance of the plant as a whole in terms of electric output, total electrical efficiency and fuel consumption.

THERMODYNAMIC ANALYSIS

The development of the equations and the algorithms for the STEAM program are based on the thermodynamic evaluation of each component in the steam cycle [4,5], as presented in this section. The following nomenclature has been used in the analysis.

Nomenclature

Pressure variables (MPa)

P1 = Boiler outlet
P2 = Turbine inlet
P3 = Turbine first steam extraction
P4 = Turbine second steam extraction
P5 = Turbine exhaust
P6 = Condenser
P7 = Condenser pump discharge
P12 = Boiler feedwater pump inlet
P13 = Boiler feedwater pump discharge
P14 = Boiler inlet

Enthalpy variables (KJ/Kg)

H1 = Boiler outlet
H2 = Turbine inlet
H3 = Turbine first steam extraction
H3S = Turbine first section isentropic expansion enthalpy
H4 = Turbine second steam extraction
H4S = Turbine second section isentropic expansion enthalpy
H5 = Turbine exhaust
H5S = Turbine third section isentropic expansion enthalpy
H6 = Condenser outlet
H7 = Condenser pump discharge
H8 = Steam jet air ejector condensate outlet
H9 = Condensate from process to deaerator
H10 = Condensate from h-p feedwater heater to deaerator
H11 = Feedwater pump turbine exhaust
H11S = Feedwater pump turbine isentropic expansion enthalpy
H12 = Deaerator outlet
H13 = Feedwater pump discharge
H14 = Boiler inlet
H15 = High pressure steam to process
H16 = Low pressure steam to process
H17 = Condensate to desuperheater
H19 = H-P feedwater heater steam inlet

Entropy variables (KJ/Kg^{o}K)

S2 = Turbine inlet
S3 = Turbine first steam extraction
S3S = Turbine first section isentropic expansion
S4 = Turbine second steam extraction
S4S = Turbine second section isentropic expansion
S5 = Turbine exhaust
S5S = Turbine third section isentropic expansion

Vapor quality variables (Kgsteam/Kgliquid)

X3 = Turbine first steam extraction
X3S = Turbine first section isentropic expansion vapor quality
X4 = Turbine second steam extraction
X4S = Turbine second section isentropic expansion vapor quality
X5 = Turbine exhaust
X5S = Turbine third section isentropic expansion vapor quality

Specific volume variables (M^3/Kg)

V6 = Condenser outlet
V12 = Deaerator outlet

Work (KJ/Kg), power (KW) and efficiency (%) variables

Wtur1 = Work done by the turbine first section
Wtur2 = Work done by the turbine second section
Wtur3 = Work done by the turbine third section
Wturb = Total work done by the steam turbine
Wconp = Condenser pump work
Wbft = Feedwater pump turbine work
Wbfp = Feedwater pump work
Wnet = Steam cycle net work
KW = Steam turbine power output
Etur1 = Turbine first section polytropic efficiency
Etur2 = Turbine second section polytropic efficiency
Etur3 = Turbine third section polytropic efficiency
Ecpump = Condenser pump efficiency
Ebft = Feedwater pump turbine polytropic efficiency
Ebfp = Feedwater pump efficiency
Egen = Electric generator efficiency
Eboiler = Boiler efficiency

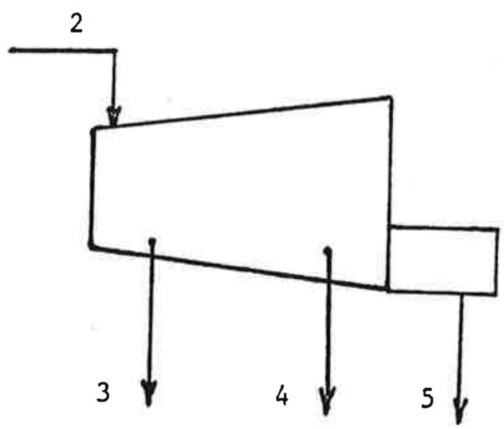
Combustion variables

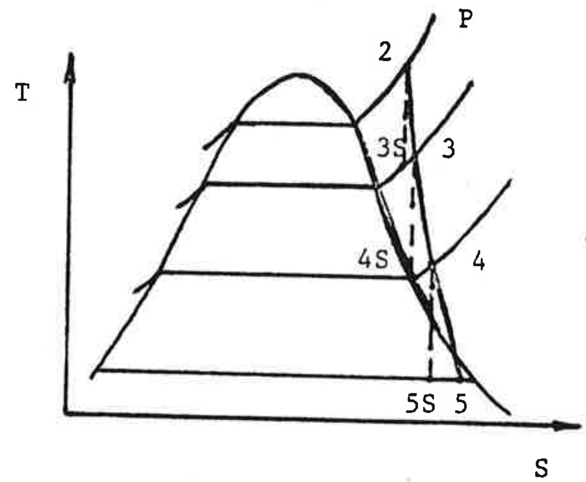
c = Carbon content in fuel (Kg/Kgwetfuel)
h = Hydrogen content in fuel (Kg/Kgwetfuel)
o = Oxygen content in fuel (Kg/Kgwetfuel)
s = Ash content in fuel (Kg/Kgwetfuel)
w = Moisture content in fuel (Kg/Kgwetfuel)
MWfuel = Molecular weight of fuel (Kg/Kg-mol wet fuel)
MWair = Molecular weight of air (Kg/Kg-mol air)
Osm = Stoichiometric oxygen-fuel ratio (Kg-mol O2/Kgwetfuel)
Asm = Stoichiometric air-fuel ratio (Kg-mol air/Kgwetfuel)
As = Stoichiometric air-fuel ratio (Kgair/Kgwetfuel)
AFratio = Actual air-fuel ratio (Kgair/Kgwetfuel)
MWFDF = Wet fuel-Dry fuel ratio (Kgwetfuel/Kgdryfuel)
DAFR = Air-Dry fuel ratio (Kgair/Kgdryfuel)
HHVwet = Wet fuel high heating value (KJ/Kgwetfuel)
Tgin = Fuel-air average temperature at the furnace inlet (^oC)
TrefC = Combustion products reference temperature (^oC)
Tstack = Temperature of flue gases leaving the stack (^oC)
Tini = Fuel-air reference temperature (^oC)
PA1 = Combustion process pressure
DHairin = Sensible heat gain of air at furnace inlet (KJ/Kgair)
DHwbag = Sensible heat gain of fuel at furnace inlet (KJ/Kgwetfuel)
Ppw = Partial pressure of water vapor (MPa)
CO2hloss = Sensible heat loss of CO2 (KJ/Kgwetfuel)
N2hloss = Sensible heat loss of N2 (KJ/Kgwetfuel)
O2hloss = Sensible heat loss of O2 (KJ/Kgwetfuel)
H2Ohloss = Sensible heat loss of H2O (KJ/Kgwetfuel)
AHloss = Total heat loss of flue gases (KJ/Kgwetfuel)
USloss = Fraction of burnt solids
RADloss = Fraction of heat not lost to radiation and convection
IMCloss = Fraction of heat not lost due to incomplete combustion

HEATav - Heat available for steam generation (KJ/Kgwetfuel)
STfuel - Steam-Fuel ratio (Kgsteam/Kgwetfuel)
Eboiler - Boiler efficiency (%)
Mfuel - Fuel consumption rate (Kgwetfuel/hr)
Rwfcane - Wetfuel-cane ratio (Kgwetfuel/Kgcane)
Ccrate - Cane consumption rate (Kgcane/hr)
STcane - Process steam-Cane ratio (Kgpsteam/Kgcane)
KWh - Electricity-cane ratio (KWh/Kgcane)
FEfrac - Fraction of fuel going to electricity

Thermodynamic analysis of the steam cycle components

- Steam turbine





Mass balance:

$$\sum_i m_i = \sum_j m_j$$

in out

Energy balance:

$$Q \quad - \quad W \quad = \quad \sum_j m_j H_j \quad - \quad \sum_i m_i H_i$$

heat work out in

Considering an isentropic expansion (adiabatic and irreversible process), the ideal work done by each section is:

$$W_I \quad = \quad \sum_i m_i H_i \quad - \quad \sum_j m_j H_j$$

work in out

The real work done on an irreversible process takes into account the efficiency of each section (E_{ff}):

$$W_R \quad = \quad E_{ff} * W_I$$

Therefore the real work done by each section in the model considered in KJ/Kgsteam is:

```
Wtur1 = Etur1/100 * M2 * ( H2 - H3S )                     (1)
Wtur2 = Etur2/100 * ( M2 - M3 ) * ( H3 - H4S )            (2)
Wtur3 = Etur3/100 * ( M2 - M3 - M4 ) * ( H4 - H5S )       (3)
```

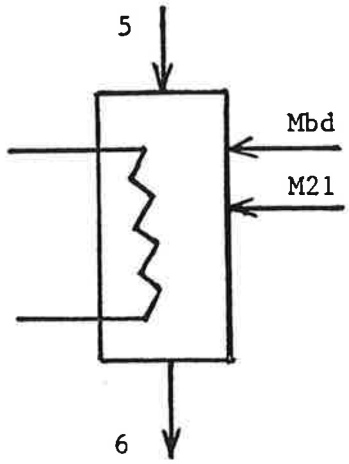
where the mass flow quantities are given in fractions of the main steam flow at the boiler outlet. The total thermodynamic work is the sum of the individual quantities:

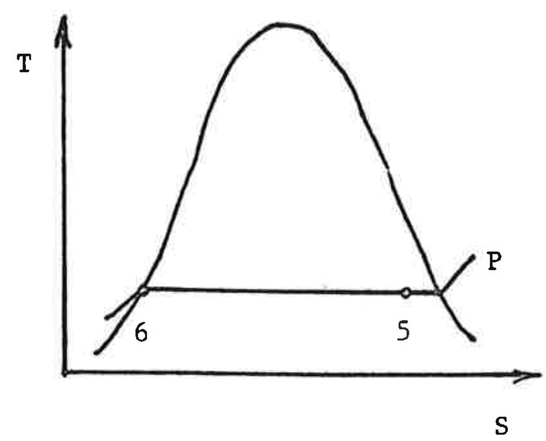
```
Wturb = Wtur1 + Wtur2 + Wtur3                             (4)
```

The electric power generated in KW is:

```
KW = ( M1 * Wturb * Egen/100 )/3600                       (5)
```

- Condenser





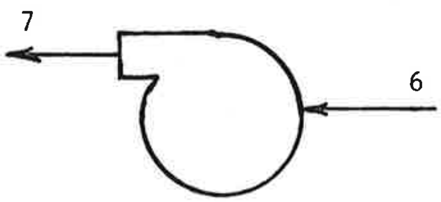
Assuming total condensation (H6) of the steam coming from the turbine exhaust (H5), the mass balance on the steam cycle circuit part of the condenser is:

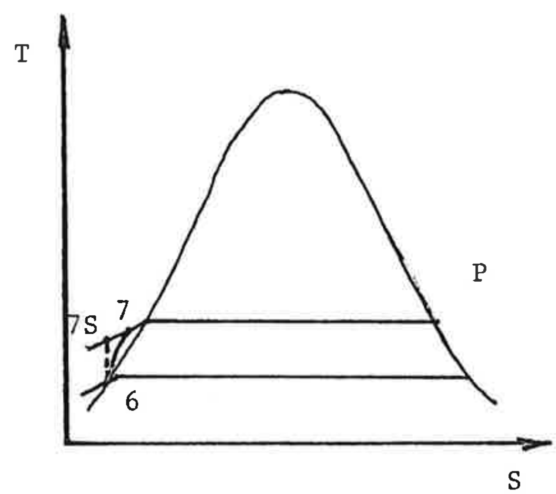
$$\underbrace{\sum_i m_i}_{\text{in}} = \underbrace{\sum_j m_j}_{\text{out}}$$

The mass flows in the model are:

$$M5 + Mbd + M21 = M6 \qquad (6)$$

- Condenser pump





Mass balance:

$$\underbrace{\sum_i m_i}_{\text{in}} = \underbrace{\sum_j m_j}_{\text{out}}$$

Energy balance:

$$\underbrace{Q}_{\text{heat}} - \underbrace{W}_{\text{work}} = \underbrace{\sum_j m_j H_j}_{\text{out}} - \underbrace{\sum_i m_i H_i}_{\text{in}}$$

Considering an isentropic pumping process (adiabatic and irreversible process), the ideal work done by the pump is:

$$W_I = \sum_j m_j H_j - \sum_i m_i H_i$$

work out in

The real work done on an irreversible process takes into account the efficiency of the pump (E_{ff}):

$$W_R = W_I / E_{ff}$$

Therefore the real work done by the condenser pump in the model considered in KJ/Kgsteam is:

$$Wconp = M6 * (H7 - H6S) / (E_{cpump} / 100) \quad (7)$$

or

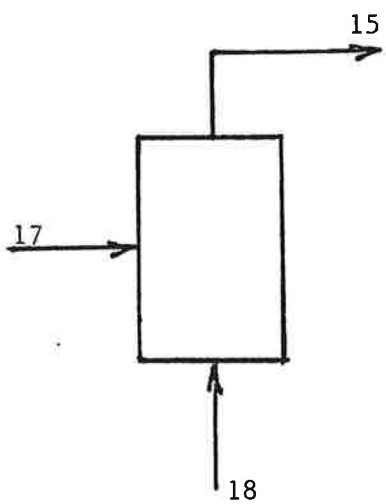
$$Wconp = M6 * (H7 - H6) \quad (8)$$

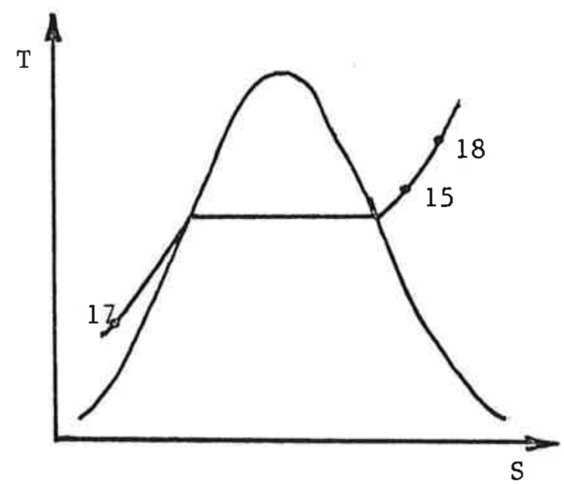
Considering water as an incompressible fluid, the work done can also be expressed as:

$$Wconp = M6 * V6 * (P7 - P6) * 1000 / (E_{cpump} / 100) \quad (9)$$

Combining equations (8) and (9), the enthalpy at the pump discharge (H7) can be obtained.

- Desuperheater





Mass balance:

$$\sum_i m_i = \sum_j m_j$$

in out

Energy balance:

$$\underset{\text{heat}}{Q} - \underset{\text{work}}{W} = \underset{\text{out}}{\sum_j m_j H_j} - \underset{\text{in}}{\sum_i m_i H_i}$$

Considering the desuperheater as an open system where an adiabatic mixing process takes place without any exchange of work with its surroundings, we have:

$$\underset{\text{in}}{\sum_i m_i H_i} = \underset{\text{out}}{\sum_j m_j H_j}$$

Combining both mass and energy balances, the model equations are:

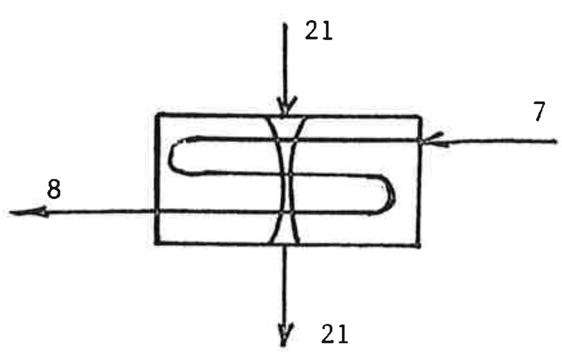
M17 + M18 = M15 (10)

M17*H17 + M18*H18 = M15*H15 (11)

The mass flows in the desuperheater are:

M18 = M15 * (H15 - H17)/(H3 - H17) STEAM IN (12)
M17 = M15 - M18 CONDENSATE IN (13)

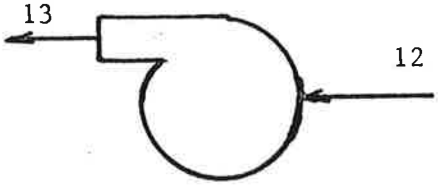
- Steam jet air ejector

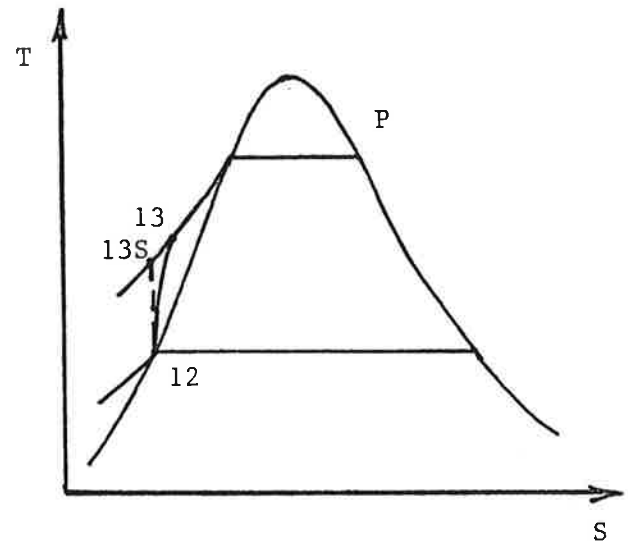


Assuming that the SJAE serves only as a non-condensible gases remover, mass or energy transfer is not considered in the analysis. Thus:

$$M8 = M6 - M17 \tag{14}$$
$$H8 = H7 \tag{15}$$

- Boiler feedwater pump





Mass balance:

$$\underset{\text{in}}{\sum_i m_i} = \underset{\text{out}}{\sum_j m_j}$$

Energy balance:

$$\underset{\text{heat}}{Q} - \underset{\text{work}}{W} = \underset{\text{out}}{\sum_j m_j H_j} - \underset{\text{in}}{\sum_i m_i H_i}$$

Considering an isentropic pumping process (adiabatic and irreversible process), the ideal work done by the pump is:

$$\underset{\text{work}}{W_I} = \underset{\text{out}}{\sum_j m_j H_j} - \underset{\text{in}}{\sum_i m_i H_i}$$

The real work done on an irreversible process takes into account the efficiency of the pump (E_{ff}):

$$W_R = W_I/E_{ff}$$

Therefore the real work done by the feedwater pump in the model considered in KJ/Kgsteam is:

$$Wbfp = M12 * (H13 - H12S) / (E_{bfp} /100) \quad (16)$$

or

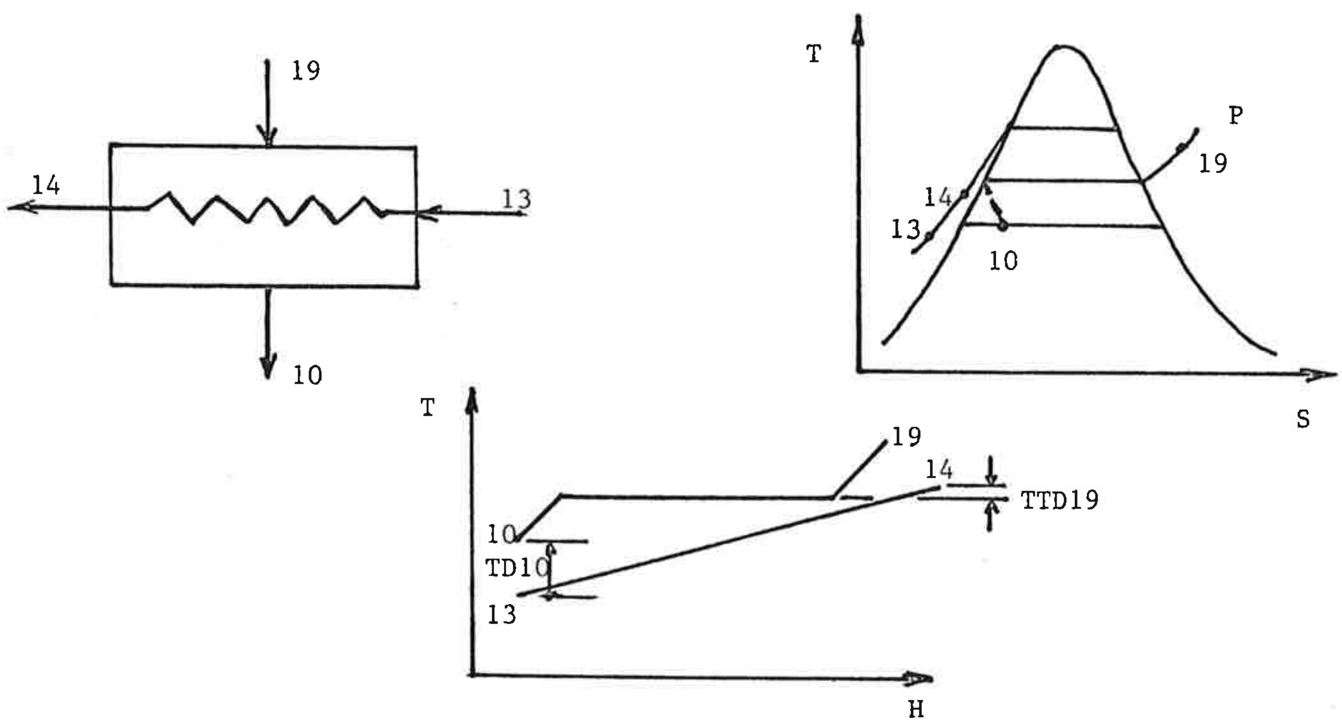
$$Wbfp = M12 * (H13 - H12) \quad (17)$$

Considering water as an incompressible fluid, the work done can also be expressed as:

$$Wbfp = M12 * V12 * (P13 - P12) * 1000 / (E_{bfp} / 100) \quad (18)$$

Combining equations (17) and (18), the enthalpy at the pump discharge (H13) can be obtained.

- High-pressure, closed-type feedwater heater



From the above figure it can be seen that:

$$T14 = Tsat(P19) - TTD19 \quad (19)$$
$$T10 = Tsat(P12) + TD10 \quad (20)$$

Mass balance:

$$\sum_i m_i = \sum_j m_j$$

in out

Energy balance:

$$Q - W = \sum_j m_j H_j - \sum_i m_i H_i$$

heat work out in

Considering the whole feedwater heater as an open system where an adiabatic process takes place without any work exchange with its surroundings, we have:

$$\sum_i m_i H_i = \sum_j m_j H_j$$

in out

Combining both mass and energy balances, the model equations are:

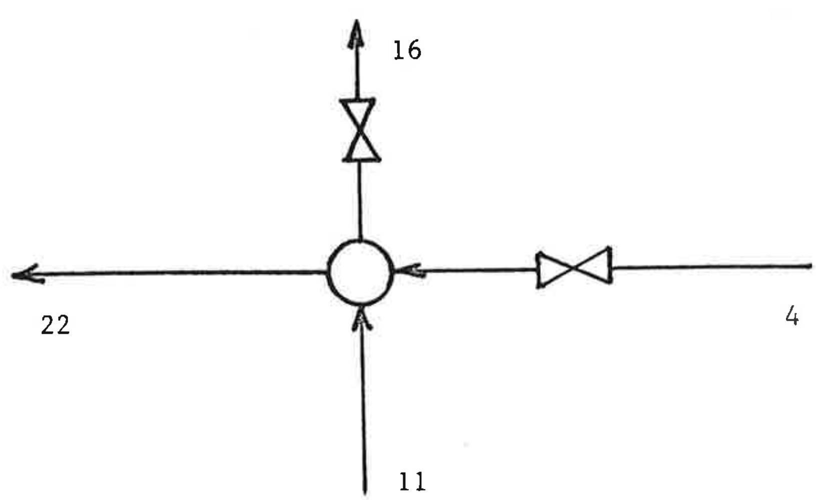
$$M19 = M10 \qquad M13 = M14 \tag{21}$$

$$M19*H19 + M13*H13 = M10*H10 + M14*H14 \tag{22}$$

The steam mass flow in the high-pressure feedwater heater is:

$$M19 = M13 * (H14 - H13)/(H19 - H10) \qquad \text{STEAM IN} \tag{23}$$

- Mixing of flow of the second extraction steam and the flow of the feedwater pump turbine exhaust



Mass balance:

$$\sum_i m_i = \sum_j m_j$$
$$\text{in} \qquad \text{out}$$

Energy balance:

$$\underset{\text{heat}}{Q} - \underset{\text{work}}{W} = \underset{\text{out}}{\sum_j m_j H_j} - \underset{\text{in}}{\sum_i m_i H_i}$$

Considering an adiabatic mixing process taking place without any exchange of work, we have:

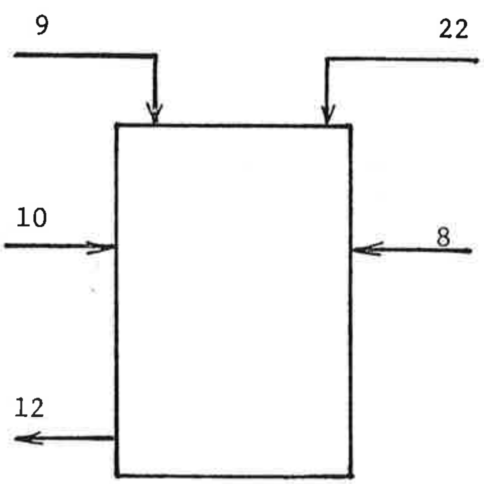
$$\underset{\text{in}}{\sum_i m_i H_i} = \underset{\text{out}}{\sum_j m_j H_j}$$

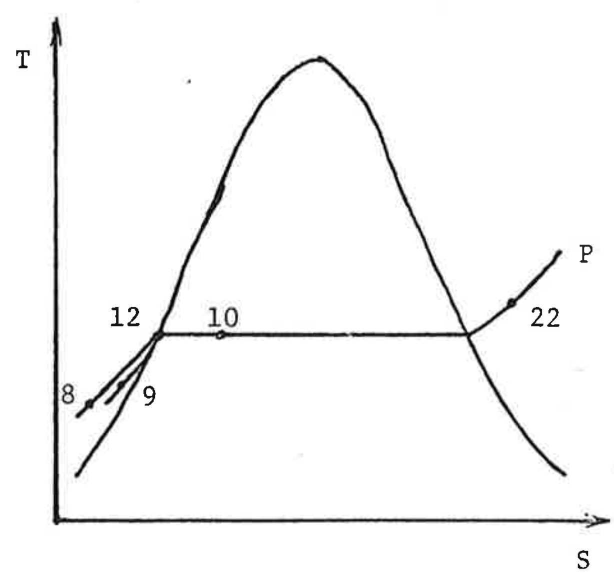
Combining both mass and energy balances, the model equations are:

$$M4 + M11 = M22 + M16 \tag{24}$$

$$M4*H4 + M11*H11 = M22*H22 + M16*H16 \tag{25}$$

- Deaerator





Mass balance:

$$\sum_i m_i = \sum_j m_j$$
$$\text{in} \qquad \text{out}$$

Energy balance:

$$Q - W = \sum_j m_j H_j - \sum_i m_i H_i$$
$$\text{heat} \quad \text{work} \quad \text{out} \qquad \text{in}$$

Considering the deaerator as an open system where an adiabatic mixing process takes place without any exchange of work with its surroundings, we have:

$$\sum_i m_i H_i = \sum_j m_j H_j$$
$$\text{in} \qquad \text{out}$$

Combining both mass and energy balances, the model equations are:

$$M8 + M9 + M10 + M22 = M12 \tag{26}$$

$$M8*H8 + M9*H9 + M10*H10 + M22*H22 = M12*H12 \tag{27}$$

Combining equations (25) and (27), we obtain M4 and M22.

- Combustion analysis

The mass balance considered for complete combustion was the following:

$$\begin{aligned}(c/12)C + (h/1)H + (o/16)O + (w/18)H_2O + (c/12+h/4-o/32)(1+m)(O_2+3.76N_2)\rightarrow \\ \rightarrow (c/12)CO_2 + (h/2+w/18)H_2O + m(c/12+h/4-o/32)O_2 + \\ + (c/12+h/4-o/32)(1+m)(3.76)N_2\end{aligned} \tag{28}$$

The energy balance in the steam generator is:

$$Q - W = \sum_j m_j \Delta H_j - \sum_i m_i \Delta H_i$$
$$\text{heat} \quad \text{work} \quad \text{reactants} \quad \text{products}$$

Considering Q as the heat released in the combustion process that can be used for steam production, the energy equation can be expressed in the following form:

$$\Delta HAIR \Big]_{T_{ini}}^{T_{ain}} + \Delta HFUEL \Big]_{T_{ini}}^{T_{fin}} + HHVwet =$$

$$= \Delta HCO_2 \Big]_{T_{refC}}^{T_{stack}} + DHN_2 \Big]_{T_{refC}}^{T_{stack}} + \Delta HO_2 \Big]_{T_{refC}}^{T_{stack}} +$$

$$+ \Delta HH_2O \Big]_{T_{refC}}^{T_{stack}} + Q \qquad (29)$$

The heat available for steam generation must take into account the losses due to unburnt solids, radiation, convection and incomplete combustion; therefore:

$$HEATav = Q * USloss * RADloss * IMCloss \qquad (30)$$

The efficiency of the boiler is given by:

$$Eboiler = (HEATav)/(HHVwet) \qquad (31)$$

PROGRAM APPLICATION IN COGENERATION FACILITIES

Two applications of the STEAM program are discussed here.

Cogeneration plant proposed for the Monymusk Sugar Factory in Jamaica

The projected actual performance of the plant on which the computer model was based, a regenerative Rankine system proposed for the Monymusk Sugar Factory [6], was used to check the accuracy of the model. The proposed facility at Monymusk consists of two biomass-fired, spreader-stoker type steam generators and a single tandem compound condensing type turbine generator with two extractions. During the harvesting season the unit will burn bagasse and provide low and high pressure process steam and will produce electric power for internal use or for sale. In the off-season, the unit would operate on barbojo as a power producer only, generating electricity for sale to the utility grid.

Table B.1 Assumed steam power plant characteristics used as inputs to model the cogeneration facility proposed for Monymusk.

--- STEAM GENERATOR ---
- INLET WATER PRESSURE (MPa) = 7.68
- OUTLET STEAM PRESSURE (MPa) = 6.31
- OUTLET STEAM TEMPERATURE (^{o}C) = 482.22
- MAIN TOTAL STEAM FLOW (KG/HR) = 149820.00
- BLOWDOWN MASS FLOW (KG/HR) = 4494.60
- MOISTURE OF FUEL ENTERING (% KGH2O/KGWETFUEL)= 50.00
- TEMPERATURE OF FUEL ENTERING (^{o}C) = 25.00
- TEMPERATURE OF COMBUSTION AIR ENTERING (^{o}C) = 80.00
- EXCESS COMBUSTION AIR (%)= 40.00
- TEMPERATURE OF COMBUSTION GASES LEAVING THE STACK (^{o}C) = 240.00
- RATIO OF WET FUEL TO CANE (KGFUEL/KGCANE) = 0.30
- HIGH HEATING VALUE OF THE FUEL (KJ/KGWETFUEL) = 9284.00

--- STEAM TURBINE ---
- FIRST SECTION EFFICIENCY (%) = 81.00
- SECOND SECTION EFFICIENCY (%) = 81.00
- THIRD SECTION EFFICIENCY (%) = 81.00
- FIRST EXTRACTION PRESSURE (MPa) = 1.48
- SECOND EXTRACTION PRESSURE (MPa) = 0.24
- PRESSURE DROP FROM BOILER TO STEAM TURBINE (%) = 5.60
- PRESSURE DROP FROM EXTRACTION 1 TO HIGH PRESS. HEATER (%) = 7.64
- PRESSURE DROP FROM EXTRACTION 2 TO DEAREATOR (%) = 4.89
- GENERATOR EFFICIENCY (%) = 93.00

--- CONDENSER ---
- CONDENSER PRESSURE (MPa) = 0.01
- CONDENSER PUMP OUTLET PRESSURE (MPa) = 0.72
- CONDENSER PUMP EFFICIENCY (%) = 80.00
- STEAM JET AIR EJECTOR MASS FLOW (KG/HR) = 227.00

--- BOILER FEEDWATER TURBINE ---
- MASS FLOW (KG/HR) = 8172.00
- TURBINE EFFICIENCY (%) = 76.00
- BOILER FEEDWATER PUMP EFFICIENCY (%) = 80.00

--- HIGH PRESSURE FEEDWATER HEATER ---
- TERMINAL TEMP. DIFFERENCE (HIGH TEMP. SIDE (^{o}C)) = 2.77
- TERMINAL TEMP. DIFFERENCE (LOW TEMP. SIDE (^{o}C)) = 5.55

--- PROCESS STEAM CONDITIONS ---
- TEMPERATURE OF HIGH PRESSURE STEAM (^{o}C) = 253.00
- MASS FLOW OF HIGH PRESSURE STEAM (KG/HR) = 66284.00
- TEMPERATURE OF LOW PRESSURE STEAM (^{o}C) = 173.00
- MASS FLOW OF LOW PRESSURE STEAM (KG/HR) = 19976.00

Table B.1 lists the input parameters to the STEAM program, based on the proposed Monymusk facility [7] and the following additional assumptions:

- The analysis of the fuel considered (bagasse in this case) is the following [8]:

FUEL CONSTITUENT	KG / KG dry fuel
Carbon (C)	0.44
Hydrogen (H)	0.06
Oxygen (O)	0.46
Ash (S)	0.04

- The moisture content (w) was taken as 0.5 KG/KGwetfuel, the high heating value as 9284 KJ/Kgwetfuel and the ratio of wet fuel to cane (bagasse recovery) as 0.30 [9].

- For the steam generating unit, 40% excess combustion air, preheating of the air up to 80 ^{o}C and a stack temperature of 240 ^{o}C was assumed. A factor of 0.975 was given to both the unburnt solids and the radiation and convection losses as suggested for the furnace type assumed [10]. A factor of 0.96 was used for the incomplete combustion losses [11].

- The polytropic efficiency for a multistage condensing type steam turbine was taken from Figure B.3 for a 35000 KW, 6 MPa model [12]. The same efficiency for all the turbine sections was assumed.

- The polytropic efficiency for the feedwater pump turbine, for all the pumps in the system and for the electric generator was given a value of 76%, 80% and 93% respectively [13].

- Barbojo was the fuel used for the analysis of the off-season case. The composition and heating value of the fuel were assumed to be the same as those for barbojo, except for adjustments due to a different moisture content (0.25 Kg$H_2$0/Kgwetfuel). The higher heating value was, therefore, 12548 KJ/Kgwetfuel. No process steam is required during the off season; therefore the input parameters to the program were:

  High pressure process steam
  Pressure: 1.48 MPa
  Temperature: 253 ^{o}C
  Mass flow: 0 Kgsteam/hr

  Low pressure process steam
  Pressure: 0.24 MPa
  Temperature: 173 ^{o}C
  Mass flow: 0 Kgsteam/hr

Table B.2 shows the pressure, temperature, mass flow and enthalpy calculated at each stage of the steam cycle depicted in Figure B.1. The

Table B.2. Calculated steam cycle parameters (proposed Monymusk plant).

CYCLE STAGE	PRESSURE (MPa)	TEMPERATURE (°C)	MASS FLOW (KG/HR)	ENTHALPY (KJ/KG)
1	6.31	482.22	149820.00	3381.08
2	5.96	482.22	149593.00	3385.26
3	1.48	315.84	88272.03	3080.49
4	0.24	147.84	18313.15	2761.40
5	0.01	49.13	43007.82	2383.53
6	0.01	49.13	47729.42	205.91
7	0.72	49.13	47729.42	206.81
8	0.72	49.13	44507.11	206.81
9	0.23	124.43	86260.00	522.66
10	0.23	129.98	17038.34	546.23
11	0.24	156.84	8172.00	2781.10
12	0.23	124.43	154314.60	522.66
13	7.68	124.43	154314.60	532.58
14	7.68	191.07	154314.60	812.43
15	1.48	253.00	66284.00	2940.79
16	0.24	173.00	19976.00	2815.32
17	0.72	49.13	3222.31	206.81
18	1.48	147.84	63061.69	3080.49
19	1.37	315.84	17038.34	3080.80
20	1.48	315.84	8172.00	3080.49
21	6.31	482.22	227.00	3381.08

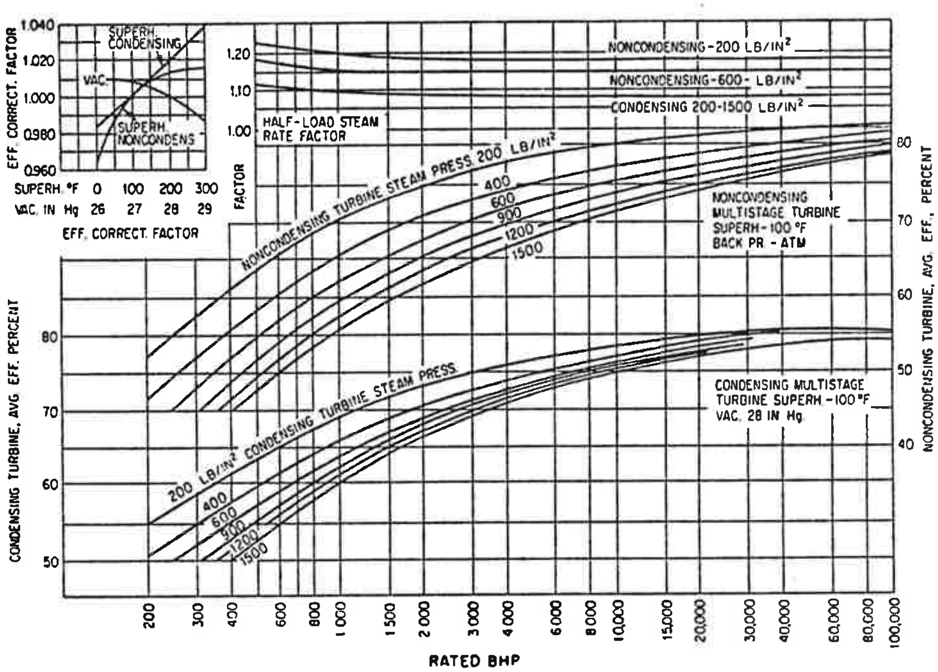


Figure B.3. Average efficiency of multistage steam turbines [14].

comparison between the calculated and the given [15] main performance characteristics of the cogeneration power plant are listed in Table B.3.

Table B.3 Cogeneration facility performance comparison.

---- ON-SEASON ----

		CALCULATED	FROM [1]
* HEAT INPUT TO STEAM GENERATOR (KJ/KGWETFUEL)			
- HEATING VALUE OF FUEL	:	9284.00	9284.00
- SENSIBLE ENTHALPY OF FUEL	:	3.51	NA
- SENSIBLE ENTHALPY OF AIR	:	286.67	NA
TOTAL HEAT INPUT	:	9574.18	NA
* HEAT LOSSES (KJ/KGWETFUEL)			
- CO2 FLUE GASES	:	16.30	NA
- N2 FLUE GASES	:	520.53	NA
- O2 FLUE GASES	:	40.98	NA
- H2O VAPOR	:	2085.96	NA
TOTAL HEAT LOSSES	:	2663.77	NA
* HEAT AV. FOR STEAM GENERATION (KJ/KGWETFUEL)	:	6306.44	NA
* BOILER EFFICIENCY (%)	:	67.93	NA
* FUEL CONSUMPTION RATE (TONWETFUEL/HR)	:	61.02	61.87 (a)
* CANE CONSUMPTION RATE (TONCANE/HR)	:	203.41	206.23
* RATIO OF TONS OF PROCESS STEAM/TONCANE	:	0.42	0.41
* ELECTRICAL POWER OUTPUT (GROSS KW)	:	21030.86	21067.00
* ELECTRICITY GENERATED (GROSS KWH/TONCANE)	:	103.39	102.15
* ELECTRICAL POWER OUTPUT (NET KW)	:	19603.86	19640.00
* ELECTRICITY GENERATED (NET KWH/TONCANE)	:	96.37	95.23
* TOTAL CYCLE EFFICIENCY (FUEL TO ELECTRICITY)	:	13.36	13.20

---- OFF-SEASON ----

* FUEL CONSUMPTION RATE (TONWETFUEL/HR)	:	40.45	40.64 (b)
* ELECTRICAL POWER OUTPUT (GROSS KW)	:	33335.06	34250.00
* ELECTRICAL POWER OUTPUT (NET KW)	:	31335.00	32250.00
* TOTAL CYCLE EFFICIENCY (FUEL TO ELECTRICITY)	:	23.64	24.17

(a) Bagasse is the on-season fuel
(b) Barbojo is the off-season fuel

While a number of assumptions have been made regarding the characteristics of the proposed Monymusk plant, the STEAM model appears to give a system performance similar to that projected in [16].

Cogeneration plants at factories with different process steam demands

To assess the effect of reduced process steam demand on the cogeneration plant performance, three cases were analyzed using the STEAM program. The process steam demands were chosen according to those at "conventional", "steam conserving" and "electrified" raw sugar factories, as discussed in Appendix G. The cane throughput of the factories was assumed to be 175 Tons/hr.

"Conventional" sugar factory case

In this sugar factory operating mode, all of the system characteristics and assumptions of the model described in the previous section are kept with the exception of the following changes:

- To accomodate the amount of bagasse produced by the processing of 175 tons of cane per hour the cogeneration facility capacity was reduced in size. This was done by decreasing the main total steam flow of the cycle to 132650 Kg/hr and keeping the same parameters of the power plant described above.

- The process steam conditions were changed to satisfy the requirements of the conventional sugar factory case (209 Kgsteam/Tcane at 2.07 MPa and 165 Kgsteam/Tcane at 0.24 MPa). Therefore the input parameters were:

  High pressure steam
  Pressure: 2.07 MPa
  Temperature: 315 ^{o}C
  Mass flow: 36575 Kgsteam/hr

  Low pressure steam
  Pressure: 0.24 MPa
  Temperature: 121 ^{o}C
  Mass flow: 28875 Kgsteam/hr

- As in the cogeneration plant proposed for Monymusk, barbojo was the fuel used for the analysis of the off-season case in the "conventional" sugar factory. The composition, moisture and high heating value of the fuel were taken from the Monymusk plant case. No process steam is required in the off-season; therefore the input parameters to the program were:

  High pressure process steam
  Pressure: 2.07 MPa
  Temperature: 315 ^{o}C
  Mass flow: 0 Kgsteam/hr

Low pressure process steam
Pressure: 0.24 MPa
Temperature: 121 ^{o}C
Mass flow: 0 Kgsteam/hr

"Steam conserving" sugar factory case

The same assumptions made in the "conventional" sugar factory operating mode were applied to the steam conserving case with the exception of the process steam characteristics (209 Kgsteam/Tcane at 2.07 MPa). Therefore the input parameters were:

High pressure steam
Pressure: 2.07 MPa
Temperature: 315 ^{o}C
Mass flow: 36575 Kgsteam/hr

Low pressure steam
Pressure: 0.24 MPa
Temperature: 121 ^{o}C
Mass flow: 0 Kgsteam/hr

The "steam conserving" sugar factory off-season case has the same assumptions and results as the one in the "conventional" plant case.

"Electrified" sugar factory case

The same assumptions made in the conventional sugar factory operating mode were applied to the electrified factory case with the exception of the process steam characteristics (100 Kgsteam/Tcane at 0.24 MPa).
Therefore the input parameters were:

High pressure steam
Pressure: 2.07 MPa
Temperature: 315 ^{o}C
Mass flow: 0 Kgsteam/hr

Low pressure steam
Pressure: 0.24 MPa
Temperature: 121 ^{o}C
Mass flow: 17500 Kgsteam/hr

The "electrified" sugar factory off-season case has the same assumptions and results as the ones in the "conventional" plant case.

The results obtained for each of the cogeneration plants with different process steam demands are shown in Table B.4.

Table B.4. Performance of different operating modes of a sugar factory

Case	Cane consumption (Tons/hr)	Fuel* consumption (Tons/hr)	Electricity generated (Net Kw)	Elec-cane ratio (Kwh/Ton)
<u>On-season</u>				
Conventional case	175.0	52.5	17952	102.5
Steam conserving case	175.0	52.5	20376	116.0
Electrified factory case	175.0	52.5	25478	145.5
<u>Off-season</u>		34.8	26951	

* Fuel consumption refers to bagasse consumption during the on-season and barbojo consumption during the off-season.

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1. Ronco Consulting Corporation and Bechtel National, Inc., "Jamaica Cane/Energy Project Feasibility Study," funded by the US Agency for International Development and the US Trade and Development Program, Washington, DC, 1986.

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Appendix C

COMPUTER SOFTWARE FOR GAS TURBINE, STEAM TURBINE, AND SUGAR FACTORY CALCULATIONS

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CONTENTS:

Gas Turbine Systems C.1

- Indirectly-Fired C.1
- Gasifier-Gas Turbines C.1

Steam Turbine Systems C.1

- Small Turbo-Generators C.1
- Double-Extraction Condensing C.1

Factory End-Use Equipment C.1

- Evaporators C.1
- Juice Heaters C.2
- Cane Mills C.2
- Electric Motors C.2

References for Appendix C C.2

A number of computer programs were written in the course of the present study to facilitate technical analysis of gas turbine systems, steam turbine systems, sugar factory end-use equipment, and electric motors, as summarized in this appendix. All of the software was written in Pascal and compiled with the Turbo Pascal compiler, except for one program which was written in FORTRAN. All programs were written for IBM-PC or compatible microcomputers. Unannotated listings of the programs are included in Appendix I.

Gas Turbine Systems

Indirectly-Fired: A core program was developed to model indirectly-fired simple and STIG cycles. For detailed discussion of the modeling of steam or water injected gas turbines, see [1] and [2]. For modeling of fluidized-bed combustor/heat exchangers, see [3]. Additional programs, consisting primarily of mass and energy balances, were written to model evaporative cooling, bagasse drying, topping combustion, and recovery of latent heat from exhaust gases. Some of the results from this modeling effort are given in Appendix A.

Gasifier-Gas Turbines: The performance of gasifier-STIG systems were based on discussions with General Electric personel [4,5]. (See Appendix A.) In addition, a generalized gas-turbine performance computer program (written in FORTRAN) was developed [6] to assist in future modeling efforts.

Steam Turbine Systems

Small Turbo-Generators: Small back-pressure and condensing steam-turbine-generator systems like those found in most sugar factories today were modeled based primarily on [7].

Double-Extraction Condensing: A model was developed for a double-extraction condensing steam turbine cycle using parameters for the proposed system at the Monymusk factory [8] together with assumed values for additional parameters which wer not available for the Monymusk design. This model was used primarily to predict the general effect of factory steam conservation on the performance of the steam turbine. The model and results of parametric calculations are described in Appendix B.

Factory End-Use Equipment

To estimate the steam demands of raw sugar factories, a number of factory components were modeled. The modeling, which is discussed in greater detail in Appendix G, was based largely on [9] and discussions with industry experts.

Evaporators: Three evaporator technologies were modeled: (1) short-tube rising film (Robert or Calandria) evaporators, which are found in the vast majority of sugar factories today; (2) falling film evaporators, and; (3) evaporators using in conjunction with mechanical vapor recompression.

Juice Heaters: Two juice heater technologies were modeled: shell-and-tube heat exchangers and plate-and-gasket heat exchangers. Conventional steam-to-juice heat transfer was considered, as was condensate-to-juice heat transfer.

Cane Mills: The cane milling power requirements were modeled as a function of the fiber content of the cane.

Electric Motors: Software was developed to predict the performance of individual electric motors based on input values for key measured variables. The electric-motor modeling and measurement program is discussed in detail in Appendix H.

References for Appendix C

1. E.D. Larson and R.H. Williams, "Technical and Economic Analysis of Steam-Injected Gas Turbine Cogeneration," in Energy Sources: Conservation and Renewables, D. Hafemeister, H. Kelly, and B. Levi (eds.), American Institute of Physics, New York, 1985.

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Appendix D

CAPITAL AND O&M COST ESTIMATES FOR GAS TURBINES AND STEAM TURBINES FIRED WITH BIOMASS

Eric Larson

CONTENTS:

Capital Costs D.1

Operating and Maintenance Costs D.1

- Operating-Labor Cost Estimates D.1
- Maintenance Costs D.2
- Summary D.2

Previous Studies D.2

- Biomass-Fired Steam Turbine Systems D.2
  - Jamaica Cane/Energy Project D.2
  - Wood-Residue-Fired Cogeneration D.2
  - Power-Only and Cogeneration Plants D.2
  - 7.6 MW Wood-Fired Powerplant D.3
- Indirectly-Fired Gas Turbine Systems D.3
  - 8 MW Biomass-Fired Combined Cycle D.3
  - 10 MW Biomass-Fired Combined Cycle D.3
  - Steam-Injected Coal-Fired Gas Turbine D.3
- Gas Turbines Fired Directly with Gasified Biomass D.3
  - Coal-Gasifier STIGs D.3

Figure D.4

Tables D.5

References for Appendix D D.16

CAPITAL COSTS

Table D.1 gives unit installed capital cost estimates for gas turbine and steam turbine power plants used in the financial analysis in the present study. As discussed in this appendix, the estimates were developed from a number of detailed engineering design studies, engineering scoping studies, and discussions with industry experts.

For steam turbine systems, the scale economies are evident in Table D.1. Based on values shown there, the unit cost for condensing-extraction steam turbines can be estimated as

$$\$/kW = C_o \times (MW)^{-0.30},$$

where C_o = 4182 and MW is the rated net generating capacity in megawatts.

For indirectly-fired steam-injected gas turbines, the cost estimates for the two smaller systems in Table D.1 have been developed based on combined-cycle cost estimates. Taken together the second and the third estimate shown (for a coal-fired steam-injected gas turbine), suggest that there are no scale economies for these systems. This is reasonable since the fuel-handling and combustion equipment for the larger capacity units would generally require field assembly rather than shop fabrication, which adds cost, while smaller systems would suffer some penalty in efficiency. This rough approximation has been verified through discussion with industry personel [1]. For the present study, the average of the 3 unit costs shown in Table D.1 ($1900/kW) is used in the financial analysis.

There appear to be stronger scale economies associated with the steam-injected gas turbine powerplants using gasified biomass (Table D.1), though not as strong as for the steam turbine system. Even in the 50 MW size range, it is expected that shop fabrication could be utilized extensively, since the fuel conversion system would be a high-pressure unit, which contributes to lowering overall material requirements. For gas-turbine units sized between 5 and 52 MW, the unit capital cost is estimated from

$$\$/kW = C_o \times (MW)^{-0.22},$$

where C_o = 2371.

OPERATING AND MAINTENANCE COSTS

Operating-Labor Cost Estimates: The operating labor requirements for both steam-turbine and gas-turbine cogeneration systems operating on solid fuels would be comparable, since both utilize a turbine/generator, a pressurized boiler, and a solid-fuel combustion system. Based on detailed engineering design studies and discussions with cogeneration plant operators in the United States, the estimated minimum labor required to operate and maintain biomass-fueled cogeneration plants of up to 20 MW capacity would be as shown in Table D.2. For larger plants, the number of employees at a plant will depend strongly on local practices. A relationship between the number of employees and plant capacity for Jamaican power plants has been developed (Figure D.1), based on actual employment data for electric utility plants in Jamaica [2].

Labor wage rates will strongly depend on the local employment practice. For the present analysis, the average annual salary of a utility power plant employee in Jamaica, $5400 [3], is used.

Maintenance Costs: Fixed ($/kW-yr) and variable ($/kWh) maintenance costs for steam turbine and gas-turbine powerplants have been estimated based on previous studies (Table D.3). These costs are quite similar for steam-turbine and indirectly-fired gas turbine plants, because both systems require the processing of large volumes of fuel through similar combustion and heat exchanger systems, and the fuel-handling/combustion maintenance costs are significantly larger than those associated exclusively with the prime mover. For the gas turbine fired with gasified biomass, the estimated fixed maintenance costs are comparable to those for the other systems, but the variable costs are considerably lower. The lower variable cost is attributed primarily to the absence of heat exchanger tubes operating in direct contact with burning solid fuel.

Summary: Table D.4 summarizes all of the cost-related assumptions used in the financial analysis for three sizes of steam turbine powerplants and for gas turbine powerplants based on specific engines.

PREVIOUS STUDIES

Tables D.1-D.4 were developed based on detailed engineering design studies, engineering scoping studies, and discussions with industry experts, as described in this section.

Biomass-Fired Steam Turbine Systems

Jamaica Cane/Energy Project: The feasibility study by Bechtel National Inc. of a cogeneration facility for the Monymusk Sugar Factory provides cost estimates for a single-controlled-extraction condensing steam-turbine system [4]. In the full condensing mode, this plant is rated to produce 32.25 MW of electricity (net of plant). In the extraction mode, it will produce 19.64 MW of electricity (net) plus 66,400 kg/hr of 1.5 MPa superheated process steam and 20,000 kg/hr of saturated process steam at 0.2 MPa. In the base case analyzed by Bechtel, the plant would produce 171.1 million kWh of electricity annually. The estimated capital and O&M costs for this plant are given in Table D.5.

Wood-Residue-Fired Cogeneration: In a study done for the Electric Power Research Institute [5], the performance and costs of 6 MW_e, 12 MW_e, and 24 MW_e biomass-fired cogeneration systems that would be located in the Northwestern part of the United States have been evaluated. Each system would supply electricity and 20,455 kg/hr of saturated process steam at about 1 MPa pressure. The report provides detailed capital and O&M cost estimates, as shown in Table D.6.

Power-Only and Cogeneration Plants: Another study for the Electric

Power Research Institute [6] assesses the performance and cost of two steam-turbine based power plants, one supplying power only and the other supplying both process steam and power. The power only plant utilizes a condensing steam turbine to produce 25 MW of electricity. The cogeneration plant uses a single-extraction condensing steam turbine to produce 19.74 MW of electricity and 29,545 kg/hr of saturated steam at 1.7 MPa. The cost estimates for these plants are given in Table D.7.

7.6 MW Wood-Fired Powerplant: This is discussed in the second paragraph of the following section.

Indirectly-Fired Gas Turbine Systems

8 MW Biomass-Fired Combined Cycle: Braun and Wilkinson [7] present a detailed conceptual plant design and analysis of a biomass-fired combined-cycle powerplant rated to produce 8 MW_e. The system would burn 42% wet hog-wood fuel using gas turbine exhaust as combustion air in an advanced, ceramic-based spreader-stoker type combustor, the hot gases from which would transfer heat through a ceramic heat exchanger to pressurized air, heating it to 954°C. The hot air would drive a Nuovo Pignone MS1002 gas turbine, nominally rated at 4530 kW with natural gas, but derated to 3993 kW with indirect firing. The combustor flue gases would then raise steam in a HRSG, which would drive a condensing steam turbine to produce an additional 4750 kW. Estimates of the capital and O&M cots for the 8.7 MW_e plant are shown in Table D.8.

10 MW Biomass-Fired Combined Cycle: Becker, Nobe, and Watson [8] present the results of a study of two combined-cycle, power-only systems burning 50% wet biomass, both with a gas-turbine inlet temperature of 943°C (1730°F). The study specifies the use of wet-cell gasifier/combustors, with one system using a ceramic air heat exchanger, and the other using a metallic heat exchanger plus an auxiliary-fuel trim burner between the air heater and turbine inlet. The gas turbine considered is the Nuovo Pignone MS1002 (rated 4530 kW ISO, but derated to 3969 kW with indirect firing). The performance of the two systems are comparable, and only a single cost estimate is provided. Average net power output for the two plants is 9230 kW, and cycle efficiency is 21.0% (HHV). For comparison, they calculate the performance of a steam-turbine cycle consuming the same amount of fuel. In this case, 7600 kW are produced at an efficiency of 17.3%. Table D.9 shows some of the economic comparisons provided in the study.

Steam-Injected Coal-Fired Gas Turbine: Davis and Fraize [9] have developed a cost estimate for a generic, 51.2 MW_e indirectly-fired steam injected gas turbine cycle burning coal in an atmospheric fluidized-bed combustor. No operating and mainatenance costs are given. The cost breakdown is shown in Table D.10.

Gas Turbines Fired Directly with Gasified Biomass

Coal Gasifier/STIGs: The expected performance and detailed costs of several powerplants fired directly with gasified coal from an air-blown

Lurgi gasifier are given by Corman in a study conducted for the US Department of Energy [10]. The technical performance of the systems of interest are described in Appendix A. Costs for a 101 MW coal-gasifier-STIG system utilizing two Lurgi Mark IV gasifiers and 2 LM-5000 STIGs are given in Table D.11. A cost estimate for a 5 MW coal-gasifier STIG based on the LM-500 with steam injection is given in Table D.12.

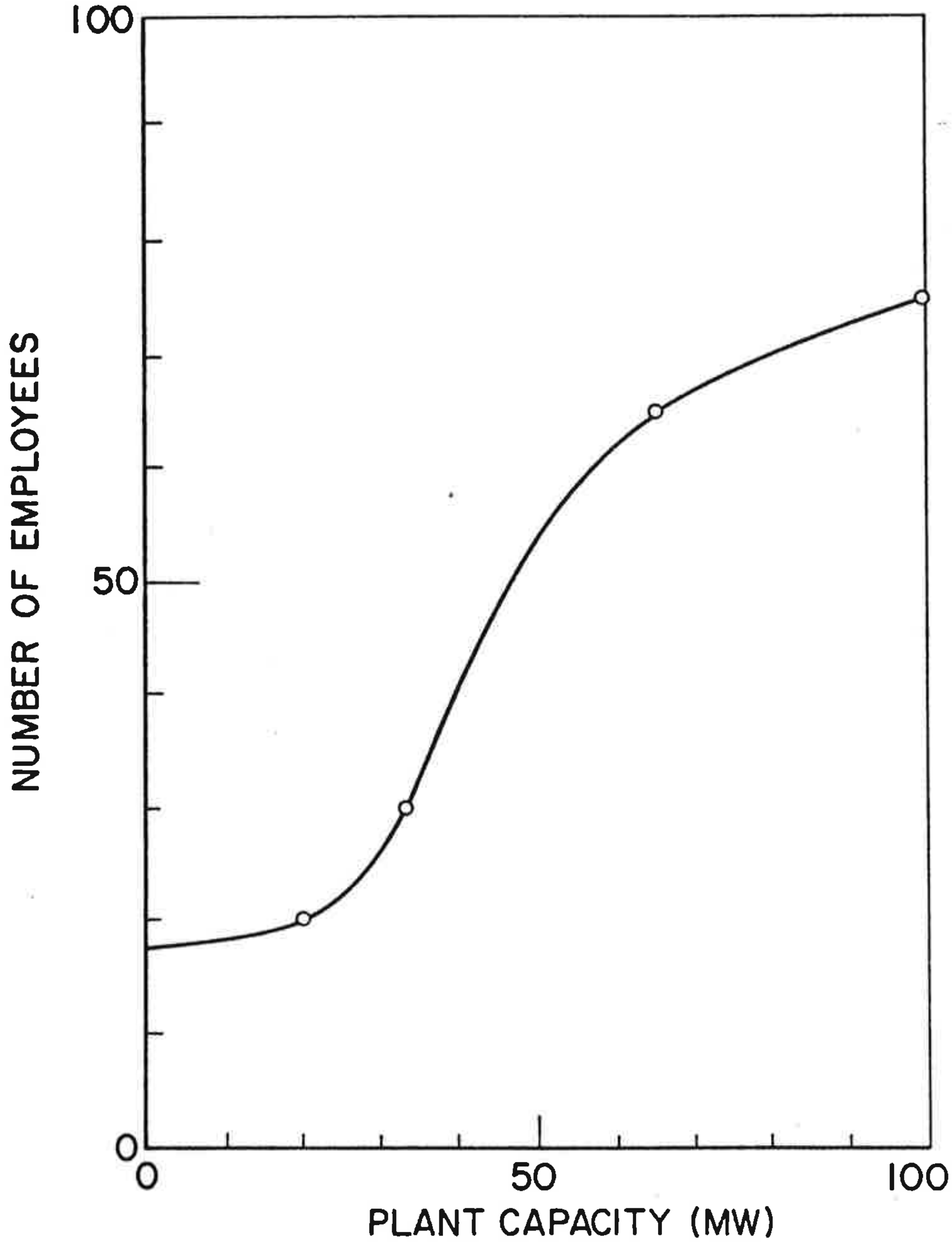

Figure D.1. Estimated number of full-time employees required at cogeneration plants with rated capacity from 0 to 100 MW, based on data on Jamaican electric utility powerplants provided in [11].

Table D.1. Summary of estimated unit installed capital costs for biomass-fired power-only and cogeneration plants.

Primary Reference	Electrical Output (MW)	Installed Cost[a] (1985 $/kW)
Steam-Turbines		
[12]	32.25	1,480
[13]	25.0	1,750
[14]	7.6	2,280
Indirectly-Fired Steam-Injected Gas Turbines		
[15]	8.7	1,400[b]
[16]	9.2	2,210[b]
[17]	51.2	2,130[c]
Gasifier-Steam-Injected Gas Turbines		
[18]	53	990[d]
[19]	5	1,650[e]

[a]Costs have been converted to constant 1985 dollars using the GNP deflator.

[b]From the original cost estimate for an indirectly-fired combined cycle was subtracted the steam-turbine-related costs (8% of the total). An added cost of $150/kW was assumed for replacement of the conventional simple-cycle gas turbine engine with a steam-injected one.

[c]Original cost estimate for a coal-fired system.

[d]From the original cost estimate for a coal-fueled system (involving 2 LM-5000 gas turbines) have been subtracted the costs associated exclusively with coal (chemical sulfur removal), which represents about 20% of the original cost estimate.

[e]Projected for a system based on the General Electric GE-38 gas turbine to be introduced commercially in the early 1990s. This estimate was obtained from one based on the General Electric LM-500 gas turbine, from which was subtracted $100/kW, to account for the lower expected cost of the GE-38 compared to the LM-500 engine.

Table D.2. Estimated labor requirements for operation and on-site maintenance of biomass-fired cogeneration systems.[a]

Title	Full-Time Positions
Management	
Operations Manager	1
Secretary-bookkeeper	1
Operations	
Control Operator (Steam engineers)	4
Plant Equipment Operators	4
Engineering Technologist	1
Fuel Handler	1
Maintenance	
Mechanical/Electrical Foreman	1
Plant Mechanic	1
Utility Helper	1

[a]Based on engineering design studies [20,21] and discussions with operators of steam-injected gas-turbine cogeneration plants [22,23].

Table D.3. Estimated fixed and variable maintenance costs for biomass-fueled power generating plants.[a]

Primary Reference	Fixed Maintenance (1985 $/kW-yr)	Variable Maintenance (1985 mills/kWh)
Steam-Turbine Systems[b]		
[24]	20.0	2.5
[25]	29.7	3.4
Indirectly-Fired Gas Turbine Systems[c]		
[26]	20.6	2.5
[27]	27.9	3.5
Directly-Fired Gas Turbines Using Gasified Biomass[d]		
[28]	24.8	0.9

[a]Costs have been converted to constant 1985 dollars using the GNP deflator.

[b]Based on operation as power-only plants.

[c]Based on operation of combined-cycle power-only plants.

[d]Based on coal-gasifier-steam-injected gas turbine power-only plant.

Table D.4. Summary of cost assumptions for financial calculations.

PRIME MOVER	ELECTRICAL CAPACITY (MW)	INSTALLED CAPITAL ($/kW)	COST ($10^6$$)	MAINTENANCE Fixed ($10^3$$)	Variable ($/kWh)	OPERATING Employees (Number)	LABOR Cost ($10^3$$)
Condensing-Extraction Steam Turbines							
Generic	27.0	1556	42.01	664.2	0.003	24	129.6
Generic	10.0	2096	20.96	246.0	0.003	18	97.2
Generic	3.0	3008	9.02	73.8	0.003	18	97.2
Indirectly-Fired Steam-Injected Gas Turbines							
ASEA GT-35C	21.4	1900	40.66	526.4	0.003	20	108.0
ALLISON 501-K	3.2	1900	6.08	78.7	0.003	18	97.2
Gasifier-Steam-Injected Gas Turbines							
GE-LM-5000	53.0	990	52.5	1304	0.001	55	297.0
GE LM-1600	20.0	1230	24.5	492.0	0.001	20	108.0
GE GE-38	5.4	1650	8.9	133.0	0.001	18	97.2

Table D.5. Estimated capital and non-fuel operating costs for a condensing-extraction steam-turbine cogeneration plant proposed for construction at the Monymusk sugar factory, Jamaica (1986 US $).[a,b]

CAPITAL COSTS (1000 $)		
Direct Costs		32,800
Boiler island (excluding civil costs)	11,900	
Turbine generator	5,900	
Other mechanical equipment	3,300	
Civil/structural/architectural	2,200	
Piping	3,300	
Electrical and controls	5,900	
Field Indirect Costs (incl. Construction Management)		7,200
Architect/Engineer Services		3,400
Project Insurance Allowance		1,000
Owner/Operator Costs		3,300
Import duties and stamp taxes	2,700	
Initial parts and spares	200	
Initial fuel supply	400	
Total Capital		47,700
OPERATING COSTS (1000 $)		
Fixed Costs		1,285
Supervision and technical payroll	240	
Labor (manual) payroll	120	
Administrative and indirects	225	
Insurance	700	
Variable Costs		530
Maintenance materials and tools	290	
Consumables	240	
Contingencies, Fees, etc. (10%)		185
Total Annual Operating and Maintenance		2,000

[a]Source: [29]

[b]The output is 32.25 MW when operated in the full condensing mode.

Table D.6. Capital and operating cost estimates for three biomass-fired condensing-extraction steam turbine turbine cogeneration systems designed to produce equal amounts of process steam (in 1982$).[a,b]

	6 MW	12 MW	24 MW
Capital Equipment	7,349,900	14,340,100	21,792,700
Yard work	48,800	139,600	191,800
Fuel Handling	626,100	1,851,800	2,293,000
Boiler	3,330,300	7,359,000	10,708,700
Emission Controls	986,900	1,773,300	2,686,700
Turbine/Generator	1,812,300	2,010,900	4,478,100
Switchyard	319,600	496,600	501,900
Utilities	225,900	708,900	931,600
Buildings	1,397,800	1,660,000	2,523,200
Boiler	543,400	765,000	1,162,800
Tubine/Generator	854,400	895,000	1,360,400
Construction Administration	1,242,000	2,317,000	3,521,200
Engineering	753,100	1,410,700	2,144,000
Contingency	993,700	1,877,000	2,852,700
Land Purchase	1,500	15,000	15,000
Escalation	1,577,400	2,866,100	4,372,200
Interest During Construction	1,010,000	2,000,000	2,960,000
TOTAL CAPITAL	14,325,400	26,485,900	40,181,000
Operating Costs	718,000	1,524,100	2,562,100
Fixed	491,000	933,100	1,945,100
Renewals and replacement	67,000	122,000	186,000
Insurance	23,300	46,600	93,100
Operation and maintenance	180,000	351,000	534,000
Administrative and general	28,700	57,500	57,500
Property tax	189,000	350,000	536,000
Fuel inventory cost	3,000	6,000	21,000
Variable	227,000	531,000	617,000
Operating labor[c]	191,400	382,700	382,700
Utilities	35,600	148,300	234,300

[a]Source: [30].

bThe 6 MW, 12 MW, and 24 MW plants produce annually 39,420,000 kWh, 78,840,000 kWh, and 157,680,000 kWh, respectively, and have approximate electricity to heat production ratios of 0.38, 0.77, 1.54.

[c]Based on labor requirements of:

Superintendent	1 per day	1 per day	1 per day
Mechanic/oiler	1 per day	1 per day	1 per day
Boiler Operator	1 per shift	1 per sh.	1 per sh.
Assistant Operator/utility	1 per shift	1 per sh.	1 per sh.
Chip dozer operator	---	1 per sh.	1 per sh.
Dump truck & yard	---	1 per sh.	1 per sh.

Table D.7. Capital and operating cost estimates for biomass-fired steam-turbine cogeneration and power-only plants (in 1979$).[a]

	Power-only 25 MW	Cogeneration[b] 19.74 MW
Total Plant Equipment	27,197,400	27,269,400
Site preparation	3,135,000	3,135,000
Site utilities	431,000	431,000
Buildings and structures	4,952,000	4,952,000
Fuel handling	1,210,000	1,210,000
Refuse handling	331,100	331,100
Steam generator	5,640,000	5,640,000
Turbine/generator	3,290,000	3,380,000
Heat rejection equipment	821,000	750,000
Boiler feedwater equipment	978,500	925,000
Emissions controls	1,843,300	1,843,300
Electrical interface	563,000	563,000
Instrumentation and controls	1,530,000	1,530,000
Contingency (10%)	2,472,500	2,479,000
Engineering (8%)	2,175,800	2,181,600
Management (4.75%)	1,292,000	1,295,300
Land Aquisition	200,000	200,000
TOTAL DIRECT PLANT COST	30,865,200	30,946,300
Operating and Maintenance Costs		
Labor (24 shifts/wk @ $22,700/shift)	544,800	544,800
Overhead (35%)	190,680	190,680
Maintenance (1.7% of direct costs)	524,708	526,087

[a]Source: [31]

[b]Cogeneration plant with an electricity to heat ratio of approximately 0.96.

Table D.8. Estimated capital and operating cost estimates for an 8 MWe combined-cycle power plant, utilizing a ceramic heat exchanger and fired indirectly with biomass (in 1984 $).[a]

a. Plant Capital Equipment Cost	
Land	120,000
Buildings	834,100
Primary ceramic furnace and ceramic heat exchanger	2,435,000
Gas turbine	1,300,000
Hot air piping and valves	419,000
HRSG, dust collector, exhaust stack	1,300,000
Steam turbine and condenser	932,000
Steam piping and valves	66,000
Cooling tower	117,000
Alternator (generator)	605,000
Fuel handling systems	800,000
System controls	430,000
High voltage interconnection equipment	790,000
Miscellaneous power train, pumps, fans, etc.	552,000
Total	$ 10,700,000
b. Indirect Construction Costs	
Includes: Temporary buildings and building maintenance, temporary utilities and utility maintenance, field administration and office staff, quality assurance and control, office equipment, supplies and expenses, and laboratory testing.	
Total (estimate)	$ 475,000
c. Engineering, Design, and Construction Management	$ 1,200,000
d. Contingency Allowance	$ 360,000
e. Client Expenses	$ 100,000
f. Spare Parts (at startup)	$ 236,000
TOTAL CAPITAL COST	$ 13,071,000

Annual Operating Labor Costs

	Positions	Annual Wage	Wage Total
a. Management			
Operations Manager	1	$ 27,500	$ 27,500
Secretary-Bookkeeper	1	$ 14,000	$ 14,000
b. Operations			
Control Operator (Lic. st eng)	4	$ 26,400	$ 105,600
Plant Equipment Operator	4	$ 22,500	$ 90,000
Engineering Technologist	1	$ 25,900	$ 25,900
Fuel Handler	1	$ 22,500	$ 22,500
c. Maintenance			
Mech. and Electrical Foreman	1	$ 26,900	$ 26,900
Plant Mechanic	1	$ 24,100	$ 24,100
Utility Helper	1	$ 18,000	$ 18,000
Subtotal	15		$ 354,500
Overhead (35%)			$ 124,075
Total Operating Labor Costs			$ 478,575
Total Consumable Parts (not itemized)			$ 236,000
TOTAL OPERATING COST (excluding fuel)			$ 714,575
MAINTENANCE COST (not itemized)			3.4 mills/kWh

[a]Source: [32].

Table D.9. Comparison of the estimated characteristics of a biomass-fired combined cycle and a biomass-fired steam-turbine cycle.[a]

	Combined Cycle	Steam Cycle
Power Out (MWh/yr)	74,930	59,981
Fuel Throughput (ton/day)	464	464
Yearly fuel (ton/year)	152,397	152,397
Life of plant (years)	20	20
Total plant cost (1988 $)	22,855,000	18,996,000
Unit cap. costs (1988 $/kW)	2,356	2,442
Annual O&M Costs (1988 $)	835,000	668,000

[a]Source: [33].

Table D.10. Capital cost estimate for a 51.2 MW steam-injected gas turbine fired indirectly and burning coal in an atmospheric fluidized bed combustor (in 1975$).[a]

Component	Total Cost (million $)	Unit Cost ($/kWe)
Coal pulverizers (major components)	0.08	1.60
Air/Steam Heater (major components, 88.8 MWth)	5.57	111.40
Economizer (major components, 38.1 MWth)	1.27	25.40
Electrostatic Precipitator (major components)	0.57	11.40
Turbine-Compressor-Generator (major components)	1.74	34.80
Solids Handling Equipment	1.10	22.00
Stack Gas Scrubber	--	---
Water Treatment Plant	1.77	35.40
Steam Generators (57.5 MWth)	1.93	38.60
Balance of Plant	14.21	284.20
Subtotal	28.24	564.80
A&E Fee and Contingency	9.07	181.40
Interest and Escalation	20.49	409.80
TOTAL	57.80	1156.00

[a]Source: [34].

Table D.11. Estimated costs for 101 MW coal-gasifier/steam-injected gas turbine powerplant (in 1985 $).[a]

CAPITAL COSTS ($/kW)		
I. Process Capital Cost		862.9
Fuel handling and preparation	39.6	
Blast air system	13.5	
Gasification plant	160.9	
Raw gas physical cleanup	8.8	
Raw gas chemical cleanup	175.0	
Gas turbine/HRSG (2 units)	294.4	
Balance of plant, Mechanical	40.2	
Electrical	65.0	
Civil	65.5	
II. Total Plant Cost		1,153.2
Total process capital cost	862.9	
Engineering home office (10%)	86.3	
Process contingency (6.2%)	53.6	
Project contingency (17.4%)	150.4	
III. Total Plant Investment		1,174.0
Total plant cost	1,153.2	
Allowance/funds during construction	20.8	
IV. Total Capital Requirement		1,241.5
Total plant investment	1,174.0	
Prepaid royalties	0.0	
Preproduction costs (2.8%)	32.3	
Inventory capital (2.7%)	31.3	
Initial chemicals & catalysts (0.2%)	2.5	
Land (0.12%)	1.4	
OPERATING COSTS		
I. Fixed Operating Labor (1000 $/yr)		5,095
Operating labor	1,761	
Maintenance labor	1,002	
Administrative & support labor	829	
II. Maintenance Materials ($/kW-yr)		14.9
III. Variable O&M (mills/kWh)		1.0
Raw water		0.3
Solids disposal		0.6
Catalyst and binder		0.1
IV. H_2SO_4 Sales (credit)		-2.4

[a]Source: [35].

Table D. 12. Cost estimates for a 5-MW coal-gasifier-steam-injected gas turbine powerplant (in 1985 $/kW).[a]

Fuel Supply		240
Gas cleanup[b]	117	
Gasifier	45	
Coal Handling	54	
Ash Handling	24	
Gas Turbine/HRSG		374
Construction		549
Buildings/Civil Engineering	184	
Controls	57	
Piping	73	
Electrical	76	
Erection	74	
Spare Parts	38	
Other	47	
Office and Administrative		737
Warranty	47	
Home Office (Engineering, etc.)	215	
Overhead	285	
Margin	190	
TOTAL CAPITAL COST ($/kW)		1,900

[a]Source: [36].

[b]The physical cleanup (including cyclones) would account for less than 5% of the total, based on Table D.11.

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9. F. Davis and W. Fraize (MITRE Corporation), "Steam-Injected Coal-Fired Gas Turbine Power Cycles, Performance and Cost Analysis," prepared for the US Department of Energy, July 1979.

10. J.C. Corman (Program Manager), "System Analysis of Simplified IGCC Plants," prepared for the US Department of Energy by the General Electric Company, Schenectady, New York, September 1986.

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22. J.E. Kaiser, Operations Manager, IPT Energy Management Corporation, Palo Alto, California, personal communication, February 1987.

23. A.C. Iwanick, Power and Recovery Superintendent, Simpson Paper Company, Shasta Mill, Anderson, California, personal communication, February 1987.

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Appendix E

AVOIDED COST CALCULATIONS FOR JAMAICA

Eric Larson
Robert Williams

CONTENTS:

New 61 MW Coal-Steam Power Plant E.1

Existing Oil-Fired Steam Power Plants E.1

Table E.2

References for Appendix E E.2

New 61 MW Coal-Steam Power Plant

A 61 MW steam plant fired with imported coal was identified in a recent study [1] as a least-cost generating expansion option for the Jamaica Public Service electric utility. This plant was chosen as the basis for determining the avoided costs used in the financial analysis presented in the main text. The relevant cost and performance assumptions for this plant are shown in Table E.1, together with a breakdown of the capital, fuel, labor, and maintenance components of the avoided costs for two different coal prices.

Existing Oil-Fired Steam Power Plants

A representative heat rate of 14,500 kJ/kWh was chosen for existing oil-fired steam-turbine power plants in Jamaica for purposes of calculating the cost of generating electricity in oil-steam plants. The average heat rates for the two JPS steam-electric plants in the early 1980s [2] were:

	HEAT RATE (kJ/kWh)	
Year	Hunts Bay	Old Harbour
1981	14,643	15,368
1982	14,992	17,443
1983	14,828	14,458

The O&M costs for these plants in 1983 were \$0.0037/kWh (1983\$) for Hunts Bay and \$0.0028/kWh for Old Harbour. A value of \$0.003/kWh (1985\$) was used for the calculations presented in the main text. With residual oil at \$3.2/GJ, the full generating cost would be (.014500x3.2) + 0.003 = \$0.0494/kWh.

Table E.1. Cost and performance assumptions and levelized busbar costs of generating electricity for a 61 MW coal-fired power plant identified as a least-cost new-generating option for Jamaica.[a]

Assumptions

Capacity (MW net of plant)	61
Full-Load Heat Rate (kJ/kWh)	12,030
Annual Capacity Factor (%)	66
Plant Cost (installed 1985$/kW)	1,195
Coal Infrastructure Cost (1985$/kW)	121[b]
Annual Labor Cost (1000 1985$)	358
Maintenance Cost (1985$/kWh)	0.003
Discount Rate (%/year)	12
Plant Life (years)	30

Levelized Busbar Costs (1985$/kWh)

Coal at:	$1.43/GJ	$2.08/GJ
Capital	0.0283	0.0283
Fuel	0.0172	0.0250
Labor	0.0010	0.0010
Maintenance	0.0032	0.0032
TOTAL	0.0497	0.0575

[a]All assumptions in this table are from [3]. Costs have been converted to 1985 dollars using the US GNP deflator.

[b]No coal delivery system exists today in Jamaica. The $121/kW represents one-sixth of the cost of building a coal-handling port and the associated infrastructure required to deliver coal to 6 plants in Jamaica. The total cost for infrastructure development, based on [4] is estimated to be $44.45 million (1985$).

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1. Montreal Engineering Company (MONENCO), "Least-Cost Expansion Study," prepared for the Jamaica Public Service Company, Ltd., Kingston, Jamaica, 1985.

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Appendix F

SITE VISITS

CONTENTS:

Bechtel Power Corporation Headquarters (October 15, 1986)	F.1
Jamaica (October 28 - November 5, 1986)	F.1
Princeton University (December 1 - December 19, 1986)	F.1
Jamaica (January 9 - January 18, 1987)	F.1
Rosenblad Evaporators (January 21, 1987)	F.1
General Electric Corporate R&D Center (January 28, 1987)	F.2
Industrial STIG Sites (February 11 - February 13, 1987)	F.2
Jamaica (March 15 - March 24, 1987)	F.2
Hawaii (April 22 - April 24, 1987)	F.2
Jamaica (May 15 - May 23, 1987)	F.2
Arlington, Virginia, USA (June 19, 1987)	F.3
Jamaica (June 28 - June 30, 1987)	F.3

In the course of the present study, researchers at the Center for Energy and Environmental Studies participated in a number of site visits and meetings for the purpose of data gathering and information exchange, as listed in chronological order below.

<u>Bechtel Power Corporation Headquarters</u> (Oct. 15, 1986)

Meeting at Bechtel Power Corporation Headquarters, Gaithersburg, Virginia.
CEES participants: Larson, Socolow, Williams.
Bechtel participants: W. Adams, R. Buta, H. Causilla, E. Lam, A. Menendez, G. Soroka, H. Wen.
USAID participants: A. Jacobs, J. Kadyszewski.

<u>Jamaica</u> (Oct. 28 - Nov. 5, 1986)

Visit to Jamaica by Larson, Ogden, Socolow, Williams.
USAID Mission: F. Ahimaz, C. Mathews.
USAID Jamaica Cane/Energy Project: J. Keppeler.
Sugar Industry Research Institute: M. Hylton, I. Sangster.
Jamaica Sugar Holdings: R. Campbell.
New Yarmouth & Appleton: J. Lanigan.
Monymusk Factory: J. Blanchard.
Petroleum Company of Jamaica: R. Ashby, S. Marston.

<u>Princeton University</u> (Dec. 1 - Dec. 19, 1986)

Visit by Francisco Correa (CESP, Brazil) to CEES, Princeton.

<u>Jamaica</u> (Jan. 9 - Jan. 18, 1987)

Visit by Baldwin to Jamaica:
Sugar Industry Research Institute: E. Finlay, M. Hylton, I. Sangster.
Bernard Lodge Factory: W. Johnson, C. Salter.
USAID Mission: F. Ahimaz, C. Mathews.

<u>Rosenblad Evaporators</u> (Jan. 21, 1987)

Visit by Larson and Ogden to Rosenblad Evaporators, Inc., Princeton, New Jersey: A. Rosenblad.

General Electric Corporate R&D Center (Jan. 28, 1987)

Visit by Larson to General Electric Corporate R&D Center, Schenectady, New York: J. Corman, M. Erbes, A. Furman, R. Lavigne, D. Smith.

Industrial STIG Sites (Feb. 11 - Feb. 13)

Visit by Larson to industrial sites in California where steam-injected gas turbine cogeneration systems are operating:
International Power Technology, Inc., Palo Alto and San Jose: J. Kaiser, J. Randolph.
Simpson Paper Company, Anderson: A. Iwanick, J. Burnham.

Jamaica (Mar. 15 - Mar. 24)

Visit by Larson, Ogden, and Williams to Jamaica:
USAID Mission: C. Mathews.
Sugar Industry Research Institute: M. Hylton, I. Sangster.
Jamaica Sugar Holdings: R. Campbell.
New Yarmouth & Appleton: J. Lanigan, M. Meany.
Monymusk Factory: J. Blanchard.
Petroleum Company of Jamaica: R. Ashby, R. Jones, S. Marston.

Hawaii (April 22 - April 24)

Presentation of a paper by Larson and Ogden at the Second Pacific Basin Biofuels Workshop, Kauai Island, Hawaii.

Jamaica (May 15 - May 23)

Visit by Baldwin to Jamaica:
Sugar Industry Research Institute: E. Finlay, M. Hylton.
Bernard Lodge Factory: W.Johnson.
USAID Mission: C. Mathews, D. McClellan.

Arlington, Virginia, USA (June 19)

Workshop on Biomass-Gasifier Steam-Injected Gas Turbine Cogeneration for the Cane Sugar Industry organized by Larson and Williams in Arlington, Virginia.
USAID: John Kadyszewski, Alan Jacobs
Princeton Univ: Williams, Larson, Ogden, Baldwin, Hochgreb, A. Behrens
World Bank: Matthew Mendes
Interamerican Development Bank: Gustavo Calderon
US Trade and Development Program: Jack Williamson
Copersucar (Brazil): Isaias Macedo
DNAEE (Brazil): Benedito Carraro
Univ. of Sao Paulo (Brazil): Jose Moreira
HSPA (Hawaii): Charles Kinoshita
Hamakua Sugar (Hawaii): Francis Morgan, John Bersch
Hawaiian Electric Light Co: Norman Oss
SIRI (Jamaica): Ian Sangster
General Electric: Jim Corman, Tony Furman, Mike Horner, Al Christensen
US DOE: Simon Friedrich, Rita Bajura, John Eustis
Ronco (USA): Jack Keppler
Rockefeller Bros: Tom Wahman
IIEC (USA): Deborah Bleviss
IT Power (USA): Tom Hoffman

Jamaica (June 28 - June 30)

Presentation by Larson and Ogden in Kingston, Jamaica. In attendance:
Jamaica Public Service: Roy Monroe
SIA: Alvin Burnett
JSH: Clyde Williams
PCJ Engineering: Steve Shelton, Roddy Ashby
MMET: Gottfried Perkins
SIRI: Ian Sangster, Mike Hylton
Ronco: Jack Keppler
USAID: Charley Mathews, Henry Steingass