AERODERIVATIVE TURBINES FOR STATIONARY POWER

Robert H. Williams
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INTRODUCTION

A revolution is underway in electricity generating technology. It may soon radically transform the power industry, in both industrial and developing countries. This revolution involves not an exotic new technology, but rather the upgrading of the familiar but little-used gas turbine.

In power generation the gas turbine has been the weak sister of the steam turbine, because of its lower efficiency and requirement for high-quality fuel. In the electric utility industry the gas turbine has until recently been restricted largely to little-used peaking plants; in cogeneration (simultaneous production of electricity and process heat in the same unit), the gas turbine has been used mainly in applications characterized by steady steam loads. Innovations, though, are making it possible for gas turbines to compete in cogeneration markets characterized by variable heat loads, and to compete in central-station applications with conventional baseload and load-following technologies, using low-quality as well as high-quality fuels.

While both heavy-duty industrial turbines (designed specifically for stationary applications) and aeroderivative gas turbines (derived from jet engines) will have important roles in power generation, the focus here is on aeroderivative turbines, especially steam-injected gas turbines (in which large quantities of steam are injected into the combustor and gas path to increase the power output and the electrical conversion efficiency). Though much less familiar than the heavy-duty industrial turbines, aeroderivative turbines offer some important advantages under current and likely future market conditions for stationary power in many parts of the world.

THE PLIGHT OF THE US ELECTRIC UTILITY INDUSTRY

The once rosy outlook for electric power in the United States became clouded in the early 1970s, when an era of predictable load growth and declining prices came abruptly to an end.

Between 1935 and 1973, the sales of electricity by utilities grew fairly steadily and predictably, averaging 8.5% per year, about twice the GNP growth rate in this period. The share of GNP spent on electricity did not increase in this period, however, because the inflation-corrected price of electricity declined at an annual rate of 4.4% per year (Figure 1).[1]

Since 1973 growth in electricity demand has slowed dramatically. Between 1973 and 1980 electricity sales rose at an average rate of 3.2% per year (1.25 times as fast as GNP), and from 1980 to 1986 at 1.7% per year (0.70 times as fast as GNP). Slowing growth in demand has led in turn to a virtual cessation of orders for new central station power plants (Figure 2), and to widespread cancellations of capacity planned when it was expected that historical growth rates would continue. From 1974 through 1985, 93 nuclear generating plants (for which the sunk costs, in nominal dollars, were $10.3 billion) and 41 coal-fired plants (with sunk costs of $0.4 billion) were cancelled (1). Slower growth in demand has led to continual downward revisions in electric utility industry forecasts of electricity demand growth; the projected average annual demand growth rate has declined continually, from 7.5% in 1974 to 2.1% in 1987. Despite these downward revisions, the industry has continued to overestimate future demand growth, although the difference between projected and actual growth rates is converging (Figure 3).

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[1] Unless explicitly indicated otherwise prices in this paper are presented in January 1986 dollars. Where the primary data used were originally in the nominal dollars of other years, conversions to constant dollars were made using the gross national product deflator.

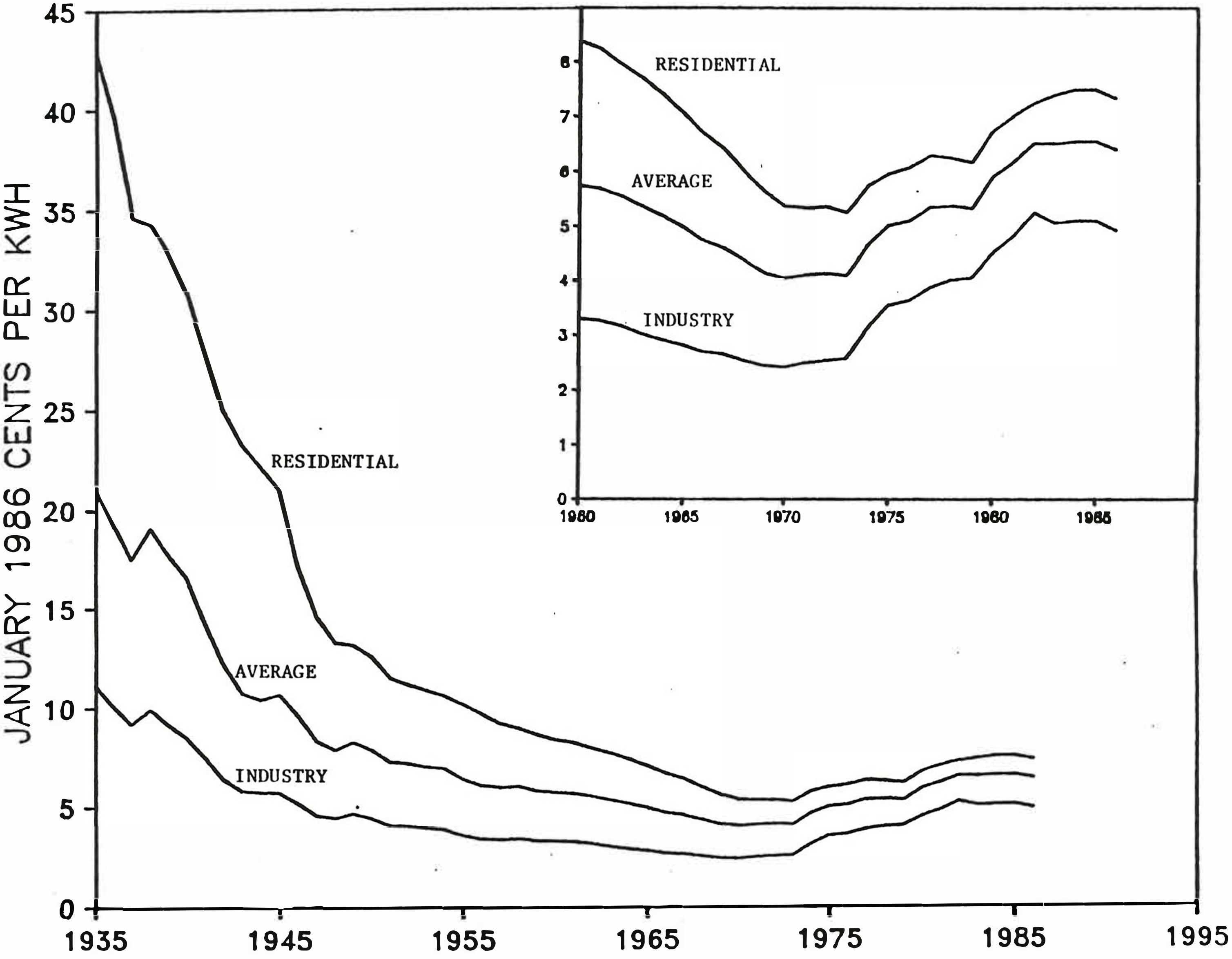

Figure 1.

Long term and recent (insert) electricity price trends in the United States. The prices shown are the total revenues divided by the total electricity sales (2), expressed in January 1986 cents per kWh.

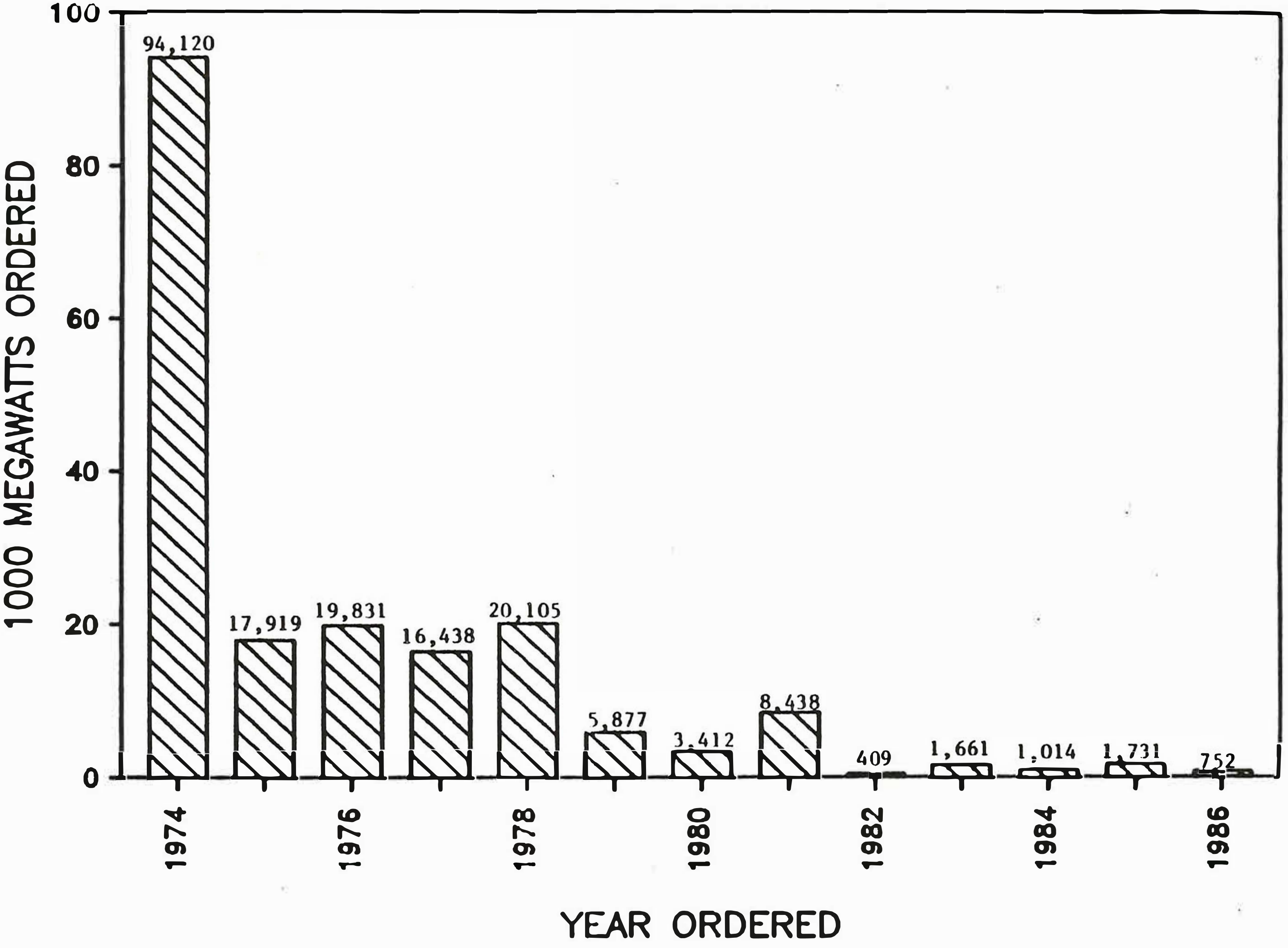

Figure 2.

New orders for central station power plants in the United States (3). The total in 1986, 752 MW, was for 11 gas turbines. This was the first year since World War II that no steam or hydroelectric turbine units were ordered by U.S. electric utilities.

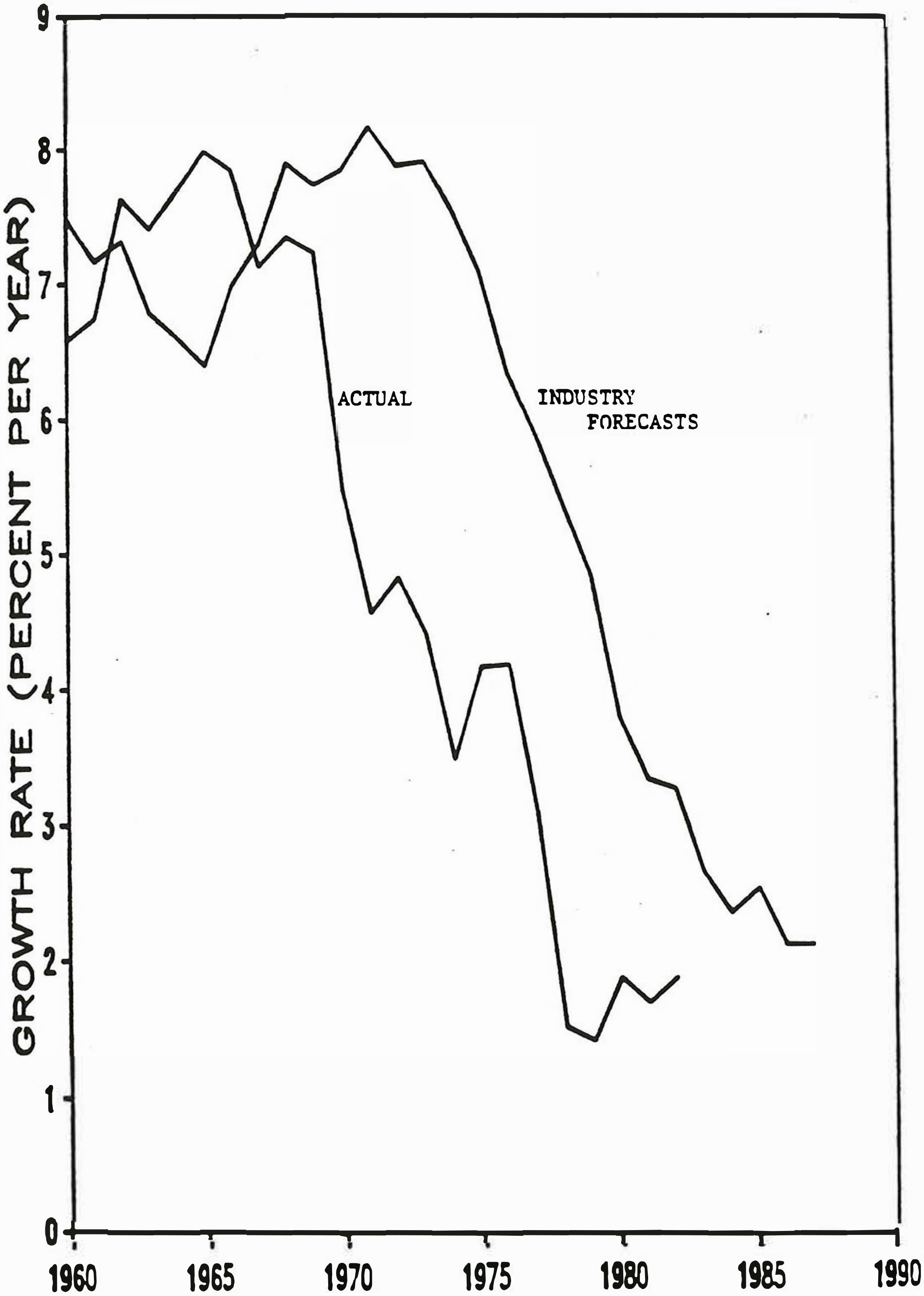

Figure 3.

The actual annual growth rate for electricity sales in the United States (2) (five-year running average over the indicated year and the four following years) and annual growth rates projected by the Edison Electric Institute, Washington, DC (looking four years into the future up till 1967 and six years into the future, 1968-75) and by the North American Electric Reliability Council, Princeton, New Jersey (ten year projections, 1976-87).

The slowdown in electricity demand growth is due to saturation in the ownership of many electricity-intensive consumer products (4), the ongoing structural shift in the economy toward less energy-intensive and electricity-intensive economic activities (5), and a shift to more energy-efficient end-use technologies as a response to electricity prices that have risen on average at 3.1% per year from 1973 to 1986 (Figure 1).

The reversal of the long-term downward trend in the electricity price was due only in part to the oil price shocks of the 1970s. Electricity prices actually bottomed a few years before the 1973 oil crisis (Figure 1), and the 4% decline in the US average electricity price since 1982 is modest compared to the 70% decline in the price of imported oil since its peak in 1980. The main reason for the electricity price increases is the fact that the capital costs of central station power plants have escalated dramatically. The cost of the 13 nuclear power plants brought into service in 1987 was nearly $3800 per kW (nominal dollars), compared to about $160 per kW (nominal dollars) for the 11 units brought into service in the period 1968-1971 (6). Escalations for coal-fired steam plants have been less severe but nevertheless substantial.

Electricity rate increases and the Public Utility Regulatory Policies Act of 1978 (PURPA) and the 1982 and 1983 Supreme Court decisions upholding PURPA's provisions, have led to a competitive challenge for utilities from independent cogenerators and small power producers. PURPA encourages cogeneration and the production of electricity from renewable energy sources in small installations by requiring utilities (a) to purchase the electricity from qualifying producers at a price equal to the cost the utility could avoid by not having to produce that power and (b) to provide back-up power at reasonable rates. As of the end of 1986 some 47 GW of capacity had been certified by the Federal Energy

Regulatory Commission (FERC) for PURPA benefits, nearly three fourths of which is due to cogeneration (Figure 4).

The greatest challenge to utilities from cogeneration comes from the steam-using basic industries, where the economics of cogeneration are the most favorable. The extent of this competition may ultimately be limited by the facts that (a) these industries generally are either not growing much or are going into decline, and (b) they tend to be concentrated geographically in certain parts of the country, such as California, the Gulf Coast, the Mid-Atlantic states. However, the momentum toward independent power generation created by PURPA may lead to even more competition in power generation in the future. In 1987 the Federal Energy Regulatory Commission began considering establishing a scheme to allow competitive bidding for utilities' incremental power requirements, a scheme that would allow cogenerators, small power producers, other independent power producers, and utilities to compete on the same basis (7).

The slowdown in electricity demand growth, the escalations in the costs of constructing new large central station power plants, and the competitive challenges from independent power producers have made utility power plant construction a risky financial undertaking. Many utilities are seeking ways to postpone new construction projects as long as possible, by extending the lives of existing generating plants, managing electrical loads to facilitate the generation of more electricity by existing plants, promoting electricity conservation, and purchasing electricity from independent power producers and Canada.

This strategy should lead to more efficient use of existing capacity and help avoid the rate hikes that have accompanied new construction projects since

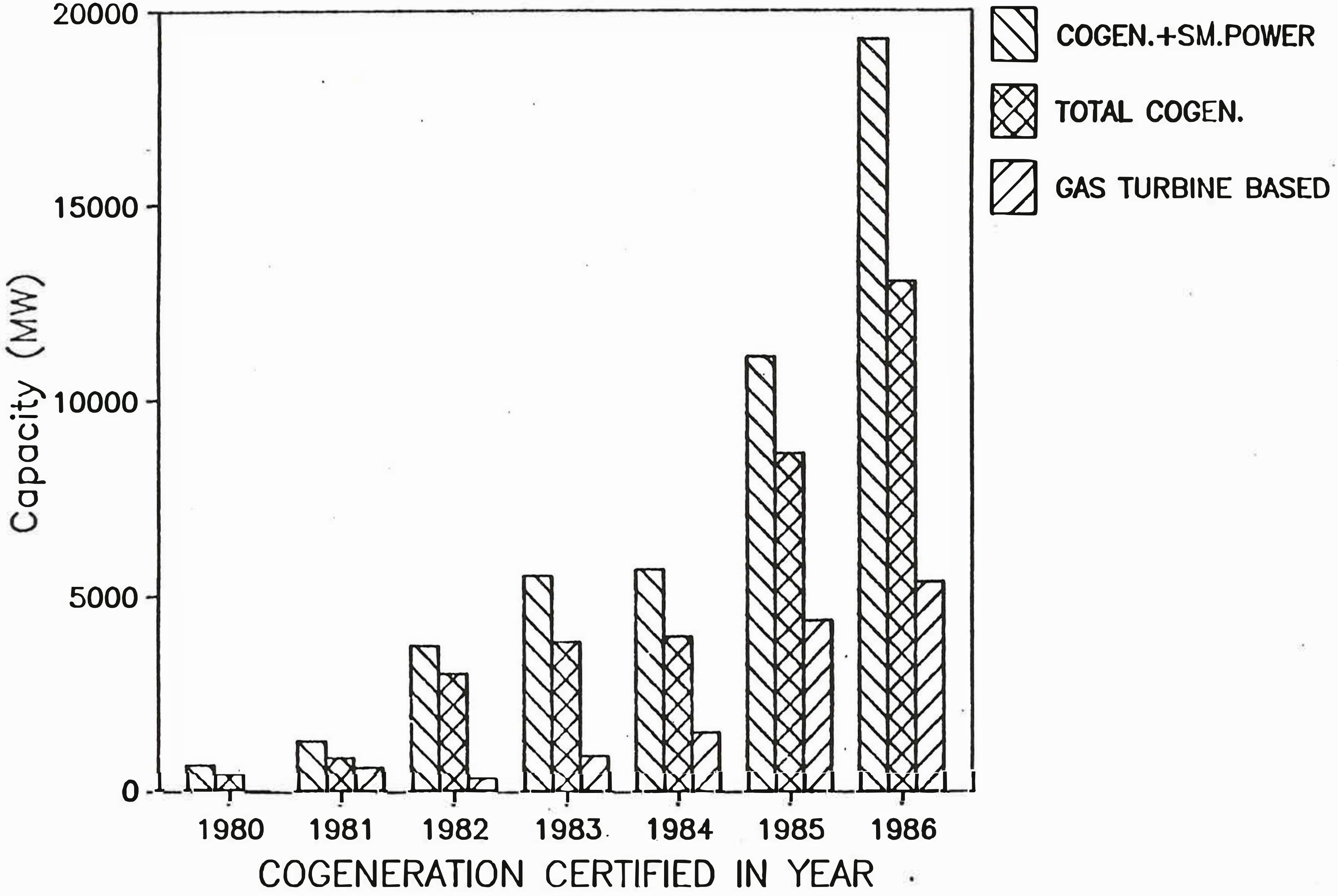

Figure 4.

Annual cogeneration and small power production capacity for facilities certified by the Federal Energy Regulatory Commission to be eligible for the benefits allowed under the Public Utility Regulatory Policies Act (8).

the early 1970s. But the reluctance to build also implies a reluctance to innovate.

Technological innovation in the power sector is important partly because electricity seems to play an important role in fostering productivity improvements (9). The pursuit of innovations in power technology could ultimately lead to greater electricity cost reductions than can be achieved by making marginal improvements in the existing system, thereby helping make the overall economy more productive. One indicator of the importance of bringing these costs under control is the fact that in the 1980s, when electricity demand has been growing more slowly than GNP, about 3.7% of GNP has been spent on electricity, up sharply from a nearly constant 2.2% in the decade prior to 1973, when electricity demand grew twice as fast as GNP! Cost-cutting innovations would also better equip utilities to face the competitive challenges from independent power producers; the extent to which they are willing to innovate to make their product more competitive may determine their long-term role in the power generation business. Finally the challenge of responding to increasing environmental concerns, especially about acid rain and climatic change from the buildup of carbon dioxide in the atmosphere from burning fossil fuels, will require technological innovation to avoid driving up the cost of power with costly "band-aid" cleanup technologies.

THE PROSPECTS FOR IMPROVING STEAM-ELECTRIC POWER TECHNOLOGY

Before discussing the opportunities for innovation afforded by advanced gas turbine technologies, we discuss the prospects for improving the technology for nuclear and fossil fuel-based steam-electric power generation.

The cost escalations that have made coal-fired steam-electric plants expensive and have essentially killed nuclear power as an option for new construction in the foreseeable future in the United States are due in part to tightening environmental and safety rules. Other important factors include inadequate quality control in equipment manufacture and construction, bottlenecks that have arisen because each big project has been in many ways unusual, and escalating labor costs arising from shortages of qualified manpower and declines in labor productivity. Many such problems result in not only direct cost increases, but also indirect cost increases associated with the accumulated interest charges from extended construction periods.

For nuclear power once more to become a competitive option in the United States, capital costs must be reduced dramatically. The Electric Power Research Institute projects that if the the nuclear licensing process were streamlined, the construction period shortened, and labor productivity improved, the capital cost for nuclear power could be reduced from about $3000 per kW for a new plant that would be ordered today to $1600 per kW (10). If this could be achieved, nuclear power would be able to compete with coal-based power in conventional steam plants with flue gas desulfurization (Table 1). While such improvements are necessary, they are not sufficient to bring about the rebirth of nuclear power. As discussed below, a born-again nuclear industry would face much stiffer competition than that offered by today's coal-fired steam-electric plants. Moreover, the public must be convinced that nuclear power can be made safe--a formidable challenge in light of public attitudes about nuclear power developed in the aftermath of the Three Mile Island and Chernobyl accidents. Unless public confidence in nuclear power is restored, there will continue to be resistance to industry demands for streamlining the regulatory process.

Table 1. Cost/Performance Characteristics for US Central Station Power Plants[a]

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1. Steam-Electric Plants

Type	Coal[b,c]			Light Water Reactor[d] Current	Light Water Reactor[d] Target
Unit Size (MW)	2 x 500	500	200	1100	1100
Efficiency (%)[e]	34.6	34.6	34.6	33.4	33.4
Unit Cost ($/kW)	1300	1360	1820	2960	1610
Levelized Busbar Cost (cents/kWh)					
Capital[f]	1.56	1.63	2.18	3.54	1.93
Fuel	1.80	1.80	1.80	0.87	0.87
O&M	0.85	0.95	1.31	1.06	1.06
TOTAL	4.21	4.38	5.29	5.47	3.86

2. Natural Gas-Fired Gas Turbine Systems[g]

	1986 Natural Gas Price[h]				2X 1986 Natural Gas Price			
	Cur.CC	Adv.CC	STIG	ISTIG	Cur.CC	Adv.CC	STIG	ISTIG
TIT (^{o}F)	2000	2300	2200	2500	2000	2300	2200	2500
Unit Size (MW)	236	205	4 x 51	110	2 x 118	205	4 x 51	110
Efficiency (%)[e]	41.9	45.0	40.0	47.0	41.9	45.0	40.0	47.0
Unit Cost ($/kW)	490	490	410	410	490	490	410	410
Levelized Busbar Cost (cents/kWh)								
Capital[f]	0.59	0.59	0.49	0.49	0.59	0.59	0.49	0.49
Fuel	1.91	1.78	2.00	1.70	3.81	3.55	4.00	3.40
O&M	0.28	0.28	0.28	0.28	0.28	0.28	0.28	0.28
TOTAL	2.78	2.65	2.77	2.47	4.68	4.42	4.77	4.17

3. Alternative Coal-Gas-Fired Gas Turbine Systems[c,i]

	Oxygen-Blown Gasifier				Air-Blown Gasifier		
	Cold Gas Clean-Up				Hot Gas Clean-Up		
	Current Com. Cycle			Adv. Com. Cycle		STIG	ISTIG
TIT (^{o}F)	2000	2000	2000	2200	2200	2200	2500
Unit Size (MW)	100	250	500	600	520	2 x 50	110
Efficiency (%)[e]	34.3	35.7	36.0	37.9	37.6	35.6	42.1
Unit Cost ($/kW)	2630	1940	1630	1500	1120	1240	990
Levelized Busbar Cost (cents/kWh)							
Capital[f]	3.15	2.32	1.95	1.79	1.34	1.49	1.18
Fuel	1.82	1.74	1.73	1.64	1.65	1.75	1.48
O&M	2.02	1.14	0.85	0.77	0.43	0.68	0.58
TOTAL	6.99	5.20	4.53	4.20	3.42	3.92	3.24

Notes for Table 1

[a] All costs are in January 1986 US dollars.

[b] Unit capital costs, efficiencies, and O&M costs are EPRI estimates, for a bituminous coal-fired subcritical steam plant with flue gas desulfurization (10).

[c] The assumed coal price is $1.73/GJ, the average utility price projected for 1995 by the US Department of Energy (11).

[d] Reactor plant size, unit capital costs, and efficiencies are EPRI estimates (10). The two sets of capital costs are the current cost and an EPRI target for "improved" conditions--resulting from higher construction labor productivity, shorter construction period, streamlined licensing process, etc. The assumed nuclear fuel cycle cost is $0.81/GJ, EPRI's projection for the period 1990-2000 (10). The assumed O&M cost is the 1985 US average for nuclear power plants (12), twice as large as the EPRI estimate for new plants (10).

[e] Based on the fuel's higher heating value and for operation at 100% load.

[f] For a 6.1% real discount rate [recommended by EPRI (10)], 30-year plant life, and 70% capacity factor. No taxes or tax incentives are included.

[g] The "current" combined cycle is two 75 MW GE Frame 7E gas turbines plus an 86 MW steam turbine; the indicated performance is an EPRI estimate (10). The "advanced" unit is a recently commercialized 135 MW GE Frame 7F gas turbine plus a 70 MW steam turbine; the indicated performance is a General Electric estimate (28).

The STIG unit is a commercial steam-injected gas turbine based on the GE LM 5000 (L. Gelfand, Manager, Advanced Programs and Ventures, General Electric Marine and Industrial Division, Cincinati, Ohio, personal communication, February 1987). The ISTIG unit is an intercooled steam-injected gas turbine under development, based on the LM 5000 (13,14).

The assumed unit capital costs for STIG and the current combined cycle (20% higher than for STIG) are from a Bechtel study (15). The unit capital cost for the advanced combined cycle is assumed to be the same as for current combined cycles. The assumed unit capital cost for ISTIG (the same as for STIG) is probably an overestimate, in light of the fact that with only minor modifications the output of STIG would more than double in being converted to ISTIG.

In all cases the assumed O&M costs are EPRI estimates for combined cycles (10), even though a Bechtel analysis indicates that steam-injected gas turbine systems offer inherent O&M cost savings compared to combined cycle units (15).

[h] The average gas price for electric utilities was $2.22/GJ in 1986.

[i] The performance/cost values for combined cycles fired with oxygen-blown gasifiers are EPRI estimates for the Texaco gasifier (10). The corresponding numbers for systems using an air-blown gasifier are from a GE study exploring less costly, more energy-efficient alternatives to the Texaco gasifier (16).

While the economics of coal-fired steam-electric power is more favorable at present than that of nuclear power, coal power generation costs are still much higher than in the late 1960s and early 1970s. Environmental constraints imply that a return to the economic conditions of that earlier era is probably unrealistic. A brief history of the reductions in costs of fossil fuel-based power generation up to 1970 highlights the obstacles to significantly improving today's technology.

Improvements in efficiency (Figure 5) and increases in scale (Figure 6) were the major factors leading to the dramatic reductions in the costs of providing electricity in the United States (Figure 1) from the turn of the century until 1970. In the first decade of this century, thermal efficiencies averaged 5% or less and typical power plants had capacities of the order of 1 MW. From that time on the average efficiency climbed nearly continuously, reaching its present average value of about 32% around 1960 (Figure 5). Electrical rates continued tumbling for a decade after efficiency plateaued (Figure 1) largely because of scale economy gains. Between 1960 and 1970 the capacity of the largest turbogenerator in service increased from less than 300 MW to 800 MW, and has since increased to 1300 MW (Figure 6).

There are probably no further opportunities for exploiting economies of scale. As Fisher recognized even before the Oil Embargo of 1973, the shift to large scale plants was a major contributing factor to the 50% rise in the unit capital cost of nuclear power in the previous decade, because of the associated increased proportion of high-cost field construction and the reduced proportion of low-cost factory construction (18a). And even where scale economy gains can be realized in construction, these gains tend to be offset by losses in reliability for the larger units (19).

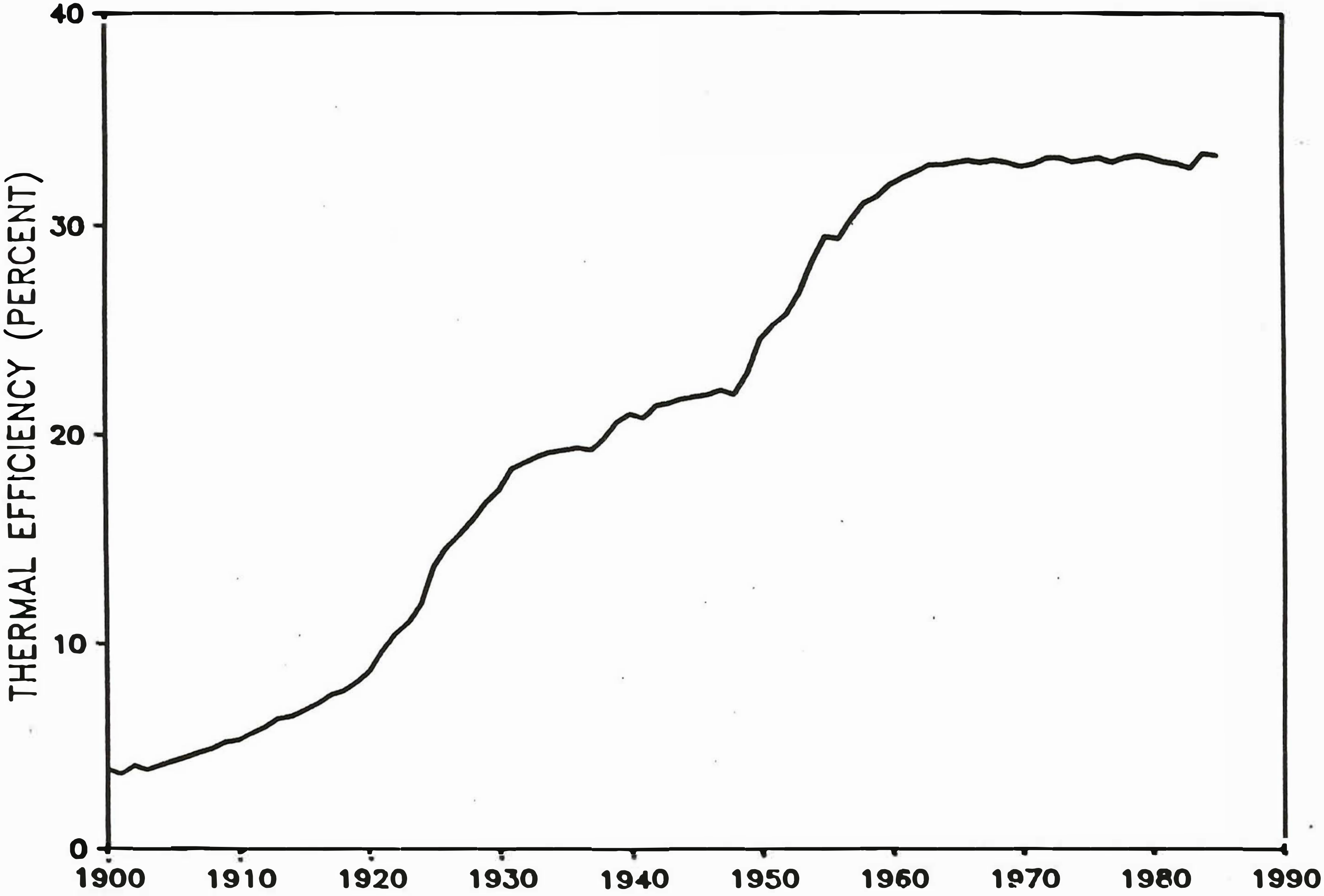

Figure 5.

The historical trend in the average efficiency of electricity generation in central station thermal power plants in the United States. Data for the period 1900-1925 are from Series M 90 and M 91, Part 1 of Ref. 17. Data for 1926-1955 are from Series S 107, Part 2 of Ref. 17. Data for 1956-1985 are from Ref. 12.

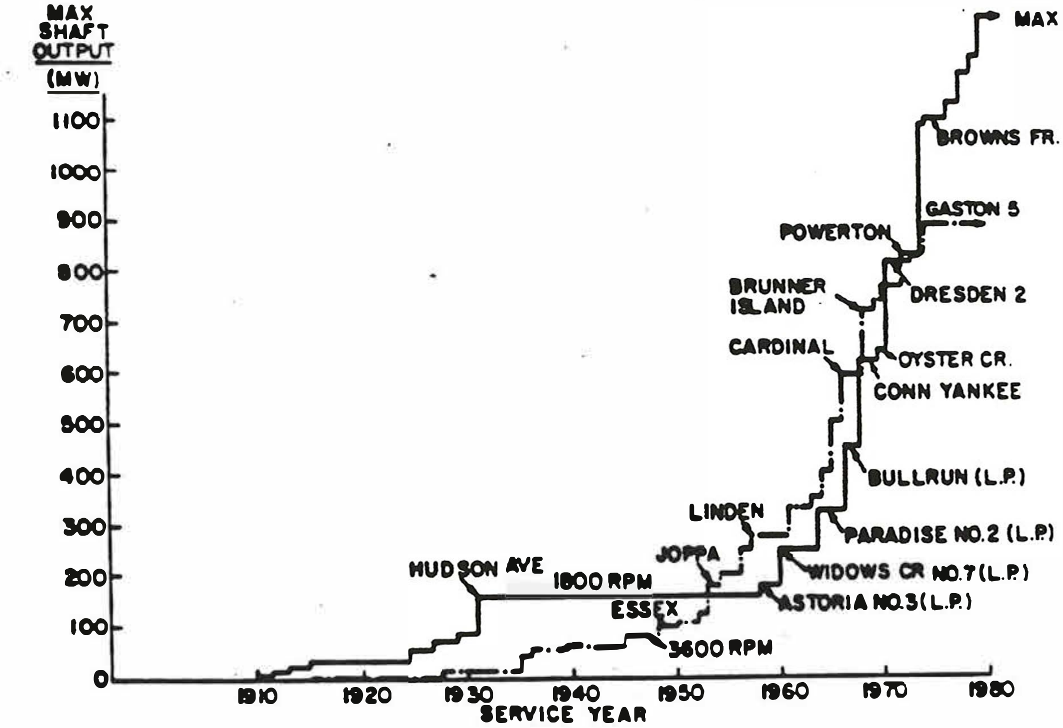

Figure 6.

The historical trend in the maximum shaft power output of the largest turbo-electric generator in service in the United States (18).

Since the 1920s, most gains in efficiency in steam-electric power plants have been due largely to increases in maximum steam temperatures and pressures. By the 1950s peak temperatures had reached 565 °C (1050 °F), and peak pressures 165 bar (2400 psia) for subcritical steam units and 240 bar (3500 psia) for supercritical steam units,[2] values that have not been exceeded to date.

Further gains in efficiency through increases in maximum operating temperatures will be difficult to achieve, since increasing problems of materials strength, oxidation, and corrosion rapidly become more serious, dictating shifts to much more costly high-strength, oxidation- and corrosion-resistant alloys for the large steam-tubing heat exchangers that transfer heat from the combustor to steam at high temperature and pressure. (See, for example, Figure 7, which shows, for a number of alloys used in steam tubing exposed to high temperatures, that the maximum allowable stress declines rapidly beyond a critical threshold.)

Peak steam temperatures have not increased since the 1950s, and in fact utilities today tend to choose a slightly lower peak temperature of 540 °C (1000 °F) in coal plants. They do so not only because of the lower capital cost, but also because, even with judicious choice of better tubing materials, higher temperature operating conditions have led to more forced outages, owing to tubing damage from problems such as coal-ash corrosion (20).

A 1976 Westinghouse study [the results of which are consistent with many other studies carried out since the 1950s (18)] indicates the magnitude of the tradeoff involved in increasing the maximum steam temperature of a 500 MW steam plant; an increase from 540 to 650 °C (1000 to 1200 °F) would increase the

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[2] 1 bar = 10^6 dynes/cm^2, approximately equal to one standard atmosphere (1.013 bar or 14.7 psia).

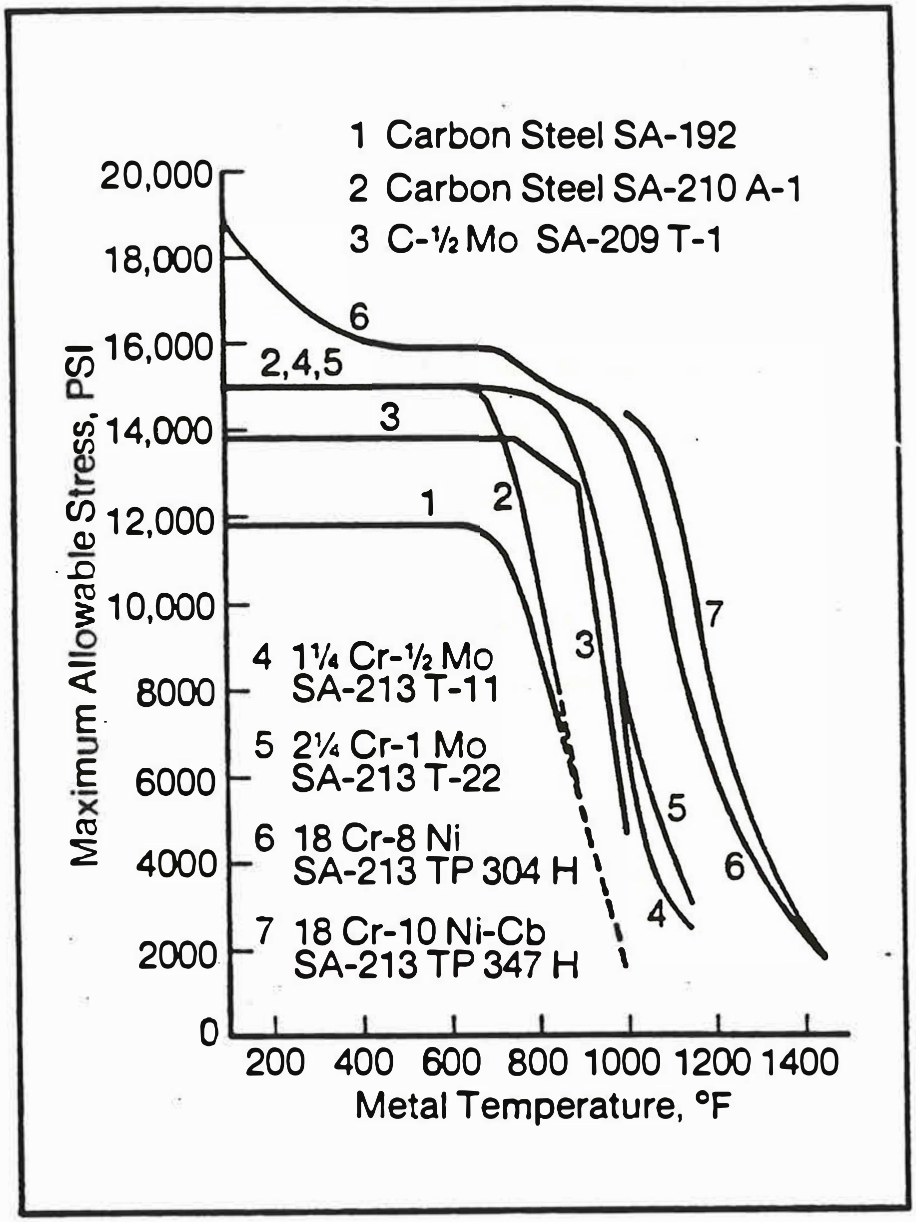


Figure 7.

Effect of temperature on the maximum allowable stress for different steel alloys used for steam tubing in high temperature service, according to the boiler code of the American Society of Mechanical Engineers (ASME) (20). 1 = low strength carbon steel; 2 = intermediate strength carbon steel; 3 = a ferritic alloy containing 0.5 percent molybdenum; 4 = ferritic alloy containing 1.25 percent chromium and 0.5 percent molybdenum; 5 = ferritic alloy containing 2.25 percent chromium and 1.0 percent molybdenum; 6 = austenitic stainless alloy containing 18 percent chromium and 8 percent nickel; 7 = austenitic stainless alloy containing 18 percent chromium and 10 percent nickel.

plant efficiency by 6% but at the cost of a 26% increase in capital cost (21). Applying these values to the 500 MW steam plant described in Table 1 implies that the coal price would have to increase four-fold before it would be worthwhile to shift to the higher peak steam temperature!

There has been recent progress in the development of small-scale (10 MW or less) steam plants burning clean fuels (e.g. natural gas) with steam conditions up to 815 °C (1500 °F) and 105 bar (1500 psia) for cogeneration applications (22), but considerable development work is needed to extend these advances to coal-fired systems (to overcome coal-ash corrosion problems at high temperatures) and to utility-scale units [because of the formidable problems of fabricating large turbines from the superalloys required at high operating temperatures (23)].

While the outlook for fundamental improvement in steam-electric power technology is not promising, it may be feasible to increase efficiency without pushing peak working fluid temperatures further, through development of the recently proposed Kalina cycle (23a). The basic modifications of the steam Rankine cycle widely used in modern steam-electric power plants (e.g. reheat, regenerative feedwater heating, and preheating of combustion air) were introduced in the 1920s (18). The Kalina cycle is a novel modified Rankine cycle that uses as a working fluid a mixture of ammonia and water that is varied throughout the cycle. In the boiler the ammonia, having a lower boiling point, starts to boil off from the mixture first, decreasing the concentration of ammonia in the rest of the liquid, thereby increasing its boiling point; the boiling point keeps changing as the ammonia/water ratio changes, making it possible to improve the efficiency of heat transfer from the heat source to the working fluid. A second water-rich stream is added to the vapor exhausted from the turbine so that this mixture condenses at 1.43 bar (20.7 psia) and 15.5 °C

(60 °F), a temperature that is lower than the typical 47 °C (116 °F) at 0.1 bar (1.5 psia) for a conventional steam plant, leading to another efficiency gain (23b). A demonstration project for a 3 MW Kalina cycle is being planned. The plant, to be built at the US Department of Energy's Engineering Center in Canoga Park, California, is expected to be operating by 1989 (23c). The big uncertainties regarding the Kalina cycle are the complicated "plumbing" and possible difficulties associated with managing the binary working fluid at high temperatures and pressures, which might lead to significant capital and operating and maintenance cost penalties. Also, the performance gains estimated for the Kalina cycle have been for very small assumed pressure drops and tight temperature differences--conditions that are difficult to achieve in practice and should tend to increase the cost of the heat exchanger equipment (23b).

THE OUTLOOK FOR STATIONARY POWER APPLICATIONS OF GAS TURBINES

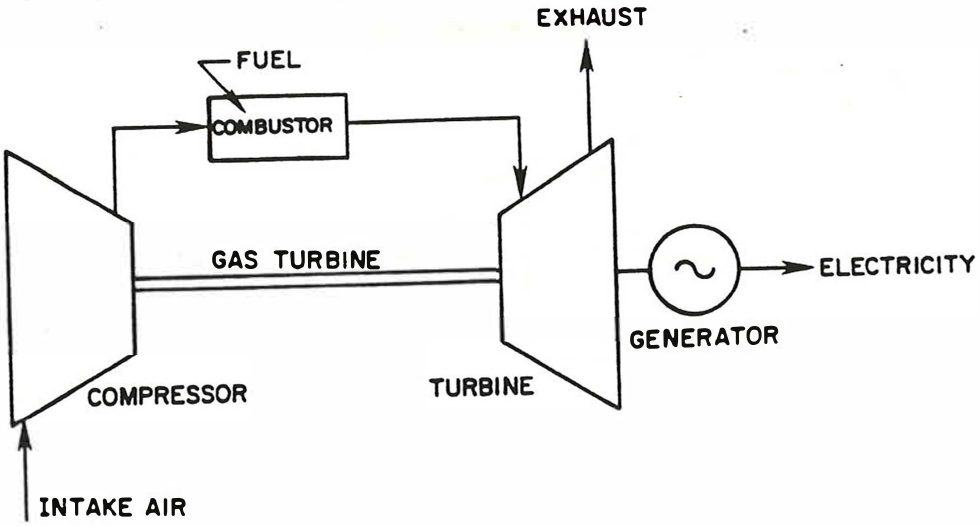
In contrast to the stagnant demand for new steam turbine power plants, the market outlook for gas turbines is auspicious. Utilities display growing interest in use of the gas turbine to cope with uncertainties in forecasts of electricity demand and fuel prices. There is already a booming cogeneration market for gas turbines in the United States; some 13 GW, or nearly 40% of the cogeneration capacity certified by the FERC as qualifying for PURPA benefits between 1980 and 1986 was based on the use of the gas turbine (Figure 4). Interest in the gas turbine reflects both long-standing attractions of this technology and recent improvements that make it possible for the gas turbine to compete in a much wider range of markets.

Traditional Roles for Gas Turbines

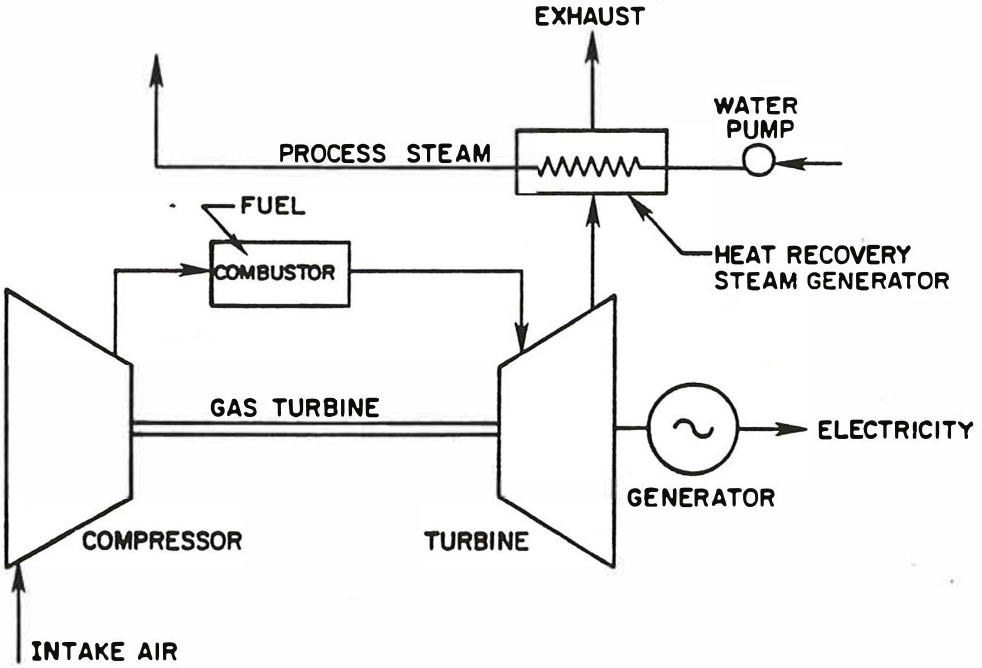
The historical attraction of the gas turbine for utilities has been its low cost--$300 per kW (10) or less, a small fraction of the cost of coal or nuclear power plants (Table 1). This low cost reflects the utter simplicity of the simple cycle gas turbine. While a steam turbine power plant requires costly heat exchangers to tranfer heat from the combustor to the steam working fluid that drives the turbine, in a gas turbine power plant the hot fuel combustion products drive the turbine directly (Figure 8a). Also, while large condensers and often cooling towers are required to condense a steam turbine's exhaust steam, the exhaust from a gas turbine is discharged directly into the atmosphere.

But simplicity has been a mixed blessing for the simple cycle gas turbine. Even though the turbine inlet temperature is high in a gas turbine [1100 ^{o}C (2000 ^{o}F), compared to 540 ^{o}C (1000 ^{o}F) for a steam turbine], the efficiency has been less than 30%, largely because the exhaust of a simple cycle gas turbine is much hotter [425 to 540 ^{o}C (800 to 1000 ^{o}F)] than that of a condensing steam turbine. Also, clean fuels have been required to avoid damaging the turbine blades with the combustion products, a constraint that has limited the use of the gas turbine mainly to liquid or gaseous fuels that have been costly or whose long-term availability is uncertain. These constraints have limited the gas turbine in utility applications mainly to peaking service.

Its low unit capital cost has also helped make the gas turbine attractive for cogeneration applications. Because of the relative insensitivity of gas turbine unit costs to scale (Figure 9), the gas turbine tends to be favored over the steam turbine for all but the largest cogeneration installations. The use of the high-temperature turbine exhaust to raise steam in a heat recovery steam generator (HRSG) for heating applications (Figure 8b) makes the gas turbine a thermodynamically efficient cogeneration device, even if the efficiency of the turbine for producing power only is relatively poor.



(a)



(b)

Figure 8. a,b

Simple power cycle (8a): fuel burns in air pressurized by compressor, combustion products drive turbine, and hot turbine exhaust gases are discharged to atmosphere. Simple cogeneration cycle (8b): like simple power cycle, except that hot turbine exhaust gases are used to raise steam in HRSG for heating.

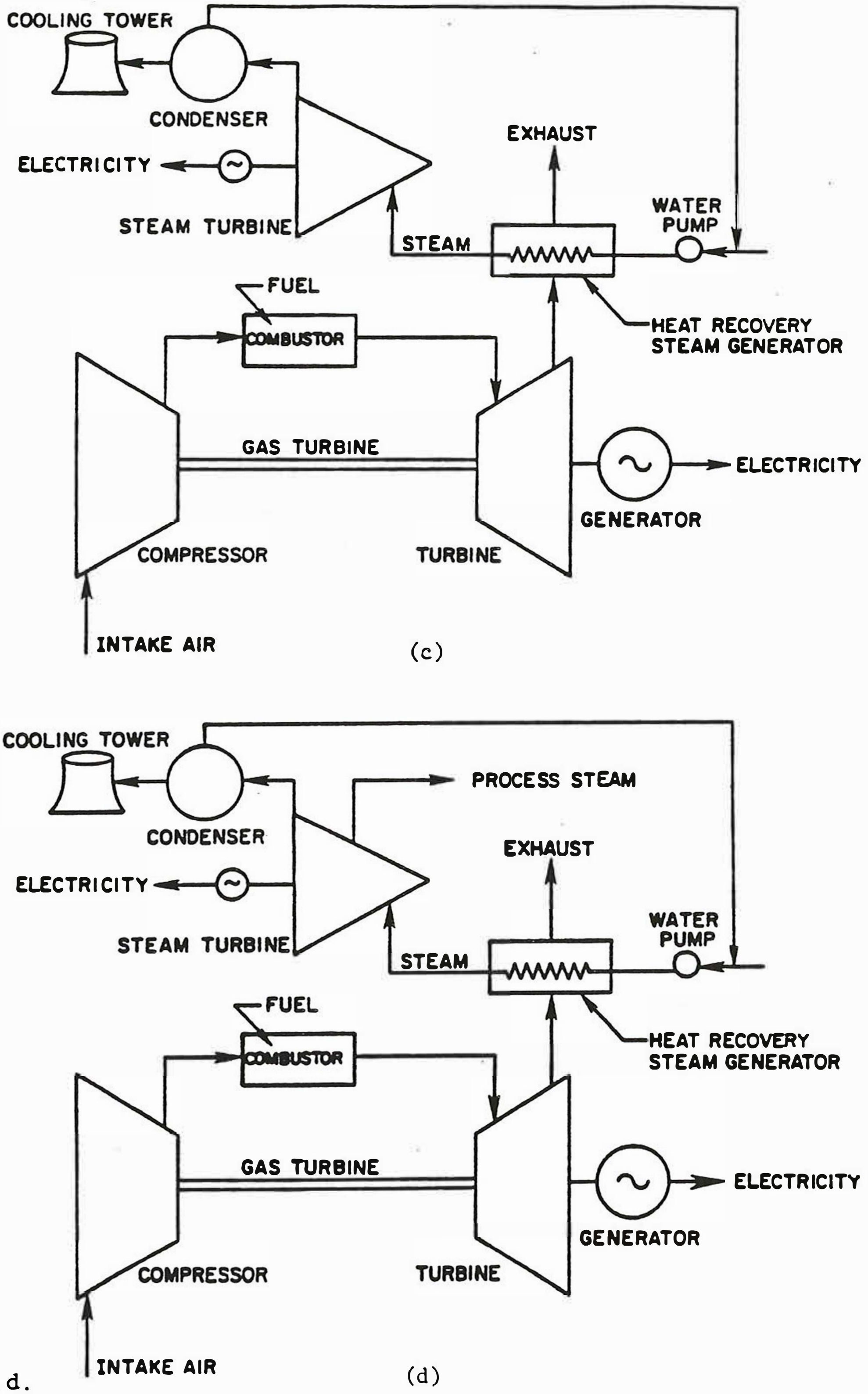
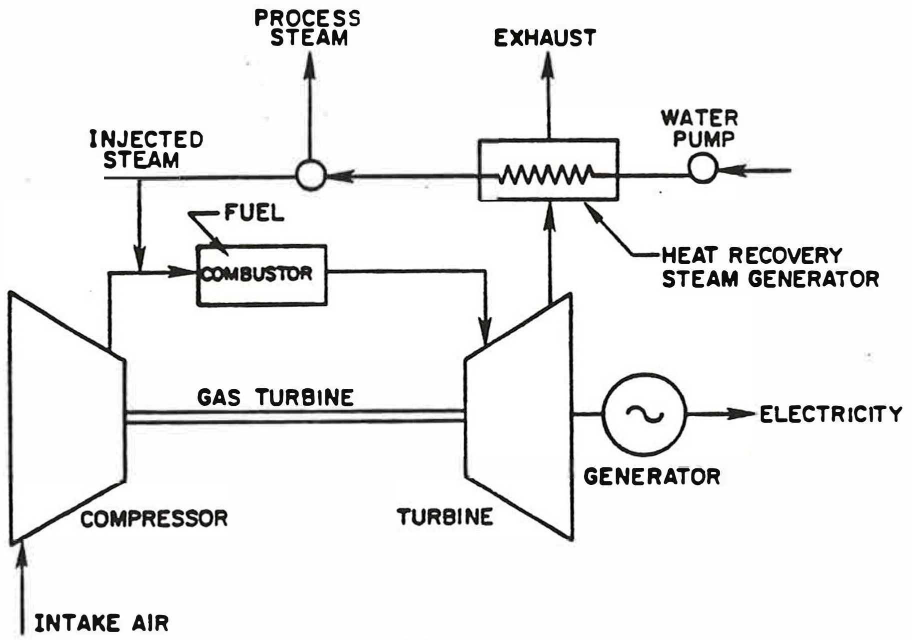
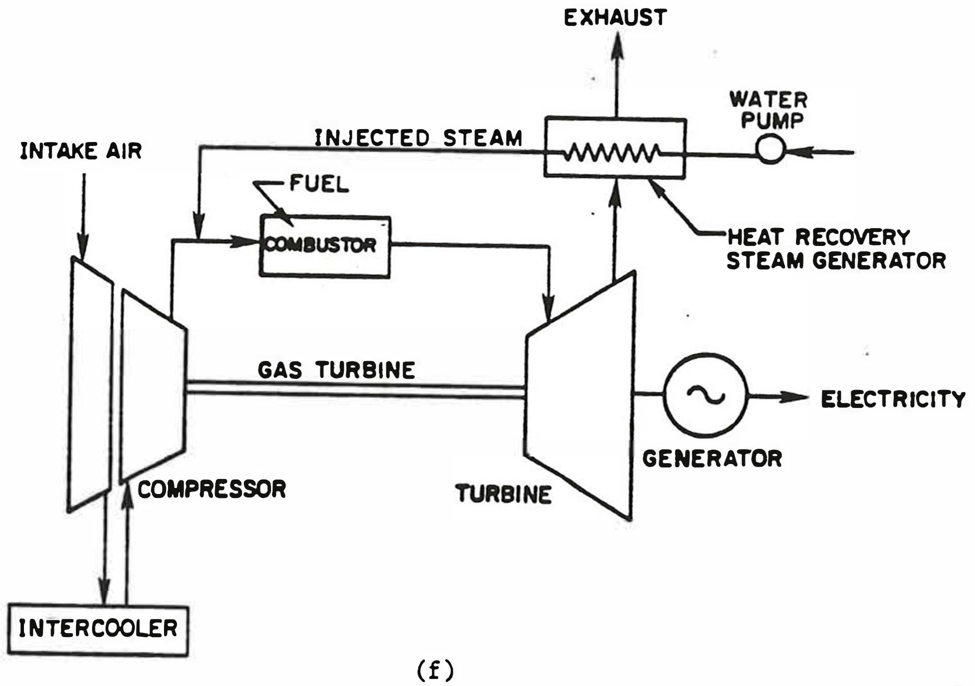


Figure 8. c,d.

<u>Combined cycle for power</u> (8c): like simple cogeneration cycle, except that steam from HRSG is used to produce extra power in condensing steam turbine. <u>Combined cycle for cogeneration</u> (8d): like combined cycle for power, except that some steam is bled from steam turbine for heating.



(e)



(f)

Figure 8. e,f.

STIG (8e): like simple cogeneration cycle, except that steam not needed for heating is injected into combustor for increased power output and higher electrical efficiency. ISTIG (8f): like STIG with full steam injection except that intercooler between compressor stages allows for operation at much higher turbine inlet temperature because of improved air cooling of turbine blades.

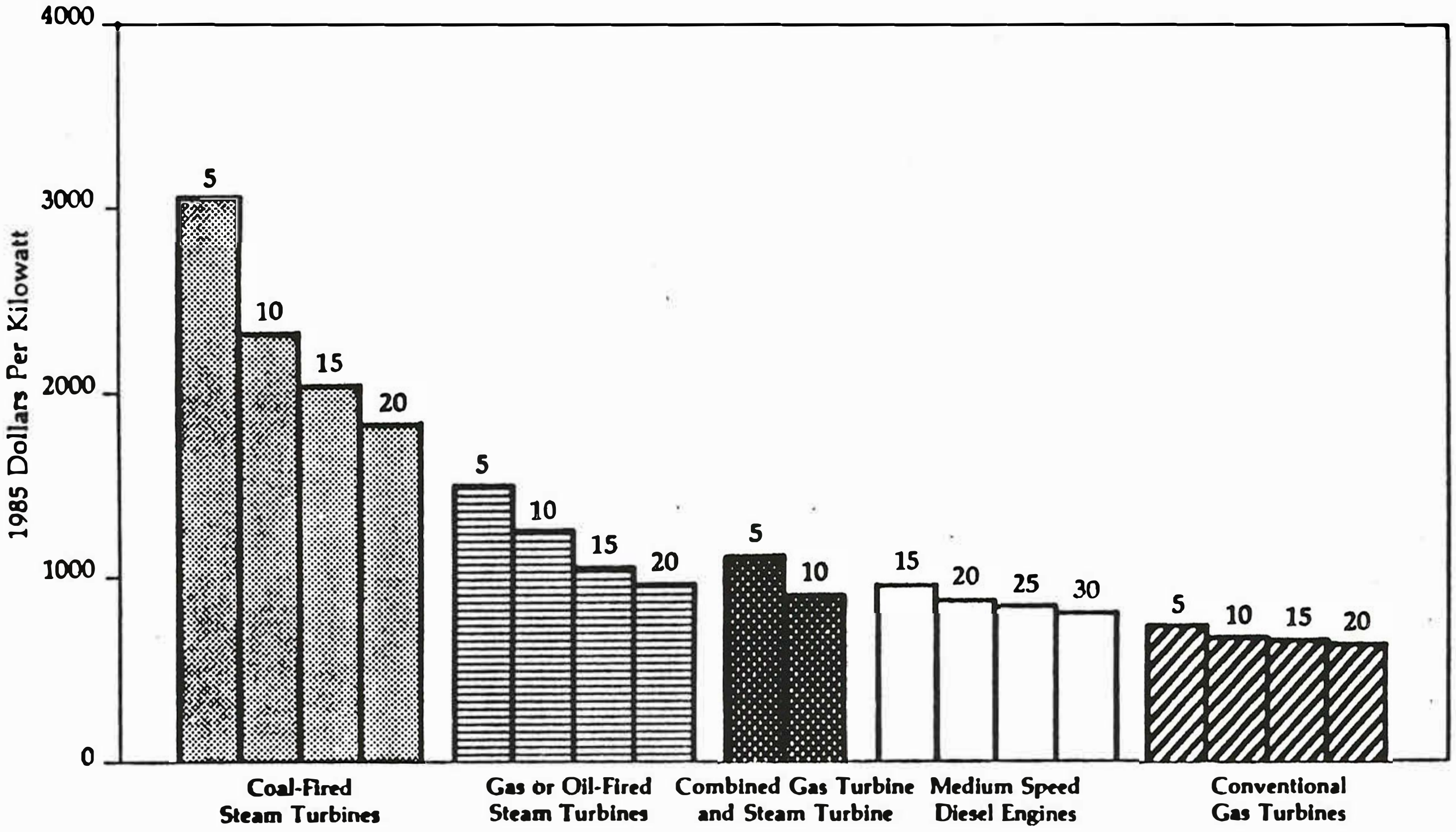


Figure 9.

Unit installed costs for small-scale cogeneration systems. The numbers at the tops of the bars are the installed electrical generating capacity in MW (24).

A major shortcoming of the simple cycle gas turbine in cogeneration is that it is not well-suited to cogeneration applications involving highly variable steam loads, because it is often uneconomical to produce only power with a gas turbine, or to operate it at part electrical load.[3]

It is now possible to overcome the constraints restricting gas turbines to peaking service for utilities and baseload service for cogeneration because (a) the performance of the basic gas turbine cycle is improving steadily, and (b) various simple cycle modifications offer opportunities for both improving efficiency and reducing capital cost. A brief review of the history of the gas turbine is helpful in understanding these possibilities.

A Brief History

Although the gas turbine has been under development since the turn of the century, until recent decades its progress was much slower than that of the steam turbine. Slow progress was due largely to the fact that, in a gas turbine, considerable compressor power is required to bring the air working fluid up to the high pressure level of the combustor. Even with today's gas turbines, half or more of the gross output of the turbine is required to drive the compressor. In many early turbines it was a formidable task to get any net power out of a gas turbine unit at all. To overcome this problem the cycle efficiency had to be improved, a challenge that has been met largely by the development of improved blade materials that enable the turbine blades to withstand increasing turbine inlet temperatures.

A major milestone in the history of the gas turbine was the initiation of

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[3] A single-shaft machine must be operated at constant rotational speed to accommodate the generator. Thus to reduce electrical output the fuel input is reduced, thereby reducing the turbine inlet temperature and electrical efficiency.

German and British programs in the mid-1930s to explore the use of gas turbines for aircraft propulsion. The success of these initial efforts led the United States to launch major jet engine development programs during and following World War II: the cost of these programs between 1940 and 1980 totalled about $10 billion (18). These efforts have been enormously successful, both in improving jet engine reliability and thrust-to-weight ratios and in increasing turbine inlet temperatures, at an average rate of more than 20 °C per year, between 1950 and 1980 (Figure 10).

Improvements in jet engine technology and electricity demand growth that was more rapid than expected stimulated considerable interest in the use of short lead-time gas turbines for stationary power applications in the late 1960s. Between 1965 and 1975, installed gas turbine capacity in the US electric utility industry increased from 1.3 GW to 43.5 GW (18). But after the oil shock of 1973, commercial interest in stationary gas turbines ground to a halt as a result of the sharp rise in oil and gas prices, concerns about gas scarcity and oil import dependency, and the sharp reduction in electricity demand growth; the installed gas turbine capacity of the US utility industry in 1985 was no greater than in 1975 (12).

The end of commercial interest in gas turbines for stationary power did not slow fundamental progress in improving gas turbine technology, however. One reason is that commercial airlines pressed vendors to improve the efficiency of jet engines, because the rising world oil price increased the fuel costs of air passenger travel from 11 to 32% of the total cost of air passenger service in the 1970s (26)! US Department of Defense support for research and development on jet engines for military applications also continued at a high level, averaging about $450 million per year in the decade

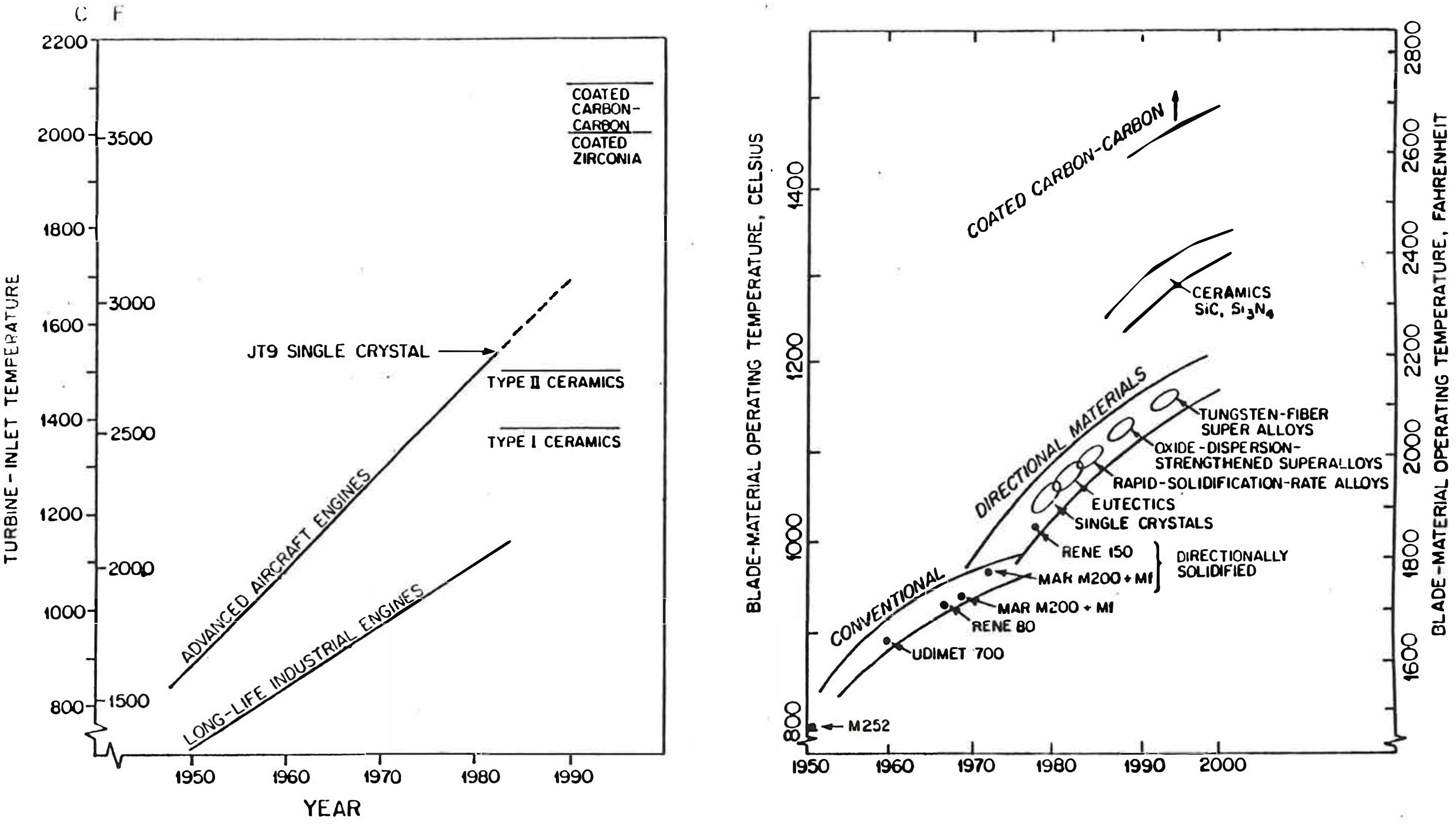

Figure 10.

The trend in turbine inlet temperatures for advanced aircraft jet engines and long-life industrial turbines (left) and turbine blade material operating temperature (right) (25). <u>Note:</u> When an aircraft engine is modified for stationary applications the rated turbine inlet temperature is reduced about 110 ^{o}C (200 ^{o}F) to promote long-life operation.

ending in 1986 (27). Continuing R&D in this area is expected to bring significant further increases in turbine inlet temperatures by the turn of the century, as a result of major improvements in blade materials (Figure 10) and more effective blade-metal cooling technologies.

A paradoxical aspect of the development of the stationary gas turbine is that most of the relatively simple "low-technology" cycle modifications available for improving performance (e.g. reheat, intercooling, regeneration, evaporative regeneration, and steam injection) remain largely unexploited, even though enormous "high-technology" advances have made in turbine blade materials, design, and fabrication. This is because such cycle modifications involve the use of large quantities of steam or water or the introduction of heavy or bulky heat exchangers that are not relevant to aircraft applications. This situation presents an enormous opportunity because it means that major improvements can be made in the performance of gas turbines for stationary power applications, with relatively modest R&D efforts.

Progress in Combined Cycle Technology

One gas turbine cycle modification is familiar to the electric utility industry: the gas turbine/steam turbine combined cycle, which accounted for some 4.6 GW of utility generating capacity in the United States in 1985 (11). In a combined cycle steam produced from the hot gas-turbine exhaust in a HRSG is used to drive a steam turbine to produce extra electric power (Figure 8c). With advanced gas turbines now commercially available for stationary applications (28), combined cycle efficiencies of 45% [at a firing temperature of 1260 ^{o}C (2300 ^{o}F)] can be realized in 200 MW plants costing less than $500 per kW. Such plants can produce electricity at a busbar cost only three fifths of that for a large new coal plant at the 1986 average natural gas price in the

United States (Table 1).

Of course electric utilities cannot be certain that natural gas prices will remain low over the entire expected lives of combined cycle facilities. However, recent developments in coal-gas turbine technology offer a means by which utilities can minimize the risks.

In 1979 a major private-sector effort was launched to demonstrate the ability to operate gas turbines on gasified coal.[4] This effort led to the construction of a 94 MW combined cycle power plant coupled to a Texaco coal gasifier, at Cool Water, California, operated by the Southern California Edison Company as part of a joint industrial effort involving the Electric Power Research Institute (EPRI), the Bechtel Corporation, the General Electric Company, Texaco, and a Japanese consortium under the rubric the Japan Cool Water Program. Plant operation began in June 1984, and the demonstration is expected to run till June 1989. The effort has been a technical success. The plant was built on time; the actual capital cost ($263 million) did not exceed the initial target; and the plant has operated reliably, with low pollutant emissions (see below) (31).

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[4] A gas turbine can also be fired directly with coal using a pressurized fluidized bed combustor (PFBC). Here sulfur is removed during combustion by a reaction with dolomite that forms an inert magnesium oxide-calcium sulfate complex, and particulate matter is removed from the combustion products in cyclones before they are directed to the turbine. This technology could be a serious competitor to the first generation of gasifier/gas turbine power plants (29). But with the PFBC it would not be possible to exploit expected continuing improvements in gas turbine technology, because the temperature of the combustor must be limited. The optimal temperature for sulfur capture is a bed temperature of about 850 °C (1550 °F), with a rapid decline in sulfur removal for either higher or lower temperatures (20). Also operation above about 950 °C (1740 °F) can lead to ash agglomeration in the bed. The agglomerates thus formed can lead to segregation of the bed and a cessation of fluidization (30). These problems do not arise with gasification, where sulfur and particulates are removed from the gas stream before the gas enters the combustor.

Cool Water technology could not provide power competitively at the scale of this demonstration plant; the busbar cost would be about two thirds higher than for a conventional steam plant with flue gas desulfurization (Table 1). However, there are substantial scale economies to be exploited. First, there are scale economies to be gained in the combined cycle unit, arising from the scale-sensitivity of the steam turbine sub-unit. Second, there are scale economies to be realized in gasification. With the Texaco gasifier, gasification takes place in oxygen, provided by a scale-sensitive oxygen plant. Based on EPRI capital and operating cost estimates, a 600 MW unit using advanced gas turbines that have recently become available (28) would probably be competitive (Table 1).

The success of the Cool Water demonstration is leading to the formulation of utility capacity expansion strategies that offer flexibility in the face of continuing uncertainty about future electricity demand and fuel prices (32). While natural gas prices are low, natural gas-fired capacity could be added in the near term in units as small as 135 MW (the size of the individual gas turbines that would be involved in advanced combined cycle units, see Table 1, note g), thereby avoiding financial commitments to larger amounts of capacity that might not be needed. These units could be expanded to combined cycle units as demand grows and gas prices rise; and they could ultimately be modified to operate on gasified coal if necessary.[5]

A Comparison of Industrial and Aeroderivative Turbines

The combined cycle is a good technology for beginning a transition to greater use of gas turbines in stationary power applications. It marries the

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[5] A variation on this strategy involves "repowering" existing steam plants with gas turbine topping cycles. The repowered plants would be fired initially with natural gas, with the flexibility to shift later to gasified coal (32,33).

new gas turbine technology to the familiar steam turbine. But it would be a mistake to limit utility use of advanced gas turbines to this option, because there are other possibilities that may prove to be even more attractive in some applications.

In exploring alternative gas turbine strategies it is necessary to distinguish between industrial turbines and aeroderivative units. Industrial turbines are heavy-duty machines designed specifically for stationary applications. Various vendors offer units in relatively large sizes of 70 to 135 MW. The tendency has been to design them with modest compression ratios (8 to 16). They are thus well-suited for combined cycle operations because the turbine exhaust gases are thereby relatively hot [593 °C (1099 °F) for the most recently offered advanced industrial unit (28)], making it possible to produce high quality steam in the HRSG. In contrast, aeroderivative units are lightweight and compact, with relatively small capacities (30 to 35 MW at the high end of available capacities), and the trend is toward high compression ratios (18 to 30); all such characteristics reflect jet engine design requirements. Though relatively efficient as electricity producers, such engines tend to be poor candidates for combined cycle applications since the turbine exhaust gases are not especially hot. However, they are good candidates for other efficiency- and output-augmenting cycle modifications such as steam injection, discussed below.

While aeroderivative turbines are not nearly as familiar as heavy-duty industrial turbines for stationary applications, they warrant greater attention not only because, with appropriate cycle modifications, they can perform as well as or better than industrial units with today's technology (see below), but also because in the future aeroderivative units may be able to outperform industrial turbines in important ways. There are two reasons for this judgment. While there are only modest ongoing development efforts to improve industrial turbines in the United States, there is continuing heavy government support for jet engine R&D, including, for example, the new $3.4 billion, 13-year Integrated High Performance Engine Technology program supported by the Department of Defense and the National Aeronautics and Space Administration (34). Such R&D efforts are expected to lead to major improvements in aircraft engine technology, including substantial further improvements in turbine inlet temperatures (Figure 10). To fully capture the thermodynamic benefits of increasing turbine inlet temperatures, high compression ratios are necessary, such as those available in aeroderivative turbines. Of course, it would be entirely feasible to design heavy-duty industrial turbines with high compression ratios, but doing so would require costly development efforts.

Despite such advantanges offered by aeroderivative turbines, many utility managers are reluctant to consider these turbines in their capacity expansion plans. One concern is that, because in these turbines' manufacture emphasis is given to the use of special materials to meet the low weight and compactness requirements of jet engines, aeroderivative engines are inherently more costly per kW than industrial turbines, where such constraints are not relevant. While the use of more costly materials does tend to raise the cost of aeroderivatives, a compensating factor is that a greater proportion of the aeroderivative power plant can be built at the factory, where costs are easier to control than in the field. Moreover, the various cycle modifications that would be employed for stationary applications of aeroderivatives tend to lower unit costs. For example, when a simple cycle gas turbine is modified for both steam injection and intercooling, its output can be tripled, resulting in a lower unit capital cost than that of a combined cycle based on an industrial turbine (Table 1).

Another concern is that because aeroderivative engines are more delicate pieces of equipment than heavy-duty industrial turbines, they are less reliable. This might be true if aeroderivative turbines were maintained like industrial units; instead they are maintained like jet engines. Their compact, modular construction makes it easy to remove and replace failed parts quickly.[6] In fact the entire basic engine can be removed and replaced with a spare (flown in, if necessary) from a lease-engine pool, resulting in short downtime.[7] With aeroderivative units it is not necessary to schedule major downtime for repairs, as is the case with heavy-duty industrial units. Statistical data on utility use of industrial turbines, combined cycles, and aeroderivative turbines compiled by the North American Electric Reliability Council shows no significant differences in the availabilities[8] of the three types of engines, which averaged more the 90 percent in all cases between 1982 and 1984 (35).

A closely related concern is the cost of maintenance. It is widely believed that maintenance costs of gas turbines, heavy-duty industrial as well as aeroderivative, are much higher than those of steam-electric plants. This

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[6] Complete inspection (with any necessary replacements) of the hot section of a GE LM-2500 aeroderivative turbine requires a crew of five working 100 person-hours (36). The same job requires a six-person crew working 480 person-hours for a GE Series 5000 industrial turbine that has a comparable output (37).

[7] This possibility arises because the gas generator, the "high technology" part of an aeroderivative engine, where maintenance is most crucial, is easily transported. The gas generator for the largest aeroderivative turbine available, General Electric's LM-5000, weighs just 4770 kilograms and measures only 1.8 m x 2.1 m x 4.6 m.

[8] The availability of a plant is the percentage of the time it is actually available for service when called upon.

belief is supported by utility experience; between 1982 and 1985 maintenance costs for utility gas turbines averaged 0.76 cents per kWh, compared to 0.26 cents per kWh for coal-fired steam plants (12). Some utilities report maintenance costs for gas turbines as high as 1.0 to 1.5 cents per kWh (35). These statistics should be interpreted with care, though, because the data for coal-fired plants are for carefully maintained baseload units, while the gas turbine data are for peaking plants that typically operate at an average capacity factor of only 5 to 7%[9] and are often not carefully maintained. In considering gas turbines for baseload or load-following utility service, a more appropriate historical record is that for gas turbines operated in baseload cogeneration configurations at industrial plants. Preventive maintenance programs carried out over the last 20 years for aeroderivative gas turbines used for cogeneration at the Dow Chemical Company resulted in maintenance costs of 0.2 to 0.3 cents per kWh (35).

Another concern often expressed about aeroderivative turbines is that utilities will not be interested in them because of their small unit capacities. However, pressed by the financial risks of planning based on large power plants, many utilities are already beginning to shift the focus of their planning efforts to smaller units. Moreover, utilities would be able to improve overall reliability with multiple small units on the same site. The ongoing trend toward more competition in power generation is also making market conditions more favorable for introducing these smaller-scale power-generating technologies.

STEAM-INJECTED GAS TURBINES

The most significant development to date relating to stationary power

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[9] The capacity factor of a plant is the amount of electricity produced in a given period expressed as a percentage of the potential production in that period if the plant were operated at its rated capacity.

applications of aeroderivative gas turbines was the introduction in the early 1980s of the steam-injected gas turbine (STIG), a variant of the simple gas turbine in which high pressure steam recovered in the HRSG is injected into the combustor, where it is heated to the turbine inlet temperature and then expanded in the turbine (Figure 8e).[10] Steam injection can give rise to large increases in power output and electrical efficiency. The only extra work required with steam injection, compared to a simple cycle gas turbine, is that needed to pump the feedwater to boiler pressure, which is negligible compared to the work required to compress the main air flow. This and the fact that the specific heat of steam is double that of air account for the large increases in efficiency and power output that arise with steam injection (13,38). Aeroderivative engines are chosen for steam injection, because, unlike heavy-duty industrial turbines, these units are designed to accommodate turbine flows considerably in excess of their nominal ratings, so that only minor strengthening is required to operate them as baseload STIGs (39).

Injecting small amounts of steam (or water) in stationary gas turbines (heavy-duty industrial as well as aeroderivative) for the control of NO_x emissions is a well-established practice (40,41). Only recently has injecting large amounts of steam attracted serious commercial interest as a means of

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[10] The injected water must be treated to avoid turbine blade corrosion problems. Because the minimum water treatment level required is not yet known (35), present practice is to be conservative. Even so, water treatment costs are minor. For STIG cogeneration units based on the Allison 501-KH, water treatment costs have been estimated to be 0.09 cents per kWh (for 1.63 liters per kWh and water treatment costs of 0.05 cents per liter, personal communication from C. Koloseus, International Power Technology, Inc., April 1985). For central-station STIG units based on the GE LM-5000 the capital cost for make-up and waste-water treatment (based on typical river water quality in the Eastern United States) has been estimated to be less than $20 per kW, some 5% of the total installed cost (15).

increasing efficiency and power output in stationary applications. Yet the concept is not new. The idea of using steam injection to increase power and efficiency is discussed in textbooks published in 1970 (42) and 1980 (43), in various articles dating from the mid-1970s (39, 44-50), and in a 1951 Swedish patent application (51), which was rejected in 1953. The injection of water into gas turbines dates to the earliest use of jet engines, when water was often injected to increase thrust during takeoff. Moreover, the third gas turbine ever to produce net power, a 400 to 800 horsepower unit with an efficiency of 3.5% built by Charles Lemale and Rene Armengaud in Paris in 1905-1906, was a steam-injected gas turbine. The stated purpose of steam injection in the Lemale-Armengaud turbine, however, was to help cool the turbine blades in a machine that operated with a very high combustor temperature (25, 52).

STIG for Cogeneraton

The commercialization of STIG for cogeneration applications grew out of the post-PURPA flurry of interest in gas turbine cogeneration. The STIG concept was introduced to cope with the most troublesome problem for simple cycle gas turbines in cogeneration applications: their poor part-load performance. With a STIG unit, steam not needed for process applications can be injected back into the combustor to produce more electric power; the provisions of PURPA often make it attractive to sell this extra power to the utility, thus extending the economic viability of gas turbine cogeneration to a wide range of variable-load applications (13).[11]

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[11] A combined cycle with a condensing steam turbine using steam extraction to provide steam for process (Figure 8d) can also be used economically in variable steam load applications: steam not needed for process is expanded through the lower turbine stages and condensed to produce more power. But the scale economies associated with steam turbines limit the economical use of the combined cycle to relatively large installations. STIG technology allows the gas turbine to be used in small-scale, variable steam-load applications.

The first commercially operated STIG cogeneration units involved the use of the Cheng cycle, a patented version of STIG introduced by International Power Technology, Inc (53, 54). Cheng cycle units have been marketed using the Detroit Diesel Allison 501-KH turbine. Without steam injection, this turbine is rated to produce about 3.5 MW of electric power at 24% efficiency when producing power only. With full steam injection, it will produce about 6 MW at 34% efficiency (13). At the time of this writing six units based on the Allison 501-KH had been installed and two more ordered. More recently, four larger STIG units based on General Electric's LM-5000 have been installed at industrial sites [the first involving an in-the-field modification of a simple cycle cogeneration unit at a paper mill in California (55)]. The LM-5000, derived from the CF6-50 high-bypass-ratio turbofan engine used in wide-body commercial airplanes (e.g. the DC-10 Series 30, the Boeing 747, and the Airbus A300), is a 33.1 MW unit with a compression ratio of 25:1 and an efficiency of 33% when operated on natural gas. With full steam injection the output and efficiency of the LM-5000 increase to 51.4 MW and 40% respectively (55a).

STIG and ISTIG for Central Station Power

The use of steam injection for cogeneration has stimulated interest for central station applications, in which all the steam raised in the HRSG is injected for power and efficiency augmentation. A paper by a Bechtel analyst indicates that STIG plants based on the LM-5000 and using once-through steam generators would have several advantages over combined cycle units--including a unit capital cost lower by one sixth, water requirements less by one third, a 6% higher availability, and the possibility of remote operation without operators in continuous attendance (15).

A major drawback of STIG is that it is less energy-efficient than the advanced combined cycle technology that has recently become available (28). Accordingly, despite a modest capital cost advantage for STIG, the busbar cost would be lower for advanced combined cycles (Table 1).

A more interesting candidate for central-station applications is a proposed modified LM-5000 using intercooling between the two compressor stages, as well as steam injection (Figure 8f). One result of intercooling is that it improves the efficiency of the compressor and thus reduces the amount of power needed to run the compressor. The addition of an intercooler to a simple gas turbine increases the power output but decreases the efficiency, because the efficiency gain at the compressor would be more than offset by the extra fuel requirements for heating the cooled air exiting the compressor up to the turbine inlet temperature (43). But modern aeroderivative turbines use air bled from the high-pressure compressor to cool the turbine blades, so that intercooling in this instance leads to an efficiency gain as well. Because of the lower temperature of the air used to cool the blades, the metal temperatures can be kept acceptably low, while the turbine inlet temperature is raised from about 1211 ^{o}C (2211 ^{o}F) for the simple-cycle LM-5000 to 1370 ^{o}C (2500 ^{o}F). Detailed evaluations by General Electric indicate that the intercooled STIG (ISTIG) based on the LM-5000 will produce about 110 MW with a 47% efficiency, at an installed capital cost of about $400 per kW [personal communication from G. Oganowski, General Electric Company, November 1987; (13, 14)].

The projected ISTIG efficiency is somewhat higher than that for an advanced combined cycle and its estimated capital cost is somewhat less, leading to a lower busbar cost (Table 1). The expected performance is so good that the busbar cost would be less than for a large coal-fired steam-electric plant with flue gas desulfurization even with a natural gas price double the average for 1986 (Table 1).

Despite the indicated efficiency advantage of the ISTIG compared to the advanced combined cycle, this is not the result of a systematic comparison of steam-injected and combined cycle designs. Recently, however, a systematic comparison has been made in a study carried out under the auspices of the Engineering Research Association for Advanced Gas Turbines (ERAAGT) in Japan. In 1978 ERAAGT launched a project to develop a high-efficiency gas turbine for power generation. As part of this effort a pilot gas turbine with a turbine inlet temperature of 1300 °C (2370 °F) has been undergoing tests at Tokyo Electric Power Company since 1984.[12] In a comparison of steam-injected and combined cycle designs based on this pilot plant,[13] it was found that the combined cycle version would have an efficiency of 48%, while the steam-injected unit would be 49% efficient and would be less costly per kilowatt because it would be less complex (56).

Despite this finding, the predicted performance difference is too small to declare unequivocally that steam-injected designs are more efficient. In looking to the future, the balance could tip in favor of combined cycles if the

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[12] The pilot unit has an intercooler that employs a water spray type direct contact heat exchanger and a second (reheat) combustor between the intermediate pressure and low pressure turbine stages.

[13] The steam-injected and combined cycle designs, both having intercooling and reheat, were optimized for the same turbine inlet and turbine blade temperatures. In the optimization process the peak steam temperature in the HRSG was limited to 566 °C (1050 °F), and the turbine blades were assumed to be steam cooled in the steam-injected design but air cooled in the combined cycle design. Steam cooling of the blades in a combined cycle would result in a significant reduction in efficiency because the steam bled off for cooling the blades would not be available for powering the steam turbine, which would be the most energy-effective use of the steam (56a).

Kalina cycle is successfully developed and used instead of the steam Rankine cycle in combined cycles, for example. But there are also many possible modifications to the STIG cycle.

One such such cycle modification is the chemically recuperated gas turbine, which involves using some of the turbine exhaust heat to reform the fuel with steam in the presence of an appropriate catalyst (56b, 56c). For example, methane fuel could be converted into a mixture of hydrogen, carbon monoxide and carbon dioxide by reacting it with steam. As the steam-reforming reaction is highly endothermic, the chemical energy content of the products is greater than that of the fuel from which it is derived; thus through steam reforming, low-quality heat can be converted into to high-quality chemical energy. To the extent that some of the turbine exhaust heat can be used for chemical recuperation as an alternative to heat recuperation through steam injection, there would be a net cycle efficiency improvement because of the reduction of the latent heat loss to the stack. (More than half the heat used to raise steam in the HRSG is the latent heat needed to evaporate water, which is lost to the stack in a STIG cycle.) Steam injection plus steam reforming of methanol as fuel has been shown to increase the efficiency of a simple cycle gas turbine from 30% to 47%, while reducing the unit capital cost of the turbine by 15% (57). Even further gains would be possible if intercooling were combined with steam injection and chemical recuperation.

Because of the uncertainties relating to an efficiency comparison of steam-injected and combined cycle designs, the decision as to whether it is worthwhile to give more emphasis in stationary applications to steam-injected cycles should be made on grounds other than efficiency alone. Especially noteworthy are the facts that: STIG and ISTIG units are simpler than combined cycle units, requiring no steam turbine, condenser, or cooling tower; pollution controls would be less costly than with combined cycle units (see below); the small size of STIG and ISTIG units implies flexibility in capacity planning, improved reliability, and ease of maintenance through lease-pool arrangements; their small size also makes them good candidates for cost-cutting innovations and the economies of mass production; and steam-injected gas turbines will continue to benefit from expected continuing improvements in jet engine technology.[14] Such considerations, collectively considered, provide a compelling case for promoting expanded roles for steam-injected turbine technologies.

It has been estimated that to develop ISTIG would take four to five years and cost $100 million, including the cost ($40 million) for the first unit (16). As no proof-of-concept is involved, only good engineering design, the technological risk associated with development is small. Accordingly, bringing the technology to market requires only the sale of a few units to pay for the relatively modest development costs.

Coal-Fired STIG/ISTIG

The uncertainty about the long-term availability of natural gas at affordable prices is a major obstacle to a broad shift by utilities to advanced gas turbines. The Cool Water project did demonstrate that gas turbines can be shifted to operate successfully on gas derived from coal, should natural gas become scarce and expensive. But a shortcoming of the "backstop technology"

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[14] Presently available aeroderivative turbines do not even fully exploit technology already proven for jet engines. For example, the turbine blades in the first and second stages of the LM-5000 are made out of alloys that are not state-of-the-art: Rene 80 (60% nickel, 14% chromium, 10% cobalt, 5% titanium, 4% molybdenum, 4% tungsten, and 3% aluminum) plus codep B (aluminum plus titanium diffusion coating). Rene 80 was introduced in the late 1960s (Figure 10, right).

demonstrated at Cool Water is that, even when an advanced gas turbine is used and scale economies are exploited, the overall cost of electricity would be no less than that of power from a conventional coal-fired steam-electric plant with flue gas desulfurization (Table 1). In the present utility investment climate it will be hard to persuade many utilities to take a chance on a new technology that offers no economic benefits. Accordingly, most utility planners willing to emphasize gas turbines in their capacity expansion plans are those who feel that over the expected lives of these plants the chances of having to shift to gas derived from coal are remote.

This situation would be different if the coal-gas backstop technology offered significant economic advantages over conventional coal-fired steam plants. A 1986 analysis for the US Department of Energy by the General Electric Corporate R&D Center offers one approach to addressing this challenge. This study, which considered several gasifiers and gas turbine technologies, identified three strategies as the most promising for reducing capital costs and improving the coal-to-electricity conversion efficiency, thereby reducing overall costs: (a) replacing the oxygen-blown Texaco gasifier with an air-blown Lurgi fixed bed gasifier, thus eliminating the need for the costly and scale-sensitive oxygen plant; (b) employing hot-gas desulfurization instead of a scrubber (cold-gas cleanup) for sulfur removal, thus improving efficiency; (c) using an ISTIG instead of a combined cycle, further improving efficiency and eliminating the scale-sensitive steam turbine bottoming cycle for the combined cycle. With these strategies the GE study estimated that the installed capital cost would be less than $1000 per kW in a 110 MW unit with an overall coal-to-busbar efficiency of 42.1%. The resulting busbar cost would be one fifth less than that of either a coal-fired steam plant with flue gas desulfurization or an advanced combined cycle plant fired by coal gas derived from a Texaco gasifier, and one sixth less than EPRI's target for nuclear power in a reborn nuclear power industry (Table 1). The Lurgi/ISTIG technology would offer the environmental benefits of coal gasification (see below) in a power plant one sixth or one fifth as large as a commercial-scale version of the technology demonstrated at Cool Water, thus bringing to coal-based power technology the advantages of small-scale units.

The Lurgi gasifier is a proven, commercially available system. ISTIG is not commercially available, but it involves no technological proof-of-concept. The unproven part of the proposed system is the hot-gas clean-up, which would involve the use of iron and zinc oxide catalysts to remove the sulfur from the gases exiting the gasifier (in the form of H_2S and COS) before these gases are delivered to the combustor. The proposed sulfur removal technology has been proven technically in bench and pilot scale investigations, but field experience is needed to demonstrate the long-term performance of the catalysts involved (16).

Lurgi/ISTIG technology would seem to be a recipe for success, offering improvements over conventional power technology with regard to capital cost, efficiency, environmental benefits, reliability, and planning flexibility, to offset the risks involved in moving ahead. The history of technology shows that of all the many inventions that come along, the successful ones tend to be those, like Lurgi/ISTIG, that improve many factors of production simultaneously (58). Technological innovation is so disruptive of the status quo that new technologies are successful only if potential users cannot afford to ignore them. This feature of new technologies is especially important in industries like the electric utility industry, where slow and uncertain demand growth discourages new investment of any kind.

Indeed, the attractiveness of the Lurgi/ISTIG concept led the Department of Energy to select for funding a pilot/demonstration project proposed by General Electric to develop essential features of this technology under the Department's Clean Coal Technology Demonstration Program. The $156 million project was to include testing the hot-gas cleanup concept at a GE gasifier test facility, followed by the construction of a 5 MW pilot plant and a 50 MW commercial demonstration project based on the use of a STIG unit. (Under the Clean Coal Technology Demonstration Program the government provides half the total support, the private sector the other half.) In the fall of 1987, however, the project was canceled, because the required private-sector support was not secured.

This project illustrates the difficulties involved in attracting utility interest in new power generating technology today. But the cancellation is perhaps understandable in light of the limited potential payoff. What was to be demonstrated was a Lurgi/STIG, not a Lurgi/ISTIG, system. While success with the latter would represent a major advance over Texaco/advanced combined cycle (ACC) technology, the benefits offered by Lurgi/STIG are marginal; the projected unit capital cost would be midway between what is projected for Texaco/ACC and Lurgi/ISTIG units, but the efficiency would be only 35.6%, compared to 37.9% for a Texaco/ACC unit, so that the busbar cost would be only about 7% less than for the Texaco/ACC system (Table 1). Since General Electric at the time had no independent plans to commercialize ISTIG (e.g. for natural gas-fired applications), a successful Lurgi/STIG outcome was probably insufficiently attractive, in light of both the technical risks involved and the uncertain long-term outlook for natural gas.

At the time of this writing significant efforts are under way to improve the overall economics of gas turbine-based power systems fired with gas derived from coal. Most notably, the Appalachian Project, a US DOE-supported commercial demonstration, involving the use of an air-blown KRW fluidized bed gasifier, hot-gas cleanup, and a 63.5 MW combined cycle power plant, is moving ahead, with operation scheduled to begin in 1993 (58a); also various advanced coal gasification/combined cycle concepts are being advanced abroad, with especially intense activity in West Germany (58b). With the collapse of the Lurgi/STIG project, however, there is no ongoing coal gasification/gas turbine project underway to exploit the advantages of aeroderivative gas turbine technology.

Biomass-Fired STIG

While there is far more coal than oil or natural gas left in the world, most coal resources are concentrated in a few locations, with the United States, Soviet Union, and China accounting for more than three fourths of the world total (59). Most developing countries have negligible coal resources, but many could use biomass (the chemical energy stored in plants) as fuel. In so doing, the use of gasified biomass in steam-injected gas turbines is one promising way to exploit the biomass resource.

Biomass already accounts for more than 40% of total energy use in developing countries, mainly in the form of firewood and crop residues used in the domestic sector for cooking (60). However, at present biomass is used inefficiently, so that little useful energy is obtained. Because of the low efficiency of photosynthesis, biomass cannot play a major role in the development of developing countries unless it is upgraded into modern energy carriers through the introduction of high-efficiency conversion technologies for making gases, liquids, and electricity, and through the use of energy-efficient utilization devices (61).

The possibilities for modernizing bioenergy are well illustrated by the findings of a 1987 study assessing the prospects for using advanced gas turbines for cogeneration in the cane sugar industry of Jamaica, with sugar cane residues as fuel (Figure 11) (62). While interest is growing in cogeneration in the sugar industry, this interest has been focused on the use of commercially available steam turbines. Experience with fossil fuels, though, indicates sharply rising unit capital costs for steam turbines at the small scales likely to characterize most biomass-fired installations; the lower unit costs of gas turbines and their relative insensitivity to scale (Figure 9) suggest that gas turbines might be more promising candidates for biomass-based cogeneration applications. Detailed analysis confirms this judgment and shows that systems involving biomass gasifiers and steam-injected gas turbines would be less capital-intensive and less scale-sensitive than conventional extraction steam turbines fired with biomass. In this comparison the gas turbine system is the Lurgi/STIG technology proposed for use with coal (16), but without the chemical hot-gas cleanup technology, which is not needed with biomass fuels, since they usually contain little sulfur.

It might seem that the cane sugar industry would be an unlikely candidate for such cogeneration technology, because at present all or nearly all the bagasse (the residue from the crushing of sugar cane) is used onsite to provide the steam and mechanical power needs of the sugar factory. However, examination of sugar factories shows that they have been intentionally designed to be inefficient energy users, to consume bagasse that would otherwise pose a waste disposal problem. If more energy-efficient steam-using technologies already widely used in the beet sugar industry (e.g. falling film evaporators,

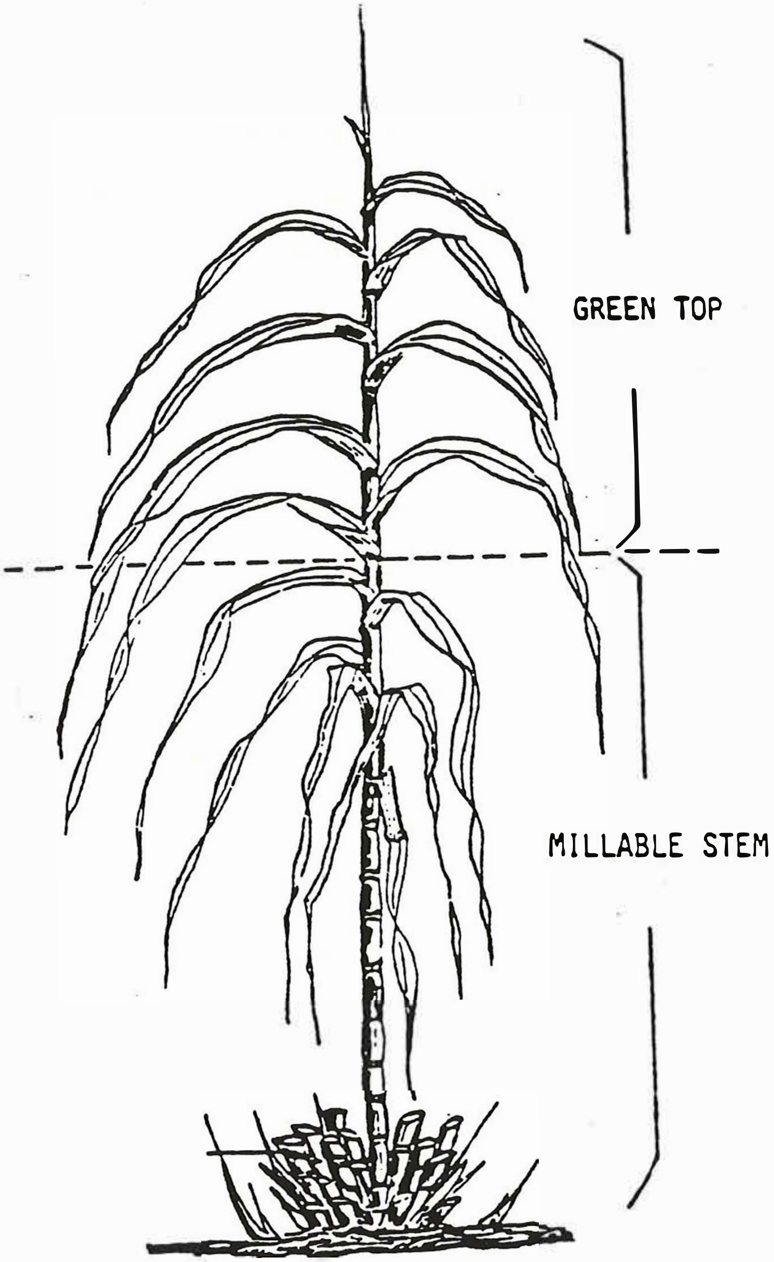

Figure 11.

The above-ground components of a sugar cane plant (63). In many parts of the world sugar cane fields are burned to remove the leaves before harvesting; the stems (left intact by burning) are then harvested and the tops are cut off in the fields by hand. The stems are then transported to the sugar factory where they are crushed to remove the sugar juice. Bagasse, the residue of crushing the stems, is now used as fuel to provide the energy needs of the factory. If sugar factories were made more energy-efficient a large amount of bagasse would be freed up to produce extra electricity in a cogeneration facility at the sugar factory while meeting onsite energy needs . If the cane could be harvested green, some of the tops and leaves could be harvested as well and stored for electricity production in the off-season. (Sugar mills typically operate only about half the year.)

condensate juice heaters, etc.) were adapted for use in the cane sugar industry, it would be possible to use sugar cane residues both to meet onsite energy needs and to produce large quantities of electricity for export to the utility grid. Specifically, the amount of electricity generated onsite with cane residues can be increased from the present level, typically 20 kWh per tonne of cane, up to about 250 kWh per tonne of cane with extraction steam turbine technology and up to nearly 500 kWh per tonne with steam-injected gas turbines fired with gasified cane residues (Figure 12). Moreover, for Jamaica the electricity thus produced would be less costly than the least-costly alternative new source of power being considered by the utility, coal-fired power stations; also, the total cost of the cogenerated electricity would be less than the operating cost for central station electricity generation at existing oil-fired central station power plants in Jamaica. In addition, preliminary analysis indicates that this cane sugar power would often be competitive with electricity from new hydroelectric sources in Brazil (62).

The fact that biomass applications of STIG do not require chemical hot-gas cleanup has implications for gasification/gas turbine development generally, because the demonstration effort required to prove commercial readiness would take much less time than for coal, some four to five years, compared to nine years. This consideration, the favorable estimated economics (which in many parts of the world are not constrained by present low natural gas prices), and large potential markets (see below) suggest that biomass applications warrant high priority in efforts to extend gas turbine technology, and especially aeroderivative gas turbine technology, to the use of low-quality fuels.

ENVIRONMENTAL ASPECTS OF ADVANCED GAS TURBINE TECHNOLOGIES

Advanced gas turbines offer major environmental as well as economic

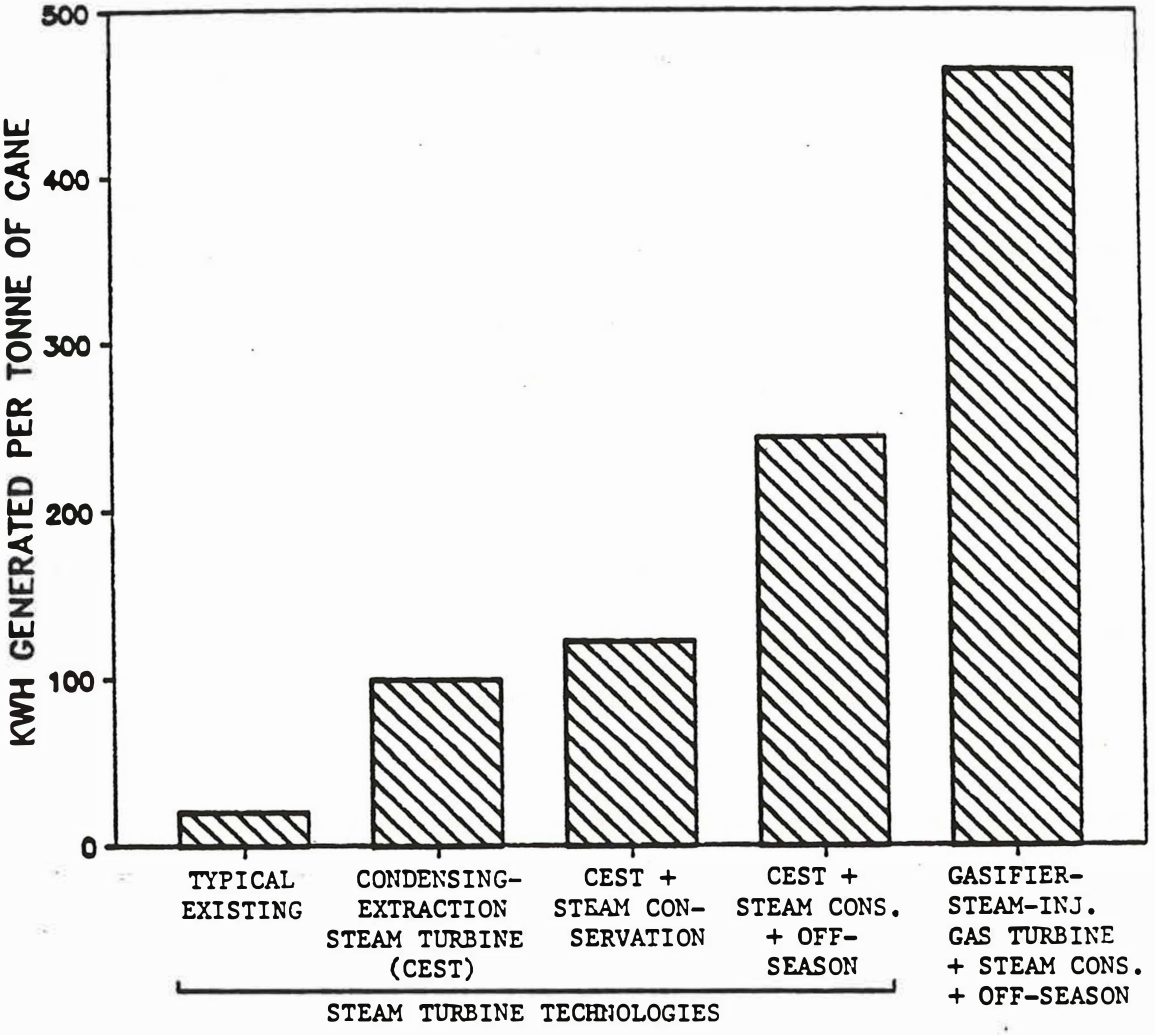

Figure 12.

Electricity generating potential per tonne of sugar cane at a raw sugar factory, using sugar cane residues as fuel (62). The leftmost bar represents the current situation at many factories. The next three bars show what can be accomplished if existing inefficient steam turbine cogeneration technology is replaced by modern condensing-extraction steam turbine cogeneration technology. The first of these bars is for the case where process steam demands are unchanged from what they are at present. The second shows the increased production possible if cost-effective steam-saving technologies are deployed in the factory. The third shows the further increase that can be achieved if some barbojo is harvested, stored, and used to produce electricity in the off-season. The final bar shows the production potential with steam-injected gas turbines deployed in a steam-conserving sugar factory, with barbojo used for electricity production in the off-season.

benefits. Natural gas-fired gas turbines emit negligible amounts of sulfur oxides, particulates, carbon monoxide, and unburned hydrocarbons. The high combustion temperatures lead to high emissions of nitrogen oxides (NO_x), however. Uncontrolled NO_x emissions amount to some 0.22 kg/GJ (0.5 lb/million BTU) or more, far in excess of the federal New Source Performance Standard for natural gas fueling promulgated in the United States in 1977, 0.086 kg/GJ (0.2 lb/million BTU), and some state standards, which are 0.043 kg/GJ (0.1 lb/million BTU) or lower.

Among available technologies for reducing NOx emissions, a well-established approach involves the injection of steam or water into the primary combustion zone. Doing so reduces NO_x formation by reducing the flame temperature. NO_x emissions tend to fall exponentially with the amount of water or steam injected. With water injection the electrical efficiency is reduced, because the percentage increase in fuel required to bring the mixture up to the turbine inlet temperature exceeds the percentage increase in power output resulting from the increased turbine mass flow. With steam injection the electrical efficiency is also reduced for combined cycle systems (where the optimal use of the steam produced in the HRSG is for power generation in the steam turbine) (41), but not for STIG or ISTIG cycles, where NO_x control is an automatic side benefit of the use of steam injection to increase power and efficiency. An emissions rate of 0.043 kg/GJ (0.1 lb/million BTU) in fact can be achieved using less than 40% of the steam available for injection in the steam-injected LM-5000, and lower emissions rates were measured for higher steam injection rates in the first LM-5000 converted to steam injection (55).[15]

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[15] As additonal steam is injected to control NO_x emissions to even lower levels, CO emissions increase, to levels that are eventually problematic. Determining the optimal level of steam injection into the primary combustion

With coal gasification even coal plants can achieve low pollutant emissions. The Cool Water project demonstrated emissions levels for SO_2, NO_x, and particulates far below New Source Performance Standards (Table 2). Alternative coal gasification technologies are expected to have comparable emissions performance.

While new coal-burning steam-electric power plants generally meet New Source Performance Standards, the large quantities of SO_2 and NO_x emitted by existing plants are becoming increasingly problematic because of growing concerns about acid rain (65). In 1983 coal plants spewed 15.6 million tons of SO_2 (62% of the US total) and 7.1 million tons of NO_x (32% of the US total) into the atmosphere (66). New legislation requiring reductions of these emissions at existing power plants may be forthcoming. While much of the emphasis in the ongoing debates is on requiring the retrofitting of control systems such as stack gas scrubbers on these old power plants, the only benefit that would be gained thereby is a reduction of the pollutant emissions, at considerable cost. An alternative would be to encourage scrapping existing coal-fired steam plants (regardless of their remaining useful lives) and replacing them at the same sites with new advanced gas turbine power plants, but using where possible the old plants' equipment (e.g. coal-handling equipment).

Consider first the case in which the new power plants would be fired with gas derived from coal. With all the incremental costs of the new facilities allocated to sulfur removal (taking no credit for reduced NO_x emissions or

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zone involves balancing considerations of both NO_x and CO emissions. If still higher levels of steam injection are desired for power and efficiency augmentation, the extra steam is injected sufficiently far from the primary combustion zone so as not to affect pollutant emissions further.

Table 2. Actual Air Pollutant Emissions from the Cool Water Demonstration Power Plant vs. EPA New Source Performance Standards[a]

	Measured Emissions[b]	EPA New Source Performance Standards
SO_2	95 percent removal (0.033 lb/million BTU)	90 percent removal (maximum = 1.2 lb/million BTU)
NO_x	0.061 lb/million BTU	0.6 lb/million BTU
Particulates	0.001 lb/million BTU	0.03 lb/million BTU

[a] The Cool Water plant produces 94 MW at an average efficiency of 30.2 percent, using the Texaco gasifier (67).

[b] For Utah (SUFCO) design coal.

other benefits), the cost of this scrap-and-build strategy can be expressed as the cost per ton of SO_2 removed and compared to the cost of SO_2 removal with scrubbers. Figure 13 shows that SO_2 removal with Lurgi/ISTIG would cost about $350 per ton, compared to $290 to $560 per ton for scrubbers. The remarkable result that Lurgi/ISTIG would be competitive with scrubbers in most circumstances is due to the fact that, despite the higher capital cost of the Lurgi/ISTIG option, there would be a significant coal savings because of the higher plant efficiency. It is noteworthy that the much less electricity-efficient Lurgi/STIG and Texaco/ACC options, costing respectively some $600 and $710 per ton of SO_2 removed, would not be competitive with scrubbers.

Of course the advanced Lurgi/ISTIG option is constrained by the fact that it would not be commercially available for about a decade, if the development program went ahead. But ISTIG units could be fired initially with natural gas. Doing so for 10 years before switching to coal would result in the same cost of sulfur removal as with Lurgi/ISTIG units for a gas price of $3 per GJ.

Still another important environmental benefit of advanced gas turbine power generating technologies is the potential for reduced emissions of carbon dioxide. Global warming by the so-called greenhouse effect, associated with the atmospheric buildup of carbon dioxide, has become a focus of concern (70).

In general, emphasis on natural gas fuel for the transition to the post-fossil fuel era would help slow the atmospheric build-up of carbon dioxide. Burning one energy unit of natural gas releases just 0.55 times as much CO_2 as the combustion of one energy unit of coal. Furthermore, generating electricity with natural gas in gas turbines as efficient as ISTIG would release just 0.4 times as much CO_2 per kWh generated as a conventional coal-fired steam plant.

Biomass-fired power generating technologies would also be helpful where

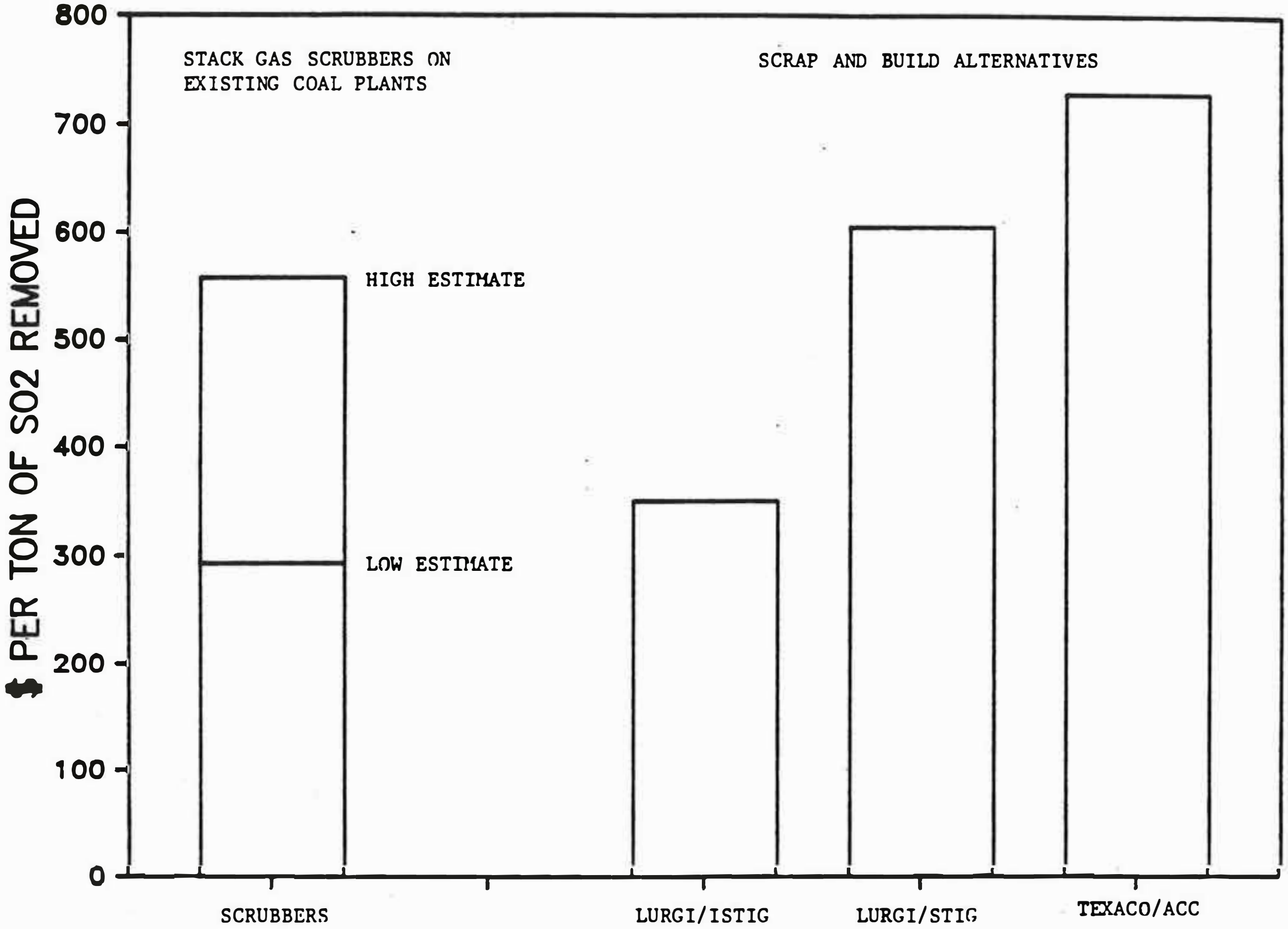

Figure 13.

The cost of sulfur removal with alternative acid rain control strategies, for coal with an average sulfur content of 3.1%. The bar on the left shows the range of estimated costs for putting stack gas scrubbers on existing coal steam-electric plants, for capital costs in the range $185 to $330 per kW, extra O&M costs in the range 0.4 to 0.8 cents per kWh, a 60 percent average capacity factor, and 85% sulfur removal (68). The three bars on the right are for cases in which existing plants are retired and new coal gas-based gas turbine plants are built at these sites, allocating all the incremental cost to sulfur removal, assuming 95% sulfur removal with coal gasification. All the cost and performance characteristics for the new plants are from Table 1, except that capital costs are reduced 10 percent because some of the existing facilities can be used in the new plants, based on detailed estimates for Lurgi/STIG and Lurgi/ISTIG (private communication from J.C. Corman, G.E. Corporate R&D Center, May 12, 1987). In taking credit for the operating costs of the retired plants, it is assumed that the efficiency of the existing plants is 33.2 percent, the average for coal plants in 1985 (12), and that the O&M cost for the existing coal plants is 0.36 cents per kWh, the average for Midwest coal plants without scrubbers (69). A 6.1% discount rate and a 30-year lifetime are assumed for all cases.

the biomass fuel is produced on a renewable basis. There would be no net buildup of atmospheric CO_2, since that released in combustion would just balance that removed from the atmosphere in photosynthesis. Highly efficient advanced gas turbines would be especially important; by squeezing more useful energy out of biomass, they would reduce the need to burn fossil fuels.

Also, efficient coal-gas fired turbines would be better in this regard than conventional coal-fired steam plants. A Lurgi/ISTIG unit fired with coal would emit only 0.8 times as much CO_2 per kWh as a conventional coal-fired steam plant. While this is not nearly so dramatic as the reduction achievable with natural gas firing, it could be important if there were a concerted effort to replace existing coal-fired steam plants with advanced coal-gasification ISTIG plants as a result of concerns about acid rain. With this strategy a significant reduction in CO_2 emissions could be achieved for the existing stock of coal-fired plants well before normal retirement.

POTENTIAL APPLICATIONS OF STEAM-INJECTED GAS TURBINES

Important potential applications for steam-injected gas turbines include the use of natural gas and coal-gas fired units for central power stations in the United States, Western Europe, and developing countries, and biomass-gas-fired units for cogeneration applications in industries where crop residues or processing wastes can be used as feedstock. While these examples do not exhaust the possibilities, quantitative discussions of these markets illustrate the practical potential offered by this class of technologies.

Central Station Power in the United States

A useful point of departure in assessing the relative roles of natural gas and coal-derived gas for power generation in the United States is a consideration of the natural gas resource base, the potential role of gas imports, and future gas prices.

While natural gas is probably far less abundant than coal, it appears to be more abundant than oil, accounting for about 70% of total new field discoveries and a comparable percentage of the estimated undiscovered oil and gas resources in the lower 48 states (71). Current estimates are that remaining conventional gas resources amount to a 35 to 60 year supply at the present rate of production (Table 3). Higher recovery rates in known gas-producing fields,[16] as well as the exploitation of unconventional gas sources (from coal seams, Devonian shale, and tight sands) with advanced technology, could significantly increase potential gas resources.

The United States might also expect significant natural gas imports from Canada and Mexico and perhaps also Venezuela, in light of the fact that gas reserves and resources in these countries are large in relation to production (Table 4) and foreseeable domestic markets. These countries may thus be interested in exporting gas to the United States.

The likely future price of natural gas for power generation in the United States is highly uncertain, although the trend is toward lower expected future gas prices than was the case a few years ago. The most recent projection of the American Gas Association is that the average price for electric utilities will increase from $2.17 per GJ in 1987 to $2.95 per GJ in 2000 and to $4.07 per GJ in 2010 (74). This price trend is consistent with the estimate of the Gas Research Institute that future gas supplies of the order of 630 EJ are available in the lower 48 states at marginal costs up to $4 per GJ (Table 3).

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[16] Recent data indicate that non-associated gas reserves in many fields represent only about 55% of the gas-in-place, far less than the 80 - 90% level previously thought. Improving recovery to the latter level in west south central states would add some 200 EJ to reserves over and above reserve appreciations currently expected (71).

Table 3. Alternative Estimates of Remaining U.S. Natural Gas Resources

Source and Type of Estimate	Estimate in EJ
United States Geological Survey (as of January 1, 1985)[a,b]	
Identified Reserves	356
Undiscovered Resources	
95% probable higher than	202
50% probable higher than	296
5% probable higher than	517
TOTAL	
95% probable higher than	558
50% probable higher than	652
5% probable higher than	873
Potential Gas Committee (as of December 31, 1986)[a,c]	
Proved reserves	210
Undiscovered resources	
Probable	178
Possible	325
Speculative	303
TOTAL	1016
Gas Research Institute (as of January 1, 1981)[d,e]	
Marginal Cost ($/GJ)	
2	425
3	535
4	630
5	665
6	685
7	720
8	735

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[a] Excludes unconventional sources of natural gas, such as gas from coal seams and tight gas formations.

[b] See Ref. 72.

[c] See Ref. 73.

[d] Proved reserves plus estimated reserve appreciation in discovered fields plus estimated recoverable undiscovered resources, for the lower 48 states, based on existing gas production technology. The marginal cost is the cost of gas from new fields discovered in a particular year, levelized over the expected life of these fields, assuming a 10% real rate of return after taxes.

[e] See Ref. 71.

With this utility gas price path the life cycle cost of a 110 MW natural gas-fired ISTIG plant operated in the period 1993-2010 would be one fourth less per kWh than the cost of electricity from a 500 MW coal-steam plant with flue gas desulfurization (Table 1). However, even with this relatively slow growth in the gas price, a shift to gas derived from coal would be cost-justified sometime in the period 2000-2010, if Lurgi/ISTIG or the equivalent is developed and the costs estimates for this technology (Table 1) are borne out.[17]

Another potential US market involves replacing the 123 GW of existing oil- and gas-fired steam-electric plants (12) with natural gas-fired ISTIG units. While these are load-following plants operated at low capacity factor, they are so much less efficient than ISTIG units (32% vs 47%) that it would be worthwhile replacing them with ISTIG units, even with fuel prices as low as $2 per GJ ($12 per barrel of oil equivalent).[18] Doing so for all oil- and gas-fired steam plants would lead to producing the same amount of electricity as projected for such plants in the year 2000 by the Department of Energy (11), while saving fuel equivalent to 0.75 million barrels per day of oil.

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[17] The gas price at which a shift to coal gas would be justified is estimated to be $3.5 per GJ. This is obtained by setting the operating cost of a natural gas-fired ISTIG unit equal to the levelized cost of electricity from a Lurgi/ISTIG unit derived from the natural gas-fired unit. Here the capital cost involved is assumed to be the sum of (a) $580 per kW (the difference between the capital costs of coal gas-fired and natural gas-fired ISTIG units), (b) $137 per kW (one third of the cost of the original ISTIG unit, to account for depreciation), and (c) $10 per kW [the cost of converting the combustor to low BTU gas, some $1 million (personal communication, J. C. Corman, General Electric Corporate R&D, December 1987)].

[18] The breakeven price is determined by setting the levelized busbar cost from a natural gas-fired ISTIG unit equal to the operating cost of an existing steam-electric plant, assuming a 45% capacity factor for the ISTIG unit, the same fuel price for both plants, and an O&M cost of 3.8 mills per kWh for the existing steam plants [the average value in the United States in 1985 (12)].

Central Station Power in Western Europe[19]

Outside of the Netherlands and Italy, natural gas has been little used for power generation in Western Europe (accounting for less than 5% of all electricity produced in 1984), largely because of the belief that natural gas should be saved for "more noble purposes," since electricity can be readily produced from abundant coal and nuclear energy sources. This situation could be radically changed, however, because of the growing availability of natural gas supplies in Europe and the favorable economics of power generation based on advanced gas turbines.

Estimated remaining recoverable natural gas resources are about three fourths as large in Western Europe as in the United States (Table 4), but European gas resources are much less developed. While proved reserves of natural gas declined 30% in the United States between 1973 and 1987, they increased by a comparable percentage in Western Europe in this same period (76). Europeans also have the opportunity to purchase substantial quantities of gas from Algeria and the Soviet Union, where resources are far in excess of domestic needs (Table 4).

One of the important considerations limiting the use of natural gas for power generation in Europe is that its price has been closely coupled to the world oil price. For example, the border price of gas imported from the Netherlands to France increased from \$1.9 per GJ in 1976 to \$4.2 per GJ in 1982

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[19] In this paper fuel values are expressed in terms of the gross or higher heating (HHV), the convention in the United States. In Europe and many developing countries the convention is to use the net or lower heating value (LHV). The HHV differs from the LHV in that it takes into account the latent heat of condensing the water vapor in the fuel combustion product gases. For natural gas the HHV is approximately 10% higher than the LHV; for coal it is typically about 3% higher. Thus, for example, ISTIG operated on natural gas would be 52% percent efficient on a LHV basis, compared to 47% on a HHV basis.

Table 4. Natural Gas Production, Reserves, and Resources for Selected Countries[a]

	Pop.[b] (million)	Prod.[c] (EJ/year)	Rsrv.[d] (EJ)	Rsrv./Prod. (years)	Rsrc.[e] (EJ)	Rsrc./Pop. (GJ/capita)	Rsrc./Prod. (years)	Rsrc./En.[f] (years)
United States	236.7	19.7	215	11	653	2,760	33	9
Canada	25.2	2.9	101	35	426	16,950	147	42
Mexico	76.8	1.5	84	56	213	2,780	142	50
Venezuela	18.0	0.66	60	86	125	6,950	178	69
Western Europe	378.0	7.4	225	30	482	1,270	65	9
United Kingdom	55.6	1.6	30	19	81	1,460	51	10
Norway	4.1	1.0	97	97	292	70,600	292	173
Netherlands	14.4	2.9	75	26	87	6,040	30	35
Algeria	21.3	1.4	119	85	158	7,410	113	353
Soviet Union	275.0	22.6	1580	70	2727	9,920	121	52

[a] Pop. = population; Prod. = annual production; Rsrv. = proved reserves; Rsrc. = remaining resources; En. = total annual energy consumption.

[b] Population as of mid-1984 (75).

[c] Natural gas production in 1984 (76).

[d] Proved reserves as of January 1, 1985 (76).

[e] Proved reserves plus estimated reserve appreciation in discovered fields plus estimated recoverable undiscovered resources, as of January 1, 1985 (72).

[f] Total annual energy consumption data are for 1984 (77).

and then fell back to $1.9 per GJ in 1986 (78). An International Energy Agency report on the outlook for natural gas projects that in the late 1990s and beyond the border price of gas in Europe will be 73 - 80% of the crude oil price, reaching $3.4 to $5.3 per GJ by 2000 and $5.7 to $6.9 per GJ by 2010 (80), as it follows the expected rise in the world oil price. The typical gas price for electric utilities would probably be about $1 per GJ higher than the border price, to cover transmission and distribution costs from the border to the power plants.[20] Such projections discourage the use of natural gas for power generation, because life cycle average gas prices must typically be no higher than $3.2 to $3.7 per GJ for natural gas-fired ISTIG units to be competitive with new coal or nuclear steam-electric plants in Europe. (See Table 5 for the 5% discount rate case.)

The high European gas prices projected by the International Energy Agency are a result of the assumption that competition between gas and oil at the point of end use will determine the market price of gas. However, if marginal costs were low and there were major markets in which natural gas could compete with coal, competition with coal might instead determine the price of gas.

Current and projected gas prices are indeed far in excess of the marginal costs of bringing forth new gas supplies in Europe, according to a 1986 study by the International Gas Trade Project at MIT, which has analyzed the costs of increasing supplies from the major sources of gas for Western European markets on a source-by-source basis (78). Gas supplies at low marginal costs appear to

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[20] The weighted average cost of transmission and distribution inside borders in Europe was about $1.8 per GJ in 1984 (80). In the United States the difference between the retail price and the wellhead price averaged about $2 per GJ between 1981 and 1985; in this same period the difference between the gas price for electric utilities and the wellhead price averaged $1 per GJ (81). Thus a reasonable estimate for the price of gas to electric utilities in Europe is $1 per GJ more than the border price.

Table 5. Levelized Costs (cents/kWh) for Electric Power Generation from Alternative Sources in Western Europe[a]

Discount Rate (%)	5%	10%
	Levelized Busbar Cost	
Nuclear[b]		
6 year construction		
Capital	1.67	3.14
Fuel	0.94	1.05
Operation & Maintenance	0.52	0.52
TOTAL	3.13	4.71
10 year construction		
Capital	1.84	3.80
Fuel	0.94	1.05
Operation & Maintenance	0.52	0.52
TOTAL	3.30	5.31
Coal/Steam w/FGD[c]		
Capital	1.23	2.19
Fuel	1.80	1.80
Operation & Maintenance	0.52	0.52
TOTAL	3.55	4.51
ISTIG w/Gasified Coal[d]		
Capital	1.05	1.76
Fuel	1.49	1.49
Operation & Maintenance	0.58	0.58
TOTAL	3.12	3.83
ISTIG w/Natural Gas[e]		
Capital	0.44	0.73
Fuel	0.766 x P	0.766 x P
Operation & Maintenance	0.28	0.28
TOTAL	0.72 + 0.766 x P	1.01 + 0.766 x P
TOTAL (breakeven gas price[f]) in competition with:		
Nuclear, 6-year construction	3.13 ($3.15/GJ)	4.71 ($4.83/GJ)
Nuclear, 10-year construction	3.30 ($3.37/GJ)	5.31 ($5.61/GJ)
Coal/Steam w/FGD	3.55 ($3.69/GJ)	4.51 ($4.57/GJ)
ISTIG w/Gasified Coal	3.12 ($3.13/GJ)	3.83 ($3.68/GJ)

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[a] All costs are for a 30-year plant life and a 70% capacity factor. All taxes and subsidies are neglected.

[b] Based on an International Energy Agency (IEA) study assessing the outlook for electricity in IEA member countries (79). For a site with two 1100 MW(e) units and start-up in 1990. For a 5% (10%) discount rate the unit capital cost is estimated to be $1580/kW ($1810/kW), assuming a 6-year lead time, and $1740/kW ($2200/kW), assuming a 10-year lead time.

Notes for Table 5, cont.

[c] For a site with two 600 MW(e) units and start-up in 1990. For a 5% (10%) discount rate case the unit capital cost is estimated to be $1160/kW ($1270/kW), assuming a 4-year lead time (79). The efficiency is 35% (36%, LHV basis). The coal price is assumed to be $50/tonne ($1.75/GJ).

[d] For a 110 MW(e) ISTIG unit fired with gas derived from coal in a Lurgi gasifier with hot gas clean-up. For a 5% (10%) discount rate the unit capital cost is estimated to be $985/kW ($1010/kW), assuming a 2-year lead time. The coal price is assumed to be $50/tonne ($1.75/GJ). The efficiency is 42.1% (43.4%, LHV basis) (16).

[e] For a 110 MW(e) ISTIG unit fired with natural gas. For a 5% (10%) discount rate the unit capital cost is estimated to be $410/kW ($420/kW), assuming a 2-year lead time. The efficiency is 47% (51.7%, LHV basis).

[f] Breakeven gas prices, expressed in HHV terms, are about 10% less than the corresponding prices expressed in LHV terms.

be so large over the coming decades that gas could become a major fuel for power generation.

To illustrate the possibilities, suppose that all incremental power generation in Western Europe after 1995 were based on natural gas-fired ISTIG units. If overall electricity production were to grow at 2.5% per year after 1995 [in the midrange of projections made in 1985 by the International Energy Agency (79)], this implies that by 2010 180 GW of electric power capacity would be advanced gas turbines, accounting for 30% of all electricity production. Under this scenario gas turbines would consume 8.5 EJ of natural gas in 2010, or about two fifths of total gas demand then, if gas demand in other sectors were to grow at 1.1% per year [the average of the high and low projections made by the International Energy Agency in 1986 (80)]. Even with this very large increase in aggregate demand, the marginal cost of gas would still be only about $2.3 per GJ in 2010, according to the MIT analysis (Figure 14).

If this natural gas-based power generating technology were "backstopped" with a capability to shift to gas derived from coal, the result could be a capping of natural gas prices at levels far below what is being forecast. The backstop gas price, obtained by equating the cost of converting an ISTIG plant to coal with the cost of continuing to operate the ISTIG unit on natural gas, would be in the range $3.3 to $4.0 per GJ, depending on the assumed discount rate.[21] The corresponding border price would be $2.3 to $3.0 per GJ, far below

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[21] The capital cost for converting ISTIG units to coal-gas operation is estimated as in Note 17. The coal price is assumed to be $50 per tonne ($1.75 per GJ). This is the average price of imported coal and also the price of Australian coal imported into the European Economic Community between 1984 and 1986 (82). In light of the abundance of coal, the multiplicity of sources, and the low cost of transporting coal long distances, it is assumed here that the coal price remains stable in the coming decades. With these assumptions and the other parameters indicated in Table 5, the backstop utility gas price is estimated to be $3.3 per GJ ($4.0 per GJ) with a 5% (10%) discount rate.

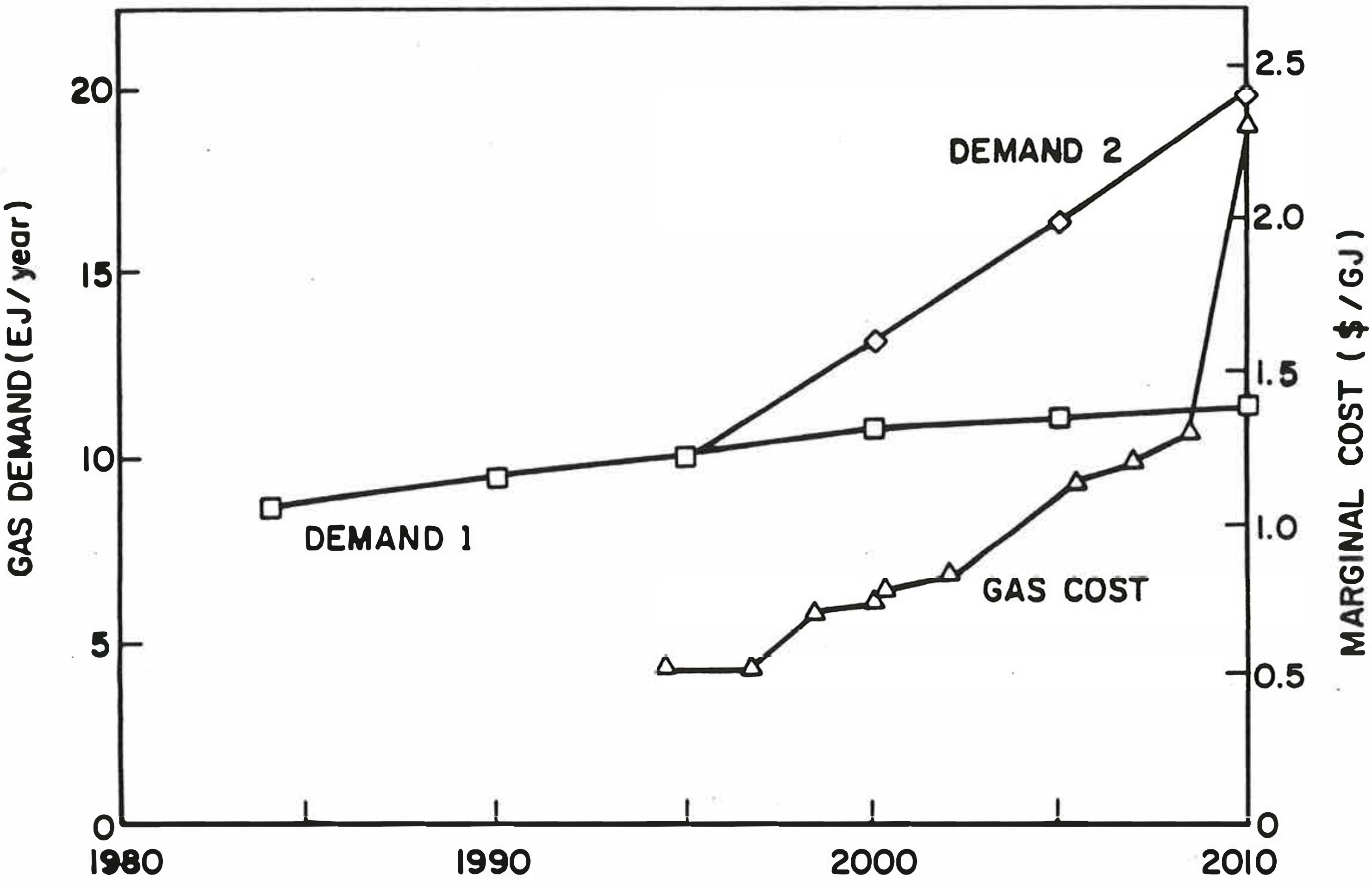

Figure 14.

Two alternative projections of natural gas demand in Western Europe. Demand 1 is the average of the high and low projections made in 1986 by the International Energy Agency (80); Demand 2 superimposes on the Demand 1 projection additional demand for gas associated with providing all incremental electricity production with natural gas-fired ISTIG units after 1995. It is assumed that total electricity production grows at 2.5% per year [in the midrange of projections presented in a 1985 International Energy Agency Study (79)], from 1888 TWh in 1984 to 3588 TWh in 2010, of which 1110 TWh is accounted for by ISTIG units. The marginal cost curve shown for natural gas was developed in the 1986 MIT International Gas Trade Project (78) and is for the gas supply levels of the Demand 2 projection.

the $5.7 to $6.9 per GJ forecast for 2010 by the IEA (80).

The availability of this backstop technology would put a ceiling on the market price of gas because, if gas producers tried to set a higher price, they would lose a large gas market to coal, and the backstop price would still probably be higher than the marginal cost of gas through the first decade in the next century.

If the gas price could be controlled at this backstop price, the result would probably be lower electricity costs through 2010 from natural gas-fired ISTIG units than would be the case for either nuclear power plants (even when nuclear power plants are built quickly, in only six years) or coal steam plants with flue gas desulfurization, whether costs are evaluated with a 5 or a 10% discount rate (Table 5).

In addition to these utility benefits, the benefits from lower gas prices for gas consumers in Europe other than electric utilities would be worth perhaps $40 billion per year in 2010, for the midrange natural gas demand forecast by the International Energy Agency (80).

Of course similar benefits could be derived from technology that is already commercially ready, e.g. the Texaco/ACC technology as a coal-gas backup for advanced combined cycle units fired with natural gas. However, the backstop gas price with this technology would be some $0.7 to $1.1 per GJ higher than with Lurgi/ISTIG (depending on the discount rate). Thus the benefit to nonutility consumers in Europe in 2010 would be $8 to $12 billion per year more if Lurgi-ISTIG were the backstop instead. This public benefit represents a 7 to 10 day simple payback on the total estimated development cost of ISTIG and Lurgi/STIG technology, some $220 million. It would seem that Western European governments would have a strong stake in bringing advanced coal gasification/gas turbine backstop technology to commercial readiness, even if there were little prospect of its being used for two or three decades!

Central Station Power in Developing Countries

Natural gas-based power generation using advanced aeroderivative gas turbines such as ISTIG may be of interest to many developing countries because:

- there are significant natural gas resources in many developing countries;
- a shift from oil to gas for domestic applications would often be desirable in such countries, whether they are oil exporters or oil importers;
- power generation is an attractive initial market for natural gas that can facilitate natural gas system infrastructure development;
- the economics of generating power with advanced aeroderivative gas turbines would often compare favorably with alternatives;
- the scale and maintenance characteristics of aeroderivative gas turbines are well-suited to developing country situations;
- the low capital intensity of advanced gas turbine technology is especially important because capital is scarce in many developing countries.

Natural gas could play a significant role in development, because natural gas resources exist in about 50 developing countries, including 30 that import oil (83), and because gas resources are large compared with energy use and present gas production (Table 6).

For oil-exporting developing countries a shift to gas would make more oil available for export, an important consideration for the 1990s and beyond, when tight conditions can be expected once more in the world oil markets. A shift to gas would be even more important for oil-importing developing countries, many of which have natural gas reserves that could support far higher production than at present (Table 7).

In developing natural gas markets, an initial focus on power generation might often be desirable. The large initial market that could be provided by electric power generation would often justify the expense of building a gas

Table 6. Alternative Measures of Remaining Natural Gas Resources

Resources[a] (Exajoules)		Resources/ Population[b] (Gigajoules/Person)		Resources/ Energy Use[c] (Years)		Resources/ Gas Production[d] (Years)	
USSR	2730	Middle East	15,400	Middle East	326	Middle East	1389
Middle East	2320	USSR	9,880	Africa	58	Africa	349
N. America	1310	N. America	3,310	USSR	52	Asia/Oceania	337
Asia/Oceania	929	W. Europe	1,270	S. America	23	S. America	128
Africa	621	Africa	1,160	Asia/Oceania	15	USSR	121
W. Europe	482	S. America	1,100	N. America	15	W. Europe	65
S. America	290	Asia/Oceania	350	W. Europe	9	N. America	54
E. Europe	30	E. Europe	271	E. Europe	2	E. Europe	13

[a] Proved reserves plus estimated reserve appreciation in discovered fields plus estimated recoverable undiscovered resources, as of January 1, 1985 (72).

[b] Using population estimates for 1984 (75).

[c] Using total commercial energy consumption data for 1984 (77).

[d] Using natural gas production data for 1984 (76).

Table 7. Oil-Importing Developing Countries with Significant Natural Gas Reserves

	Proved Reserves of Gas[a] (EJ)	Production of Gas[b] (EJ)	Oil Consumption[b] (EJ)	Net Energy Imports As Percentage of Merchandise Exports[c] (percent)
AFRICA				
Ivory Coast	3.71	-	0.053	14
Tanzania	3.27	-	0.025	?
Morocco	0.14	0.003	0.163	50
Zaire	0.03	-	0.035	12
SOUTH AMERICA				
Argentina	25.07	0.478	0.848	6
Brazil	3.49	0.081	1.558	37
Chile	4.58	0.037	0.195	16
Colombia	4.36	0.187	0.286	14
ASIA				
Bangladesh	13.85	0.091	0.056	41
Burma	10.30	0.033	0.046	3
India	19.13	0.125	1.374	30
Pakistan	20.38	0.310	0.223	52
Papua New Guinea	0.54	-	0.029	25
Thailand	8.06	0.090	0.440	33

[a] As of January 1, 1987 (84).

[b] Gas production and oil consumption data are for 1984 (77).

[c] For 1985 (83b).

delivery system, thereby helping to make gas available to other users at reasonable cost (85). Moreover, World Bank studies indicate that the highest economic value of gas would be for its use as a fuel oil substitute, e.g. in electricity generation (86), for which the higher the efficiency of the generating technology, the higher the value of the gas (87). In this context ISTIG looks attractive.

In many areas power generating units would be able to use gas that is now wasted. About 13% of the gas produced in developing countries was flared or vented in 1985 (Table 8), and in some areas half or more of the produced gas is thus wasted. This waste occurs because fields where gas is produced as a by-product of oil production are remote from markets (86). If directed to ISTIG units, the gas now flared could provide as much electricity as 55 large (1000 MW) nuclear power plants: equivalent to about one fifth of all the electricity produced in developing countries (Table 8).

The economics of power generation based on advanced gas turbines would be favorable in many developing countries, owing to the low capital costs for this technology and the fact that long-run marginal costs for gas are low. A World Bank study of 10 countries found that (a) long run marginal costs measured at the wellhead and the city-gate were in the ranges $0.25 to $1.38 per GJ and $0.30 to $1.89 per GJ respectively, (b) these costs are not likely to rise in the foreseeable future, and (c) these results can be extrapolated to other countries, because the countries involved in the study had such a wide range of reserve and production characteristics (83). These low prices mean that gas turbine units having cost and performance characteristics like those of ISTIG and fired with natural gas priced near its long-run marginal cost would be competitive with coal or nuclear plants in most circumstances. And even at a

Table 8. Electricity Production Potential from Flared/Vented Gas in Developing Countries

	Production[a]	Production	ISTIG Generation w/Flared, Vented Gas[b,c]	
	(Petajoules)	Flared/Vented[a] (percent)	(TWh per Year)	(% of Electricity Produced)
L. AMERICA	4561	10	60.9	13
Mexico	1433	8	15.4	18
Argentina	675	17	16.1	36
Bolivia	179	2	0.57	34
Brazil	210	17	4.7	3
Colombia	199	11	3.0	11
Trinidad & Tobago	289	17	7.0	257
Venezuela	1216	4	7.0	16
Other	299	18	7.3	9
AFRICA	5513	16	117.2	52
Algeria	3861	5	22.8	199
Egypt	251	13	4.1	18
Libya	461	7	4.0	55
Nigeria	674	74	65.4	740
Other	267	60	20.9	12
MIDDLE EAST	4596	18	105.3	61
Iran	1370	17	227.0	611
Kuwait	207	5	1.4	10
Oman	150	2	0.42	25
Saudi Arabia	1235	10	15.7	50
UAE	907	27	31.9	481
Other	726	28	201.6	247
ASIA	4521	9	55.8	7
Brunei	340	4	1.7	204
China	757	NA	NA	NA
India	305	48	19.2	12
Indonesia	1721	7	16.8	79
Malaysia	545	12	8.5	62
Other	852	0.2	0.28	0.1
TOTALS	19191	13	339.2	20

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[a] Data on natural gas production and venting/flaring are for 1985 (88).

[b] Power generation with ISTIG is assumed to be 47% efficient.

[c] Electricity production data are for 1984 (77).

gas price of $2 per GJ such gas turbines would be competitive with hydroelectric facilities costing more than $1000 per kW of installed capacity.[22] For comparison, unit costs for hydroelectric projects in preparation range from $900 per kW in Colombia to more than $5000 per kW in Upper Volta, with $1500 per kW a typical value (83).

The scale characteristics of aeroderivative turbines are also well suited to developing countries, where the total utility grid capacity is often far too small to be well matched to larger hydroelectric or steam-electric power plants. Adding new capacity in small increments with gas turbines makes it possible to avoid the alternating periods of power glut and power shortage associated with utility planning based on large plants, and can lead to improved system reliability.

The compact, modular nature of aeroderivative gas turbines, which makes it possible to replace failed parts and even whole engines quickly with replacements from centralized maintenance facilities (flown or trucked in), is an attractive feature of this technology for many developing countries, where sophisicated maintenance capability is typically unavailable at power generating sites.

Besides such benefits to the power sector, the fact that installed capital costs are of the order of $400 per kW instead of the $1000 or $2000 per kW, or more, that coal, hydroelectric, or nuclear plants may cost, is important in view of the scarcity of capital in many developing countries. In 1983 the World Bank estimated that developing countries would require investments in new energy supplies of some $130 billion per year (in 1982 dollars) between 1982

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[22] Assuming a 10% discount rate (appropriate for many developing countries), and, for the hydroelectric facility, a 50% capacity factor, annual operation and maintenance costs of 1% of the capital cost, and a 50-year lifetime.

and 1992, and that half of this investment would have to come out of foreign exchange earnings, requiring an annual average real increase of 15% in foreign exchange allocations for energy supply expansion (83). Even though electricity production accounts for less than one fifth of primary commercial energy use in developing countries, the Bank estimate is that about half of this capital will be required for the electrical sector. Such resource allocations for electricity and energy generally are unrealistic, particularly given the financial vise in which many developing countries find themselves today, squeezed between high debt costs and low export-commodity prices. One of the ways to reduce this capital burden would be to give greater emphasis to low-capital-cost power-generating technologies such as ISTIG. So doing could be quite effective in light of the fact that the Bank's electricity projection envisages that 42% of incremental electricity production will be from from coal, 35% from hydroelectric plants, 11% nuclear, and only 11% from natural gas (83).

Not only are the overall capital requirements small for these advanced gas turbine power plants, but also, some industrializing countries could draw on indigenous management and engineering talent for much of the design and construction effort required. The power turbine, the heat recovery steam generator, and the electrical generator, as examples, are system components that can be readily manufactured in many parts of the world. The part of the system for which it may be difficult to avoid expenditures of foreign exchange is the so-called "gas generator." But this "high technology" part of the system, derived from a jet engine, actually accounts for only a modest fraction of the total power plant cost; the mass-produced CF6 jet engine, upon which General Electric's LM-5000 is based, costs only about $6 million (83a). The gas generator's contribution to the capital cost of a 110 MW ISTIG derived from the LM-5000 would thus be only $55 per kW.

Biomass-Based Cogeneration

Gas turbine-based cogeneration in the sugar industry using cane sugar residues as fuel (discussed above for Jamaica) may be relevant for many of the 70 sugar-producing developing countries. In these countries almost 50 GW of generating capacity could be supported by steam-injected gas turbines operated in the cogeneration mode, at the 1985 level of cane production (Table 9). The electricity that could be produced in these plants is equivalent to about one fourth of the electricity produced by electric utilities, or about as much electricity as is produced with oil in these countries.

The potential generating capacity supportable by cane sugar residues could grow considerably if cane-sugar-based alcohol, already well established in Brazil, comes into wider use as an oil substitute (62). The combined production of alcohol and electricity at sugar cane processing facilities could improve the overall economics of alcohol production.

Gas turbines, if they are successfully developed for firing with cane sugar residues, might also be used with other biomass residues such as corn stover and rice husks. The overall power-generating potential of these residues is comparable to that of cane sugar residues. The corn stover power-generating potential is concentrated in the United States and that for rice husks is concentrated in Asia (Tables 10 and 11). Extension of gas turbine technology to these fuels depends on the ability to collect and process the biomass into a suitable gas turbine fuel at acceptable cost, the appropriateness of the scale of the technology to the scale at which the biomass feedstock can be profitably gathered for processing, and the competing uses of these residues.

Table 9. Potential Gas Turbine Capacity with Sugar Cane Residues as Fuel[a]

Region	1985 Cane Production (million tonnes)	Supportable Gas Turbine Capacity[b] [MW(e)]
SOUTH AMERICA	257.37	17,823
Brazil	211.30	14,633
Colombia	13.67	947
Argentina	11.88	823
Peru	7.10	492
Venezuela	4.70	325
ASIA	201.16	13,931
India	70.16	4,859
China	42.50	2,943
Thailand	23.93	1,657
Indonesia	17.05	1,181
Philippines	16.65	1,153
Pakistan	14.10	976
Taiwan	6.90	478
CENTRAL AMERICA	145.34	10,065
Cuba	78.89	5,463
Mexico	34.92	2,418
Panama	9.21	638
Guatemala	5.00	346
AFRICA	70.72	4,897
South Africa	25.40	1,759
Egypt	8.15	564
Mauritius	6.84	474
Zimbabwe	4.56	316
Sudan	4.50	312
Swaziland	3.96	274
Kenya	3.70	256
OCEANIA	38.38	2,658
Australia	34.39	2,382
Fiji	3.67	254
UNITED STATES	28.12	1,947
EUROPE	3.22	223
WORLD	744.31	51,544

[a] Regional totals include more than the sum for the individual countries shown.

[b] Based on Ref. 62, assuming a 206-day cane crushing season, factories operating 22 hours per day during the crushing season, gas turbines with performance characteristics of gasifier STIG units based on the LM-5000, and bagasse available from the cane crushing as fuel.

Table 10. Potential Gas Turbine Capacity with Corn Stover as Fuel[a]

Region	1985 Corn Production (million tonnes)	Supportable Gas Turbine Capacity[b] [MW(e)]
NORTH AMERICA	232.58	18,253
United States	225.18	17,673
Canada	7.39	580
ASIA	89.89	7,055
China	64.00	5,023
India	7.80	612
Thailand	5.15	404
Indonesia	4.55	357
Philippines	3.54	278
North Korea	2.30	181
Turkey	1.50	118
EUROPE	72.93	5,724
Romania	14.00	1,099
Soviet Union	13.50	1,060
France	12.30	965
Yugoslavia	9.89	776
Hungary	6.50	510
Italy	6.35	498
Spain	3.21	252
Austria	1.73	136
Greece	1.70	133
Bulgaria	1.50	118
SOUTH AMERICA	32.00	2,511
Brazil	19.00	1,491
Argentina	13.00	1,020
AFRICA	25.47	1,999
South Africa	8.50	667
Egypt	3.70	290
Kenya	2.65	208
Nigeria	2.25	177
Zimbabwe	2.25	177
Tanzania	2.07	162
Malawi	1.50	118
Ethiopia	1.45	114
CENTRAL AMERICA	11.13	874
Mexico	10.00	785
OTHER	15.69	1,232
WORLD	479.69	37,647

[a] Regional totals include more than the sum for the individual countries shown.

[b] Assuming 1/2 tonne of stover per tonne of corn (which represents about 2/3 of the total stover), an energy energy content of 15 GJ/tonne of stover, a stover-to-electricity conversion of 33% (HHV), and a 100% capacity factor.

Table 11. Potential Gas Turbine Capacity with Rice Husks as Fuel[a]

Region	1983 Rice Production (million tonnes)	Supportable Gas Turbine Capacity[b] [MW(e)]
ASIA	416.74	16,781
China	172.18	6,933
India	90.00	3,624
Indonesia	34.30	1,381
Bangladesh	21.70	874
Thailand	18.54	746
Burma	14.50	584
Vietnam	14.50	584
Japan	12.96	522
Philippines	8.15	328
South Korea	7.61	306
Pakistan	5.21	210
North Korea	5.20	209
Nepal	2.74	110
Sri Lanka	2.20	89
Malaysia	2.00	81
Kampuchea	1.70	68
Iran	1.40	56
Laos	1.00	40
Afghanistan	0.65	26
SOUTH AMERICA	12.13	488
Brazil	7.76	312
Colombia	1.78	72
Peru	0.77	31
Argentina	0.65	26
Venezuela	0.51	20
AFRICA	4.59	185
Egypt	2.44	98
Madagascar	2.15	86
UNITED STATES	4.52	182
EUROPE	4.52	182
Soviet Union	2.50	101
Italy	1.06	43
CENTRAL AMERICA	1.31	53
Mexico	0.66	26
Cuba	0.49	20
OCEANIA	0.52	21
Australia	0.52	21
WORLD	449.83	18,113

[a] Regional totals include more than the sum for the individual countries shown.

[b] Assuming 1/4 tonne of husks per tonne of rice, an energy energy content of 14.8 GJ/tonne of husks, a husk-to-electricity conversion efficiency of 33% (HHV), and a 100% capacity factor.

While crop residues would be important initial fuels for gas turbines, a shift might subsequently be made to biomass from energy plantations, where fast-growing trees or other forms of biomass are grown for their fuel value.

PUBLIC POLICY ISSUES

One might think that, since the economics of advanced aeroderivative turbines are so compelling, market forces alone would prompt the implementation of these new technologies. However, various institutional constraints limit the effectiveness of market forces.

Toward the Deregulation of Power Generation

Utilities, as regulated monopolies, are not sufficiently motivated to provide electricity in the least costly manner. Consider the proposal made here to replace existing oil- and gas-fired steam-electric plants with natural gas-fired ISTIG units. In a free market, a steam-electric plant with an operating cost higher than the total cost of an ISTIG unit would be retired in favor of the latter, even if the steam plant had just been installed. In the real world, utilities are reluctant to retire capacity that is not fully depreciated. Policies to promote economic efficiency in utility capacity planning would help overcome this problem. New policies being considered at the time of this writing to promote more competition in power generation [e.g. allowing competitive bidding for new electricity supply sources and extending PURPA benefits to independent power producers other than the cogenerators and small power producers that currently qualify (7)] would of course be helpful in this regard. Ironically, the availability of this advanced gas turbine technology both offers utilities new ways to make their product more competitive and provides the technological basis for moving toward the complete deregulation of power generation.

The basic idea behind utility regulation is the belief that the provision of electricity represents a natural monopoly, i.e. whenever unit costs decline with increasing plant size, inexorable cost pressures force dominance by a single firm. Single firms are granted geographic monopolies and are regulated to ensure both that the consumer is protected from monopolistic abuses and that the monopolist is permitted a fair return on investment.

But central-station generating technologies like ISTIG are relatively small-scale power sources that can compete with large-scale central station plants. Moreover, today's transmission technology makes it possible to serve any particular need for power by generating facilities dispersed over a wide region. Both of these developments undermine the original rationale for the regulation of electric power generation.

But the rationale for continued regulation of transmission and distribution remains strong. Duplication of transmission and distribution facilities would be wasteful. Moreover, moves toward deregulation of generation should probably be accompanied by increased regulation of transmission. Both stronger interconnections and broad access to transmission lines at just and reasonable rates would be needed to ensure that deregulation of generation led to improved economic efficiency.

While the emergence of competitive, relatively small-scale generating technologies creates a favorable environment for the deregulation of generation and thus the prospect of introducing cost-controlling competition into the power business, moves in this direction should be made cautiously, to ensure maintenance of service quality and equitable allocation of the costs and benefits of change.

Extracting Civilian Benefits from Military Spending

Vendors of advanced aeroderivative turbines do not market them aggressively for central station applications. The aircraft turbine division of the one US company that offers large aeroderivative turbines for stationary applications actively competes with the division of that company selling industrial turbines, and the latter is responsible for the company's marketing of gas turbines for stationary power. The other US company that manufactures large aircraft engines no longer markets turbines for stationary power in the United States. In both instances the security of the lucrative military jet engine market and the large uncertainties of the utility market have led management to concentrate on the former and ignore the latter.

Since defense R&D expenditures are largely responsible for the impressive advances in aircraft turbine technology, perhaps the federal government should press the vendors to advance civilian spinoffs, e.g. by requiring that they make modest commitments to modifying these engines for stationary applications as a condition of continuing support for jet engine R&D. Doing so would seem politically appealing, owing to the wide interest in identifying advanced technologies that will help the United States compete in world markets.

Advancing Coal-Gas/Aeroderivative Turbine Development

Public sector support is needed for R&D aimed at optimizing coal-gas/aeroderivative turbine technology. The lack of utility interest in new generating technology and uncertainties about gas prices and supplies make it unlikely that the private sector alone can be relied on to bring this technology forward in a timely manner.

While coal interest groups would of course argue for such R&D, those seeking greater use of natural gas in power generation would also benefit.

Greater use of natural gas in power generation would lead to less costly electricity (at least in the near term), while reducing local air pollution, acid rain, and CO_2 emissions. But utilities may be reluctant to make a major shift to natural gas unless they can be assured that an economically attractive coal-gas "backstop technology" is available.

In light of the enormous benefits to nonutility gas customers in Europe of having a backstop technology with the cost and performance characteristics of Lurgi/ISTIG, a joint US/European development effort in this area might be warranted.

Creatively designed acid rain legislation might also be useful here. Legislation that would motivate utilities to "scrap and build" with new technologies like Lurgi/ISTIG as an alternative to installing scrubbers on existing plants could both allow the achievement of environmental goals and promote technological innovation in an industry biased toward plant life extension rather than new construction.

Advancing Biomass-Gas/Aeroderivative Turbine Development

Bringing biomass-gas/STIG technology to commercial readiness would be much less costly and take much less time than bringing coal-based technology to a similar point, because the low sulfur content of biomass obviates the need for hot-gas cleanup technology and because a pilot plant would be close in scale to a commercial unit. Also, unlike the situation with coal, there are large biomass markets where technologies like biomass-gas/STIG would be highly competitive under today's market conditions.

Yet public sector support is needed for development. While most biomass applications would be in developing countries, most such countries are reluctant to pursue technologies that are not fully proven in the marketplace.

Burdened with more pressing problems, developing countries are generally unable to commit the R&D support needed even for modest efforts such as this.

Public sector R&D support from the industrial countries can be justified not just because the required funding would be modest, but also because programs in this area would provide industrial countries enormous benefits. The reduced capital requirements for power generation, the reduced overall costs of power, and the reduced oil dependency of countries that adopted biomass-gas turbine technologies would help make those countries better able to grow, to service their debts, and to be active trading partners in the world economy.

CONCLUSION

For the next two to four decades advanced gas turbines offer multiple benefits for power generation. The prospects of reducing electric power costs in both industrial and developing countries, of reducing local air pollution and acid rain emissions to low levels, and of reducing carbon dioxide emissions to levels considerably below those associated with coal-fired steam-electric plants are benefits not easily matched by alternatives. These technologies would even appear to be competitive with nuclear power in many situations, making it possible for the world to slow the drift toward plutonium recycle, with its attendent risks of nuclear weapons proliferation (89).

While the benefits resulting from the wide use of heavy-duty industrial gas turbines would be large, the benefits would be much greater if aero-derivative turbine technology were also fully exploited for stationary power applications. With the latter high efficiency and low capital cost could be achieved at much smaller scales, resulting in greater flexibility in capacity planning, improved reliability, and ease of maintenance. Their small size also makes aeroderivative turbines good candidates for cost-cutting innovations and economies of mass production. Aeroderivative turbines will continue to benefit more directly from improvements in jet engine technology than heavy-duty industrial turbines.

While wide use of advanced aeroderivative turbines in stationary power applications will not easily come about through the normal workings of the market, the required interventions by the public sector are modest. Some of the most important initiatives needed would be aimed at making the market in power generation work better. And where R&D support is needed, the amounts involved pale in comparison with the multibillion-dollar R&D programs spurred by the oil price shocks of the 1970s, and can easily be justified by the benefits that would be derived.

Wide use of advanced gas turbines would not solve the electric power problem for all time. Eventually the tightening of world gas supplies, concerns about the atmospheric buildup of carbon dioxide, and land use constraints on bioenergy use would limit the attractiveness of expanded use of these engines for power generation. However, a major shift to gas turbines for power generation in the decades immediately ahead would buy time to develop alternative clean power sources for the long term, e.g. the direct conversion of sunlight into electricity using amorphous silicon solar cells (90). Even in the unlikely event that such alternatives would not be forthcoming, emphasis on gas turbine power would give us breathing room to improve the technologies we already have to be more compatible with global resource, environment, and security constraints.

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