Expanding Roles for Gas Turbines in Power Generation

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Robert H. Williams and Eric D. Larson

Abstract

For the next two to four decades the gas turbine is likely to assume major new roles in power generation–in central station and cogeneration applications, in industrialized and developing countries. The gas turbine will be much more widely used both because the changing circumstances of the electric power industry are especially conducive to the gas turbine and because improvements in gas turbine technology are making gas turbines more competitive. In a wide range of circumstances, new, highly-efficient, gas turbine-based power plants will be able to provide electricity at lower cost and with less adverse environmental impacts or safety problems than coal or nuclear steam-electric plants.

Already gas turbine/steam turbine combined cycles are attracting the interest of power planners throughout the world. While combined cycles offer many advantages compared to conventional steam-electric power plants, this class of energy-efficient gas turbine-based power systems does not exhaust the possibilities. In addition, advanced gas turbine cycles involving steam-injection for power and efficiency augmentation have great promise for some important market applications. The various steam-injected gas turbine cycles that are available or under development are based on turbines derived directly from aircraft engines. Both types of turbines have major roles to play in power generation; hence, in decades ahead a more balanced mix of heavy-duty industrial and aeroderivative turbines than is presently anticipated will most likely evolve in power markets.

1 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 an upgrading of the familiar but little-used gas turbine–the neglected step-sister of the steam turbine in power generation.

Though it has always offered a low unit capital cost, the gas turbine has traditionally been restricted in utility applications to peaking plants, because of its low efficiency and requirement for high-quality fuel. Its peripheral role in power generation also fostered less-than-rigorous maintenance practices, helping to give the gas turbine a reputation of poor reliability among utility planners.

Although in many parts of the world its use for cogeneration has been inhibited by institutional constraints, the simple cycle gas turbine's high thermodynamic efficiency for combined heat and power production as well as its low capital cost have long made it an economically attractive option for cogeneration applications. But the simple cycle gas turbine has been used mainly in cogeneration applications characterized by steady steam loads due to its poor part-load performance.

Innovations, though, are making gas turbines competitive in cogeneration markets characterized by variable heat loads and in central-station applications with conventional baseload and load-following technologies, using low-quality as well as high-quality fuels.

This chapter will show how the changing environment for power generation tends to favor a technology like the gas turbine and how changing gas turbine technology is making the gas turbine an increasingly strong competitor as a power source. A distinction is made here between heavy-duty industrial turbines (designed specifically for stationary applications) and aeroderivative turbines (derived from jet engines). The heavy-duty industrial turbine is quite familiar in the power sector and is the technology of choice for the gas turbine/steam turbine combined cycle systems that are beginning to come into wide use in various parts of the world. The various configurations of aeroderivative turbines of interest–e.g., the steam-injected gas turbine, the intercooled steam-injected gas turbine, the chemically recuperated, steam-injected gas turbine–are much less well-known. In this paper, which has a future-oriented perspective, emphasis is on aeroderivative turbines, because their most interesting cycle modifications represent relatively new developments, and because this new technology offers advantages in some important markets. Both types of turbines have major roles to play in power generation; hence in the decades ahead a more balanced mix of heavy-duty industrial and aeroderivative turbines than is anticipated will most likely evolve in power markets.

2 The Policy Context

The electric power industry needs a technological revolution. Business-as-usual is becoming increasingly untenable. Public concerns about nuclear power risks and the environmental problems posed by fossil fuel power plants have made electric utility planning more and more difficult. And compounding these problems are the escalating costs of electricity that are reducing its competitiveness as an energy carrier.

The Chernobyl accident has led to a considerable stiffening of public opposition to nuclear power and to sharp limitations on nuclear power programs in various parts of the world. As we will show, gas turbines would be economical alternatives to nuclear power in many instances.

The large quantities of SO_2 and NO_x emitted by existing fossil fuel plants, especially coal-fired plants, are among the most significant pollutant emissions leading to acid deposition, which has become a serious international problem because of the transnational air transport of these pollutants. The need to control acid deposition is leading to proposals to reduce emissions from existing power plants in some areas. Gas turbine systems would be an attractive alternative in such situations.

Global warming from the greenhouse effect, associated with the buildup of CO_2 in the atmosphere, has also become a major environmental concern. Again, as we will show, gas turbines would make significant contributions in efforts to cope with the greenhouse problem.

The electric utility industry has also been experiencing rising electricity costs–a marked departure from the long-term historical trend, as illustrated by the situation in the U.S. Up until 1970 the outlook for electric power looked bright in the U.S. Between 1950 and 1970, the real cost of fossil-fueled steam plants fell by more than a factor of two (Figure 1). And cost-cutting innovations in the U.S. power industry persistently led to a reduction in the average real price of electricity by about 25% for each doubling of cumulative electricity production throughout the period 1926 to 1970 (Figure 2). If the trend up to 1970 had persisted to the present, the average price of electricity in the U.S. today would be 1/3 lower than in 1970. Instead, the average electricity price in the U.S. today is 40% higher than in 1970 or more than double what it would have been if the long-term, cost-cutting trend continued (Figure 3).

Escalating capital costs for new central station power plants have contributed greatly to these rising electricity prices. A nuclear plant ordered in the U.S. in 1970 cost about \$900 per kW (1).[1] In a 1985 study by the International Energy Agency (IEA), it is estimated that the cost of a new nuclear plant that would be

[1] Unless explicitly indicated otherwise, prices are presented here in 1987 dollars. Conversions to 1987 dollars were made using the U.S. gross national product deflator, if original data were in the nominal dollars of other years.

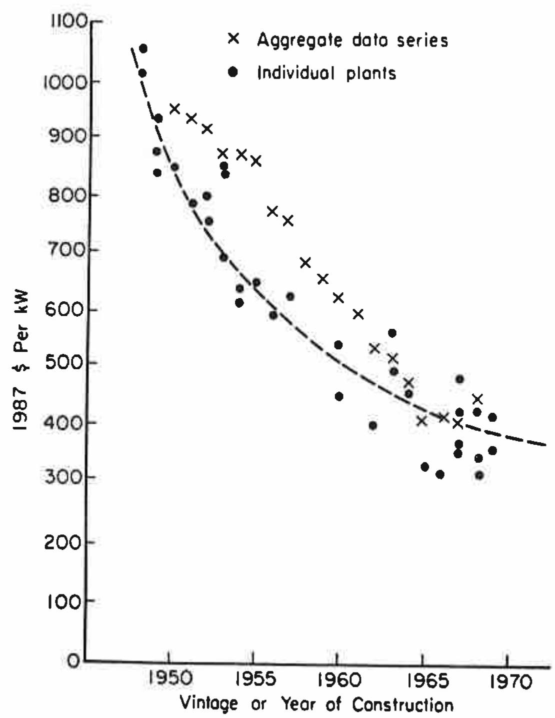


Figure 1. The cost of capacity additions of fossil-fueled steam-electric plants in the U.S., in 1987 dollars per kW.

Source: Reference 1.

started up in 1990 in Europe would cost $1900 per kW if construction took ten years or $1700 per kW if construction could be completed in six years (3). The Electric Power Research Institute (EPRI) has estimated that the cost of a new nuclear plant ordered today in the U.S. would be $3060 per kW, but that this cost could be reduced to $1670 per kW in a "reborn" nuclear industry, i.e., one featuring a streamlined nuclear licensing process, a shorter construction period (six instead of eight years), and improved labor productivity (4). The costs of coal-fired steam-electric plants with flue gas desulfurization (FGD), which cost about $500 per kW in the U.S in 1970 (1), have also escalated markedly. The IEA has estimated that the installed cost of a plant with two 600 MW units would be about $1230 per kW in Europe (3); EPRI has estimated a slightly higher cost ($1340 per kW) for a plant with two 500 MW units in the U.S. (4).

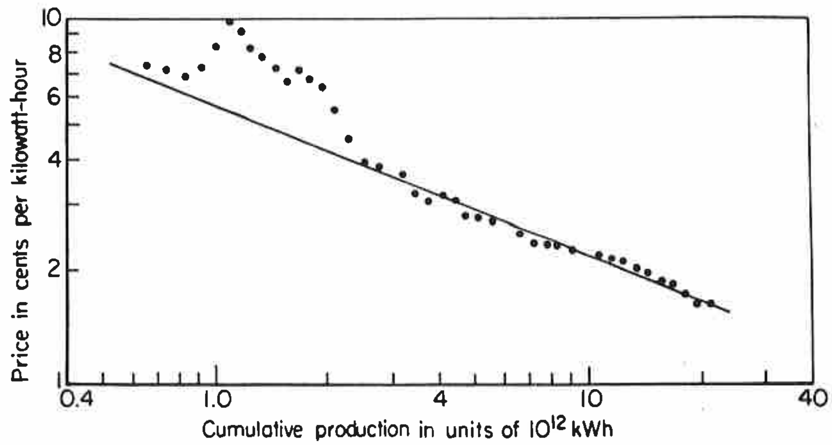


Figure 2. The average price of electricity (in 1970 cents/kWh) vs. cumulative production of electricity in the U.S., 1926 to 1970. The trend line corresponds to a 25 percent reduction in price for each doubling of cumulative production. (The price rose above the trend line during the Great Depression in large part because of the high and relatively inflexible fixed charges associated with electricity generation that continued in the face of depression-diminished demand.)

Note: $1 of 1970 = $2.80 of 1987.

Source: Reference 2.

In a 1987 World Energy Conference (WEC) study, it is projected that the ongoing escalation in power generation costs will continue (Table 1). For industrial countries, it is projected that the share of GDP that will have to be spent on electricity supply expansion will be in the range 2.0% to 2.7% of GDP in 2000, compared to 2.2% in 1980, even though electricity demand is projected to grow only 0.65 to 0.83 times as fast as GDP, 1980–2000. For developing countries, where electricity demand growth is expected to be more rapid, it is projected that the share of GDP that will have to be spent on electricity supply expansion will increase from 1.5% of GDP in 1980 to the range of 2.6% to 5.5% in 2000. For the already capital-constrained developing countries, this means that supporting electricity demand growth rates that are modest by historical standards will be extremely difficult.[2]

[2] The WEC capital expenditure estimates are for electricity demand growth rates for developng countries in the range of 4.5% to 6.8% per year, 1980–2000. For comparison, the growth rate has averaged about 7% since 1980, and the long-term historical average growth rate has been about 9% per year.

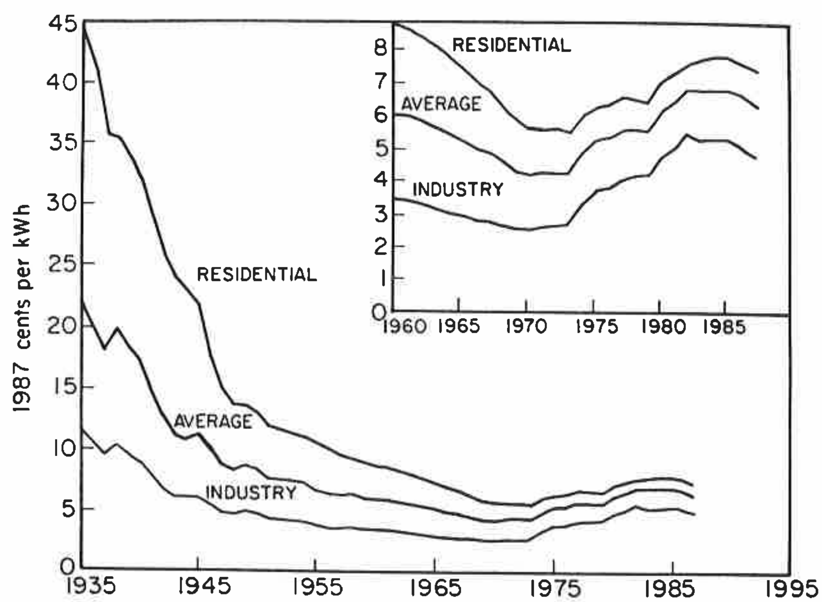


Figure 3. Long-term and recent (insert) electricity price trends in the U.S. The prices shown are the total revenues divided by electricity sales, expressed in 1987 cents per kWh.

Source: Reference 5.

3 The Prospects for Improving Steam-Electric Power Technology

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

The cost escalations plaguing steam-electric power generation 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.

Table 1. Capital requirements and growth rates for electricity projected by the World Energy Conference.[a]

	1980	2000Lb	2000Hb
Cost for New Generating Capacity ($/kW)			
Hydroelectric	2740	3360	4110
Nuclear	2060	2540	3080
Fossil Fuel, Thermal	1030	1230	1510
Average Capital Requirements by Region ($/kW)			
Industrial Countries			
Generation	1480	2000	2390
T & D	2740	2770	3030
Developing Countries			
Generation	1690	2070	2480
T & D	810	1700	2480
Centrally Planned Economies			
Generation	1370	1810	2320
T & D	1370	1960	2620
Overall Capital Requirements for Electricity [10^9 $/year (% of GDP)]			
Industrial countries	226 (2.2)	302 (2.0)	488 (2.7)
Developing countries	44 (1.5)	148 (2.6)	381 (5.5)
Centrally planned economies	60	147	233

Average Growth Rates (%/year)	*1980–2000L*[b]	*1980–2000H*[c]
For GDP		
Industrial countries	2.0	3.0
Developing countries	3.5	4.5
For Primary Energy Consumption		
Industrial countries	0.15	1.3
Developing countries	2.5	4.7
Centrally planned economies	1.8	2.3
For Electricity Generation		
Industrial countries	1.3	2.5
Developing countries	4.5	6.8
Centrally planned economies	2.7	3.2

[a] According to a 1987 World Energy Conference (WEC) study (6).
[b] 2000L (2000H) is for the WEC low (high) growth scenario.

A 1974 analysis by John Fisher of the escalation in nuclear power costs in the decade leading up to the first oil crisis provides an important insight associated with these construction-related problems that seems relevant for power cost escalation generally since 1970 (2):

"When measured in constant dollars per kilowatt of capacity, the cost of constructing a nuclear power plant increased by perhaps 50 percent in the past decade... When power plant costs rise an explanation is required, as we expect all power plant costs to decline through the economies of scale and new technology. The environmental movement was responsible for part of the rise in nuclear plant costs, by causing various procedural delays and by requiring additional expensive safeguards to protect against hypothetical accidents. But there appears to be another cause for increasing construction costs, associated with a growing portion of high-cost field construction and a shrinking proportion of low-cost factory construction for the very large power plants now being built... the costs associated with a shift to field from factory can more than offset anticipated economies of scale..."

Fisher pointed out that historically, as electric utility plant capacity doubled every decade, factory capacity also doubled, as did field construction at each site. Manufacturing and construction costs per kW declined in the factory and in the field, since each of these increased its scale of operations. As long as both activities grew in proportion, the economies of scale produced similar cost reductions in each, and therefore an overall cost reduction, even though the unit cost of field construction was always higher than the unit cost of factory construction. This pattern held until plant size reached about 200 MW. Then, because design engineers felt that scale economies would be much more important for nuclear than for fossil fuel plants, nuclear power plant capacities were built in sizes of the order of 1000 MW–shifting a greater portion of the construction from the factory to the field, upsetting the pattern of the past, with the result that a much larger fraction of the construction was carried out at smaller, less-efficient field locations. Fisher's important insight is that the widely touted economies of scale in power plant construction are illusory because: (*a*) field construction is inherently more costly than factory construction, and (*b*) with field construction it is never possible to get very far down the "learning curve," in contrast to the situation with factory production. This "diseconomy of scale" problem has persisted to the present.

The increase in scale for coal-fired power plants to the present range of 500 to 600 MW was in part a competitive response to large-scale nuclear plant construction. Also, the pursuit of scale economies was seen as an opportunity for continuing the historical reductions in the cost of electricity (Figures 2 and 3), after the long-term trend toward increased thermodynamic efficiency of power generation ceased in the late 1950s (Figure 4). But as in the case of nuclear power, the point of diminishing returns to scale appears to have been reached or exceeded for coal plants. Even where scale economy gains might be realized in construction, these gains tend to be offset by losses in reliability for the larger units (7).

What are the prospects for improving thermodynamic efficiency? 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 and peak pressures 165 bar for subcritical steam units and 241 bar for supercritical steam units.

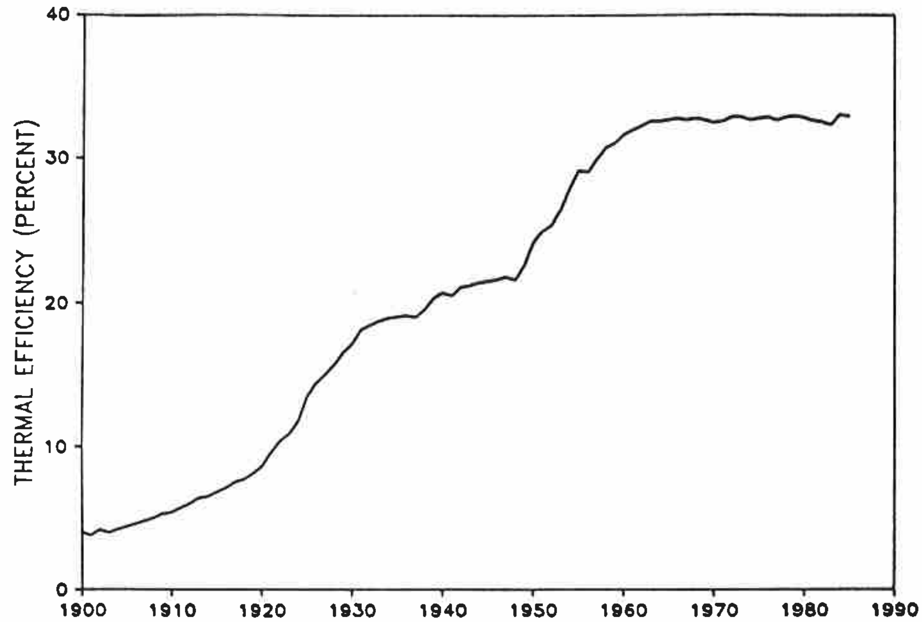


Figure 4. The historical trend in the average efficiency (higher or gross heating value basis) of electricity generation in central station thermal power plants in the U.S.

Source: Reference 5.

There are ongoing developmental efforts aimed at improving steam-electric power plant efficiency by increasing peak steam temperatures (8,9). But as peak steam temperatures are increased, problems of materials strength, oxidation, and corrosion rapidly become more serious, dictating shifts to 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 5, 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 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 (10).

A 1976 Westinghouse study–the results of which are consistent with many other studies carried out since the 1950s (11)–indicates the magnitude of the

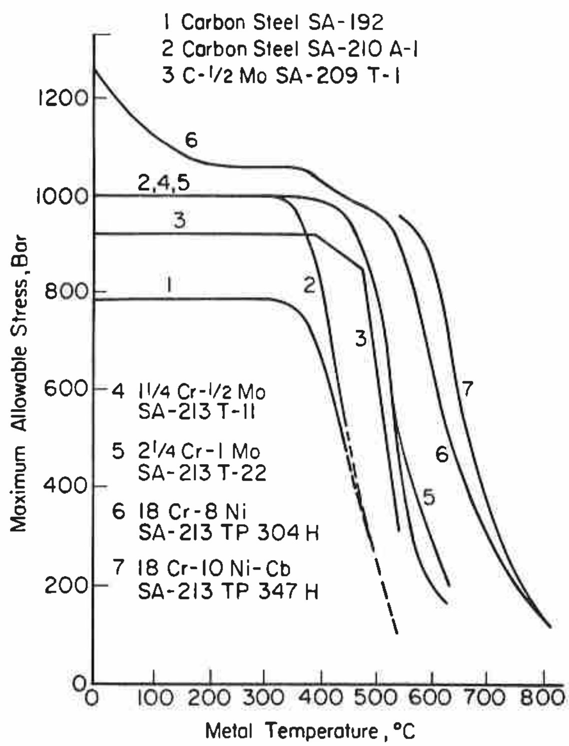


Figure 5. Effect of temperature on the maximum allowable stress for different steel alloys used for steam tubing in high temperature service, according to the boiler code of the American Society of Mechanical Engineers (ASME) (10). 1 = low strength carbon steel; 2 = intermediate strength carbon steel; 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.

tradeoff involved in increasing the maximum steam temperature of a 500 MW steam plant; an increase from 540 to 650 °C would increase the plant efficiency by 6%, but at the cost of a 26% increase in capital cost (12). On a lifecycle cost basis, the price of coal would have to increase from \$50 to \$200 per tonne before it would be worthwhile to shift to the higher peak steam temperature.

While the outlook for major improvements in steam-electric power technology is not auspicious, it may be feasible to increase efficiency without pushing peak working fluid temperatures further, through development of the recently proposed Kalina cycle (13,14). The Kalina cycle is a novel modified Rankine cycle that uses as a working fluid a mixture of ammonia and water, the relative proportions of which vary throughout the cycle. A 3 MW demonstration plant, to be built at the U.S. Department of Energy's Engineering Center in Canoga Park, California, is expected to be operating by 1989 (15). 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 estimates for the Kalina cycle are for very small assumed pressure drops and tight temperature differences–conditions that are difficult to achieve in practice (14).

4 The Outlook for Stationary Power Applications of Gas Turbines

Rising costs of steam-electric power plants and slow, uncertain electrical load growth have led to dramatic reductions in the construction of new central station power plants in many countries; in the U.S., for example, there were virtually no orders for central station power plants between 1982 and 1986 (Figure 6). These conditions are leading utility planners to give more attention to the gas turbine for meeting future power needs. On the basis of contacts made with the majority of the large electric utilities, Gluckman at the Electric Power Research Institute estimated that *some 40 GW of new gas turbine-based generating capacity is on order or being planned in the U.S for installation by 1995* (16).

Emerging utility interest in gas turbines is complemented by a boom in gas turbine sales to cogenerators in the U.S. Electric utility rate increases and the Public Utility Regulatory Policies Act of 1978 (PURPA), along with the 1982 and 1983 Supreme Court decisions upholding its provisions, have led to a competitive challenge for utilities from independent cogenerators and small power producers in the U.S. 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 can avoid by not having to otherwise supply that power and (*b*) to provide back-up power at reasonable rates. Between 1980 and 1987, 62 GW of electrical generating capacity was certified as qualifying for PURPA benefits by the Federal Energy Regulatory

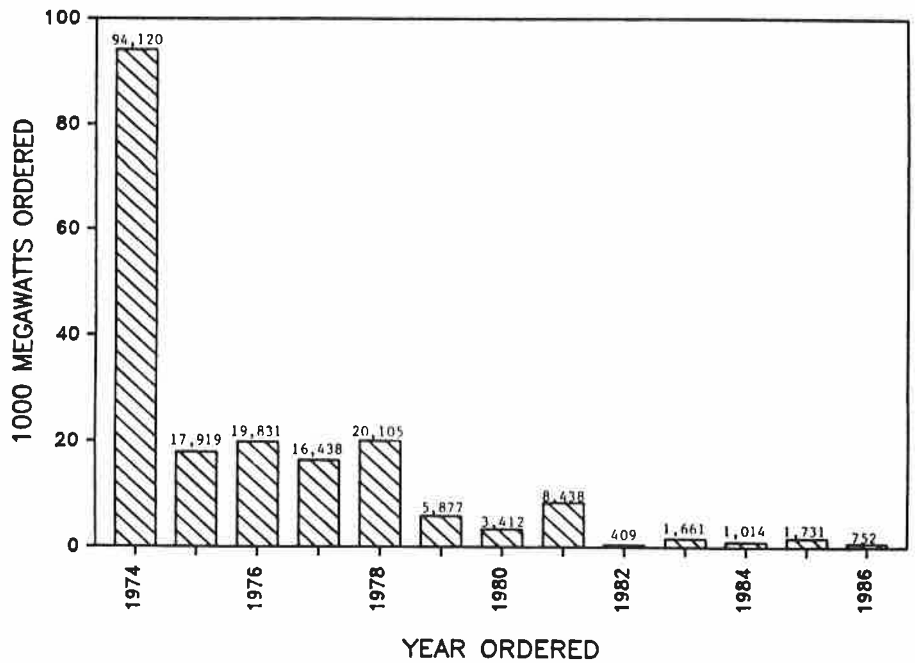


Figure 6. New orders for central station power plants in the U.S. (17). The total in 1986–752 MW–was for 11 gas turbines. This was the first year since World War II that no steam or hydroelectric turbine units were ordered by U.S. electric utilities.

Commission (FERC), nearly three-fourths of which is due to cogeneration (Figure 7). *Some 20 GW of the cogeneration capacity certified in this period–more than the sum of all utility orders for all kinds of central station power plants, 1980–1986* (Figure 6)–*was based on the gas turbine* (Figure 7).

Recent interest in the gas turbine for stationary power reflects both long-standing attractions of this technology and recent improvements that make it possible for the gas turbine to compete in a wider range of markets.

4.1 Traditional Roles for Gas Turbines

The historical attraction of the gas turbine for utilities has been its low cost–\$300 per kW (4) or less–a small fraction of the cost of coal or nuclear power plants. This low cost reflects the utter simplicity of the simple cycle gas turbine. While costly heat exchangers are required in a steam turbine power

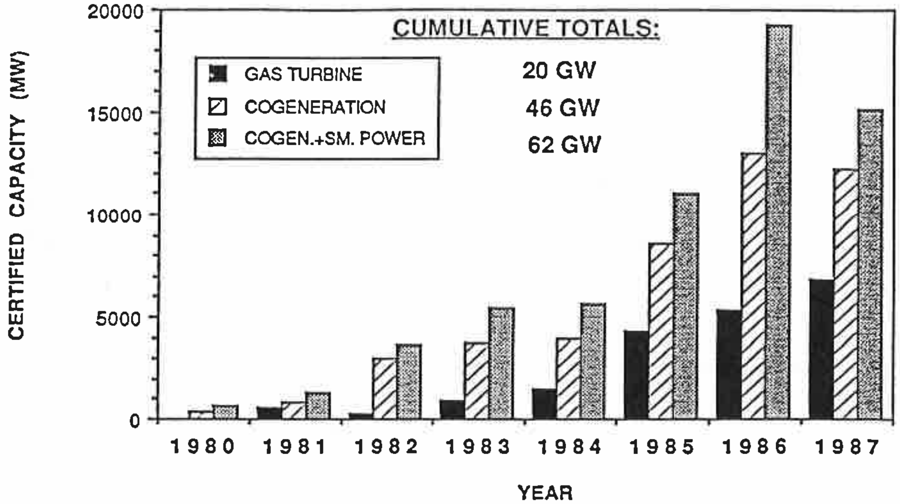


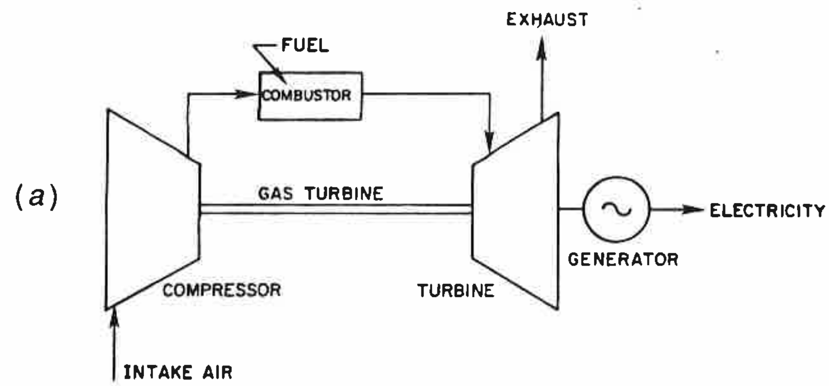
Figure 7. Annual cogeneration and small power production capacity for facilities certified in the U.S. by the Federal Energy Regulatory Commission to be eligible for the benefits allowed under the Public Utility Regulatory Policies Act (19).

plant to transfer 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 to the atmosphere.

But simplicity has been a mixed blessing for the simple cycle gas turbine. It has meant a low efficiency–the average efficiency of utility peaking units in the U.S. in 1985 was only 29%[3] (18). 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. Because of these constraints, utilities have used gas turbines mainly for 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 (425 to 540 °C) turbine exhaust to raise steam in a heat

3 Efficiencies are given here in terms of the fuel's higher (gross) heating value.



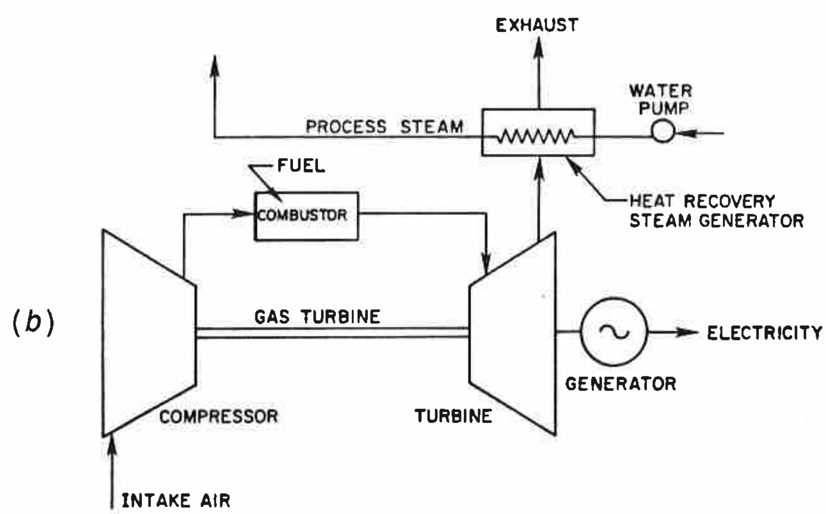


Figure 8. (*a*) *Simple power cycle*: fuel burns in air pressurized by compressor, combustion products drive turbine, and hot turbine exhaust gases are discharged to atmosphere. (*b*) *Simple cogeneration cycle*: like simple power cycle, except that hot turbine exhaust gases are used to raise steam in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

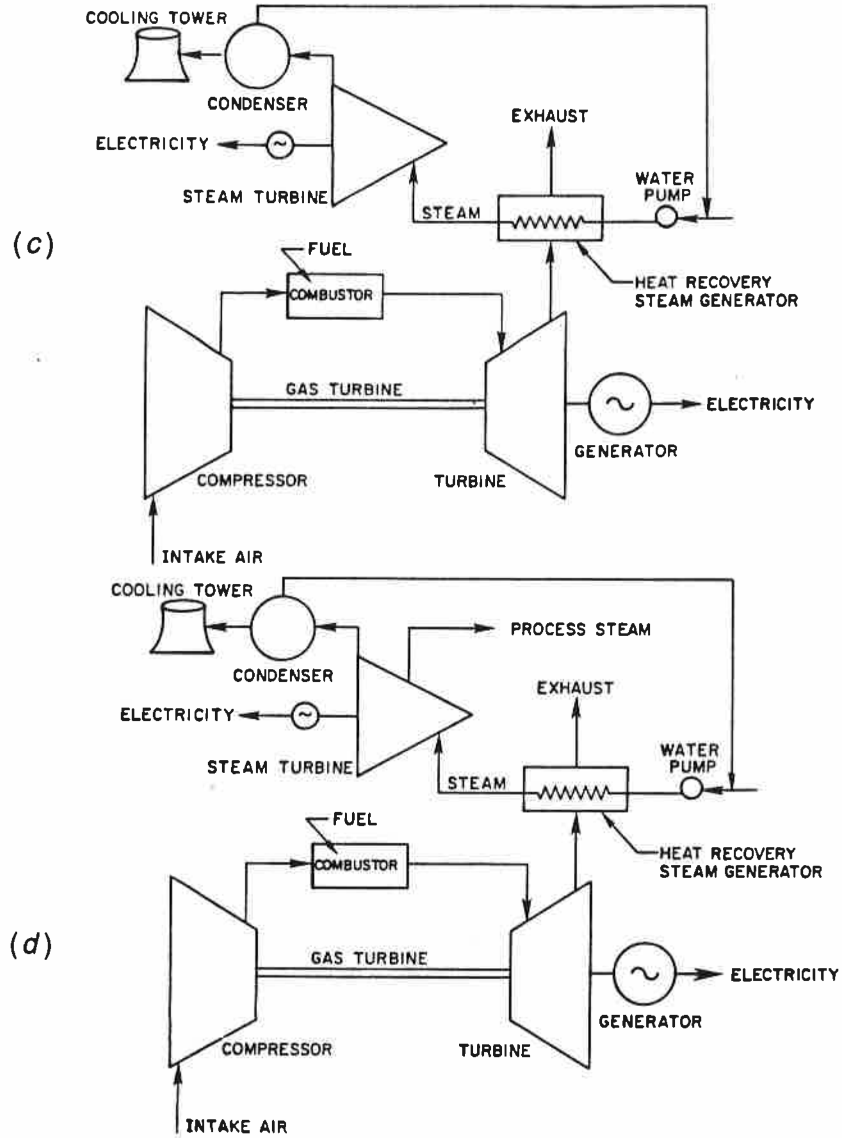
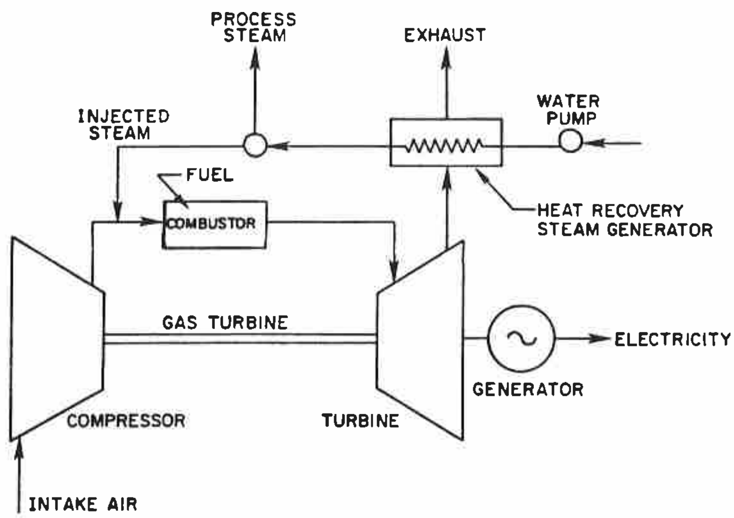


Figure 8. (*c*) *Combined cycle for power*: like simple cogeneration cycle, except that steam from HRSG is used to produce extra power in condensing steam turbine. (*d*) *Combined cycle for cogeneration*: like combined cycle for power, except that some steam is bled from steam turbine for heating.

(e)



(f)

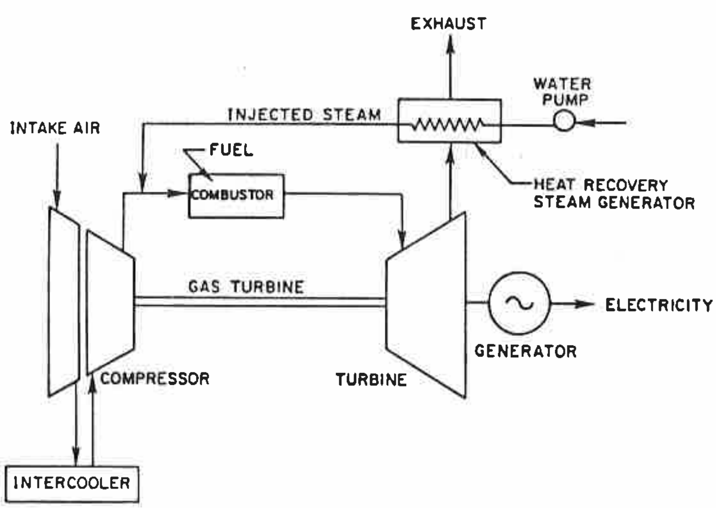


Figure 8. (*e*) *Steam-injected gas turbine* (STIG): like simple cogeneration cycle, except that steam not needed for heating is injected into combustor for increased power output and higher electrical efficiency. (*f*) *Intercooled steam-injected gas turbine* (ISTIG): like STIG with full steam injection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

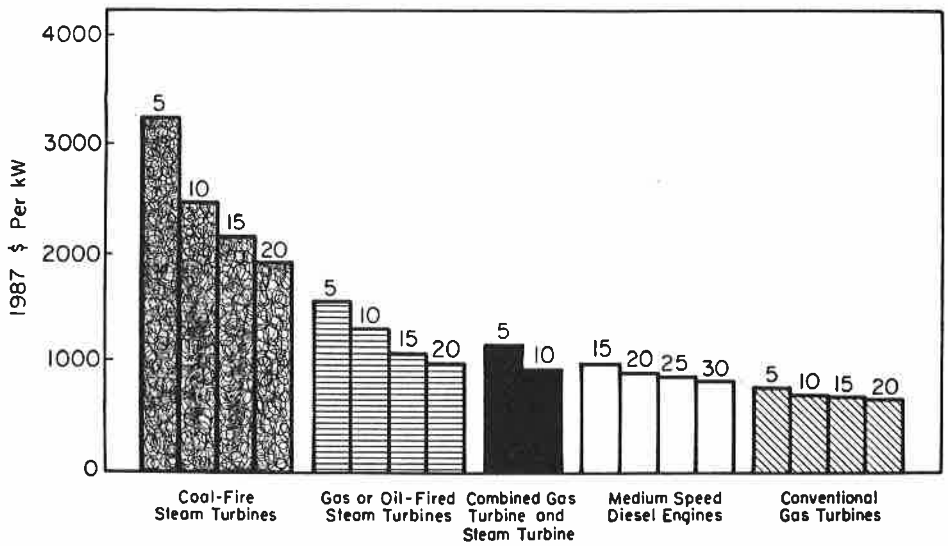


Figure 9. Unit installed costs for small-scale cogeneration systems. The numbers at the tops of the bars are the installed electrical generating capacity in MW (20).

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 major shortcoming of the simple cycle gas turbine in cogeneration is that it is often uneconomical in applications involving highly variable steam loads, because achieving a high thermodynamic efficiency depends on being able to make use of the full electrical and thermal output capacities.

It is now possible to overcome the constraints which have confined 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.

4.2 A Brief History

An early major milestone in the history of the gas turbine was the initiation of 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 U.S. 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 (11). These efforts have been successful, both in improving jet engine reliability and thrust-to-weight ratios and in increasing efficiency by 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 U.S. electric utility industry increased from 1.3 GW to 43.5 GW (11). But subsequently 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 a sharp reduction in electricity demand growth; the installed gas turbine capacity of the U.S. utility industry in 1985 was no greater than in 1975 (18).

The end of commercial interest in gas turbines for stationary power in the U.S. 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. 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 (21)! U.S. 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 ending in 1986 (22). 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.[4]

A paradoxical aspect of the development of the stationary gas turbine is that most of the well-known "low-technology" cycle modifications available for improving performance–e.g., reheat, intercooling, regeneration, evaporative regeneration, steam injection, and steam-reforming of fuel–remain largely unexploited, even though enormous "high-technology" advances have been made in turbine blade materials, design, and fabrication. This is because such

[4] A significant difference between the steam turbine and the gas turbine is that the maximum temperatures of the metal and the working fluid are oppositely related for these technologies. In steam turbine systems the maximum temperature of the metal is always higher than that of the working fluid; thus metallurgical contraints that limit the maximum metal temperature make it difficult to increase efficiency by increasing the working fluid temperature. But in gas turbine-based cycles the metal temperature is lower than that of the working fluid, and the difference between these temperatures is increasing continually with improvements in turbine blade cooling technology, leading to continual improvements in efficiency.

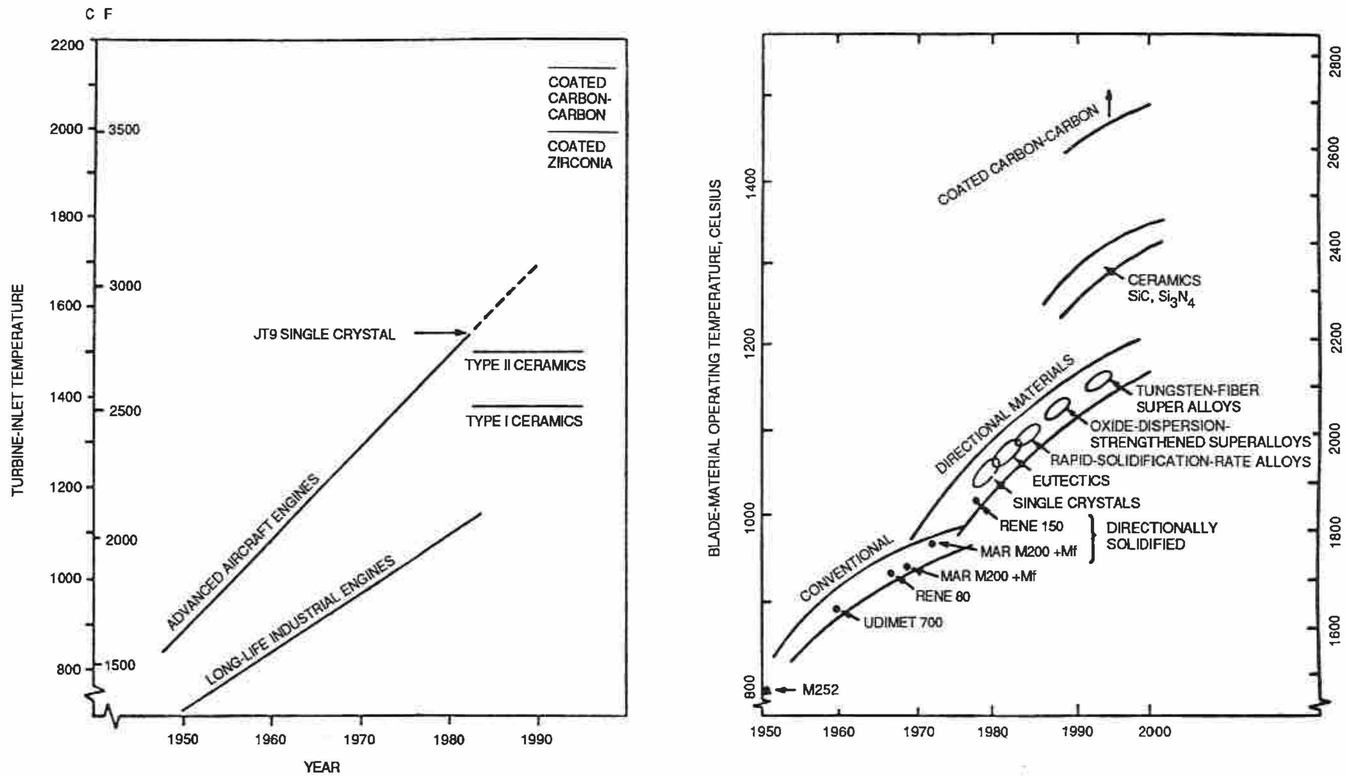


Figure 10. The trend in turbine inlet temperatures for advanced aircraft jet engines and long-life industrial turbines (left) and turbine blade material operating temperature (right) (23).

Note: When an aircraft engine is modified for stationary applications the rated turbine inlet temperature is reduced about 110 °C to promote long-life operation.

cycle modifications involve the introduction of heavy or bulky heat exchangers or the use of large quantities of steam or water, neither of which is 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.

4.3 Progress in Combined Cycle Technology

One gas turbine cycle modification is familiar to the electric utility industry: the gas turbine/steam turbine combined cycle (Figure 8c), which accounted for some 4.7 GW of utility generating capacity in the U.S. in 1985 (24). With advanced gas turbines now commercially available for stationary applications (25), a combined cycle efficiency of 45% can be realized in 200 MW plants costing $520 per kW. For comparison, a 36% efficient natural gas-fired steam-electric plant consisting of two 500 MW units would cost $760 per kW (Table 2). These combined cycle plants could produce electricity at a busbar cost only three-fifths of that for large new coal plants at the 1987 average natural gas price in the U.S. (Table 2).

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 in the U.S. to demonstrate the ability to operate gas turbines on gasified coal.[5] This effort led to the construction of a 94 MW combined cycle power plant coupled to a

[5] A gas turbine can also be fired directly with coal using a pressurized fluidized bed combustor (PFBC) – a technology that is is inherently simpler than a gas turbine/gasification system. With this technology, 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 (33). 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, with a rapid decline in sulfur removal for either higher or lower temperatures (10). Also, operation above about 950 °C can lead to ash agglomeration in the bed. The agglomerates thus formed can lead to segregation of the bed and a cessation of fluidization (34). These problems do not arise with gasification, where sulfur and particulates are removed from the gas stream before the gas enters the combustor. These problems could also be overcome using designs being considered for advanced PFBC systems, involving the partial gasification of coal in a carbonizer, followed by burning the char/lime residue from the carbonizer in a PFBC unit in high excess air, followed by the burning of the fuel gas mixed with the exhaust gas from the PFBC unit in a topping combustor (35). However, such systems are not simpler than gasification systems–they are more complicated.

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) (32).

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 2). 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, 600 MW units using advanced gas turbines that have recently become available (25) would probably be competitive (Table 2).

The success of the Cool Water demonstration is leading to the formulation of proposals for utility capacity expansion strategies that offer flexibility in the face of continuing uncertainty about future electricity demand and fuel prices (36). It is proposed that while natural gas prices are relatively low, natural gas-fired gas turbines be installed to support demand growth, thereby avoiding financial commitments to larger amounts of more costly capacity that might not be needed. These units could be expanded to combined cycle units as demand grows and gas prices rise; and ultimately they could be modified to operate on gasified coal if necessary.[6]

4.4 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 new gas turbine technology to the familiar steam turbine. But it would be a mistake to

[6] A variation on this proposal 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 (36,37).

Table 2. Cost and performance characteristics for U.S. central-station power plants.[a]

1. *Coal and Nuclear 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)	1340	1410	1880	3060	1670
Levelized Busbar Cost (cents/kWh)					
Capital[f]	1.61	1.69	2.25	3.66	2.00
Fuel	1.86	1.86	1.86	0.91	0.91
O&M	0.89	0.99	1.37	1.11	1.11
TOTAL	4.36	4.54	5.48	5.68	4.02

2. *Natural Gas-Fired Plants*[g]

	1987 Natural Gas Price[h]				*2 X 1987 Natural Gas Price*			
	Steam	*ACC*	*STIG*	*ISTIG*	*Steam*	*ACC*	*STIG*	*ISTIG*
TIT (°C)	540	1260	1200	1370	540	1260	1200	1370
Unit Size (MW)	2 x 500	205	4 x 51	114	2 x 500	205	4 x 51	114
Efficiency (%)[e]	36.3	45.0	40.0	47.0	36.3	45.0	40.0	47.0
Unit Cost ($/kW)	760	520	410	400	760	520	410	400
Levelized Busbar Cost (cents/kWh)								
Capital[f]	0.9	0.63	0.49	0.48	0.91	0.63	0.49	0.48
Fuel	2.08	1.68	1.89	1.61	4.17	3.36	3.78	3.22
O&M	0.49	0.29	0.29	0.29	0.49	0.29	0.29	0.29
TOTAL	3.48	2.60	2.67	2.38	5.57	4.28	4.56	3.99

3. *Coal-Gas-Fired GasTurbine Systems*[c,i]

	Oxygen-Blown Gasifier				Air-Blown Gasifier		
	Cold Gas Clean-Up				Hot Gas Clean-Up		
	CCC			ACC		STIG	ISTIG
TIT (°C)	1090	1090	1090	1200	1200	1200	1370
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)	2720	2000	1680	1550	1160	1300	1030
Levelized Busbar Cost (cents/kWh)							
Capital[f]	3.26	2.39	2.01	1.85	1.39	1.56	1.23
Fuel	1.88	1.81	1.79	1.70	1.71	1.81	1.53
O&M	2.11	1.19	0.89	0.80	0.45	0.71	0.60
TOTAL	7.25	5.39	4.69	4.35	3.55	4.08	3.36

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Notes for Table 2

[a] All costs are 1987 U.S. dollars.

[b] Capital costs, efficiencies, and O&M costs are EPRI estimates, for a bituminous coal-fired subcritical steam plant with flue gas desulfurization (4).

[c] The assumed coal price is \$1.79/GJ, the average U.S. utility price projected for 2000 by the U.S. Department of Energy (24).

[d] Reactor plant size, unit capital costs, and efficiencies are EPRI estimates (4). 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 \$0.84/GJ, EPRI's projection for the period 1990–2000 (4). The assumed O&M cost is the 1985 U.S. average for nuclear power plants (18), twice as large as the EPRI estimate for new plants (4).

[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 (4)], a 30-year plant life, and a 70% capacity factor. No taxes or tax incentives are included.

[g] The steam plant involves 165 bar, 540 °C steam (with single reheat to 540 °C) driving a conventional turbine/electric generator (4). The advanced combined cycle (ACC) 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 (25). 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, Cincinnati, Ohio, personal communication, February 1987). The ISTIG unit is a proposed intercooled steam-injected gas turbine, based on the LM 8000 (26,27,28). The unit capital costs for the steam-electric and ACC plants are EPRI estimates (4); that for STIG units is a Bechtel estimate (29); that for the ISTIG is based on estimates made by GE and the staff of the California Energy Commission (28,30). The O&M costs are EPRI estimates (4) for all but STIG and ISTIG units. For the latter the values are those estimated by EPRI for combined cycles (4), even though a Bechtel analysis indicates that steam-injected gas turbine systems offer inherent O&M cost savings compared to combined cycle units (29).

[h] The average gas price for U.S. electric utilities was \$2.10/GJ in 1987.

[i] The performance/cost values for current combined cycles (CCC) and advanced combined cycles (ACC) fired with gas derived in oxygen-blown gasifiers are EPRI estimates for the Texaco gasifier (4). The corresponding numbers for systems using an air-blown Lurgi fixed bed gasifier are from a GE study exploring less costly, more energy-efficient alternatives to the Texaco gasifier (31), using EPRI cost analysis guidelines (4), to be consistent with the EPRI cost estimates for oxygen-blown systems.

limit utility use of advanced gas turbines to this option, because alternatives may offer advantages in some applications.

In exploring alternative gas turbine strategies, it is useful to distinguish between the characteristic features of heavy-duty industrial turbines and aeroderivative units. Various vendors offer heavy-duty industrial units in sizes ranging up to 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 for the most recently offered advanced industrial unit (25)–making it possible to produce high quality steam in the heat recovery steam generator (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 simple cycle aeroderivatives are relatively efficient as electricity producers, such engines tend to be poor candidates for combined cycle applications, since the turbine exhaust gases are not nearly as hot as in heavy-duty industrial units. Until recently this attribute led to the neglect of aeroderivatives as a serious candidate for central station power generation. However, recent developments have shown that aeroderivatives 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 (see below), but also because aeroderivatives have some other important attributes.

First, aeroderivatives can bring back to power generation the advantages of cost-cutting mass production. Moreover, when an aeroderivative is introduced for power generation, it is already well-advanced on the learning curve, because large-volume production of jet engines for aircraft applications has preceded it.

Second, the aeroderivatives are expected to benefit from continuing advances in jet engine technology, which can be transfered quickly and at low incremental cost to stationary applications. While there are only modest ongoing development efforts to improve industrial turbines in the U.S., there is continuing heavy U.S. government support for jet engine R&D. This includes, 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 (38). Such R&D efforts are expected to lead to major improvements in aircraft engine technology, including substantial further increases in turbine inlet temperatures (Figure 10).

Many utility managers are reluctant to consider aeroderivatives in capacity expansion plans. One concern is that, because in their 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 2).[7]

Another concern is that because aeroderivative engines are more delicate 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.[8] 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.[9] With aeroderivative units, it is not necessary to schedule downtime for major maintenance, as is the case with heavy-duty industrial units. Also, statistical data on utility use of industrial turbines, combined cycles, and aeroderivative turbines compiled by the North American Electric Reliability Council show no significant differences in the availabilities of the three types of engines (42).

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 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 (18). Some utilities report maintenance costs for gas turbines as high as 1.0 to 1.5 cents per kWh (42). 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% 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

[7] General Electric's LM-5000 is the 33 MW aeroderivative gas turbine which provided the basis for the first design of a 110 MW intercooled steam-injected gas turbine (ISTIG) (27). The LM-5000 in turn is derived from the CF6 turbofan jet engine which sells for $6 million (39). As the CF6 weighs 4770 kg, it is indeed costly on a per unit mass basis–$1260 per kg. [For comparison, at the time of this writing, gold and silver were selling on the world market for $14,500 and $225 per kg, respectively.] But this "high technology" part of ISTIG contributes only $53 per kW or 13% of its estimated installed cost of $400 per kW (Table 2).

[8] 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 (40). The same job requires a six-person crew working 480 person-hours for a GE Series 5000 industrial turbine that has a comparable output (41).

[9] This possibility arises because the gas generator, the "high technology" part of an aeroderivative engine, for which 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.

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 (42).

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 building 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.

5 Steam-Injected Gas Turbines

The most significant development to date relating to stationary power 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 flow air. 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 (26,43). Aeroderivative engines are chosen for steam injection, because, unlike heavy-duty industrial engines, these units are designed to accommodate mass flows considerably in excess of their nominal ratings, so that only minor modifications are required to operate them as baseload STIGs (44).

[10] The injected water must be treated to avoid turbine blade corrosion problems. Because the minimum water treatment level required is not yet known (42), 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 U.S.) has been estimated to be less than $20 per kW, some 5% of the total installed cost (29).

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 (45,46). Only recently has injecting large amounts of steam attracted serious commercial interest as a means of 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 (47,48), in various articles dating from the mid-1970s (44, 49–55), and in a 1951 Swedish patent application (56) that 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.

5.1 STIG for Cogeneration

The commercialization of STIG for cogeneration applications grew out of the post-PURPA flurry of interest in gas turbine cogeneration in the U.S. 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 (26).[11]

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. (57,58). 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 (26). At the time of this writing six units based on the Allison 501-KH had been installed and two more ordered. More recently, three 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 (59)] and fourteen more are either under construction or on order; and seven STIG units based on GE's LM-2500 are being planned

[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.

(personal communication from M. Horner, Marine and Industrial Turbine Division, General Electric Company, Cincinnati, Ohio, December 13, 1988, and William Flye, Stewart & Stevenson Services, Inc., Houston, December 7, 1988). 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 as a simple cycle on natural gas; with full steam injection the output and efficiency of the LM-5000 increase to 51.4 MW and 40% respectively (60). The LM-2500 is a 21.4 MW unit with a compression ratio of 18.5:1 and an efficiency of 33% in the simple cycle mode; with full steam injection its output and efficiency are 26.8 MW and 36%, respectively (60).

5.2 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 with cooling towers–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 (29).

A major drawback of STIG is that it is less energy-efficient than combined cycle technology now on the market (25). Accordingly, despite a modest capital cost advantage for STIG, the busbar cost would usually be lower for combined cycles (Table 2).

A more interesting candidate for central-station applications is a proposed modified STIG using intercooling between the two compressor stages (Figure 8f).[12] One result of intercooling is that less power is needed to run the compressor. The addition of an intercooler to a simple gas turbine increases the power output but decreases the efficiency; the reduced compressor work

[12] The intercooled STIG could also be used for cogeneration. An ISTIG unit based on the LM-5000 would produce about twice as much steam in the heat recovery steam generator as a STIG unit, largely because the turbine exhaust flow would be increased 26%, and its temperature would be increased from 395 to 441 °C (27). About 44% of the produced steam would have to be injected for NOx control and cooling of the combustor. The rest – some 27,200 kg/hour at 41.3 bar plus 15,400 kg/hour at 13.8 bar – could be used for process. In the full cogeneration mode the electrical output of the ISTIG unit would be 97 MW, and electricity production would represent 42.3% of the higher heating value of the fuel input (personal communication from M. Horner, General Electric Company, September 1988).

requirements would be more than offset by the extra fuel requirements for heating the cooled air exiting the compressor up to the turbine inlet temperature. 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. Detailed design work carried out at General Electric indicates that an intercooled STIG (ISTIG) based on the LM-8000[13] will be able to operate at a turbine inlet temperature of 1370 °C and produce about 114 MW with an average efficiency of 48.3% and a guaranteed efficiency of 47.0%, at an installed capital cost of $400 per kW (28).

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 2). The busbar cost would probably be less than for a large coal-fired steam-electric plant with flue gas desulfurization even if the natural gas price is double the average for 1986 (Table 2).

Despite the indicated efficiency advantage of the ISTIG compared to the combined cycle, this is not the result of a systematic comparison of steam-injected and combined cycle designs. And the estimated 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, for example, if the Kalina cycle were successfully developed and used instead of the steam Rankine cycle in combined cycles. But there are also many possible modifications to the STIG cycle.

One 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 (61,62). 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 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 has been shown to

[13] The LM-8000 is based on an upgraded version of the CF6 jet engine, the CF6–80C2, for which production totalled 110 engines in 1987 and is expected to be 260 engines in 1988 (39).

increase the efficiency of a simple cycle gas turbine from 30% to 47% when operated on methanol, while reducing the unit capital cost of the turbine by 15% (63). Further gains would be possible if intercooling were combined with steam injection and chemical recuperation, as shown in an evaluation of chemically recuperated, natural gas-fueled ISTIG units carried out by General Electric analysts for the California Energy Commission (64).

Because of the uncertainties relating to an efficiency comparison of advanced STIG and combined cycle designs, decisions to commercialize advanced STIG technologies should be made on grounds other than efficiency alone.

An ISTIG has several advantages over a combined cycle unit: it is simpler, requiring no steam turbine, condenser, or cooling tower; pollution controls would be less costly than with combined cycle units (see below); the small unit capacities of 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 quickly from expected continuing improvements in jet engine technology.

A minus with STIG cycles is that they exhaust significant quantities of steam to the atmosphere. While the absolute level of makeup water requirements actually favors steam-injected cycles–some 0.6 kg per kWh for an ISTIG unit, compared to 4.1, 1.8, and 0.8 kg per kWh, for a nuclear plant, a large fossil-fuel fired steam-electric plant, and an advanced combined cycle, respectively (27)–all the water required for STIG cycles must be processed to boiler quality. In fact, STIG cycles require about five times the high-quality water and demineralization processing capacity required for combined cycles (65). Although these water processing requirements typically would not give rise to significant economic penalties (footnote 10), it could be a source of concern in water-scarce situations. But in such instances makeup water requirements could be reduced to zero by condensing water vapor out of the exhaust stream of the heat recovery steam generator for reuse, using a condensing heat exchanger. For STIG units, it has been estimated that complete water recovery could be achieved for an 11% increase in capital cost and a 1.2% increase in fuel requirements per kWh (65).[14]

Such considerations, collectively considered, suggest that advanced STIG cycles warrant development. It has been estimated that to develop ISTIG would take four to five years and cost $100 million, including the cost ($40 million)

[14] For an ISTIG unit operated on natural gas about two-thirds of the water vapor in the exhaust stream would have to be recovered to reduce makeup water requirements to zero, at zero relative humidity. The rest of the water vapor in the exhaust is a product of fuel combustion.

for the first unit (31). 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.

5.3 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" 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 2). 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 think 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 U.S. Department of Energy by the General Electric Corporate R&D Center offers one approach to addressing this challenge (31). 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 about $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 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 2). 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, and significant progress is being made in this area (35). Nevertheless, field experience is needed to demonstrate the long-term performance of the catalysts involved (31).

The attractiveness of the Lurgi/ISTIG concept led the U.S. 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 an existing General Electric 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 pilot and commercial demonstration phases of the project were canceled, because the required private-sector support was not secured.

At the time of this writing other 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 U.S. 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 (66); also various advanced coal gasification/combined cycle concepts are moving ahead outside the U.S., with especially intense activity in West Germany (67). 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, even though a recent U.S. Department of Energy (DOE) analysis (35) that systematically compared an air-blown, pressurized fluidized bed gasifier/ISTIG unit with various combined cycle-based systems concluded that the ISTIG-based system would be the least costly. The DOE study estimated, for example, that the unit capital cost and fuel requirements per kWh for the ISTIG-based system would be 37% and 15% less, respectively, than for mature Cool Water technology.

6 Environmental Aspects of Advanced Gas Turbine Technologies

Natural gas-fired gas turbines emit negligible amounts of sulfur oxides and particulates. The high combustion temperatures lead to high emissions of nitrogen oxides (NO_x), however. Their uncontrolled NO_x emissions (Table 3) exceed the levels established in the federal New Source Performance Standards (NSPS) for natural gas-fired gas turbines promulgated in the U.S. in 1977[15] and are far in excess of the standards in some states with especially severe air quality problems.[16]

Among available technologies for reducing NO_x emissions, a well-established approach involves the injection of steam or water into the primary combustion zone. NO_x emissions tend to fall exponentially with the ratio of steam or water injected in the primary combustion zone to fuel, as demonstrated empirically for steam in the first field-modified STIG unit derived from the LM-5000 (Figure 11). NO_x is controlled when steam or water is injected into the primary combustion zone because so doing reduces the flame temperature (Table 3).

With water injection, 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, so that the electrical efficiency is reduced. 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) (50), but not for STIG or ISTIG cycles, where NO_x control is an automatic side benefit.

Dramatic reductions in NO_x emissions are also possible with chemically recuperated gas turbine cycles, with and without additional steam injection for NO_x control, as indicated for chemically recuperated STIG and ISTIG (CRSTIG and CRISTIG) cycles in Table 3. As with steam and water injection, the chemically recuperated cycles achieve low NO_x emissions levels because

[15] For utility gas turbines consuming more than 100 million BTU per hour (approximately 10 MW) the standard is 75 ppm x (n/25) by volume (@ 15% O_2), where n is the turbine efficiency in percent. The standard for all other continuous-duty gas turbines consuming more than 10 million BTU per hour and producing less than 30 MW is 150 ppm x (n/25).

[16] The toughest proposed standards in the U.S. are those proposed in August, 1988, by the South Coast Air Quality Management District (SCAQMD) in California (69): an emission level of 9 ppm x (n/25) for all new stationary gas turbines with capacities greater than 0.3 MW (tentative adoption date: January 1989) and an emission level of 12 ppm x (n/25) for existing turbines, within 30 months of the adoption date. The proposed standards are part of the proposed SCAQMD plan to bring the greater Los Angeles area into compliance with the U.S. ambient air quality regulations established under the Clean Air Act.

Table 3. Estimated NO_x emissions for alternative cycles based on the LM-5000.[a,b]

	Adiabatic Flame Temperature (T°K)		NO_x Emission Rate (ppm @ 15% O_2)[c]	
1. Uncontrolled Simple Cycles[d]	2530		260	
2. Steam-Injected Cycles	*STIG*	*ISTIG*	*STIG*	*ISTIG*
Dry[e]	2548	2471	301	159
S/F[f] = 1.0	2406	2329	89.5	43.6
S/F[f] = 2.0	2274	2199	25.3	11.6
S/F[f] = 3.0	2158	2085	7.4	3.2
3. Chemically Recuperated, Steam-Injected Cycles	*CRSTIG*	*CRISTIG*	*CRSTIG*	*CRISTIG*
Dry[e]	2223	2161	15	7.6
S/F[f] = 0.2	2107	2048	4.1	2.0
S/F[f] = 0.3	2055	1997	2.2	1.0
S/F[f] = 0.5	1959	1905	0.63	0.29

a The adiabatic flame temperature (AFT) is calculated for stoichiometric conditions–for methane @ 300 °K in simple and dry STIG/ISTIG cycles; for methane @ 400 °K in wet STIG/ISTIG cycles; for a mixture (@ 950 °K) of 10% methane, 62% steam, 22% hydrogen, 1% carbon monoxide, and 5% carbon dioxide (a typical fuel composition expected from the steam-reforming of natural gas) for CRSTIG/CRISTIG cycles. (A reheat turbine would be needed to achieve the turbine exhaust temperature needed for steam reforming. Because of the reduced oxygen level in the reheat combustion "air", the AFT and hence NO_x formation in the reheat combustor would be significantly lower than in the primary combustor. This effect is neglected here.) The temperature of steam for NO_x control is assumed to be 578 °K. For the calculated AFT, the indicated NO_x emission level is obtained from an empirical relationship between AFT and NO_x emissions (68). For the lowest AFTs considered, empirical data are not yet available, and the indicated NO_x emissions, obtained by extrapolation, may underestimate actual emissions. While thermal NO_x emissions are strongly correlated with AFT, prompt NO_x emissions are not. At high AFT, thermal emissions dominate; at low AFT, prompt NO_x emissions become more important.

b For a compression ratio of 27.6:1, 31.3:1, and 33.5:1, and an air temperature at the compressor exit of 787 °K, 816 °K, and 658 °K, for the simple cycle, STIG/CRSTIG cycles, and ISTIG/CRISTIG cycles, respectively (27).

c For a typical turbine, 1 ppm is approximately equivalent to 1.7 grams per GJ of fuel.

d The uncontrolled NO_x emissions rate for this simple cycle turbine is higher than for the turbines used in combined cycles, because the low pressure ratio of the gas turbines used in combined cycles leads to a lower compressor exit temperature and hence a lower AFT.

e "Dry" means that all steam is injected with the dilution air (i.e. no steam is injected into the primary combustion zone).

f S/F is the molar ratio of steam/fuel for steam injected into the primary combustion zone for NO_x control.

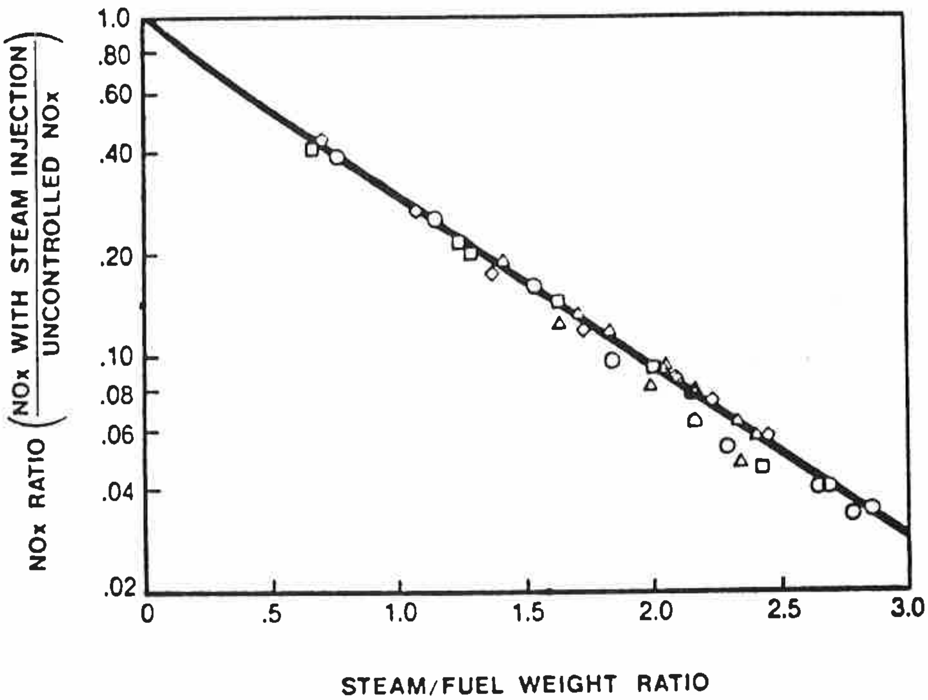

Figure 11. The NO_x reduction ratio as a function of the ratio of the weight of the steam injected into the primary combustion zone to the weight of the fuel, measured at the first field-modified STIG unit based on the LM-5000, at Simpson Paper Company, Anderson, California (59).

with steam-reformed fuel, flame temperatures are lower than with natural gas fuel (since the heating value of the steam-reformed fuel is much lower *per mole* than that of the fuel from which it is derived). CRSTIG and CRISTIG cycles are also more efficient electricity generators than cycles that do not use steam-reformed fuel (64). The combination of low NO_x emissions and high efficiency achievable with these cycles has led the South Coast Air Quality Management District (SCAQMD) in California and the California Energy Commission to examine chemically recuperated gas turbine cycles as a promising technological strategy for reducing NOx emissions in Southern California while simultaneously controlling costs (personal communication from Jack Janes, California Energy Commission, December 15, 1988)

CO emissions increase as the level of steam injection increases, while NO_x emissions are declining. (Similarly, increased CO emissions might arise with chemically recuperated gas turbine cycles, since a lower flame temperature is the mechanism responsible for the higher CO emissions.) Figure 12 shows, for example, that if NO_x is controlled in a natural gas-fired LM-5000 to levels below 25 ppm, the CO emissions would be in excess of 50 ppm. Determining the optimal level of steam injection into the primary combustion zone involves balancing considerations of both NO_x and CO emissions. If, by the time the maximum acceptable CO emissions level is reached, still higher levels of steam injection are desired for power and efficiency augmentation, extra steam is injected sufficiently far from the primary combustion zone so as not to affect pollutant emissions further.

Achieving extremely low levels of NO_x emissions with either steam injection or steam-reformed fuel might require supplemental control of carbon monoxide emissions. Catalytic oxidation of the exhaust gas (the technology used in the U.S. to control CO emissions from cars) is a promising, relatively low-cost strategy for accomplishing this (68).

Using injected steam to reduce NO_x emissions of combined cycles to levels below 10 ppm would probably not be pursued because of the efficiency penalties associated with steam injection. Instead, the favored approaches would probably involve a combination of water or steam injection plus selective catalytic reduction (injecting ammonia into the turbine exhaust gas stream to reduce NO_x in the presence of a catalyst) or staged or premixed combustion (not widely available today) plus selective catalytic reduction (or the equivalent) (68)–approaches that are inherently more costly ways to control NO_x than the approaches available for aeroderivative turbines.

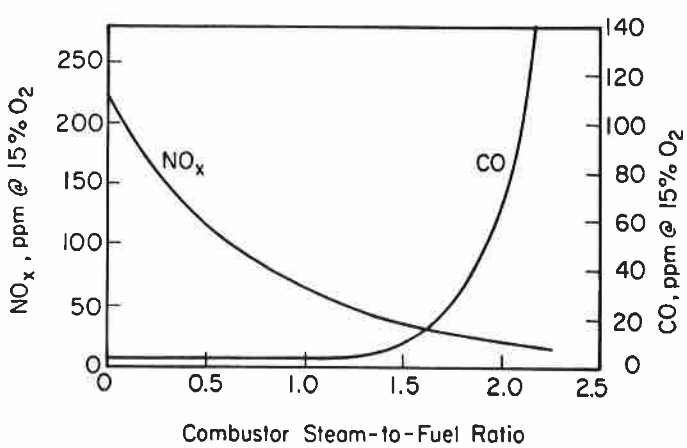

Figure 12. Typical effects of combustor steam injection on NO_x and CO emissions at full load operation (28).

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 U.S. New Source Performance Standards (Table 4). With advanced coal gasification technologies that involve hot-gas cleanup, NO_x control will be more difficult, however. Many coals contain 0.5 to 2 percent nitrogen by weight (dry basis), much of which is converted into ammonia in the gasifier. At Cool Water, this ammonia condensed out at the low temperatures realized with the "scrubber" gas cleanup technology used, but with hot gas cleanup the ammonia will be carried over into the combustor, where it can be converted to NO_x. Catalytic decomposition of ammonia or staged combustors will probably be needed to control NO_x emissions from this fuel-bound nitrogen in coal gasification systems using hot-gas cleanup (35).

Still another important environmental benefit of advanced gas turbine power generating technologies is the potential for reduced emissions of carbon dioxide, which is desirable in light of heightened concerns about the global greenhouse warming. 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.

Even 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. Applying advanced gasification technology to biomass grown on a renewable basis (71) would lead to zero net emissions of carbon dioxide, since the carbon dioxide released in combustion would just balance the carbon dioxide removed from the atmosphere in growing the biomass.

Table 4. 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 (0.014 kg/GJ)	90 percent removal (maximum = 0.52 kg/GJ)
NO_x	0.026 kg/GJ	0.26 kg/GJ
Particulates	0.00043 kg/GJ	0.013 kg/GJ

a The Cool Water plant produces 94 MW at an average efficiency of 30.2 percent, using the Texaco gasifier (70).

b For Utah (SUFCO) design coal.

7 Potential Applications of Advanced Gas Turbines

7.1 Natural Gas Resources

Natural gas will dominate initial applications of advanced gas turbines, because gas supplies will be abundant in many parts of the world in the decades immediately ahead. According to estimates by the U.S. Geological Survey, there is about as much conventional natural gas left in the world as conventional crude oil, but globally gas is used at just half the rate oil is (Table 5). Remaining gas resources for the U.S. and Canada are about 50% greater than oil resources, while for all industrialized countries remaining gas resources are more than twice as large as remaining oil resources (Table 5).

The outlook for gas is especially promising for developing countries. Natural gas resources exist in about 50 developing countries, including 30 that import oil (75). Also, gas resources are large in relation to gas production in developing countries; although they have about as much gas as industrialized countries, they produce it at just one-fifth the rate it is produced in industrialized countries. Outside the Middle East, developing country gas resources are equivalent to more than a 200-year supply at the current rate of production (Table 5).

7.2 Natural Gas/Coal-Gas Central-Station Power Applications in the U.S.

Even in the U.S., where natural gas resources are more fully developed than in most of the rest of the world, natural gas-fired gas turbines can play important roles in power generation in the decades immediately ahead.

One important initial application for ISTIG technology would involve replacing the 127 GW of existing oil and gas-fired steam-electric plants expected to be operating in the U.S. in 2000 (24) with natural gas-fired ISTIG units. While these are load-following steam plants typically operated at low capacity factor [projected by DOE to average 46% in 2000 (24)], they are so inefficient (32%) 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).[17]

[17] 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 46% capacity factor for the ISTIG unit, the same fuel price for both plants, and an O&M cost of 4.0 mills per kWh for the existing steam plants [the average value in the U.S. in 1985 (18)].

Table 5. Natural gas and oil resources and production.

	Natural Gas		Crude Oil	
	Resources[a] (EJ)	Production[b] (EJ/year)	Resources[a] (EJ)	Production[b] (EJ/year)
Industrialized Countries				
U.S. / Canada	1079.0[c]	21.0	720.2	23.3
Western Europe	481.6	7.3	318.8	8.6
Australia / New Zealand	149.3	0.6	36.7	1.3
U.S.S.R. / Eastern Europe	2757.6	27.1	991.9	25.9
SUBTOTALS	4467.5	56.0	2067.6	59.1
Developing Countries				
Central America	228.3	1.3	342.7	6.5
South America	290.4	1.7	523.8	7.7
Asia	779.5	3.9	641.3	11.6
Africa	620.9	2.0	627.2	11.1
Middle East	2316.8	2.6	3175.1	23.0
SUBTOTALS	4235.9	11.5	5310.1	59.9
GLOBAL TOTALS	8703.4	67.5	7377.7	119.0

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

b Production in 1985 (73).

c The resource estimate given here for the U.S. (650 EJ) may underestimate remaining gas resources. A more recent assessment carried out for the U.S. Department of Energy under the auspices of the Argonne National Laboratory (74) estimated that remaining gas resources in the lower 48 states of the U.S. recoverable at wellhead prices less than \$2.75/GJ amount to 633 EJ, with 189 EJ of additional resources recoverable at costs in the range \$2.75/GJ to \$4.60/GJ.

Doing so for all oil and gas-fired steam plants in the U.S. would lead to producing the same amount of electricity as DOE projected for such plants in 2000 (24) while saving the fuel equivalent to 0.82 million barrels per day of oil. Considerations of both the cost savings potential and the large NO_x reduction potential (especially important in Southern California) of ISTIG technology, led the staff of the California Energy Commission to a recommendation along these lines–that Southern California Edison Company retire some 5700 MW of existing gas-fired steam-generating capacity in favor of ISTIG plants (30). Supported by the California South Coast Air Quality Management District, this recommendation was under active consideration by the Southern California Edison Company at the time of this writing.

Another potential application of advanced gas turbines for central station power generation in the U.S. is as an acid rain control strategy. The large quantities of SO_2 and NO_x emitted by existing coal-fired steam-electric power plants are among the most significant pollutant emissions leading to acid rain (76). Growing concern about acid rain will probably lead to U.S. legislation in the not-to-distant future aimed at curbing these emissions (77). 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 (78). With all the incremental costs of the new facilities allocated to sulfur removal (giving no credit for reduced NO_x emissions or other benefits), the cost of this scrap-and-build strategy can be expressed as the cost per tonne 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 $400 per tonne, compared to $340 to $640 per tonne 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 gasifier/advanced combined cycle (Texaco/ACC) options, costing respectively some $690 and $810 per tonne 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 20 years before switching to coal would lead to a cost of sulfur dioxide removal during this period of $330 per tonne and $640 per tonne, with natural gas prices of $3 per GJ and $4 per GJ, respectively, prices which are 50% and 100% higher than the average 1987 U.S. utility gas price.

7.3 Natural Gas/Coal-Gas Central-Station Power Applications in Western Europe

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 change radically, however, because of: (*a*) the growing availability of natural gas

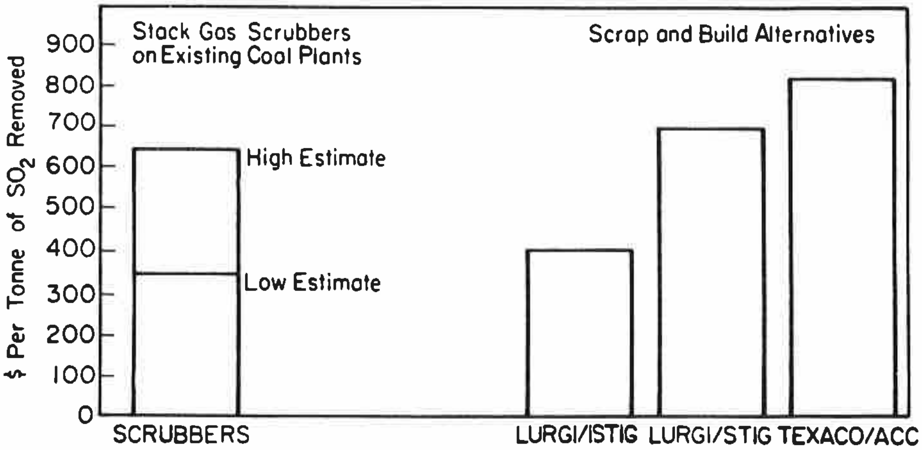

Figure 13. The cost of sulfur removal with alternative acid rain control strategies for coal with an average sulfur content of 3.1% (78). The bar on the left shows the range of estimated costs for putting stack gas scrubbers on existing coal steam-electric plants, for capital costs in the range \$193 to \$344 per kW, extra O&M costs in the range 0.42 to 0.83 cents per kWh, a 60 percent average capacity factor, and 85% sulfur removal. 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 2, except that capital costs are reduced 10 percent because some of the existing facilities can be used in the new plants. 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 the U.S. in 1985, and that the O&M cost for the existing coal plants is 0.38 cents per kWh, the average for Midwest coal plants without scrubbers. A 6.1% discount rate and a 30-year lifetime are assumed for all cases.

The major cost uncertainties for the Lurgi/ISTIG option are the costs for the chemical hot-gas cleanup system. The uncertainty in the capital cost of the cleanup system is ± 25%, or ± \$27 per tonne of sulfur dioxide removed. At the targeted catalyst consumption rate of 0.5%, the contribution of the cost of the catalyst to sulfur dioxide removal is \$41 per tonne. But the consumption rate could be as high as 1% or as low as 0.25%, so that the catalyst cost could range from \$21 to \$83 per tonne of sulfur dioxide removed. Thus, the cost of sulfur removal with Lurgi/ISTIG is probably in the range \$352 to \$469 per tonne, with the most likely value being about \$400 per tonne (78).

supplies in Europe, (*b*) the favorable economics of power generation based on advanced gas turbines, and (*c*) growing concerns about coal and nuclear power.

Estimated remaining recoverable natural gas resources are about three-fourths as large in Western Europe as in the U.S. (72), but European gas resources are much less developed. While proved reserves of natural gas declined 30% in the U.S. between 1973 and 1987, they increased by a comparable percentage in Western Europe in this same period (79). Europe also has the opportunity to purchase substantial quantities of gas from Algeria and the Soviet Union, where gas supplies are far in excess of domestic needs.

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 \$2.0 per GJ in 1976 to \$4.4 per GJ in 1982 and then fell back to \$2.0 per GJ in 1986 (80). An International Energy Agency (IEA) report on the outlook for natural gas has projected that in the late 1990s and beyond the border price of gas in Europe will be 73–80% of the crude oil price, reaching \$3.5 to \$5.5 per GJ by 2000 and \$5.9 to \$7.2 per GJ by 2010 (81), 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.[18] Such projections discourage the use of natural gas for power generation, because lifecycle gas prices must typically be no higher than \$3.7 to \$4.4 per GJ for natural gas-fired ISTIG units to be competitive with new coal or nuclear steam-electric plants in Europe (Table 6).

The high European gas prices projected by the IEA 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 cost 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 (80). Gas supplies at low marginal costs appear to 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 IEA (3)], then by 2010 180 GW of electric power capacity would be advanced gas turbines, accounting for 30%

[18] The weighted average cost of transmission and distribution inside borders in Europe was about \$1.9 per GJ in 1984 (81). In the U.S., 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 (82). Thus, a reasonable estimate for the price of gas to electric utilities in Europe is \$1 per GJ more than the border price.

Table 6. Levelized costs (cents/kWh) for electric power generation from alternative sources in Western Europe.[a]

	Levelized Busbar Cost	
Nuclear[b]		
	6-year construction	10-year construction
Capital	2.01	2.25
Fuel	1.00	1.00
Operation & Maintenance	0.54	0.54
TOTAL	3.55	4.09
Coal/Steam w/FGD[c]		
Capital	1.46	
Fuel	1.88	
Operation & Maintenance	0.54	
TOTAL	3.88	
ISTIG w/Gasified Coal[d]		
Capital	1.22	
Fuel	1.55	
Operation & Maintenance	0.60	
TOTAL	3.37	
ISTIG w/Natural Gas[e]		
Capital	0.47	
Fuel	0.766 x P	
Operation & Maintenance	0.29	
TOTAL	0.76 + 0.766 x P	

[a] All costs are for a 6% discount rate, 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 (3). For a site with two 1100 MW(e) units and start-up in 1990, the unit capital cost is estimated to be $1700/kW ($1900/kW) for a 6-year (10-year) lead time.

[c] For a site with two 600 MW(e) units with flue gas desulfurization (FGD) and start-up in 1990, the unit capital cost is estimated to be $1230/kW, assuming a 4-year lead time (3). The efficiency is 35% (36%, LHV basis). The coal price is assumed to be $52/tonne ($1.82/GJ).

[d] For a 110 MW(e) ISTIG unit fired with gas derived from coal in a Lurgi gasifier with hot gas clean-up, the unit capital cost is estimated to be $1030/kW, assuming a 2-year lead time. The coal price is assumed to be $52/tonne ($1.82/GJ). The efficiency is 42.1% (43.4%, LHV basis). See Table 2.

[e] For a 114 MW(e) ISTIG unit fired with natural gas, the unit capital cost is estimated to be $400/kW, assuming a 2-year lead time. The efficiency is 47% (52%, LHV basis). Here P is the average lifecycle cost of natural gas ($/GJ). See Table 2.

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, assuming gas demand in other sectors grew at 1.1% per year [the average of the high and low projections made by the IEA in 1986 (81)]. Even with this very large increase in aggregate demand, the marginal cost of gas would still be only about $2.5 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 about $3.6 per GJ,[19] and the corresponding border price would be about $1

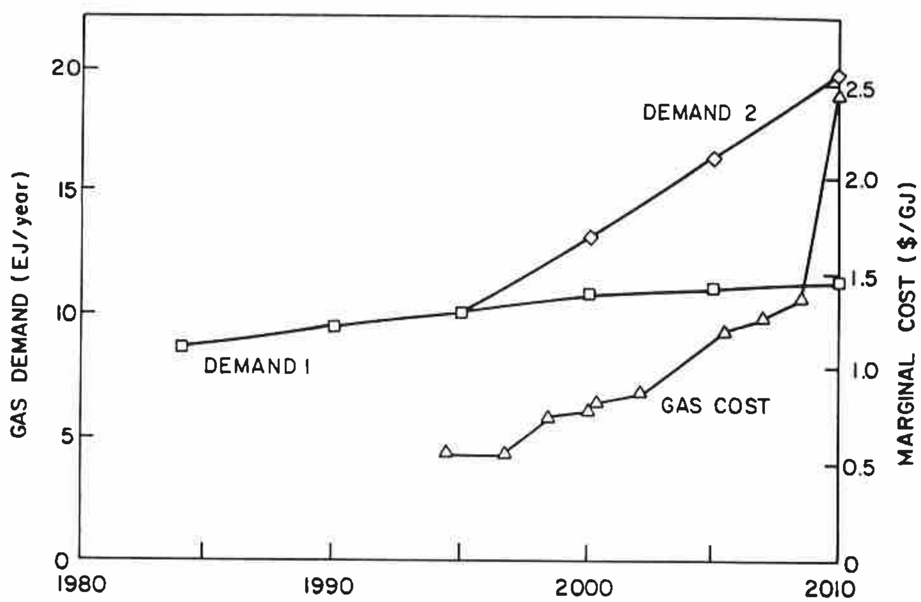

Figure 14. Two alternative projections of natural gas demand in Western Europe. Demand 1 is the average of the high and low projections made in 1986 by the International Energy Agency (81); Demand 2 superimposes on the Demand 1 projection additional demand for gas associated with providing all incremental 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 (3)], 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 (80) and is for the gas supply levels of the Demand 2 projection.

[19] The coal price is assumed to be $52 per tonne ($1.82 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 (83). 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 6, the backstop utility gas price is estimated to be $3.6 per GJ.

per GJ less, far below the \$5.9 to \$7.2 per GJ forecast for 2010 by the IEA (81).

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, i.e., in only six years) or coal steam plants with flue gas desulfurization (Table 6).

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 IEA (81).

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 about \$1 per GJ higher than with Lurgi/ISTIG. Thus, the annual benefit to nonutility consumers in Europe in 2010 would be some \$10 billion greater if Lurgi-ISTIG were the backstop instead. It would seem that Western European governments 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!

7.4 Natural Gas/Gas Turbine Power for Developing Countries

While the abundance of their natural gas resources (Table 5) suggests that natural gas could play a major role in the energy economies of many developing countries, the use of natural gas is presently inhibited by the lack of gas transmission and distribution infrastructure, which is costly to develop. This problem could often be overcome if power generation were emphasized as an initial market. Some of the large revenues generated in power sales could be used to pay for the construction of the gas delivery system, thereby helping to make gas available to other users at reasonable cost (84).

Its low capital cost makes the gas turbine an especially attractive technology for developing countries in light of the unaffordability of capital investments for electricity based on conventional sources (Table 1).

Not only are the overall capital requirements small for these advanced gas turbine power plants, but also, many 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 "gas generator," the "high technology" part of the system that is derived from a jet engine. The gas generator actually accounts for only a modest fraction of the total power plant cost; the mass-produced CF6 jet engine, from which LM-5000 STIG and ISTIG units would be derived, costs only about $6 million–thus contributing only $53 per kW to the cost of the ISTIG unit (see footnote 7).

The scale characteristics of aeroderivative turbines are also well suited to developing countries. In most developing countries, the total utility grid capacity is too small to be well matched to much 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 turbines makes it possible to replace failed parts and even whole engines quickly with replacements flown or trucked in from centralized maintenance facilities (see footnote 9). This feature of the aeroderivatives is especially attractive for many developing countries, where sophisticated maintenance capability is typically unavailable at power generating sites. The required maintenance network is already in place in most developing countries that have their own commercial airlines; their planes are typically maintained through centralized lease-pool arrangements. This advantage is reflected, for example, in the fact that of the 210 General Electric LM-2500 aeroderivative turbines in service throughout the world as of 1986, 54, 8, and 26 were being used in developing countries of Latin America, Africa, and Asia, respectively (personal communication from L. Gelfand, Marine and Industrial Turbine Division, General Electric Company, Cincinnati, Ohio, February 1987).

8 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, of reducing carbon dioxide emissions to levels considerably below those associated with coal-fired steam-electric plants, and of avoiding the risks of expanded dependence on nuclear power, are benefits not easily matched by alternatives.

While the benefits resulting from the wide use of heavy-duty industrial gas turbines would be large, there are good reasons for also bringing advanced aeroderivative turbines into wide use. It appears that controlling pollutant emissions responsible for acid rain to very low levels would be more readily accomplished with various advanced aeroderivative turbines than with combined cycles. Also, with aeroderivatives the advantages of high efficiency and low unit capital costs can be extended to modest scale, resulting in greater flexibility in capacity planning, improved reliability, and ease of maintenance. And the small size of aeroderivatives makes it possible to reverse the trend in power technology toward costly field construction and bring most construction work back to the factory, where the economies of mass production can be exploited. Moreover, aeroderivative turbines will continue to benefit more directly from improvements in jet engine technology than heavy-duty industrial turbines.

Wide use of advanced gas turbines would not solve the electric power problem for all time. Eventually, the tightening of world gas supplies and concerns about the atmospheric buildup of carbon dioxide will limit the attractiveness of further expanding the use of these engines for power generation with fossil fuels. However, a major shift to fossil fuel-fired 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 (85).

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