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EFFECT OF GAS TURBINE EFFICIENCY AND FUEL COST ON COST OF PRODUCING ELECTRIC POWER

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SECTION 1

SUMMARY

Gas turbine efficiencies which will be needed to produce power in a combined cycle gas turbine-steam turbine system (COGAS system) at costs from 6 to 10 mils per kilowatt hour are tabulated as a function of fuel cost from 40 to 100 cents per million Btu. Improvements in gas turbine efficiency from 29 to 37 percent are envisioned over the next nine years, which would result in combined cycle efficiencies from 42 to 54 percent. The research improvements envisioned which would improve the efficiency of the gas trubine are primarily those which will increase the temperature at which the gas turbines can operate. The level of effort needed to increase the operating temperatures at this rate is expected to be an additional three to eight million dollars per year for research studies. Combined with other work being done by the gas turbine manufacturers this effort could be expected to increase the turbine inlet temperatures by an average of 90°F per year, which is enough to increase gas turbine efficiency at the rate of almost 1% per year.

SECTION 2

INTRODUCTION

The purposes of this work are to present data on the costs of fuel and of electric power produced by gas turbine systems as a function of gas turbine efficiency. Since turbine efficiency can be improved by developments which are currently envisioned, it is also the purpose of this report to estimate the amount of research effort and the elapsed time required to achieve various levels of increased turbine efficiency.

An extensive study of the potential attractiveness of several advanced power cycles for producing electric power was finished in 1970 by United Aircraft Research Laboratories (ref. 1). In these studies it was assumed that fossil fuels would be gasified to produce a fuel with very low sulfur content which would then be used with 1) conventional steam turbines, 2) gas turbines, 3) combined gas turbines and steam turbines, 4) topping cycles, such as a potassium system, 5) bottoming cycles, such as steam-fluorocarbon systems, or 6) closed cycle gas turbine power systems with inert gases, such as carbon dioxide or sulfur dioxide working fluids, to produce power for electric utilities.

The most attractive systems of all were the combined gas turbine-steam turbine power systems, which were referred to as combined cycle or COGAS systems. Of five specific types of COGAS systems evaluated, the waste heat recovery system was judged to be superior to the exhaust fired system, the supercharged system, the gas generator supercharged system, or the two pressure supercharged system.

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1. Robson, F. L., Giramonti, A. J., Lewis, G. P., and Gruber, G., "Technical and Economic Feasibility of Advanced Power Cycles and Methods of Producing Non-Polluting Fuels for Utility Power Stations," United Aircraft Research Laboratories, National Air Pollution Control Administration, Contract CPA 822-69-114, Final Report, UARL Report J-970855-13, December 1970.

SECTION 3

DESCRIPTION OF SYSTEM

The waste heat combined gas and steam turbine system (COGAS system) consists of three subsystems; 1) a fuel gasification-desulfurization subsystem, 2) a gas turbine subsystem, and 3) a steam turbine subsystem. The fuel gasification-desulfurization system would consist of an air compressor, a gasifier, a waste heat boiler, the desulfurization unit, and several heat exchangers.

In these calculations it has been assumed that a low temperature gasification process would be used, of the amine or potassium carbonate type, and the gas fed to the gas turbine subsystem at a temperature betweeen 100 and 230°F. Whether or not this heat is supplied to the gas turbine system in the form of sensible heat or as chemical energy makes no difference to the gas turbine subsystem performance per million Btu's supplied since the chemical energy will be converted to thermal energy as a part of the gas turbine subsystem and the temperatures achievable will be greater than the system is able to utilize.

The gas turbine subsystem will consist of the fuel burner, an air compressor, power turbine, and electric generator. The steam turbine subsystem will consist of a steam boiler, a steam turbine, an electrical generator and condenser, and pumps. A simplified diagram showing the gas turbine and steam turbine subsystems is given in Figure 1 (ref. 2).

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2. Giramonti, A. J., "Advanced Power Cycles for Connecticut Electric Utility Station," UARL Report L-971090-2, January 1972.

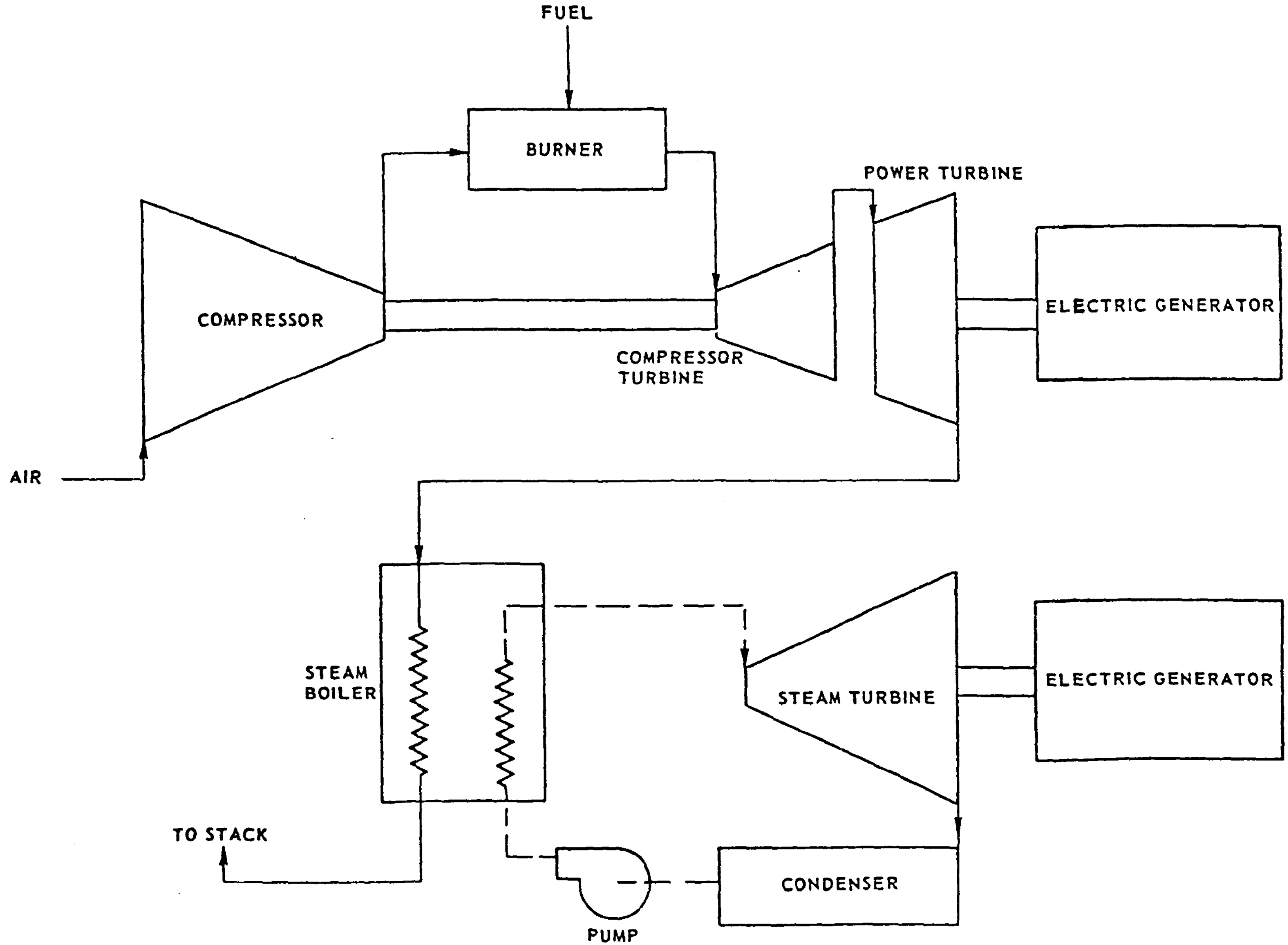

Figure 1. Gas Turbine, Steam Turbine Combined Cycle Power System

SECTION 4

COST DATA

The electric power costs to be calculated in this study are bus bar power costs in mils per kilowatt hour for COGAS systems. These are to include all of the costs of electric power generation, but do not include any costs of ditribution. The bus bar power cost can be thought of as consisting of three principal factors; the fuel cost, the plant operating cost, and capital charges. We are to assume various fuel costs for the gasified desulfurized fuel as a parameter in this study.

These fuel costs are to include; the capital charges for the gasification and desulfurization subsystem, the cost of fuel to this subsystem, and the operating costs for it. Since these factors are included in the fuel cost to the gas turbine and steam turbine sybsystems, we need only to calculate fuel usage and figures on the capital and operating costs of these two subsystems in order to calculate the bus bar power cost.

The capital costs for the gas turbine and steam turbine subsystems include; the cost of the major equipment items, such as the compressor, electric generator, and burner for the gas turbine subsystem, and the steam boiler, steam turbine, electric generator, and condenser for the steam turbine subsystem. They also include miscellaneous plant equipment and interest during construction as well as land and buildings. Pieces of miscellaneous station equipment include; miscellaneous electrical equipment, fuel tanks and fuel storage, fuel unloading and transfer equipment, and wet-cooling towers, and were estimated to cost 10% of the cost for land, buildings, and major installed equipment items. The interest during construction was assumed to be 10% of the total cost of these same items plus the cost of the miscellaneous plant equipment. A graph of capital cost for these systems as a function of gas turbine efficiency is shown in Figure 2 (ref. 3). The capital charges were figured as being 17% of the capital cost, and an 80% on-stream factor was assumed.

The operating costs for these systems must cover the cost of plant labor, maintenance, and supplies. These costs were estimated as being 1.0 mil per kilowatt hour.

In order to calculate the fuel costs for these combined systems, we must first relate the gas turbine efficiency to the overall system efficiency for both the gas and steam turbines. Figure 3 shows a correlation between combined cycle efficiency and gas turbine efficiency (ref. 3, 4).

To perform calculations for this report, we first selected a gas turbine efficiency in the range of interest. Based upon present state-of-the-art turbine technology, which allows use of gas temperatures as hot as 1800°F, we can postulate gas turbine efficiencies in the range of 29.5%. By 1976, if an aggressive R&D program is followed, it appears possible that inlet temperatures of 2200°F and gas turbine efficiencies of 32% are feasible. By 1982 inlet temperatures of 2600°F and overall system efficiencies of 37% for gas turbines seem feasible. Selecting specific gas turbine efficiencies over this range, we then calculate the capital cost for the system using Figure 2.

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3. Robson, F. L., Chief, Utility Power Systems, United Aircraft Research Laboratories, East Hartford, Connecticut, personal communication, 13 August 13, 1973.

4. Giramonti, A. J., Senior Systems Engineer, United Aircraft Research Laboratories, East Hartford, Connecticut, personal communication, 13 August 1973.

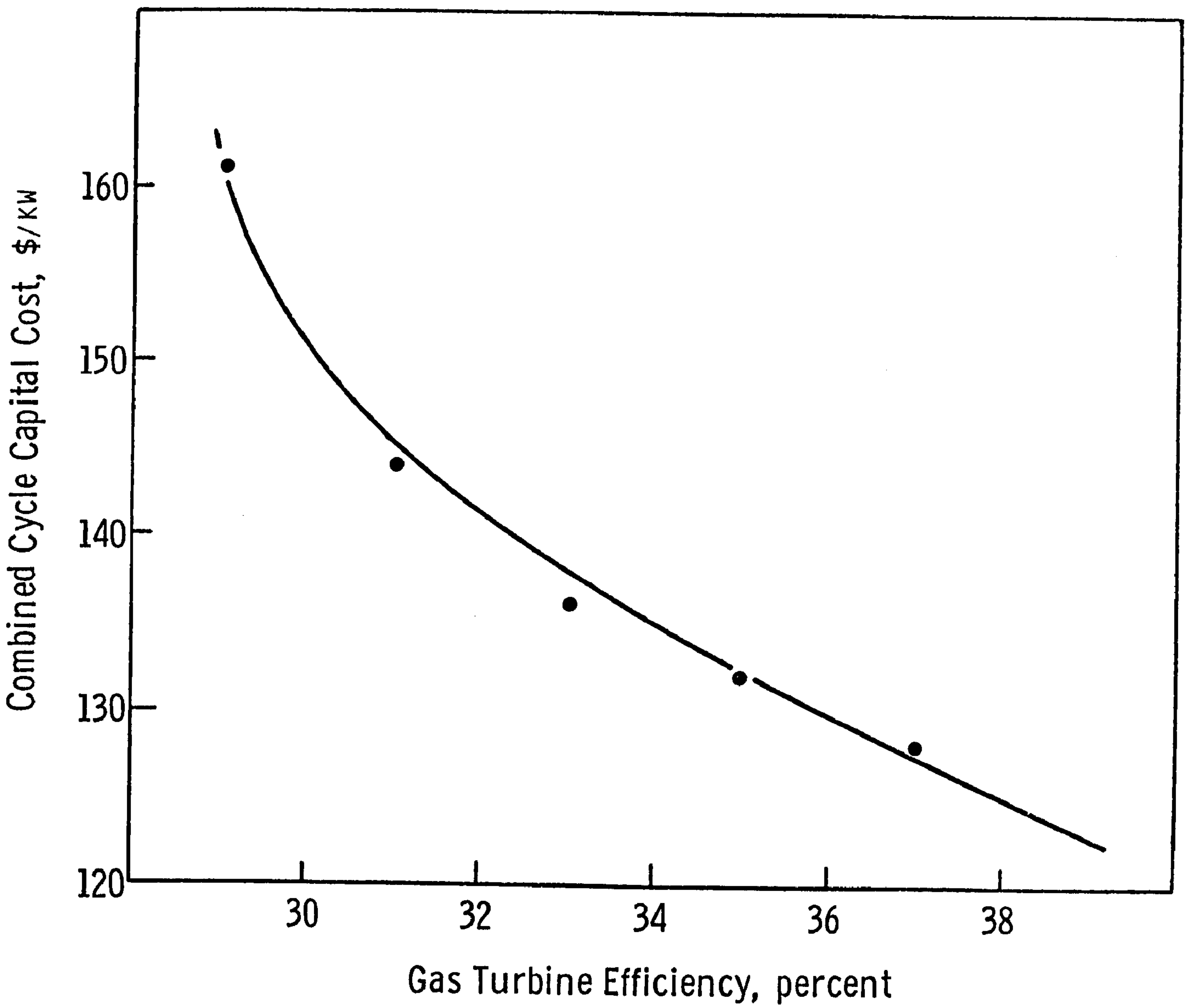

Figure 2. Capital Cost of Gas Turbine and Steam Turbine Subsystems as a Function of Gas Turbine Efficiency.

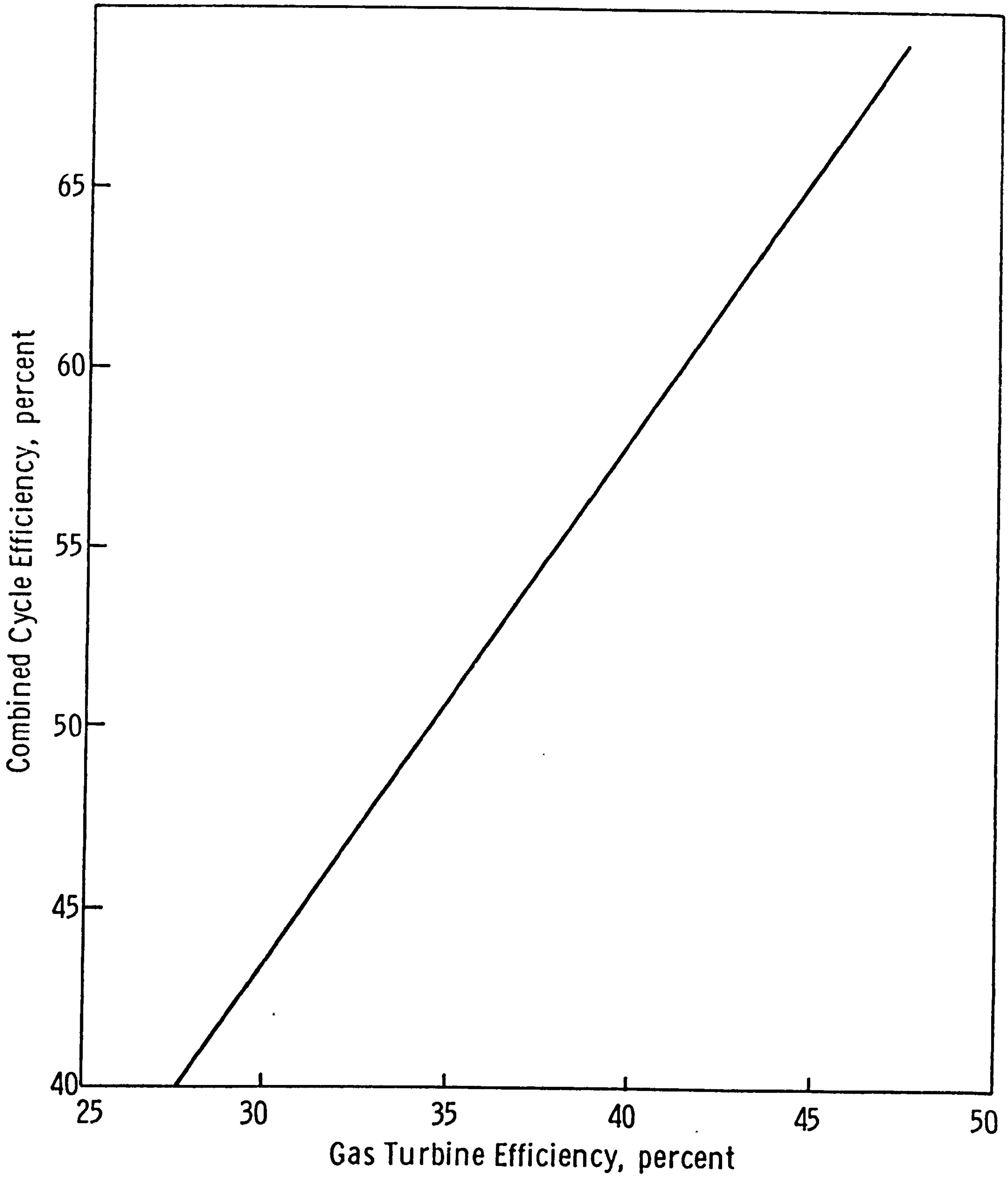

Figure 3. Combined Cycle Efficiency as a Function of Gas Turbine Efficiency

The capital charges in mils per kilowatt hour are then found by multiplying the capital cost in dollars per kilowatt by 1000 mils per dollar times $\frac{\text{year}}{8{,}760\text{ hr}}$ times $\frac{1}{0.80}$ times 17%. This yields a factor of 0.02426 for converting capital costs in dollars per kilowatt to capital charges in mils per kilowatt hour. We then add a constant factor of 1.0 mil per kilowatt hour for operating cost.

The cost of fuel per kilowatt hour is found by multiplying the cost of fuel in dollars per million Btu times 3,413 Btu's per kilowatt hour times 1 over the overall system efficiency times 1000 mils per dollar.

The overall system efficiencies are found by the use of Figure 3. By adding up these three components of cost we obtain a bus bar power cost in mils per kilowatt hour. Calculations for gas turbine efficiencies of 29, 31, 33, 35, and 37% are shown in Table 1 as a function of the fuel cost in cents per million Btu's.

The data in Table 1 were graphed in Figure 4 where power cost is plotted against gas turbine efficiency with fuel cost in cents per million Btu's plotted as a parameter. Using Figure 4 we are then able to pick off specific values of gas turbine efficiency which gives specified values of bus bar power cost in mils per kilowatt hour at selected fuel costs in cents per million Btu's. These figures are shown in Table 2. In cases where the present gas turbine efficiency is more than sufficient to achieve the bus bar power cost for that given fuel cost, an entry of <29% is made in Table 2 to indicate that this bus bar power cost is achievable with present state-of-the-art units. In cases where the bus bar power costs cannot be achieved for that specific

Table 1

COST FACTORS FOR COGAS SYSTEMS AS A FUNCTION OF GAS TURBINE EFFICIENCY

	Gas Turbine Efficiency, %				
	29	31	33	35	37
Capital Cost, $M̄	161	144	136	132	128
Capital Charges, mils/KWH	3.90	3.49	3.30	3.20	3.10
Operating & Maintenance Cost, mils/KWH	1.0	1.0	1.0	1.0	1.0
Combined Cycle Efficiency, %	42.0	45.0	48.0	50.8	53.8
Fuel Cost, mils/KWH for fuel at:					
40¢/M̄ Btu	3.25	3.03	2.84	2.69	2.54
50 " "	4.06	3.79	3.55	3.36	3.17
60 " "	4.88	4.55	4.27	4.03	3.81
70 " "	5.69	5.31	4.98	4.70	4.44
80 " "	6.50	6.07	5.69	5.37	5.08
90 " "	7.31	6.83	6.40	6.05	5.71
100 " "	8.13	7.58	7.11	6.72	6.34
Power Cost mils/KWH for fuel at:					
40¢/M̄ Btu	8.15	7.52	7.14	6.89	6.64
50 " "	8.96	8.28	7.85	7.56	7.27
60 " "	9.78	9.04	8.57	8.23	7.91
70 " "	10.59	9.08	9.28	8.90	8.54
80 " "	11.40	10.56	9.99	9.57	9.18
90 " "	12.21	11.32	10.70	10.25	9.81
100 " "	13.03	12.07	11.41	10.92	10.44

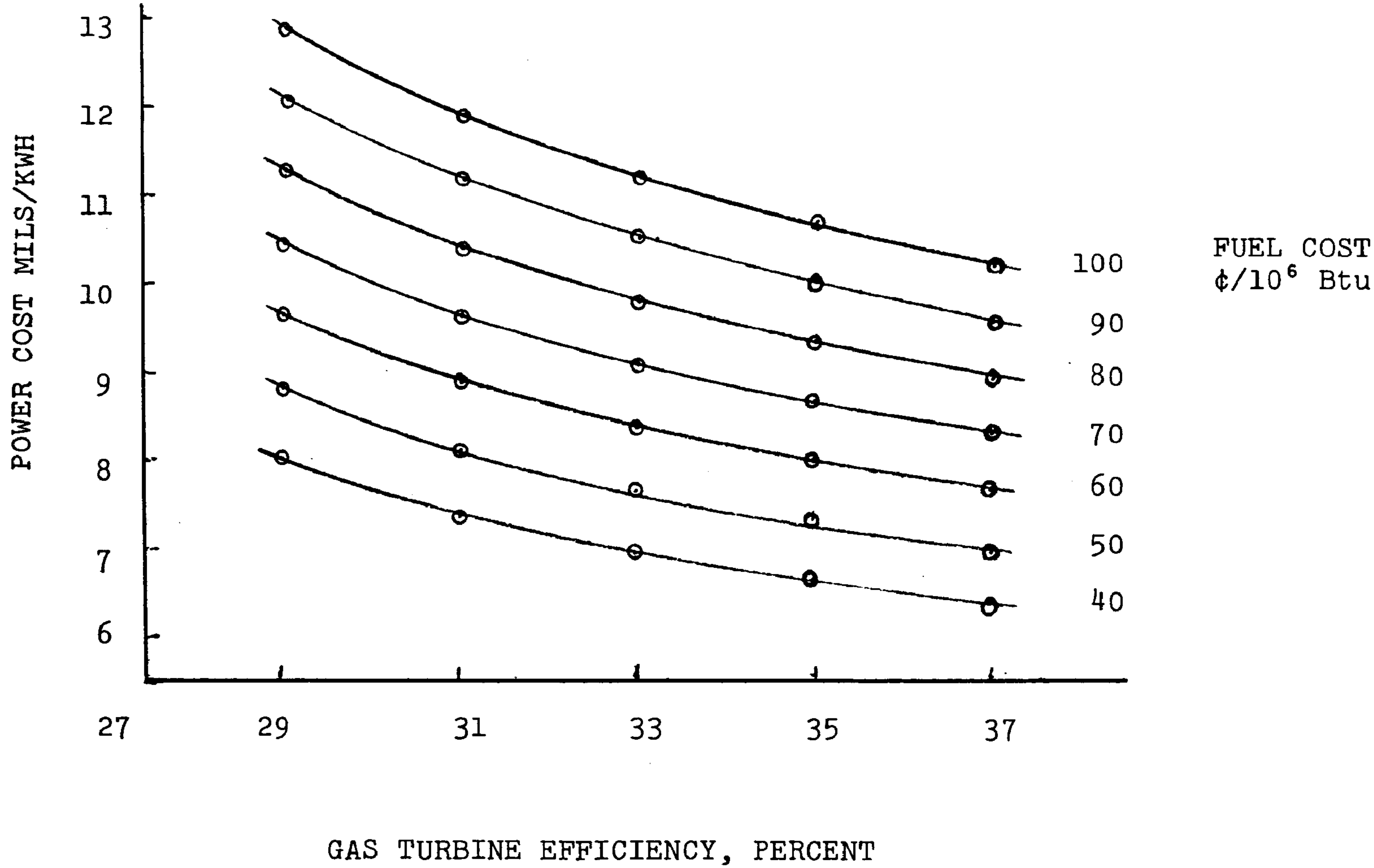

Figure 4. Effect of Gas Turbine Efficiency and Fuel Cost on Power Cost

Table 2

GAS TURBINE EFFICIENCIES TO YIELD VARIOUS BUS BAR POWER COSTS AS A FUNCTION OF FUEL COST

Fuel Cost ¢/10^6 Btu	Bus Bar Power Cost, Mils/KWH				
	6	7	8	9	10
40	>37	34.0	29.5	<29	<29
50	>37	>37	34.7	29.1	<29
60	>37	>37	36.5	31.3	<29
70	>37	>37	>37	34.3	30.4
80	>37	>37	>37	>37	33.0
90	>37	>37	>37	>37	36.2
100	>37	>37	>37	>37	>37

fuel cost, by any gas turbine efficiency presently planned (above 37%), >37% is inserted in that space to indicate this. As we can see from this table, the combined cycle does not offer any realistic hope of achieving bus bar power as low as 6 mils per kilowatt hour, even at very low fuel costs. However, bus bar power costs in the range of 7 to 10 mils per kilowatt hour are definitely achievable using these systems.

SECTION 5

COMMENTS ON COST DATA

Since cost estimates are usually sensitive to the basic assumptions made, an effort has been made to check some of the assumptions which will significantly affect the costs calculated in the previous section. The factors checked include present system efficiency, reasonableness of inlet temperatures, capital costs, capital charges, interest during construction, and operating costs. This section also defines the items that are assumed to be in the fuel system and hence are considered to be included in the fuel cost.

A certain amount of checking of the basic assumptions made in the United Aircraft calculations was done by consulting with Mr. Robert L. North, plant superintendent of the South Meadow Station of Hartford Electric Light Company (ref. 5) and Mr. Howard Keyton, chief mechanical engineer of the Dayton Power and Light Company (ref. 6). Mr. North has a 13 megawatt prototype, two 22 megawatt units, and four 49 megawatt units of the gas turbine type. These systems are not coupled with steam turbines, but are used independently, primarily for topping power and for emergency operations. Mr. North was present during a test run when a unit was performance tested for acceptance at a rating of 36.5 megawatts. The fuel usage during this test run was 12,370 Btu's per kilowatt hour which gives an overall efficiency of 27.6%. This efficiency is rather close to the 29.5% figure suggested by United Aircraft as being the state of the art for 1800°F inlet temperatures.

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5. North, L., Plant Superintendent, South Meadow Station, Hartford Electric Light Company, Hartford, Connecticult, personal communication, 13 August 1973.

6. Keyton, H., Chief Mechanical Engineer, Dayton Power & Light Co., Dayton, Ohio, personal communication, 15 August 1973.

That the gas turbine efficiency would increase from 29.5% to 32% to 37% as the gas turbine inlet temperatures increase from 1800°F to 2200°F to 2600°F seems reasonable. Based upon turbine exit gas temperatures of 1100°F, the Carnot efficiencies for inlet temperatures of 1800, 2200, and 2600°F are 31.0, 41.6, and 49.0% respectively. The Carnot efficiency, therefore, is increasing even more rapidly than the predicted gas turbine efficiencies.

The capital costs expected for COGAS systems in the 200 to 260 megawatt range have been evaluated extensively by Dayton Power & Light Company. According to Mr. Howard Keyton, their evaluation of five systems from three different manufacturers showed that the capital cost in this size range varied from $160 to $180 per kilowatt (1976 dollars) and that the heating rate for these units ranged from 8100 to 8800 Btu's per kilowatt. The figure of $161 per kilowatt for the present state-of-the-art COGAS system quoted earlier obviously falls in this range. The heating rate of 8100 Btu's per kilowatt corresponds to an overall system efficiency of 42.1%, which compares quite closely with the 41.4% predicted for a 29.5% gas turbine efficiency as shown in Figure 2. Since this study was completed by Dayton Power & Light only recently, it was concluded that the figures on overall system efficiency and on capital cost represent the state-of the-art in the gas turbine industry rather well.

When asked about the percentage used to allow for amortization of the capital costs, Mr. Keyton said that a factor of 17.15% reflects Dayton Power & Light's recent experience. This factor allows for depreciation, interest, and taxes, and compares very well with the 17% used in the calculations in this report.

Dayton Power & Light has recently spent 7.7 million dollars in interest on an 81.5 million dollar installation, and they have estimated that they would spend 10.4 million dollars in interest on a 111 million dollar installation which is contemplated. These factors worked out to an interest payment of 9.4%. Considering the rising interest rate, 10% has been used in these calculations.

The most controversial item in the cost estimate is the 1.0 mil per kilowatt allowance for operation and maintenance. According to Mr. Keyton, the labor to operate gas turbines is virtually non-existent since they can be started remotely by pushing a button and need only very cursory surveillance while operating. The major cost for gas turbines to date has been in maintenance. At Dayton Power and Light maintenance costs for gas turbines have averaged 3.6 mils per kilowatt for one type of unit, and 1.3 mils per kilowatt for another which has yet to have its first major overhaul. Another utility, in New York state, experienced a maintenance cost for gas turbines ranging from 3 to 5 mils per kilowatt.

Mr. North stated that the maintenance cost on their gas turbines was initially only 0.52 mil per kilowatt hour, when they were running at 1800°F. This figure, however, rose considerably as temperatures were boosted to 1900°F to get increased power from the turbines. This gives credibility that 1800°F is truly achievable today, but this is very near the limit of the capability of existing gas turbines. Mr. North also stated that these turbines had an availability of 99.3% and that they had a start-up reliability of 93.1% over a period of 7,831 start-ups.

The reasons for high maintenance costs for gas turbines are 1) the units have not been designed with minimum maintenance cost in mind, 2) the units have been pushed fairly hard in many cases, stretching the maximum use temperatures and increasing the wear on them, and 3) the fuels used often do not meet the manufacturer's specifications. Clean fuels with a minimum of particulate inclusion are definitely recommended for gas turbines, yet they are occasionally fed fuels containing particulates or corrosive materials such as salt water. The manufacturers are making strenuous efforts to design the next generation of gas turbines so that they will have markedly less maintenance requirements, and hopefully the overall combined system maintenance cost can be kept down near 1 mil per kilowatt.

According to Mr. Keyton, the figures on maintenance cost for six different installations of steam turbines varied from 0.6 to 1.0 mil per kilowatt, with the newer units having the lower figure. Since the maintenance costs for the steam turbine subsystem will be averaged in with those for the gas turbine subsystem, the latter could run over 1.0 mil/KWH and still have this figure as an average for the combined cycle plant. Based upon Mr. North's experience and the probable improvement in system reliability expected with further design modifications by the manufacturers, I have decided to accept 1.0 mil/KWH as reasonable.

The numbers given in the previous section have been generated from previous studies at United Aircraft Research Laboratories which were not specifically oriented along the objectives of this task. The numbers in this report have been pulled together from previous studies and are logically consistent within themselves, but are not comparable with other turbine efficiency numbers from other sources, unless exactly the same basic assumptions are used. For instance, higher gas turbine efficiencies can be obtained for a given inlet temperature if one wishes to maximize the gas turbine efficiency rather than maximize the overall combined cycle power plant efficiency.

Another major simplification made in this study is that many of the design criteria and cost factors were held constant during these studies to simplify them. In more exhaustive accurate calculations, one would optimize the COGAS system over a range of conditions for each inlet turbine temperature and fuel cost combination. This was not done in this case.

In practice, when the COGAS systems are designed, the gasification system is thoroughly integrated with the gas turbine and steam turbine subsystems. As a result of this integration, it is not always easy to determine exactly which pieces of equipment and what system power costs should be charged against the gasification and desulfurization system, and which ones should be charged against the two power-producing subsystems. In this study we have assumed that the capital and operating costs of the air compressor to supply air for the gasification system would be charged to the fuel cost.

Since the capital cost of this compressor is \$20 to \$25 per kilowatt, and its power consumption is likely to be 6 to 9% of the total power station power output, this is a highly significant cost item and it is important that its effect be included in the cost of fuel in cents per million Btu's. There are additional heat exchangers for fuels over and above the waste heat boiler, which are also included in the fuel cost. Also, due to the incremental cost for flow of steam from the gasification process, one should add additional costs for the superheater steam turbine generator set, condenser, and deaerator of the steam turbine subsystem to the fuel cost. This additional capacity in this subsystem could add as much as \$30 per kilowatt to its capital cost.

SECTION 6

RESEARCH NEEDS

It is apparent from examining the figures in Figure 3 that considerable gains in an overall system efficiency are possible if higher inlet turbine temperatures could be utilized in gas turbines. Unfortunately, much of the technology which in the past has been used as a basis for developing higher operating temperatures for gas turbines has come out of military and aerospace R&D programs, which now have been drastically cut back. The key areas which need further development are either better materials or better cooling methods in order to achieve the higher temperatures while retaining the necessary "creep" resistance and corrosion resistance to keep the turbine working effectively.

Over the past decade, the rate of rise of inlet turbine temperatures which have been utilized has risen at a nearly linear rate of approximately 70°F per year. This is shown in Figure 5 (ref. 2). In order to sustain and even slightly increase this rate of increase to 90°F per year, it will require an investment of three to five million dollars per year of of seed money from some governmental source. Since this is not forthcoming from the Department of Defense or NASA, another source is needed. This fund of three to five million dollars per year, it should be noted, should be spent with one prime contractor and should be spent over a period of several years to insure that the work started is actually brought to an effective fruition. This program should start at the lower level of funding and increase to the five million dollar figure. Since it takes four years for a gas turbine to be developed after the research on which

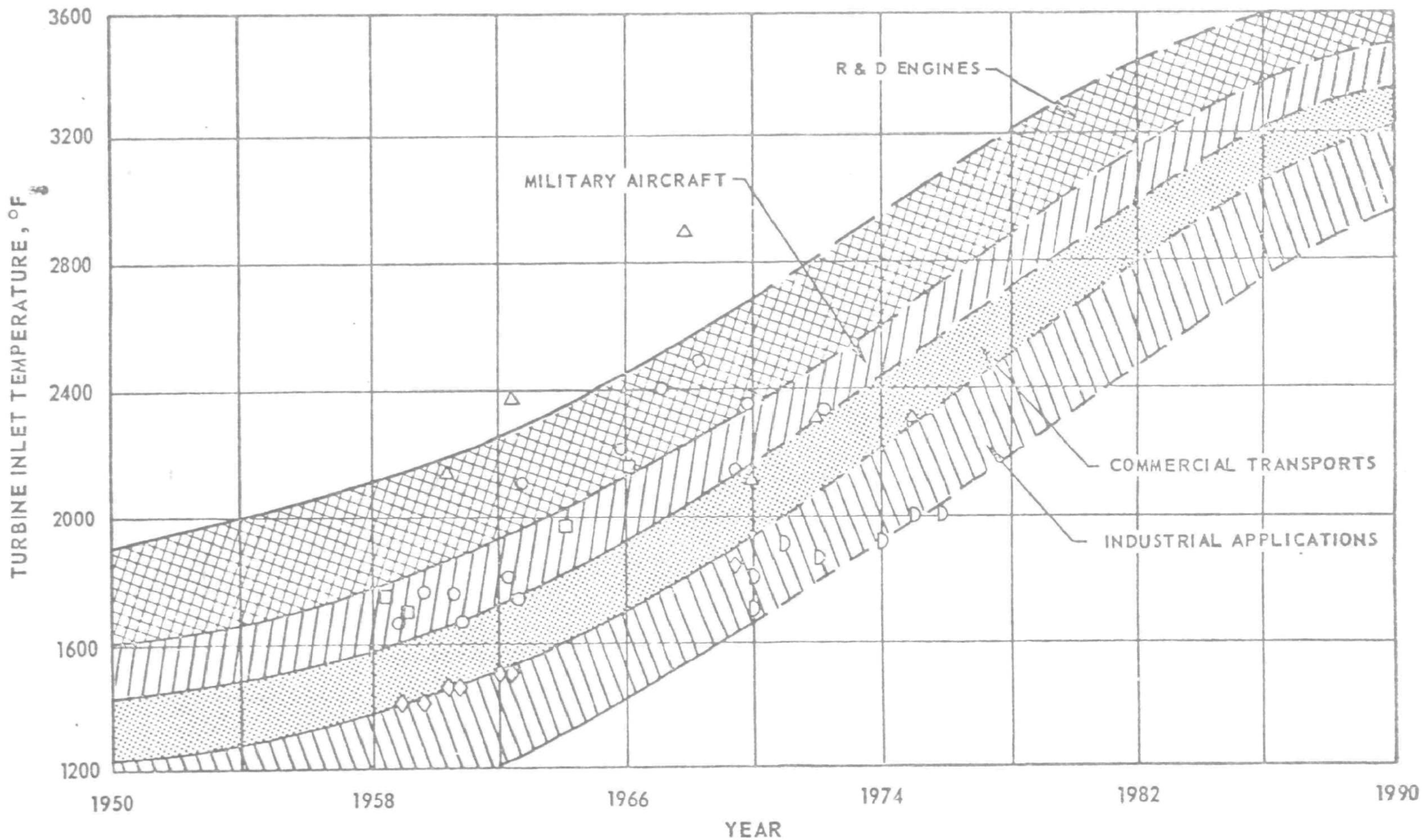

Figure 5. Progression of Estimated Gas Turbine Inlet Temperatures

it is based is available, reaching the goal of 2600°F, which is scheduled for 1982, would require that this investment start now and continue until the year 1978. This research program would include work both on cooling methods, and on new materials, such as ceramics having higher temperature capabilities.

The efficiency of a gas turbine is directly related to the inlet temperature of the turbine section. To insure long lifetimes, metal temperatures of rotating components should be kept to 1500°F or lower. Current techniques use high-pressure air bled from the compressor to cool the turbine blades. Such techniques allow temperatures of over 2200°F to be attained, but higher temperatures could require air flows beyond the capability of available bleed flows, i.e. the performance benefits of bleed flow cooling are outweighed by the performance degradation due to the high flow of bleed air which is unavailable to do work.

The use of water to cool the blades would not cause performance degradation and could actually contribute some work. There are several alternative methods of water cooling available and the merits of these systems should be evaluated.

As an alternative to various cooling techniques to keep material temperature to 1500°F, ceramics operating at temperatures of 2000°F$^+$ could result in higher turbine operating conditions without associated cooling penalties. Ceramics could be used in burners, seals, nozzles, and eventually blades. Currently, several research programs are being carried out in this area, but applications may be difficult to implement in larger size gas turbines.

In addition to these studies on directly finding ways to increase the operating temperatures, tests also ought to be run on the utilization of low Btu fuel in gas turbines. Analytical studies should identify any additional hardware problems which will need work to implement the use of this low Btu gas at the higher temperatures in gas turbines.

Although preliminary rig-type tests have been made on the combustion of fuel gases varying from 100 to 140 Btu/scf, much remains to be done before such combustion systems can be commercially realized. A series of analytical and experimental tests on high pressure combustion rigs, and on the formation of NO_x from combusting low-Btu gas, needs to be carried out. Burner can modifications must be identified and suitably redesigned cans should be fabricated and run on a full-scale engine.

A series of analytical studies of advanced power cycle concepts should be carried out with the objective of identifying specific hardware development programs. Such studies could be extensions of current EPA-sponsored efforts or could be in new areas. For example, a current EPA-sponsored study deals with integrating coal gasifiers, low- and high-temperature cleanup processes, and combined-cycle systems. Part of this study is devoted to identifying the areas of technology needing exploration in order to realize the advantages of the integrated system. There will be a need to further analyze the various technology areas identified in order to define actual programs needed to bring the required areas to commercial realization.

The study on the use of low Btu fuel would require an expenditure of two million dollars over a two to three year period. The analytical study to identify further problems would be a two or four man year study costing on the order of $100,000 to $200,000 over a one year period.

The above comments on research needs were suggested by Dr. Robson and Mr. Giramonti of United Aircraft (ref. 3, 4). These recommendations were reviewed with a representative of General Electric Company, Mr. Donald R. Plumley (ref. 7). Mr. Plumley basically agreed rather closely with the United Aircraft suggestions. He suggested that the present state-of-the-art temperature can be throught of as being approximately 1850°F, and that gas turbine efficiencies of 37% and temperatures of 2600°F are definitely reasonable goals for ultimate achievement at the end of the decade.

The programs to develop water cooling of turbine blades and investigate the use of ceramics were heartily endorsed by Mr. Plumley. He did suggest, however, that the amounts of money to be invested in them might well need to be in the four to eight million dollar range per year. Mr. Plumley suggested that some work could be included on finding metals with creep and corrosion resistance adequate for turbine usage above 1500°F, although the improvements in these materials might be small compared to the effect of finding ceramics which would operate at 2600°F. He also suggested that work might profitably be done on finding ways to increase the pressure ratio since gas turbines operating at higher temperatures have a tendency to be more efficient if higher pressures are also used.

Mr. Plumley pointed out that this program did not include any studies on fabrication technology for these materials at higher temperatures. This is an additional area in which monies could be profitably expended, although there is a tendency for all of the manufacturers to do their own work in this area. Development work of this type tends to be expensive, however, and more monies could be profitably spent in the development of gas turbines by funding fabrication studies.

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7. Plumley, D.R., Manager, Operations Planning, Gas Turbines Products Division, General Electric Co., Schenectady, N.Y. personal communication, 17 August 1973.

Mr. Plumley reported that studies on combustion of low Btu fuel gases and analytical studies on integration of the subsystems in the COGAS system are currently being made by his company and also by Westinghouse, and government programs funded at this time in these areas would therefore probably be too late as far as they were concerned.

In general Mr. Plumley agreed that the principal research areas suggested by Dr. Robson and Mr. Giramonti were the ones which needed work, that government funding would be necessary to bring about the improved efficiencies they envision as possible, and that the amounts of money to be spent should be several million dollars per year for several years to have a high probability of reaching gas turbine efficiencies of 37% within 10 years.

SECTION 7

COMMENTS ON THIS STUDY

The above analysis of research needs has focused only on the gas turbine subsystem. Since the steam turbine subsystem has already been developed very well, no further research is needed in this area. The same is not true, however, of the gasification and desulfurization systems. Investment in sizable research programs to advance gas turbine subsystem technology to higher efficiencies has some desirability even without coal gasification desulfurization systems, in that the higher efficiency of the combined cycles would reduce the amount of fuel burned per kilowatt hour produced by as much as one-third, hence reducing pollution produced. However, to get pollution levels down to those desired in the EPA standards, it would be necessary also to continue to push coal gasification and desulfurization systems which could work with these gas turbine systems. The cost of these continuing developments in coal gasification and desulfurization will probably be much greater than that needed for research on gas turbine efficiency improvement.

The task order for this work suggested a range of fuel costs from 30 to 70 cents per million Btu's. Discussions with Dr. Paul Spaite indicated that gasified desulfurized fuels would probably be more expensive than this (ref. 8), so we increased the range of fuel costs to 40 to 100 cents/10^6 Btu for this study. When these systems are finally developed however, there is no guarantee that fuel costs will not exceed one dollar per million Btu's. Calculations could be made for higher fuel costs if so desired, based on the methods used in this report.

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8. Spaite, P., Consultant to EPA, Cincinnati, Ohio, personal communication, 6 August 1973.

Finally, it should be repeated that the figures in this study are based upon many assumptions. These assumptions have been checked as well as possible within the limited time available, and they seem reasonable. These calculations, however, have not been optimized for each individual condition, hence these costs should not be used for detailed comparisons with other cost figures on similar systems.

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7. Plumley, D. R., Manager, Operations Planning, Gas Turbines Products Division, General Electric Co., Schenectady, New York, personal communication, 17 August 17, 1973.

8. Spaite, P., Consultant to EPA, Cincinnati, Ohio, personal communication, 6 August 1973.

TECHNICAL REPORT DATA

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1. REPORT NO. EPA-650/2-74-041	2.	3. RECIPIENT'S ACCESSION NO.
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15. SUPPLEMENTARY NOTES

16. ABSTRACT The report gives results of a study of the effect of gas turbine efficiency and fuel cost on the cost of producing electric power. It indicates that combining gas and steam turbines (COGAS systems) can increase overall power generation efficiency. It tabulates gas turbine efficiencies which must be achieved to produce power at costs of 6-10 mills per kWh, as a function of fuel costs of 40-100 cents per million Btu. Improved gas turbine efficiency of 29-37 percent is seen over the next 9 years, resulting in combined cycle efficiencies of 42-54 percent. Improved research envisioned, which would improve gas turbine efficiency, is primarily that which will increase gas turbine operating temperature. The level of effort needed to increase operating temperatures at this rate is expected to be an additional $3-8 million per year for research. Combined with other work by gas turbine manufacturers, this effort could be expected to increase turbine inlet temperatures by an average of 90°F per year, which is enough to increase gas turbine efficiency at the rate of almost 1 percent per year.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS		b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Air Pollution	Steam Electric Power Generation	Air Pollution Control	13B
Gas Turbine Power Generation	Electric Power Generation	Stationary Sources	
Gas Turbines	Cost Effectiveness	Gas Turbine Temperature	10A
Temperature		Combined Cycle	13G
Steam Turbines		COGAS Systems	14A
		Fuel Costs	

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