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ORNL/HUD/MIUS-27

USE OF COAL AND COAL-DERIVED FUELS IN TOTAL ENERGY SYSTEMS FOR MIUS APPLICATIONS

VOLUME I, SUMMARY REPORT

U.S. DEPARTMENT OF HOUSING AND URBAN DEVELOPMENT

hudmius

MODULAR INTEGRATED UTILITY SYSTEMS

improving community utility services/ supplying electricity, heating, cooling, and water/ processing liquid and solid wastes/ conserving energy and natural resources/ minimizing environmental impact

ENERGY RESEARCH & DEVELOPMENT ADMINISTRATION USA

ERDA - FOSSIL ENERGY

DIVISION OF COAL CONVERSION AND UTILIZATION

MASTER

OAK RIDGE NATIONAL LABORATORY

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Printed in the United States of America. Available from
National Technical Information Service
U.S. Department of Commerce
5285 Port Royal Road, Springfield, Virginia 22161
Price: Printed Copy $4.50; Microfiche $2.25

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ORNL/HUD/MIUS-27
UC-90e

Contract No. W-7405-eng-26

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Volume I, Summary Report

A. P. Fraas

T. D. Anderson
W. J. Boegly, Jr.
J. H. DeVan
R. S. Holcomb
H. Inouye
M. E. Lackey
S. A. Reed
P. L. Rittenhouse
G. Samuels
C. L. Segaser
J. J. Tudor

Research sponsored jointly by the

Division of Energy, Building Technology and Standards
Office of Policy Development and Research
U.S. Department of Housing and Urban Development
under
HUD Interagency Agreement No. IAA-H-40-72 ERDA 40-333-72

and

Division of Coal Conversion and Utilization
Office of Fossil Energy
Energy Research and Development Administration
under
ERDA Contract No. E(49-18)-1742

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APRIL 1976

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FOREWORD

The Department of Housing and Urban Development (HUD) is conducting the Modular Integrated Utility System (MIUS) Program, which is devoted to development and demonstration of the technical, economic, and institutional advantages of integrating the systems for providing all or several of the utility services for a community. The utility services include electric power, heating and cooling, potable water, liquid waste treatment, and solid waste management. The objective of the MIUS concept is to provide the desired utility services consistent with reduced use of critical natural resources, protection of the environment, and minimized cost. The program goal is to foster, by effective development and demonstration, early implementation of the integrated utility system concept by the organization, private or public, selected by a given community to provide its utilities.

A program for developing a coal-fueled MIUS at the Oak Ridge National Laboratory (ORNL) is being jointly sponsored by the Department of Housing and Urban Development, Office of Policy Development and Research; and the Energy Research and Development Administration, Fossil Energy (formerly Office of Coal Research of the Interior Department). The objectives of Phase I of the program, "Concept Preliminary Evaluation," were the investigation and evaluation of various ways in which coal and coal-derived fuels might be employed in MIUS systems. The results of this evaluation are presented in this report. Volume I is a summary of the results and Volume II is a complete report of the work. The fuels considered include high and low sulfur bituminous coals, lignite, anthracite, the products of various coal gasification, liquefaction, and solvent refining processes, coal loaded with sewage sludge after being used as a filtering medium, and coal mixed with residential and industrial solid wastes. The potential performance of all types of power conversion systems that might be used with these fuels were evaluated together with the problems foreseen in the development effort for each system.

Under HUD direction several agencies are participating in the HUD-MIUS Program; these include the Energy Research and Development Administration, the Environmental Protection Agency, the National Aeronautics and Space Administration, the Department of Commerce, the National Bureau of Standards, the Department of Defense, the Department of Health, Education and Welfare, and the Department of the Interior.

ABSTRACT

A program for developing a coal-fueled Modular Integrated Utility System (MIUS) at the Oak Ridge National Laboratory is being jointly sponsored by the Department of Housing and Urban Development, Office of Policy Development and Research; and the Energy Research and Development Administration, Fossil Energy (formerly Office of Coal Research of the Interior Department). The objectives of Phase I of the program, "Concept Preliminary Evaluation," were the investigation and evaluation of various ways in which coal and coal-derived fuels might be employed in MIUS systems. The results of this evaluation are presented in this report. Volume I is a summary of the results and Volume II is a complete report of the work.

The fuels considered in the study include high and low sulfur bituminous coals, lignite, anthracite, the products of various coal gasification, liquefaction, and solvent refining processes, coal loaded with sewage sludge after being used as a filtering medium, and coal mixed with residential and industrial solid wastes. The types of power conversion systems considered for use with these fuels include gas engine, diesel engine, conventional gas turbine, open and closed cycle gas turbine with fluidized bed furnace, steam turbine and engine with conventional furnace, and steam turbine and engine with fluidized bed furnace.

The principal conclusions of the study are as follows:

1. MIUS systems based on small, on-site coal gasification or liquefaction plants would have much higher capital and operating costs than systems in which coal is burned directly.

2. A fluidized bed combustion system in which coal is burned in a bed of limestone appears to be the most attractive system for direct utilization of coal. The advantages of this system include making it possible to reduce the sulfur emissions in the stack gas by a factor of about ten, so that burning high-sulfur coal can be made environmentally acceptable, and the ability to burn any type of coal or lignite or solid waste.

3. A closed cycle gas turbine coupled to a fluidized bed coal combustion system appears to be the most promising system for using coal for MIUS applications. Analyses indicate that this system will convert about 30% of the energy in the fuel to electricity and about 50% into heat that can be used for domestic hot water and building heating and air conditioning.

INTRODUCTION

A program for developing a coal-fueled Modular Integrated Utility System (MIUS) is being jointly sponsored at the Oak Ridge National Laboratory (ORNL) by the Department of Housing and Urban Development (HUD), Office of Policy Development and Research; and the Energy Research and Development Administration (ERDA), Fossil Energy (formerly Office of Coal Research of the Interior Department). This program had its inception some years ago when HUD foresaw the impending energy shortage and initiated work on small total energy systems for use with new housing complexes. In these systems the waste heat from the thermodynamic cycle used to generate electricity is used to heat both domestic hot water and buildings in the winter and for absorption air conditioning systems in the summer. ORNL has been assisting HUD in this work, first by looking at the problems of supplying heat to building complexes from district heating systems tied to central stations,[1] and subsequently by examining various small total energy systems. Hundreds of such systems are in use currently in the U.S. making use of diesel or gas engines or small gas turbines.

The shortages of gas and fuel oil that began to develop early in 1973 led to an examination of the possibilities of employing coal on-site as the fuel, particularly moderately high sulfur coal because of its ready availability. A review of the problems of sulfur removal favored a fluidized bed coal combustion system such as that shown in Fig. 1. The combustion air is blown up through a perforated bed plate to fluidize a bed of particles. This system makes it possible to remove about 90% of the sulfur in the coal by combining it with crushed limestone in the bed to give calcium sulfate. A tube bank in the bed must be employed to remove about half the heat of combustion and thus keep the bed temperature to the range of 1500 to 1700°F, the region for good conversion of the sulfur to calcium sulfate. Operation at this temperature also serves to minimize NO_x formation and avoids fusion of the ash. The fluidized bed combustion system also operates well with liquid or gaseous fuel, char, a low sulfur coal, or solid organic waste, hence it can serve as an incinerator.

The majority of the housing complexes sponsored by HUD have involved 500 to 1000 residential units for which the electric power requirements

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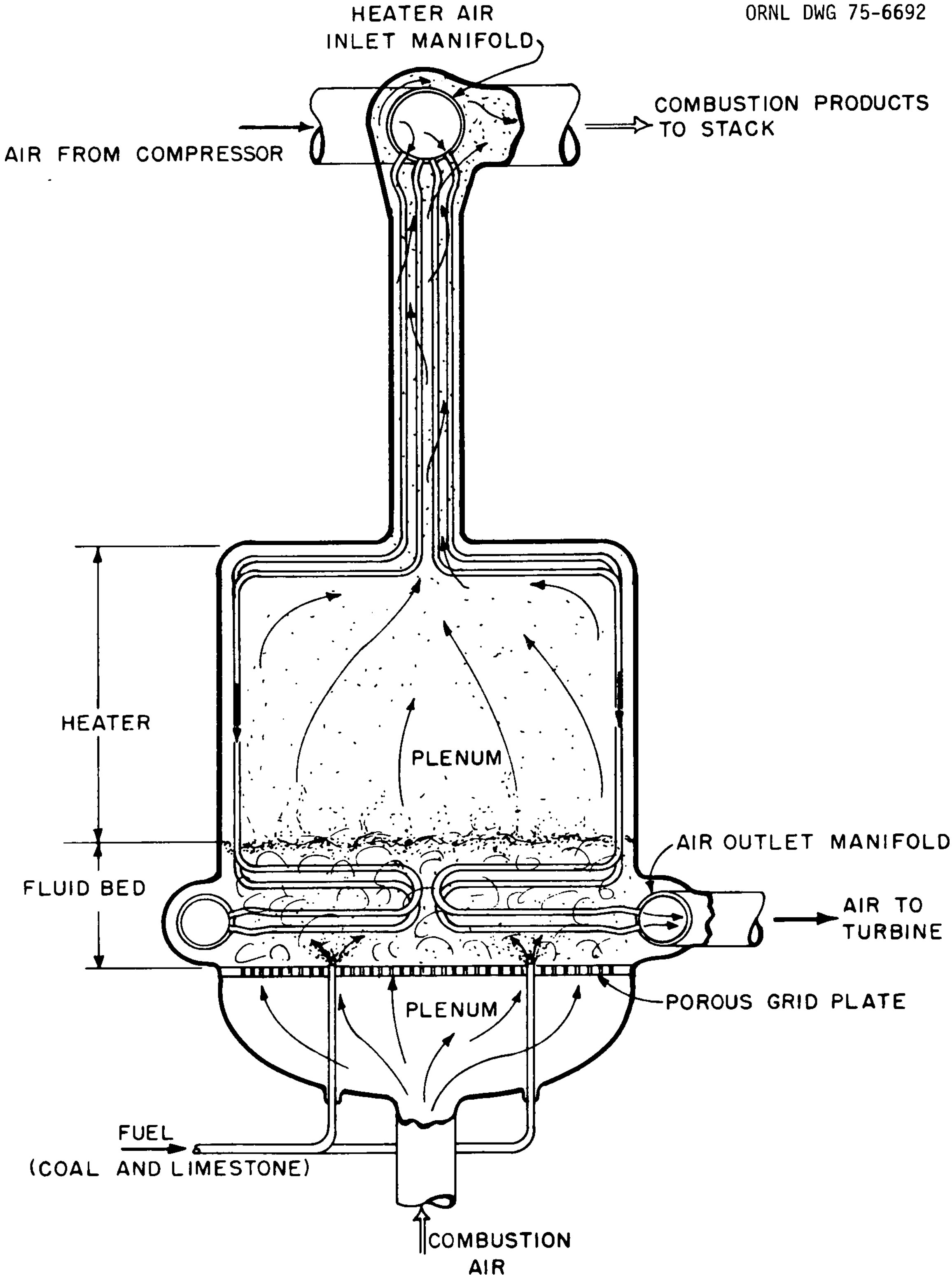

Fig. 1. Schematic Diagram showing a fluidized bed coal combustion system designed as the heat source for a closed cycle gas turbine.

have run 1 to 2 MW(e). Extensive experience with power plants for installations of this sort indicates that to obtain good reliability from diesel or gas engines or conventional gas turbines it is essential to employ four or more units in parallel. Because of seasonal and diurnal variations in the load, the load factor is normally only 60 to 70%. Thus, for an installation designed for a full load of 1.5 MW(e), the usual practice is to employ four engine-generator units of about 600 kW(e) of which two would normally be in operation, one would be on standby for load peaks in unfavorable weather, and the fourth could be down for maintenance. Thus, the design power output range of interest for MIUS applications is 500 kW(e) to 1000 kW(e) per unit. This is an important factor in choosing a power conversion system because some systems (e.g., steam turbines) do not perform well in small sizes.

In selecting a power conversion system, the poor efficiency of a steam turbine relative to a gas turbine in the size range of interest here makes the latter a logical candidate for the thermodynamic cycle. Inasmuch as the air fed to the turbine will be heated by the tube bank in the fluidized bed and will not contain fly ash or corrosive gases from the coal, turbine bucket erosion and corrosion will not be problems. A preliminary study indicated that with a closed cycle gas turbine system around 80% of the energy in the fuel would be available for use, about one-third as electricity and the balance as heat in the form of 250°F hot water obtained from a waste heat recovery heat exchanger.

This appeared sufficiently attractive that ORNL proposed to HUD that a thorough study of the concept be initiated,[2] and, if this proved favorable, that a program be launched to design, develop, and construct a demonstration unit. HUD then approached OCR, and this led to an agreement between them to sponsor such a program.[3] Arrangements were then made with the USAEC for ORNL to undertake this work. The objectives of Phase I of the program, "Concept Preliminary Evaluation," were stated in the HUD/OCR Memorandum of Understanding[3] to be the investigation and evaluation of various ways in which coal and coal-derived fuels might be employed in MIUS systems. The fuels to be considered include high and low sulfur bituminous coals, lignite, anthracite, the products of various coal gasification, liquefaction, and solvent refining processes, coal loaded with sewage sludge after being used as a filtering medium, and coal mixed with residential and industrial solid wastes. The potential performance of all types of power conversion system that might be used with these fuels were to be evaluated together with the problems foreseen in the development effort for each system. This report has been prepared to summarize the results of the Phase I study. A much more comprehensive report covering the details of the study is presented in Volume II.

SUMMARY AND CONCLUSIONS

The principal results of the concept evaluation work may be summarized as follows:

1. Over half the population of the U.S. lives in urban areas east of the Mississippi and north of Memphis where the major fuel reserves are coal, and 90% of this coal has a sulfur content over 0.7%, approximately the upper limit allowable for fuels in most urban areas unless some sulfur removal system is employed. Thus, there is a strong incentive to develop a MIUS system that could operate on high sulfur coal and yet meet air quality standards.
2. MIUS systems based on small, on-site, coal gasification or liquefaction plants would have capital costs about four times that of any of about a dozen other systems considered, and their requirements for operating personnel would yield operating costs about ten times those for the other systems.
3. Extensive tests indicate that burning coal in a fluidized bed of limestone will reduce the sulfur emissions in the stack gas by a factor of about ten and will yield low NO_x emissions (of the order of 20 to 100 ppm). Further, a fluidized bed combustion system can be fueled with any type of coal or lignite or solid waste.
4. Analyses indicate that the fluidized bed coal combustion system coupled to a closed cycle gas turbine will convert about 30% of the energy in the fuel into electricity and about 50% into heat that can be used for domestic hot water

and building heating and air conditioning. This gives a good balance between the electrical and heat energy requirements of a building complex, and utilization of about 80% of the energy theoretically available in the coal except during mild weather when the load demand for building heating or air conditioning is low.

5. A closed cycle gas turbine appears to be better than an open cycle unit for MIUS applications because its efficiency is much better under part-load conditions (which represent the bulk of the operating time), and because it makes possible an increase in the system pressure by a factor of about three which in turn will cut the size and cost of the heat exchangers by a factor of about two.
6. Nine closed cycle gas turbine plants are in use in Europe burning coal, lignite, oil, gas, and industrial wastes. These units have demonstrated good reliability.
7. Over 200 fluidized bed combustion systems for roasting pyrite ores are in use in the U.S., and over 100 fluidized bed combustion systems are in use for incinerating industrial wastes and sludge from domestic sewage plants, and a high degree of reliability has been demonstrated for these units.
8. Control under part-load conditions has been a major problem in efforts to develop fluidized bed coal combustion systems coupled to steam boilers. There are basic differences in the heat transfer mechanism and conditions between steam boilers and heaters for gas turbines so that there should not be a difficult problem in starting, stopping, or running a fluidized bed combustion system over a substantial load range when coupled to a gas turbine.
9. The principal uncertainties in developing a fluidized bed coal combustion system coupled to a gas turbine appear to be the limitations on the life of the tube matrix in the fluidized bed that will be imposed by hot gas corrosion and/or erosion, and the reliability of the coal and limestone feed system. The former presents complex basic

problems in materials compatibility that may prove to be extremely difficult; the latter presents difficult mechanical design problems that appear to be tractable.

10. There are numerous other problems that will require first class engineering work. These include the design of the bed support structure with its air tuyeres and fuel feed ports, the design of the air heater tube matrix and manifold system, the adaptation of an existing gas turbine to the proposed system, the control scheme for a truly new system, and overall system design for high reliability and long life.
11. In the balance, the proposed fluidized bed coal combustion system coupled to a gas turbine appears to have outstanding advantages over any other system for using coal for MIUS applications, and merits firm support because of the large contribution to the nation's energy requirements that it has the potential of making.
12. The small plant size required for MIUS applications coupled with the much easier control problems for a fluidized bed coupled to a gas turbine as opposed to a steam boiler may make it possible to develop the proposed system for commercial use sooner than may be possible for fluidized bed coal combustion steam power plants.

COST AND AVAILABILITY OF COAL AND COAL DERIVED FUELS

The world's fuel supply and cost situation has been so turbulent during the past year that it is difficult to predict the future price and availability of typical fuels. It is clear, however, that international political considerations and the balance of payments situation provide extremely strong incentives for the U.S. to employ coal as a fuel rather than natural gas or petroleum wherever possible. From the standpoint of HUD applications, roughly half the population in the United States lives in urban areas east of the Mississippi and north of the latitude of Memphis, Tennessee. Much of the reason for the development of this area has been the availability of large reserves of coal. As shown in Table 1, 90% of this coal contains substantial amounts of sulfur, so that the imposition of air quality standards in recent years has made it necessary to turn to other fuels because there was no coal burning system available that would be at once economically attractive and satisfactory from the air quality standpoint. Thus, particular attention must be given to the ways in which coal could be employed in MIUS systems that will meet EPA standards. The first and most obvious routes are to employ coal gasification or liquefaction plants that would include facilities for removing sulfur. These can be large mine-mouth or central station type plants, or they might be small, on-site systems. The latter would have a particular advantage for a coal gasification plant in that it might make possible the use of a system that would yield low Btu gas. In either case the coal gasification or liquefaction system approach has the advantage that conventional prime movers such as diesel or gas engines can be employed and no new development work other than that already underway on coal gasification or liquefaction need be undertaken.

From the standpoint of MIUS system operation there would be essentially no difference in the system design or performance between natural gas or petroleum as fuels and synthesized gas or liquid fuels from large coal gasification or liquefaction plants. Table 1 gives typical current costs of fuels, but it is not possible to predict the relative prices of these fuels in the coming decades. The possibility of small on-site coal gasification plants coupled to MIUS systems is, however, important in the study because it would strongly affect the design of the MIUS system. Thus, a major consideration is the effect of the size of coal gasification or liquefaction plants on both their capital cost and the size of the crew required for their operation. The latter is important because it represents a major factor in the operating costs of the system. Fortunately, data are available in an OCR publication[4] for the OCR projected capital cost of such plants as a function of the coal feed rate in tons per day. A long dashed line for this projection is presented in Fig. 2. Data given in the same report for the construction cost and operating crew size are also plotted in Fig. 2, and a line has been drawn through the lower portion of the scatter band of points for the operating crew size. These data will be used

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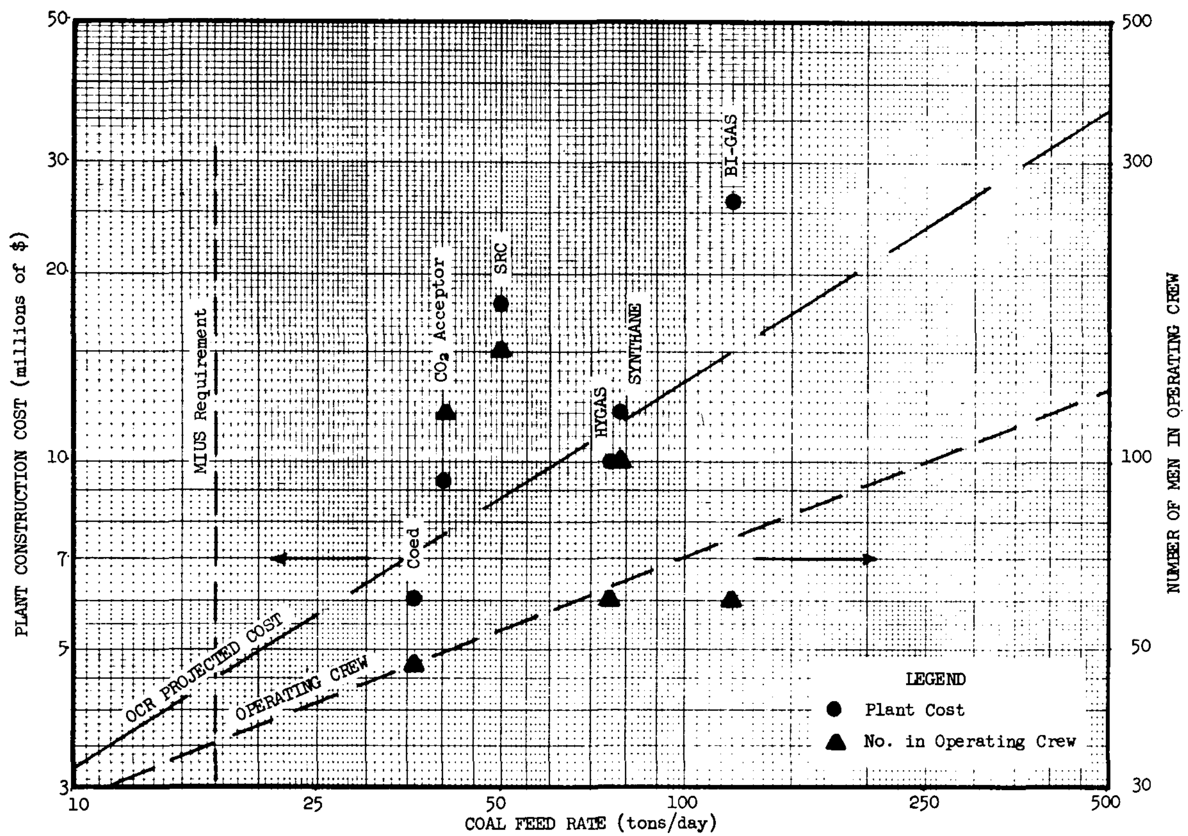

Fig. 2. Effects of plant capacity on plant construction cost and operating crew size for coal gasification and liquefaction. (Data from "Clean Energy from Coal," OCR, 1973.)

Table 1. Resources and Costs for Coal and Coal-Derived Fuels

Part A. Coal Resources by Sulfur Content
(Mapped and Explored: 0-3000 feet overburden)

	Trillion Tons	
	East of Mississippi	Total U.S.
0.7% or less sulfur	0.050	0.72
0.7% - 1.0% sulfur	0.045	0.30
1.0% - 3.0% sulfur	0.177	0.23
Over 3.0% sulfur	0.206	0.31
TOTAL	0.478	1.56

Part B. Representative Prices (f.o.b. Mine) for
Coal as of First Quarter 1974

	Heating Value (Btu/lb)	Cost/ton ($)		Cost/10^6 Btu(¢)	
		Rep. Value	Range	Rep. Value	Range
Bituminous (Eastern)					
High sulfur (>3%)	11,500	14	10-18	60	43-78
Low sulfur (<1%)	11,500	20	16-25	86	69-108
Sub-Bituminous (Western)					
Low sulfur (∿0.5%)	8,500	4.25	3.40-6.80	25	20-40
Lignite (Western)					
Low sulfur (∿0.5%)	6,750	2.50	1.60-3.25	18	12-24
Anthracite	12,700	32.50	24-45	128	79-177

Part C. Projected Cost of Coal-Derived Fuels

	Projected Price, $/$10^6$ Btu
Low or Intermediate Btu gas from coal	1.86-2.37
High Btu Coal Gasification	2.39*
Coal Liquefaction	1.58-1.92*
Solvent Refined Coal	1.07-1.30*
Methanol from Coal	2.91*

*Cost at mine-mouth exclusive of transportation costs.

in the next section for appraising the relative merits of on-site coal gasification and liquefaction plants with respect to fluidized bed coal combustion systems. It should be mentioned that an independent comprehensive study at ORNL has yielded substantially the same values as OCR projections in Fig. 2.

COMPARISON OF TYPES OF COMBUSTION SYSTEMS

Many different types of burners have been developed, generally with the characteristics of some particular fuel or some particular application in mind. The four principal types of combustion systems in current use are listed in Table 2 along with the principal fuels of interest in this study. In the matrix thus formed in Table 2 an x has been used to indicate

Table 2. Suitability of Typical Combustion Systems for Use with Different Types of Fuel for Installations Designed to Meet EPA Standards Without Equipment for Removing Sulfur from the Stack Gases

Type of Fuel	Stationary Grate	Moving Grate	Open Burner	Fluidized Bed
High sulfur bituminous coal				x
Low sulfur bituminous coal	x	x	x	x
Lignite	x	x	x	x
Anthracite	x	x	x	x
Char (from coal conversion plants)			?	x
Natural and high Btu gas			x	x
Medium Btu gas			x	x
Low Btu gas			x	x
No. 2 fuel oil			x	x
Residual fuel oil-low sulfur			x	?
Residual fuel oil-high sulfur				?
Liquid fuel from coal			x	?
Domestic solid waste + coal		x		x
Sewage sludge + coal		x		x
Wood waste + coal				x

wherever a fuel is suitable for use in a given type of burner with the proviso that no extra equipment be provided to reduce the sulfur content of the stack gases in order to meet EPA standards. For example, one could not use stationary grate or traveling grate combustion systems nor powdered coal open flame burners with high sulfur coal because the stack gases could not be released without special treatment and still meet EPA standards. An examination of Table 1 indicates that only the fluidized bed combustion system would serve to burn any of the types of fuel that were specified by OCR in the memorandum delineating the objectives of this study.

The practicality of employing a fluidized bed combustion system has been investigated by surveying the fluidized bed combustion systems in current use, as summarized in Table 3. Over 200 fluidized bed combustion systems are employed for roasting pyrite ores including copper, iron, zinc, and nickel sulfide.[5] Many of these systems employ water-cooled coils in the fluidized beds to remove heat and thus maintain the bed temperature in the proper range for yielding the product desired from the particular roasting operation. In most cases these units are used to produce both a metal ore for subsequent reduction and either sulfuric acid or sodium sulfite for paper pulp manufacture. In addition, about 140 fluidized bed combustion systems are in use as incinerators for disposing of both solid waste and aqueous suspensions of solids such as sludge from domestic sewage plants.[6] In the latter case the aqueous suspension must contain at least 35% by weight organic material to maintain the bed temperature or else auxiliary fuel must be provided. Thus, there is extensive experience totalling many hours of operation of fluidized bed combustion systems employing fuels other than coal. Although the experience with burning coal in fluidized beds has been limited to experimental units, it is evident that a substantial quantity of experience indicates that this approach is indeed feasible, and does not present any basic problems that are fundamentally different from those of fluidized beds employed for roasting sulfide ores or for incinerating wastes.

The principal problems associated with burning high sulfur coal in a fluidized bed are those associated with control of the bed temperature and the limestone feed rate to minimize emissions of SO_2. Some typical curves indicating these effects are presented in Fig. 3 for operation with

Table 3. Summary of Operating Experience with Fluidized Bed Combustion Systems

Organization Responsible for Design and Construction	Fuel	Objective	Sum Total Operating Time-hour
Copeland Systems, Inc.	Wood waste, pulp mill waste, misc. organic wastes	Incineration, in some cases heat recovery	$\sim 10^6$
Dorr-Oliver, Inc.	Sewage sludge	Incineration	$\sim 10^6$
	Pyrites	Roasting to yield SO for acid or sulfite and/or metal oxide for reduction	$\sim 3 \times 10^6$
BCURA	Coal	R&D on fluidized bed combustion of coal and high sulfur residual fuel oil	$\sim 10^4$
Pope, Evans, and Robbins, Inc.	Coal	R&D on fluidized bed combustion of coal	~ 9000
Argonne National Laboratory	Coal	R&D on fluidized bed combustion of coal and lime regeneration	700
Combustion Power, Inc.	Municipal solid waste, wood waste and coal	Incineration with electrical energy as a by-product	471 (total on bed) 271 (with turbine)
Esso Research	Coal	R&D on coal combustion and lime regeneration	~ 100

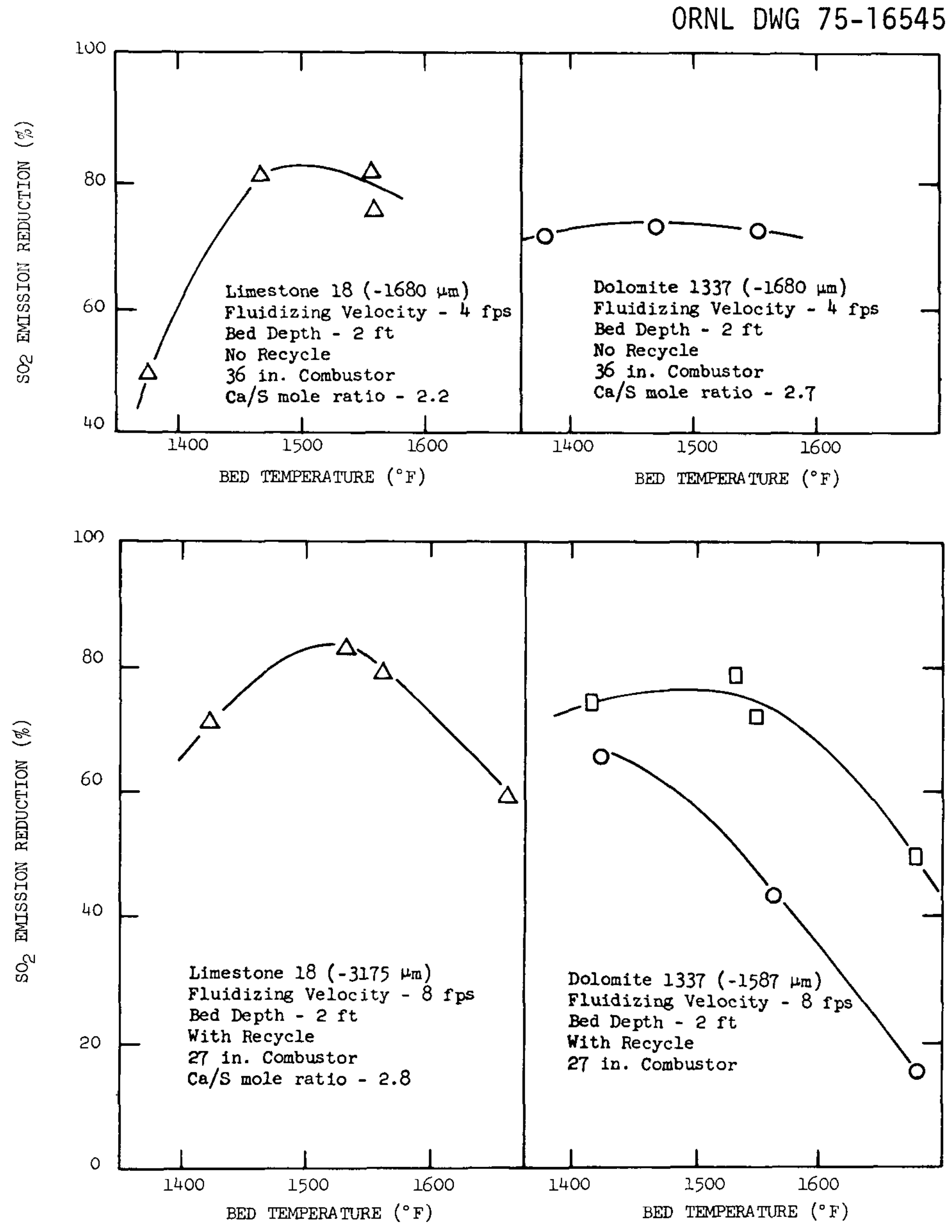

Fig. 3. Effect of bed temperature on SO_2 reduction for Pittsburgh coal (Ref. 4)

representive coal and limestone feed materials. Apparently many factors influence the effectiveness of the limestone in retaining sulfur in the bed; recent work at BCURA indicates that as much as 98.5% of the sulfur can be retained in the bed at a temperature of 1750°F and a calcium-sulfur ratio of about 2.[7] In this same series of tests the NO_x content of the stack gases ran between 25 and 100 ppm for amounts of excess air ranging from 5 to 10%. Thus, it appears that the fluidized bed coal combustion system makes it possible to keep the emissions of SO_2 and NO_x well within EPA standards even when burning relatively high sulfur coal.

COMPARISON OF THE PERFORMANCE AND COST OF TYPICAL SYSTEMS WITH DIFFERENT FUELS

A wide variety of different power conversion systems operating on some six different fuels have been considered as sources of electrical and thermal energy for building complexes of the sort envisioned for MIUS application. Five reference cases with central stations supplying electricity were considered. The first of these made use of gas-fired steam boilers at the site of the building complex to supply domestic hot water and heat for the buildings in winter. Electric motor-driven Freon compressors were assumed for supplying air conditioning in the summer. The second case considered was an all electric installation with electricity used for heating the buildings and the domestic hot water supply. The third case considered made use of electricity from a central station to drive electric motor-driven heat pumps to take care of both building heating in the winter and air conditioning in the summer. The fourth case considered was a central station coupled to a district heating system which would distribute superheated water through a system of mains to an entire city. The fifth case again entailed a central station coupled to a district heating system but in this instance one making use of a light water reactor. These reference cases were then compared with 12 different MIUS systems. The first of these made use of conventional gas engines operated on natural gas with heat recovery from the engine jackets and waste heat boilers in the exhaust gas system. A second system was similar except that an on-site coal gasification plant was employed. The third and forth MIUS systems were similar to the

the previous two except that diesel engines were used in place of gas engines and, for the on-site fuel supply plant, a coal liquefaction plant was employed. The third pair of MIUS systems employed a conventional open cycle gas turbine fired with natural gas or oil and the same system with an on-site coal gasification plant. The next two systems employed a steam turbine, the first with a conventional gas-fired furnace and the second with a fluidized bed coal combustion system. The last two systems considered made use of a reciprocating steam engine, the first with a conventional oil- or gas-fired furnace and the second with a fluidized bed coal combustion system. The results of the comparison are summarized in Table 4.

In carrying out the study extensive use was made of previous work carried out on a representative building complex of 720 residental units in the Philadelphia area (referred to in previous studies as the Model A System).[8] Estimates were first made for the efficiency of conversion of energy in the fuel into electricity under average load conditions for each of the units. These estimates included the loss in efficiency associated with operation at part-load most of the time, electrical losses in transmission lines, and losses in coal gasification or liquefaction plants associated with converting the relatively low quality coal into high quality gas or liquid fuel. The resulting estimates are summarized in the first column of the table.

Variations in the ratio of electrical to heat loads through the course of the year, particularly in going from winter to spring or fall conditions make it impossible to utilize all of the waste heat from the thermodynamic cycle in any of the systems considered. As a consequence of both this factor and differences in the thermal efficiency of the prime movers, an important parameter is the estimated fuel consumption per year per residential unit taking the energy theoretically available in the original fuel as the base. A third major consideration is the total capital investment required for all elements of the system including the central station where one is required; this is most conveniently expressed in dollars per residential unit. Another major cost consideration is that for operating personnel expressed in terms of mils per kilowatt hours. Note that the central stations benefit from the economies of scale in this area. Yet another

ORNL DWG 75-14466

Table 4. Summary of Major Considerations in Choosing a Power Conversion System for Building Complexes

Major Conditions: Philadelphia area \$400/kW(e) = capital cost of fossil fuel central station and electrical transmission system. Domestic hot water consumption = 600 Btu/yr·residential unit at 150°F.

System	Average Load Conversion Efficiency from Fuel to Electricity ~%	Estimated Fuel Consumption per year per Residential Unit ~10^6 Btu	Estimated Capital Cost \$/Residential Unit	Estimated Unit Cost for Operating Personnel mils/kWhr	Range of Fuels Useable*	Principal Developmental Problems
Central station, gas-fired steam boiler	32	185	3,000	7	C,G,O,W	S removal
Central station, electrical resistance heat	32	228	4,700	4	C_s,C,G,O,W	S removal
Central station, electric motor driven heat pump	32	170	4,250	6	C_s,C,G,O,W	S removal
Central station, district heating system	32	149	3,785		C_s,C,G,O,W	Installation of huge district heating system
LWR central station, district heating system	28	164	4,100		U	Installation of huge district heating system
Gas engine-natural gas	29	148	3,260	10	G	None
Gas engine-on-site coal gasification	20	211	16,760	160	C_s,C,G	Reliability, corrosion, S removal
Diesel engine-fuel oil	32	134	3,260	10	O	None
Diesel engine-on-site coal liquefaction	23	192	16,760	148	C_s,C,O	Reliability, corrosion, S removal
Conventional gas turbine-natural gas or oil	23	176	3,260	10	G,O	None
Conventional gas turbine-on-site coal gasification	16	252	16,760	160	C_s,C,G,O	Reliability, corrosion, S removal
Open cycle gas turbine with fluid bed	23	176	4,100	15	C_s,C,G,O,W	Reliability, hot corrosion in bed
Closed cycle gas turbine with fluid bed	29	140	4,000	15	C_s,C,G,O,W	Reliability, hot corrosion in bed
Steam turbine-conventional furnace	16	254		15	C,O,G	New turbine-generator required reliability
Steam turbine-fluidized bed	16	254		15	C_s,C,O,G,W	Reliability, control, hot corrosion
Steam engine-conventional furnace	16	254		15	C,G,O	None
Steam engine-fluidized bed	16	254		15	C_s,C,G,O,W	Reliability, corrosion, S removal

*Legend for Fuel Type -
C_s High sulfur coal
C Low sulfur coal
G Gas
O No. 2 fuel oil
W Solid wastes
U Uranium

consideration is the range of fuels useable. In this case it was assumed that fossil fuel-fired central stations would make use of coal and that a stack gas cleanup system would be employed. If a conventional on-site combustion system were to be employed, it was assumed that high sulfur coal would not be an acceptable fuel. The final column in the table is an indication of the principal development problems anticipated.

In reviewing the table a particularly significant set of numbers appears in the column for the estimated capital cost in dollars per residential unit. Note that the high cost of an on-site coal gasification or liquefaction plant makes such installations cost about four times as much as any of the others. Note that the estimated cost for operating personnel in mils/kWhr is also excessive for the cases in which on-site coal gasification or liquefaction plants were employed.

In examining the second column giving the estimated fuel consumption per year per residential unit, note that the on-site coal gasification and liquefaction plants also yield relatively high fuel consumptions, as do the steam turbine and steam engine plants.

If one considers only those plants that will have systems that will operate on high sulfur coal, it appears that the principal candidates are a central station coupled to a district heating system, and a closed cycle gas turbine with a fluidized bed combustion system. Surprisingly, the latter gives the most attractive performance if the detailed bases for the estimates presented in this table are correct. It must be emphasized that the results are sensitive to the various assumptions that have gone into the estimates so that the absolute values given in Table 4 are probably subject to uncertainties of the order of 10%. However, the study summarized in Table 4 indicates that the fluidized bed coal combustion system coupled to a closed cycle gas turbine is attractive and merits serious attention.

A major question not treated in Table 4 is that of reliability. This quantity is very difficult to estimate, and for a new system such as the fluidized coal combustion system coupled to a closed system gas turbine one can only surmise the probable reliability on the basis of experience with roughly similar systems. Fortunately, good data are available from the extensive operating experience that has been obtained with both conventional open cycle gas turbines and closed cycle gas turbines employing conventional combustion systems. This experience indicates that a degree of reliability comparable to that of gas engines and diesel engines might be obtained, at least so far as the gas turbine-generator is concerned. Although data on coal stokers in the size range of interest here are not available to give an explicit numerical estimate of the reliability of the coal feed system for a fluidized bed coal combustion power unit, extensive experience with hundreds of thousands of such systems indicates that a high degree of reliability can be obtained. Thus, it appears that there are good prospects of obtaining the high reliability desired for a MIUS application of the fluidized bed coal combustion system coupled to a closed cycle gas turbine.

At OCR's request an effort was made to appraise the possibility of using in a MIUS application the various advanced conversion systems currently being considered in Washington. The results of a brief survey of these systems are summarized in Table 5. The R&D investment in most of these systems has already run from $40,000,000 to billions of dollars and yet there are still major basic problems that remain to be solved. Many of the systems are suited only to large central station plants and are completely unsuited to MIUS applications. At least one of these two considerations makes each of the systems a much less promising candidate for a coal-fueled MIUS system than a fluidized bed coal combustion system coupled to a gas turbine.

THERMODYNAMIC CYCLE ANALYSIS

It was thought initially that the system could be simplified by employing an open cycle gas turbine.[9] Four cycles of this type were examined, and one was found to yield good performance at full load. However, part-load performance was poor, and this led to examination of the performance characteristics of closed cycles. These were found to give attractive performance both at full load and part load.

For MIUS applications much of the operating time must be at part load with a substantial amount of reserve capacity immediately available. In an open cycle the only way to reduce the power output is to reduce the turbine inlet temperature, and this reduces the cycle efficiency. Further,

Table 5. Major Considerations in Assessing the Suitability of Advanced Conversion Systems to MIUS Applications

System	Maximum Output from a Unit that has been built	Demonstrated Thermal Eff. %	Maximum Operating Time on a Unit-hr	Estimated Total R&D Investment in U.S.~$x10^-6	Principal Problems
Fuel cells	~15 kW(e)*	~37*	2,000*	~500	Cost, availability, and life of catalyst; difficulty in controlling concentration and PH of electrolite to close limits required
Solar energy	~50 hp*	~10*	~5x10^4 *	~500	Cost
Magnetohydrodynamic generators	4,000 kW(e)*	~5*	250*	~40*	Corrosion, erosion, and thermal stress at high temperatures; fringing current losses; ultra high temperature heat exchangers
Helium gas turbine	~15 kW(e)	~25	~6,000	~30	He leakage
Potassium vapor cycle topping cycle	100 hp	~15	~3,000*	~30	Details of engineering design of boiler, turbine, and condenser-steam generator
Dissociating gas cycle	—	—	0	<1	Corrosion
Supercritical CO_2 cycle	0	—	0	~3	Corrosion at high temperature

*Maximum output, thermal efficiency, and/or operating time not obtained with the same unit.

it reduces the volume flow rate through the turbine. Thus, a gas turbine with fixed rotor and stator blades running at constant speed to maintain a constant generator output frequency will be subject to substantial shifts in the operating points for the gas flow through the compressor and turbine, and this will lead to reductions in efficiency. These losses could be avoided with variable angle stator blades in the compressor and/or turbine, but commercial units with such features are not available. In the closed cycle system, on the other hand, the temperature structure through the entire system can be kept essentially constant and hence the relative velocities in the rotors and stators of the compressor and turbine can be kept fixed so that the efficiency will not change; the power output can be changed simply by varying the basic pressure in the system.

Of the four closed cycles considered, a good compromise between complexity and efficiency was given by a closed cycle gas turbine with a recuperator and a waste heat boiler in the closed cycle air stream and a rotary generator for preheating the combustion air stream with heat from the stack gas. This has the additional advantages of giving improved combustion conditions in the fluidized bed. A system of this type is shown in Fig. 4. The extra heat exchanger to close the cycle, i.e., that required for cooling the air leaving the waste heat boiler, proved to be relatively inexpensive so that it represents a small fraction of the total heat exchanger cost. Further, its cost was far more than offset by the reductions in the cost of the rest of the heat exchangers made possible by system pressurization.

The performance of a gas turbine cycle is quite sensitive to the choice of pressure ratio, compressor and turbine efficiency, the pressure drops through the various components of the system (particularly the heat exchangers), and the heating or cooling effectiveness of the heat exchangers (particularly the recuperator). Similarly, the cost of the heat exchangers per unit of useful output is very much dependent on the choice of system pressure for peak load operation in a closed cycle gas turbine, the heating or cooling effectiveness of the heat exchangers, and the pressure drop allocated to the heat exchangers. Figure 5 shows the effect of pressure ratio on the gross thermal efficiency of gas turbine cycles for two values of compressor inlet temperature and two sets of values for

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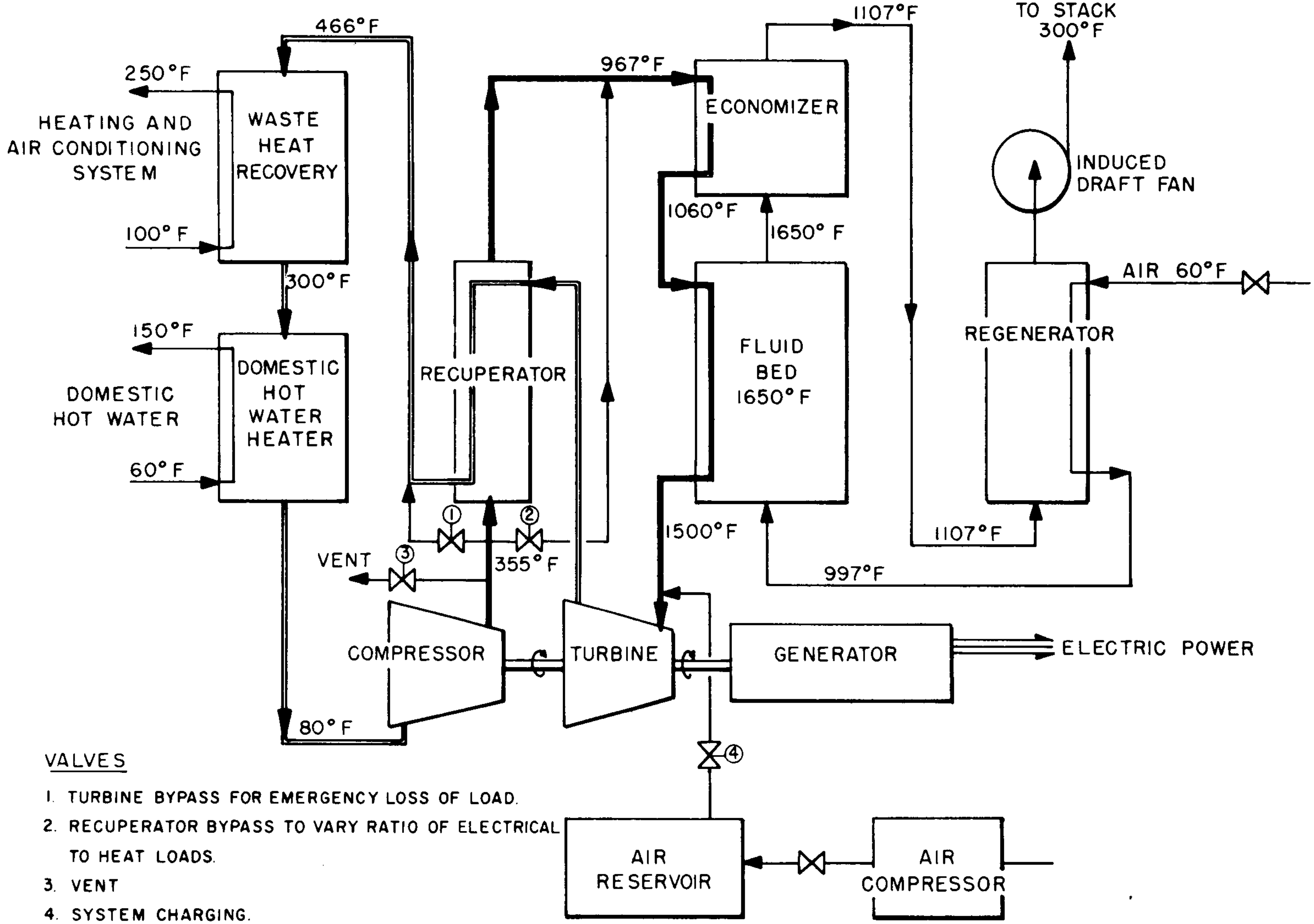

Fig. 4. Flow sheet for the reference design closed cycle system.

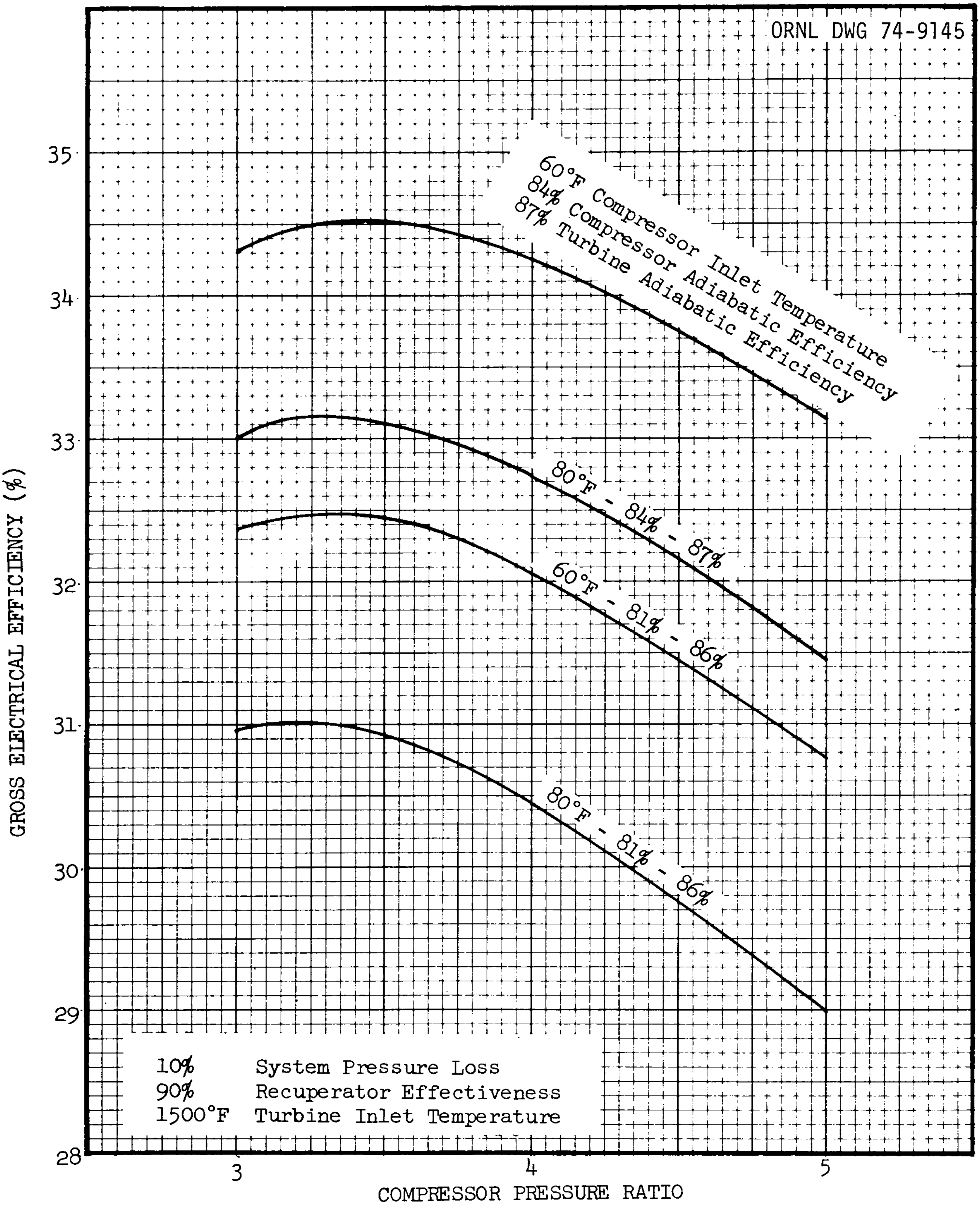

Fig. 5. Effects of component efficiency and compressor inlet temperature upon the gross electrical efficiency for a regenerative cycle without intercooling or reheat.

turbine and compressor efficiencies. The lower of the latter two sets represents typical values for units in current production while the higher turbine and compressor efficiency set is representative of values expected in small turbine generator units currently under development.

If one is to employ a commercial gas turbine, discussions with manufacturers indicate that the peak pressure should be limited to about 12 atm because the casings are commonly designed to permit operation with pressure ratios of as much as 12 to 1 in open cycle gas turbine units. If the speed of these units is reduced to give a lower pressure ratio, the compressor inlet pressure can be raised to a level consistent with the discharge pressure of 12 atm. On this basis estimates were made of the cost of the heat exchangers per kilowatt electric for a range of recuperator heating effectiveness and pressure losses in the heat exchangers and duct work. This was done for a representative set of values of compressor pressure ratio, compressor and turbine efficiencies, compressor and turbine inlet temperatures, and fluidized bed operating temperatures. The results are plotted in Fig. 6. These curves indicate that a recuperator effectiveness of about 90% with a set of pressure losses in the system totalling about 10% will yield a good compromise between heat exchanger cost and overall thermal efficiency. If fuel costs are added to the capital charges, and the influence of system total pressure loss and recuperator heating effectiveness of design parameters are investigated, one gets a set of curves such as that shown in Fig. 7. These indicate that changing the assumed cost of coal from \$10/ton to \$40/ton has relatively little effect on the combination of system pressure loss and recuperator effectiveness giving minimum electric power costs, and that a recuperator effectiveness of 90% coupled with a total pressure loss in the system of about 10% yields close to the best combination for the range of fuel costs considered. As one would expect, the higher the cost of fuel, the more advantageous one finds a higher recuperator effectiveness to be.

CONCEPTUAL DESIGN FOR THE FLUIDIZED BED GAS TURBINE SYSTEM

A series of attempts to develop layouts for a fluidized bed combustion system incorporating a heater for a gas turbine led to the evolution of four different layouts for the fluidized bed air heater-economizer

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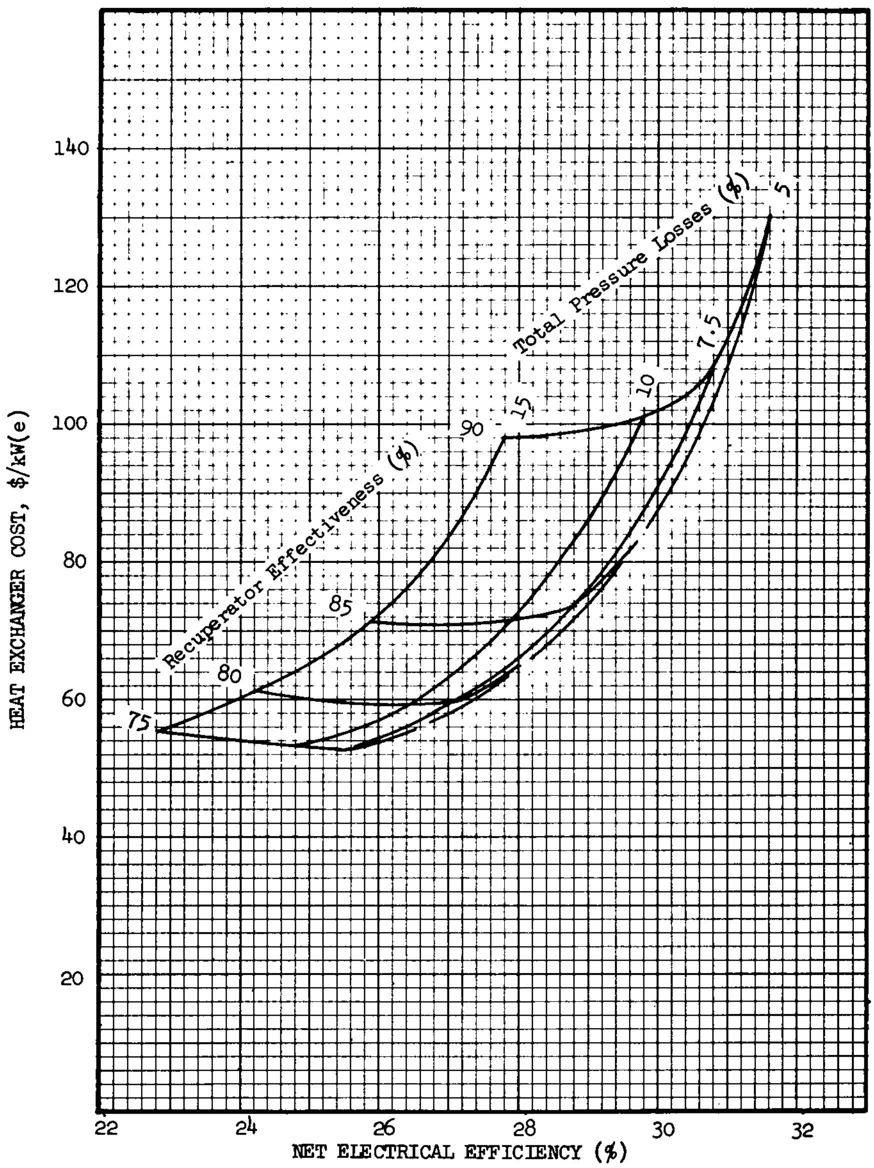

Fig. 6. Capital cost of the heat exchangers used in a regenerative cycle without intercooling or reheat as a function of the recuperator effectiveness, the system total pressure losses, and the net electrical efficiency. The system is operated at a compressor pressure ratio of 3.5:1 at an inlet temperature of 80°F, a compressor adiabatic efficiency of 84%, a turbine inlet temperature of 1500°F and a turbine adiabatic efficiency of 87%. Fluidized bed temperature = 1650°F.

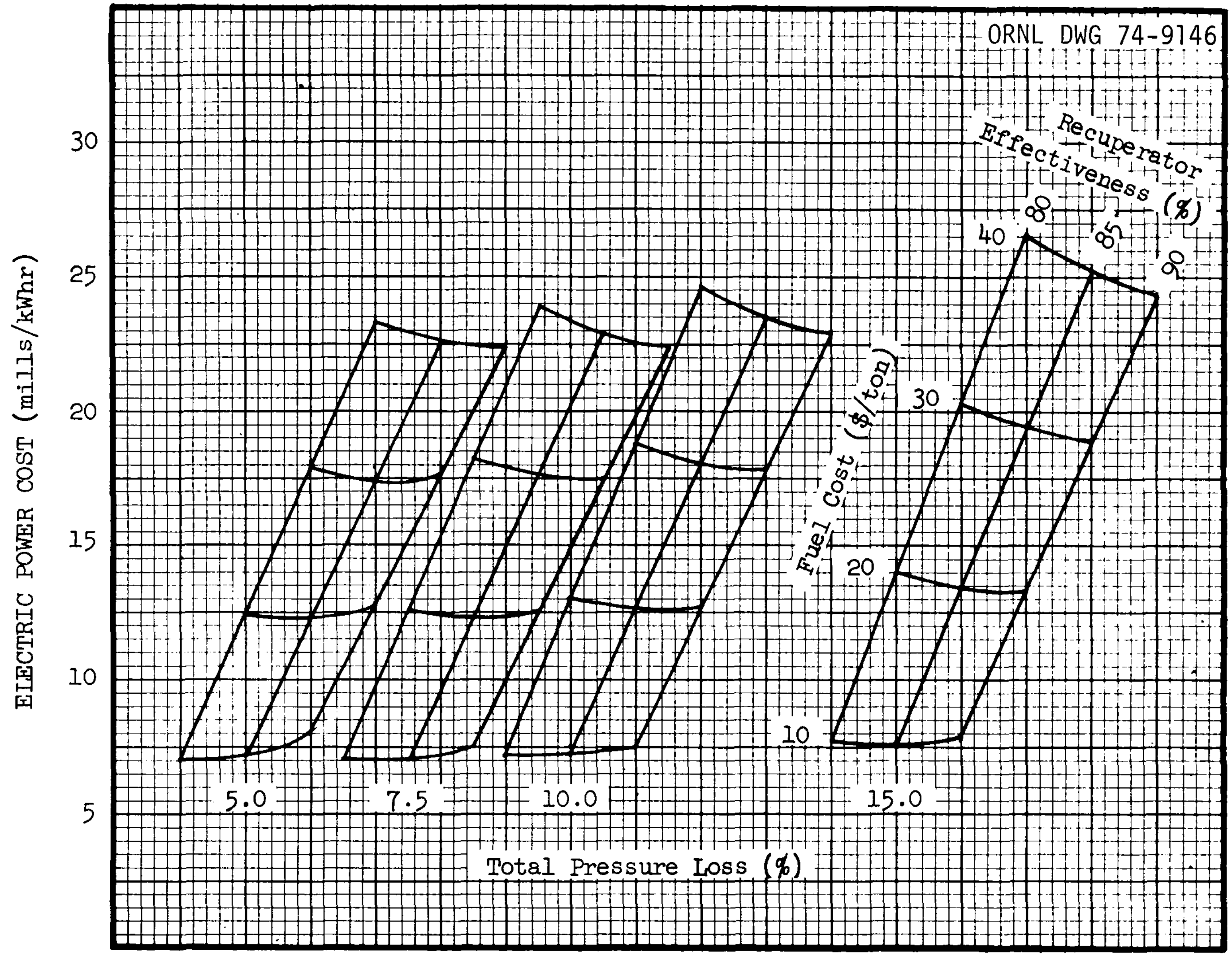

Fig. 7. Fractional electrical power cost associated with the fuel and heat exchanger cost for a regenerative cycle without intercooling or reheat at a load factor of 70% and 15% capitalization. The system is operated at a compressor pressure ratio of 3.5:1 and an inlet temperature of 80°F, a compressor adiabatic efficiency of 84%, a turbine inlet temperature of 1500°F and a turbine adiabatic efficiency of 87%. Fluidized bed temperature = 1650°F.

region. Of these, that shown in Fig. 8 was chosen as the reference design for purposes of this study. Dimensional and performance data for this reference design are presented in Table 6. Preheated air enters a plenum under the bed, flows up through the bed, through the plenum chamber over the bed, and then up and outward through the economizer region. The heat transfer surface is constructed of 1/2 in. OD round tubes welded into manifolds at the top and bottom. A major consideration in selecting the geometry of Fig. 8 was to employ simple plane bends insofar as possible and cover a large fraction of the furnace wall area with tubes cooled by the air flowing from the compressor to the turbine.

Bed Depth

The pumping power loss associated with air flow through the bed is directly proportional to the bed depth, hence it is desirable to make the bed depth as small as possible. However, there must be sufficient heat transfer surface area in the bed to remove the appropriate fraction of the heat of combustion required to hold the bed temperature to 1650°F. It should be noted that experience with fluidized bed operation indicates that about 1/3 of the heat lost from the bed flows to the walls of the plenum chamber over the bed either by direct radiation from the bed surface or by thermal radiation from particles ejected from the bed and refluxing in the plenum chamber.

Initially an effort was made to employ 1 in. OD tubes in the bed. However, the experience at BCURA has indicated that the tube centerline spacing in the bed ought not be less than 3 tube diameters. To facilitate assembly it is desirable to loop the tubes through the bed as indicated in Fig. 8. To obtain a suitable length diameter ratio for the tubes and thus obtain the desired heating effectiveness in the bed, it is necessary to reduce the tube diameter to 1/2 in. or else to increase the number of layers of tubes in the bed. Layout studies coupled with performance calculations favored the use of 1/2 in. OD tubes in the configuration of Fig. 8.

Plant Layout

The fluidized bed of Fig. 8 was incorporated in the closed cycle gas turbine system for which a flow sheet is presented in Fig. 4. The

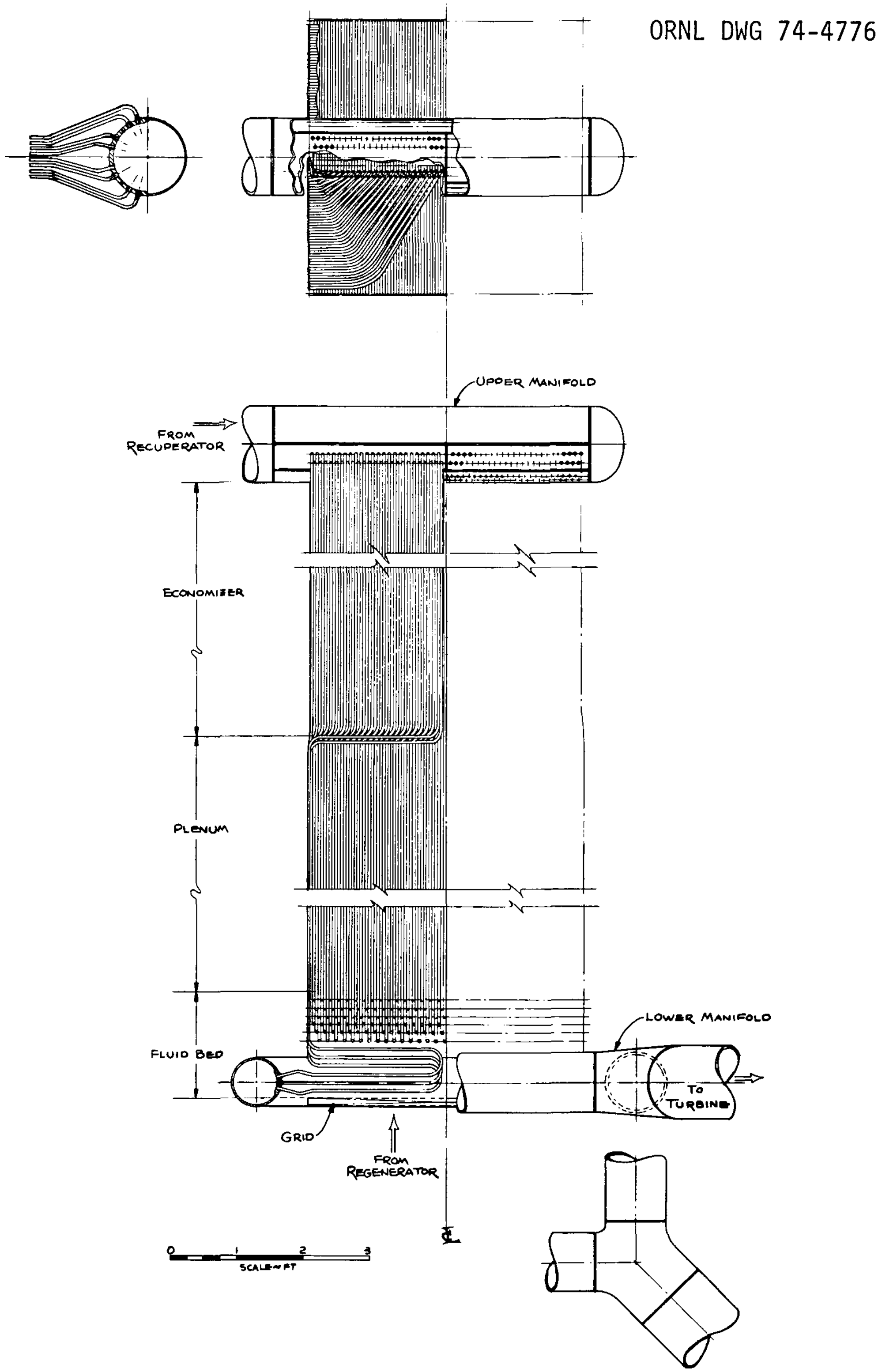

Fig. 8. Layout for the reference design fluidized bed-heater economizer unit.

proportions and performance characteristics of the principal components in the design system are also given in Table 6.

The reference design of Fig. 8 was then incorporated in a plant layout as shown in Fig. 9. This layout was made to get some idea of the problems associated with coupling the principal components of the system. It is evident from Fig. 9 that the large and bulky recuperator obtained by fabricating the unit of simple 0.50 in. OD tubes leads to a large and clumsy unit. Discussions with heat exchanger manufacturers indicate that a very much more compact and less expensive unit can be obtained. This should markedly simplify the duct system and reduce the cost of the duct work.

Availability of Components

With the exception of the fluidized bed coal combustion chamber with its associated heater and economizer, all of the rest of the equipment in the system appears to be commercially available. In addition to the recuperator cited above, the rotary regenerator and the finned-tube heat exchangers for the waste heat recovery and cooler units are commercial items. The cyclone separators and the bags for removing particulate matter from the stack gases are also commercially available. The principal problem in procurement is that associated with the turbine-generator unit. Most of the units currently available make use of a combustion chamber that is an intergral part of the engine so that if one is to couple them to an external gas heater, new casings would be required for the engine, and this would be a very expensive operation if one were to obtain only one or a few units for experimental purposes. Fortunately at least one engine model is available which was designed for operation with an external combustion chamber. Discussions with the manufacturer of this unit indicate that it probably can be used with little or no modification if one wished to employ it in an experimental system. At least one other unit in the size range desired is under development and would be even better suited to this application.

Table 6. Principal Parameters for the Reference Design Closed Cycle Gas Turbine with a Fluidized Bed Coal Combustion System

Thermodynamic Cycle	
Net electrical output, kW(e)	673
Gross electrical output, kW(e)	748
Turbine air inlet temperature, ^{o}F	1,500
Compressor air inlet temperature, ^{o}F	80
Compressor pressure ratio	3.5
Full load compressor discharge pressure, atm	12
Pressure losses in ducts and heat exchangers, $\Delta P/P$, %	10
Adiabatic efficiency of the turbine, %	87
Adiabatic efficiency of the compressor, %	84
Thermodynamic cycle efficiency, gross, %	31.1
Thermodynamic cycle efficiency, net, %	29.9
Turbine air flow, lb/sec	14.15
Compressor work, Btu/lb air	66.35
Turbine work, Btu/lb air	116.47
Net work from the cycle, Btu/lb air	50.12
Furnace	
Higher heating value of coal, Btu/lb	12,000
Combustion air flow, lb/sec	1.97
Flue gas flow, lb/sec	2.13
Coal flow rate, lb/sec	0.188
Coal flow rate, lb/hr	677
Excess air, %	10
Air temperature into the bed, ^{o}F	997
Fluid bed operating temperature, ^{o}F	1,650
Fluid bed operating density, lb/ft^3	55
Superficial gas velocity leaving bed, ft/sec	2.65
Fluid bed cross-sectional area, ft^2	42.7
Fluid bed depth, in.	20
Weight of material in the bed, lb	2,300
No. of tubes in the bed	628
Tube OD, in.	0.500
Tube ID, in.	0.444
Tube length in bed, ft	6.5
Air mass flow rate inside tubes, $lb/sec\cdot ft^2$	21.0
Plenum chamber height, ft	8.0
Tube centerline spacing in plenum wall, in.	0.50
Weight of tubing in bed and plenum walls, lb	1,460
Total surface area inside tubes, ft^2	1,200
Recuperator	
High pressure air inlet temperature, ^{o}F	355
High pressure air outlet temperature, ^{o}F	967
High pressure air mass flow rate, $lb/sec\cdot ft^2$	21.5
Low pressure air mass flow rate, $lb/sec\cdot ft^2$	8.62

Table 6 (continued)

Low pressure air inlet temperature, ^oF	1,070
Low pressure air outlet temperature, ^oF	466
No. of 0.50 in. OD, 0.444 in. ID tubes	611
Tube length, ft	47
High pressure air mean density, lb/ft^3	0.368
Low pressure air mean density, lb/ft^2	0.100
Low pressure air pressure drop, $\Delta P/P$	0.019
High pressure air pressure drop, $\Delta P/P$	0.019
Combined pressure drop, $\Delta P/P$, %	0.038
Total surface area inside tubes, ft^2	3,338
<u>Economizer</u>	
High pressure air inlet temperature, ^oF	967
High pressure air outlet temperature, ^oF	1,060
High pressure air mass flow rate, $lb/sec\text{-}ft^2$	21.0
Flue gas mass flow rate, $lb/sec\text{-}ft^2$	2.87
Flue gas inlet temperature, ^oF	1,650
Flue gas outlet temperature, ^oF	1,107
No. of 0.50 in. OD, 0.444 in. ID tubes	628
Tube length, ft	4.63
Total surface area inside tubes, ft^2	338
High pressure air mean density, lb/ft^3	0.325
Flue gas air mean density, lb/ft^3	0.0722
High pressure air pressure drop, $\Delta P/P$	0.006
Flue gas air pressure drop, $\Delta P/P$	0.0116
<u>Regenerator</u>	
Heat transfer matrix material	Cercor
Heat transfer matrix dia., in.	30
Heat transfer matrix length, in.	3
Heat transfer matrix face area for flue gas, ft^2	3.27
Heat transfer matrix face area for combustion air, ft^2	1.64
Flue gas inlet temperature, ^oF	1,107
Flue gas outlet temperature, ^oF	300
Combustion air inlet temperature, ^oF	80
Combustion outlet temperature, ^oF	997
Pressure drop in H_2O (total for both streams)	10
Heat transfer matrix surface area, ft^2/ft^3	960

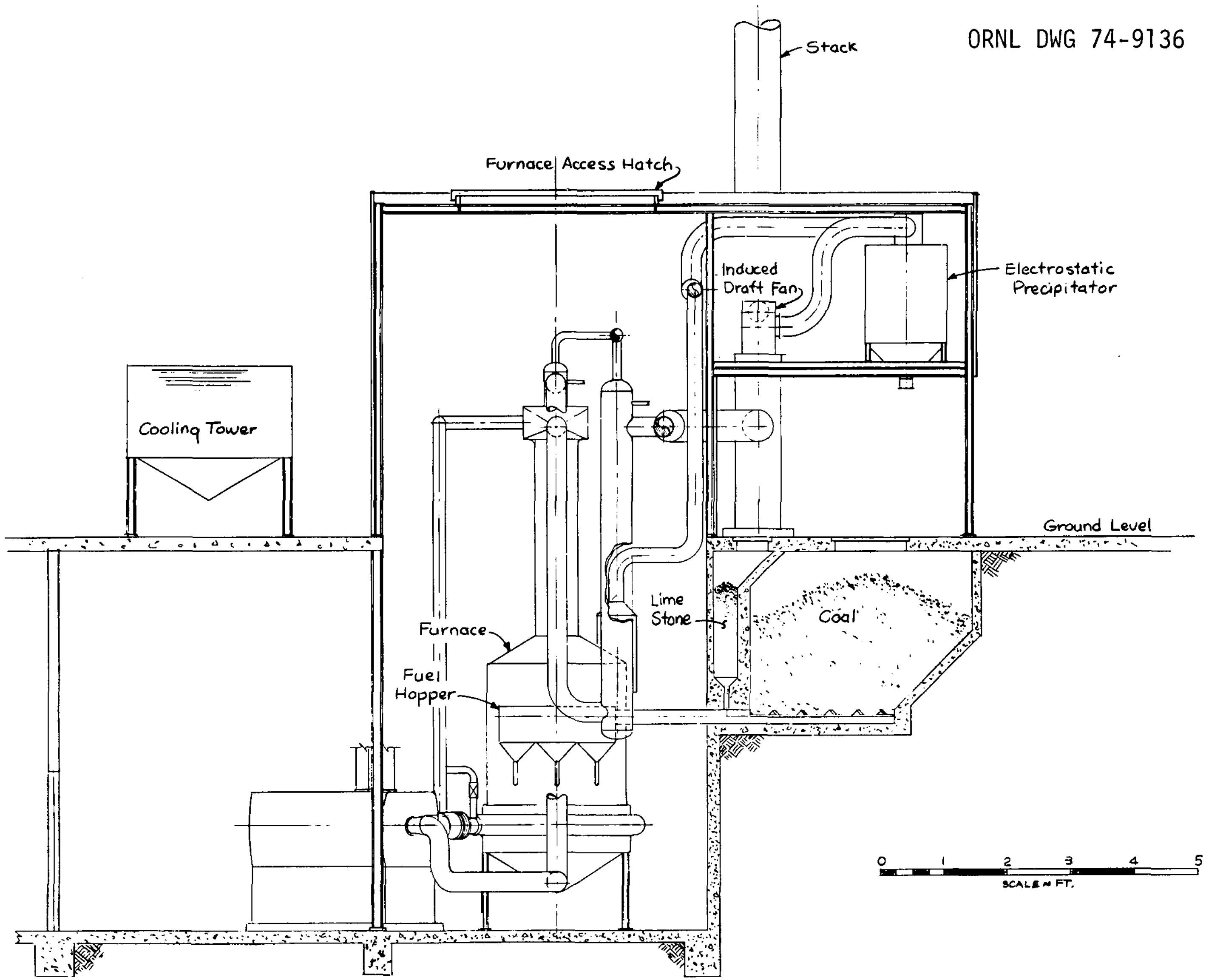

Fig. 9. Layout for a MIUS power plant employing the fluidized bed combustion system of Fig. 8.

METALLURGICAL CONSIDERATIONS

It is believed that the most serious problem presented by the fluidized bed coal combustion system coupled to a gas turbine as proposed here is presented by combustion gas-side corrosion of the air heater tubes in the bed. A review of the information available on fluidized bed coal combustion system operation coupled with the broad background of experience with combustion systems indicates that the mechanism of hot corrosion is one in which a normally protective oxide coating is destroyed by trace amounts of materials such as Na_2SO_4, $NaVO_3$, and oxides of molybdenum and vanadium. One theory is that these compounds interact chemically with the protective oxide scale and allow sulfur containing compounds to attack the substrate. A second theory is that these compounds drastically reduce the adhesion of the protective scale. In either case sulfurization of the substrate means that sulfur in some form is accessible at discontinuities in the normal oxide scale.

The applicability of past experience with other combustion systems to fluidized bed combustion systems is difficult to assess because of the much lower combustion temperatures in the fluidized bed (which one would expect to have a favorable effect), and the possibility of erosion of the protective scale by the turbulent particles in the bed. The limited experience available indicates that the latter will not be a problem, but much more extensive testing will be necessary to validate this tentative conclusion.

The heater tubes in the bed will operate in the temperature range of 1550°F to 1600°F, and will have to sustain an internal pressure of the order of 10 atm. Thus, the high temperature strength of the candidate alloys becomes an important consideration in addition to corrosion resistance. Test materials will be selected from alloy systems which exhibit relatively low creep rates up to 1600°F and which have demonstrated resistance to sulfidation and oxidation in combustion environments.

INSTRUMENTATION AND CONTROL

Coupling a fluidized bed coal combustion chamber to a gas turbine presents some unusual instrumentation and control problems. These include maintaining the desired voltage and frequency over the wide range of electrical loads experienced in the course of a day and the large diurnal and seasonal variations in the ratio of electrical to heat loads. Fortunately, in a closed cycle gas turbine this ratio can be varied by allowing air to bypass the recuperator (see Fig. 4). Further, although it is not economically practical to store electricity, it is practical to store hot water to help accommodate diurnal variations in the ratio of electrical to heat loads. Thus, the plant can be operated at the power required to meet the electrical load, and excess heat can be stored in the daytime for use at night. This poses some unconventional control problems, but they do not appear to be difficult.

Control System Design Precepts

After considering a variety of approaches to the control problem, a consistent set of design precepts was evolved that appears to give a reasonably straightforward control system that will meet all of the required boundary conditions. These precepts are as follows:

1. The fluidized bed will be operated at a constant temperature chosen for nearly optimum sulfur removal. To accomplish this the coal feed flow rate and combustion air flow rate will be slaved to the bed temperature.
2. The gas turbine and generator speed will be held constant to maintain a constant output frequency of 60 Hz. This will be accomplished by varying the pressure in the closed cycle gas turbine system. An air reservoir (see Fig. 2) will be provided to facilitate the changes in system pressure level.
3. The rate of heat release in the bed is primarily dependent on the combustion air flow rate, hence the primary control on bed temperature will be on the combustion air flow. The amount of coal in the bed would ordinarily be equivalent to that consumed in about 1 min of operation.
4. The fuel-air ratio would be controlled to provide about 10% excess air.

5. The limestone would be mixed with the coal in the region where the coal is fed into the air stream used to convey it into the furnace. The limestone flow rate would be adjusted to some definite proportion of the coal flow rate depending on the sulfur content of the coal.
6. Emergency control for an abrupt loss in electrical load would be obtained by opening a valve to allow air to bypass the turbine and flow directly from the compressor outlet to the cooler inlet. Only about one-third of the air need be bypassed in order to go from full load to zero load with a gas turbine.
7. The ratio of heat to electrical output can be increased for cold weather conditions by allowing air from the compressor outlet to bypass the recuperator and flow directly to the economizer. This will be as much as double the ratio of heat to electrical output.

The rate at which the electrical load will increase or decrease under normal operating conditions will not exceed about 0.7%/min except in the summer if large Freon compressors are used to supplement the absorption air conditioning system. Starting a large compressor around noon in summer would probably impose a step increase of about 10% in the electrical load, and this would pose a difficult control problem.

The control of closed cycle gas turbines has commonly presented difficulties because the systems have been relatively sluggish because they have been designed for high peak pressures, have had large volumes, and have tried to make use of the compressor of the gas turbine for charging the high pressure gas reservoir used for control purposes. Release of gas from the reservoir has commonly been to the compressor inlet, and this has led to a relatively low system response rate to a step increase in load. A much higher response rate can be obtained by using a separate compressor for charging the storage reservoir to a pressure well above the maximum system pressure, and allowing the gas added to the system to go through a heat transfer matrix so that it would enter the system just ahead of the turbine at about the turbine inlet temperature. A preliminary analysis indicates that a good way to do this is to place a heat transfer matrix similar to that of the regenerator in the outlet manifold for the tubes in the fluidized bed. This will run at the turbine inlet temperature and will provide sufficient heat capacity so that air from the storage reservoir flowing through this heat transfer matrix will be heated to the turbine inlet temperature. This arrangement should yield a good response characteristic.

MAJOR PROBLEM AREAS

The reference design system outlined in Table 6 appears to be sufficiently promising to merit an experimental investigation of this concept. The principal problems appear to be those associated with the fluidized bed-air heater system. The limited scope of the analysis presented in this study has made it necessary to make many approximations and neglect many important design details. These include the details of the geometry of the heater tubes in the fluidized bed and plenum chamber walls, provisions for differential thermal expansion and support of the various components in the heater including the manifolds and outer casing, the basic support grid for the fluidized bed, the fuel feed spouts, and the ducts coupling the heater and fluidized bed to the gas turbine. Extensive experience at ORNL with high temperature heat exchangers and equipment for gas-cooled and liquid-cooled reactors indicates that these problems will require much detailed analysis, and many compromises must be made between heat transfer, fluid flow, stress analysis, fabricational problems, and capital costs to arrive at an overall design that will be well proportioned and free of weaknesses in detailed elements. This will require an extensive examination of information on fluid flow and heat transfer in fluidized beds, particularly those that have been used for combustion of coal and residual fuel oil. Such a systematic examination of the effects of design factors should produce a much more complete and better design than the first conceptual reference design of Fig. 8 and Table 6, and will provide a much better basis for estimating the capital and operating costs for both an experimental system and production units.

In addition to the analytical design and layout work it will be necessary to carry out a series of bench tests to resolve many subtle questions not susceptible to analysis. Quite a number of approaches have been considered, but the best appears to be the construction of a lucite model of a 24 in. square segment of the fluidized bed with the 0.50 in. OD tubes of the reference design. This can be coupled to a commercial coal feed system and used to investigate key practical questions by operation with air at room temperature and coal, limestone, and other fuel feed materials. Typical problems include the following:

a. Coal and limestone feed system characteristics.
b. Coal and limestone feed port detail design.
c. Wood, waste, sludge, etc., feed port detail design.
d. Startup fuel and feed port detail design.
e. Air tuyere design (perforations in the plate on which the bed rests).

Basic Technology

Although not essential for a minimal scope effort directed toward a test of a demonstration system, it would be highly advantageous to broaden the program to cover the more important technological questions. If the broader approach is taken, one will be in a much better position to diagnose and cope with difficult problems that will inevitably arise.

The most immediate set of questions has to do with uncertainties in extending the information obtained in the cold flow bench tests outlined above to hot flow conditions. The relative importance of thermal radiation as a heat transfer mechanism, for example, represents one major uncertainty. This and other similar questions could be answered by operating a hot flow version of the cold flow system outlined above. Important additional insights would be obtained with respect to the following:

a. Economizer design.
b. Hot manifold and piping design.
c. Plenum design — use tubes as baffles?
d. Bed temperature vs. type of fuel and limestone.
e. Ash removal — just let attrition feed fines to cyclones? Is this stable?
f. How low can air flow drop? Will bed particle size vary with load? Response rate? Is pulsed operation in a practicable approach to operation at low loads?

g. Control to hold constant bed temperature or let it drop with load?

h. Possibilities for burning virtually any fuel in a single basic furnace with minimal changes in the fuel feed system and other components.

Probably the most important factor limiting the life of a fluidized bed combustion system is corrosion of the tubes in the bed by combustion gases. For the gas turbine system proposed here this problem differs from that for steam boilers in that the tube metal temperature is much higher. There are so many subtle effects that it is hard to say at this stage just what should be done experimentally, but it would be highly desirable to assign a first-class metallurgist to the problem of evolving a research program that would give good perspective on hot gas corrosion in fluidized bed combustion systems for gas turbines. This should include good integration of the information from operating experience gained with other types of fluidized bed combustion system including not only steam boilers but the various types of fluidized bed incinerators and pyrite roasting systems.

Erosion, corrosion, and deposits have been major problems in gas turbines when attempts have been made to employ residual fuel oil or coal as the fuel evolved for a unit suited to MIUS applications, a major saving in capital cost could be effected. The direct combustion system has the further advantage that the presence of water in the fuel does not degrade the performance because the loss of heat required for vaporization of the water is offset by the increased turbine work stemming from the increased mass flow through the turbine without an increase in the compressor work (except for an almost trivial amount of pump work required for injection of water slurries). This is true even if massive amounts of water are injected as would be the case if slurries of sewage sludge were employed.

G. S. Leighton has suggested that the problems with turbine bucket erosion and deposits are probably dependent on the size and character of the particles suspended in the gas stream, e.g., the smaller the particles the less damaging they probably are, and there may be a size threshold below which no damage would result. The character of the particles may also be an important factor.

In attempting to assess the problem to determine what might be done in this area, it is clear that the first step should be a thorough and critical examination of all of the experience that has been gained in this area. On completing this survey and analyzing the results it is likely that a number of well-defined problems will emerge, and that some worthwhile experiments to investigate these problems can be suggested. However, it seems unwise to suggest either the character or the scope of such experiments until the above survey of the entire problem area has been completed.

RECOMMENDED PROGRAM FOR PHASE II AND PHASE III

The original ORNL proposal to HUD contemplated a minimal cost effort to demonstrate the feasibility of the basic concept. Subsequent discussions with HUD and OCR have indicated that they would like to see this effort on the demonstration of the feasibility of the concept supplemented with a more broadly-based technology program. As a consequence, in carrying out the program recommended for the next 3 years the effort has been divided into two portions, one on concept feasibility and one on basic technology. The objectives of this work and the approaches envisioned are outlined in the previous section.

The phasing of the major steps in the concept feasibility demonstration portion of the program are indicated in the bar chart of Fig. 10 and the currently estimated costs are summarized in Table 7. In Phase II the detail design problems would be examined both analytically and in cold flow bench tests, the effects of design parameters on the cost of commercial components would be explored with vendors, and the key elements and design features of a complete system would be established including good estimates of the cost and delivery schedule for each of the major items. This will provide a much better basis for estimating the costs and schedule for the work in Phase III, the detail design and construction of the closed cycle gas turbine system coupled to a fluidized bed combustion chamber for demonstration of the feasibility of the concept. In the Phase IV portion of the effort, the initial period of shakedown and performance tests will be concerned with investigations of the effects of startup and shutdown procedures on the times required for these operations, the practicable range

ORNL DWG 75-14462

OCR-HUD/ORNL Study of the Use of Coal and Coal-Derived Fuels in

Total Energy Systems for MIUS Applications

PROGRAM PLAN

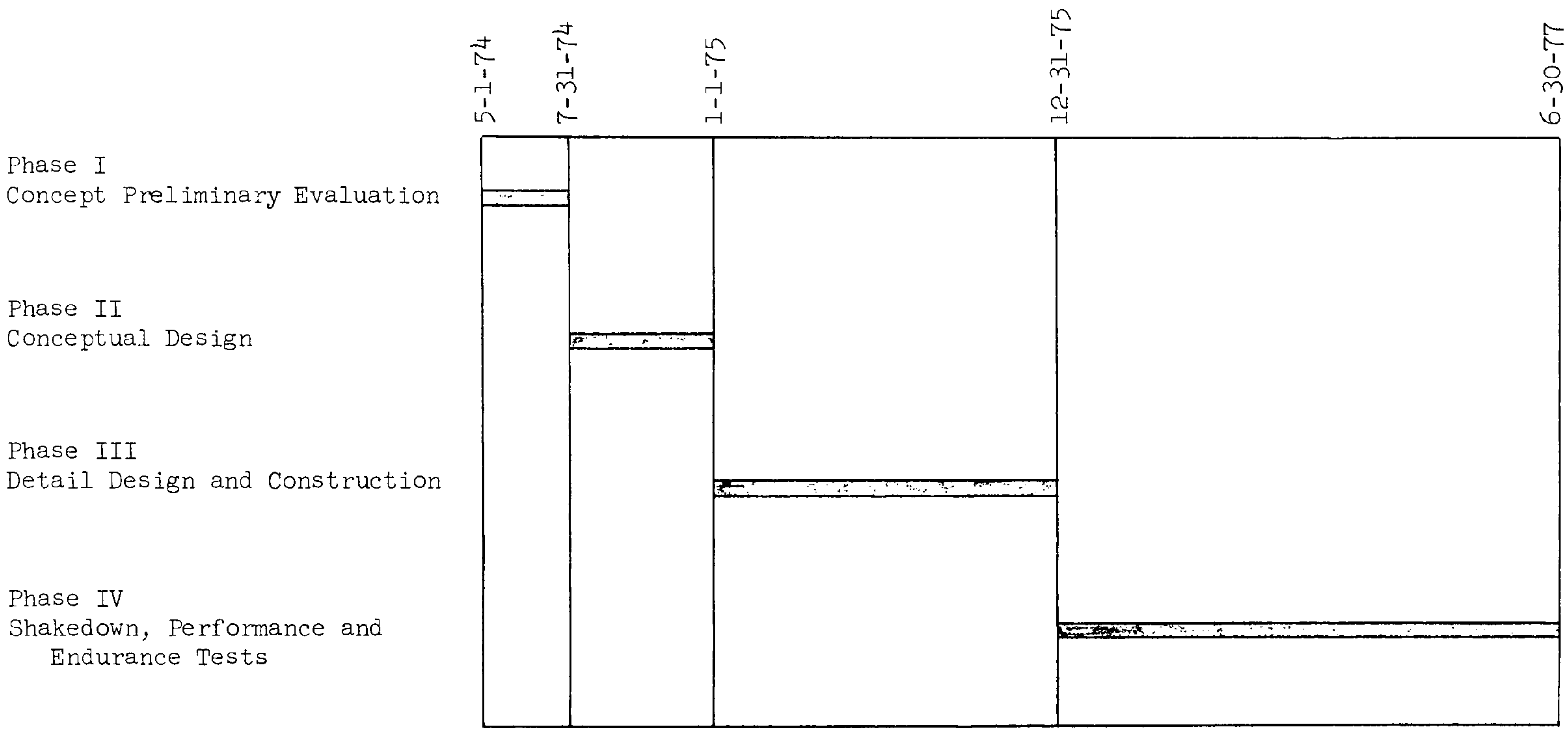

Fig. 10. Major Steps of the Program Plan.

Table 7. Estimated Costs for Major Elements of a Minimum Cost Program to Demonstrate the Feasibility of a Fluidized Bed Coal Combustion System Coupled to a Gas Turbine for MIUS Applications

	Phase I May 1 to August 31 1974	Phase II September 1, 1974 to January 31, 1975	Phase III February 1, 1975 to August 31, 1976	Phase IV September 1, 1976 to June 30, 1977
Design and analysis	$200,000	$200,000	$ 500,000	$100,000
Bench tests		50,000	50,000	
Subcontracts		60,000	100,000	
Procurement			500,000	
Installation			150,000	
Operation				340,000
Total	$200,000	$310,000	$1,300,000	$440,000
Overall total = $2,250,000*				

*This estimate of the program cost was made in July, 1974. Since that time, the cost estimate has been increased as a result of escalation and the use of a firm conceptual design as the basis for cost estimation.

of power outputs for good control, and the response characteristics of the system when subjected to abrupt changes in load including the complete loss of the electrical load.

Table 8 summarizes the estimated costs of the major elements in the broadly based technology program recommended. It must be emphasized that the scale of the experimental effort that will be in order cannot be estimated well at this stage because it will be heavily dependend on the findings in Phase II.

Table 8. Estimated Costs for Major Elements of a Basic Technology Program in Support of the Fluidized Bed Coal Combustion System-Gas Turbine Concept for MIUS Applications

	Phase II	Phase III	Phase IV
Hot corrosion of alloys in a fluidized bed	25,000	?	?
Design, construction, and operation of a section of a fluidized bed combustion system to investigate effects of going from cold flow to hot flow conditions	25,000	100,000	*
Investigation of the effects of particle size and character on gas turbine bucket corrosion, erosion, and deposits	25,000	?	?

*Might be used for corrosion, erosion, etc. tests.

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