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COGENERATION TECHNOLOGY ALTERNATIVES STUDY (CTAS)

GENERAL ELECTRIC COMPANY
FINAL REPORT

VOLUME I – SUMMARY REPORT

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FOREWORD

The Cogeneration Technology Alternatives Study (CTAS) was performed by the National Aeronautics and Space Administration, Lewis Research Center, for the Department of Energy, Division of Fossil Fuel Utilization. CTAS was aimed at providing information which will assist the Department of Energy in establishing research and development funding priorities and emphasis in the area of advanced energy conversion system technology for advanced industrial cogeneration applications. CTAS included two Department of Energy-sponsored/NASA-contracted studies conducted in parallel by industrial teams along with analyses and evaluations by the National Aeronautics and Space Administration's Lewis Research Center.

This document describes the work conducted by the Energy Technology Operation of the General Electric Company under National Aeronautics and Space Administration contract DEN3-31.

The General Electric Company contractor report for the CTAS study is contained in six volumes:

Cogeneration Technology Alternatives Study (CTAS), General Electric Company Final Report

Title	DOE Number	NASA Contract Report No.
GE Vol. 1 - Summary Report	DOE/NASA/0031-80/1	CR-159765
Vol. 2 - Analytic Approach	DOE/NASA/0031-80/2	CR-159766
Vol. 3 - Industrial Process Characteristics	DOE/NASA-0031-80/3	CR-159767
Vol. 4 - Energy Conversion System Characteristics	DOE/NASA-0031-80/4	CR-159768
Vol. 5 - Cogeneration System Results	DOE/NASA-0031-80/5	CR-159769
Vol. 6 - Computer Data	DOE/NASA-0031-80/6	CR-159770

Members of the technical staffs of the following organizations have developed and provided information for the General Electric Company Cogeneration Technology Alternatives Study. The contributions of these people in time, effort, and knowledge are gratefully appreciated.

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This General Electric Company contractor report is one of a set of reports describing CTAS results. The other reports are the following:

Cogeneration Technology Alternatives Study (CTAS), Vol. I, Summary Report, NASA TM-81400.

Cogeneration Technology Alternatives Study (CTAS), Vol. II, Comparison and Evaluation of Results, NASA TM-81401

Cogeneration Technology Alternatives Study (CTAS) - United Technologies Corporation Final Report

Title	DOE Number	NASA Contract Report No.
UTC Vol. 1 - Summary	DOE/NASA/0030-80/1	CR-159759
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Vol. 4 - Heat Sources, Balance of Plant and Auxiliary Systems	DOE/NASA-0030-80/4	CR-159762
Vol. 5 - Analytic Approach & Results	DOE/NASA-0030-80/5	CR-159763
Vol. 6 - Computer Data	DOE/NASA-0030-80/6	CR-159764

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Section 1

SUMMARY

Cogeneration systems in industry simultaneously generate electric power and thermal energy. Conventional nocogeneration installations use separate boilers or furnaces to produce the required thermal energy and purchase electric power from a utility which rejects heat to the outside environment. Cogeneration systems offer significant savings in fuel but their wide spread implementation by industry has been generally limited by economics and institutional and regulatory factors. Because of potential savings to the nation, the Department of Energy, Office of Energy Technology sponsored the Cogeneration Technology Alternatives Study (CTAS, The National Aeronautics & Space Administration, Lewis Research Center, conducted CTAS for the Department of Energy with the support of Jet Propulsion Laboratory and study contracts with the General Electric Company and the United Technologies Corporation.

OBJECTIVES

The objective of the CTAS is to determine if advanced technology cogeneration systems have significant payoff over current cogeneration systems which could result in more widespread implementation in industry and to determine which advanced cogeneration technologies warrant major research and development efforts.

Specifically, the objectives of CTAS are:

1. Identify and evaluate the most attractive advanced energy conversion systems for implementation in industrial cogeneration systems for the 1985-2000 time period which permit use of coal and coal-derived fuels.

2. Quantify and assess the advantages of using advanced technology systems in industrial cogeneration.

SCOPE

The following nine energy conversion system (ECS) types were evaluated in CTAS:

1. Steam turbine
2. Diesel engines
3. Open-cycle gas turbines
4. Combined gas turbine/steam turbine cycles
5. Stirling engines
6. Closed-cycle gas turbines
7. Phosphoric acid fuel cells
8. Molten carbonate fuel cells
9. Thermionics

In the advanced technology systems variations in temperature, pressure ratio, heat exchanger effectiveness and other changes to a basic cycle were made to determine desirable parameters for many of the advanced systems. Since coal and coal-derived fuels were emphasized, atmospheric and pressurized fluid bed and integrated gasifiers were evaluated.

For comparison, currently available non-condensing steam turbines with coal-fired boilers and flue gas desulfurization, gas turbines with heat recovery steam generators burning residual and distillate petroleum fuel and medium speed diesels burning petroleum distillate fuel were used as a basis of comparison with the advanced technologies.

In selecting the cogeneration energy conversion system configurations to be evaluated, primary emphasis was placed on system concepts fired by coal and coal-derived fuels. Economic evaluations were based on industrial ownership of the cogeneration system. Solutions to institutional and regulatory problems which impact the use of cogeneration were not addressed in this study.

Over fifty industrial processes and a similar number of state-of-the-art and advanced technology cogeneration systems were matched by

General Electric to evaluate their comparative performance. The industrial processes were selected as potentially suited to cogeneration primarily from the six largest energy consuming sectors in the nation. Advanced and current technology cogeneration energy conversion systems, which could be made commercially available in the 1985 to 2000 year time frame, were defined on a consistent basis. These processes and systems were matched to determine their effectiveness in reducing fuel requirements, saving petroleum, cutting the annual costs of supplying energy, reducing emissions, and improving the industry's return on investment.

Detailed data were gathered on 80 process plants with major emphasis on the following industry sectors:

1. SIC20 - Food and Kindred Products
2. SIC26 - Pulp and Paper Products
3. SIC28 - Chemicals
4. SIC29 - Petroleum Refineries
5. SIC32 - Stone, Clay and Glass
6. SIC33 - Primary Metals

In addition, four processes were selected from SIC22 - Textile Mill Products and SIC24 - Lumber and Wood Products. The industry data includes current fuel types, peak and average process temperature and heat requirements, plant operation in hours per year, waste fuel availability, electric power requirements, projected growth rates to the year 2000, and other factors needed in evaluating cogeneration systems. From this data approximately fifty plants were selected on the basis of: energy consumption, suitability for cogeneration, availability of data, diversity of types such as temperatures, load factors, etc., and range of ratio of process power over process heat requirements.

Based on the industrial process requirements and the ECS characteristics, the performance and capital cost of each cogeneration system and its annual cost, including fuel and operating costs, were compared with nocogeneration systems as currently used. The ECS was either sized to match the process heat requirements (heat match) and electricity either bought or sold or sized to match the electric power (power match) in which case an auxiliary boiler is usually required to supply the remaining heat needs. Cases where there was excess heat when matching the power were excluded from the study. With the fuel variations studied there are 51 ECS/fuel combinations and over 50 processes to be potentially matched in both heat and power resulting in a total of approximately 5000 matches calculated. Some matches were excluded for various reasons; e.g., the ECS out of temperature range or excess heat produced, resulting in approximately 3100 matches carried through the economic evaluation. Results from these matches were extrapolated to the national level to provide additional perspective on the comparison of advanced systems.

RESULTS

A comparison of the results for these specific matches lead to the following observations on the various conversion technologies:

1. The atmospheric and pressurized fluidized bed steam turbine systems give payoff compared to conventional boiler with flue gas desulfurization-steam turbine systems which already appear attractive in low and medium power over heat ratio industrial processes.

2. Open-cycle gas turbine and combined gas turbine/steam turbine systems are well suited to medium and high power over heat ratio industrial processes based on the fuel prices used in CTAS. Regenerative and steam injected gas turbines do not appear to have as much potential as the above systems, based on GE results. Solving low grade coal-derived fuel and NO_x emission problems should be emphasized. There is payoff in these advanced systems for increasing firing temperature.

3. The closed-cycle gas turbine systems studied by GE have higher capital cost and poorer performance than the more promising technologies.

4. Combined-cycle molten carbonate fuel cell and gas turbine/steam turbine cycles using integrated gasifier, and heat matched to medium and high power over heat ratio industrial processes and exporting surplus power to the utility give high fuel savings. Because of their high capital cost, these systems may be more suited to utility or joint utility-industry ownership.

5. Distillate-fired fuel cells did not appear attractive because of their poor economics due to the low effectiveness of the cycle configurations studied by GE and the higher price of distillate fuel.

6. The very high power over heat ratio and moderate fuel effectiveness characteristics of diesel engines limit their industrial cogeneration applications. Development of an open cycle heat pump to increase use of jacket water for additional process heat would increase their range of potential applications.

To determine the effect of the national fuel consumption and growth rates of the various industrial processes together with their distribution of power to heat ratios, process steam temperatures and load factors, each energy conversion system was assumed implemented without competition and its national fuel, emissions, and cost of energy estimated. In this calculation it was assumed that the total savings possible were due to implementing the cogeneration systems in new plants added because of needed growth in capacity or to replace old, unserviceable process boilers in the period from 1985 to 1990. Also, only those cogeneration systems giving an energy cost savings compared with nocogeneration were included in estimating the national savings. Observations on these results are:

1. There are significant fuel, emissions, and energy cost savings realized by pursuing development of some of the advanced technologies.

2. The greatest payoff when both fuel energy savings and economics are considered lies in the steam turbine systems using atmospheric and pressurized fluidized beds. In a comparison of the national fuel and energy cost savings for heat matched cases, the atmospheric fluidized bed showed an 11% increase in fuel saved and 60% additional savings in levelized annual energy cost savings over steam turbine systems using conventional boilers with flue gas desulfurization whose fuel savings would be, if implemented, 0.84 quads/year and cost savings $1.9 billion/year. The same comparison for the pressurized fluidized bed showed a 73% increase in fuel savings and a 29% increase in energy cost savings.

3. Open-cycle gas turbines and combined-cycles have less wide application but offer significant savings. The advanced residual-fired open-cycle gas turbine with heat recovery steam generator and firing temperature of 2200 F were estimated to have a potential national saving of 39% fuel and 27% energy cost compared to currently available residual-fired gas turbines whose fuel savings would be, if implemented, 0.18 quads/year and cost savings $0.33 billions/year.

4. Fuel and energy cost savings are several times higher when the cogeneration systems are heat matched and surplus power exported to the utility than when the systems are power matched.

Other important observations made during the course of performing CTAS were:

1. Comparison of the cogeneration systems which are heat matched and usually exporting power to the utility with the power matched systems shows the systems exporting power have a much higher energy savings, often reaching two to five times the power match cases. In the past, with few exceptions, cogeneration systems have been matched to the industrial process so as not to export power because of numerous load management, reliability, regulatory, economic and institutional reasons. A concerted effort is now underway by a number of government agencies, industries, and utilities to overcome these impediments and it should be encouraged if the nation is to receive the full potential of industrial cogeneration.

2. The economics of industrially owned cogeneration plants are very sensitive to fuel and electric power costs or revenues. Increased price differentials between liquid fuels and coal would make integrated gasifier fuel cell or combined-cycle systems attractive for high power over heat industrial processes.

3. Almost 75% of the fuel consumed by industrial processes studied in CTAS, which are representative of the national industrial distribution, have power over heat ratios less than 0.25. As a result energy conversion systems, such as the steam turbine using the atmospheric or pressurized fluidized bed, which exhibit good performance and economics when heat matched in the low power over heat ratio range, give the largest national savings.

Section 2

INTRODUCTION

BACKGROUND

Cogeneration is broadly defined as the simultaneous production of electricity or shaft power and useful thermal energy. Industrial cogeneration in the context of this study refers specifically to the simultaneous production of electricity and process steam or hot water at an individual industrial plant site. A number of studies addressing various aspects of cogeneration as applied to industry have been made in the last few years. Most of these focused on the potential benefits of the cogeneration concept. CTAS, however, was concerned exclusively with providing technical, cost, and economic comparisons of advanced technology systems with each other and with currently available technologies as applied to industrial processes rather than the merits of the concept of cogeneration.

While recognizing that institutional and regulatory factors strongly impact the feasibility of widespread implementation of cogeneration, the CTAS did not attempt to investigate, provide solutions, or limit the technologies evaluated because of these factors. For example, cogeneration systems which were matched to provide the required industrial process heat and export excess power to the utilities were evaluated (although this has usually not been the practice in the past) as well as systems matched to provide only the amount of power required by the process. Also, no attempt was made to modify the industrial processes to make them more suitable for cogeneration. The processes were defined to be representative of practices to be employed in the 1985 to 2000 time frame.

The cogeneration concept has been applied in a limited fashion to power plants since the turn of the century. Their principal advantage is that they offer a significant saving in fuel over the conventional method of supplying the energy requirements of an industrial plant by purchasing power from the utility and obtaining steam from an on-site process boiler.

The saving in fuel by a cogeneraiton system can be seen by taking a simple example of an industrial process requiring 20 units of power and 100 units of process steam energy. A steam turbine cogeneration system (assuming it is perfectly matched, which is rarely the case) can provide these energy needs with fuel effectiveness or power plus heat over input fuel ratio of 0.85 resulting in a fuel input of 141 units. In the conventional nocogeneration system the utility with an efficiency of 33% requires 60 units of fuel to produce the 20 units of power and the process boiler with an efficiency of 85% requires 118 units of fuel to produce the required steam making a total fuel required of 178 units. Thus the cogeneration system has a fuel saved ratio of 37 over 178 or 21%.

In spite of this advantage of saving significant amounts of fuel, the percentage of industrial power generated by cogeneration, rather than being purchased from a utility, has steadily dropped until it is now less than 5% of the total industrial power consumed. Why has this happened? The answer is primarily one of economics. The utilities with their mix in ages and capital cost of plants, relative low cost of fuel, steadily improving efficiency and increasing size of power plants all made it possible to offer industrial power at rates more attractive than industry could produce it themselves in new cogeneration plants.

Now with long term prospects of fuel prices increasing more rapidly than capital costs, the increased use of waste fuels by industry and the need to conserve scarce fuels, the fuel savings advantage of cogenerating will lead to its wider implementation. The CTAS was sponsored by the US Department of Energy to obtain the input needed to establish R&D funding priorities for advanced energy conversion systems which could be used in industrial cogeneration applications. Many issues, technical, institutional and regulatory, need to be addressed if industrial cogeneration is to realize its full potential benefits to the nation. However, the CTAS concentrated on one portion of these issues, namely, to determine from a technical and economic standpoint the payoff of advanced technologies compared to currently available equipments in increasing the implementation of cogeneration by industry.

OBJECTIVE, OVERALL SCOPE, AND METHODOLOGY

The objectives of the CTAS effort were to:

1. Identify and evaluate the most attractive advanced conversion systems for implementation in industrial cogeneration systems for the 1985-2000 time period which permit increased use of coal or coal-derived fuels.

2. Quantify and assess the advantages of using advanced technology systems in industrial cogeneration.

To select the most attractive advanced cogeneration energy conversion systems incorporating the nine technologies to be studied in the CTAS, a large number of configurations and cycle variations were identified and screened for detail study. The systems selected showed desirable cogeneration characteristics and the capability of being developed for commercialization in the 1985 to 2000 year time frame. The advanced energy conversion system-fuel combinations selected for study are shown in Table 2-1 and the currently available systems used as a basis of comparison are shown in Table 2-2. These energy conversion systems were then heat matched and power matched to over 50 specific industrial processes selected primarily from the six major energy consuming industrial sectors of food; paper and pulp; chemicals; petroleum refineries; stone, clay and glass; and primary metals. Several processes were also included from wood products and textiles.

On each of these matches analyses were performed to evaluate and compare the advanced technology systems on such factors as:

- Fuel Energy Saved
- Flexibility in Fuel Use

Table 2-1

GE-CTAS ADVANCED TECHNOLOGY COGENFRATION ENERGY CONVERSION SYSTEMS MATCHED TO FUELS

	Coal	Coal Derived Liquids Residual	Coal Derived Liquids Distillate
Steam Turbine	AFB*	Yes	---
Pressurized Fluid Bed	Yes	---	---
Gas Turbine			
Open Cycle-HRSG	---	Yes	Yes
Regenerative	---	---	Yes
Steam Injected	---	Yes	---
Combined Gas Turbine/Steam Turbine Cycle			
Liquid Fired	---	Yes	---
Integrated Gasifier Combined Cycle	Yes	---	---
Closed Cycle-Helium Gas Turbine	AFB	---	---
Thermionic			
HRSG	FGD*	Yes	---
Steam Turbine Bottomed	FGD	Yes	---
Stirling	FGD	Yes	Yes
Diesels			
Medium Speed	---	Yes	Yes
Heat Pump	---	Yes	Yes
Phosphoric Acid Fuel Cell Reformer	---	---	Yes
Molten Carbonate Fuel Cell			
Reformer	---	---	Yes
Integrated Gasifier			
HRSG	Yes	---	---
Steam Turbine Bottoming	Yes	---	---

* AFB - Atmospheric Fluidized Bed
  FGD - Flue Gas Desulfurization

Table 2-2

GE-CTAS STATE OF ART COGENERATION ENERGY CONVERSION MATCHED TO FUELS

	Coal	Petroleum Derived Residual	Petroleum Derived Distillate
Steam Turbine	FGD	Yes	---
Gas Turbine	---	Yes	Yes
Diesel	---	Yes	Yes

- Capital Costs
- Return on Investment and Annual Energy Cost Saved
- Emissions
- Applicability to a Number of Industries.

These matches were evaluated, both on a specific process site basis, and on a national level where it was assumed that each ECS is applied without competition nationwide to all new applicable industrial plants.

Because of the many different types of conversion systems studied and myriad of possible combinations of conversion system and process options, key features of the study were:

- The use of consistent and simplified but realistic characterizations of cogeneration systems
- Use of the computer to match the systems and evaluate the characteristics of the matches.

A major effort was made to strive for consistency in the performance, capital cost, emissions, and installation requirements of the many advanced cogeneration energy conversion systems. This was accomplished first by NASA-LeRC establishing a uniform set of study groundrules for selection and characterization of the ECS's and industrial processes, calculation of fuel and emissions saved and analysis of economic parameters such as levelized annual energy cost and return on investment. These groundrules and assumptions are described in Section 3. Second, in organizing the study, as shown in Figure 2-1, GE made a small group called Cogeneration Systems Technology responsible for establishing the configuration of all the ECS's and obtaining consistent performance, cost and emission characteristics for the advanced components from the GE organizations or subcontractors developing these components. This team, using a standard set of models for the remaining subsystems or components, then prepared the performance, capital costs, and other characteristics of the overall ECS's. As a result, any component or subsystem, such as fuel storage and handling, heat recovery steam generator or steam turbine, appearing in

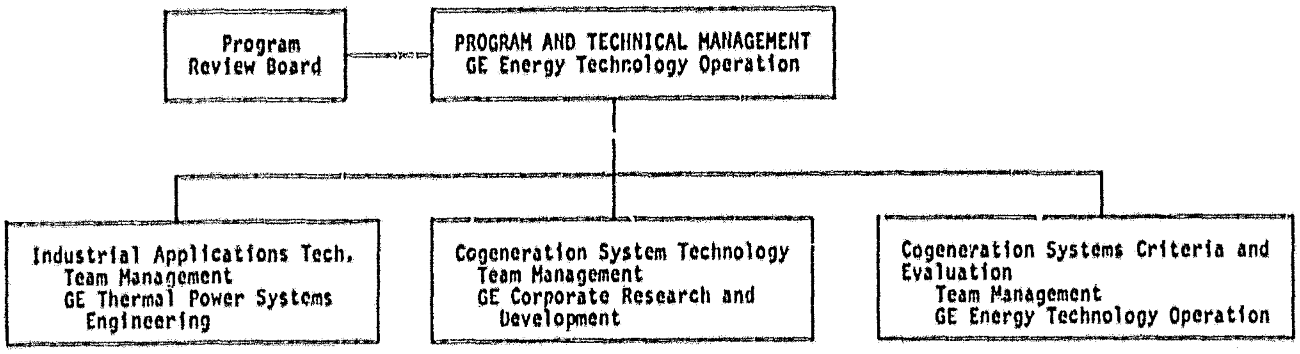


Figure 2-1. GE-CTAS Project Organization

more than one type ECS is based on the same model. This method reduces the area of possible inconsistency to the advanced component which, in many ECS's, is a small fraction of the total system. The characterization of the ECS's is described in Sections 5 and 6. The functions of obtaining consistent data on industrial processes from the industrial A&E subcontractors was the responsibility of the Industrial Applications Technology group and is described in Section 4. Matching of the ECS's and processes and making the overall performance and economic evaluations and comparisons was the responsibility of Cogeneration Systems Criteria and Evaluation. The methodology of matching the cogeneration systems is detailed in Section 8, the results of the performance analysis in Section 9, economic analysis in Section 10, the national savings in Section 11, and overall results and observations in Section 12.

Section 3

STUDY GROUNDRULES AND ASSUMPTIONS

Because of the scope and complexity of the CTAS and the need for a degree of consistency between the two parallel contractors, a number of groundrules were specified by NASA-LeRC. In the listing shown below these groundrules are grouped as applying principally to definition of the industrial processes; energy conversion system (ECS) performance, capital cost or emissions; matching the ECS to the industrial processes; economic analysis of matches; and the national savings when cogeneration is implemented versus nocogeneration. In establishing many of these groundrules NASA-LeRC obtained recommendations from DOE and the contractors. In addition to the common groundrules specified by NASA-LeRC, assumptions were made by the GE contractor. These are identified as (GE).

INDUSTRIAL PROCESS CHARACTERISTICS

In defining the more than 50 industrial processes to be studied in CTAS the following guidelines and groundrules were followed:

1. Processes be representative of the state-of-the-art which would be installed in new plants built during the 1985 to 2000 year time frame.

2. Represent a large national energy consumption and potential for cogeneration (a principal criterion).

3. Emphasize industrial processes requiring process steam and hot water. (GE)

4. Use average yearly capacity factors or operating hours and during the operating times use average electrical load and process heat requirements. (GE)

DEFINITION OF ENERGY CONVERSION SYSTEMS (ECS)

During the selection and definition of the performance, capital costs, and other characteristics of the energy conversion systems the following groundrules were used:

1. Advanced energy conversion systems were studied which could be commercially available in the 1985 to 2000 time frame after an intensive R&D program.

2. Emphasize energy conversion systems fueled by coal and coal derived liquids with the properties shown in Table 3-1.

3. Design and cost the ECS's to include cleanup equipment required to meet the emission requirements shown in Table 3-2. When uncertainty was encountered as to how the emission level specified could be met, the deficiency was included as a required development and a rough cost estimate included in the capital costs.

4. Assume boiler and heat recovery steam generators (HRSG) to have a boiler feedwater temperature of $170^{o}F$. (GE)

5. Set exhaust stack temperatures at $300^{o}F$ or higher if required by pinch point requirements, except for fuel cells. (GE)

6. Assume all process and auxiliary boiler efficiencies equal 85%. (GE)

7. All bottoming turbines; e.g., in the combined-cycle fuel cell and thermionic are 1465 psia/$1000^{o}F$ turbines. (GE)

8. Do not employ supplemental firing of heat recovery steam-generators. (GE)

9. Cost commercially available components, islands and balance of plant items common to more than one ECS using the same performance-cost model; e.g., steam turbines, boilers, heat recovery steam-generators, fuel storage and handling, structures, etc.

Table 3-1

LIQUID FUELS SPECIFICATIONS

	Petroleum #2 Distillate	Petroleum #5 Residual	Coal-Derived #2 Distillate	Coal-Derived #5 Residual
Sulfur, % wt.	.5	.7	.5	.7
Nitrogen, % wt.	.06	.25	.8 nominal	1.0 nominal
Hydrogen, % wt.	12.7	10.8	9.5 nominal	8.5 nominal
Ash, % wt.	--	.03	.06	.26
Specific Gravity	.85	.96	.95	1.05
Viscosity, Centistokes at 100° F	2.5	40	2.5	40
Boiling Range, °F 90% pts.	430-675	500-800	430-675	500-800
Cetane No.	45	40	45	40
Trace Elements, ppm wt. (order of magnitude)				
Vanadium	$\leq$ .5	30	.5	2
Sodium & Potassium	$\leq$ .5	50	1	20
Calcium	$\leq$1.0	5	2	5
Lead	$\leq$ .5	5	1	5
Iron	--	--	30	30
Titanium	--	--	20	50
High (Gross) Heating Value, Btu/lb	19,250	18,500	17,700	17,000

Table 3-2

EMISSION LIMITATION GUIDELINES

Emissions from energy conversion systems or auxiliary furnaces shall not exceed the values shown below:

(All units in $lbs/10^6$ Btu Heat Input)

Pollutant	Solid (Fuel Type)	Liquid	Gaseous[(a)]
NO_x	0.7	(b)	0.2
SO_x	1.2	0.8	0.2
Particulates	0.1	0.1	0.1
Smoke	20 SAE number	20 SAE number	20 SAE number

(a) For systems or auxiliary furnaces using LBtu gas produced on-site from coal, the solid fuel limitation shall apply.

(b) The NO_x limitations for the various liquid fuels is keyed to the nitrogen content in the fuel as follows:

Liquid Fuel	NO_x
Petroleum Distillate	0.4 $lbs/10^6$ Btu heat input
Petroleum Residual Fuel	0.5
Coal-Derived Distillate	0.5
Coal-Derived Residual Fuel	0.5

MATCHING OF ENERGY CONVERSION SYSTEMS (ECS) TO INDUSTRIAL PROCESSES

When the ECS is matched to an industrial process the following groundrules were used:

1. Match the ECS in two ways, (1) match the power requirements of the process, and (2) match the process heat requirements of the process. In the power match, if additional heat is required, an auxiliary boiler is added or, if excess process heat is produced by the ECS, the match is dropped from further consideration (GE). In the ECS heat match, if the ECS cannot supply the process power requirements, the needed power is purchased from the utility. If excess power is generated by the ECS, it is exported to the utility for revenue.

2. Nocogeneration case assumptions:

   - Place principal emphasis on a coal-fired nocogeneration process boiler. (GE)

   - Process boiler efficiency - 85%. (GE)

   - Process boiler type and fuel sized as follows: (GE)

     <30 x 10^6 Btu/yr heat output, petroleum or coal residual

     30 x 10^6 - 100 x 10^6 Btu/hr heat output, coal AFB

     >100 x 10^6 Btu/hr heat output, coal, flue gas desulfurization

   - Waste or by-product fuels converted to heat at various efficiencies depending on type of waste fuel. Fossil fuel and by-product fuel assumed to be fired in same boiler. (GE)

   - Utility fuel-electric efficiency - 32% including transmission and distribution losses.

   - Process boiler emissions are:

	lb/10^6 Btu Fired		
	NO_x	SO_2	Part.
petroleum residual-fired boiler	0.22	0.75	0.016
coal-derived residual-fired boiler	0.5	0.8	0.1
AFB coal	0.27	1.2	0.1

   - Emissions due to burning waste or by-product fuels are not included. (GE)

3. Cogeneration case assumptions:

   - o Approximate the process steam saturation temperature used to determine the performance parameters of a cogeneration system by using the peak temperature in systems consisting of a heat recovery steam-generator to supply process steam. When the process steam is extracted from a steam turbine, the weighted average temperature of multiple process steam conditions is used.

   - o In the fuel saved by type calculations assume that the mix of utility fuel displaced by cogenerated power is 23% gas and oil and 77% coal. Utility emissions are set equal to specifications shown in Table 3-2.

   - o Auxiliary boiler efficiency - 85%. (GE)

   - o Waste or by-product fuels combustible in all systems that use coal except for systems with coal gasifier.

   - o Emissions due to burning waste or by-product fuels are not included. (GE)

   - o Minimum size of energy conversion system not observed when calculating fuel energy or emissions savings. (GE)

ECONOMIC EVALUATION OF ENERGY CONVERSION SYSTEM-INDUSTRIAL PROCESS MATCHES

In the economic analysis the following groundrules and values of parameters were used:

1. In the calculation of return on investment (ROI) and levelized annual energy cost (LAEC) use the detailed methodology prescribed in NASA "Groundrules for CTAS Economic Analysis".

2. All economic calculations are made on an inflation-free basis. (Sometimes this is called using constant dollar analysis and in this report all results are in 1978 dollars. Escalation of particular expense or revenue above the inflation rate is included).

3. Assume all ECS plants are 100% industrially-owned.

4. Use values of specific parameters in the economic analysis as shown in Table 3-3.

5. When the maximum practical size of a component is exceeded by the ECS plant size requirement, use the minimum number of equal size units which will not exceed the maximum size allowed for the component. (GE)

Table 3-3

ECONOMIC ANALYSIS GROUNDRULES
(All Costs are in 1978 Constant Dollars)

Factor	Value
Annual Inflation Rate	0
Cost of Debt (before taxes) Above Inflation	3%
Fraction of Debt in Capital	30%
Cost of Preferred Equity Above Inflation	-
Fraction of Preferred Equity in Capital	0
Cost of Common Equity Above Inflation	7%
Federal & State Income Tax Rate	50%
Tax Depreciation Method	Sum of Years Digits
Tax Depreciation Life	15 Years
Salvage Value	0
Investment Tax Credit	10%
Local Real Estate Taxes and Insurance	3%
Useful Life of Investment	30 Years
First Full Year of Operation	1990
Capital Cost Escalation Rate Above Inflation	0
Cost of Fuels, Power & Expendables for 1985 in 1978 $'s	
Coal	$ 1.80/10^6 Btu
Distillate Oil (Petroleum or Coal-Derived)	$ 3.80/10^6 Btu
Residual Oil (Petroleum or Coal-Derived)	$ 3.10/10^6 Btu
Natural Gas	$ 2.40/10^6 Btu
Purchased Power	$ 0.033/kWh
Exported Power	0.6 x purchase power rate
Limestone	$10.00/Ton
Dolomite	$12.50/Ton
Escalation of Fuels & Power Above Inflation	
Coal	1%
Distillate Oil (Petroleum or Coal-Derived)	1%
Residual Oil (Petroleum or Coal-Derived)	1%
Natural Gas	4.6% (1985-2000) 1.0% (2000-)
Purchased & Exported Power	1%
Limestone	0
Dolomite	0

NATIONAL SAVINGS ANALYSIS

In estimating indicators of the nationwide fuel and emissions savings to permit comparison of the various types of ECS's, the following ground-rules were followed:

1. Potential cogeneration applications consist of new industrial process plants built from 1985 to 2000 because of the need for additional capacity or to replace old or obsolete plants. (GE)

2. In comparing ECS's on a national level, assume each ECS is implemented independently of all other ECS's.

Section 4

INDUSTRIAL PROCESSES

Industrial process data representative of those major energy consuming processes expected to be in place in the 1985-2000 time period were used to provide a realistic framework for the evaluation of cogeneration systems. Industry experts provided data on processes selected primarily from the six major energy-consuming industry groups as listed in the Manufacturing Division of the Standard Industrial Classification (SIC) Manual:

(1) Food and Kindred Products

(2) Paper and Allied Products

(3) Chemical and Allied Products

(4) Petroleum Refining

(5) Stone, Clay and Glass Products

(6) Primary Metal Industries

This section describes the process selection and provides a summary of pertinent data.

INDUSTRIAL DATA SUBCONTRACTORS

Table 4-1 presents the industry groups used in CTAS, the industry experts subcontracted with to provide data and the national industrial energy consumption of these groups as reported by the Annual Survey of Manufacturers, 1976.

Table 4-1

CTAS INDUSTRY GROUPS
Industrial Process Data Subcontractors & 1976 Energy Consumption

SIC	Industry	*Purchased Power & Electric Energy, Btu x 10^{12}	*% National Industrial Energy	Subcontractor
20	Food & Kindred Products	937.5	7.4	General Energy Assoc.
22	Textile Mill Products	328.6	2.6	J.E. Sirrine Co.
24	Lumber & Wood Products	243.8	1.9	J.E. Sirrine Co.
26	Paper & Allied Products	1 294.6	10.3	J.E. Sirrine Co.
28	Chemical & Allied Products	3 017.1	23.9	Dow Chemical, Midland
29	Petroleum & Coal Products	1 291.7	10.2	Dow Chemical, Midland
32	Stone, Clay & Glass Products	1 219.6	9.7	GE Lamp Glass (Glass)
				Kaiser Engineers (Stone & Clay)
33	Primary Metal Industries	2 380.5	18.9	Kaiser Engineers
	Total	10 713.4	84.9	
	All Industries	12 625.3	100.0	

* Source: U.S. Department of Commerce, Annual Survey of Manufacturers, 1976, Issued March 1978

The textile and lumber products industry groups were added to the six major energy consumers industry groups because processes in the textile industry have a high steam use and the wood products industry has a high growth rate.

The energy consumption of these industry groups as measured by the Annual Survey of Manufacturers 1976 data is about 85% of all U.S. manufacturing industries. (The data include only purchased fuel and electric power and does not take into account the use of energy from industry-owned sources or the electric utility conversion efficiency of fuel energy to electric energy.)

INDUSTRIAL PROCESS SELECTION

The industrial process subcontractors gathered data on present energy use and energy consumption growth trends and projections for the top energy consuming industries within their assigned industrial groups. The initial data were reviewed and screened and representative industrial plants were selected for use in following tasks of this study for evaluation of cogeneration systems. The following factors were considered or used in selecting the industrial plants:

- Process energy consumption characteristics representative of those anticipated to be used in the 1985-2000 time period.
- Processes represent major energy consumers and reflect a reasonable distribution in the industry groups previously specified.
- Processes include diverse energy needs requiring a variety of power systems.
- Processes using a variety of fuel types with emphasis on those using clean fuels.
- Processes be potentially good candidates for cogeneration with emphasis on topping or front end systems.

Typical plant capacities were selected for each industry to represent sizes of new plants expected to be constructed in the 1985-2000 time period. Fifty nine representative industrial plants were selected and approved by NASA for use in this study. Included were multiple plants employing the same process but having different capacities to account for the influence of plant size on cogeneration economics. A list of the industries selected for further study is presented in Table 4-2.

DATA SUMMARY

Process data sheets were filled out by the industrial process subcontractors for their assigned industries. Each subcontractor was requested to supply completed data sheets, process descriptions, flow diagrams, a discussion of current plants and future plans or trends, analysis of energy requirements, and a rationale for selection of the process for study. The narrative report and data sheets as completed by the subcontractors are included in Volume III, Industrial Process Characteristics.

Some of the data for each of the selected industries are presented in Table 4-2. The electric power requirements are given in both MW of electricity and converted to the heat equivalent, MBtu/hr. The process

Table 4-2

SELECTED INDUSTRY PROCESSES & SUMMARY OF ENERGY REQUIREMENTS

SIC Code	Process No.	Description	Process Electric Power MW_e	Process Electric Power MBtu/hr	Process Steam MBtu/hr	% Hot Water	Temperature ^oF Peak	Temperature ^oF Avg.	Power /Heat Ratio	Load Factor hrs/yr	Primary Fuel	By-Product or Waste Fuel Avail MBtu/hr	National Energy Consumption Utility + Site 10^{12} Btu/yr 1978	1985	2000
20 FOOD AND KINDRED PRODUCTS															
2011	1	Meat-Packing	1.940	6.625	24	40	250	250	0.28	2100	Gas		71	96	168
2026	1	Fluid Milk	1.310	4.474	11	50	250	250	0.41	2100	Gas		71	80	101
2046	1	Wet Corn Milling	28.500	97.327	659		250	250	0.15	6600	Gas		104	141	159
2063	1	Beet Sugar Refining	4.700	16.050	301		250	250	0.05	2800	Gas	76.47	100	118	162
2082	1	Malt Beverage	6.040	20.627	86	60	250	250	0.24	6600	Gas		75	120	190
22 TEXTILE MILL PRODUCTS															
2260	1	Textile Finishing	6.200	21.173	158		341	331	0.13	6240	Coal		75	75	75
24 LUMBER AND WOOD PRODUCTS															
2421	1	Soft Wood-Lumber Sawmill	1.500	5.123	30		353	353	0.17	4000	Bark-Sawdust	41.2	237	300	400
2436	1	Soft Wood-Plywood/Veneer	3.000	10.245	75		406	406	0.14	6000	Bark	100.0	100	150	275
2492	1	Particle Board	5.000	17.075	37		406	406	0.46	8000	Natural Gas	41.2	32	100	172
26 PAPER & ALLIED PRODUCTS															
2621	2	Bleached Kraft	50.000	170.750	780		366	340	0.22	8400	Coal	353	416	454	784
2621	4	Unbleached Kraft	29.000	99.035	610		366	328	0.16	8400	Coal	259	405	441	950
2621	6	Neutral Sulfide Semichemical	20.000	68.300	307		366	345	0.22	8400	Coal		63	69	128
2621	7	Thermo-Mechanical Pulping	31.300	106.889	183		366	355	0.58	8400	Coal		102	110	205
2621	8	Waste Paper	15.000	51.225	224		366	355	0.21	8400	Coal		176	191	419
28 CHEMICAL & ALLIED PRODUCTS															
2800	1	Small Integrated Power Plant	32.500	110.923	1100			366	0.101	8760					
2800	2	Medium Integrated Power Plant	77.200	263.484	1054			366	0.25	8760					
2800	3	Large Integrated Power Plant	97.200	331.744	947			366	0.35	8760					
2812	1	Chlorine - Caustic Sods	120.000	409.800	265		338	311	1.55	8500	Any		180	240	300
2813	1	Cryogenic Oxygen	34.000	116.110	0		0	0	999.99	8400	Electric		22	33	66
2819	1	Alumina	30.290	103.440	980		495	434	0.11	8136	Coal-Oil		53	76	135
2821	2	Vinyl Chloride	4.000	13.660	207		422	373	0.07	8300	Gas		50	110	160
2821	3	Low Density Polyethylene Resin	55.000	187.825	16		448	448	11.74	7900	Any		18	38	60

Table 4-2 (Cont'd)

SELECTED INDUSTRY PROCESSES & SUMMARY OF ENERGY REQUIREMENTS

SIC Code	Process No.	Description	Process Electric Power MW_e	Process Electric Power MBtu/hr	Process Steam MBtu/hr	% Hot Water	Temperature °F Peak	Temperature °F Avg.	Power /Heat Ratio	Load Factor hrs/yr	Primary Fuel	By-Product or Waste Fuel Avail MBtu/hr	National Energy Consumption, Utility + Site 10^{12} Btu/yr 1978	1985	2000
28 CHEMICAL & ALLIED PRODUCTS (Cont'd)															
2822	1	Styrene-Butadiene Rubber	7.500	25.612	35		338	338	0.73	7900	Any		7	9	13
2824	1	Polyester Fibre	32.000	109.280	30		406	406	3.64	7900	Gas-Oil		30	55	75
2824	2	Nylon Fibre	11.000	37.565	23		274	274	1.63	8760	Any		14	20	25
2865	2	Cumene-Benzene	0.600	2.049	0		0	0	999.99	8400	Gas-Oil		6.5	10	15
2865	3	Phenol/Acetone	6.000	20.490	300		489	398	0.07	8200	Any		20	45	60
2865	4	Ethylbenzene	0.700	2.390	220		489	489	0.01	7900	Oil-Gas		22	45	65
2869	1	Methanol Synthesis	1.500	5.123	133		574	538	0.04	7880	Feedstock	352.9	0	0	0
2869	4	Ethanol	3.300	11.270	400		460	460	0.03	7900	Gas-Oil	70.6	18	24	30
2873	1	Ammonia Synthesis	3.500	11.952	640		598	598	0.02	8400	Gas-Oil		200	250	305
2874	1	Phosphoric Acid	4.000	13.660	92		353	292	0.15	7900	Gas-Oil		35	48	60
2895	1	Carbon Black	4.000	13.660	20		298	298	0.68	7900	Oil-Gas		18	20	24
29 PETROLEUM REFINING															
2911	1	Small Refinery	14.000	47.810	375		470	389	0.13	8760	Oil-Der		560	580	630
2911	2	Medium Refinery	52.000	177.580	1333		470	395	0.13	8760	Oil-Der		850	870	950
2911	3	Large Refinery	126.000	430.290	3042		470	385	0.14	8760	Oil		1220	1250	1280
32 STONE, CLAY AND GLASS															
3211	1	Flat-Glass	5.600	19.124	0		0	0	999.99	7500	Nat-Gas				
3221	1	Glass Containers	5.100	17.416	0		0	0	999.99	7500	Nat-Gas				
3229	1	Press-Blown Glass	1.100	3.756	0		0	0	999.99	7500	Nat-Gas				
3241	1	Cement	20.316	69.379	0		0	0	999.99	7920	Coal				
33 PRIMARY METALS															
3312	1	Specialty Steel	60.000	204.900	93		448	446	2.20	6700	Nat-Gas		560	643	835
3325	1	Integrated Steel	280.000	956.200	912		448	445	1.05	8400	Cok-Coal	529.4	3080	3539	4596
3325	4	Mini-Steel	40.000	136.600	91		448	446	1.50	6700	Nat-Gas		360	612	1070
3331	1	Copper-Fire Smelted	24.800	84.692	0		0	0	999.99	8400	Oil		4.6	5.8	9.3
3331	4	CopperAnode Smelted	10.100	34.491	40		364	364	0.86	7620	Oil		12.2	15.5	24.8
3334	1	Aluminum	756.000	2581.740	0		0	0	999.99	8760	Oil		31.8	49.2	86.4

heat requirement indicates the quantity of steam required in MBtu/hr, the percent of the heat that is supplied as hot water when it is not all steam, and both peak and average temperatures. The power to heat ratio (P/H), as implied, is the ratio of process P/H (steam) in the same units. The load factor indicates the number of hours per year that the industry operates or requires heat and power. The primary fuel listed is that currently being used. In those industries where waste fuel is available, the quantity in MBtu/hr is shown. The last three columns show the projected national energy consumption in 10^{12} Btu/yr for the year 1978 and for the years 1985 and 2000. These data include fuel energy required for sensible (direct) heat required as well as that for steam and generation of electric power by a utility.

Graphical summaries of this data are shown in Figures 4-1 to 4-3. In Figure 4-1 the P/H is shown versus the total process heat. Diagonal lines indicate the electric power requirements in MW. The process heat requirements vary from 10 to over 3000 MBtu/hr. P/H varies from 0.01 to 3.6 on the figure but one process is off the scale of the chart at nearly 12 (see Table 4-2, SIC 28). Several industries have requirements for heat that are well above the range of temperatures applicable to the conversion systems being considered. These industries, such as glass, cement, copper smelters, and aluminum are shown in Table 4-2 as having no process heat requirements. However, they could have the potential for use with bottoming conversion systems to produce electricity. Because of the severe operating conditions - e.g., high temperatures and corrosive gases - each would have to be considered separately.

Figure 4-2 shows P/H ratio versus the process temperature. Except for the very high temperature industries, all require temperatures in the 250 to 600^{o}F range. Figure 4-3 shows P/H versus the load factor in hr/yr that the plant is operated. Most high energy consuming plants have high load factors excepting those in the food processing industries.

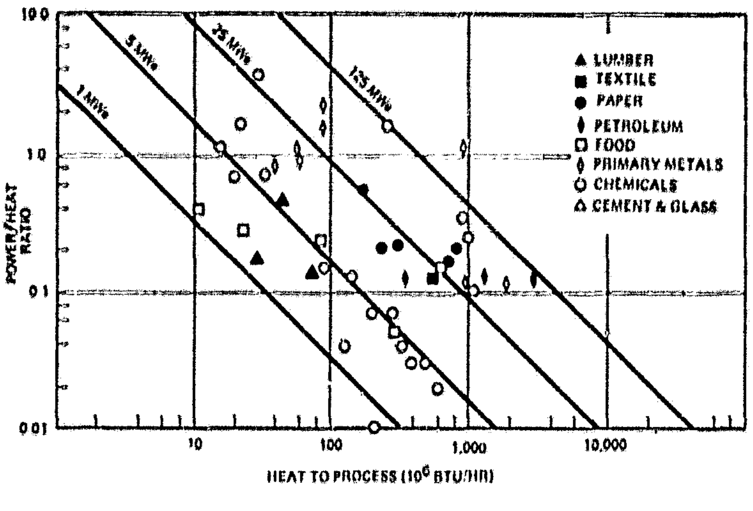


Figure 4-1. Industrial Process Characteristics Graphic Summaries (Power/Heat Ratio Versus Heat to Process)

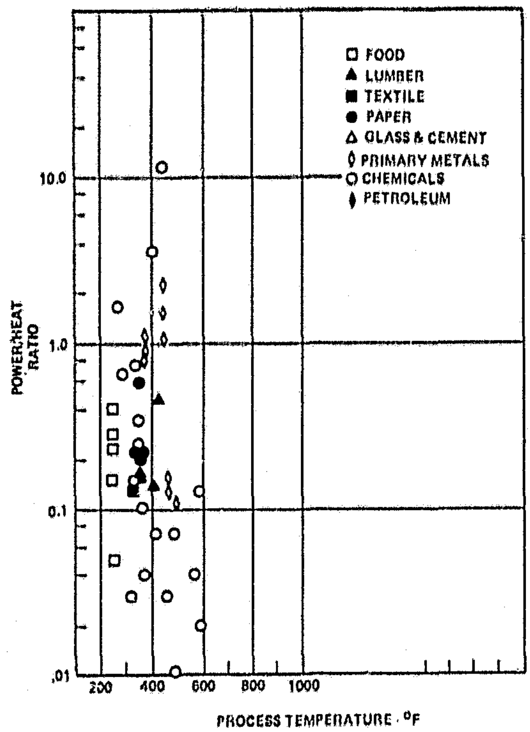


Figure 4-2. Industrial Process Characteristics Graphic Summaries (Power/Heat Ratio Versus Process Temperature)

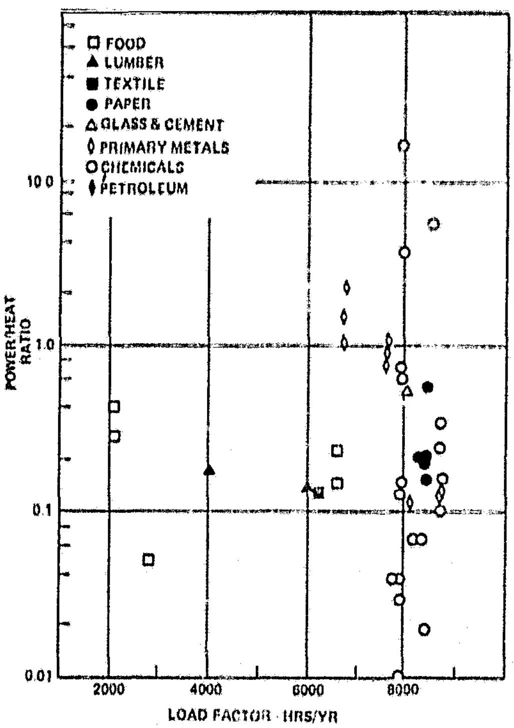


Figure 4-3. Industrial Process Characteristics Graphic Summaries (Power/Heat Ratio Versus Load Factor)

Section 5

ENERGY CONVERSION SYSTEMS

INTRODUCTION

Cogeneration couples an energy conversion system (ECS) to both a power and a process heat requirement for a particular industrial plant or process. State-of-the-art energy conversion systems that are in use for cogeneration are steam turbines, gas turbines, and diesel engines. Of these current options, only the steam turbine system is capable of burning coal. Advanced energy conversion systems considered in this study were thermionic conversion of heat to electricity, stirling cycles, closed-cycle helium gas turbine, phosphoric acid fuel cell, molten carbonate fuel cell, advanced air-cooled and water-cooled gas turbines, combined-cycle and combined-cycle with integrated coal gasifier, advanced diesel and advanced diesel with heat pump, and advanced steam generation using atmospheric fluidized beds and pressurized fluidized beds to burn coal. Each advanced energy conversion system was evaluated at a projected level of performance and cost that could be commercially available to industry in the time span of 1985 to 2000. More advanced performance can be projected beyond that time frame, but the contribution to national fuel savings would be small. The significant developments required for each type of advanced energy conversion system are enumerated.

A means of expressing the important performance attributes of energy conversion systems was developed in this study in order to explicitly match the heat to process and the power cogenerated to the designated process temperature. The expressions that result are very simple, and they are based on fundamental thermodynamic relationships. These results are expressions for the power generated per unit of fuel energy and heat to process per unit of fuel energy related to the process temperature required by the industrial process. Quadratic expressions provide an excellent fit for the nearly linear results. The final results of this work are performance characterizations of each energy conversion system that can be fitted to any industrial process requirement.

The costs of energy conversion system components were subjected to a similar disciplined approach. To assure uniformity, common components, such as noncondensing steam turbines, were assigned the same cost schedule for every application. Thus, steam turbines for use with all types of boilers, with gas turbines, with fuel cells, and with thermionics all exhibit the same performance and cost schedule wherever they appear in the study. Cost comparisons were made with other more detailed studies to assure the validity of the total energy conversion system costs that were synthesized for cogeneration in this study.

ENERGY CONVERSION SYSTEM DATA SOURCES

The principal sources of data were General Electric specialists in particular fields and the General Electric Energy Conversion Alternatives Study (ECAS) (Ref.1,p 5-34) performed for NASA. Additional expertise was secured in areas where General Electric experience was not specific to industrial applications or where a broadened overview was necessary. Table 5-1 presents a tabulation of the major contributing organizations associated with each major technical aspect of the study.

The selection of data sources and energy conversion system expertise was made to obtain estimates of performance and costs that would realistically meet industrial requirements. A balance between optimism and conservatism was sought from all data sources.

Table 5-1

ENERGY CONVERSION SYSTEM DATA SOURCES

System	Sources
Steam Turbine & Steam Sources	General Electric - ECAS Study - Industrial Turbine Sales & Engineering Operation
Gas Turbine Cycles	General Electric - Gas Turbine Division
Diesel Engines	DeLaval Corporation
Pressurized Fluidized Bed Steam Cycle	General Electric - ECAS Study - Energy Systems Programs Dept.
Thermionic Steam Plant	General Electric - EPRI Study - Corporate Research & Development
Stirling Cycle	General Electric - Space Division North American Philips
Closed Cycle Gas Turbine	General Electric - ECAS Study
Fuel Cells - Molten Carbonate - Phosphoric Acid	Institute of Gas Technology General Electric - Direct Energy Conversion Programs - Energy Systems Programs Department - Energy Technology Operation
Integrated Gasifier Combined Cycle	General Electric - Corporate Research & Development - Gas Turbine Division - Energy Technology Operation
Heat Recovery Steam Generator	General Electric - Industrial Turbine Sales & Engineering Operation
Heat Pumps	General Electric - Corporate Research & Development

FUEL CONSIDERATIONS

The specifications for fuels as used in this study are presented in Section 3 (STUDY GROUNDRULES). Their application to energy conversion systems are presented in Table 5-2. Generally the lower grade of fuel was favored for the study. Coal and coal-derived liquid fuels received the major emphasis. Distillate fuels, either petroleum based or coal-derived, were included only for the few ECS's that could not tolerate low grade fuels. As examples, the regenerative gas turbine, very small stirling cycles, and small diesels require distillate. In addition, state-of-the-art turbines and diesels burning both distillate and residual grade petroleum oils were included in the study. An indication (symbol OK) is given in Table 5-2 where a fuel could be used, but it was not evaluated in this study since a lower grade of fuel could be used and should produce a better economic result

Table 5-2

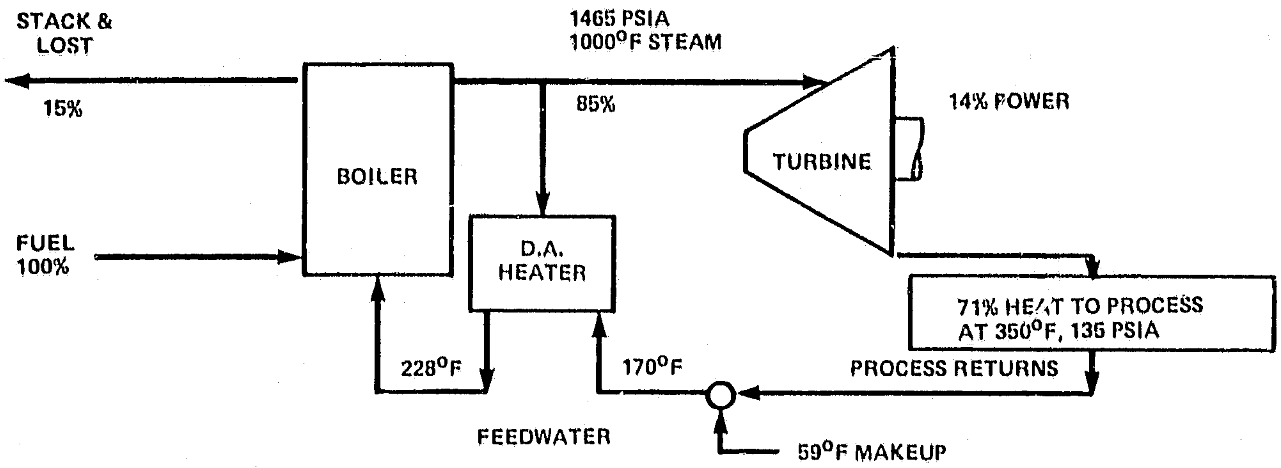
COGENERATION ENERGY CONVERSION SYSTEMS FUELS EVALUATED AND FUEL FLEXIBILITY

	Coal	Residual*	Distillate*
Steam Turbine	FGD	Yes	OK
	AFB	-	-
	PFB	-	-
Gas Turbine	-	Yes	Yes
Combined-Cycle	-	Yes	OK
Combined-Cycle - Integrated Gasifier	Yes	-	-
Helium Gas Turbine	AFB	OK	OK
Thermionic Steam	FGD	Yes	OK
Stirling Cycle	FGD	Yes	Yes
Diesel	-	Yes	Yes
Phosphoric Acid Fuel Cell	-	-	Yes
Molten Carbonate Fuel Cell	-	-	Yes
Molten Carbonate Fuel Cell - Integrated Gasifier	Yes	OK	-

FGD - Flue Gas Desulfurization
AFB - Atmospheric Fluidized Bed
PFB - Pressurized Fluidized Bed
OK - Fuel Flexibility Indicator
* - Both Petroleum Base and Coal Derived Liquids

ECS CHARACTERIZATION

The convention for describing process heat requirements has been the expression of the steam flow requirement in pounds per hour and the gage pressure at which that steam condenses. A steam turbine cogeneration system is illustrated in Figure 5-1 to serve as an example of the methodology used in this study. The boiler feedwater is brought to 228 F by a combination of makeup water at 59 F, process return water, and steam supply to the deaerator heater. For 100% fuel energy fired, of the order of 15% is accounted in stack loss and other system losses. The 85% of useful energy results in 14% electric power produced and 71% heat to process. The process temperature level is described by its condensing steam pressure, 135 psi absolute, or conventionally 120 psi gage.



VARIABLE: T PROCESS, EXHAUST PRESSURE

THROTTLE	EFFICIENCY	MW RANGE
1465 PSIA, 1000°F	80%	7.5 – 100
865 PSIA, 825°F	78%	5 – 50

ADVANCED ART: TURBINE GENERATOR NONE
STEAM BOILER-ATMOSPHERIC FLUIDIZED BEDS

Figure 5-1. Steam Turbine Cogenerator

If the steam turbine inlet conditions (Figure 5-1) were held constant at 1465 psia, 1000 F and the steam was expanded to atmospheric pressure, then a greater amount of turbine output would be achieved per pound of steam flow. Moreover, the preponderant temperature for the condensation of the exhaust steam would be 212 F. Now, if that same steam were expanded to 15 psi gage, less work would be produced, and the exhaust steam would have a predominant temperature of 250 F.

The characteristic of this steam turbine system is shown in Figure 5-2 for a non-condensing steam turbine cogeneration system with an 80% efficient steam turbine, an 85% efficient boiler and boiler feed at 170 F. Steam or process heat temperature, power, and heat to process all vary as steam turbine outlet pressure is varied. All parameters are expressed as fractions of the fuel-fired higher heating value. For the steam turbine the characteristics for power generated and for heat to process are

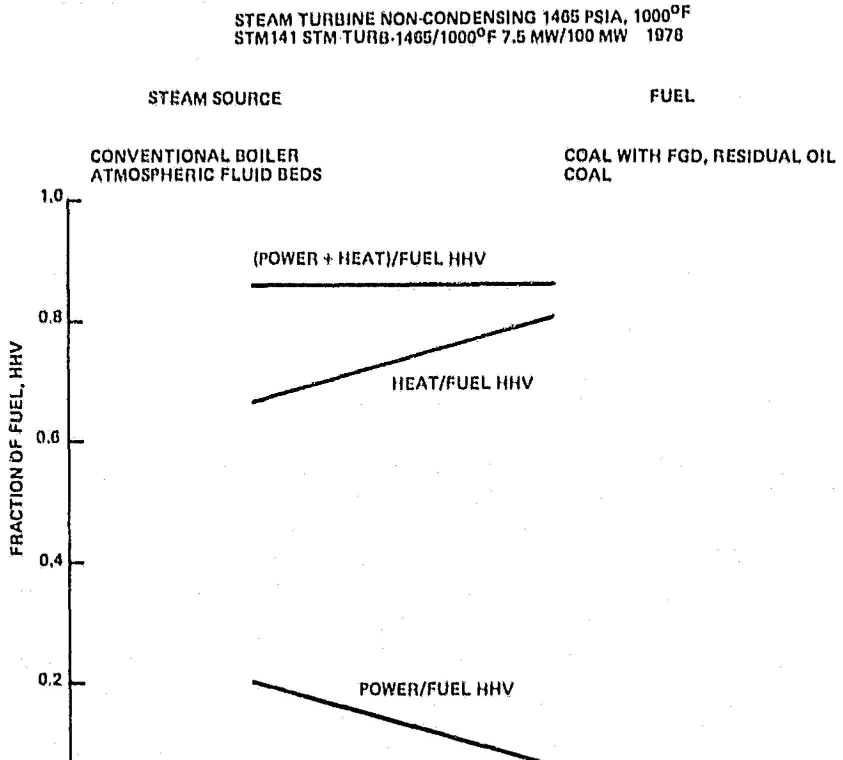


Figure 5-2. Energy Conversion System Characteristic

found to be close to linear as related to process temperature. The sum of power generated and heat to process was 0.85 at all process temperatures, and equals one minus the energy that was not made useful.

The synthesis of these cogeneration characteristics is readily understood in the context of the steam turbine cogenerator illustrated in Figure 5-1. In Figure 5-3 the turbine and the process are shown in the context of the effect of one pound of steam upon them. Evaluations start with assignment of the process temperature, TPRO. The steam tables then provide the saturation pressure for the process - that is the back pressure on the steam turbine. The isentropic steam turbine expansion work can then be found; when multiplied by the steam turbine efficiency of 80% the result is the turbine output expressed as Btu per pound of steam flow. The remainder of the steam energy span of 1353 Btu per pound (from inlet at 1491 to process return at 138) would be realized as process heat. The data for a range of process temperatures from 212 F to 500 F were calculated. These data were then correlated by a quadratic least squares fit to the process temperature:

$$\text{Btu/lb Turbine Output} = 531.85 - 0.856 * \text{TPRO} - 80 * \left(\frac{\text{TPRO}}{1000}\right)^2$$

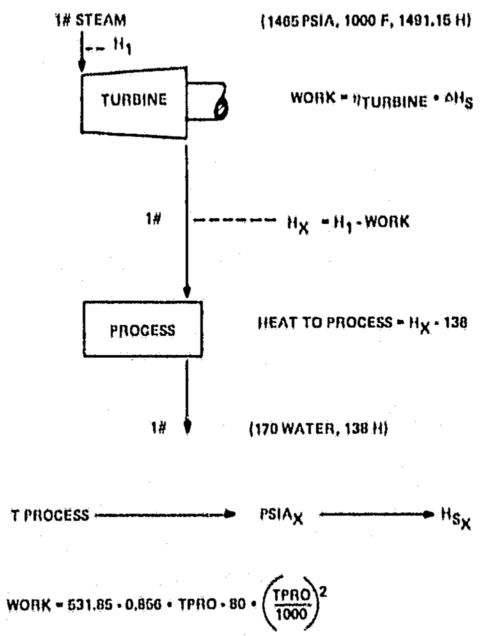


Figure 5-3. Synthesis of Steam Turbine Cogeneration Characteristic

Each energy conversion system has its own characterizing curves and constants and a range of power generation over which it can be applied. These characterizations and system parameters are presented in a series of charts for each ECS in Volume IV of the General Electric final report.

STEAM TURBINE ECS

Figure 5-1 shows a schematic of the steam turbine applied to cogeneration. The turbine is non-condensing since the entire exhaust steam flow is utilized as process steam. A condensing section on a cogeneration turbine would produce power at a lower efficiency than a utility steam turbine and would appreciably reduce the fraction of fuel energy realized in power and heat to process. The configuration of the process returns, makeup water, and feedwater system are detailed in Figure 5-1. The turbine costs were evaluated for a single automatic extraction non-condensing steam turbine. This selection provides for process steam at two levels where required, or alternatively for a feedwater heater and auxiliary steam main for the powerhouse. Two inlet throttle conditions were considered. The highest economic pressure level of 1465 psia was designated with the highest normal superheat of 1000 F. These conditions mandate full demineralization of the boiler feedwater. The lower throttle condition of 865 psia, 825 F was selected to avoid a large cost increment for high alloy steel superheaters and to use the least expensive feedwater treatment. The assigned steam turbine-generator efficiencies are within two points of the range of efficiencies appropriate to the power range of the units.

The span of steam turbine ratings selected and the chosen steam conditions represent the envelope of economic choices as evidenced by the industrial turbine application experience of General Electric. More advanced conditions have been available but the cost increments could not be justified.

Figures 5-2 and 5-3 show the cogeneration characteristics for the steam turbine system.

The steam turbine with state-of-the-art steam boilers is available today. Residual-fired boilers or coal-fired boilers with flue gas desulfurization are state-of-the-art. Substitution of coal-derived residual grade liquid fuel has already been demonstrated.

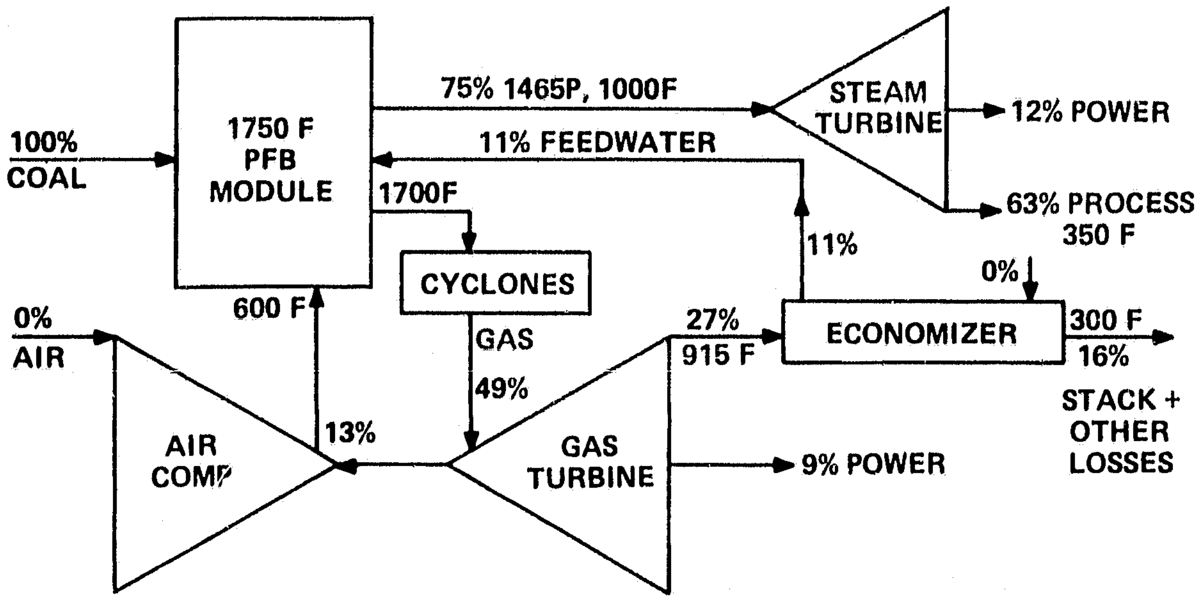
Atmospheric Fluidized Bed Boilers

The advanced art would substitute atmospheric fluidized beds for the steam boiler. Limestone and coal supported by the fluidizing air flow would burn, transfer heat to the steam, maintain the bed at 1550 F, and capture the sulfur products on the limestone. The flyash from the coal would be trapped in baghouse flue gas filters. The atmospheric fluidized bed system is expected to be less costly than the coal-fired boiler and FGD system that it would replace. Current development programs are in place to demonstrate process steam and power steam boilers of the AFB type. Commercial availability by 1985 is expected.

Pressurized Fluidized Bed Steam Cycle ECS

A second advanced means of utilizing coal for a steam turbine system is the pressurized fluidized bed system illustrated in Figure 5-4. The schematic and example heat balance at 350 F process temperature are derivatives from the electric utility PFB steam system evaluated in detail in the General Electric ECAS study (Ref.1,p 5-34). The gas turbine functions as a supercharger pressurizing the PFB and supplying all of the air for coal combustion. The gas turbine expands the combustion gases from 1700 F to 915 F. The PFB bed temperature is held at 1750 F by the simultaneous combustion of coal and intensive heat transfer to the imbedded steam generating tubes. Dolomite fed into the bed captures the sulfur from the coal.

The advanced art includes the PFB and the gas cleanup or gas turbine erosion protection means. The removal of particulates from the flue gas stream or the cladding of the gas turbine hot path to achieve erosion protection are essential developments. The system integration and control are also deemed significant developments. The evolution in PFB technology beyond raising steam and superheating it were excluded from this study. A gas-cooled PFB would transfer heat at tube metal temperatures well above those that are well proven for steam practice and was deemed to be at least a generation further away than the steam cooled PFB of this study.



FUEL:	COAL
VARIABLES:	PROCESS TEMPERATURE, STEAM TURBINE EXHAUST PRESSURE
RANGE:	13 MW - 600 MW
ADVANCED ART:	PFB, GAS CLEANUP
AVAILABILITY:	1990

Figure 5-4. Pressurized Fluidized Bed Cogenerator

GAS TURBINE - OPEN-CYCLE ECS

Table 5-3 presents the range of open-cycle gas turbine parameters. The liquid fuels are either petroleum or coal-based. The regenerative-cycle would be constrained to burning distillate. Residual firing tends to accumulate sticky deposits in regenerators that reduce the heat exchange effectiveness. Pressure ratios of 8, 12, and 16 were evaluated for advanced turbines. A value of 10 was assigned to state-of-the-art gas turbines. These values are appropriate for heavy duty industrial gas turbines. The total temperature at the first stage would be 2200 F for advanced air-cooled units and 2600 F for advanced water-cooled units.

Table 5-3

GAS TURBINE COGENERATOR PARAMETERS

• Fuels:	Residual, Distillate	
• Variables:	Process Temperature	
	Pressure Ratio -	8, (10), 12, 16
	Temperature, ^{o}F,	(1750), (2000), 2200, 2600
	Coolant	Air, Water
	Regeneration	0%, 60%, 85%
	Steam Injected	0%, 10%, 15%
	Bottoming Steam	1465 psia, 1000 F
		865 psia, 825 F
• Range:	Air Flow, pounds	per sec. 100 to 1000
	Output	10 MW to 200 MW
• Advanced Art:	2200 F	Air-Cooled Turbine
	2600 F	Water-Cooled Turbine
	CDL Fuel, Steam Injection	Water-Cooled Turbine
• Availability:	1985	Air-Cooled 2200 F
	1990	Water-Cooled 2600 F

Although greater firing temperatures have been projected for each type of turbine, these are values that are considered to be most reasonably attainable considering the pace of advancement, the time to prove out and debug advancements, and the implications of low NO_x emission constraints. State-of-the-art gas turbines were assigned 1750 F firing residual oil and 2000 F firing distillate. Regenerators were considered at 60% and 85% effectiveness. Gas turbines with steam injected at the combustor were evaluated using 15% superheated steam-to-air injection ratio which is at the exhaust visible plume limit, 10% with superheated steam and 10% with saturated steam. The latter gives a greater amount of process steam availability. Schematic heat balances for gas turbines supplied with 100 units of fuel energy are presented in Figure 5-5. The regenerative-cycle results in greater power production as compared to the simple-cycle. The regenerative effect reduces the temperature level of the exhaust gas with an adverse effect on heat to process. Thus, the sum of cogeneration energy available, both power and heat to process, was reduced by regeneration. This effect was noted in other energy conversion systems and illustrates the generality, "measures that normally improve the efficiency of thermal energy conversion systems may reduce the conversion of fuel energy to useful cogeneration energy". The schematic for the combined-cycle with a bottoming non-condensing steam turbine was included although it will be considered in a subsequent section.

Gas turbine performance is presented in Figure 5-6. Starting at the value with the least specific output is the state-of-the-art simple-cycle (SC) air-cooled (AC) unit firing residual oil at 1750 F, 10 pressure ratio (PR). The 10 PR characteristic continues to state-of-the-art distillate firing at 2000 F and then to 2200 F. At 2200 F the consequences of varied pressure ratio are shown with highest efficiency at 16 PR. Had the pressure drop imposed by the HRSG been omitted, then the advanced air-cooled simple-cycle gas turbine at 2200 F would have shown greater specific output and efficiency as illustrated.

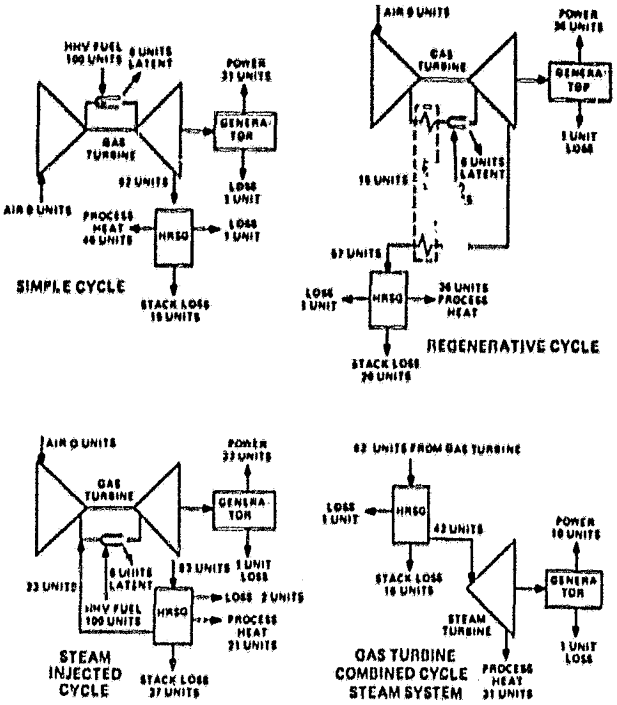


Figure 5-5. Gas Turbine Cogenerators

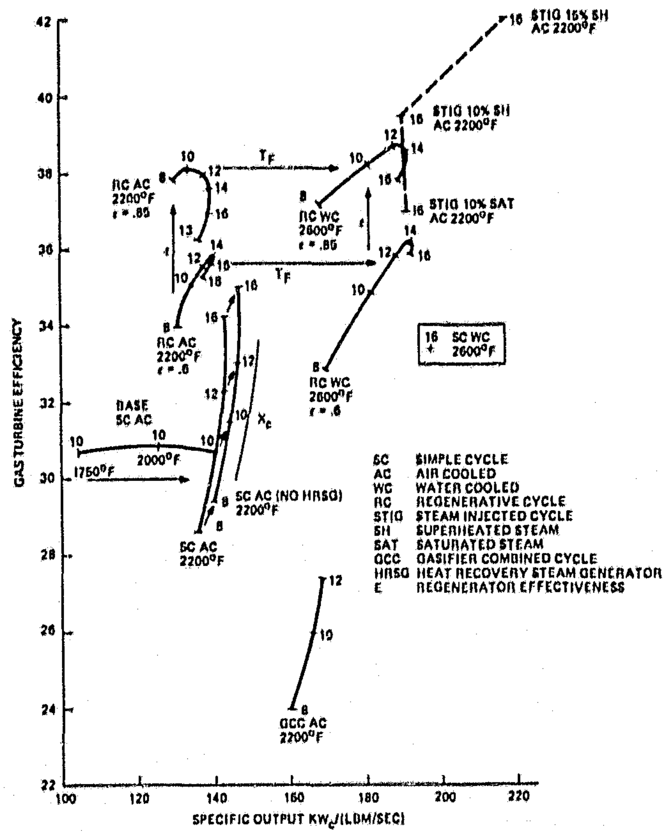


Figure 5-6. CTAS Gas Turbine Performance Map

The effect of regeneration (regenerative cycle - RC) at 60% effectiveness (ε) is found to have a higher efficiency, but at reduced specific output. With 85% effectiveness even greater efficiency results with a 38% maximum at 10 PR. The performance for the 2600 F, 16 PR simple-cycle water-cooled gas turbine is shown within the rectangular box. The specific output is significantly increased while the efficiency is less than the 16 PR air-cooled unit due to the heat removed by the water coolant. The regenerative water-cooled units reach efficiencies comparable to the air-cooled units at appreciably greater specific outputs.

The three steam injected gas turbine cases are located amongst the regenerative water-cooled characteristics. They exhibit extremely high specific output and efficiency when compared to any of the air-cooled or water-cooled alternatives.

The available thermal energy in the exhaust stream of these gas turbines is presented in Figure 5-7. The basis is a gas turbine compressor airflow of 1000 pounds per second, and heat exchange to cool the exhaust to 300 F. In general, the units with greater efficiency have a reduced amount of energy in the exhaust stream.

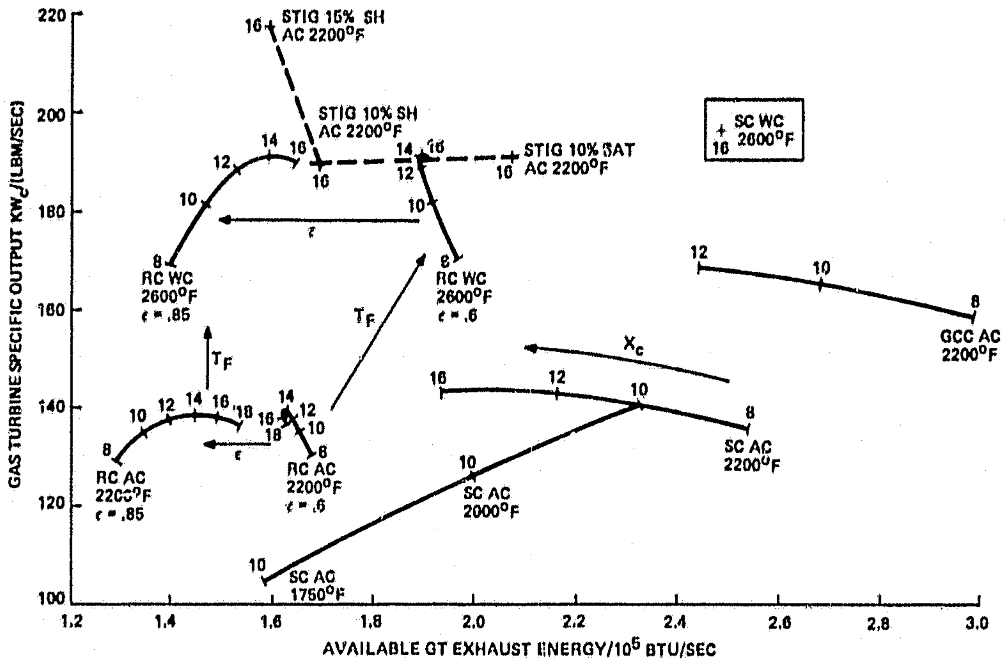


Figure 5-7. Gas Turbine Available Exhaust Energy, 1000 Pounds per Second Airflow and Exhaust-Cooled to 300 F

For the gas turbine cycles, the ratio of power to fuel HHV was independent of the temperature or heat to process. Where the exhaust temperature was sufficiently hot the exhaust could be cooled to 300 F. For those cases the heat to process was constant at the levels shown in Figure 5-7 and was independent of process temperature. The range of gas turbine compressor inlet airflow was a minimum of 100 pounds per second and a maximum of 1000 pounds per second. The lower limit was deemed to be marginal for residual firing due to the propensity for cooling passage plugging and for accelerated abrasive erosion of turbine buckets. The upper limit was deemed attainable by advances in technology for compressors and turbines. All turbine costs were based on single shaft constant speed units including the 60 cycle generator. The power range was 10 MW to 100 MW for state-of-the-art units up to 20 MW to 200 MW for advanced water-cooled units.

Advances in the gas turbine that require significant development are the achievement of 2200 F in an air-cooled gas turbine and the achievement of 2600 F in a water-cooled gas turbine. The steam injected gas turbine would require development of its combustor and steam injection control. A broad development for all gas turbines would be NO_x limiting combustion systems that would meet the new emissions standards. It was assumed that these developments would be successful for petroleum based liquid fuels, but their success for coal-derived liquid fuels with high fuel-bound nitrogen was deemed moot.

DIESEL ECS

The diesel engines considered were of medium speed and size that are typically applied in industry and in municipal power generation. Residual oil is the typical fuel. Distillate would become a required fuel only in small sizes. Diesel advancement has been evolutionary. It is expected to continue that way. Cylinder coolant temperature level may climb from the 150 F level to 250 F for advanced diesels. General Electric feels that concepts such as the adiabatic diesel with ceramic parts or the slow speed coal-burning diesel will require prolonged development to meet the standards of reliability and maintenance expense required for industrial implementation, and would be beyond the advanced diesels that will be ready for cogeneration application over the period 1985 to 2000. Therefore, such concepts were not included in this General Electric study. Table 5-4 presents the details of diesel heat balances appropriate for cogeneration. For the state-of-the-art diesels only 58% of the fuel energy would be utilized if the heat to process temperature was above 175 F. For the advanced diesel more heat is available at higher temperatures. Nonetheless, only 63% of the fuel energy would be available to be utilized for cogeneration at a process temperature of 300 F.

Table 5-4

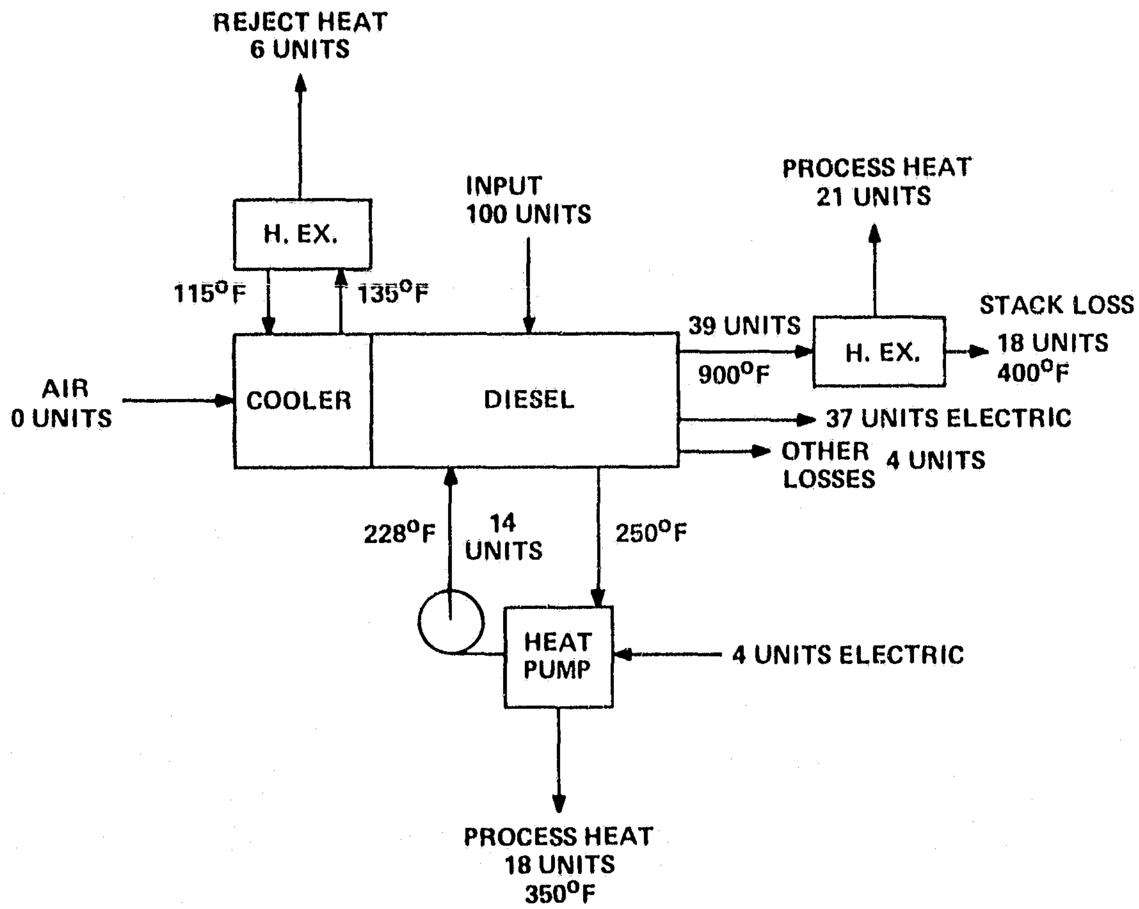
COGENERATION DIESEL HEAT BALANCES - RESIDUAL FUEL

Energy Source	State-of-the-Art Energy/Fuel Energy		Advanced Energy/Fuel Energy	
Air Cooler	0.0576	115 F to 135 F	0.0576	115 F to 135 F
Lube Oil	0.0481	156 F to 170 F	0.050	228 F to 250 F
Jacket Water	0.1332	160 F to 175 F	0.0874	228 F to 250 F
Exhaust Gas	0.2201	300 F to 820 F	0.254	300 F to 900 F
Subtotal	0.459		0.449	
Power Net	0.361		0.371	
Total	0.820		0.820	
Losses	0.180		0.180	

Diesel Heat Pumped ECS

The drastic reduction in available heat to process at temperatures above 228 F in the advanced diesel is a severe detriment to the diesel cogenerator. Higher coolant temperatures such as 300 F or 350 F for the jacket water would require severe reductions in power output to maintain cylinder wall temperatures that assure lubrication of the upper piston rings. Also the gross distortion of the cylinders from cold to operating temperatures would introduce great design integrity uncertainties. An open-cycle heat pump was added to the advanced diesel so that the jacket water heat could be realized as process heat at temperatures higher than 228 F. The compressor of the heat pump was electrically driven to assure flexibility and ease of control.

A heat balance for the diesel-heat pump cogenerator serving a 350 F process is presented in Figure 5-8.



- VARIABLE: PROCESS TEMPERATURE
- ADVANCED ART: VAPOR COMPRESSION HEAT PUMP
  DIESEL JACKET WATER 250°F
- AVAILABILITY: 1990

Figure 5-8. Diesel Heat Pump Cogenerator Schematic Heat Balance

The heat pump is added to the basic advanced diesel which is unchanged. The heat pump delivers 18 units of heat from 14 units of jacket water heat and 4 units of electrical drive input. The aggregate heat to process is 39 units per 100 units of fuel energy, and the net power produced is 33 units. Without the heat pump these values would be 21 and 37 respectively. The heat to process is nearly doubled by application of the heat pump, and the fuel energy utilization becomes 72% in place of 58%.

The heat pump system would require modest development effort. The compressor inlet steam density is comparable to atmospheric air. Conventional compressor technology is applicable. Primary concerns would be the influence of the temperature level on the compressor and its seals. As compared to the advanced diesel alone, the diesel heat pump cogenerator has a greatly enhanced characteristic as shown in Figure 5-9.

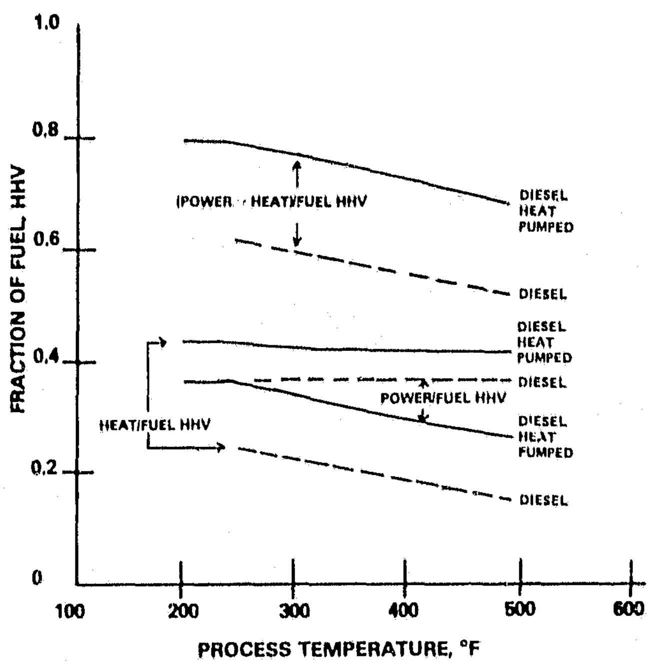


Figure 5-9. Energy Conversion System Characteristics. Advanced Diesel, Heat Pump Providing Process Steam from Jacket Water Heat by Vapor Compression; Jacket Water Temperature, 250°F; Residual Fuel; 2 to 15 MW; Availability, 1990

The development of the diesel to the performance levels projected was deemed to be evolutionary. Higher supercharge pressures, intercooling and aftercooling charge air, and evolution into compound engines are recognized development routes. Alternate fuels such as coal slurries in oil are being considered by DOE but were not included in this study. Degradation of performance and of the injection equipment due to the hardness of coal particles, their slow burning and their ash content were considered by GE to be barriers to their economic use in industrial cogeneration.

The jacket water temperature of the medium speed diesel would be brought to 250 F. This is deemed to be a significant development for an industrial size diesel. Small diesels experience only small thermal distortion due to temperature. The means to accommodate higher temperatures are more severely limited as diesel size increases. Higher temperatures such as 300 F or 350 F jacket water would be excellent for coupling to industrial processes. In GE's judgement, extrapolation from the evolutionary history of diesel development shows that these temperatures are not to be expected in the time span of 1985 to 2000. The open-cycle heat pump using 250 F jacket water as its heat source was considered as an alternative to reach high process temperatures. Although the evaluation and costing were based on conventional components, such a unit would be a significant development. Its system integration and control would also be significant.

Both current and advanced diesels will produce exhaust products that exceed future NO_x emission standards. Exhaust gas denoxification systems will become mandatory for all industrial diesels in the future. In the time span to 1990 such exhaust treatments should be developed and commercially demonstrated. The diesel engine representative for this study determined that the total cost attributed to advanced diesel cogeneration systems should cover the expense of this additional equipment.

COMBINED GAS TURBINE-STEAM TURBINE ECS

Liquid-fired combined-cycle energy conversion systems were synthesized from the advanced simple-cycle gas turbines already considered and the two non-condensing steam turbines that formed the basis for this entire study. A basic heat balance is presented schematically in Figure 5-5 by combination of the simple cycle-diagram in the upper left and the steam-cycle at the lower right. The specific combinations evaluated are detailed in Table 5-5. The utilization of fuel energy was greatest at 0.76 for the unit at lowest pressure ratio and air-cooled, and measures that enhance efficiency such as increased pressure ratios had a detrimental effect on the overall utilization of energy for cogeneration. There were no advancements in these combined-cycles except for those already enumerated for the gas turbine.

Table 5-5

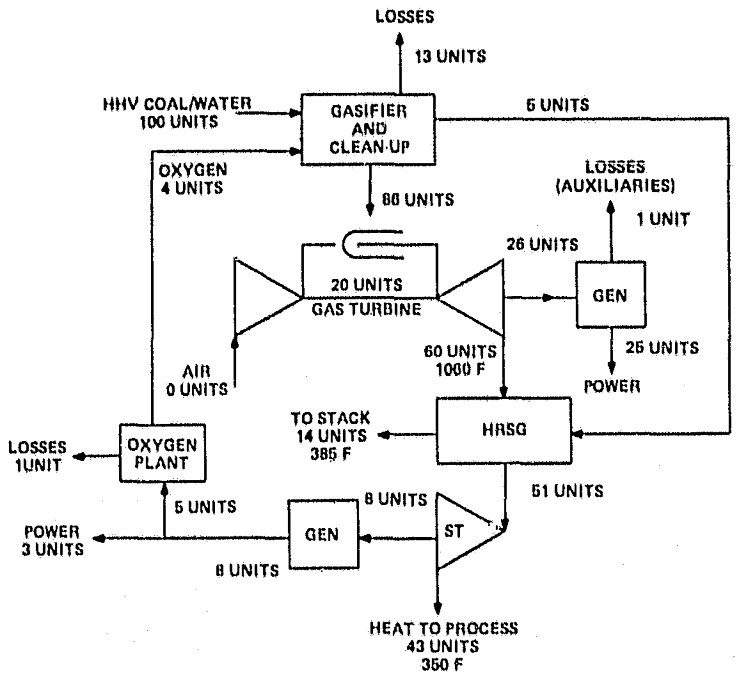
ADVANCED COMBINED-CYCLE COGENERATORS, RESIDUAL FIRED

Pressure Ratio	Steam Turbine	Size	(Power + Heat)/ Fuel HHV
Air-Cooled Gas Turbine, 2200 F, 1985 Availability			
8	1465 psia, 1000 F	14 MW to 136 MW	0.76
12	1465 psia, 1000 F	14 MW to 143 MW	0.72
16	865 psia, 850 F	17 MW to 165 MW	0.72
Water-Cooled Gas Turbine, 2600 F, 1990 Availability			
16	1465 psia, 1000 F	20 MW to 200 MW	0.69

Integrated Gasifier Combined-Cycle ECS

The gasification of coal can be integrated with a gas turbine burning the product fuel gas and a non-condensing steam turbine to form a unique cogeneration system.

Figure 5-10 presents a schematic and sample heat balance for the adaptation of coal gasification to fuel a gas turbine - steam turbine combined-cycle for cogeneration. The steam turbine is a non-condensing 1465 psia, 1000 F unit as described earlier. The gasifier is an advanced entrained bed Texaco oxygen-blown gasifier. The hot gas stream that leaves the gasifier contains sulfurous compounds and other chemical species that could harm the gas turbine or would violate emission limitations. An extensive gas cleanup system cools these gases, chemically removes objectionable species, and then reheats the fuel gas and resaturates it with water vapor. Heat collected in cooling the raw fuel gas is used for making steam and reheating the clean fuel gas.



FUEL: COAL

VARIABLES: PROCESS TEMPERATURE
STEAM TURBINE EXHAUST PRESSURE

RANGE: 80 MW - 600 MW

ADVANCED ART: GASIFIER, GAS CLEANUP, GAS TURBINE
SYSTEM INTEGRATION

Figure 5-10. Integrated Gasifier-Gas Turbine Cogenerator

The high volume of the coal-derived intermediate-Btu fuel gas requires a special combustion system for the gas turbine. A firing temperature of 2100 F, pressure ratio of 12:1, and first-stage turbine nozzle water-cooling were used for the advanced gas turbine. The greater mass flow of combustion gases as compared to a conventional gas turbine produce greater generator output and more steam from the HRSG. The non-condensing steam turbine produces about one fifth of the total power output at 350 F process temperature. The cogeneration characteristics for process temperatures from 200 F to 450 F are presented in Figure 5-11.

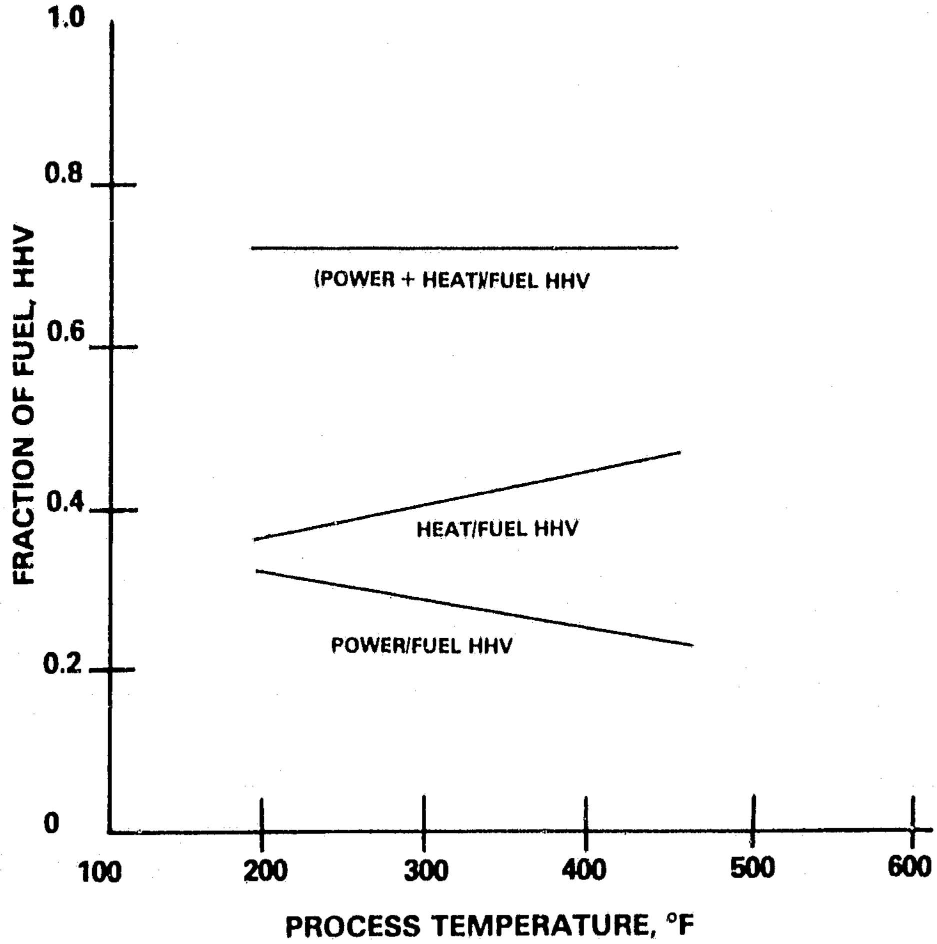


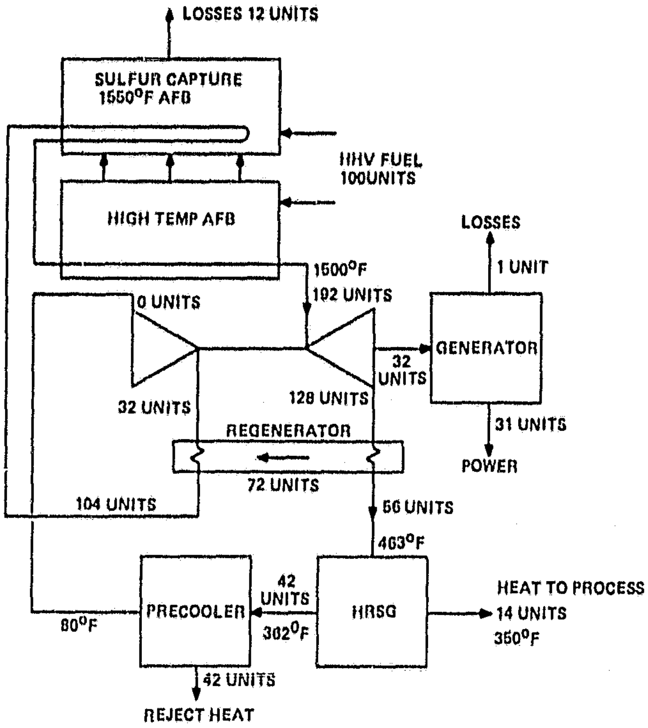
Figure 5-11. Energy Conversion System Characteristics. Integrated Coal Gasification with Water-Cooled Gas Turbine. Pressure Ratio, 12; Firing Temperature, 2100°F; Steam Turbine 1465 psia, 1000°F Non-Condensing; Coal Fuel

Advanced art for this coal-fueled gas turbine and steam turbine would be the gasifier, the gas cleanup system, the gas turbine, and the system integration and control. The required high pressure level for coal gasification requires numerous gasifier components to be developed beyond the state-of-the-art. The fuel gas cleanup system requires development to assure the retention of chemical and thermal energy after the cleanup process. The high level of system integration to achieve high efficiency mandates significant system integration and control development to avoid spurious system upsets and outages.

CLOSED-CYCLE GAS TURBINE ECS

The closed-cycle gas turbine system selected for cogeneration was adapted from the General Electric ECAS study (Ref.1,p 5-34). The helium turbine and compressor designs closely resemble machinery designed for use with the high temperature helium-cooled nuclear reactor and the European 50 MW unit that is operational in a fossil-fired demonstration district heating cogeneration application. A schematic of the system serving a 350 F process demand is presented in Figure 5-12. The coal-fueled atmospheric fluidized bed combustors are in two stages in order to heat the helium to 1500 F. This differs significantly from the AFB designs for steam where the bulk of the heating is below 600 F and the non-boiler portion is all below 1000 F. As shown in Figure 5-12, the high temperature AFB stage would operate at temperatures up to 2000 F where very little sulfur could be captured. The lower temperature 1550 F AFB bed would capture the sulfur from the gases leaving the high temperature bed as well as that from the coal burned within it, using limestone as the sulfur sorbent. Combustion air preheat would require high temperature elements in order to fully utilize the exhaust energy and reach a minimum loss stack temperature of 300 F.

All of these special features add to the cost of the AFB for helium as compared to the AFB for steam. This added costliness must be the case wherever the heated medium is hotter, 1000 F to 1500 F in this case,



FUEL:	COAL
VARIABLES:	PROCESS TEMPERATURE 250°F TO 550°F REGENERATOR 0%, 60%, 85% EFFECTIVENESS
RANGE:	50 MW - 300 MW
ADVANCED ART:	TWO STAGE AFB - HELIUM HEATER REGENERATOR
AVAILABILITY:	1990

Figure 5-12. Helium Closed-Cycle Cogenerator

or has poorer heat transfer coefficients than steam. The closed-cycle using air as its medium has lower heat transfer coefficients than helium, would require even greater cost in its AFB and other heat exchangers, and has poorer aerodynamic characteristics than helium. Consequently, only helium was considered as a working fluid in the General Electric evaluation.

The closed-cycle heat balance example achieves high efficiency in making power through the use of an 85% effective regenerator. As a result, the helium flow to the HRSG is at 463 F, and relatively little process steam is produced. A heat rejection system is necessary to bring the helium to the 80 F compressor inlet condition. The heat rejection deprives the closed-cycle of considerable cogeneration energy. The closed-cycle gas turbine is best adapted to cogeneration where there would be a considerable demand for heating at low temperature. Water heating service and space heating as in a district heating service would provide the opportunity for greater fuel energy utilization than provided by typical industrial processes.

The cogeneration characteristics for the helium closed-cycle gas turbine with a regenerator effectiveness of 60% is presented in Figure 5-13. At higher process temperatures greater cycle heat rejection is required so that the sum of power plus process heat becomes progressively less and cogeneration effectiveness is reduced.

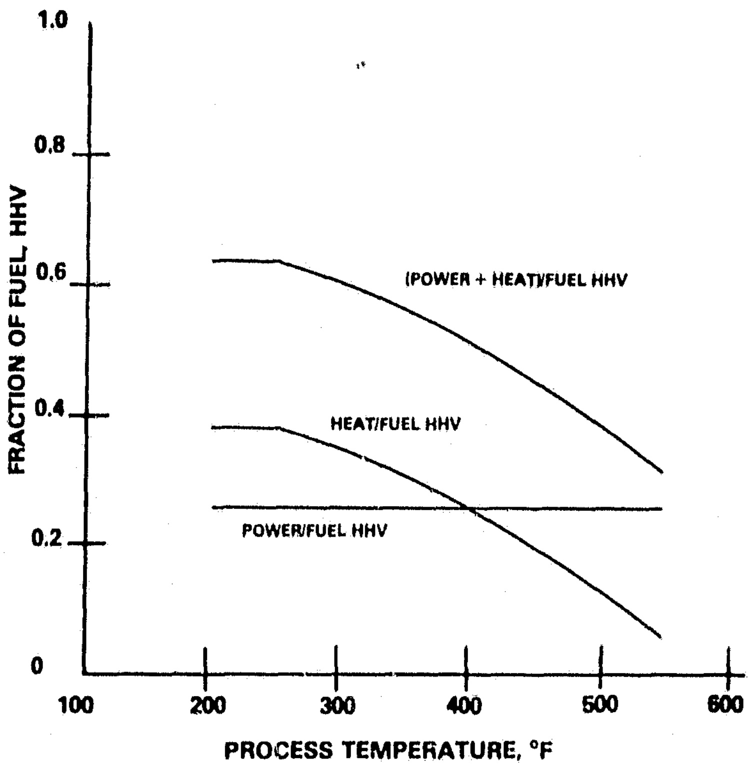
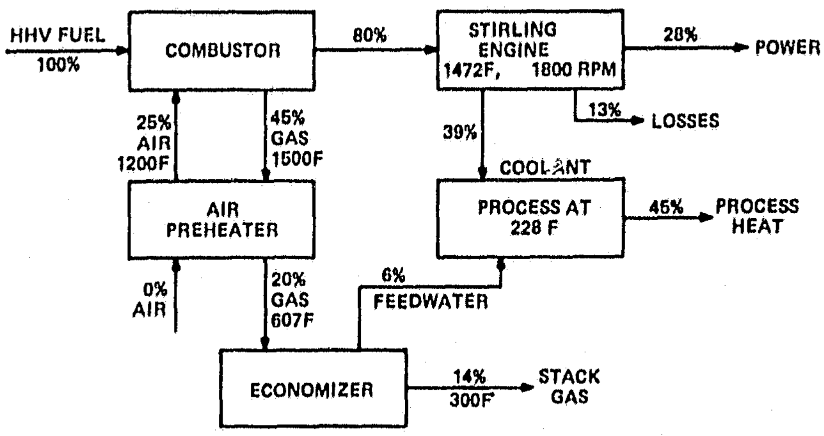


Figure 5-13. Energy Conversion System Characteristics. Helium Closed-Cycle Gas Turbine, AFB Coal Fuel; Regenerator Effectiveness, 60%; Applicable Size, 50 to 300 MW; Availability, 1990

The helium closed-cycle gas turbine unit was not considered to be a significant development. A 50 MW unit is already operational in Germany. It and other closed-cycle gas turbine units utilize oil, coke oven gas, and pulverized coal as fuels. The significant advanced art would be development of a two-stage atmospheric fluidized bed to burn coal and capture sulfur while heating helium from 1000 F to 1500 F. The two-stage gas-heating AFB represents a major development beyond the development of steam-producing AFB's. The gas-heating AFB must use high alloy heat exchanger material or ceramic materials. These material requirements greatly increase the cost of the gas-heating AFB as compared to the steam-producing AFB.

STIRLING CYCLE ECS

The stirling cycle uses helium as an enclosed working medium in a piston engine configuration. The heat input to the helium is at 1472 F from an external combustion heat source as illustrated in the schematic and heat balance of Figure 5-14. Small demonstration stirling cycles have



FUEL : COAL, RESIDUAL, DISTILLATE
VARIABLES : PROCESS TEMPERATURE 228F TO 500F
RANGE : 500 kW TO 2 MW
ADVANCED ART: INDUSTRIAL STIRLING CYCLE
AIR PREHEATER TO 1200F
COAL BURNER HEAT EXCHANGER
AVAILABILITY: 1990

Figure 5-14. Stirling Cycle Cogenerator

run on distillate. Residual firing is an expected evolution. Coal firing would require a separate off-engine combustor with a heat coupling medium such as a helium loop capable of operation above 1500 F. Pulverized coal firing with flue gas desulfurization was deemed the most certain means to provide heat from coal. The two-stage AFB used for the helium closed-cycle gas turbine could not be used since all of the heat would be required at temperatures hotter than the sulfur capture stage of that unit. Serving a process heat demand at 228 F, the stirling cycle of Figure 5-14 achieves 28% efficiency related to the fuel higher heating value and delivers 45% heat to process for a cogeneration energy utilization of 73%. Figure 5-15 shows the cogeneration characteristics for process temperatures from 200 F to 500 F. Consideration was given to use of hydrogen as a working fluid and to slower unit speeds of 900 RPM in place of 1800 RPM. Although better efficiency would result, these alternatives would adversely affect the industrial safety and the specific cost of the stirling cycle and were eliminated from the study.

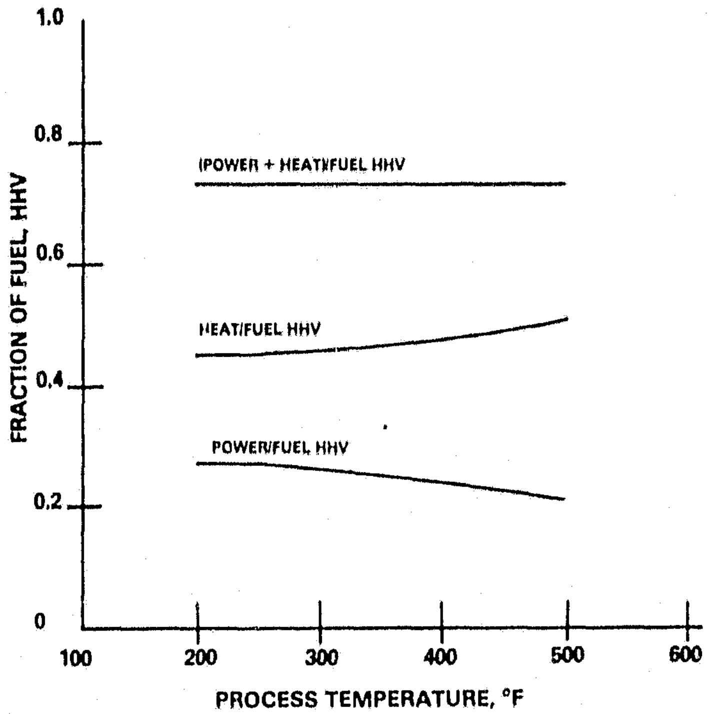


Figure 5-15. Energy Conversion System Characteristics. Stirling Engine Cycle, 1472°F Hot Side, Helium Working Fluid; Fuel Energy into Engine, 80%; Fuels: Distillate, Residual, Coal with FGD; Applicable Size, 0.5 to 2 MW; Availability, 1990

Stirling cycle efficiency would be improved by use of heat input temperatures above 1472 F. This selected temperature level corresponds to the availability of super alloy metals with adequate creep rupture strength when hot. Ceramics that might permit higher temperatures and efficiencies were judged to be inappropriate selections for this study since the likelihood of their development to commercialization by 1990 was remote.

Significant developments are necessary in order to commercialize an industrial-size stirling cycle for cogeneration application. Development efforts to date have focused on smaller units for automotive service where the fuel would be distillate. The larger industrial size and the shift to residual fuel firing represent significant developments. The high temperature air preheater requires development. The adaptation for coal-firing was deemed to represent a development effort comparable to that of the industrial size stirling cycle itself.

THERMIONIC ECS

Thermionic units receive high temperature radiant and convective heat transfer at their emitters, and transmit both direct current electricity and heat energy to their collectors. The collectors are most readily cooled by use of heat pipes connecting the collector to extended finned cooling surfaces that are cooled by airflow. The thermionic unit performance is shown in Figure 5-16 along with values appropriate for a combined thermionic-steam utility power plant as labeled "EPRI". The high temperature (1600 K) unit was cooled to 710 F collector temperature to achieve a high 38% heat input to direct current conversion. The low temperature (1300 K) unit has the same cogeneration (CTAS) efficiency of 25% as that used for the utility study.

The heat balance shown in Figure 5-17 shows that 17% of the fuel higher heating value is realized as direct current electricity, and 71% would be available as input to a steam boiler to provide process heat or to power a non-condensing bottoming steam turbine. The thermal energy leaving the thermionic units serves to preheat the combustion air to 1000 F. The unit size would be from 3 to 100 MW; a 1465 psia, 1000 F

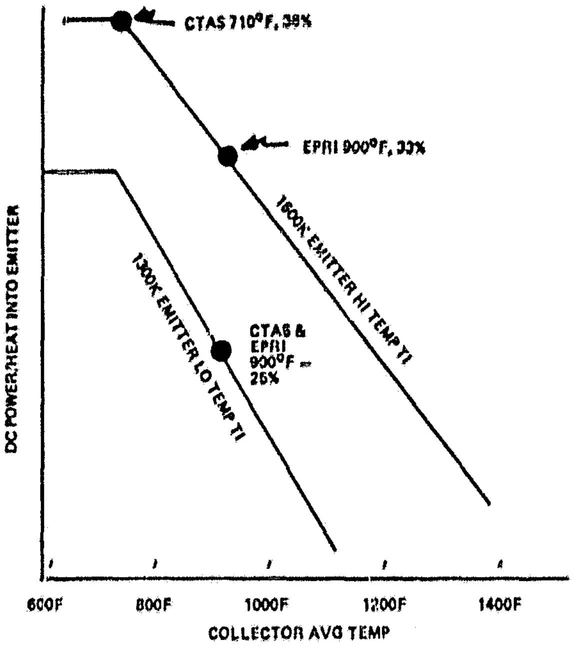


Figure 5-16. Thermionic Unit Performance

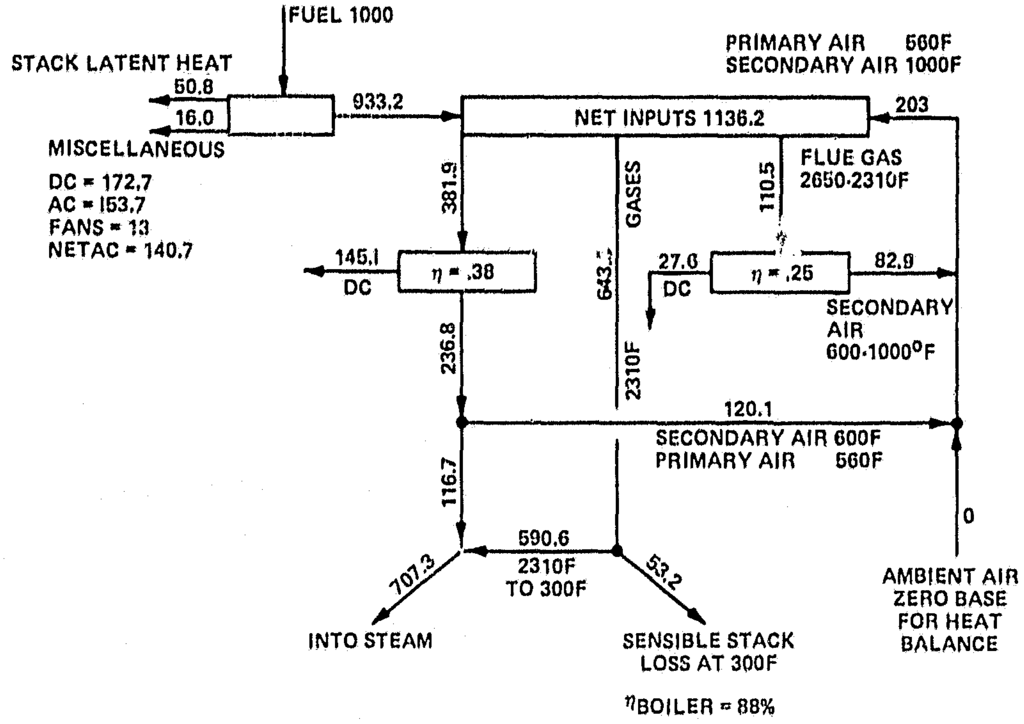


Figure 5-17. Thermionic-Steam Cogenerator Heat Balance Based on 1000 Btu Coal HHV

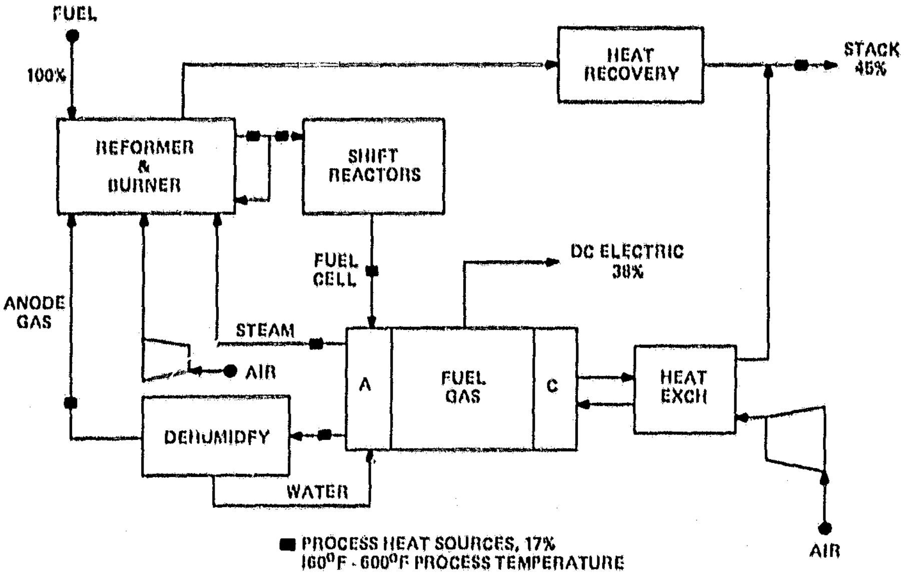
non-condensing steam turbine bottoming cycle would increase the size range to 12 MW to 300 MW. Residual oil would be fired in small units. Pulverized coal would be fired in large units and would require flue gas desulfurization. In both configurations staged combustion with 1000 F secondary air would be used to limit NO_x emissions.

The thermionic topping system has been studied conceptually for electric utility power generation, and now for industrial cogeneration application. Unit performance used in all these studies exceeds current performance appreciably. Significant thermionic element development is required before the development of conceptual applications can be started. One concept that is susceptable to early development is that of assembly of many thermionic elements into large panels and the incorporation of heat pipes to cool them. The conversion of dc to ac power from numerous low voltage dc elements requires development to assure high reliability and to achieve significant cost reduction. This development requirement is common to all dc energy producers.

An availability date of 1995 was applied to thermionic energy conversion for industrial cogeneration.

PHOSPHORIC ACID FUEL CELL

The phosphoric acid fuel cell operating at 375 F is shown schematically in Figure 5-18 with a rudimentary heat balance. The fuel gas at the anode is hydrogen. Since sulfur poisons the fuel cell, the distillate fuel oil must be processed through a zinc oxide reactor to remove its sulfur. The zinc oxide consumption imposes an appreciable operating expense. The reformer burns spent anode fuel gas and some distillate oil as its heat source and uses the bulk of the distillate fuel as a chemical feedstock. There is extensive heat exchange at the reformer that heats the incoming fluid streams and cools the effluent gas streams. The shift reactors produce a high concentration of hydrogen in the fuel gas stream. A great loss of water vapor would occur if a 300 F stack temperature were used. The stack gases are cooled to 100 F in order to recover and recycle water in the system. The cleanliness of the exhaust products permits this unusual practice. This high latent heat rejection at the stack produces the high 45% stack energy loss.



PHOSPHORIC ACID FUEL CELL

FUEL:	DISTILLATE - DESULFURIZED
VARIABLES:	PROCESS TEMPERATURE 160°F to 600°F
RANGE:	1 MW - 10 MW
ADVANCED ART:	PHOSPHORIC ACID FUEL CELL SHIFT REACTORS SYSTEM INTEGRATION
AVAILABILITY:	1985

Figure 5-18. Phosphoric Acid Fuel Cell Cogenerator

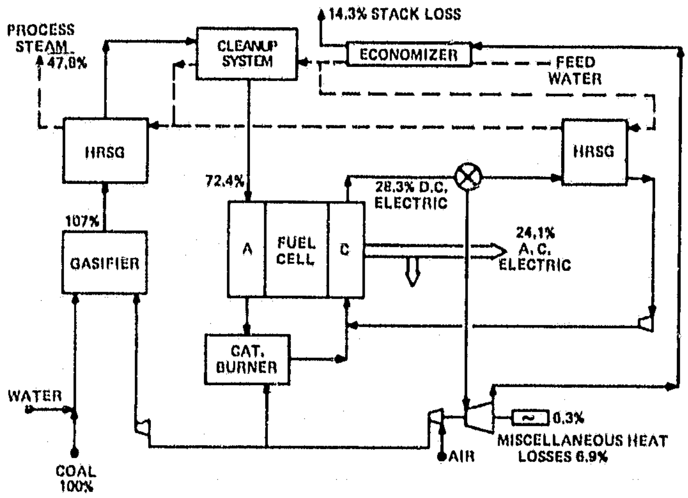
The cogeneration power produced is 38% of the fuel higher heating value. Although the fuel cell operates at a nominal 325 F to 375 F level, other heat exchangers operate at temperatures up to 750 F. Process steam can be produced at temperature levels from 160 F to 600 F to the extent of 0.17 of the fuel energy. If a water heating load were available in the range of 50 F to 200 F, then an additional 0.309 of fuel energy would be available for that service. The low temperature level of this additional heat source precludes its economic use with an open-cycle heat pump such as that described for use with the advanced diesel engine.

The low temperature phosphoric acid fuel cell module is currently the subject of a DOE commercialization study. Use of distillate fuels requires significant fuel gas cleanup system development to assure that the fuel cell module will not be poisoned. In common with other dc power sources, the dc to ac conversion system would benefit from further development.

MOLTEN CARBONATE FUEL CELL

The molten carbonate fuel cell operates at a high temperature of 1300 F. Figure 5-19 presents a schematic and heat balance for a coal-fueled molten carbonate fuel cell energy conversion system. The pressurized coal gasifier would be the entrained bed Texaco type where the effluent gases are at 2475 F. These gases are cooled by an HRSG enroute to the gas cleanup system. The fuel gas that is not consumed in the anode side of the fuel cell at 1300 F is burned with supplementary air in the catalytic burner. These combustion gases with added air provide the necessary oxygen on the cathode side of the fuel cell. The recirculation loop has an HRSG, a blower, and a hot gas bleed-off to the expansion gas turbine. The gas turbine exhaust passes through an economizer to be cooled to the minimum stack temperature of 300 F. The aggregate net ac power produced is 30.4% of the fuel energy of which 6.3% is produced by the gas turbine generator. The aggregate steam production from all HRSG's sends 47.8% heat to process.

The ability to produce high pressure steam can be exploited to increase power production by the addition of a non-condensing steam turbine with 1465 psia, 1000 F throttle conditions.



MOLTEN CARBONATE FUEL CELL

FUELS:	COAL, DISTILLATE
VARIABLES:	PROCESS TEMPERATURE 200°F TO 500°F
ADVANCED ART:	MOLTEN CARBONATE FUEL CELL GASIFIERS, SYSTEM INTEGRATION
AVAILABILITY:	1990

Figure 5-19. Molten Carbonate Fuel Cell Cogenerator

A greatly simplified system would be used for a small distillate-fired molten carbonate fuel cell. The basic fuel cell would be unchanged. The distillate would be processed in an autothermal reformer with air and steam to form the fuel gas. That gas stream would be cooled in an HRSG and then passed through a zinc oxide reactor to remove sulfur. The expansion gas turbine would be omitted and the air would be supplied by motor driven compressors. Table 5-6 shows the characteristics for these molten carbonate fuel cell energy conversion systems.

Table 5-6

MOLTEN CARBONATE FUEL CELL ENERGY CONVERSION SYSTEMS

Fuel	Coal		Distillate
Fuel Processor	Entrained Gasifier		Autothermal Reformer
Air Supply	Gas Turbine		Air Compressor
Fuel Energy	100%	100%	100%
Power Output	30%	38%*	41%
Process Heat	48%	40%*	23%
Utilization	78%	78%*	64%
Minimum Size	100 MW	125 MW	4.4 MW
Maximum Size	1000 MW	1250 MW	25 MW
Date Available	1990	1990	1990

* Bottomed by 1465 psia, 1000 F non-condensing steam turbine with process heat at 350 F.

Many of the significant developments for the molten carbonate fuel cell have already been considered. The coal gasifier would be of the Texaco entrained bed type and would be the same development already considered for the integrated coal gasifier combined-cycle ECS. The full cleanup system would also be comparable for both these systems. The molten carbonate fuel cell module is itself a significant development. The total system integration and control would be significant for the coal-fueled system. The dc to ac development would be comparable to that considered for the thermionic ECS.

OVERVIEW

A summary of the performance characteristics of the various types of ECS's is shown in Table 5-7 for a saturated steam to process temperature of 350^{o}F (for many ECS's the performance is a function of process steam temperature). A level of performance for each advanced energy conversion system was developed that was considered appropriate for units to be commercially available between 1985 and 1995. Overly ambitious performance goals tend to result in expensive refinements that typically reduce plant reliability. State-of-the-art industrial cogeneration systems reflect a dedication to simplicity and reliability that has been followed in defining the advanced technology applicable in the future.

Table 5-7

COGENERATION ENERGY CONVERSION SYSTEM (ECS) PERFORMANCE CHARACTERISTICS

ECS	Performance Characteristics at Process Sat. Steam = 350^{o}F*			
Current State-of-Art	Power / Heat	Power / Fuel	Process Heat / Fuel	Power + Process Heat / Fuel
FGD STM TURB - COAL	.20	.14	.71	.85
GT-HRSG - RESIDUAL	.68	.29	.43	.72
DIESEL-HRSG - RESIDUAL	2.03	.36	.18	.54
Advanced				
AFB STM TURB - COAL	.20	.14	.71	.85
PFB STM TURB - COAL	.32	.21	.64	.84
INT GAS COMB CYCLE - COAL	.66	.28	.43	.71
INT GAS FUEL CELL MC - STM TURB	.96	.38	.40	.78
STIRLING - COAL	.54	.26	.47	.73
CLOSED CYCLE GT HELIUM - COAL	.36	.18	.49	.67
THERMIONIC-STM TURB - COAL	.44	.26	.59	.84
GT-HRSG - RESIDUAL	.66	.31	.46	.77
COMB CYCLE GT - RESID	1.08	.37	.34	.72
STM INJ GT - RESIDUAL	2.70	.36	.13	.49
DIESEL - RESIDUAL	1.75	.37	.21	.58
DIESEL-HEAT PUMP - RESIDUAL	.78	.33	.43	.76
REGEN GT - DISTILLATE	.85	.33	.39	.72
FUEL CELL - DISTILLATE	2.24	.38	.17	.55
FUEL CELL MC - DIST.	1.77	.41	.23	.65

* Performance characteristics of most ECS's varies with process steam temperature.

REFERENCE

1. NASA Report CR 134949, Vol. II, Part 2 "ECAS General Electric Phase II Final Report, Volume II Advanced Energy Conversion Systems - Conceptual Designs Part 2, Closed Turbine Cycles", December, 1976, General Electric, Brown DH, Pomeroy BD, Shah RP

Section 6

CAPITAL COSTS

CAPITAL COST METHODOLOGY

It is essential that there is consistency among the capital cost estimates if economic distinctions are to be made. Three distinct data sources were used for the basis of costs in this study. Considerable effort was made to assure that the final cost assemblage for each energy conversion system represented a complete power plant, including all of the required elements of an industrial power house, and was consistent with all the others regardless of the source of data.

A major part of the cost of most systems is in components that are parts of many other systems. The cost of each component; e.g., a steam turbine, was based on the same methodology regardless of which ECS it was a part of. This method of costing helped to assure consistency between ECS's. The cost of a diesel engine or a small gas turbine, for example, to be installed in a purchaser's building on purchaser provided foundations and connected at purchaser's expense is just a small part of a new "green field" industrial power house with all prerequisite services and amenities. For example, a diesel-generator adapted for cogeneration costs 210 dollars per kilowatt; however, completely installed the cost is 540 dollars per kilowatt, and the entire power house installation would cost 1000 dollars per kilowatt. The complete power house installed costs are reported in this study.

To corroborate the level and order of these complete plant costs, comparisons were made to more detailed evaluations of large installations such as utility power plants. Corroboration was found in every instance.

Explicit cost evaluation requires detailed build-up to provide confidence in the final estimates. Where only cost estimates are required, there are techniques that permit extrapolation from data sources of high confidence with good assurance that the new data is of a high level of fidelity. These techniques are used for individual equipment and for complete power plant systems. The concept is that the cost of an entity does not increase linearly as its size increases. Instead the cost varies as the size to an exponent. For example, the appropriate exponent has been found to be 0.6 for heat exchangers and 0.8 for steam turbine generators. At some unit size it may become necessary to add multiple units rather than continue increased unit sizes. Some elements like fuel cell modules and DC to AC inverters and thermionic converters are small in unit capacity and are always aggregates of numerous modules with little cost advantage in the conversion system itself as their numbers increase. Economics of scale, however, still apply to other components of the power plant costs.

For the purpose of this study data were secured at two unit ratings for equipment cost, direct field material to install the equipment, and direct field labor to install the equipment. These data were input to the computer. The computer thereafter compares the equipment size required to the input data and interpolates costs along a power law fit of the input data. When the equipment size exceeds the limit of the input data, additional units are added to reduce the required unit size and the same search made. This procedure continues until sizes within the span allowed are found.

The elements that comprise a major sector or island of the energy conversion system are presented in Table 6-1. The costs developed from Table 6-1 only include direct costs. Cost adders above these levels are 1% for start-up, 2% for spare parts, 90% for indirect field costs, and an additional 26% made up of 6% engineering, 15% contingency, and 5% fee. The resulting multipliers to get total installed costs are presented in Table 6-2 along with a set of multipliers to derive only the indirect portion of costs.

Table 6-1

GE-CTAS CAPITAL COSTS

COST ISLANDS MASTER LIST

Major Islands Accounts:		Major Component Accounts:
1.0 Fuel Handling	1	Gas Metering/Scrubber
	2	Gas Storage
	3	Gas Pressure Regulation
	4	Fuel Oil Unloading
	5	Fuel Oil Storage
	6	Fuel Oil Transfer
	7	Fuel Oil Pump and Heater Set
	8	Coal Unloading
	9	Coal Storage
	10	Coal Preparation
	11	Coal Transfer
	12	Limestone/Dolomite Unloading
	13	Limestone/Dolomite Storage
	14	Limestone/Dolomite Preparation
	15	Limestone/Dolomite Transfer
2.0 Fuel Utilization and Cleanup	20	Gas-fired Boiler
	21	Oil-fired Boiler
	22	Coal-fired Boiler
	23	Coal-fired AFB Boiler
	24	Coal-fired PFB Boiler
	25	Coal Gasifier
	26	Liquid Waste Boiler
	27	Solid Waste Boiler
	28	Reformer, Shifter, and Cleanup for Fuel Cells
	29	Stirling Engine Combustion and Cleanup
3.0 Energy Conversion	30	Steam Turbine-Generators, Non-condensing
	31	Gas Turbine-Generators
	32	Diesel Engine-Generators
	33	Thermionic Boiler/Generator and Cleanup
	34	Stirling Engine-Generators
	35	Fuel Cells-Molten Carbonate
	36	Fuel Cells-Phosphoric Acid
	37	Prime Conversion Bottoming HRSG and Steam Turbine-Generator
4.0 Bottoming Cycle	40	Heat Recovery Steam Generators
	41	Steam Turbine-Generator, Condensing
	42	Organic Vapor Boiler
	43	Expansion Turbine-Generators
	44	Regenerators, Vapor
5.0 Heat Sink	50	Cooling Towers, Wet, Induced-Draft
	51	Circulating Pumps
	52	Steam Condensers
	53	Vapor Condensers
6.0 Heat/Energy Storage	60	Media
	61	Containment
	62	Heat Exchangers
7.0 Process Interface	70	Heat Exchangers
	71	Heat Recovery/Process Steam Generators
8.0 Balance of Plant	80	Master Control
	81	Electric Switchgear and Transformer
	82	Interconnecting Piping, Ducting, Wiring
	83	Structures and Miscellaneous
	84	Service Facilities

Table 6-2

CTAS CAPITAL COST STRUCTURE

Total Installed Cost		
Equipment	*	(1 + 0.01 + 0.02) * (1.26)
Material	*	(1 + 0.01) * (1.26)
Direct Labor	*	(1 + 0.01 + 0.90) * (1.26)
Indirect Cost		
Equipment	*	0.2978
Material	*	0.2726
Direct Labor	*	1.4066

Another aspect of the methodology was the derivation of some costs where detailed evaluations had not been done. An example would be the residual oil-fired thermionic plant. It was determined that the difference in cost from oil-fired to coal-fired steam boilers at the same firing rate should be appropriate for the thermionic units. These differences were derived and were applied to the coal-fired data to derive the costs for the oil-fired thermionic unit. The coal-fired stirling cycle represented the reverse transition. Cost of the oil-fired unit was known. The oil to coal cost difference was added to the oil-base case to determine the coal-fired case.

DATA SOURCES

Two of the energy conversion system costs were derived from the General Electric study for ECAS (Ref.1, p 6-8). These were the pressurized fluidized bed steam cycle plant and the helium closed cycle gas turbine plant. As indicated in the previous section, costs for the thermionic energy conversion systems were derived on a similar basis from the General Electric EPRI study (Ref. 2, p 6-8).

A number of energy conversion systems costs were synthesized from the data bank used by General Electric in application engineering for industrial power generation including cogeneration. These included all nocogeneration boilers firing all types of fuels, both of the package and of the field erected type, and conventional power boilers providing steam for turbines. Also, cost of heat recovery steam generators for gas turbines were from the same source as were industrial steam turbine costs.

The bulk of the advanced energy conversion systems costs were synthesized from data on basic equipment costs. The following were added to each system to complete the power house assemblage:

Component	Component Description
80	Master Control
81	Electric-Switchgear
82	Interconnecting Piping
83	Structures-Miscellaneous
84	Service Facilities

The stirling cycle costs were produced by General Electric in collaboration with North American Philips. The costs were then reviewed with the General Electric Locomotive Diesel Engine Department. The molten carbonate and phosphoric acid fuel cell costs were developed by General Electric in collaboration with the Institute of Gas Technology. The integrated gasifier combined-cycle costs and performance were developed from EPRI reports (Ref. 3, 4) on Coal Gasification Combined-Cycle Systems and internal GE studies. All gas turbine cost estimates were new evaluations in 1978 dollars for cogeneration applications. The diesel cost estimates were derived by the DeLaval Corporation to represent growth versions of current cogeneration diesel systems. The heat pump for the diesel used cost estimates based on one of the more expensive air compressors that would satisfy the performance requirements so that the cost estimates would cover modifications necessary to handle steam.

COST COMPARISONS

Since cost differences are a dominant factor in economic appraisals, it is essential that costs developed for cogeneration systems have a high level of consistency. The smallest plant sizes are subject to the greatest uncertainty for relative costs. For a comparison of relative costs an industrial plant having 10 megawatts power demand and 137 million Btu per hour process heat at 300 F was selected. The capital cost was evaluated as dollars per kilowatt of electrical power produced after deletion of the direct and indirect costs of an auxiliary boiler if one was necessary. Table 6-3 presents the results. The order of listing generally follows increasing cost. As expected distillate-fired units tend to be least expensive followed by residual-fired and then coal-fired units.

Table 6-3

CAPITAL COSTS FOR 10 MW POWER DEMAND AND 137 MILLION BTU PER HOUR AT 300 F
(Auxiliary Boiler Cost Deleted)

	CAPITAL COST, $/kW		
Energy Conversion System	Coal Fired	Residual	Distillate
Phosphoric Acid Fuel Cell			580
Gas Turbine-State-of-the-Art		775	655
-Steam Injected		665	
-Combined Cycle		680	
-Advanced		695	
-Regenerative			745
Steam Turbine-Adv. Boiler	1260-AFB		
	1540-PFB		
-State-of-the-Art	1635-FGD	840	
Stirling Cycle	1445-FGD	845	845
Diesel -Advanced		980	
-Heat Pumped		995	
-State-of-the-Art		1040	1040
Integrated Gasifier Comb. Cycle	1555-G		
Molten Carbonate Fuel Cell	2200-G		510
-Steam Turbine	2205-G		
Helium Closed-Cycle G.T.	2645-AFB		
Thermionic	5660-FGD	4410	
-Steam Turbine	3450-FGD	2700	

FGD - Flue Gas Desulfurization
AFB - Atmospheric Fluidized Bed
PFB - Pressurized Fluidized Bed
G - Gasifier

Among distillate-fueled units the phosphoric acid fuel cell and state-of-the-art gas turbine are the least expensive alternatives at 10 MW rating. For residual fired units several gas turbine alternatives are least costly. The state-of-the-art residual fired gas turbine is less costly than the steam turbine, stirling cycle or diesel. For coal fired units the steam turbine with atmospheric fluidized bed is least costly followed by the stirling cycle, then the PFB steam cycle, the integrated gasifier combined-cycle, and finally the state-of-the-art steam turbine plant with flue gas desulfurization. The greatly advanced cycles are most costly. The source of these costs are apparent. The molten carbonate system is complex because of the gas cleanup required by the fuel cell. The helium closed-cycle features a two-stage AFB furnace that heats gas over a high temperature span. The thermionic units are inherently costly notwithstanding the assignment that they would be manufactured into large panels in the factory in order to reduce field erection costs.

These data at a low power level represent the highest levels of costs that are expected. The cost data are of a nature that unit costs decrease as size and ratings increase. The best sources of comparative data are at power levels between 400 MW and 1000 MW for complete electric utility plants. Such plants would tend to be more complex than cogeneration power plants. They would incur costs for heat rejection systems and for low temperature-low pressure elements of their energy conversion machinery. At the same time they tend to be more efficient. Nonetheless, one would expect their order of costliness to be similar to that for cogeneration plants. Hence the major issue is one of order and relative costs, not of absolute cost level.

Several data sources were available as discussed previously. These include the General Electric in-depth studies for ECAS and for EPRI. Values were taken from those studies and adapted to the same basis as the CTAS costs. The ascending order of costs and their ratios were corroborated for the gas turbine, steam turbine with residual boiler and AFB, PFB and FGD, for the helium gas turbine with AFB and the thermionic-steam turbine cycle with FGD. These data are presented in the detailed General Electric report, Volume IV. The corroboration that has been found indicates that a consistency exists among the costs that are synthesized for each type cogeneration energy conversion system in this study. The discipline of using common components as elements for all systems, of applying a consistent basis for indirect costs, and bringing each system to a common level of completeness assures that no system has been either favored or penalized by arbitrary assignment of costs.

REFERENCES

1. NASA Report CR-134949, Vol. II, Part 2 "ECAS General Electric Phase II Final Report, Volume II Advanced Energy Conversion Systems - Conceptual Designs Part 2, Closed Turbine Cycles", December 1976, General Electric, Brown DH, Pomeroy BD, Shah RP.

2. EPRI Report AF-664, Volume 1, "Comparative Study and Evaluation of Advanced Cycle Systems", February 1978, General Electric, Pomeroy BD, Fleck JJ, Marsh WD, Brown DH, Shah RP.

3. EPRI Report AF-642, "Economic Studies of Coal Gasification Combined-Cycle Systems for Electric Power Generation", January 1978, Fluor Engineers and Constructors, Irvine, CA.

4. EPRI Report AF-753, "Economics of Texaco Gasification-Combined-Cycle Systems", April 1978, Fluor Engineers and Constructors, Irvine, CA.

Section 7

SIGNIFICANT GENERIC DEVELOPMENTS

In Section 5 required developments particular to specific energy conversion systems were identified. Certain developments have broad generic impact on advanced energy conversion systems and thus merit aggressive development effort irrespective of the particular advanced systems that are favored. Several of these have been abstracted as a result of this study.

HIGH TEMPERATURE AIR PREHEATERS

Wherever an ECS receives all of its heat at high temperature (closed helium gas turbine, stirling cycle, thermionics) then the combustion gas energy below such high temperatures must be used to the greatest advantage. When that gas heats incoming air for combustion the fraction of fuel energy realized at high temperature is greatly increased. High temperature air preheat (to 1500 F or 2000 F) is rarely used because of the great expense of such heat exchangers and the likelihood of their adverse effect on plant reliability and availability. A significant breakthrough in the technology of high temperature air preheaters would enhance the prospects of many advanced energy conversion systems.

DC TO AC ENERGY CONVERSION

The phosphoric acid fuel cell, the molten carbonate fuel cell, and thermionic elements all deliver their electrical output as direct current, dc. The inversion to ac is currently realized at a cost of 50$/kW. This high cost penalty results from the need to protect the dc generating system as well as to perform the inversion of ac function. Advanced development that would reduce this cost while providing full system protection would benefit these systems as well as other dc generators such as MHD (magnetohydrodynamics) that was not a part of this study.

COAL GASIFICATION, FUEL GAS CLEANUP

The molten carbonate fuel cell and the integrated coal gasifier combined-cycle are dependent on the development of advanced coal gasification systems. As compared to the state-of-the-art Lurgi coal gasifiers, the advanced developments require reduced steam and air or oxygen feeds. The development objective is to realize a higher fraction of the fuel energy in the gaseous fuel product of the gasifier.

The fuel gas cleanup system that removes tars and sulfur and other unwanted components imposes thermodynamic penalties on the system. The cooling of the product gas produces some heat that is of low thermal value, and in some designs becomes heat rejection from the plant.

Advanced developments that improve the thermodynamic performance or reduce the cost of coal gasification and fuel gas cleanup systems will have significant impact on advanced energy conversion systems.

NO_x FROM COAL-DERIVED LIQUID FUELS

As compared to petroleum-derived liquid fuels, the coal-derived counterparts have exceedingly high levels of fuel-bound nitrogen. The reduction of exhaust NO_x to permissible levels may be achieved by either modification of the combustion process or exhaust gas treatment for denoxification. While the combustion process is particular for each energy conversion system, the exhaust gas denoxification development could have broad applications to diesels, gas turbines and other advanced energy conversion systems.

FLUIDIZED BED COMBUSTION

The sequence of evolution envisioned for fluidized bed combustion of coal indicates the merit of broad research and development for fluidized beds apart and in addition to their development for particular advanced energy conversion systems. Process steam boilers are already offered commercially, and steam power boilers are at the development stage. Pressurized fluid beds are in development. All of these are single-stage units. To service heating loads that are at high temperatures (1500 F to 2000 F) a two-stage fluidized bed is needed. The very hot top bed would not capture sulfur. Its exhaust would flow through the lower temperature bed that would perform the sulfur capture fucntion. This development would provide coal-firing with sulfur capture for closed-cycle gas turbines, for stirling cycles and for other high temperature gas heating services. Fluidized bed technology has broad impact on a variety of advanced energy conversion systems and merits research and development effort with a broad focus.

Section 8

ECS-INDUSTRIAL PROCESS MATCHING

This section presents the terminology and strategies used in this study for employing energy conversion systems in cogeneration applications.

GENERAL

ECS-Industrial process matching refers to the selection of ECS size to meet the heat and/or power needs of a given industrial process. An ECS used to simultaneously supply heat and power to an industrial process is commonly referred to as a cogeneration system. The discussion of cogeneration system performance in this study refers to the performance of the entire industrial energy supply system which includes the cogenerating ECS and, where required, an auxiliary boiler or purchased electric power.

NOCOGENERATION CASE

An industry must select the means by which heat and electric power are supplied to the process. One choice is to use a process boiler to supply all of the heat and to purchase all electric power from a utility. This case is called the nocogeneration case. The heat rejected at the utility generating site is not used.

COGENERATION CASE

An industry may choose to provide heat and electric power to the process in part or completely through use of an energy conversion system that produces both power and useful heat. This case is referred to as the cogeneration case. Both power and useful heat are produced simultaneously on-site.

ECS-PROCESS MATCHING

The possibilities for matching the ECS's with the processes are shown in Figures 8-1 and 8-2. Figure 8-1 represents the case where the ratio of power to heat of the ECS is greater than that required by the process. The ordinate of the figure represents power and the abscissa represents heat. The circled point at the intersection is the power and heat required by the process. Any point along the sloped line beginning at the origin and moving upward and to the right represents an energy conversion system of increasing size. The slope of the line is descriptive of the energy conversion system (power/heat ratio) characteristic and is often dependent upon the temperature at which heat is required by the process. As is readily observed, when the size of energy conversion system is selected to match the power required by the process, the heat output of the ECS is not sufficient to meet the process needs and an auxiliary boiler must be used to make up the deficiency.

When the size of energy conversion system is selected to meet the heat needs of the process (no auxiliary boiler), more electric power is produced than required by the process and the excess power must be exported to the utility.

Figure 8-2 represents the case where the ratio of power to heat of the ECS is less than that required by the process. When the ECS is sized to produce the heat required by the process the power output is less than the process needs and the deficiency must be purchased from the utility. In the case where the ECS is sized to produce the power required by the process, more heat is produced than can be used by the process. Increasing the ECS size above that for matching heat in this case decreases the advantages of cogeneration and this was excluded from further investigation in this study.

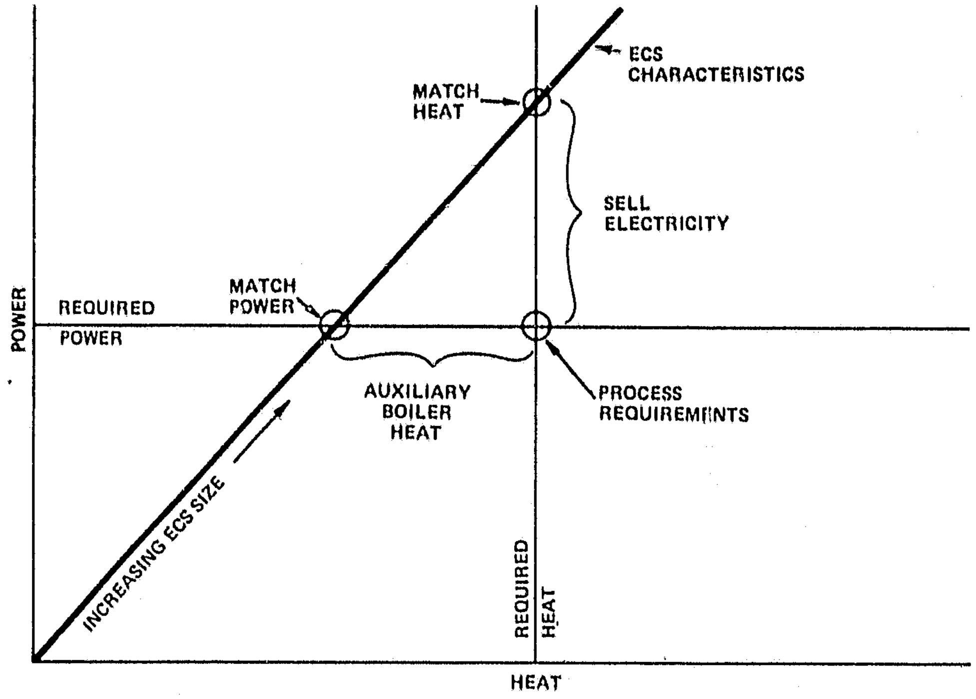


Figure 8-1. Matching of Energy Conversion System Output and Industrial Process Requirements (Power/Heat of ECS Greater than Required)

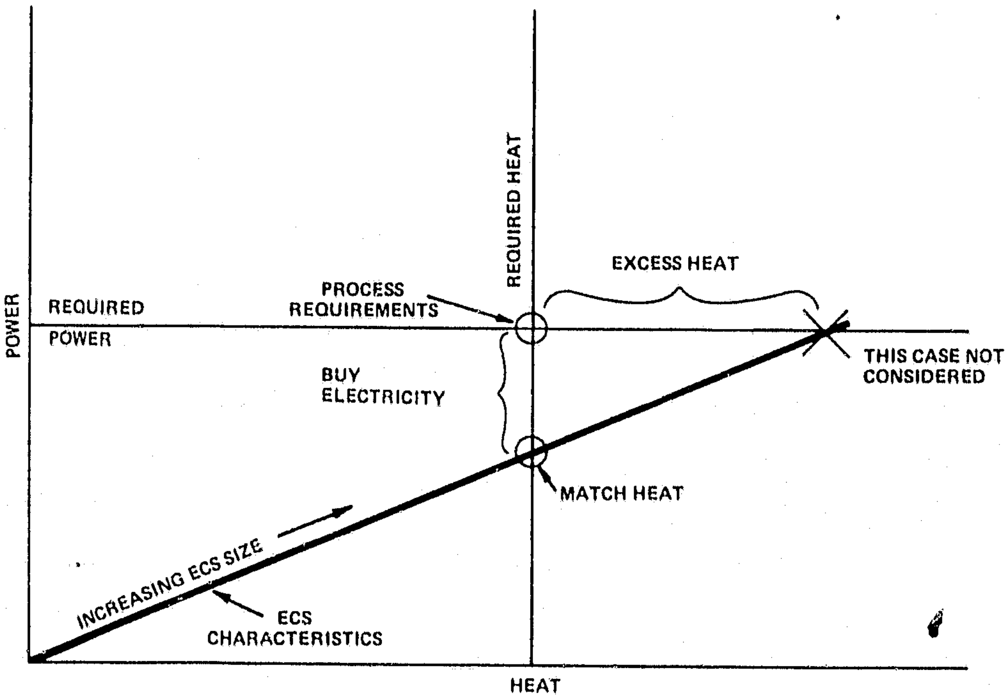


Figure 8-2. Matching of Energy Conversion System Output and Industrial Process Requirements (Power/Heat of ECS Less Than Required)

The case where the energy conversion system is sized to meet the power needs of a process is referred to as a power match. Similarly, the case where the energy conversion system is sized to meet the heat needs of a process is referred to as a heat match.

The energy conversion system characteristics and the cost described in Sections 5 and 6, and the process parameters described in Section 4 were entered into a computer data bank. A computer program was written to match up the heat and power needs of each process with the appropriate size of each type of energy conversion system. The computer data bank and computer program are described in Volume II.

In summary, each match of energy conversion system and process (cogeneration case) yielded many calculated parameters of technical and economic interest. Each cogeneration case is compared to the no-cogeneration case technically and economically and the results are reported in the next three sections. Complete computer printouts of the results are given in Volume VI.

FUEL ENERGY USES

The methodology used in accounting for the nocogeneration and cogeneration fuel energy in the various ECS-process matches shown in Figures 8-1 and 8-2 is essential to understanding the fuel energy saved between the cogeneration and nocogeneration systems. A detailed explanation of the relationships between the ECS efficiency, fuel utilization effectiveness, utility system efficiency, process boiler efficiency and the process heat and power demands for the various type matches is described in detail in Volume V, Section 8.3. Here only the matches where the cogeneration ECS has a higher power to heat ratio than required by the process will be briefly described.

In Figure 8-1 the match labeled "Match Power" consists of an energy conversion system (which does not supply enough process heat) and an auxiliary boiler added to meet the total process heat requirements. The fuel and process energy of this match is shown graphically in Figure 8-3.

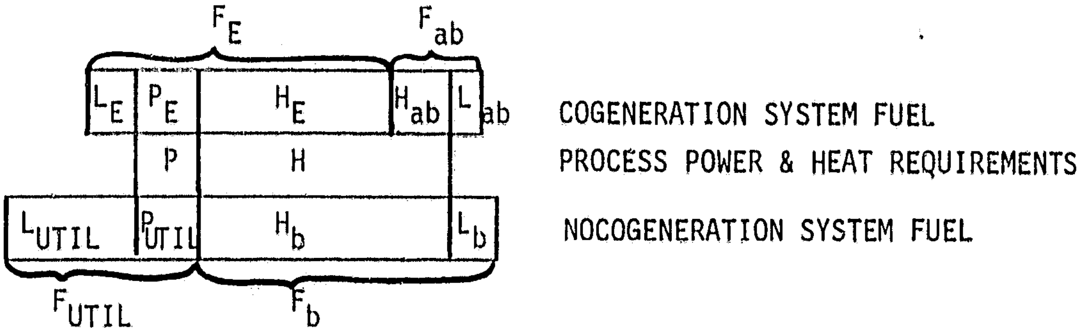


Figure 8-3. Representation of Fuel Inputs with Auxiliary Boiler (Power Match)

The length of the center bar represents the sum of the process power, P, and process heat, H, required. The lower bar represents the total fuel consumed by the nocogeneration system consisting of the utility fuel, F_{UTIL}, made up of the portion generating power, P_{UTIL}, and the utility losses, L_{UTIL}, and the process boiler fuel, F_b, generating steam, H_b, and the boiler stack and auxiliary losses, L_b. The upper bar represents the cogeneration ECS fuel, F_E, consisting of the portion of its fuel generating power, P_E, steam, H_E, and the fuel for the ECS losses, L_E, and the auxiliary boiler fuel, F_{ab}, consisting of the fuel to generate the remaining required steam, H_{ab}, and the boiler losses, L_{ab}.

By contrast the fuel bar chart for the match labeled "Match Heat" on Figure 8-1 is shown in Figure 8-4. Notice that the cogeneration ECS produces more power than required by the process and in order to compare the systems on a consistent basis the nocogeneration system fuel must include the utility fuel to generate power equal to that produced by the cogeneration ECS.

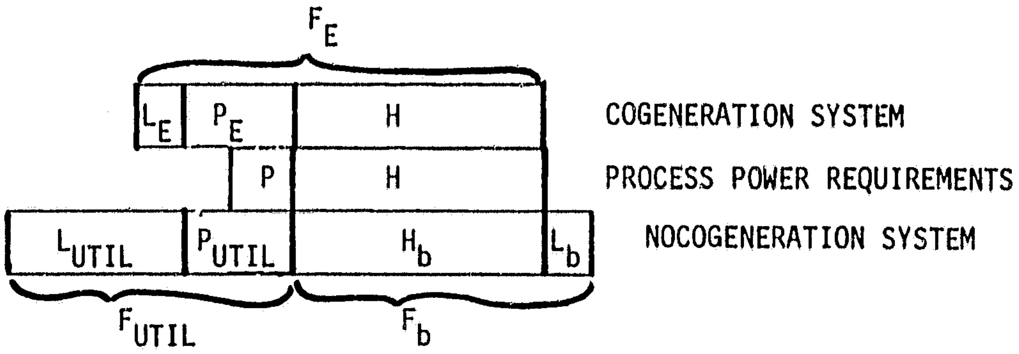


Figure 8-4. Representation of Fuel Inputs When Exporting Power (Heat Match)

Section 9

COGENERATION SYSTEMS PERFORMANCE

This section presents the potential fuel energy savings of cogeneration systems in parametric form and fuel energy and emissions savings for a representative number of the actual systems studied. The functional relationships between fuel energy saved and energy conversion system parameters and process heat and power demands are discussed. It is shown that the possible institutional barrier restraint on ability to export power limits the fuel savings potential of many systems.

An important indicator of the performance of a cogeneration system is the fuel energy saved ratio (FESR) defined by

$$FESR = \frac{(\text{Fuel Used})_{NOCOGEN} - (\text{Fuel Used})_{COGEN}}{(\text{Fuel Used})_{NOCOGEN}} \qquad (9\text{-}1)$$

Functional relationships describing the influence of ECS performance parameters, utility system and nocogeneration boiler efficiency and process heat and power needs are developed in Volume V, Section 8.3. When the energy conversion system power to heat ratio is greater than or equal to the process power to heat ratio, the following expressions describe the fuel energy savings ratio:

$$(P/H)_{ECS} \geq (P/H)_{PROCESS}$$

Power Match

$$FESR = 1 - \left[\frac{((P/H)_{PROCESS} + 1)/\eta_{ef}}{\dfrac{(P/H)_{PROCESS}}{\eta_{UTIL}} + \dfrac{1}{\eta_b}}\right]$$

Equation (9-2)

Heat Match

$$FESR = 1 - \left[\frac{((P/H)_{ECS} + 1)/\eta_{ef}}{\dfrac{(P/H)_{ECS}}{\eta_{UTIL}} + \dfrac{1}{\eta_b}}\right]$$

Equation (9-3)

where

$(P/H)_{ECS}$ = Power to heat ratio of ECS when supplying power and heat to a process at the required temperature.

$(P/H)_{PROCESS}$ = Power to heat ratio of the process.

η_{UTIL} = Utility conversion efficiency of fuel energy (HHV) to electric power (.32 used in this study).

η_b = Process boiler (nocogeneration) conversion efficiency of fuel energy (HHV) to heat required by the process at the required temperature (.85 used in this study).

η_{ef} = Energy conversion system effectiveness (efficiency of fuel utilization). This is simply the sum of the ECS electrical conversion efficiency and the fraction of fuel energy input (HHV) delivered to the process as heat at the required temperature.

The energy conversion system effectiveness is related to the electrical conversion efficiency and heat recovery fraction (at a process required temperature) of the energy conversion system in the following manner

$$\frac{P}{F} + \frac{H}{F} = \eta_{ef} \qquad (9\text{-}4)$$

where

P = Net power generation

H = Net heat delivered to process at a specified temperature

F = Fuel consumption (HHV)

The effectiveness, power to heat ratio and electrical generating efficiency can all be related using the previous equation

$$P/H = \frac{P/F}{\eta_{ef} - P/F} \qquad (9\text{-}5)$$

Equation 9-2 shows that for power match cases, fuel energy savings are limited by the process power to heat ratio (provided $(P/H)_{ECS} \gtrsim (P/H)_{PROCESS}$). For the heat matched case (Equation 9-3) the fuel energy saved ratio is a function only of ECS parameters and is not limited by the process power to heat ratio as in the power match case. In either the heat match or power match case, the energy conversion system effectiveness directly influences the fuel energy saved ratio. Increasing the electrical generating efficiency of an ECS at the expense of reducing the heat available (at the required temperature for a process) may reduce its fuel savings ability if the effectiveness is reduced.

Figure 9-1 shows parametrically the influence of energy conversion system effectiveness (η_{ef}) on the fuel energy saved ratio for power matches.

Figures 9-1 and 9-2 show that the fuel energy saved ratio is limited by the process power to heat ratio for the power match cases. Figure 9-2 further shows that the electrical generating efficiency need not be high to achieve the maximum fuel savings.

FUEL ENERGY SAVINGS POTENTIAL OF SELECTED ENERGY CONVERSION SYSTEMS

From the previous discussion it is observed that fuel energy savings depend upon whether export power is allowed or not, the ratio of power to heat required by the process, the ECS ratio of power to heat, and the effectiveness of the ECS. The ECS parameters are often functions of the temperature at which heat is supplied. Figures 9-3 through 9-8 display the range of fuel energy savings ratios with selected ECS's for heat matches and power matches for process power to heat ratios of 0.1, 0.25 and 1.0. For most ECS's, the fuel energy savings vary from a high value corresponding to process heat supplied at a low temperature (250°F, shown by ●) and a low value corresponding to process heat supplied at a high temperature (shown by O). The high temperature used for each ECS when computing the fuel energy savings displayed in these figures is given in Table 9-1.

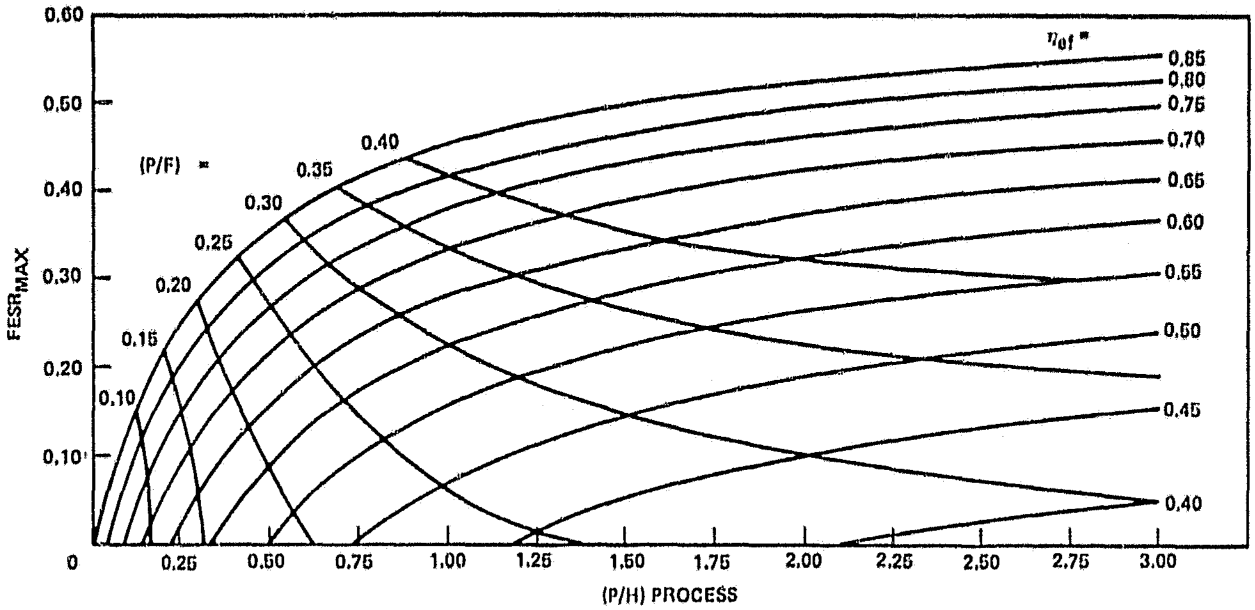


Figure 9-1. Maximum Fuel Energy Saved Ratio When Process Power Matched by ECS - ECS (P/H) Greater Than or Equal to Process (P/H)

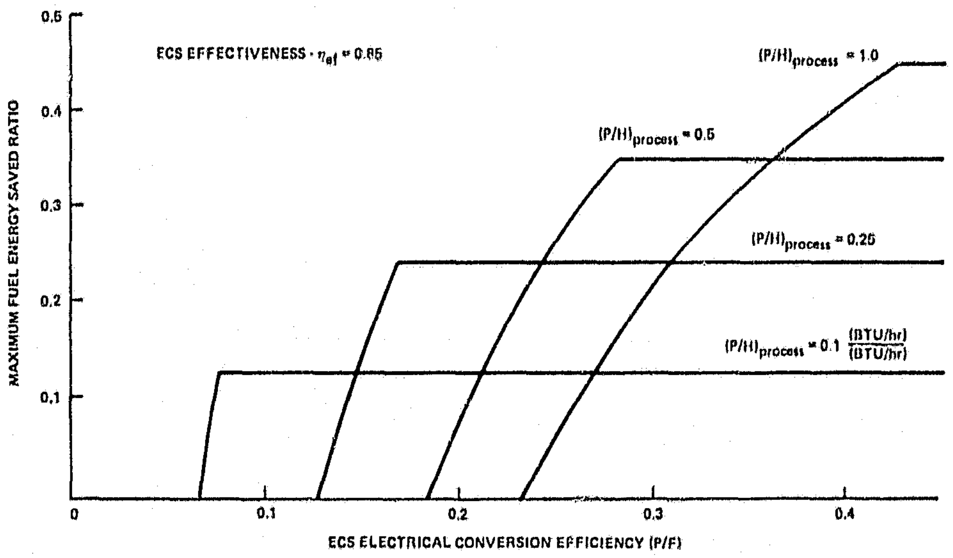


Figure 9-2. Maximum Fuel Energy Saved Ratio Vs ECS Electric Power Conversion Efficiency (ECS Power Output Equal to Process Power Needs (No Export Power))

Table 9-1

MAXIMUM STEAM TEMPERATURE USED FOR FIGURES 9-3 - 9-6

Key	ECS Description	Abbreviated Title	Maximum Steam Temperature Used, ^{o}F
1	Steam Turbine, AFB or FGD 1465 psia, 1000^{o}F	STM TURB. AFB,FGD	500
2	Steam Turbine, PFB, 1465 psia, 1000^{o}F	PFB STM TURB.	600
3	Thermionic, Steam Turbine, Bottomed, 1465 psia, 1000^{o}F	THERMIONIC STM TURB	500
4	Stirling Engine	STIRLING, COAL	500
5	Helium, Closed-Cycle, Gas Turbine, 85% Regenerator Effectiveness	HELIUM GAS TURB.	400
6	Integrated Coal Gasifier, Molten Carbonate Fuel Cell, 1465 psia, 1000^{o}F Steam Turbine Bottomed	INT. GAS, FUEL CELL, MC, ST.	500
7	Integrated Coal Gasifier, Combined-Cycle	INT. GAS COMBINED-CYCLE	500
8	Gas Turbine 1750^{o}F, p_r 10, Air-Cooled, State-of-the-art, Residual Fuel	GAS TURBINE SOA	600
9	Gas Turbine, 2200^{o}F, p_r 12, Air-Cooled, Residual Fuel	GAS TURBINE RESID.	600
10	Combined-Cycle, GT, 2200^{o}F, p_r 12, Residual Fuel, Steam Turbine, 1465 psia, 1000^{o}F	COMBINED-CYCLE	600
11	Gas Turbine, Steam Injected, 2200^{o}F, p_r 16	STM INJ. GAS TURBINE	400
12	Diesel, Advanced, Residual Fuel	DIESEL, ADV. RESID.	450
13	Diesel & Vapor Compression Heat Pump	DIESEL, HEAT PUMP	500
14	Diesel, State-of-the-art, Residual Fuel	DIESEL, SOA	450
15	Gas Turbine, Air-Cooled, Regenerative, 60% Regenerator Effectiveness 2200^{o}F, p_r 12, Distillate Fuel	GAS TURB. REGEN. DIST.	600
16	Phosphoric Acid Fuel Cell, Distillate Fuel	FUEL CELL, PH ACID, DIST.	600
17	Molten Carbonate Fuel Cell, Distillate Fuel	FUEL CELL, MC, DIST.	600

The variations in fuel energy savings with temperature are due to the variation of energy conversion system power to heat ratio and effectiveness with the temperature at which heat must be supplied to process. There are three ECS's whose characteristics do not vary with temperature because all reject heat recovered for process use is available at a high temperature. These are steam injected gas turbine burning residual fuel, and the distillate fired fuel cells. These ECS's show up only as a point on the plots.

The line identified as the maximum theoretical fuel energy savings corresponds to a cogeneration system with an 85% effectiveness. For power match cases the maximum fuel energy savings for an 85% effectiveness versus the process power to heat ratio is the top line in Figure 9-1. The high power/heat ECS's are missing from the figures corresponding to the process power/heat of 0.1 (Figures 9-3 and 9-4) because they are off scale.

Low Process Power to Heat Ratio

Focusing on Figure 9-3, the heat match for a process power to heat ratio of 0.1 shows that power would have to be exported in all cases. The power produced by the ECS when sized to match the process heat requirements exceeds the process power needs for all cases. For example, if it were desired to use a stirling engine in a cogeneration application for a process having a power to heat ratio of 0.1 and the stirling engine was sized to meet the heat needs of the process, then the power produced would be from four to six times what is required by the process depending on the process temperature required. The costs for this system would be commensurately higher than a system that met the miminum process needs. When the stirling engine is sized to meet the power needs of the process (see Figure 9.4) it can only produce from 16 to 25% of the process heat needs (the exact amount depends on the temperature that process heat is required). An auxiliary boiler would have to be purchased to provide the remaining 75 to 84% of the process heat needs. Although not studied here, in some cases it is possible to vary the ECS design and configuration to change (usually reduce) its P/H to better match the needs of a given process.

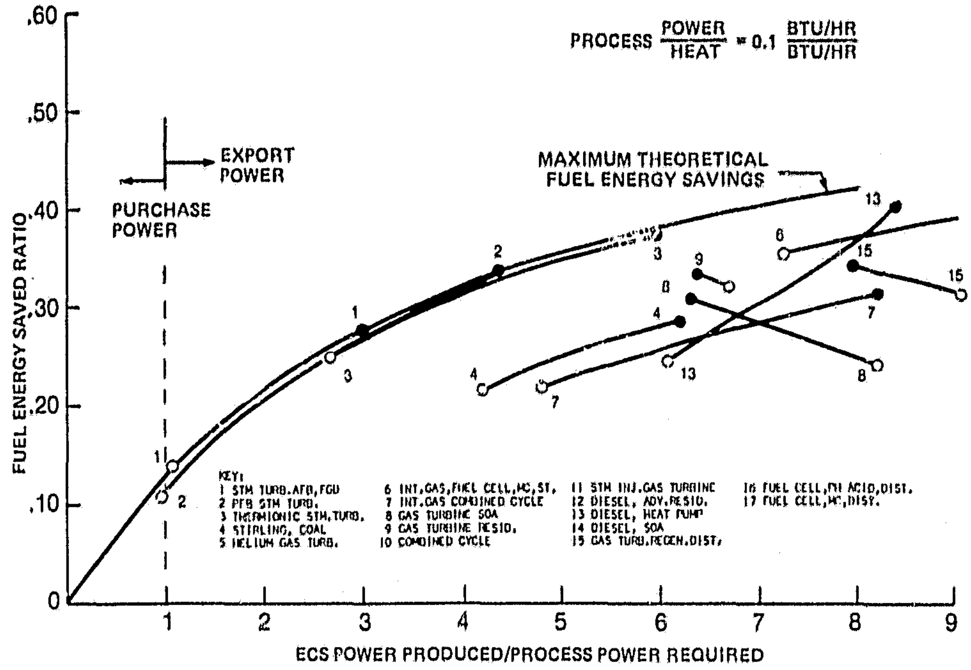


Figure 9-3. Fuel Energy Saving Potential of Energy Conversion Systems When Matched to Industrial Process Heat Needs (P/H = 0.1)

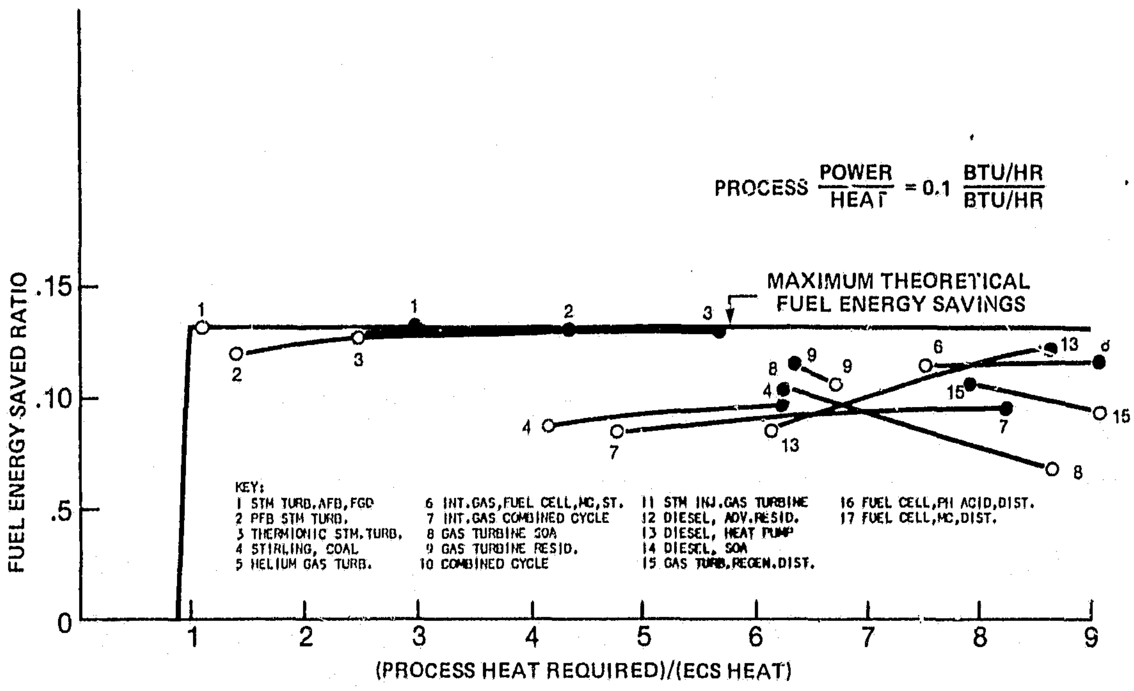


Figure 9-4. Fuel Energy Saving Potential of Energy Conversion Systems When Matched to Industrial Process Power Needs (P/H = 0.1)

C-2

Intermediate Power to Heat Ratio

Figure 9-5 represents the heat match case for a process power to heat ratio of 0.25. It is interesting that most of the enery conversion systems here would still be exporting power even at this higher process power to heat ratio.

Figire 9-6 is the power match case for a process power to heat ratio of 0.25. Note that the maximum fuel savings possible has increased from 13.8% for the 0.1 process power to heat ratio to 24.8%. With the exception of the PFB and steam turbine supplying heat at most process temperatures supplementary boiler capacity must be added to provide the shortfall between energy conversion system heat output and process requirements.

High Power to Heat Ratio

Figure 9-7 is the heat match case for a process power to heat ratio of 1. Only a few of the cogenerating systems in this case would be exporting power.

Figure 9-8 is the power match case for a process power to heat ratio of 1. It is observed here that most systems would provide more heat than was needed by the process (process heat required/ECS heat <1). The greatest fuel energy savings are obtainable with high power/heat options such as integrated gasifier molten carbonate fuel cell with steam turbine bottoming and the combined-cycle.

Comparison of Fuel Energy Saved Ratio at a Fixed Process Temperature

Figure 9-9 provides a summary of the fuel energy savings ratio of the selected energy conversion systems when providing heat to an industrial process at 400°F for process power to heat ratios of 0.1, 0.25 and 1. The export power allowed case is the heat match case. If more power is produced than required by the process, it is assumed to be exported. Any shortfall in power required versus that produced is assumed to be purchased from the utility.

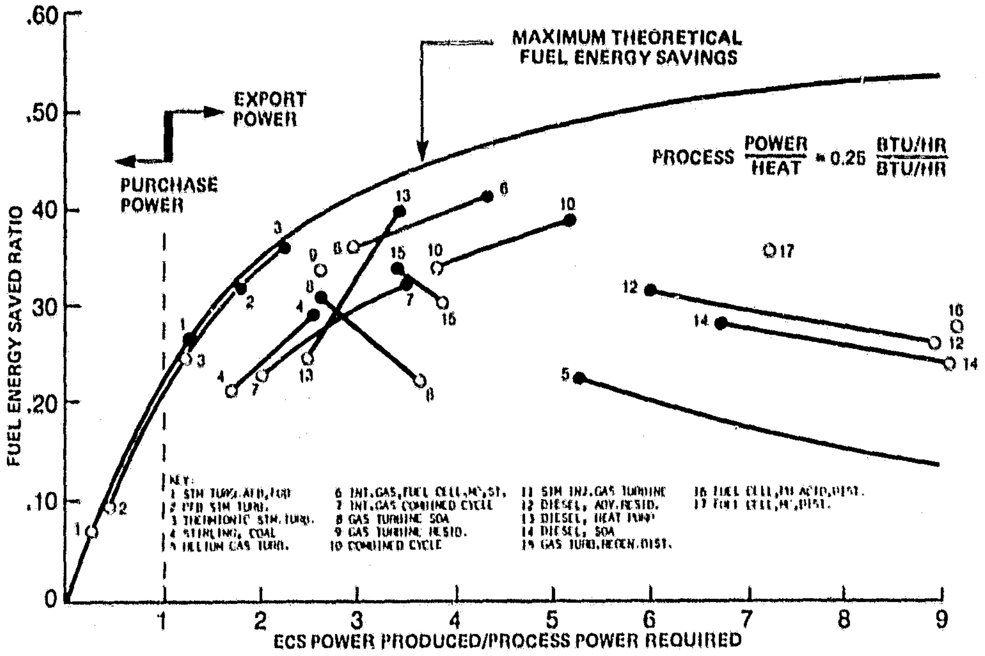


Figure 9-5. Fuel Energy Saving Potential of Energy Conversion Systems When Matched to Industrial Process Heat Needs (P/H = 0.25)

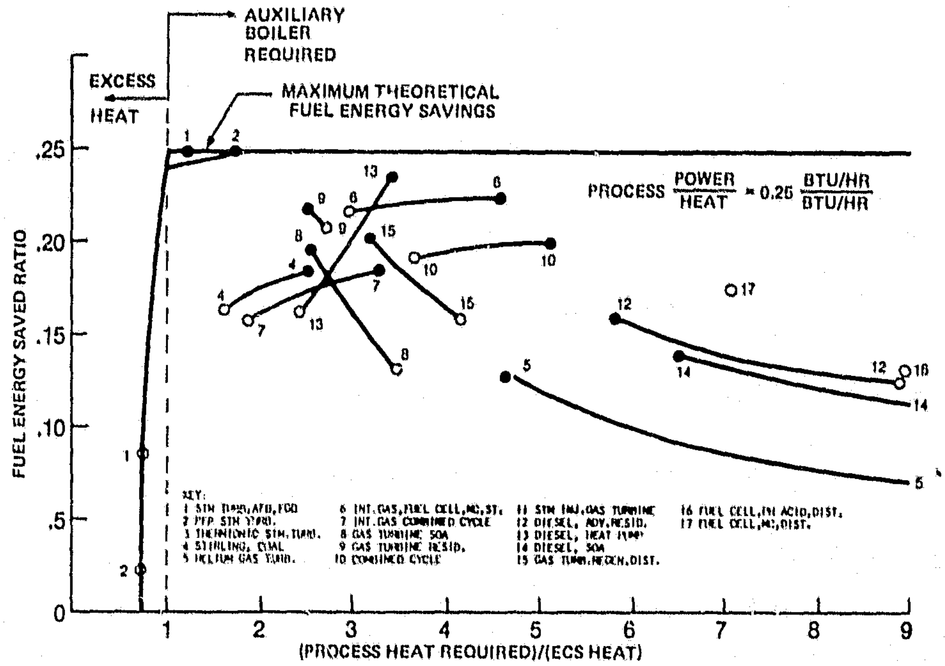


Figure 9-6. Fuel Energy Saving Potential of Energy Conversion Systems When Matched to Industrial Process Power Needs (P/H = 0.25)

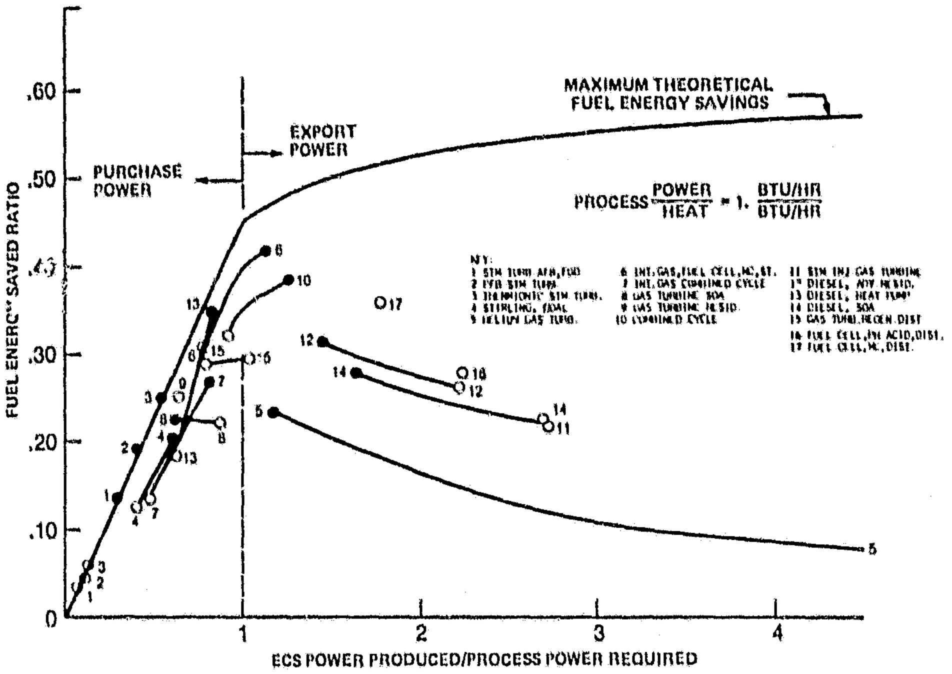


Figure 9-7. Fuel Energy Saving Potential of Energy Conversion Systems When Matched to Industrial Process Heat Needs (P/H = 1.0)

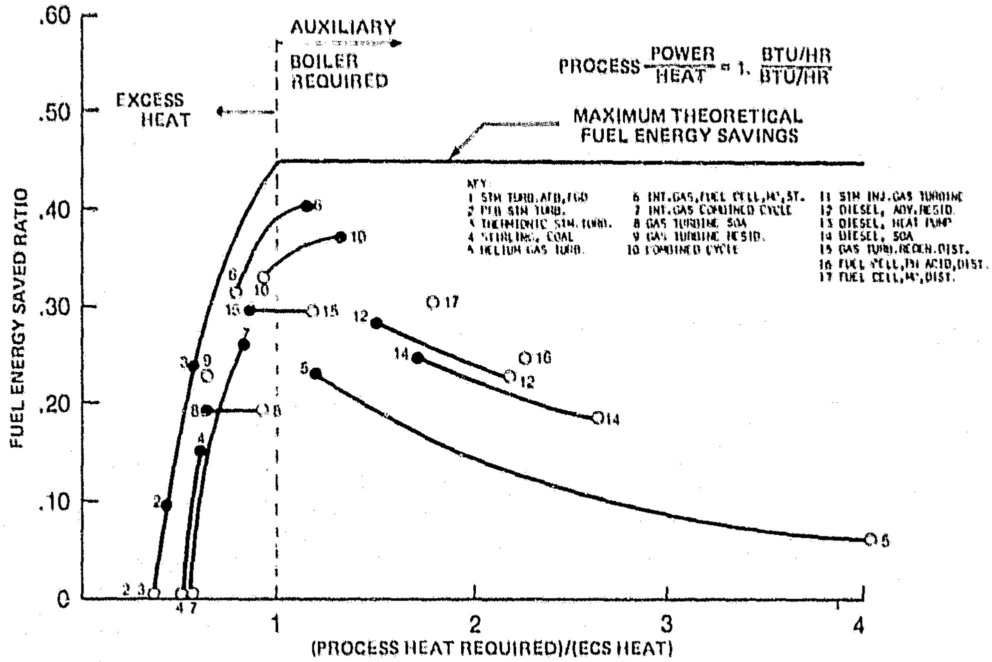


Figure 9-8. Fuel Energy Saving Potential of Energy Conversion Systems When Matched to Industrial Process Power Needs (P/H = 1.0)

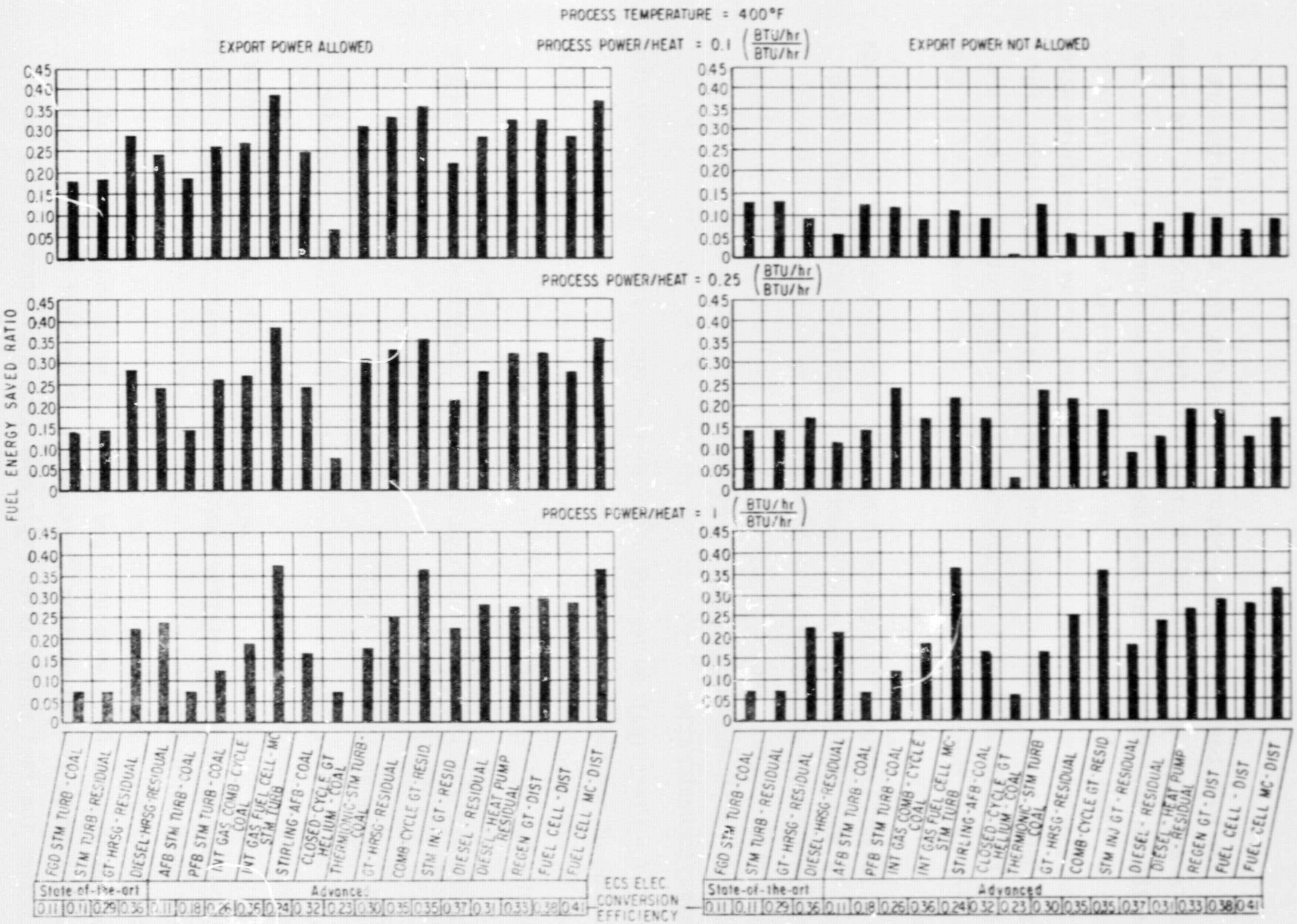


Figure 9-9. Summary of Fuel Energy Savings Ratio for Selected Energy Conversion Systems

For each bar chart in the figure the results for state-of-the-art ECS's are shown on the left and fifteen selected advanced ECS's are shown on the right. These fifteen have been selected as representative of the various types of ECS's studied. Several gas turbines with heat recovery steam generators of various pressure ratios and firing temperatures were considered but only one of these was selected for this comparison. For both the state-of-the-art and advanced systems those utilizing coal are on the left, then those utilizing residual fuel are next followed by those that can only use distillate fuel.

Several conclusions can be drawn from this figure. The most obvious one is that the restriction of power export would significantly affect the potential fuel energy savings in the low to intermediate power to heat ratio process range. The reduction in fuel energy savings between the no export and export power cases diminishes with increasing process power to heat ratio.

The electrical conversion efficiency of each system is given at the bottom of the figure. Note that respectable values of fuel energy savings can be achieved at low process power to heat ratios at low ECS electrical generating efficiencies (11 - 18%).

ENERGY AND EMISSIONS SAVINGS RESULTS FOR REPRESENTATIVE MATCHES OF ECS's AND INDUSTRIAL PROCESSES

Fuel Energy Saved Ratio Results

Fuel energy saved ratios were computed for all energy conversion systems (described in Section 5) matched up with all processes studied (described in Section 4). The computer-generated results are presented in Volume V. A representative sampling of fuel energy saved ratio results for selected plants and selected energy conversion systems are presented in Table 9-2 for power matches and Table 9-3 for heat matches. Waste and by-product fuels were utilized where available and feasible, as specified in the assumptions (Section 3). By-product or waste fuel increases the fuel energy saved ratio when used and decreases the fuel energy saved ratio when not used.

Table 9-2

FUEL ENERGY SAVED RATIO OF COGENERATION SYSTEMS FOR SELECTED INDUSTRIAL PROCESSES

POWER MATCH

	STATE-OF-THE ART				ADVANCED														
	FGD STM TURB - COAL	STM TURB - RESIDUAL	GT-HRSG - RESIDUAL	DIESEL-HRSG - RESIDUAL	AFB STM TURB - COAL	PFB STM TURB - COAL	INT GAS COMB CYCLE - COAL	INT GAS FUEL CELL MC - STM TURB	STIRLING - COAL	CLOSED CYCLE GT HELIUM - COAL	THERMIONIC-STM TURB - COAL	GT-HRSG - RESIDUAL	COMB CYCLE GT - RESID	STM INJ GT - RESID	DIESEL - RESIDUAL	DIESEL-HEAT PUMP - RESIDUAL	REGEN GT - DIST	FUEL CELL - DIST	FUEL CELL MC - DIST
MEAT PACKING	.26	.26	.21	.19	.26	.26	.19	.24	.21	.12	.26	.23	.21	.10	.19	.24	.21	.19	.18
MALT BEVERAGES	.24	.24	.19	.20	.24	.24	.18	.22	.20	.11	.24	.21	.19	.10	.20	.22	.19	.20	.17
BLEACHED KRAFT PAPER	--	--	.22	.14	--	.30	-.11	-.05	.22	.11	.30	.25	.24	.12	.17	.25	.23	.16	.21
THERM-MECH PULPING	--	--	.27	.18	--	--	.26	.34	--	--	--	.32	.30	.15	.21	.31	.29	.20	.27
INTEGRATED CHEMICAL	--	--	.22	.14	--	--	.21	.27	.21	.11	.30	.25	.23	.12	.17	.25	.23	.16	.21
CHLORINE	--	--	--	.24	--	--	--	--	--	--	--	--	--	.20	.29	--	--	.26	.35
NYLON	--	--	--	.27	--	--	--	--	--	--	--	--	--	.20	--	--	--	.27	.35
PETRO-REFINING	.16	.16	.11	--	.16	.16	.11	.14	.11	.05	.16	.14	.13	--	--	.11	.12	.09	.11
INTEGRATED STEEL	--	--	--	.22	--	--	--	--	--	--	--	--	--	--	.26	--	--	.28	.34
COPPER	--	--	--	.20	--	--	--	.38	--	--	--	--	.34	.17	.24	--	--	.23	.30
ALUMINA	.14	.14	.09	--	.14	.13	.09	.12	.09	.04	.13	.11	.10	--	--	.09	.09	.07	.10

Note: Matches producing excess heat, or match not possible because process temperature required exceeds ECS capability, are shown by --

Table 9-3

FUEL ENERGY SAVED RATIO OF COGENERATION SYSTEMS FOR SELECTED INDUSTRIAL PROCESSES

HEAT MATCH

	STATE-OF-THE ART				ADVANCED														
	FGD STM TURB - COAL	STM TURB - RESIDUAL	GT-HRSG - RESIDUAL	DIESEL-HRSG - RESIDUAL	AFB STM TURB - COAL	PFB STM TURB - COAL	INT GAS COMB CYCLE - COAL	INT GAS FUEL CELL MC - STM TURB	STIRLING - COAL	CLOSED CYCLE GT HELIUM - COAL	THERMIONIC-STM TURB - COAL	GT-HRSG - RESIDUAL	COMB CYCLE GT - RESID	STM INJ GT - RESID	DIESEL - RESIDUAL	DIESEL-HEAT PUMP - RESIDUAL	REGEN GT - DIST	FUEL CELL - DIST	FUEL CELL MC - DIST
MEAT PACKING	.28	.28	.31	.33	.28	.33	.31	.42	.32	.14	.37	.34	.38	.22	.33	.40	.34	.35	.36
MALT BEVERAGES	.28	.28	.31	.37	.28	.33	.31	.42	.34	.14	.37	.34	.38	.22	.37	.40	.34	.33	.36
BLEACHED KRAFT PAPER	.29	.29	.29	.25	.21	.36	.17	.33	.31	.14	.40	.33	.36	.22	.29	.34	.33	.28	.36
THERM-MECH PULPING	.12	.12	.29	.25	.12	.2	.27	.39	.24	.09	.27	.33	.36	.22	.29	.34	.33	.28	.36
INTEGRATED CHEMICAL	.16	.16	.29	.25	.16	.26	.27	.39	.26	.11	.32	.33	.36	.22	.29	.34	.33	.28	.36
CHLORINE	.08	.08	.16	.26	.08	.12	.17	.30	.13	.04	.15	.18	.29	.22	.29	.22	.21	.28	.36
NYLON	.09	.09	.15	.27	.09	.13	.17	.30	.14	.05	.16	.17	.30	.22	.29	.23	.20	.28	.36
PETRO-REFINING	.18	.18	.27	--	.18	.26	.26	.39	.23	.09	.31	.33	.35	--	--	.28	.31	.28	.36
INTEGRATED STEEL	.06	.06	.12	.22	.06	.11	.03	.21	.16	.06	.16	.14	.18	--	.26	.13	.17	.28	.32
COPPER	.09	.09	.25	.25	.09	.15	.23	.39	.19	.07	.21	.28	.36	.22	.29	.32	.32	.28	.36
ALUMINA	.15	.15	.26	--	.15	.23	.25	.38	.22	.09	.29	.33	.34	--	--	.26	.31	.28	.36

Note: Matches producing excess heat, or match not possible because process temperature required exceeds ECS capability, are shown by --.

For these selected results, the highest fuel energy saved ratio for state-of-the-art systems is achieved by both the gas turbine and diesel in both heat and power matches. The highest fuel energy saved ratio for advanced systems is achieved by the integrated coal gasifier molten carbonate fuel cell in the heat match case and by the distillate-fired molten carbonate fuel cell. Comparing advanced residual fueled systems, the air-cooled gas turbine and combined-cycle have the best fuel energy saved ratio. There is no single system that consistently has fuel energy savings higher than all others. Each system alone performs well in some specific application, but not necessarily better than all others in that application.

Emissions Saved Ratio Results

The emissions saved ratio is calculated in a manner analogous to the fuel energy saved ratio. It is simply the rate of pollutant emissions (NO_x, SO_x, and particulates) for the nocogeneration case minus the emissions rate for the cogeneration case divided by the nocogeneration emissions rate. Pollutants resulting from combustion of by-product or waste fuels were ignored. The emissions saved ratio and emissions saved by type for each ECS-industrial process matchup are given in Volume V. A representative sampling of emissions saved ratio results for selected ECS's and selected plants are presented in Tables 9-4 through 9-7. Tables 9-4 and 9-5 assume a coal fired nocogeneration system. Tables 9-6 and 9-7 assume residual fuel is used as the nocogeneration fuel. The lower emissions saved ratio, when the residual fuel nocogeneration case is assumed, results from the fact that the nocogeneration emissions are reduced significantly in most cases. All systems with the exception of the diesel save emissions over the nocogeneration case. Of the advanced coal burning systems, the integrated coal gasifier molten carbonate fuel cell has the best emissions saved ratio. The phosphoric acid fuel cell has the best emissions saved ratio of the advanced liquid fueled systems.

Table 9-4
EMISSIONS SAVED RATIO FOR COGENERATION SYSTEMS FOR SELECTED INDUSTRIAL PROCESSES
POWER MATCH
COAL NOCOGENERATION BASE

	STATE-OF-THE ART				ADVANCED														
	FGD STM TURB - COAL	STM TURB - RESIDUAL	GT-HRSG - RESIDUAL	DIESEL-HRSG - RESIDUAL	AFB STM TURB - COAL	PFB STM TURB - COAL	INT GAS COMB CYCLE - COAL	INT GAS FUEL CELL MC - STM TURB	STIRLING - COAL	CLOSED CYCLE GT HELIUM - COAL	THERMIONIC-STM TURB - COAL	GT-HRSG - RESIDUAL	COMB CYCLE GT - RESID	STM INJ GT - RESID	DIESEL - RESIDUAL	DIESEL-HEAT PUMP - RESIDUAL	REGEN GT - DIST	FUEL CELL - DIST	FUEL CELL MC - DIST
MEAT PACKING	.18	.28	.32	-1.8	.36	.41	.12	.51	.13	.19	.18	.11	.13	.03	-.03	.00	.46	.66	.43
MALT BEVERAGES	.10	.21	.45	-1.1	.29	.35	.04	.43	.05	.13	.09	.04	.06	-.04	-.08	-.06	.42	.63	.39
BLEACHED KRAFT PAPER	--	--	.57	.12	--	.47	-.12	.33	.19	.25	.27	.27	.28	.17	.19	.22	.55	.57	.55
THERM-MECH PULPING	--	--	.53	-1.7	--	--	.26	.84	--	--	--	.19	.20	.09	-.07	-.02	.50	.74	.47
CHLORINE	--	--	--	-2.4	--	--	--	--	--	--	--	--	--	.08	-.13	--	--	.83	.47
NYLON	--	--	--	-2.8	--	--	--	--	--	--	--	--	--	.06	--	--	--	.33	.46
PETRO-REFINING	.15	.25	.51	--	.33	.37	.11	.36	.09	--	.14	.15	.15	--	--	.02	.48	.58	.47
INTEGRATED STEEL	--	--	--	-1.9	--	--	--	--	--	--	--	--	--	--	-.08	--	--	.79	.49
COPPER	--	--	--	-2.2	--	--	--	.97	--	--	--	--	.16	.02	-.18	--	--	.7[illegible]	.44
ALUMINA	.12	.23	.51	--	.31	.35	.09	.31	.08	.21	.12	.15	.15	--	--	.02	.48	.5[illegible]	.47

Note: Matches producing excess heat, or match not possible because process temperature required exceeds ECS capability, are shown by --.

Table 9-5
EMISSIONS SAVED RATIO FOR COGENERATION SYSTEMS FOR SELECTED INDUSTRIAL PROCESSES
HEAT MATCH
COAL NOCOGENERATION BASE

	STATE-OF-THE ART				ADVANCED														
	FGD STM TURB - COAL	STM TURB - RESIDUAL	GT-HRSG - RESIDUAL	DIESEL-HRSG - RESIDUAL	AFB STM TURB - COAL	PFB STM TURB - COAL	INT GAS COMB CYCLE - COAL	INT GAS FUEL CELL MC - STM TURB	STIRLING - COAL	CLOSED CYCLE GT HELIUM - COAL	THERMIONIC-STM TURB - COAL	GT-HRSG - RESIDUAL	COMB CYCLE GT - RESID	STM INJ GT - RESID	DIESEL - RESIDUAL	DIESEL-HEAT PUMP - RESIDUAL	REGEN GT - DIST	FUEL CELL - DIST	FUEL CELL MC - DIST
MEAT PACKING	.20	.29	.43	-2.6	.37	.49	.28	1.0	.26	.20	.30	.16	.22	.06	-.06	.01	.49	.86	.46
MALT BEVERAGES	.15	.25	.50	-2.2	.33	.46	.26	1.0	.25	.16	.27	.13	.21	.05	-.06	-.03	.48	.86	.45
BLEACHED KRAFT PAPER	.26	.35	.56	-2.2	.41	.54	.16	1.0	.27	.25	.37	.26	.27	.09	-.07	.10	.54	.82	.50
THERM-MECH PULPING	.11	.17	.53	-2.6	.21	.35	.27	1.0	.21	.18	.25	.19	.22	.07	-.14	-.04	.51	.85	.47
CHLORINE	.07	.10	.29	-2.5	.13	.20	.17	.73	.11	.09	.14	.11	.19	.07	-.13	-.01	.32	.85	.47
NYLON	.06	.09	.20	-2.8	.11	.18	.15	.72	.10	.07	.13	.08	.17	.06	-.13	-.01	.29	.85	.46
PETRO-REFINING	.16	.27	.51	--	.34	.47	.26	1.0	.20	.21	.28	.19	.21	--	--	-.14	.49	.85	.47
INTEGRATED STEEL	.05	.08	.26	-2.2	.07	.18	.03	.82	.14	.11	.15	.13	.15	--	-.08	.05	.29	.80	.46
COPPER	.02	.07	.41	-2.7	.11	.22	.17	1.0	.11	.08	.13	.10	.17	.05	-.19	-.11	.46	.85	.45
ALUMINA	.14	.24	.51	--	.32	.36	.25	1.0	.19	.21	.27	.19	.20	--	--	-.17	.49	.85	.47

Note: Matches producing excess heat, or match not possible because process temperature require exceeds ECS capability, are shown by --.

Table 9-6
EMISSIONS SAVED RATIO FOR COGENERATION SYSTEMS FOR SELECTED INDUSTRIAL PROCESSES
POWER MATCH
RESIDUAL NOCOGENERATION BASE

	STATE-OF-THE ART				ADVANCED														
	FGD STM TURB - COAL	STM TURB - RESIDUAL	GT-HRSG - RESIDUAL	DIESEL-HRSG - RESIDUAL	AFB STM TURB - COAL	PFB STM TURB - COAL	INT GAS COMB CYCLE - COAL	INT GAS FUEL CELL MC - STM TURB	STIRLING - COAL	CLOSED CYCLE GT HELIUM - COAL	THERMIONIC-STM TURB - COAL	GT-HRSG - RESIDUAL	COMB CYCLE GT - RESID	STM INJ GT - RESID	DIESEL - RESIDUAL	DIESEL-HEAT PUMP - RESIDUAL	REGEN GT - DIST	FUEL CELL - DIST	FUEL CELL MC - DIST
MEAT PACKING	.18	.28	.32	-1.77	.36	.41	.12	.51	.13	.19	.18	.11	.1[illegible]	.03	-.03	0	.66	.46	.43
MALT BEVERAGES	.16	.26	.30	-1.65	.34	.39	.10	.46	.11	.19	.15	.10	.12	.03	-.02	0	.45	.65	.43
BLEACHED KRAFT PAPER	-	-	.41	-0.21	-	.43	-	-	.13	.20	.22	.22	.23	.12	.12	.16	.52	.54	.52
THERM-MECH PULPING	-	-	.40	-2.34	-	-	.22	.83	-	-	-	.15	.16	.04	-.13	-.07	.47	.72	.45
CHLORINE	-	-	-	-2.77	-	-	-	-	-	-	-	-	-	.06	-.15	-	-	.82	.46
NYLON	-	-	-	-2.78	-	-	-	-	-	-	-	-	-	.06	-	-	-	.83	.46
PETRO-REFINING	.06	.18	.21	-	.26	.31	.02	.29	.0	.14	.06	.06	.07	-	-	-.08	.43	.54	.42
INTEGRATED STEEL	-	-	-	-2.19	-	-	-	-	-	-	-	-	-	-	-.10	-	-	.79	.48
COPPER	-	-	-	-2.55	-	-	-	.97	-	-	-	-	.18	.05	-.14	-	-	.77	.45
ALUMINA	.03	.15	.13	-	.24	.28	-.01	.23	-.02	.13	.03	.05	.05	-	-	-.08	.42	.52	.42

Note: Matches producing excess heat, or match not possible because process temperature required exceeds ECS capability, are shown by - .

Table 9-7
EMISSIONS SAVED RATIO FOR COGENERATION SYSTEMS FOR SELECTED INDUSTRIAL PROCESSES
HEAT MATCH
RESIDUAL NOCOGENERATION BASE

	STATE-OF-THE ART				ADVANCED														
	FGD STM TURB - COAL	STM TURB - RESIDUAL	GT-HRSG - RESIDUAL	DIESEL-HRSG - RESIDUAL	AFB STM TURB - COAL	PFB STM TURB - COAL	INT GAS COMB CYCLE - COAL	INT GAS FUEL CELL MC - STM TURB	STIRLING - COAL	CLOSED CYCLE GT HELIUM - COAL	THERMIONIC-STM TURB - COAL	GT-HRSG - RESIDUAL	COMB CYCLE GT - RESID	STM INJ GT - RESID	DIESEL - RESIDUAL	DIESEL-HEAT PUMP - RESIDUAL	REGEN GT - DIST	FUEL CELL - DIST	FUEL CELL MC - DIST
MEAT PACKING	.20	.29	.43	-2.6	.37	.49	.28	1.00	.26	.20	.30	.16	.22	.06	-.06	.01	.49	.86	.46
MALT BEVERAGES	.20	.29	.43	-2.52	.37	.49	.28	1.00	.28	.20	.30	.16	.22	.06	-.03	.01	.49	.87	.46
BLEACHED KRAFT PAPER	.21	.30	.46	-2.44	.37	.51	.13	1.00	.24	.21	.35	.22	.25	.08	-.09	.06	.52	.81	.49
THERM-MECH PULPING	.06	.13	.42	-2.85	.17	.32	.24	1.00	.17	.14	.21	.15	.19	.06	-.17	-.08	.48	.85	.46
CHLORINE	.05	.08	.21	-2.85	.10	.18	.15	.72	.09	.07	.12	.08	.16	.06	-.16	-.03	.31	.85	.46
NYLON	.06	.09	.20	-2.79	.11	.18	.15	.72	.10	.07	.13	.08	.17	.06	-.13	-.01	.29	.85	.46
PETRO-REFINING	.08	.19	.41	-	.28	.43	.23	1.00	.15	.16	.24	.15	.18	-	-	-.19	.47	.85	.46
INTEGRATED STEEL	.03	.06	.19	-2.39	.08	.16	.01	.81	.12	.09	.14	.11	.13	-	-.10	.03	.27	.80	.44
COPPER	.05	.10	.35	-2.87	.13	.24	.20	1.00	.13	.11	.16	.13	.19	.06	-.17	-.07	.48	.85	.46
ALUMINA	.05	.16	.40	-	.25	.41	.21	1.00	.14	.16	.21	.15	.17	-	-	-.23	.47	.85	.46

Note: Matches producing excess heat, or match not possible because process temperature required exceeds ECS capability, are shown by - .

Section 10

ECONOMIC EVALUATION OF COGENERATION SYSTEMS

INTRODUCTION

One of the most important considerations affecting an industry's decision as to which type of cogeneration system to install, or whether to put in a cogeneration system at all, is its relative economics. Industry, considering a new cogeneration plant at high capital cost, has often found that they could not save enough in energy costs to justify the additional capital cost over installing a process boiler and purchasing power from the utility. As a result, cogeneration plants were installed only in those industries which had several characteristics favoring their economics such as large quantities of waste fuel (as in the case in many pulp paper plants), steam requirements of over 100,000 pounds per hour and continuous operation (so the utilization of the power plant equipment was high). In this section, the economics of advanced technology cogeneration systems is compared to current state-of-the-art systems to determine which advanced systems offer improved economics to permit wider implementation of industrial cogeneration.

In the future, with the prospects of fuel costs rising more rapidly than capital costs, the significantly better fuel efficiency and resulting lower fuel cost of the cogeneration type power plants will tend to make their relative economics more attractive than in the past. This rapidly rising energy cost is increasing the energy portion of the costs of production so that capital expenditures to reduce the cost of energy will receive much higher industrial management priority than in the past. Economic criteria used by industrial management in deciding between alternate methods of satisfying their power and process heat requirements include:

1. Minimum capital cost

2. Rate of return on investment (ROI). The rate of return (decrease in energy cost) on the investment (increase in capital cost) must exceed a "hurdle rate" for that industry

3. Minimum cost of energy.

Until recently, industrial management tended to weigh criteria 1 and 2 most heavily in their choice which emphasizes the short term effects. More consideration is now being given to the longer term trends in fuel and power availability and the resulting increasing energy costs.

Since industrial ownership is primarily emphasized in this study, these selection criteria establish the type of economic indices that are used in comparing the relative merits of the state-of-the-art and advanced technology cogeneration systems for a particular industrial process application. The first index is total capital cost including interest during construction of the power plant. Second is the discounted cash flow return on investment called ROI. *ROI is the discount rate which makes the difference, in discounted after tax cash flows, of two alternate power plants over their economic life equal to their difference in capital costs.* It is also analogous to the interest rate which would be obtained if the capital were loaned as an investment. So ROI is a measure of the profitability of the investment and takes into account the time value of money, taxes, depreciation and the escalation of operating expenses such as fuel and revenue from the export of surplus power. The third index is the levelized annual energy cost (LAEC) of the power plant. *LAEC is the constant cost required each year over the economic life of the power plant to cover the cost of capital and the recovery of the initial investment including all expenses, operation and maintenance, taxes and insurance, fuel and purchased power or revenue from export power.* It is analogous to the utility method of calculating the cost of electricity in dollars per kWh except here it is in total cost per year for the power plant. The term "levelized" means that the escalation of expenses like fuel is taken into account by finding the total "present worth"[1] of the expense over the economic life of the plant and then finding the annual payment required to pay off this total expense at cost of money (interest rate) for the project.

A more detailed explanation of the concepts behind ROI and LAEC is given in the following sections. The detailed equations and basic economic groundrules; e.g., cost of money, years of economic life, fuel and power costs, etc. were established by NASA-LeRC after consultation with the CTAS contractors. One important groundrule specified by NASA-LeRC was that the ROI and LAEC are calculated on an inflation-free basis in 1978 dollars. This means that the cost of money (interest) rates, discount factors and expenses do not include the effect of inflation. The following equation converts the ROI calculated in this study to the ROI_i normally used that includes the effect of inflation:

$$ROI_i = (1 + ROI)(1 + i) - 1$$

where

ROI_i includes inflation

ROI is calculated with inflation set to zero as in this study

and

i = rate of inflation over the economic life.

Escalation of expenses above inflation such as fuel and power is included in the calculations.

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(1) The "present worth" or sometimes called "discounted" value of $1 received 10 years from now in 1978 dollars at a inflation rate of 7% and a cost of capital (interest rate) above inflation of 5% for a total discount rate of (1 + .07) (1 + .05) - 1 = 0.124 is

$$\text{Present Worth of \$1} = \frac{1}{(1.124)^{10}} = \$.31$$

in 1978 dollars. In this study all calculations are done in 1978 dollars, which is another way of saying that the inflation rate is set equal to zero in all calculations unless specifically noted.

In the following subsections the analytical methodology and economic results of the power and heat matches of the various power plant/fuel types with more than 50 different industrial processes will be discussed. Also, the sensitivities of capital cost, fuel and purchased power cost on ROI and LAEC will be described. The economic groundrules and fuel and power costs are discussed in Section 3.

RETURN ON INVESTMENT (ROI) ANALYSIS

ROI is the discount rate which makes the difference in discounted, after tax cash flows for two alternative power plants over their economic life equal their difference in capital cost. In this study, cash flow, S_j, is calculated for each year of operation over the economic life, n, of the plant and is defined as:

$$S_j = \text{Cash Flow} = \text{Revenues} - \text{Cash Operating Expenses} - \text{Income Tax} \quad (10\text{-}1)$$

where the income tax is:

$$\text{Income Tax} = \text{Income Tax Rate (Revenues - Cash Operating Expenses - Tax Depreciation)} - \text{Investment Tax Credit} \quad (10\text{-}2)$$

The definition of ROI defined above can be expressed algebraically as the value of ROI which satisfies the equation:

$$C_{COGEN} - C_{NOCOGEN} = \sum_{j=1}^{n} \frac{(S_j)_{COGEN} - (S_j)_{NOCOGEN}}{(1 + ROI)^j} \quad (10\text{-}3)$$

where

C_{COGEN} = Capital cost of cogeneration system

$C_{NOCOGEN}$ = Capital cost of nocogeneration system

j = Years of plant operation = 1, 2, 3, etc. to 30

n = Economic life = 30 years

Cash flows for the nocogeneration base case, $S_{j\ NOCOGEN}$, and alternate cogeneration system $S_{j\ COGEN}$, are calculated for each of the 30 years of operation by substituting these values into Equation 10-2 to obtain the income tax and Equation 10-1 for the cash flow.

A detailed discussion of the ROI methodology and calculations is given in Volume V, Section 9.3.

Results of ROI Analysis

A sample of the ROI's calculated for selected cogeneration systems and industrial processes using a coal-fired process boiler as the nocogen base case is shown in Table 10-1 for matching the cogen ECS to the process power requirements. The large number of blanks indicate matches where excess process heat is generated and the ROI was not calculated. The negative values of ROI indicate that the nocogen capital cost was higher than the cogen but the cash flows were less for the nocogen ECS so the absolute value of ROI is the ROI realized if the nocogen system were installed instead of the cogen ECS. A ROI of 0 indicates that the sum of even the undiscounted cash flows over the 30-year life was less than the difference in capital cost between the cogen and nocogen cases and thus the ROI = 0. A ROI of 999 usually means that the capital cost and cash flows of the cogen ECS is less than the nocogen ECS and is most often found in the case where coal-fired nocogen ECS is compared with an oil-fired cogen ECS and is a "winner" investment-wise even though the ROI value cannot be calculated. Table 10-2 shows the ROI's when these cogen ECS's are heat matched to the process. Tables 10-3 and 10-4 show the ROI's for the same cogeneration systems and industrial processes as in Tables 10-1 and 10-2 but use a residual-fired process boiler as the nocogen base case.

The results of the ROI analysis for all of the cogeneration/fuel systems heat and power matched to all of the industrial processes are shown in Volume VI Computer Data, Section 12.1 for the base case of a coal-fired nocogeneration process boiler and in Section 12.2 for the base case of an oil-fired nocogeneration process boiler.

An in-depth interpretation of these ROI results is best seen from the plots of capital cost versus LAEC versus ROI which will be discussed in a later section. Inspection of these tables shows that coal-fired steam turbine systems, particularly the AFB, show up very well in those industrial processes with low power to heat ratios. Those cogen systems

Table 10-1

RETURN ON INVESTMENT OF COGENERATION ENERGY CONVERSION SYSTEMS COMPARED TO NOCOGENERATION IN SELECTED INDUSTRIAL PROCESSES

POWER MATCH

COAL NOCOGENERATION BASE

	STATE OF THE ART				ADVANCED														
	FBD STM TURB - COAL	STM TURB - RESIDUAL	GT-HRSG - RESIDUAL	DIESEL-HRSG - RESIDUAL	AFB STM TURB - COAL	PFB STM TURB - COAL	INT GAS COMB CYCLE - COAL	INT GAS FUEL CELL MC - STM TURB	STIRLING - COAL	CLOSED CYCLE GT HELIUM - COAL	THERMIONIC-STM TURB - COAL	GT-HRSG - RESIDUAL	COMB CYCLE GT - RESID	STM INJ GT - RESID	DIESEL - RESIDUAL	DIESEL-HEAT PUMP - RESIDUAL	REGEN GT - DIST	FUEL CELL - DIST	FUEL CELL MC - DIST
MEAT PACKING	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MALT BEVERAGES	5	-19	0	0	10	2	0	0	5	0	0	17	0	0	0	0	0	0	0
BLEACHED KRAFT PAPER	--	--	999	0	--	34	1	0	12	6	4	999	999	-24	0	5	-30	0	0
THERM-MECH PULPING	--	--	40	0	--	--	9	8	--	--	--	131	39	0	0	10	0	0	0
INTEGRATED CHEMICAL	--	--	999	0	--	--	15	12	12	10	6	999	51	999	0	0	0	0	0
CHLORINE	--	--	--	1	--	--	--	--	--	--	--	--	--	10	7	--	--	0	0
NYLON	--	--	--	4	--	--	--	--	--	--	--	--	--	4	--	--	--	0	0
PETRO REFINING	48	-14	-31	--	999	38	12	10	10	6	4	-25	-28	--	--	9	-61	999	0
INTEGRATED STEEL	--	--	--	0	--	--	--	--	--	--	--	--	--	--	4	--	--	0	0
COPPER	--	--	--	0	--	--	--	4	--	--	--	--	19	0	0	--	--	0	0
ALUMINA	22	-19	-35	--	999	20	6	5	6	1	0	-29	-32	--	--	0	-64	999	999

Note: Matches producing excess heat, or match not possible because process temperature required exceeds ECS capability, are shown by --.

Table 10-2

RETURN ON INVESTMENT OF COGENERATION ENERGY CONVERSION SYSTEMS COMPARED TO NOCOGENERATION IN SELECTED INDUSTRIAL PROCESSES

HEAT MATCH

COAL NOCOGENERATION BASE

	STATE OF THE ART				ADVANCED														
	FBD STM TURB - COAL	STM TURB - RESIDUAL	GT-HRSG - RESIDUAL	DIESEL-HRSG - RESIDUAL	AFB STM TURB - COAL	PFB STM TURB - COAL	INT GAS COMB CYCLE - COAL	INT GAS FUEL CELL MC - STM TURB	STIRLING - COAL	CLOSED CYCLE GT HELIUM - COAL	THERMIONIC-STM TURB - COAL	GT-HRSG - RESIDUAL	COMB CYCLE GT - RESID	STM INJ GT - RESID	DIESEL - RESIDUAL	DIESEL-HEAT PUMP - RESIDUAL	REGEN GT - DIST	FUEL CELL - DIST	FUEL CELL MC - DIST
MEAT PACKING	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
MALT BEVERAGES	12	999	0	0	24	8	0	0	8	0	0	-22	0	0	0	0	0	0	0
BLEACHED KRAFT PAPER	42	999	999	0	999	49	6	7	7	5	4	999	17	0	0	0	0	0	0
THERM-MECH PULPING	30	-2	39	0	999	22	10	9	15	4	2	136	20	0	0	8	0	0	0
INTEGRATED CHEMICAL	44	-9	2	0	999	66	14	13	10	10	6	26	9	0	0	0	0	0	0
CHLORINE	35	999	52	0	999	27	14	14	14	5	4	110	42	0	6	13	11	0	0
NYLON	9	12	15	4	[illegible]	[illegible]	4	6	14	1	0	22	17	0	8	11	7	0	0
PETRO-REFINING	43	-12	0	--	999	103	11	11	5	3	3	0	0	--	--	0	0	0	0
INTEGRATED STEEL	31	999	999	0	999	54	9	11	9	7	3	999	73	--	2	5	14	0	0
COPPER	10	999	24	0	23	8	3	4	16	0	0	72	20	0	0	11	5	0	0
ALUMINA	36	-17	0	--	999	44	8	8	3	0	0	0	0	--	--	0	0	0	0

Note: Matches producing excess heat, or match not possible because process temperature required exceeds ECS capability, are shown by --.

Table 10-3

RETURN ON INVESTMENT OF COGENERATION ENERGY CONVERSION SYSTEMS COMPARED TO NOCOGENERATION IN SELECTED INDUSTRIAL PROCESSES

POWER MATCH

RESIDUAL NOCOGENERATION BASE

	STATE-OF-THE ART				ADVANCED															
	FGD STM TURB - COAL	STM TURB - RESIDUAL	GT-HRSG - RESIDUAL	DIESEL-HRSG - RESIDUAL	AFB STM TURB - COAL	PFB STM TURB - COAL	INT GAS COMB CYCLE - COAL	INT GAS FUEL CELL MC - STM TURB	STIRLING-AFB - COAL	CLOSED CYCLE GT HELIUM - COAL	THERMIONIC-STM TURB - COAL	GT-HRSG - RESIDUAL	COMB CYCLE GT - RESID	STM INJ GT - RESID	DIESEL - RESIDUAL	DIESEL-HEAT PUMP - RESIDUAL	REGEN GT - DIST	FUEL CELL - DIST	FUEL CELL MC - DIST	
MEAT PACKING	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
MALT BEVERAGES	7	10	6	3	10	5	0	1	7	0	0	10	5	0	2	4	0	0	0	
BLEACHED KRAFT PAPER	-	-	23	1	-	22	7	5	13	9	7	30	21	9	6	11	0	0	0	
THERM-MECH PULPING	-	-	19	2	-	-	10	9	-	-	-	25	20	8	6	11	6	0	0	
INTEGRATED CHEMICAL	-	-	30	4	-	-	19	16	16	15	10	37	30	15	8	13	4	0	0	
CHLORINE	-	-	-	4	-	-	-	-	-	-	-	-	-	13	9	-	-	0	0	
NYLON	-	-	-	4	-	-	-	-	-	-	-	-	-	4	-	-	-	0	0	
PETRO-REFINING	32	100	20	-	48	30	19	17	18	15	12	29	24	-	-	7	0	0	0	
INTEGRATED STEEL	-	-	-	0	-	-	-	-	-	-	-	-	-	-	5	-	-	0	0	
COPPER	-	-	-	0	-	-	-	4	-	-	-	-	13	1	2	-	-	0	0	
ALUMINA	25	65	15	-	45	27	15	14	16	13	9	24	20	-	-	4	0	0	0	

Note: Matches producing excess heat, or match not possible because process temperature required exceeds ECS capability, are shown by -.

Table 10-4

RETURN ON INVESTMENT OF COGENERATION ENERGY CONVERSION SYSTEMS COMPARED TO NOCOGENERATION IN SELECTED INDUSTRIAL PROCESSES

HEAT MATCH

RESIDUAL NOCOGENERATION BASE

	STATE-OF-THE ART				ADVANCED															
	FGD STM TURB - COAL	STM TURB - RESIDUAL	GT-HRSG - RESIDUAL	DIESEL-HRSG - RESIDUAL	AFB STM TURB - COAL	PFB STM TURB - COAL	INT GAS COMB CYCLE - COAL	INT GAS FUEL CELL MC - STM TURB	STIRLING-AFB - COAL	CLOSED CYCLE GT HELIUM - COAL	THERMIONIC-STM TURB - COAL	GT-HRSG - RESIDUAL	COMB CYCLE GT - RESID	STM INJ GT - RESID	DIESEL - RESIDUAL	DIESEL-HEAT PUMP - RESIDUAL	REGEN GT - DIST	FUEL CELL - DIST	FUEL CELL MC - DIST	
MEAT PACKING	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	
MALT BEVERAGES	11	15	6	0	17	9	2	2	9	1	0	10	3	0	0	4	0	0	0	
BLEACHED KRAFT PAPER	24	54	16	0	46	27	8	8	9	8	5	24	15	0	0	6	0	0	0	
THERM-MECH PULPING	19	26	19	0	29	18	11	9	14	7	4	26	16	0	0	10	3	0	0	
INTEGRATED CHEMICAL	34	84	19	0	55	42	17	15	14	15	10	28	17	0	0	7	0	0	0	
CHLORINE	24	43	27	1	39	23	15	15	15	9	6	34	31	0	8	14	15	0	0	
NYLON	9	12	15	4	12	8	4	5	14	1	0	22	17	0	8	11	7	0	0	
PETRO-REFINING	31	131	1	-	54	39	14	14	10	11	8	17	10	-	-	0	0	0	0	
INTEGRATED STEEL	16	102	21	0	39	23	9	11	9	7	4	28	25	-	4	7	11	0	0	
COPPER	8	10	14	0	12	7	4	5	13	1	0	20	14	0	0	10	6	0	0	
ALUMINA	30	93	0	-	49	32	12	11	9	8	6	14	8	-	-	0	0	0	0	

Note: Matches producing excess heat, or match not possible because process temperature required exceeds ECS capability, are shown by -.

burning high priced distillate fuel; e.g., the regenerative gas turbine and fuel cells are poor economically when compared to a coal-fired nocogen ECS. Also, those cogen systems with high capital cost show up with poor ROI's; e.g., thermionics. As an economic index, ROI is very sensitive to capital costs and if ECS's are screened on ROI the selections will be different than if screened on LAEC or fuel energy saved ratio.

A comparison of the ROI's using a residual-fired process boiler with a coal-fired process boiler nocogen base case shows that the ROI's for the residual-fired nocogen base are higher than for the coal-fired nocogen base. The lower price of liquid fuel compared with coal causes the operating cost and differential cash flows of the residual nocogen system to be greater than for the coal nocogen system. Since the capital cost of the residual-fired nocogen system is less than any of the cogeneration systems, the ROI's are either positive or negative and very few have a value of 999.

LEVELIZED ANNUAL ENERGY COST (LAEC) ANALYSIS

The levelized annual energy cost is defined as the minimum constant revenue required each year over the life of the project to cover all expenses, the cost of money and recovery of the initial investment. This calculation of LAEC is often referred to as the "utility method" cost calculation and includes the cost of capital, recovery of investment, income tax, depreciation, local real estate taxes, fuel and operating and maintenance costs and the cost of purchased power or revenue from exported power in the units of total energy system costs in 1978 dollars per year. The LAEC is equal to:

$$\begin{aligned} \text{LAEC} &= \text{levelized fixed charges} \\ &+ \text{levelized operating costs} \\ &= \text{levelized revenues} \end{aligned} \tag{10-4}$$

Levelized Fixed Charges

The levelized fixed charges (LFC) are analogous to the annual mortgage payments an individual makes on his loan to purchase his house except that factors are included to take into account the tax deductions for interest, depreciation and investment tax credit. The levelized fixed charges (LFC) are calculated by the equation:

$$LFC = C \times FCR \qquad (10\text{-}5)$$

where

FCR = fixed charge rate

C = capital investment.

For the economic groundrules used in CTAS shown in Table 3-3 including zero inflation, the fixed charge rate is 0.0706. If an inflation of 6.5% is included as well as local taxes and inflation, the FCR is 0.167. A detailed discussion of this low value of FCR and details of the LAEC calculation are given in Volume V, Section 9.4.

Levelized Operating Expenses and Revenues

The operating expenses or revenue over the operating life of the power plant are levelized to account for their escalation. This levelized cost is the average annual constant payment during the life of the plant required to meet these escalating expenses. Levelization factor is the ratio of the levelized expense divided by the expense in the first year of operation. Because these levelization factors can be very large for even 10% total escalation rates, *it is very important in comparing levelized costs to understand the groundrules on inflation and the escalation above inflation of the expense or revenue.* In CTAS the inflation rate was set at zero and only the escalation of the expense or revenue above the inflation rate are used to give a levelization factor of 1.128 on oil, coal, and electric power prices.

This levelized operating costs and revenue portion of the LAEC of equation 10-4 is:

Levelized Expenses = local taxes and insurance (10-6)
+ operating and maintenance
+ purchased fuel
+ purchased electricity
- revenue from export power

Throughout the CTAS reports, revenue is considered to be a negative expense when power is sold to produce income to the industry.

Levelized Annual Energy Costs Results

A sample of levelized annual energy cost savings ratios (LAECSR) calculated for selected industrial processes and cogeneration systems with a coal-fired process boiler nocogen system as a base are shown in Table 10-5 for power matches and Table 10-6 for heat matches. The same cogeneration systems using a residual-fired process boiler nocogen system as a base are shown in Tables 10-7 and 10-8. The LAECSR is defined as:

$$LAECSR = \frac{LAEC_{NOCOGEN} - LAEC_{COGEN}}{LAEC_{NOCOGEN}} \qquad (10\text{-}7)$$

so that positive values indicate a LAEC savings when a cogeneration is installed compared to the nocogeneration base case. A negative value of LAECSR indicates the LAEC is more for the cogeneration case than the nocogeneration system.

A study of Table 10-5, 6, 7 and 8 shows the LAECSR's for the small 1.9 MW_e meat packing plant with only 2100 hours per year operation are all negative. The coal-fired FGD steam turbine performs well with the AFB steam turbine showing slightly better LAECSR's in nearly all industries. The same holds true for the state-of-the-art and advanced gas turbines. Also, there is a correlation with the cost of cogeneration fuel, with higher LAECSR's with coal-fired cogeneration systems compared with residual and the distillate-fired cogeneration systems.

Tables 10-7 and 10-8 show the same cogeneration systems as above but with the LAECSR based on residual-fired process boiler nocogeneration systems. Comparing residual nocogen based cases with the coal nocogen, we see that the residual based cases have a higher number of matches with positive LAECSR's and that values are higher than when the base is a coal-fired nocogeneration.

Table 10-5

LEVELIZED ANNUAL ENERGY COST SAVINGS RATIO OF COGENERATION OVER NOCOGENERATION IN SELECTED INDUSTRIAL PROCESSES

POWER MATCH

COAL NOCOGENERATION BASE

	STATE-OF-THE ART				ADVANCED														
	FGD STM TURB - COAL	STM TURB - RESIDUAL	GT-HRSG - RESIDUAL	DIESEL-HRSG - RESIDUAL	AFB STM TURB - COAL	PFB STM TURB - COAL	INT GAS COMB CYCLE - COAL	INT GAS FUEL CELL MC - STM TURB	STIRLING - COAL	CLOSED CYCLE GT HELIUM - COAL	THERMIONIC-STM TURB - COAL	GT-HRSG - RESIDUAL	COMB CYCLE GT - RESID	STM INJ GT - RESID	DIESEL - RESIDUAL	DIESEL-HEAT PUMP - RESIDUAL	REGEN GT - DIST	FUEL CELL - DIST	FUEL CELL MC - DIST
MEAT PACKING	-.84	-.34	-.35	-.38	-.68	-1.1	-1.7	-1.5	-.85	-1.4	-2.1	-.26	-.4	-.41	-.38	-.56	-.44	-.38	-.41
MALT BEVERAGES	.01	-.01	-.06	-.11	.08	-.06	-.20	-.24	.00	-.29	-.45	-.02	-.07	-.15	-.11	-.09	-.22	-.30	-.34
BLEACHED KRAFT PAPER	--	--	+.05	-.14	--	.25	-.05	-.10	.13	.03	-.02	.09	.05	-.07	-.08	0	-.12	-.4	-.33
THERM-MECH PULPING	--	--	.09	-.12	--	--	.13	.10	--	--	--	.15	.11	-.05	-.05	.05	.06	-.40	-.31
INTEGRATED CHEMICAL	--	--	.01	-.19	--	--	.19	.16	.15	.09	.05	.05	.02	-.11	-.13	-.04	-.18	-.48	-.41
CHLORINE	--	--	--	-.06	--	--	--	--	--	--	--	--	--	.04	.04	--	--	-.37	-.25
NYLON	--	--	--	-.01	--	--	--	--	--	--	--	--	--	-.01	--	--	--	-.31	-.19
PETRO-REFINING	.19	-.08	-.17	--	.23	.16	.08	.07	.07	.02	-.01	-.13	-.15	--	--	-.23	-.39	-.56	-.52
INTEGRATED STEEL	--	--	--	-.14	--	--	--	--	--	--	--	--	--	--	-.03	--	--	-.37	-.29
COPPER	--	--	--	-.11	--	--	--	-.05	--	--	--	--	.11	-.05	-.06	--	--	-.35	-.25
ALUMINA	.12	-.13	-.21	--	.18	.11	.01	.00	.02	-.04	-.09	-.17	-.19	--	--	-.27	-.44	-.58	-.54

Note: Matches producing excess heat, or match not possible because process temperature required exceeds ECS capability, are shown by --.

Table 10-6

LEVELIZED ANNUAL ENERGY COST SAVINGS RATIO OF COGENERATION OVER NOCOGENERATION IN SELECTED INDUSTRIAL PROCESSES

HEAT MATCH

COAL NOCOGENERATION BASE

	STATE-OF-THE ART				ADVANCED														
	FGD STM TURB - COAL	STM TURB - RESIDUAL	GT-HRSG - RESIDUAL	DIESEL-HRSG - RESIDUAL	AFB STM TURB - COAL	PFB STM TURB - COAL	INT GAS COMB CYCLE - COAL	INT GAS FUEL CELL MC - STM TURB	STIRLING - COAL	CLOSED CYCLE GT HELIUM - COAL	THERMIONIC-STM TURB - COAL	GT-HRSG - RESIDUAL	COMB CYCLE GT - RESID	STM INJ GT - RESID	DIESEL - RESIDUAL	DIESEL-HEAT PUMP - RESIDUAL	REGEN GT - DIST	FUEL CELL - DIST	FUEL CELL MC - DIST
MEAT PACKING	-.61	-.23	-.33	-.98	-.44	-.84	-2.1	-2.3	-.61	-1.3	-2.7	-.2	-.7	-1.8	-.98	-.7	-.55	-1.1	-1.7
MALT BEVERAGES	.13	.05	-.05	-.21	.21	.08	-.29	-.35	.11	-.26	-.65	.02	-.12	-1.3	-.21	-.11	-.33	-.89	-1.8
BLEACHED KRAFT PAPER	.29	.15	.03	-1.1	.27	.34	.05	.09	.10	.01	-.06	.11	.07	-.91	-.65	.07	-.21	-2.2	-1.4
THERM-MECH PULPING	.11	.01	.10	-.79	.15	.15	.16	.14	.19	-.02	-.10	.17	.12	-.65	-.42	.04	.09	-1.7	-1.0
INTEGRATED CHEMICAL	.18	-.02	-.01	-1.2	.21	.28	.25	.29	.15	.10	.06	.08	.03	-1.0	-.73	-.11	-.28	-2.5	-1.6
CHLORINE	.08	.02	.07	-.15	.09	.10	.13	.19	.10	00	-.01	.10	.18	-.12	.02	.07	.01	-.63	-.31
NYLON	.04	.03	.08	-.01	.06	.04	-.04	.02	.12	-.06	-.17	.11	.15	-.13	.07	.08	.02	-.49	-.21
PETRO-REFINING	.21	-.06	-.29	--	.25	.27	.19	.27	.01	-.03	-.06	-.07	-.14	--	--	-.50	-.70	-3.9	-2.6
INTEGRATED STEEL	.05	.03	.06	-.26	.08	.10	.06	.15	.07	.02	-.04	.08	.11	--	-.04	00	.01	-.42	-.23
COPPER	.03	.01	.10	-.50	.07	.04	-.07	-.02	.15	-.12	-.28	.15	.14	-.44	-.22	.07	.00	-1.1	-.61
ALUMINA	.16	-.11	-.39	--	.21	.21	.11	.14	-.07	-.13	-.20	-.12	-.20	--	--	-.62	-.83	-4.2	-2.8

Note: Matches producing excess heat, or match not possible because process temperature required exceeds ECS capability, are shown by --.

Table 10-7

LEVELIZED ANNUAL ENERGY COST SAVINGS RATIO OF COGENERATION OVER NOCOGENERATION IN SELECTED INDUSTRIAL PROCESSES

POWER MATCH

RESIDUAL NOCOGENERATION BASE

	STATE-OF-THE ART				ADVANCED														
	FGD STM TURB - COAL	STM TURB - RESIDUAL	GT-HRSG - RESIDUAL	DIESEL-HRSG - RESIDUAL	AFB STM TURB - COAL	PFB STM TURB - COAL	INT GAS COMB CYCLE - COAL	INT GAS FUEL CELL MC - STM TURB	STIRLING-AFB - COAL	CLOSED CYCLE GT HELIUM - COAL	THERMIONIC-STM TURB - COAL	GT-HRSG - RESIDUAL	COMB CYCLE GT - RESID	STM INJ GT - RESID	DIESEL - RESIDUAL	DIESEL-HEAT PUMP - RESIDUAL	REGEN GT - DIST	FUEL CELL - DIST	FUEL CELL MC - DIST
MEAT PACKING	-.84	-.34	-.35	-.38	-.60	-1.11	-1.69	-1.52	-.86	-1.43	-2.12	-.26	-.41	-.41	-.57	-.56	-.44	-.38	-.41
MALT BEVERAGES	.08	.06	.01	-.03	.14	.01	-.18	-.15	.06	-.20	-.35	.05	.01	-.07	-.03	-.02	-.14	-.21	-.26
BLEACHED KRAFT PAPER	-	-	.13	-.04	-	.32	.04	0	.21	.11	.07	.17	.13	.03	.01	.09	-.02	-.28	-.21
THERM-MECH PULPING	-	-	.16	-.05	-	-	.19	.16	-	-	-	.21	.17	.02	.02	.11	.01	-.30	-.22
INTEGRATED CHEMICAL	-	-	.15	-.02	-	-	.31	.29	.28	.23	.19	.19	.16	.05	.04	.11	-.01	-.27	-.20
CHLORINE	-	-	-	-.02	-	-	-	-	-	-	-	-	-	.08	.08	-	-	-.31	-.20
NYLON	-	-	-	-.01	-	-	-	-	-	-	-	-	-	-.01	-	-	-	-.31	-.19
PETRO-REFINING	.35	.13	.06	-	.38	.33	.27	.26	.25	.21	.19	.09	.08	-	-	.02	-.12	-.25	-.22
INTEGRATED STEEL	-	-	-	-.12	-	-	-	-	-	-	-	-	-	-	-.01	-	-	-.35	-.26
COPPER	-	-	-	-.10	-	-	-	-.04	-	-	-	-	.13	-.04	-.04	-	-	-.33	-.23
ALUMINA	.31	.10	.04	-	.35	.30	.22	.21	.22	.18	.13	.07	.06	-	-	0	-.14	-.25	-.22

Note: Matches producing excess heat, or match not possible because process temperature required exceeds ECS capability, are shown by -.

Table 10-8

LEVELIZED ANNUAL ENERGY COST SAVINGS RATIO OF COGENERATION OVER NOCOGENERATION IN SELECTED INDUSTRIAL PROCESSES

HEAT MATCH

RESIDUAL NOCOGENERATION BASE

	STATE-OF-THE ART				ADVANCED														
	FGD STM TURB - COAL	STM TURB - RESIDUAL	GT-HRSG - RESIDUAL	DIESEL-HRSG - RESIDUAL	AFB STM TURB - COAL	PFB STM TURB - COAL	INT GAS COMB CYCLE - COAL	INT GAS FUEL CELL MC - STM TURB	STIRLING-AFB - COAL	CLOSED CYCLE GT HELIUM - COAL	THERMIONIC-STM TURB - COAL	GT-HRSG - RESIDUAL	COMB CYCLE GT - RESID	STM INJ GT - RESID	DIESEL - RESIDUAL	DIESEL-HEAT PUMP - RESIDUAL	REGEN GT - DIST	FUEL CELL - DIST	FUEL CELL MC - DIST
MEAT PACKING	-.61	-.23	-.33	-.98	-.44	-.84	-2.11	-2.32	-.61	-1.26	-2.65	-.20	-.70	-1.75	-.93	-.70	-.55	-1.06	-1.71
MALT BEVERAGES	.19	.11	.02	-.27	.27	.14	-.20	-.26	.17	-.18	-.54	.09	-.04	-1.10	-.13	-.02	-.24	-.76	-1.58
BLEACHED KRAFT PAPER	.35	.22	.12	-.93	.41	.40	.13	.17	.17	.10	.03	.19	.15	-.75	-.50	.02	-.10	-1.94	-1.21
THERM-MECH PULPING	.17	.08	.16	-.66	.21	.21	.22	.20	.25	.05	-.02	.23	.18	-.54	-.32	.10	-.01	-1.47	-.88
INTEGRATED CHEMICAL	.30	.13	.14	-.88	.32	.39	.36	.39	.28	.23	.20	.21	.18	-.73	-.47	.05	-.09	-1.96	-1.23
CHLORINE	.12	.06	.11	-.10	.13	.14	.17	.23	.14	.05	.03	.14	.22	-.07	.06	.11	.02	-.56	-.26
NYLON	.04	.03	.08	-.01	.06	.04	-.04	.02	.12	-.06	-.17	.11	.15	-.13	.07	.08	.02	-.49	-.21
PETRO-REFINING	.36	.15	-.02	-	.40	.41	.35	.41	.20	.17	.15	.14	.08	-	-	-.20	-.36	-2.89	-1.84
INTEGRATED STEEL	.07	.05	.08	-.24	.10	.12	.08	.16	.08	.04	-.02	.10	.12	-	-.02	.02	.03	-.40	-.21
COPPER	.05	.03	.11	-.48	.08	.05	-.05	0	.16	-.11	-.26	.16	.15	-.42	-.20	.09	.02	-1.04	-.59
ALUMINA	.34	.12	-.10	-	.37	.37	.29	.32	.15	.10	.05	.12	.05	-	-	-.28	-.45	-3.08	-2.01

Note: Matches producing excess heat, or match not possible because process temperature required exceeds ECS capability, are shown by -.

A greater understanding of the interaction of the cogeneration system capital costs, LAEC's and ROI will be shown in the following section.

The LAEC calculation methodology was programmed into the computerized CTAS Cogeneration Evaluation and Data System and LAEC's calculated for all of the cogeneration/fuel systems heat and power matched as shown in Vol. VI, Computer Data, Section 12.1 for the base case of a coal-fired nocogeneration system. These same values of LAEC are repeated for the oil-fired nocogeneration case in Section 12.2 as only the LAEC's of the nocogeneration systems change because of different fuel.

SELECTION OF COGENERATION SYSTEMS BASED ON ECONOMIC CRITERIA

In the introduction of this section the economic criteria used by industrial management in deciding between alternate methods of satisfying their process heat and power requirements were low capital cost, a return on investment which exceeded the industry's "hurdle rate" and minimum cost of energy.

A graphic method of portraying these economic parameters, their relationships and the application of the above selection criteria is shown in Figure 10-1. A number of alternate nocogeneration and cogeneration systems all matched to a single industrial process are plotted at the intersection of their LAEC and capital cost on this graph. A very important characteristic of this graph is that the slope of the line connecting any two power plant alternatives plotted on this graph is a function of the ROI of implementing the alternative with the higher capital cost and lower LAEC compared with the other. This correlation was used to derive the "ROI Protractor" shown on Figure 10-1.

The first criterion in selecting a power plant to meet the energy requirements of the industrial process is minimum capital cost and, in this example, is represented by power plant A, a liquid-fired nocogeneration boiler and purchasing the required power from the utility. The next higher capital cost alternative with a lower LAEC is cogeneration oil-fired system B having a considerable savings in LAEC at a modest increase in capital cost and giving a ROI of 131% on the increase in incremental investment over system A, and other factors being equal, would almost always be selected over system A. The next higher capital cost systems are two systems, very close together, labelled G. These systems would not be selected over B even though it has an ROI of 22% compared to A because, in addition to the higher capital cost, they have a higher LAEC than B. System C, a coal-fired cogeneration system is the next higher capital cost system and gives a significant decrease in LAEC over system B and has a ROI of 45% on the incremental investment over B. The only remaining alternative system which gives a reduction in LAEC compared with C, is system D. The reduction in LAEC is small compared with the incremental increase in capital cost so its ROI is only 7% which is not high enough to be considered.

If the choice of power plants were restricted to those burning coal (shown as □ or ■ on the plot), the base coal-fired nocogeneration case is system E. Advanced Cogeneration System C gives a significant reduction in LAEC compared with E at a reduction in incremental capital cost so it is a winner. Theoretically, the ROI of C compared to E can not be calculated because there is a savings with a reduction in capital cost. As before, there is a low ROI = 7% when system D is compared to C so D would not be chosen. If the selection were limited to present state-of-the-art coal-fired systems (shown by ■) system F with a ROI of 43% compared with E would be the system selected.

On Figure 10-1, when both a power match and heat match can be made with a single cogeneration system-fuel combination, the power match is indicated by a dot, ·, and the heat match is indicated by a □ , ■ , ○ or ● and is connected to the power match by a straight solid line; e.g., line GI, JL, or KM. These GI, JL & KM systems have a much higher power to heat ratio than the process so that when heat matched to the process they generate from 3 to 6 times the power required by the process, are advanced systems and, at the price assumed received for export power of 0.6 times the purchase power, do not give a favorable ROI.

Application of the various energy conversion systems and the fuels to supply a given industry with heat and power result in a wide spectrum of economics. These plots provide a vehicle for displaying results and comparing the economics of state-of-the-art systems versus advanced systems

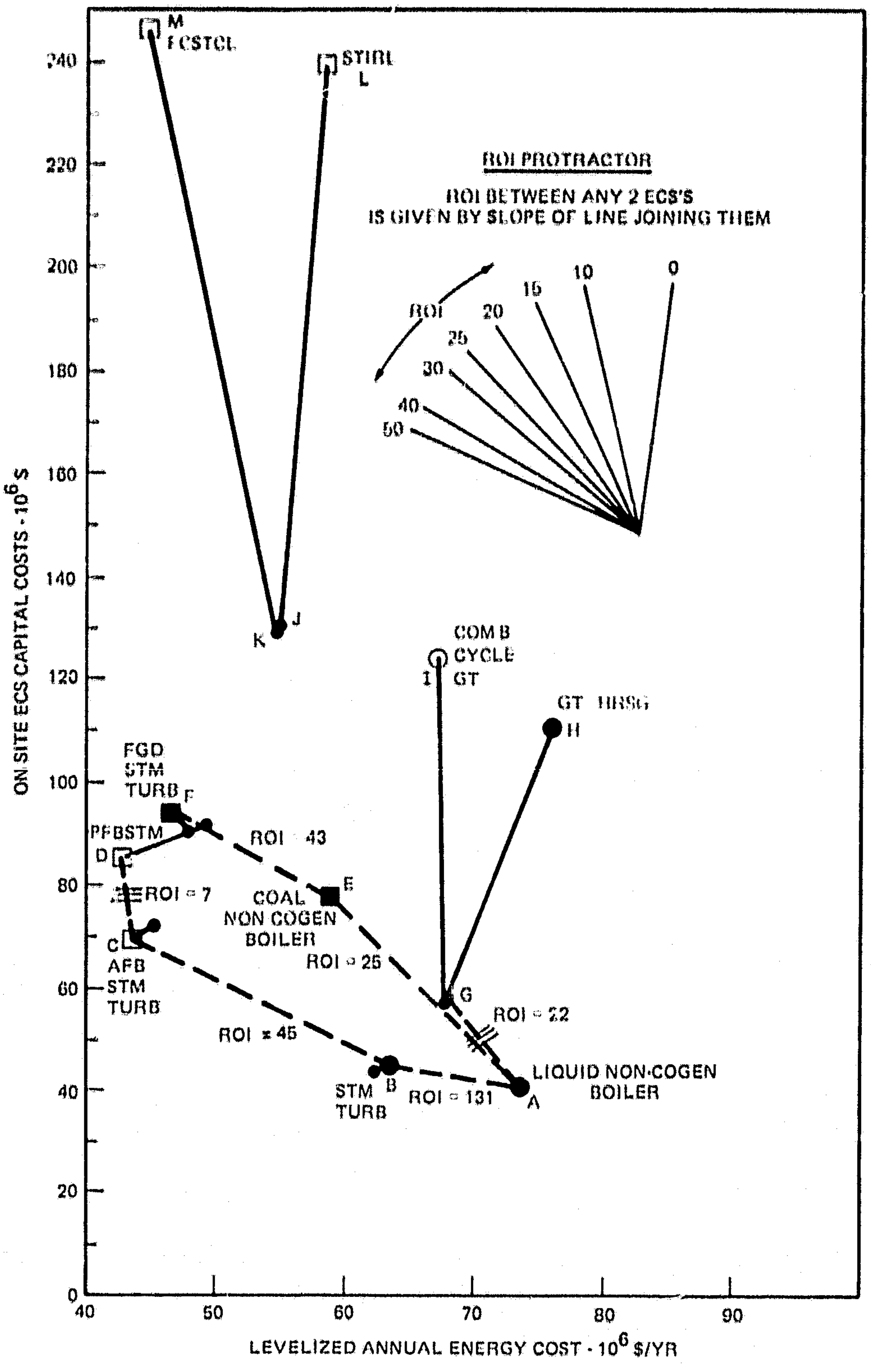

Figure 10-1. Industrial Economics of a Small Sample of Cogeneration and Nocogeneration ECS's Heat and Power Matched to a Medium Petroleum Refinery - SIC 2911-2
(A more complete selection of ECS's matched to this process is shown in Figure 10-2.)

using either coal or liquid fuels. When the fuel energy saved ratio and power generated by the various cogeneration systems are also noted on these plots, the key data for comparison can be presented on one sheet for each industrial process. Coupling the data presented by these plots for several processes with representative power to heat ratios and the energy requirement characteristics of the national population of industrial processes allows the process results to be used to infer results from a national perspective.

Figure 10-2 is a plot of selected CTAS ECS cogeneration economics for a medium-sized petroleum refinery. The refinery requires 52 megawatts of electric power and 1333 million Btu per hour of steam at 470°F and operates 8760 hr/yr. The power to heat ratio of the petroleum refinery is 0.13. About 60% of industrial process energy required in the US for steam and electric power is consumed by processes with power to heat ratios less than or equal to 0.20. Accordingly, the ECS's that have good economics and fuel energy savings for the petroleum refinery should be representative of cogeneration systems that have good performance and economics over the 0 - 0.20 power to heat range. These systems would have the most national impact because of the large fraction of national energy consumption represented by these processes.

In comparison to the liquid-fueled nocogeneration case, the liquid-fueled cogeneration systems that have a ROI greater than 15% are the power matched state-of-the-art and advanced gas turbine (GT-HRSG ·), the advanced diesel with a heat pump (DIESEL-HEAT PUMP ·), the advanced combined-cycle (COMB CYCLE ·), the state-of-the-art steam turbine (STM TURB ·, ●). These systems are all sized to match process power required with the exception of the state-of-the-art steam turbine where both the heat match and power match cases are economic. The heat match cases of all other systems have poorer economics than the power match cases. The fuel energy savings of these power matched cases are all about 11% to 14%. The steam turbine saves about 18% fuel energy and it has the best return on investment (>50%) of any system.

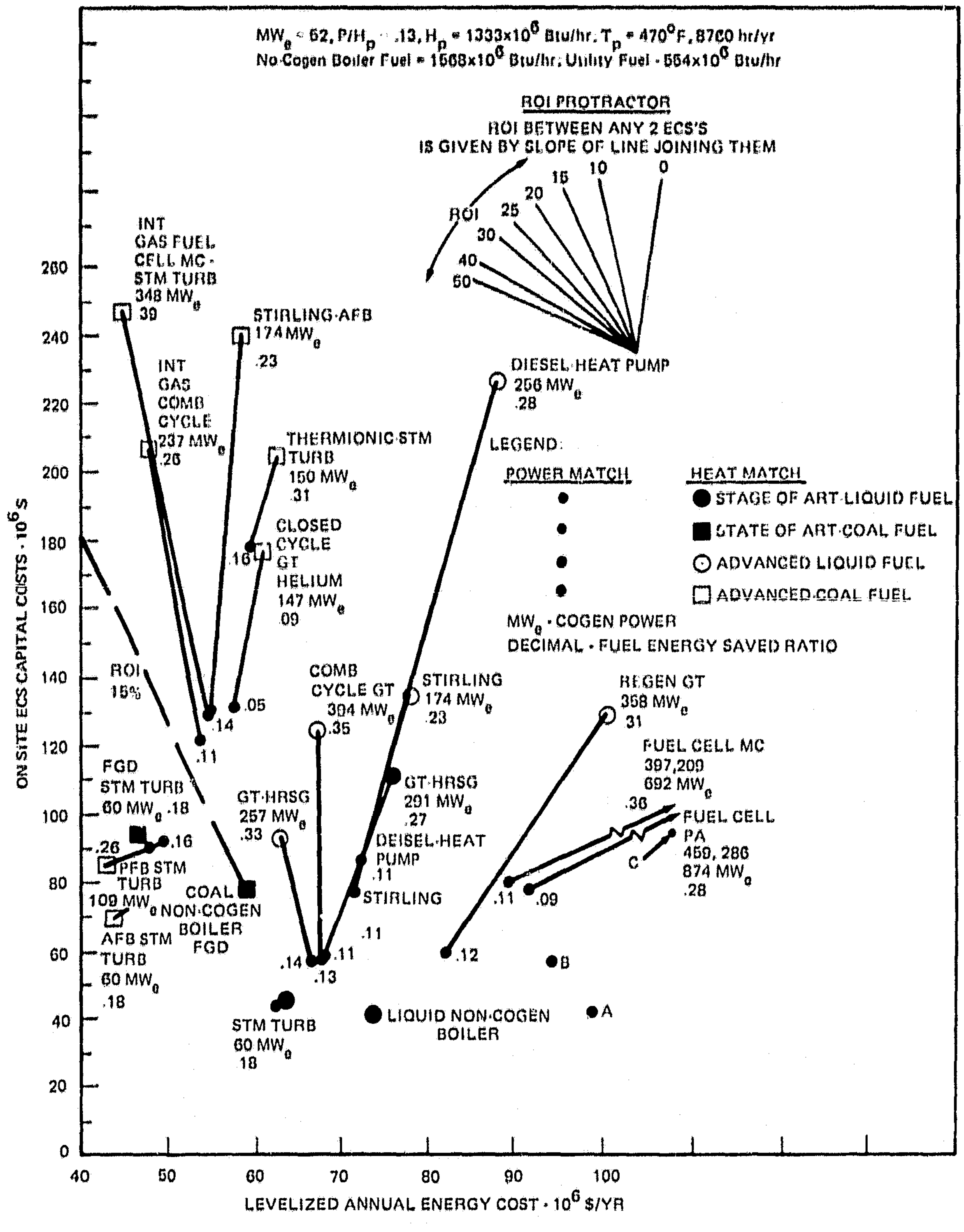

Figure 10-2. Industrial Economics of Cogeneration and Nocogeneration ECS's Heat and Power Matched to Medium Petroleum Refinery - SIC 2911-2

An area of concern on the liquid-fired systems is the possibility of an increasing price differential between liquid fuel and coal. The groundrule base price of coal used is $\$1.80/10^6$ Btu and residual liquids is \$3.10 in 1985 (in 1978 dollars). The effect of increasing the liquid price by 50% to $\$4.65/10^6$ Btu is to significantly increase the LAEC of the liquid-fired systems as shown by point A for the nocogen liquid boiler, point B for the gas turbine, (GT-HRSG ·), power matched and point C for the same gas turbine (GT-HRSG ⊙) heat matched. The slopes of the lines A-B and A-C compared to those connecting the same groundrule base costs show a significant reduction in ROI and make the liquid cogeneration ECS's uneconomical compared to the coal-fired systems.

Concentrating on coal burning systems only, the coal-fired nocogeneration case with flue gas desulfurization (COAL NON-COGEN BOILER FGD ■) costs \$78 million with a levelized annual energy cost of \$59 million. Note that the capital cost of the coal-fired nocogeneration case is about double that of the liquid-fired nocogeneration case. Even though the coal-fired nocogeneration equipment is very expensive, if the industrial can raise the capital, it appears to be a good investment with an ROI of about 25% (using the ROI protractor) compared to the liquid nocogeneration case.

The coal-fired cogeneration systems that fall to the left of the 15% ROI hurdle line are the state-of-the-art steam turbine with flue gas desulfurization (FGD STM TURB), the PFB steam turbine (PFB STM TURB), and the AFB steam turbine (AFB STM TURB) matched to process heat or power. Of the economically feasible systems, the AFB steam turbine matched to process heat gives the best economics. The capital cost is less than the nocogeneration boiler with flue gas desulfurization and the levelized annual cost of energy is also less. A ROI cannot be calculated in this situation with the nocogeneration case as the base because there would be a negative incremental investment.

Figure 10-3 shows the economics for a thermomechanical pulp mill which has a power to heat ratio of 0.58. The economics shown here may be considered representative of those for processes with power to heat ratios of from 0.20 - 0.6. About 22% of industrial energy for steam and electric power is consumed by industries that require power to heat

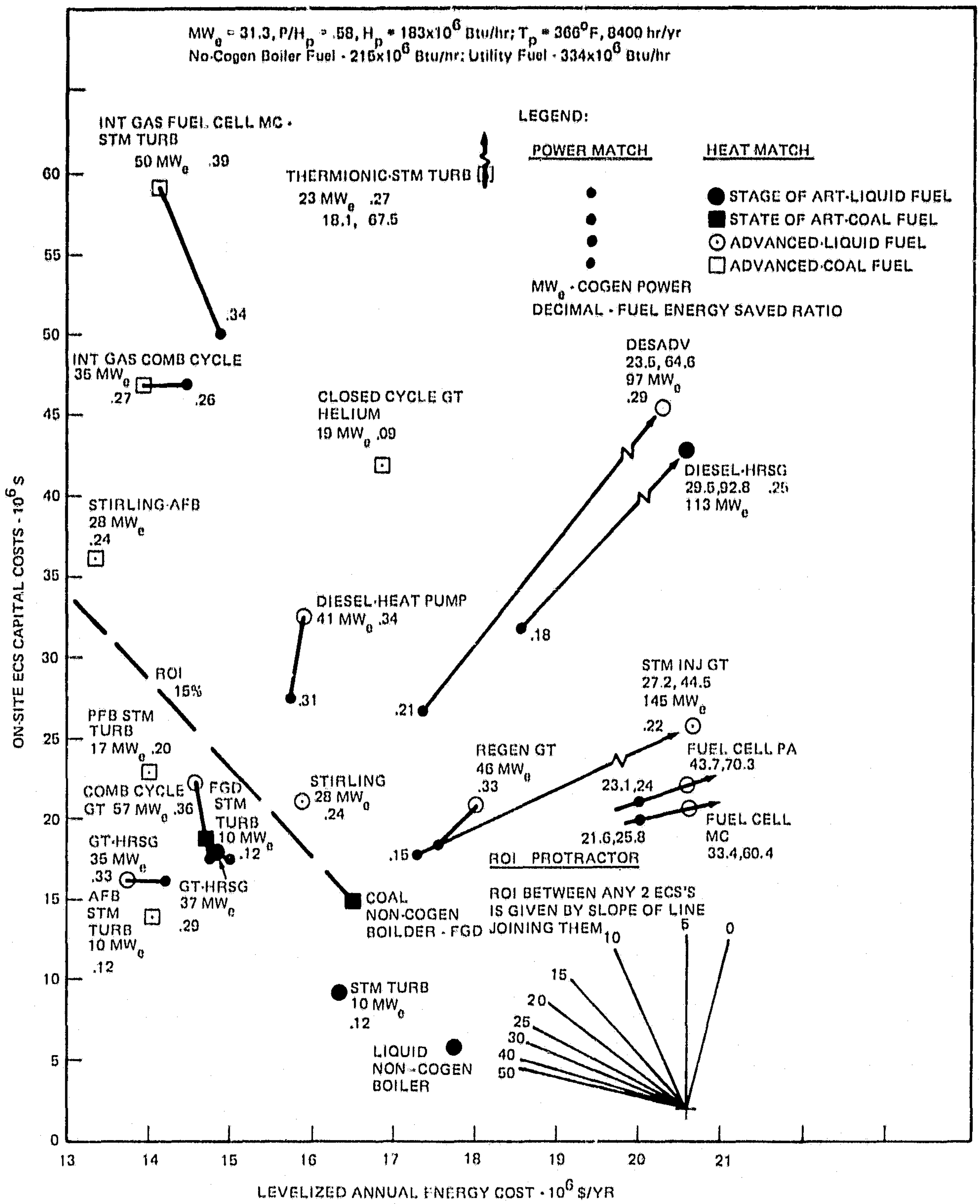

Figure 10-3. Industrial Economics of Cogeneration and Nocogeneration ECS's Heat and Power Matched to Thermo-Mechanical Pulp, SIC 2621-7

ratios over this range. For liquid fueled systems compared to the liquid fueled nocogeneration system, those that have favorable economics are the state-of-the-art steam turbine (STM TURB ●), the state-of-the-art gas turbine (GT-HRSG ●), the advanced combined-cycle (COMB CYCLE ⊙), and the advanced air-cooled gas turbine (GT-HRSG ⊙). The state-of-the-art steam turbine, while it only generates 10 MW out of the 31.3 MW required and saves 12% in fuel, still gives a good ROI (≈26%) for the lowest increment of capital cost. The other systems when now compared to the state-of-the-art steam turbine are less attractive investments (ROI's less than 15%) with the exception of the advanced air-cooled gas turbine (GT-HRSG ⊙). It has a ROI of about 25% compared to the state-of-the-art steam turbine and has a fuel energy saved ratio of 0.33.

Next, the coal fueled systems are compared to the coal fueled nocogeneration case. Systems that have good economic potential (fall to the left of the 15% ROI hurdle line) are the state-of-the art steam turbine with flue gas desulfurization (FGD STM TURB ■), the advanced PFB steam turbine (PFB STM TURB ⊡) and the advanced steam turbine with AFB (AFB STM TURB ⊡). The only state-of-the-art system in consideration here is the state-of-the-art steam turbine-boiler with flue gas desulfurization. It gives an attractive ROI of ≈27% while saving 12% in fuel energy. Of the advanced systems, the AFB steam turbine is the ultimate winner because its initial capital cost is less than that of the nocogeneration boiler with flue gas desulfurization.

Figure 10-4 shows the economics for a copper smelter which has a power to heat ratio of 0.86. The economics shown here may be considered somewhat typical for those processes with power to heat ratios from 0.6 to 1.5. About 12% of industrial energy for steam and electric power is consumed by industries that require power to heat ratios over this range. Of the liquid fueled systems compared to the liquid nocogeneration case, the state-of-the-art steam turbine (STM TURB ●) and state-of-the-art gas turbine (GT-HRSG ●) both have ROI's less than 15%. Of the advanced systems, the advanced air-cooled gas turbine (GT-HRSG ⊙) is clearly the economic winner with a ROI of ≈19%. Comparing coal-fired systems, the only system with favorable economics is the AFB steam turbine (AFB STM TURB ⊡) with a ROI of ≈22%.

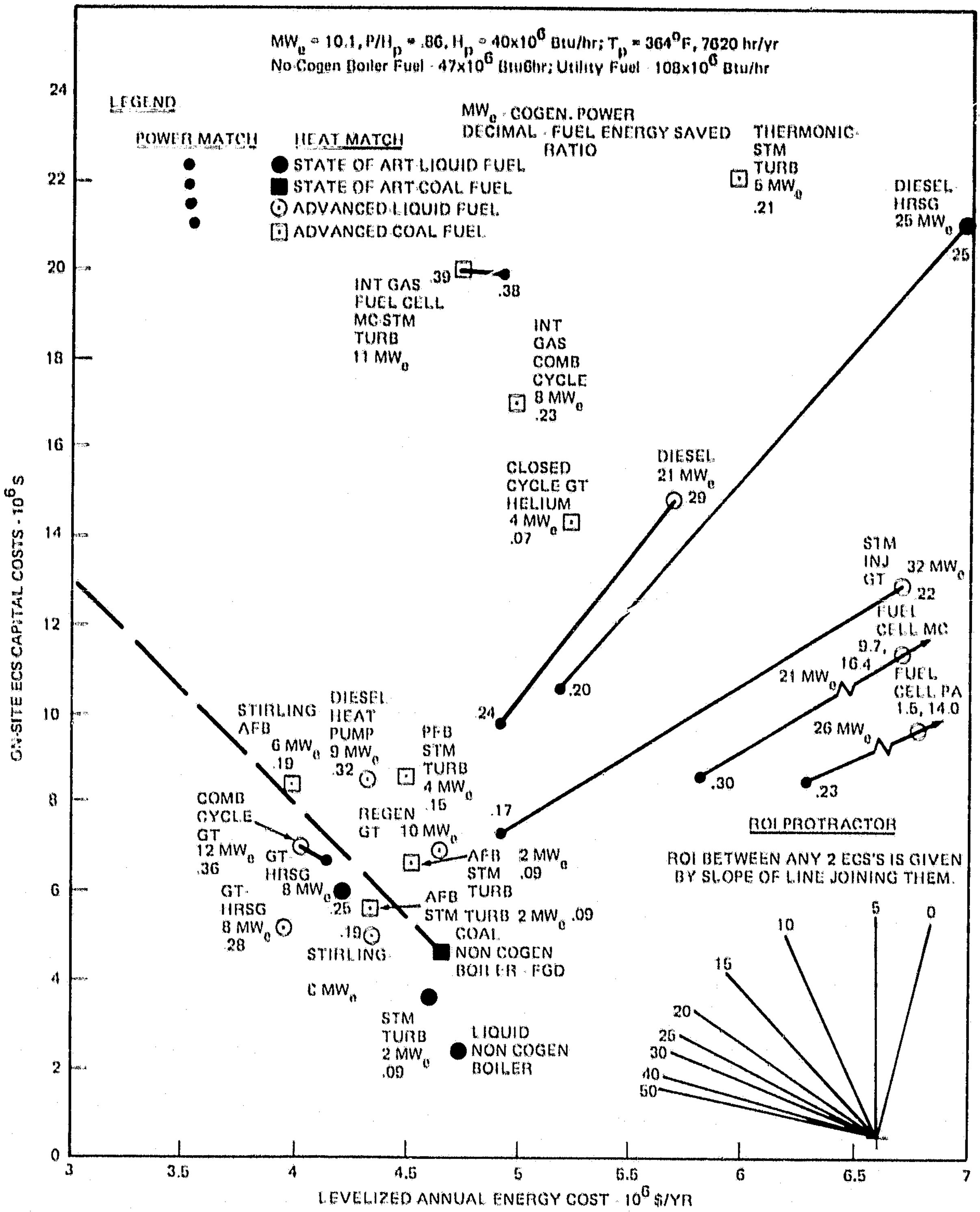

Figure 10-4. Industrial Economics of Cogeneration and Nocogeneration ECS's Heat and Power Matched to Copper Smelter, SIC 3331-4

SENSITIVITY OF ROI TO CHANGES IN COSTS

Return on Investment (ROI) is a very sensitive index of the economic performance of cogeneration systems and the question arises as to its sensitivity to changes in fuel, power, and capital costs. A conventional method of presenting these sensitivities is shown in Figure 10-5 for a steam turbine coal-fired AFB boiler cogeneration system heat matched to a medium petroleum refinery and compared to a nocogeneration residual-fired boiler with power from the utility. Four costs were varied from -10% to +50% of their base value; namely the cost of residual fuel for the nocogeneration boiler, coal fuel for the steam turbine AFB boiler and its capital cost and the price received for the power exported to the utility. None of these sensitivities are startling and, since the system has a high base ROI of 54%, it would appear to take a major change to make this AFB cogeneration system look poor. These sensitivities will be different for each industrial process with variations in energy requirements.

The costs with the greatest uncertainties are future fuel and power costs. Figure 10-6 shows the sensitivity to cogen fuel cost of several cogeneration systems heat or power matched to the same medium refinery with a residual-fired nocogeneration boiler as the base. The price of OPEC oil has risen about 50% in 1979 bringing it over the \$3.10 per 10^6 Btu in 1985 as projected by DOE in 1978 and used as a groundrule in this study. For the residual-fired combined-cycle system shown heat and power matched in Figure 10-6, an additional 20% increase would bring the heat matched combined-cycle to zero ROI. Therefore, the probable continued steep increase in oil prices needs to be carefully considered in deciding on the implementation of an oil-fired cogeneration system.

A more complete understanding of these cost sensitivities can be seen by comparing the capital cost versus levelized annual energy cost plot shown in Figure 10-7. This is the same plot for cogeneration systems matched to a medium petroleum refinery as shown in Figure 10-2 except only a few are shown and, for these, the effect of increasing the fuel, power and capital cost by 25% over the base is indicated. Now it becomes clear what the effect of these cost increases have on these cogeneration systems relative to both the coal- and oil-fired nocogeneration base cases.

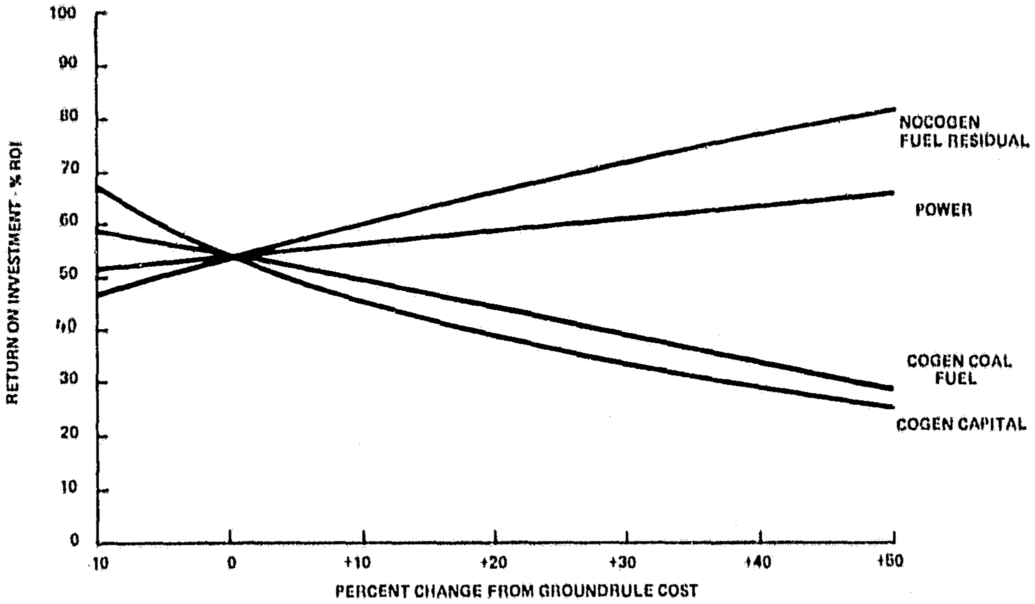

Figure 10-5. Sensitivity of ROI to Changes in Costs of Steam Turbine AFB Heat Matched to Medium Petroleum Refinery - SIC 2911-2
Base: <u>Residual Fired Nocogeneration Boiler</u> & Utility Power

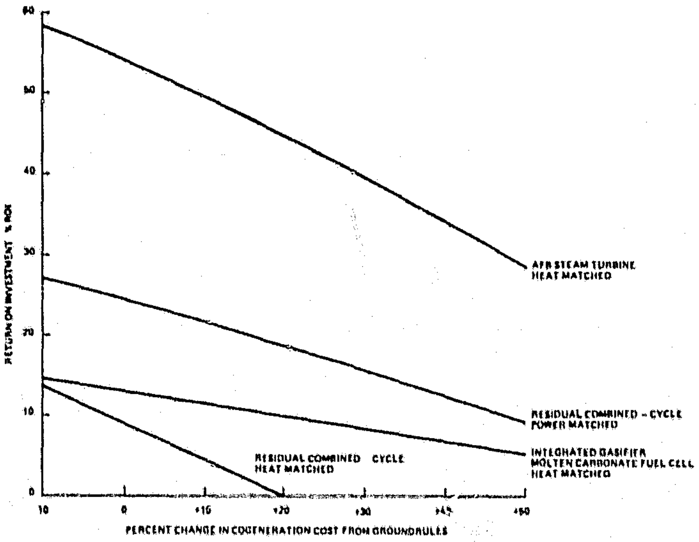

Figure 10-6. Sensitivity of ROI to Cogeneration Fuel Costs for Selected ECS's Matched to Medium Petroleum Refinery - SIC 2911-2
Base: <u>Residual Fired Nocogeneration Boiler</u> & Utility Power

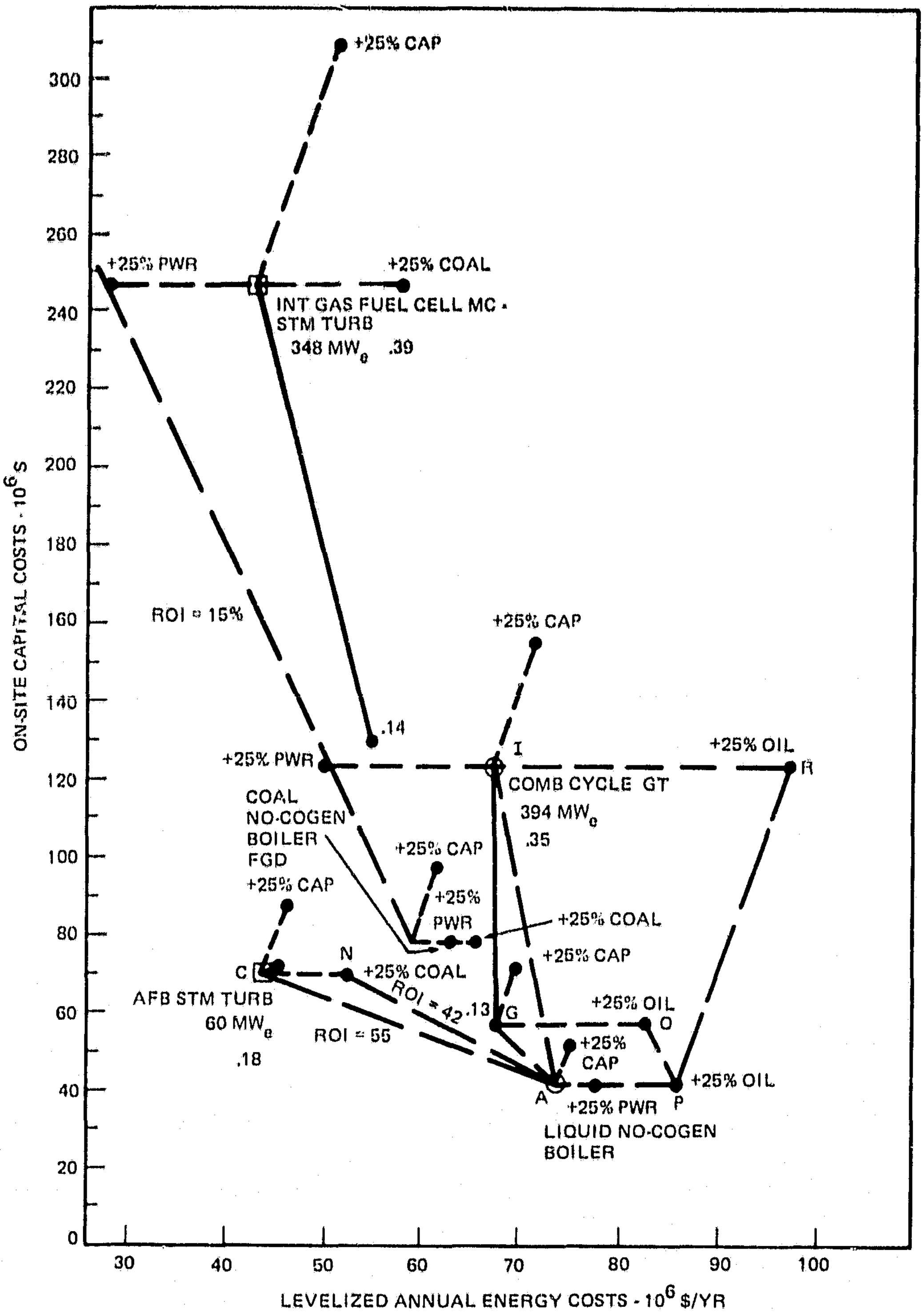

Figure 10-7. Economic Sensitivities to Fuel, Power and Capital Costs of Selected Nocogeneration and Cogeneration ECS's Heat and Power Matched to Medium Petroleum Refinery - SIC 2911-2

For instance, in the match of the steam turbine AFB with the liquid-fired nocogeneration as a base, when a line is drawn connecting the base costs from point A to point C and its slope is compared with the ROI protractor, its ROI is found to be about 55% which agrees with the base cost (0 percent change from groundrule cost) shown in Figure 10-5 and 10-6. When the cost of the AFB coal fuel is increased 25%, the change in ROI is found by drawing the line A-N and comparing its slope to the ROI protractor to give an ROI = 42 which again agrees with the results shown in Figures 10-5 and 10-6.

The much higher sensitivity to an oil cost increase shown in Figure 10-6 by the heat matched oil-fired combined-cycle, with the base case of a liquid-fired nocogen can also be understood by noting in Figure 10-7 the change in slope (and resulting decrease in ROI) of lines A-I and P-R. The decrease in sensitivity of the power matched combined-cycle can be seen by noting the smaller change in slopes of the lines A-G and P-O.

Using these plots, a wide range of contingencies can be easily investigated. Examples of cost sensitivities for other processes are shown in Volume 5, Section 9.

Section 11

NATIONAL CONSIDERATIONS

The plant basis results described in Sections 9 and 10 were extended to a national level representative of all US industry to provide a measure of comparison between energy conversion systems. The resulting national savings of fuel energy, emissions and levelized annual energy costs are presented in this section.

METHODOLOGY

The yearly rate of national savings of fuel, emissions, and capital costs were computed for the year 1990 assuming that each of the energy conversion systems were available and implemented beginning in 1985. These national savings were calculated for both heat and power matches. A basic assumption affecting the amount of total savings possible was that cogeneration could only be employed in new plants, by capacity addition to existing plants, or where replacement of old unserviceable industrial boilers was assumed necessary. Figure 11-1 displays the relationship between the yearly amount of fuel energy that cogeneration can be applied to and the total yearly amount of energy used by industry. The top line in the figure represents the total yearly rate of energy consumption by industry. The portion of energy consumption rate between the top line and the horizontal dashed line represents the increase in the rate of energy consumption from the 1985 base year due to increased industrial capacity. The portion of energy consumption rate between the horizontal dashed line and the lower solid line represents the difference from the 1985 base year attributed to the replacement of old unserviceable boilers. The amount of fuel energy considered here is all of that consumed by industry and utilities in producing the steam and hot water and power required by industrial processes. The total yearly rate of fuel energy that cogeneration could be applied to beginning from 1985 is represented by the difference between the two solid curved lines. The solid vertical line shows the amount for the year 1990.

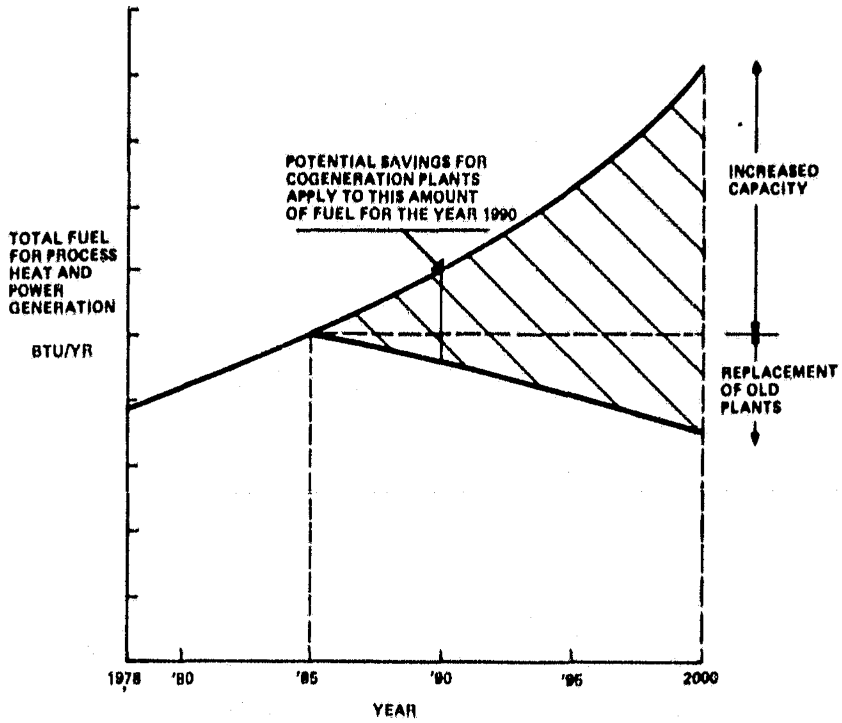

Figure 11-1. Potential Industrial Fuel Use for Process Heat and Power Generation Applicable to Cogeneration

The rate of replacement of old unserviceable industrial boilers was assumed to occur in a compound manner such that the total industrial capacity in 1985 was replaced in thirty years. This results in a compound annual replacement rate of 2.338%. The rate of increase in energy consumption varied by industry. The average annual rate of increase in energy consumption for all CTAS processes was 2.7%.

A summary of total industrial energy consumption is given in Table 11-1 for all CTAS processes for the industry groups they represent and for all of US industry. The energy consumption projections include energy for process steam, hot water, direct or sensible heat and fuel energy consumed at a utility to provide for industrial electric power

Table 11-1

NATIONAL FUEL ENERGY SAVINGS DATA BASE

Process/Sector SIC Code	Scale Factors, M Power	Scale Factors, M Heat	* Total Direct + Indirect Nocogeneration Fuel Energy, 10^{12} Btu 1985	2000	New Capacity + Replacement, 1985 - 1990
2011	.101	.084	96	168	31.44
2026	.082	.101	80	101	16.20
2046	.153	.119	141	159	23.0
2063	.372	1.052	118	162	27.38
2082	.111	.079	120	190	34.49
20	.099	.046	1688	2372	403.02
2260	.721	.608	75	75	9.19
22	.069	.081	435	435	53.28
2421	.316	.252	300	400	67.0
2436	.361	.529	150	275	51.93
2492	.178	.380	100	172	32.05
24	.079	.046	1093	1684	300.0
2621-2	.118	.107	454	784	146.05
2621-4	.148	.127	441	950	182.6
2621-6	.118	.107	69	128	24.21
2621-7	.078	.152	110	205	38.6
2621-8	.123	.105	191	419	80.61
26	.113	.064	1457	2864	543.7
2812	.041	.055	240	300	47.95
2813	.041	.041	33	66	12.61
2819-1	.046	.061	76	135	25.33
2819-2	.036	.022	229	405	75.93
2821-2	.063	.139	110	160	27.93
2821-3	2.012	2.68	38	60	10.92
2822	.022	.030	9	13	2.28
2824-1	.082	.109	55	75	15.19
2824-2	.041	.054	20	25	4.0
2865-1	.140	.419	65	90	15.4
2865-2	.004	.004	10	15	2.67
2865-3	.066	.139	45	60	10.05
2865-4	.403	1.422	45	65	11.38
2869-1	.108	.299	0	0	0
2869-2	.0403	.040	750	1100	194.16
2869-3	.108	.299	6	11	2.07
2869-4	.140	.419	24	30	4.79
2873	.207	.674	250	305	47.7
2874	.036	.025	48	60	9.59
2895	.021	.029	20	24	3.7
28	.096	.183	2321	3357	586.3
2911-1	.179	.206	580	630	87.18
2911-2	.173	.184	870	950	128.5
2911-3	.166	.154	1250	1280	163.0
29	.186	.155	2887	3058	404.9
32	0	0	1945	2115	
3312-1	.028	.028	643	835	137.0
3325-1	.016	.016	3539	4596	756.0
3325-4	.020	.020	414	538	88.0
3331-1	.002	.002	5.8	9.3	1.7
3331-2	.002	.002	7.8	12.4	2.26
3331-3	.002	.002	5.8	9.3	1.70
3331-4	.013	.013	15.5	24.8	4.53
3331-5	.016	.016	38.8	62.0	11.31
3331-6	.014	.014	23.3	37.2	6.79
3334-1	.015	.015	49.2	86.4	16.18
3334-2	.059	.059	197	346	64.86
3334-3	.074	.074	246	432	80.56
33	.369	.495	6960	9381	1557.0
TOTAL NATIONAL			19901	29858	4548.0

* NOTE. Direct + Indirect Nocogeneration fuel energy refers to industrial fuel consumption for direct process heat (sensible), steam, hot water, and the fuel consumed at a utility to provide for the process electric power needs. Utility conversion efficiency was assumed to be 33% for this data.

required. Total fuel use is given for the year 1985 and for 2000. That part of the increase due to adding capacity and replacing old plants which occurs between 1985 and 1990 is also given. Values are given for each of the 4-digit SIC codes that were considered in CTAS and the total use for each of the 2-digit SIC codes considered. The fuel use shown for the 2-digit industries includes the 4-digit industries shown and all other 4-digit industries in that category. These seven sectors account for over 75% of the total national industrial energy use. The eighth sector considered, SIC 32 (stone, clay and glass), accounts for another 7% but uses no steam and so is not included here.

The ECS configurations studied in CTAS were only capable of supplying heat in the form of steam or hot water. The industrial energy consumption data of Table 11-1 includes fuel energy for direct or sensible heat that cannot be supplied by the CTAS ECS's and that fuel energy must be excluded from the projected national fuel energy savings. Scale factors, M, given in Table 11-1 were developed in order to convert the savings determined for each of the processes when matched to an ECS into a national savings potential for that ECS. They were developed to be applied directly to the fuel energy savings ratio and the national fuel energy consumed by each CTAS process. The scale factors take into account the processes not covered by CTAS, the power to heat ratio of these processes and the amount of fuel energy that must be excluded because of use in direct heating applications. The use and derivation of the scaling factors is summarized in Volume V.

NATIONAL FUEL ENERGY SAVED

The type of fuel used for the cogeneration systems in these calculations was assumed to be coal or coal-derived liquids wherever possible. The state-of-the-art gas turbine and state-of-the-art diesel were assumed to burn petroleum-derived fuel. Utility fuel displaced here was assumed to be coal.

National fuel energy saved by fuel type for selected energy conversion systems is summarized in Figures 11-2 and 11-3. Heat match cases are presented in Figure 11-2 and the power match cases are presented in Figure 11-3.

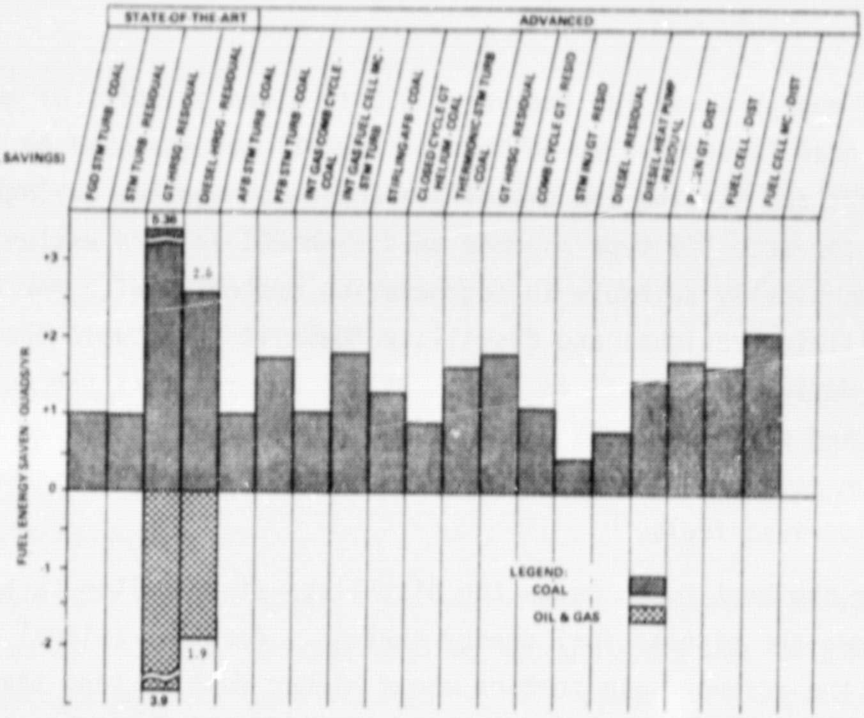

Figure 11-2. Potential for National Fuel Energy Saved by Fuel and ECS Type in 1990 (Heat Match)

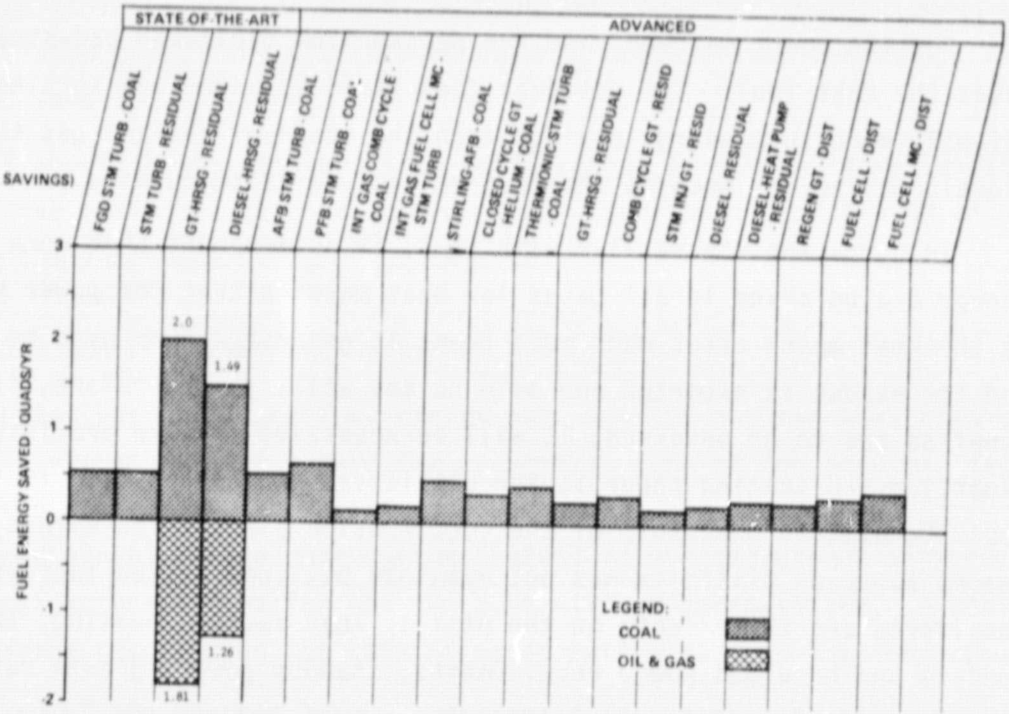

Figure 11-3. Potential for National Fuel Energy Saved by Fuel and ECS Type in 1990 (Power Match)

The fuel energy saved for the year 1990 is given in units of quads/year, where a quad is defined as 10^{15} Btu. The oil and gas used by the state-of-the-art gas turbine and diesel are shown as negative savings. The savings for each ECS type assumes that each ECS is used exclusively wherever it is technically suitable in cogeneration systems. With the advanced systems utilizing residual and distillate fuels it is assumed that these fuels will be derived from coal in 1990. It was assumed that the current gas turbine and diesel systems using residual fuel would continue to require petroleum derived residual in 1990. The utility fuel is assumed to be coal or coal-derived fuels.

For the heat match cases the distillate-fired molten carbonate fuel cell shows the highest fuel energy savings. For the residual fueled systems the advanced gas turbine shows higher fuel savings than the state-of-the-art gas turbine or diesel. For coal fueled systems, the integrated coal gasifier molten carbonate fuel cell and the pressurized fluidized bed-steam turbine show a fuel savings of more than 50% above the state-of-the-art steam turbine with flue gas desulfurization.

For the power matched case the pressurized fluidized bed-steam turbine saves the most fuel. The residual fuel-fired advanced gas turbine gives slightly more fuel energy savings than the state-of-the-art gas turbine or diesel, but not as much as the residual fueled steam turbine.

In comparing Figure 11-2 with 11-3, it is apparent that more fuel energy can be saved in all cases for heat matches than for power matches. In the heat match cases much more power is generated than used by industry and the excess is exported and sold to the utility. Therefore, if maximum benefits are to be obtained, it will be necessary to make provisions for exporting and selling power to the utilities. An alternative to this could be utility ownership of the cogeneration plant. The effect of this export power on utilities was not examined but some of the factors to be considered are the effects on the utility load factor, peaking, intermediate and baseload power requirements, standby power, growth rates, and above all, economics.

NATIONAL EMISSIONS SAVED

The national emissions saved were calculated in a somewhat simliar manner. The emission savings were calculated on a per plant basis and ratioed to a 2-digit SIC level and to a national level based on appropriate conversions from the fuel energy saved ratios, scale factors and total national energy consumption.

The national emissions saved per year in 1990 for the selected ECS's are given in Figure 11-4 for the heat matches and in Figure 11-5 for the power matches. The emissions saved for the year 1990 are given in units of million tons/year.

As with fuel energy saved, more emissions are saved with heat matches than with power matches. Diesel engines as currently used without emission scrubbing equipment were assumed in this study. As expected, the emissions of NO_x would increase significantly unless NO_x scrubbers are used to bring their level of NO_x emissions down to that required by law.

Several systems would increase the level of particulate emissions They are state-of-the-art diesel burning petroleum derived residual, and the advanced diesel and gas turbine burning coal derived residual. All systems save SO_2 emissions.

It should be pointed out that cogeneration in general saves emissions on an area basis but that on-site emissions are usually increased simply due to the increased use of fuel on site.

LEVELIZED ANNUAL ENERGY COST SAVINGS

Up to this point the fuel energy and emission savings have been shown for all systems without regard for economics. One of the economic factors discussed in Section 10 is the levelized annual energy cost (LAEC). Levelized annual energy cost saving (LAECS) is the difference between that cost with cogeneration and the cost without cogeneration. A positive saving occurs when the LAEC of cogeneration is less than nocogeneration.

Many of the matches between particular industries and ECS's result in large savings in fuel use. The totals of all these fuel savings for

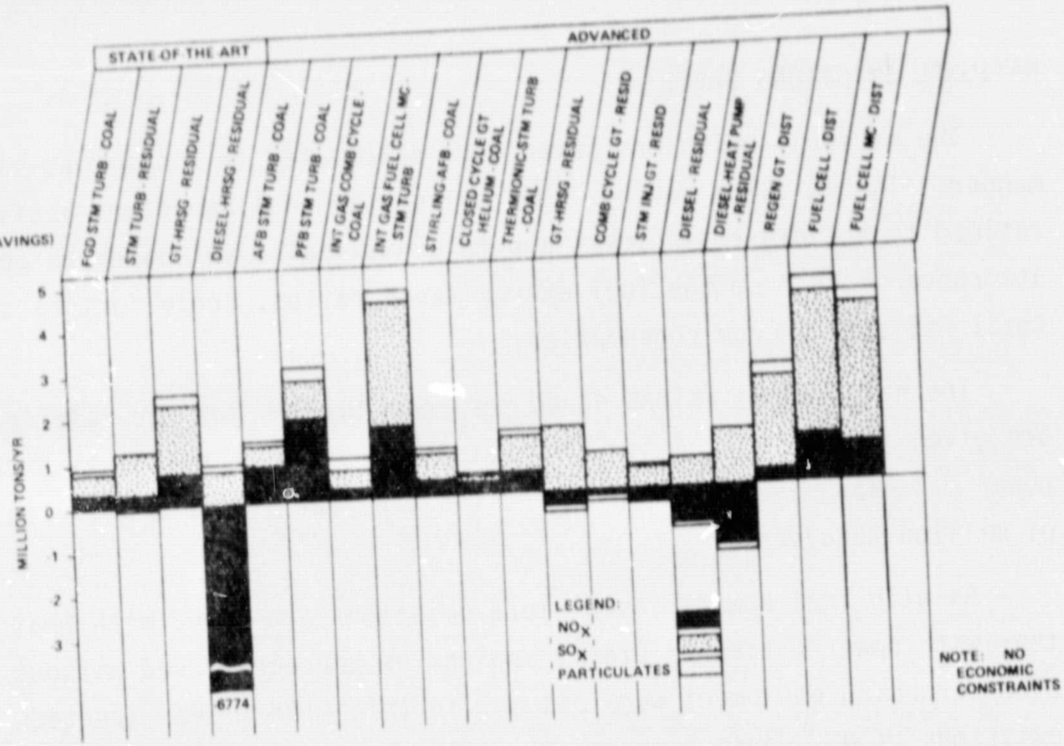

Figure 11-4. Potential for National Emissions Saved by Fuel and ECS Type in 1990 (Heat Match), Coal Nocogeneration Case

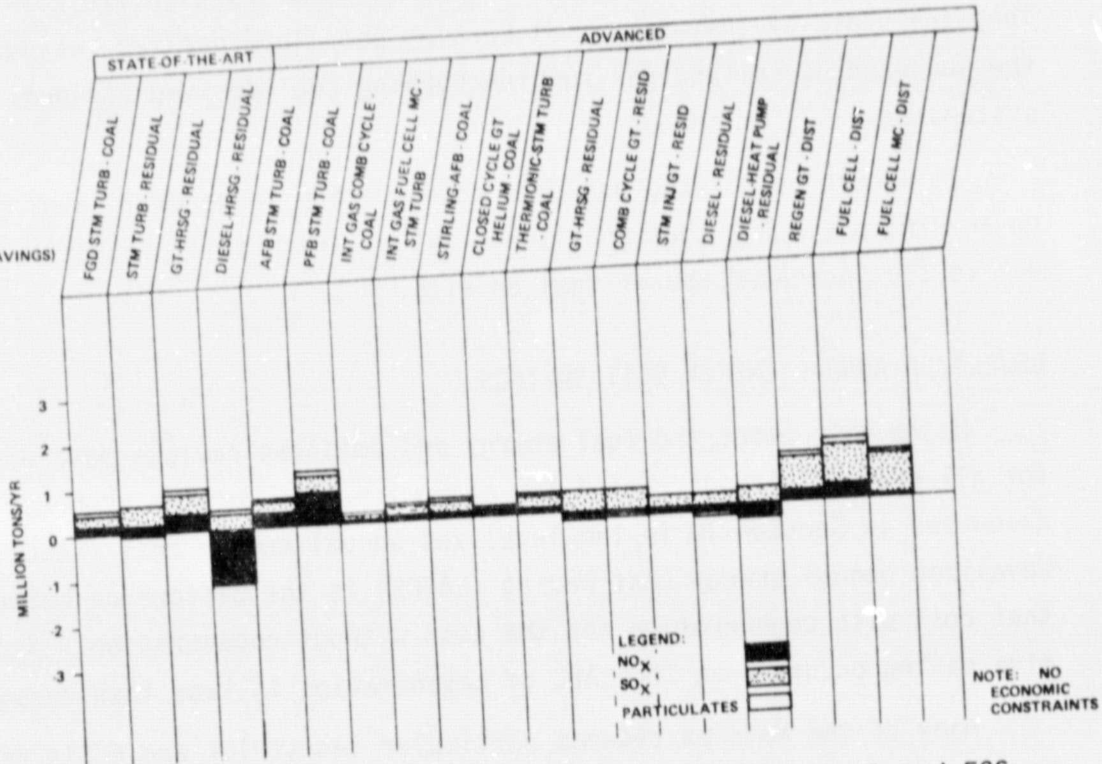

Figure 11-5. Potential for National Emissions Saved by Fuel and ECS Type in 1990 (Power Match), Coal Nocogeneration Case

each ECS was given in Figures 11-2 and 11-3. Of those matches, however, many of them had a higher annual energy cost than without cogeneration because of the cost of equipment or the cost of operation. The potential national fuel energy savings shown in Figures 11-6 and 11-7, for heat and power matches, are based on only matches that result in a levelized annual charge for energy that is no greater than that for the nocogeneration case (LAECS$\geq$0). The levelized annual energy cost savings that result from these matches are given in Figures 11-8 and 11-9 for the heat and power matches, respectively.

The potential national fuel savings of many of the advanced systems with higher capital costs are significantly reduced when it is stipulated that there must be a positive levelized annual energy cost savings (compare figures 11-2 with 11-6 or 11-3 with 11-7). Of the advanced coal fueled systems in heat matches, the PFB-steam turbine and the AFB-steam turbine both save more fuel energy than the state-of-the-art boiler-FGD steam turbine. Of the advanced residual fueled systems, the air-cooled gas turbine and the combined-cycle save the most fuel in heat matches.

For the power matched case, the coal-fueled advanced AFB-boiler steam turbine saves more fuel energy than the state-of-the-art boiler-FGD steam turbine. Of the residual fueled advanced systems, the advanced air-cooled gas turbine and the combined-cycle save the most fuel energy.

The results presented in this section are applicable to US industry as a whole. To understand why the national results came out as they did requires knowledge of the characteristics of the steam and electric power demand of the national population of industrial processes. It was shown in Section 9 that the process power to heat ratio significantly influences the fuel energy savings realizeable. The process power to heat ratio also influences the economic choice of energy conversion system for a given fuel type and process temperature. All of the energy conversion systems studied were employed in the production of steam and electric power. Therefore, a distribution of national industrial fuel energy consumption for steam and electric power versus power to heat ratio gives insight as to the potential national impact of various cogeneration technologies.

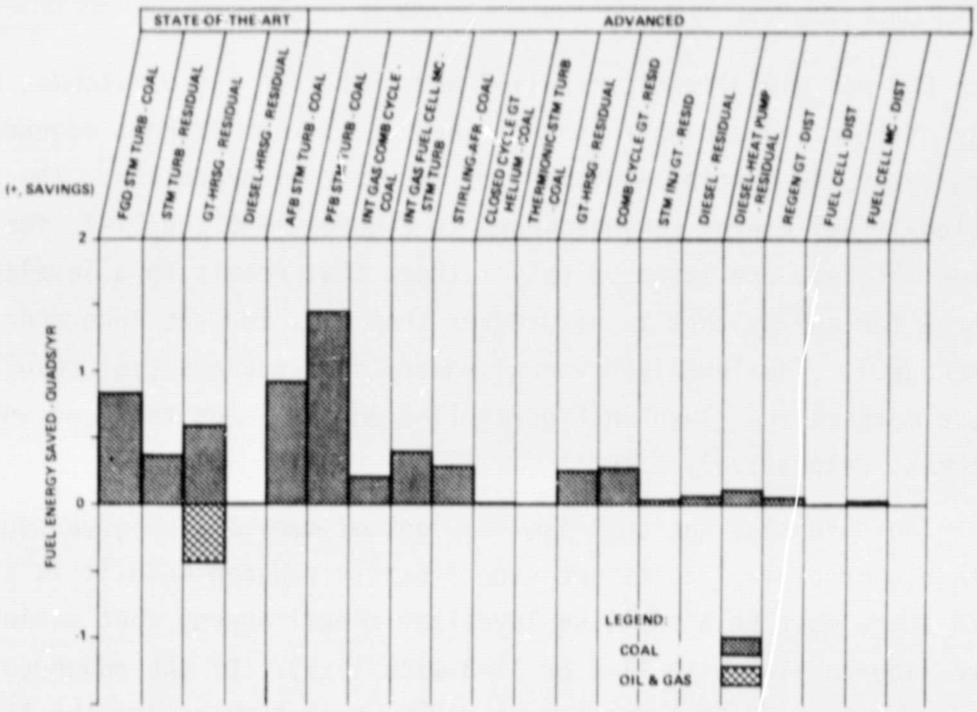

Figure 11-6. Potential for National Fuel Energy Saved by Fuel and ECS Type in 1990 (Heat Match and LAECS ≥ 0)

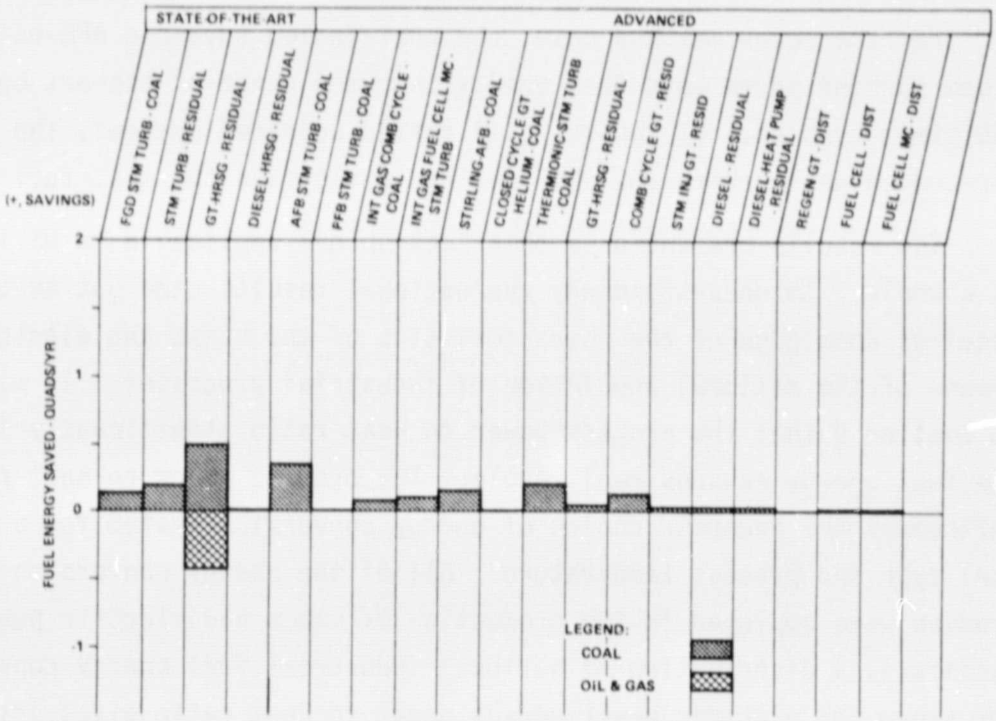

Figure 11-7. Potential for National Fuel Energy Saved by Fuel and ECS Type in 1990 (Power Match and LAECS ≥ 0)

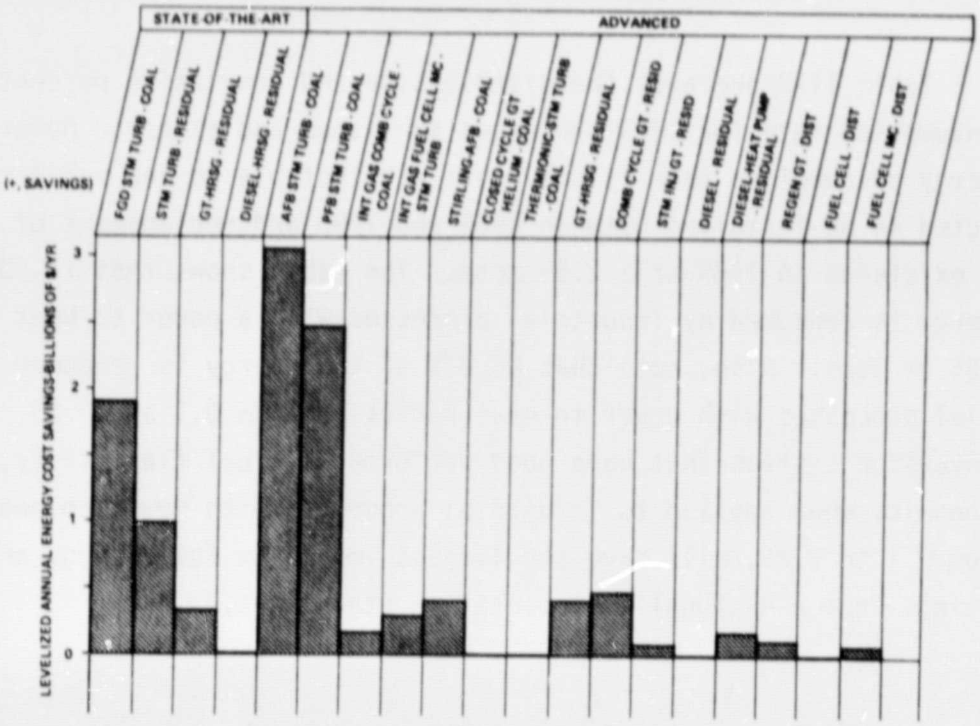

Figure 11-8. Potential for National Levelized Annual Energy Cost Savings in 1990 (Heat Match and LAECS $\geq$ 0)

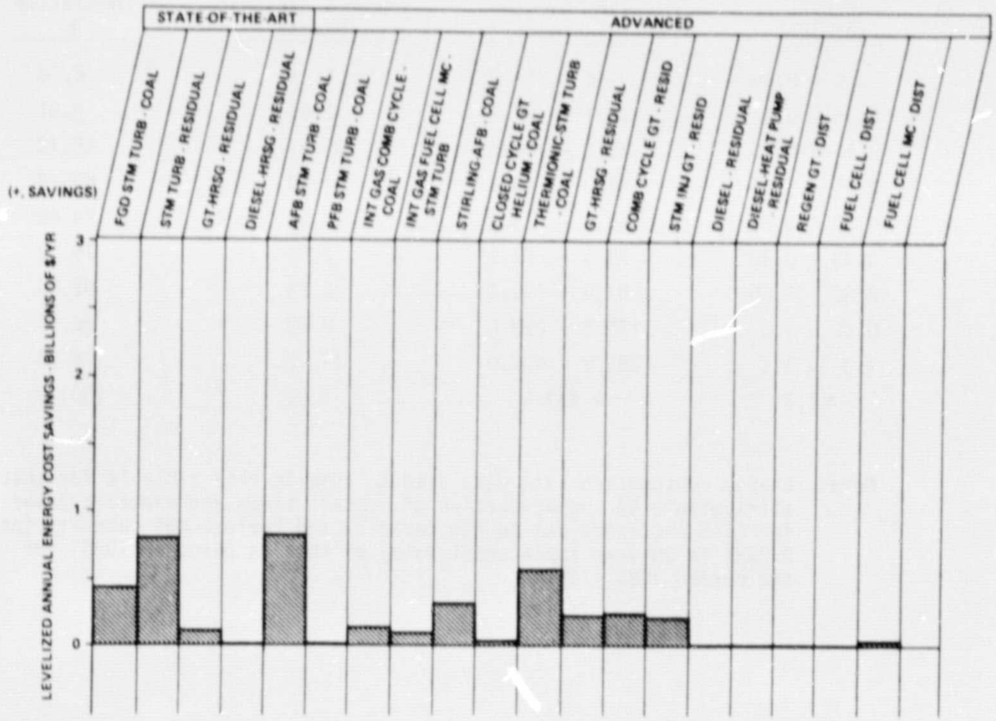

Figure 11-9. Potential for National Levelized Annual Energy Cost Savings in 1990 (Power Match and LAECS $\geq$ 0)

Table 11-2 presents the distribution and cumulative percent of energy consumption rate for CTAS processes for steam and electric power. The energy consumption rate is only that attributable to new capacity projected to be installed between 1985 and 1990 and replacement of capacity in existence in 1985 at a 2.3% rate. The table shows that 74.68% of the energy is consumed by industrial processes with a power to heat ratio of 0.25 or less. Also, note that 65.87% of the energy is consumed by industrial processes with power to heat ratios between 0.1 and 0.25. Energy conversion systems that have good performance, fuel flexibility, and economics when applied to industrial processes with power to heat ratios from 0.1 to 0.25, will have the largest impact on fuel energy and emission savings from a national implementation standpoint.

Table 11-2

DISTRIBUTION OF CTAS PROCESS ENERGY CONSUMPTION RATE FOR STEAM AND ELECTRIC POWER IN 1990

Process Ratio of Power to Heat		% of CTAS Process Energy For Steam & Electric Power	Cumulative %
$\frac{\text{Btu/hr}}{\text{Btu/hr}}$	$\frac{\text{kW}}{10^6\ \text{Btu/hr.}}$		
0 - 0.05	0 - 14.7	6.18	6.18
0.05 - 0.1	14.7 - 29.3	2.63	8.81
0.1 - 0.15	29.3 - 44.0	39.97	48.78
0.15 - 0.20	44.0 - 58.6	11.50	60.28
0.20 - 0.25	58.6 - 73.3	14.40	74.68
0.25 - 0.30	73.3 - 87.9	2.09	76.77
0.30 - 0.60	87.9 - 175.8	5.28	82.05
0.60 - 1.0	175.8 - 293.0	0.92	82.97
1.0 - 1.5	293.0 - 439.0	11.12	94.09
> 1.5	> 439.5	5.91	100.00

Note: Energy consumption rate data used to compile this table is for that attributable to the production of process steam and electric power for CTAS processes due to new capacity and replacement capacity (at 2.338% (a 30-year replacement rate) of that in place in 1985) for the period 1985 - 1990.

Consideration of the characteristics of US industrial energy demand for steam and electric power corroborates the national results presented in this section. The PFB-steam turbine and the AFB-steam turbine exhibit the highest national fuel energy savings because they perform well and have good economics in low power to heat ratio applications (since about 75% of US industrial energy required for steam and electric power is required by industry with power to heat ratios from 0 to 0.25). The higher power to heat ratio ECS's (gas turbine and combined-cycle) perform well when employed to supply heat and power to higher power to heat ratio industries. These systems have a lesser national impact because the proportion of energy consumed by US industry over the higher power to heat ratio range is less (about 25% of US industrial energy for steam and electric power is required at power to heat ratios greater than 0.25).

Section 12

RESULTS AND OBSERVATIONS

BACKGROUND

The objective of the Cogeneration Technology Alternatives Study (CTAS) is to determine the advantages of advanced relative to current industrial cogeneration systems and to evaluate and compare the advanced technologies in order to identify those justifying major research and development effort.

In CTAS the performance, emission, and cost characteristics of advanced technology cogeneration steam turbine-fluidized bed boiler, open and closed-cycle gas turbines, combined-cycle, thermionic, stirling, diesel, phosphoric acid fuel cell, and molten carbonate fuel cell energy conversion systems (ECS's) judged to be available in the 1985 to 2000 year time frame were consistently defined for comparison with currently available steam turbine-boilers, open-cycle gas turbines, and diesels. These ECS's were matched to the electric power or steam requirements of over 50 specific industrial processes selected from the food; paper and pulp; chemical; petroleum refining; stone, clay and glass; and primary metals groups. The resulting cogeneration systems were evaluated for their fuel, emissions, and cost of energy saved compared to both a coal-fired or residual-fired boiler nocogeneration system defined for each industrial process. In addition, the return on investment to the industrial owner was calculated using the nocogeneration system as a base case. These data permitted a comparison of advanced technology and currently available ECS's in a wide range of specific industrial process and their relative advantages with and without the export of power to the utility grid.

To determine the effect on comparison of systems of the national fuel consumption and growth rates of the various industrial processes together with their distribution of power to heat ratios, process steam temperatures and load factors, each ECS was assumed implemented without competition and its national fuel savings, emissions reduction, and energy cost savings estimated. In this calculation it was assumed that the total savings possible were due to implementing the cogeneration ECS in new plants added because of needed growth in capacity, or to replace old unserviceable process boilers in the period from 1985 to 1990. National fuel savings, emissions reduction, and energy cost savings were compared for advanced and currently available cogeneration systems to determine those advanced systems which indicated the greatest potential benefit.

To achieve the level of performance estimated for these attractive advanced technology systems, the significant advanced developments required were identified.

RESULTS AND OBSERVATIONS

The comparison of the various cogeneration systems required that an economic criteria for implementation by industry be established since those systems providing the highest fuel savings often had high capital costs and low returns on investment. Attractive cogeneration systems for industrial ownership were identified using the following criteria: the system would have a return on investment greater than 10% before inflation, a capital cost which is less than two and one half times the capital cost of the nocogeneration coal-fired process boiler and a fuel energy saved ratio of 0.15 or greater.

In Tables 12-1 and 12-2 the intersection of an energy conversion system with an industrial process represents a power or heat matched cogeneration system. Those matches meeting the above criteria are shown cross hatched and those shown as solid black exceed the criteria by having a fuel energy saved ratio equal to or greater than 0.25. The reason for a cogeneration system not meeting these criteria is shown by noting which

Table 12-1

SUMMARY OF DESIRABLE CHARACTERISTICS OF COGENERATION SYSTEMS FOR SELECTED INDUSTRIAL PROCESS

POWER MATCH

Legend:

- Return on Investment ≥ 10% — O (upper left of cell)
- $\frac{\text{Cogeneration Capital Cost}}{\text{Nocogeneration Capital Cost}} \leq 2.5$ — O (lower left of cell)
- Fuel Energy Saved Ratio ≥ .15 — O (upper right of cell)
- Fuel Energy Saved Ratio ≥ .25 — x
- Meets Minimum Criteria — ▨
- Meets Minimum Criteria Plus Fuel Energy Saved Ratio ≥ .25 — ■
- Match not practical because excess heat produced or process requires higher temperature process steam than can be supplied. — ---
- Does not meet any of the criteria — (blank)

	STATE-OF-THE ART				ADVANCED															
	FGD STM TURB - COAL	STM TURB - RESIDUAL	GT-HRSG - RESIDUAL	DIESEL-HRSG - RESIDUAL	AFB STM TURB - COAL	PFB STM TURB - COAL	INT GAS COMB CYCLE - COAL	INT GAS FUEL CELL MC - STM TURB	STIRLING - COAL	CLOSED CYCLE GT HELIUM - COAL	THERMIONIC-STM TURB - COAL	GT-HRSG - RESIDUAL	COMB CYCLE GT - RESID	STM INJ GT - RESID	DIESEL - RESIDUAL	DIESEL-HEAT PUMP - RESIDUAL	REGEN GT - DIST	FUEL CELL - DIST	FUEL CELL MC - DIST	
MEAT PACKING	x	O x	O O	O O	x	x	O	O	O		x	O O	O O	O	O O	O	O O	O O	O O	
MALT BEVERAGES	O O	O O	O O	O O	▨	O O	O	O	O O		O	▨	O O	O	O O	O O	O O	O O	O O	
BLEACHED KRAFT PAPER	---	---	▨	O	---	■	O	O	▨	O	x	■	▨	O	O O	O x	O O	O O	O O	
THERM-MECH PULPING	---	---	■	O O	---	---	x	x	---	---	---	■	■	O O	O O	■	O x	O O	O x	
INTEGRATED CHEMICAL	---	---	▨	O	---	---	▨	■	O O	O O	x	■	▨	O O	O O	O x	O O	O O	O O	
CHLORINE	---	---	---	O	---	---	---	---	---	---	---	---	---	▨	x	---	---	x	x	
NYLON	---	---	---	x	---	---	---	---	---	---	---	---	---	O	---	---	---	x	x	
PETRO-REFINING	▨	O O	O	---	▨	▨	O O	O O	O O	O	O O	O	O	---	---	O	O	O O	O	
INTEGRATED STEEL	---	---	---	O	---	---	---	---	---	---	---	---	---	---	x	---	---	O	x	
COPPER	---	---	---	O O	---	---	---	x	---	---	---	---	■	O O	O O	---	---	O O	O x	
ALUMINA	O O	O	O	---	O O	O O	O	O	O	O	O	O	O	---	---	O	O	O O	O O	

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OF POOR QUALITY

Table 12-2

SUMMARY OF DESIRABLE CHARACTERISTICS OF COGENERATION SYSTEMS FOR SELECTED INDUSTRIAL PROCESS

HEAT MATCH

Legend:

- Return on Investment ≥ 10% — o (upper corners)
- $\frac{\text{Cogeneration Capital Cost}}{\text{Nocogeneration Capital Cost}} \leq 2.5$ — o (lower corner)
- Fuel Energy Saved Ratio ≥ .15 — (box)
- Fuel Energy Saved Ratio ≥ .25 — x
- Meets Minimum Criteria — (hatched box)
- Meets Minimum Criteria Plus Fuel Energy Saved Ratio ≥ .25 — (black box)
- Match not practical because excess heat produced or process requires higher temperature process steam than can be supplied. — ---
- Does not meet any of the criteria — (empty box)

	STATE-OF-THE ART				ADVANCED														
	FGD STM TURB - COAL	STM TURB - RESIDUAL	GT-HRSG - RESIDUAL	DIESEL-HRSG - RESIDUAL	AFB STM TURB - COAL	PFB STM TURB - COAL	INT GAS COMB CYCLE - COAL	INT GAS FUEL CELL MC - STM TURB	STIRLING - COAL	CLOSED CYCLE GT HELIUM - COAL	THERMIONIC-STM TURB - COAL	GT-HRSG - RESIDUAL	COMB CYCLE GT - RESID	STM INJ GT - RESID	DIESEL - RESIDUAL	DIESEL-HEAT PUMP - RESIDUAL	REGEN GT - DIST	FUEL CELL - DIST	FUEL CELL MC - DIST
MEAT PACKING	x	o x	x	x	x	x	x	x	x		x	o x	x	o	x	x	x	x	x
MALT BEVERAGES			o x	o x		o x	x	x	x		x	o x	o x	o	o x	o x	o x	o x	x
BLEACHED KRAFT PAPER				x			o	x	x	o	x			o o		x	x	x	x
THERM-MECH PULPING	o o	o		x	o o		o x	x			x			o	x	x	x	x	x
INTEGRATED CHEMICAL		o o	o x	x			o x	o x	o x	o o	x		o x	o	x	x	x	x	x
CHLORINE	o o	o o		x	o o	o o	o o	o x	o		o			o	x			x	x
NYLON		o o	o o	x	o		o	x	o		o		o x	o	x	o	o	x	x
PETRO-REFINING		o o	o x	---			o x	o x	o	o	x	o x	o x	---	---	x	o x	x	x
INTEGRATED STEEL	o o	o o	o o	o	o o	o o		o o	o	o	o	o o		---	x	o		x	x
COPPER	o o	o o		x	o o	o o	o	x			o			o	x		o x	x	x
ALUMINA		o o	o x	---			x	x	o		x	o x	o x	---	---	x	o x	x	x

"O's" or "X's" are missing from the rectangle representing the cogeneration system match. Based on study results including Tables 12-1 and -2, the following observations on the various types of cogeneration systems were made:

1. The atmospheric and pressurized fluidized bed steam turbine systems give payoff comparable to conventional boiler with flue gas desulfurization-steam turbine systems which already appear attractive in low and medium power over heat ratio industrial processes.

2. Open-cycle gas turbine and combined gas turbine/steam turbine systems are well suited to medium and high power over heat ratio industrial processes based on the fuel prices used in CTAS. Regenerative and steam injected gas turbines do not appear to have as much potential as the above systems, based on GE results. Solving low grade coal-derived fuel and NO_x emission problems should be emphasized. There is payoff in these advanced systems for increasing firing temperatures.

3. The closed-cycle gas turbine systems studied by GE have higher capital cost and poorer performance than the more promising technologies.

4. Combined-cycle molten carbonate fuel cell and gas turbine/steam turbine cycles using integrated gasifier, and heat matched to medium and high power over heat ratio industrial processes and exporting surplus power to the utility give high fuel savings. Because of their high capital cost, these systems may be more suited to utility or joint utility-industry ownership.

5. Distillate-fired fuel cells did not appear attractive because of their poor economics due to the low effectiveness of the cycle configurations studied by GE and the higher price of distillate fuel.

6. The very high power over heat ratio and moderate fuel effectiveness characteristics of diesel engines limit their industrial cogeneration applications. Development of an open-cycle heat pump to increase use of jacket water for additional process heat would increase their range of potential applications.

The national savings calculated by implementing each type cogeneration energy conversion system without competition in the new plants built from 1985 to 1990 gives an index which can be used to compare the relative potential of the various types of cogeneration energy conversion systems. The absolute magnitude of these savings should not be used because each energy conversion system was assumed to be 100% implemented but using these results to compare the various systems, the following observations are made:

1. There are significant fuel, emissions, and energy cost savings realized by pursuing development of some of the advanced technologies.

2. The greatest payoff when both fuel energy savings and economics are considered lies in the steam turbine systems using atmospheric and pressurized fluidized beds. In a comparison of the national fuel and energy cost savings for heat matched cases, the atmospheric fluidized bed showed an 11% increase in fuel saved and 60% additional savings in levelized annual energy cost savings over steam turbine systems using conventional boilers with flue gas desulfurization whose fuel savings were 0.84 quads/year and cost savings \$1.9 billion/year. The same comparison for the pressurized fluidized bed showed a 73% increase in fuel savings and a 29% increase in energy cost savings.

3. Open-cycle gas turbines and combined-cycles have less wide application but offer significant savings. The advanced residual-fired open-cycle gas turbine with heat recovery steam generator and firing temperature of 2200 F was estimated to have a potential national saving of 39% fuel and 27% energy cost compared to currently available residual-fired gas turbines whose fuel savings were 0.18 quads/year and cost savings \$0.33 billions/year.

4. Fuel and energy cost savings are several times higher when the cogeneration systems are heat matched and surplus power exported to the utility than when the systems are power matched.

Other important observations made during the course of performing CTAS were:

1. Comparison of the cogeneration systems which are heat matched and usually exporting power to the utility with the power matched systems shows the systems exporting power have a much higher energy savings, often reaching two to five times the power match cases. In the past, with few exceptions, cogeneration systems have been matched to the industrial process so as not to export power because of numerous load management, reliability, regulatory, economic and institutional reasons. A concerted effort is now underway by a number of government agencies, industries, and utilities to overcome these impediments and it should be encouraged if the nation is to receive the full potential of industrial cogeneration.

2. The economics of industrially owned cogeneration plants are very sensitive to fuel and electric power costs or revenues. Increased price differentials between liquid fuels and coal would make integrated gasifier fuel cell or combined-cycle systems attractive for high power over heat industrial processes.

3. Almost 75% of the fuel consumed by industrial processes studied in CTAS, which are representative of the national industrial distribution, have power over heat ratios less than 0.25. As a result energy conversion systems, such as the steam turbine using the atmospheric or pressurized fluidized bed, which exhibit good performance and economics when heat matched in the low power over heat ratio range, give the largest national savings.

SIGNIFICANT DEVELOPMENT REQUIREMENTS

The level of performance estimated for each advanced energy conversion system studied in CTAS was premised on the achievement of certain advanced developments. The developments required for the most attractive conversion systems by fuel type are shown in Table 12-3 for coal-fired ECS's and in Table 12-4 for coal-derived liquid-fired.

Table 12-3

SIGNIFICANT DEVELOPMENTS OF MOST ATTRACTIVE ECS's
(Coal Fired)

ECS	SIGNIFICANT DEVELOPMENTS
Steam Turbine AFB	Atmospheric Fluidized Bed Boiler
Pressurized Fluidized Bed	System and Control
	Particulate Removal or Gas Turbine Erosion Protection
	Pressurized Fluidized Bed

Table 12-4

SIGNIFICANT DEVELOPMENTS OF MOST ATTRACTIVE ECS's
(Coal-Derived Liquid Fuel)

ECS	SIGNIFICANT DEVELOPMENTS
GT-HRSG, and Combined-Cycle	2200 F air-cooled gas turbine
	NO_x reduction systems

Certain developments have broad generic impact on advanced energy conversion systems and thus merit aggressive development effort regardless of the particular advanced systems that are most attractive. Table 12-5 lists the most important of these developments along with the energy conversion systems requiring their development.

Table 12-5

CRITICAL DEVELOPMENTS REQUIRED FOR COGENERATION ENERGY CONVERSION SYSTEMS

1. Fluidized Bed Combustion

    Nocogeneration AFB process steam boilers
    AFB power steam boilers
    Gas turbine for PFB system
    Helium heaters - Closed-cycle gas turbine
    - Stirling cycle

2. NO_x Reduction Systems

    Advanced diesels
    Coal-derived liquid-fired units

3. Fuel Gas Clean-up Systems and Coal Gasifiers

    Molten carbonate fuel cell
    Integrated gasifier gas and steam turbine
    Gas turbine for PFB system

4. Very High Temperature Air Preheaters

    Thermionic boiler
    Stirling cycle
    Closed-cycle gas turbine - AFB

5. DC-AC Inverters - Cost Reductions

    Thermionics
    Fuel cells