DOE/NASA/1062-80/4
NASA TM-81400

NASA-TM-81400 19800011346

COGENERATION TECHNOLOGY ALTERNATIVES STUDY (CTAS)

VOLUME I — SUMMARY

Gerald J. Barna, Raymond K. Burns,
and Gary D. Sagerman
National Aeronautics and Space Administration
Lewis Research Center

January 1980

Prepared for
U.S. DEPARTMENT OF ENERGY
Energy Technology
Fossil Fuel Utilization Division

NOTICE

ERRATA

DOE/NASA/1062-80/4
NASA Technical Memorandum 81400

COGENERATION TECHNOLOGY ALTERNATIVES STUDY (CTAS)

Gerald J. Barna, Raymond K. Burns,
and Gary D. Sagerman

January 1980

Page 45, table 15: The following footnote should be added:

[a]Negative.

N80-19626 #

DOE/NASA/1062-80/4
NASA TM-81400

COGENERATION TECHNOLOGY ALTERNATIVES STUDY (CTAS)

VOLUME I - SUMMARY

Gerald J. Barna, Raymond K. Burns,
and Gary D. Sagerman
National Aeronautics and Space Administration
Lewis Research Center
Cleveland, Ohio 44135

January 1980

Work performed for
U.S. DEPARTMENT OF ENERGY
Energy Technology
Fossil Fuel Utilization Division
Washington, D.C. 20545
Under Interagency Agreement EC-77-A-31-1062

PREFACE

The Cogeneration Technology Alternatives Study (CTAS) was undertaken to provide the Department of Energy (DOE) with comparisons and evaluations that are needed to establish research-and-development funding priorities for coal-fueled advanced energy conversion systems for industrial cogeneration. The CTAS concept was developed by John Neal of the Department of Energy. The study was performed by NASA under the direction of Eric Lister of the Department of Energy.

CONTENTS

1.0 SUMMARY

The Cogeneration Technology Alternatives Study (CTAS) was undertaken by NASA for the Department of Energy (DOE). It was a broad screening study aimed at providing technical and economic comparisons needed by DOE to help guide research-and-development (R&D) funding for advanced-technology energy conversion systems. The advanced energy conversion systems studied were those that could significantly advance the use of coal or coal-derived fuels in industrial cogeneration applications, where electric power and process heat are simultaneously produced at the industrial site.

Project management responsibilities for CTAS were delegated to NASA's Lewis Research Center. Most of the data were obtained through two contracted studies of similar scope performed by industrial teams led by the General Electric Co. and the United Technologies Corp. In addition to managing the overall study, Lewis also performed independent analyses and a comparative evaluation of the advanced energy conversion systems based on study results. Selected investigations were also performed by the Jet Propulsion Laboratory in support of Lewis. This report summarizes the major results of the CTAS effort and, based on the Lewis evaluation of overall study results, identifies the most attractive advanced-technology systems using coal or coal-derived fuels for industrial cogeneration.

The following nine types of energy conversion systems were examined in CTAS:

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

Each system type was studied with a variety of fuels, system configurations, and levels of technological advancement appropriate for implementation in the 1985-2000 time period. In addition, for the steam turbines, diesel engines, open-cycle gas turbines, and combined cycles, technology levels and fuels representative of today's commercially available equipment were included to serve as a baseline for evaluating the advantages of advanced-technology systems. Emphasis in the study was on the use of high-sulfur coal, minimally processed liquid fuels made from coal, and low- or intermediate-Btu gas produced in on-site integrated coal gasifiers.

The systems were examined for potential application to approximately 85 industrial processes selected primarily from the six highest energy-consuming U.S. industry groups; namely, chemicals, metals, petroleum refining, paper, cement and glass, and foods. The specific potential applications selected from these six industry groups included manufacturing industries, which account for about half of the energy used by industry today. The process applications encompassed a wide diversity in the electric power required, the relative magnitude of the electrical and thermal

demands, and the temperature of the hot water, steam, or direct heat needed for the process.

The systems were matched to the process requirements by using two basic strategies. In the first the energy conversion system was sized to meet the electrical demand of the process plant and, where required, a supplementary furnace was used to provide additional thermal energy. In the second strategy the system was sized to meet the thermal requirements of the process and, where required, electricity was either purchased from a utility (import) or sold to a utility (export), depending on whether the systems produced more or less electricity than was needed at the site. Different systems and strategies matched different process applications well, depending on the characteristics of both the process and the energy conversion system. The potentially attractive applications found for each advanced system were documented as part of the study.

Over 6000 cases were calculated for the various combinations of energy conversion systems, configurations, fuels, matching strategies, and industrial process plants. Included in the calculations were the fuel energy savings, annual cost savings, emissions savings, and the rate of return on investment (ROI) for the cogeneration systems - all relative to the noncogeneration situation of purchasing the electricity needed at the site from a utility and providing the thermal energy required with an on-site boiler. The cost savings calculated included fixed capital charges, fuel costs, operating and maintenance costs, and the cost (import) or credit (export) for electricity bought or sold. The emissions savings were relative to the total emissions at the plant site and at the utility. Emissions at the plant site alone were also calculated for the cogeneration cases and the noncogeneration situation. Although the emphasis in the study was on the "plant basis" analyses just described, the contractors and Lewis also extrapolated potential energy savings and other benefits for each system to a "national basis" in order to examine the relative attractiveness of the various advanced systems from a national perspective as well. This allowed a "weighting" of the percentage savings on a plant basis to be made by using the national energy consumption for each process included in the study. The contractors then extrapolated results beyond the specific processes studied to estimate benefits for the entire manufacturing sector of industry.

Results for the advanced-technology energy conversion systems were then compared with each other and with results for cases using current commercially available technology, on both a plant basis and a national basis. From Lewis' evaluation of the study results, attractive advanced energy conversion systems were identified and placed into two groups as follows:

Most attractive advanced systems	
Steam turbines	Coal, atmospheric-fluidized-bed furnace (AFB) Coal, pressurized-fluidized-bed furnace (PFB)
Open-cycle gas turbines	Coal-derived liquid fuel, residual grade
Combined cycles	Coal derived liquid fuel, residual grade
Additional attractive advanced systems	
Open-cycle gas turbines	Coal, atmospheric-fluidized-bed furnace (AFB) Coal, pressurized-fluidized-bed furnace (PFB) Integrated coal gasifier
Closed-cycle gas turbines	Coal, atmospheric-fluidized-bed furnace (AFB)
Molten carbonate fuel cells	Integrated coal gasifier Coal-derived liquid fuel, distillate grade

The advanced systems identified as the most attractive showed the widest applicability to the spectrum of process plants included in the study.

To illustrate the results obtained for these attractive advanced systems, ranges of results are presented here for nine representative industrial processes studied in common by both contractors and used by Lewis in a detailed screening of plant-basis results. The ranges shown are only for the attractive applications within the subset of the nine industrial process plants:

(1) Fuel energy savings,	14 to 44 percent	range for all attractive systems
(2) Annual cost savings,	19 to 42 percent	coal-fired attractive systems
	8 to 27 percent	attractive systems using coal-derived liquid fuels
(3) Emissions savings,	72 to 91 percent	molten carbonate fuel cells
	6 to 24 percent	GE results for gas turbines and combined cycles using coal-derived liquid fuels
	35 to 57 percent	UTC results for gas turbines and combined cycles using coal-derived liquid fuels
	25 to 54 percent	all other attractive systems
(4) Return on investment,	17 to 54 percent	the "most attractive systems"
	11 to 20 percent	the "additional attractive systems"

The higher cost savings for the attractive coal-fired advanced systems as compared with the attractive systems using coal-derived liquid fuels were primarily due to the difference in the fuel costs for the cogeneration systems. The molten carbonate fuel cell systems had the highest emissions savings of the attractive systems because of the higher quality fuel used and the characteristics of that system. In fact, the on-site emissions of some fuel cell systems were estimated to be lower than in the noncogeneration situation even though more fuel is used at the site in cogeneration. The differences in emissions savings between the GE and UTC results for open-cycle gas turbines and combined cycles fired by coal-derived liquid fuels resulted primarily from different assumptions for the oxides-of-nitrogen (NO_x) reductions achievable, particularly in NO_x from the high fuel-bound nitrogen in the residual-grade, coal-derived fuel.

In addition to the screening of advanced systems on a plant basis, Lewis evaluated the potential relative national savings of the advanced systems in the specific industries studied. The approach used by Lewis involved extrapolating the contractors' plant-basis results to the new and replacement markets between 1985 and 1990 for each of the specific processes included in the contractors' studies. Potential national energy savings and other benefits were estimated by assuming 100 percent implementation in each industry where a "hurdle" ROI was exceeded. This hurdle ROI was varied parametrically to investigate the sensitivity of potential national savings to required ROI. The national-basis evaluations made by Lewis using this approach were in general consistent with and reinforced identification of attractive systems based on the results of Lewis' plant-basis screening.

Typically, allowing the export of electricity increased the potential national energy savings by a factor of from 1.5 to 2.5. In many cases with exported electricity, 2 to 4 times more electricity was generated than was needed at the site. In other cases, 5 to 10 times more electricity was produced than was needed at the site. In these cases utility ownership rather than industrial ownership may be appropriate.

In addition to comparing the advanced systems with each other, national-basis results where all the advanced systems were assumed to be available were compared with results limited to the use of systems employing current commercially available technology alone. Results where the advanced systems were assumed to be available showed a 40 percent to more than 80 percent energy savings over the results of cogeneration systems using only current commercially available technology, depending on the ROI hurdle specified. Along with the increase in potential national energy savings was a 20 percent to more than 50 percent reduction in emissions, depending on the ROI hurdle and the assumptions for technological advances to reduce emissions. In many applications the advanced-technology systems showed higher ROI as well. Finally, the advanced energy conversion systems (which were based on the use of coal or coal-derived fuels) showed good applicability to those industries now consuming large amounts of petroleum oil. This indicates a potential for displacing the use of oil as well as for saving energy.

In reading this report it is important to keep in mind that the objectives of the study were to provide technical and economic comparisons and evaluations of advanced energy conversion systems for industrial cogeneration rather than to address the benefits of cogeneration itself. No attempt was made to propose solutions to institutional, regulatory, or market barriers that could limit the ultimate implementation of cogeneration. Further the evaluations made apply only to industrial cogeneration applications. Different relative attractiveness could very well be found for other applications such as utility powerplants (electricity only), commercial and residential total energy systems, or institutional and government installations, where the technical and economic requirements can be significantly different from those studied here.

2.0 INTRODUCTION

2.1 Objectives

The Cogeneration Technology Alternatives Study (CTAS) was undertaken by NASA for the Department of Energy (DOE) under authority of Interagency Agreement EC-77-A-31-1062. It was a broad screening study that compared and evaluated selected advanced energy conversion systems appropriate for use in industrial cogeneration systems for the 1985-2000 time period. The principal aim of the study was to provide DOE with information needed to establish research-and-development (R&D) funding priorities for advanced-technology systems that could significantly advance the use of coal or coal-derived fuels in industrial cogeneration applications.

Cogeneration is broadly defined as the simultaneous production of electricity or shaft power and useful thermal energy. When cogeneration is used, significant savings in fuel energy usually result because energy rejected from the power system, which would otherwise be wasted when generating only electricity, is recovered and used. Industrial cogeneration in the context of this study refers specifically to the simultaneous production of electricity and useful thermal energy to meet representative industrial plant requirements. A variety of potential industrial applications were selected - primarily from the high-energy-consuming industries in the United States.

The objectives of the overall CTAS effort were

(1) To identify and evaluate the most attractive advanced energy conversion systems, for implementation in industrial cogeneration systems for the 1985-2000 time period, that could permit increased use of coal or coal-derived fuels

(2) To quantify and assess the advantages of using advanced-technology systems in industrial cogeneration

CTAS was concerned exclusively with providing technical and economic comparisons and evaluations of advanced-technology systems as applied to industrial cogeneration rather than with evaluating the merits of the cogeneration concept.

2.2 Overall Scope and Methodology

At the request of DOE the following nine types of energy conversion systems were evaluated in CTAS:

(1) Steam turbines
(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

Each type of system was examined with a variety of fuels and over a range of parameters and levels of technological advancement that could be made available for implementation in the 1985-2000 time period. In addition, for the steam turbine, diesel engine, open-cycle gas turbine, and combined-cycle systems, cogeneration results for technology levels and fuels representative of current

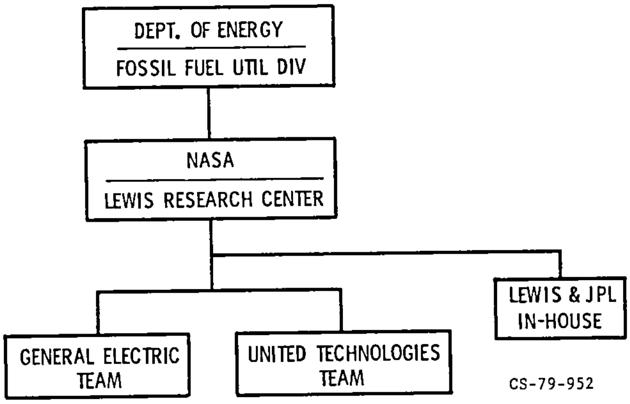


Figure 1. - CTAS organization.

TABLE 1. - CTAS CONTRACTOR TEAMS

	General Electric Co.	United Technologies Corp.
Program management	GE Energy Technology Operation	UTC Power Systems Division
Energy conversion systems	GE Internal Divisions Delaval, Inc. Institute of Gas Technology North American Phillips Corp.	UTC Internal Division Aerojet Energy Conversion Co. Bechtel National, Inc. Cummins Engine Co., Inc. Delaval Turbine and Compressor Division Dr. Phillip Myers, Consultant Mechanical Technology, Inc. Rasor Assoc. Sulzer Brothers, Ltd. Westinghouse Electric Co.
Industrial processes	GE Internal Divisions Dow Chemical Co. General Energy Assoc. Kaiser Engineers, Inc. J. E. Sirrine	Gordian Assoc.

commercially available equipment were estimated in order to serve as a baseline for evaluating the advantages of advanced-technology systems. Emphasis in the study was on the use of high-sulfur coal, minimally processed liquid fuels made from coal, and low- or intermediate-Btu gas made from coal in on-site gasifiers integrated with the cogeneration system.

The systems were examined in cogeneration applications in a wide variety of representative industrial process plants selected from the highest energy-consuming industries. The process plant applications were primarily from six major industry groups; namely, chemicals and allied products; primary metal industries; petroleum refining and related industries; paper and allied products; stone, clay, glass, and concrete products; and food and kindred products. These six major industry groups accounted for nearly 80 percent of the energy required to provide electricity and heat to the manufacturing sector of U.S. industry in 1975.

Figure 1 shows the organizational approach used in the study. The study was managed by NASA's Lewis Research Center for DOE's Division of Fossil Fuel Utilization. The majority of the data in the study were developed in the two contracted studies performed by industrial teams led by the General Electric Co. and the United Technologies Corp. Because of the great diversity of system types and industrial applications, each contractor team consisted of a prime contractor responsible for study management and a number of other organizations including divisions of the prime contractor's organization and subcontractors. This was done to bring to bear on the study expertise in all the elements necessary to establish the technical, economic, and environmental characteristics of complete cogeneration systems. The principal participants in the two contracted studies are identified in table 1.

The two contractor efforts were conducted independently and had essentially the same scope. Some common ground rules were established by NASA in consultation with DOE for use in the studies so that the results from the two contractor efforts could be more readily compared. An essential feature of the CTAS approach allowed each contractor to select design concepts and parameters, system configurations, technological assumptions, and the like consistent with the industrial experience and judgment of the various team members. It was anticipated that differences in contractor results would occur and, further, that these differences could be both valid and instructive in evaluating the merits of the various advanced conversion systems studied.

The Jet Propulsion Laboratory (JPL) supported Lewis in CTAS in a number of areas, which included conducting a survey of potential industrial applications for cogeneration and providing data on regional differences that could affect study results. Lewis, in addition to managing the overall study, performed in-house analyses to supplement and complement the contractor effort, to provide an understanding of the differences between contractor results, and to evaluate the study results.

The overall methodology employed in CTAS is shown in figure 2. Between the two contractors over 150 combinations of fuels, energy conversion systems, design options, and parameter variations were input into the synthesis of cogeneration systems for potential application to approximately 85 representative industrial process plants. Using different strategies for matching the energy conversion system to the process plant requirements, the contractors calculated plant-basis cogeneration results for more than 6000 cases. These plant-basis results included calculation of fuel energy savings, annual energy cost savings, and emissions reductions as compared with the noncogeneration situation of purchasing electricity from a utility and providing thermal requirements with an on-site

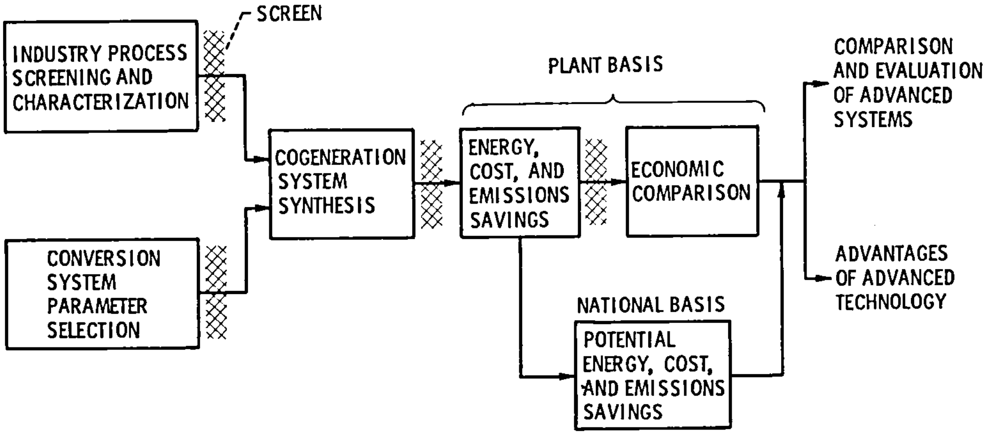


Figure 2. - CTAS methodology.

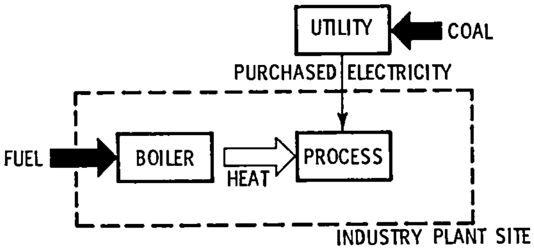


Figure 3. - CTAS noncogeneration case.

CS-79-945

boiler. From these results attractive cases for each of the nine types of energy conversion systems were examined by the contractors in a more detailed economic analysis that included calculation of return on investment and the sensitivity of results to changes in the economic ground rules. Sensitivity of results to changes in ground rules was also calculated by Lewis. Emphasis in the study was on these plant-basis calculations. However, potential benefits such as energy and emissions savings were also estimated on a national basis by each contractor in a first-order manner for each system as another input into the evaluation of the relative merit of the various concepts. Lewis independently estimated relative savings for the various systems on a national basis by using the contractors' plant-basis results as input data. The plant-basis and potential national benefits were then used by each contractor and by Lewis to compare and evaluate the advanced systems for application to industrial cogeneration.

2.3 Purpose of NASA Summary Report

The purposes of this summary CTAS report are

(1) To summarize the major results of the CTAS effort, including both the contractors' results and results from the Lewis in-house analyses

(2) To identify the most attractive advanced energy conversion systems for industrial cogeneration based on a Lewis evaluation of study results

A complete listing of the CTAS reports is provided in appendix A.

While reading this report it is important to keep in mind that the objectives of the CTAS effort were to compare and evaluate advanced energy conversion systems rather than to evaluate the merits of the cogeneration concept itself. In addition, since CTAS represents a very broad screening effort, more emphasis was placed on the relative comparisons among systems than on the absolute values of the various technical and economic results calculated. More detailed studies of the attractive systems are required to more precisely define the best configurations and to investigate those technical, economic, and other aspects of implementing advanced technology in industrial cogeneration not within the scope of this broad screening effort.

Section 3.0 defines the cogeneration concepts and options studied, identifies the industrial process plants included in the study and summarizes their characteristics, describes the energy conversion system variations examined, and provides some perspectives on the overall scope of the CTAS effort.

Section 4.0 describes the common ground rules established by NASA for the study and the major assumptions specific to each contractor's effort, defines some of the parameters used to evaluate the advanced conversion systems, and presents the screening approach used by Lewis in evaluating the advanced systems.

Section 5.0 summarizes the contractors' plant-basis results along with the national-basis results estimated by Lewis, identifies the most attractive advanced systems based on the Lewis evaluation of study results, and discusses some of the benefits of advanced-technology cogeneration systems.

Section 6.0 contains concluding remarks and some additional perspectives on CTAS results.

Appendix A identifies the contractor reports being prepared as part of CTAS and the detailed NASA report, which describes the results of the Lewis and JPL work in more detail.

Appendix B discusses the various output parameters calculated in the study and their significance.

Appendix C gives an example of the screening procedure used by Lewis to identify the most attractive energy conversion systems on the basis of the plant-site results and an example of the method used by Lewis to compare the potential of each advanced system on a national basis.

Appendix D illustrates the sensitivity of plant-basis results to changes in fuel and electricity prices.

3.0 STUDY SCOPE

This section presents the information necessary to appreciate the context in which the advanced energy conversion systems were studied and the scope of the analyses performed for the various systems. Section 3.1 introduces the various options and strategies considered in CTAS for matching energy conversion systems with industrial processes in cogeneration configurations and, in doing so, defines some of the concepts and terms used frequently in this report. Section 3.2 identifies the industrial process plants included in the study and summarizes the data for these representative applications. Section 3.3 describes the configurations and ranges of design and operating parameters investigated for the various energy conversion systems. Finally, Section 3.4 provides perspectives on the limitations in the scope of the CTAS effort.

3.1 Industrial Cogeneration Options and Strategies

In CTAS it was important to establish an approach that would allow the many conversion systems with quite different characteristics to be compared on a consistent basis over a broad range of industrial process requirements. The approach selected for CTAS was to establish for each industrial process a baseline noncogeneration case against which all cogeneration systems, both current and advanced, were then compared.

The noncogeneration concept, which represents the approach currently used by the majority of U.S. industrial plants to satisfy their requirements for electricity and process heat, is depicted schematically in figure 3. All electricity is purchased from a utility, and all process heat is produced by furnaces or boilers located at the plant site. Fuel for the on-site furnaces or boilers is in general purchased "over the fence." However, in cases where combustible wastes or byproducts that could be used as fuel were available from the industrial process, they were, where appropriate, used in both the noncogeneration and cogeneration situations. The fuel energy requirements and emissions associated with the generation of electricity at the utility and the on-site production of process heat were calculated, along with the total cost to the industrial owner of satisfying the total energy requirements of the process in the noncogeneration case. These values then provided a base against which to evaluate the relative benefits of the various current and advanced cogeneration systems. Even though a number of the industrial processes considered in CTAS currently practice cogeneration to varying degrees, a noncogeneration case was established for every process in order to achieve a consistent comparison of energy conversion systems across all industries.

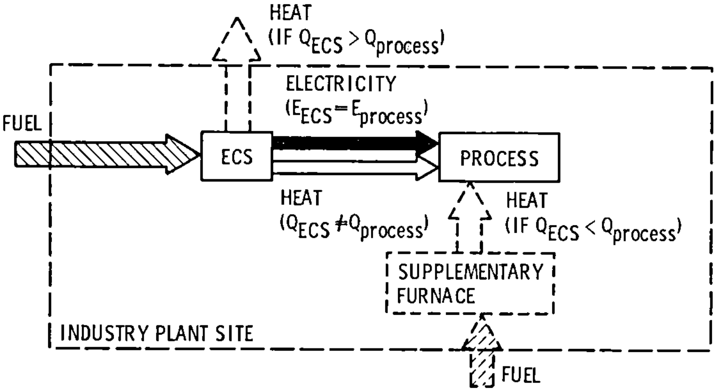
Two options or configurations can be considered when applying cogeneration to an industrial process: namely, topping and bottoming. Because of the program interests of the sponsoring DOE division, the emphasis in CTAS was on the topping option. And, although UTC did examine a few bottoming applications, this summary report presents results only for topping. In the topping cogeneration configuration, fuel is input to an energy conversion system located on an industrial plant site and generating electricity for use in the plant. Waste heat from the conversion system is recovered and used to provide heat in some form to the industrial process. (In the bottoming configuration, fuel is burned in a furnace or boiler to provide the process heat required, and the waste heat from the process is used as the thermal input to an energy conversion system that generates electricity.)

A desirable situation in the case of a topping configuration would occur when the electrical and recoverable thermal outputs from the on-site energy conversion system just match both the electrical and process heat requirements of an industrial plant. Because this in general is not the case, various alternatives or strategies must be employed in sizing an energy conversion system to match it to the requirements of an industrial plant. The two basic strategies that were considered by both CTAS contractors are shown in figure 4. In what has been designated the "match electricity" strategy (fig. 4(a)), the energy conversion system is sized to meet the electrical demand of the industrial process. If the resulting recoverable heat from the conversion system is greater than the process heat requirement, only enough heat is recovered to fulfill the process needs. If the recoverable heat from the conversion system is insufficient to meet the process requirement, a supplementary furnace is used on site to make up the deficit.

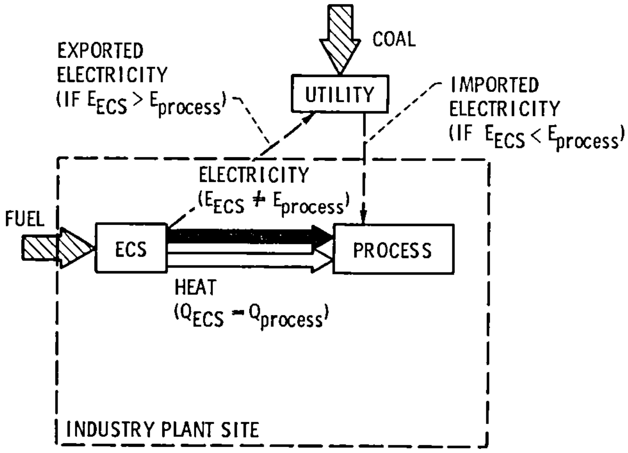
In the second basic sizing strategy, designated the "match heat" strategy (fig. 4(b)), the energy conversion system is sized such that its recoverable heat just matches the process heat requirement of the industrial plant. If the electrical output of the conversion system is not adequate to meet the plant requirement, additional electricity is purchased from a utility. On the other hand, if excess electricity is generated by the on-site conversion system, the excess is exported from the site and sold to the utility grid.

In addition to these two basic strategies, UTC also examined a strategy for sizing the conversion systems when process heat was to be supplied to a plant at multiple temperatures. This strategy is designated the "maximum energy savings" strategy.

The match-electricity, match-heat, and, in the case of UTC, maximum-energy-savings strategies were used in calculating results for the various cogeneration systems examined. For the purposes of this report, however, the results of these strategies have been evaluated and displayed by Lewis in two sets: The first set includes only cases that do not produce more electricity from the cogeneration system than is required at the site and therefore would not need to sell electricity to a utility (no export allowed). The second set of results includes cases in which electricity is sold to a utility (export allowed). Although the energy savings from cogeneration with advanced-technology systems is significantly higher if export is allowed, the current regulatory and institutional situation tends to discourage export of electricity to the utility. It was therefore felt that presenting results both with and without export allowed would be instructive. In the contractor reports results are presented by cogeneration strategy.



(a) Match-electricity strategy.



(b) Match-heat strategy.

Figure 4. - CTAS cogeneration matching strategies for topping configurations.

3.2 Industrial Process Plant Requirements

In CTAS, advanced-technology energy conversion systems were evaluated and compared for application to cogeneration systems in industrial process plants in the manufacturing sector of U.S. industry. The data developed by the contractors for the processes included in the study are summarized here. The manufacturing sector of U.S. industry is classified by the Office of Management and Budget (OMB) as Section D of the Standard Industrial Classification (SIC) code, which includes classifications of industries in two-digit codes 20 to 39 as listed in table 2. The top 10 energy-consuming two-digit industry groups from the manufacturing sector are shown in figure 5, along with the relative amounts of energy consumed and the number of four-digit subclassifications within each major industry group. The energy consumed in 1975 in the top 10 two-digit industry groups was approximately 88 percent of the total energy consumed in the entire U.S. manufacturing industry, with the top six industry groups accounting for approximately 77 percent of the total. Primary emphasis was thus placed on the top six two-digit industry groups. However, a number of the higher energy-consuming processes from the remainder of the top 10 industry groups were also included. Each CTAS contractor team independently gathered data on the characteristics of the processes within the manufacturing industry and, based on their respective data, selected processes to be considered in their studies. NASA also gathered data on the processes within the manufacturing industry. The objective of the NASA effort, which was carried out by the Jet Propulsion Laboratory, was primarily to gain the knowledge required by NASA to evaluate and coordinate the selection by the two contractors of the processes to be considered in CTAS.

A number of criteria were considered in selecting the processes. One important criterion was that the major energy-consuming industries be included, since even a small percentage savings in their energy use could have a significant national impact. It was also necessary that a diversity of process requirements representing a broad spectrum of U.S. industry be considered. Applicability over a wide variety of process requirements would obviously be a desirable trait for an advanced conversion system to penetrate the market place. In examining process requirements, such parameters as process size in terms of electrical power requirements, the ratio of electrical to process heat needs, and the temperature and form of the process heat required were felt to be important. The processes selected by the contractors, based on these criteria and other qualitative factors, for use in comparing energy conversion systems are discussed briefly in the following paragraphs. A smaller representative subset of processes that were considered by both contractors is presented in Section 4.4, Lewis Evaluation Approach. This subset is used in this summary report by Lewis to illustrate comparisons of energy conversion systems based on the plant-basis results obtained by the two contractors.

The processes selected by UTC and GE and the SIC four-digit subcategories to which they belong are shown in table 3. The four-digit classifications included by UTC currently consume about 50 percent of the energy used in the manufacturing sector of U.S. industry. The four-digit classifications included by GE represent about 58 percent of the manufacturing industry energy consumption. The SIC system classifies manufacturing and industrial plants in accordance with their products rather than the process employed or the plant size. Therefore individual plants producing similar products and included in the same four-digit industrial classification can, and do, have significantly different plant sizes and power and process heat requirements.

TABLE 2. - STANDARD INDUSTRIAL CLASSIFICATION CODE TWO-DIGIT CLASSIFICATIONS WITHIN MANUFACTURING SECTOR OF U.S. INDUSTRY

SIC code	Industry group
20	Food and kindred products
21	Tobacco manufactures
22	Textile mill products
23	Apparel and other finished products
24	Lumber and wood products, except furniture
25	Furniture and fixtures
26	Paper and allied products
27	Printing, publishing, and allied industries
28	Chemicals and allied products
29	Petroleum refining and related industries
30	Rubber and miscellaneous plastic products
31	Leather and leather products
32	Stone, clay, glass, and concrete products
33	Primary metal industries
34	Fabricated metal products
35	Machinery, except electrical
36	Electrical and electronic machinery, equipment, and supplies
37	Transportation equipment
38	Measuring, analyzing, and controlling instruments
39	Miscellaneous manufacturing industries

SIC CODE	INDUSTRY GROUP	ENERGY CONSUMPTION IN 1975, PERCENTAGE OF INDUSTRIAL ENERGY CONSUMPTION	NUMBER OF SIC FOUR-DIGIT CLASSIFICATIONS IN GROUP
28	CHEMICALS AND ALLIED PRODUCTS	22.7	28
33	PRIMARY METAL INDUSTRIES	19.8	14
29	PETROLEUM REFINING AND RELATED INDUSTRIES	9.5	5
26	PAPER AND ALLIED PRODUCTS	9.2	17
32	STONE, CLAY, GLASS, AND CONCRETE PRODUCTS	8.4	27
20	FOOD AND KINDRED PRODUCTS	7.3	47
37	TRANSPORTATION EQUIPMENT	3.3	17
22	TEXTILE MILL PRODUCTS	3.1	30
30	RUBBER AND MISCELLANEOUS PLASTIC PRODUCTS	2.2	6
24	LUMBER AND WOOD PRODUCTS	2.1	17

Figure 5. - Top 10 energy-consuming industries in U.S. manufacturing sector.

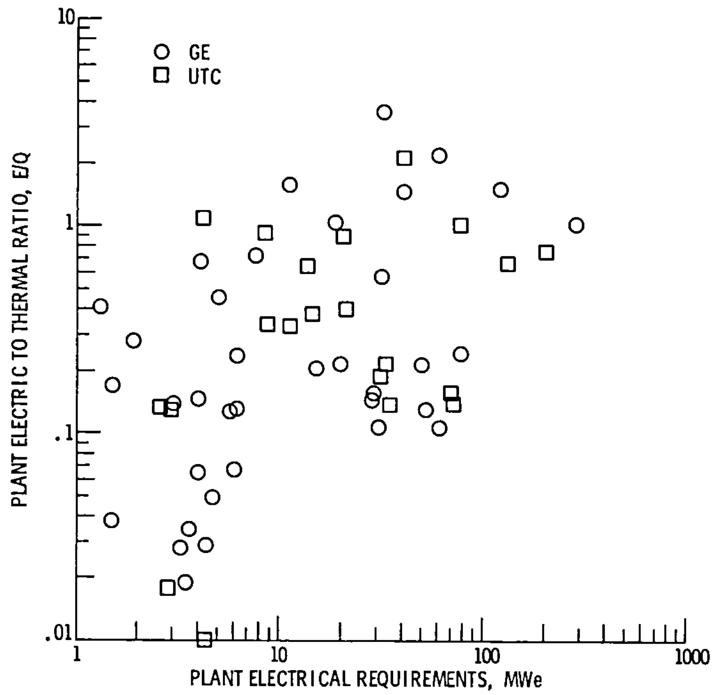


Figure 6. - Size distribution of CTAS processes.

TABLE 3. - INDUSTRIAL PROCESSES SELECTED BY GE AND UTC FOR CTAS

SIC code	Industry	GE	UTC	SIC code	Industry	GE	UTC
2011	Meat packing	X	X	2824	Nylon fiber	X	X
2026	Fluid milk	X		2865	Styrene	X	X
2046	Wet corn milling	X		2865	Phenol-acetone	X	
2063	Beet sugar	X		2865	Ethylbenzene	X	
2082	Malt beverages	X	X	2865	Cumene	X	
2051	Baking		X	2869	Ethylene	X	X
2221	Broad-woven-fabric mills		X	2869	Methanol	X	
2260	Textile finishing	X		2869	Isopropanol	X	
2421	Sawmill - softwood	X	X	2869	Ethanol	X	
2436	Plywood - softwood	X		2873	Ammonia	X	
2492	Particleboard	X		2874	Phosphoric acid	X	
2621	Unbleached Kraft mill	X		2895	Carbon black	X	
2621	Newsprint plant	X	X	2911	Petroleum refining	X[a]	X
2621	Writing-paper mill	X	X	3011	Tires - inner tubes		X
2631	Corrugated-paper mill	X	X	3211	Flat glass	X	
2631	Boxboard mill		X	3221	Glass containers	X	X
2631	Waste-paper mill	X		3229	Pressed and blown glass	X	
2800	Integrated chemical plant	X[a]		3241	Portland cement plant	X	X
2812	Chlorine-caustic soda	X	X	3312	Integrated steel mill	X	X
2813	Cryogenic-O_2:N_2	X		3325	Mini steel mill	X	
2819	Alumina	X	X	3312	Steel specialty plant	X	
2821	High-density polyethylene		X	3321	Gray iron foundry		X
2821	Low-density polyethylene	X	X	3331	Copper refining	X[a]	X
2821	Polyvinyl chloride	X	X	3334	Aluminum	X	
2822	Styrene-butadiene rubber	X	X	3711	Motor vehicles		X
2824	Polyester fiber	X					

[a]Studied in multiple sizes.

The diversity of process plant requirements represented by the selected processes is illustrated in figures 6 to 8. The process characteristics shown are the respective contractors' projections for process plants to the 1985-2000 time period. Figure 6 shows the ratio of the plant electrical requirement to plant thermal requirement E/Q plotted versus the plant electrical requirements. Plants from 1 MWe to about 300 MWe, exhibiting E/Q's from 0.01 to nearly 4.0, are shown. A few processes with electrical requirements less than 1 MWe and several with E/Q's outside the range of the ordinate of figure 6 were considered but were in general found not to be attractive for cogeneration with the conversion systems being studied.

The temperature at which process heat is required is very important in matching energy conversion systems to industrial processes. The amount of recoverable heat available from many energy conversion systems is a strong function of the temperature at which process heat is required. The recoverable heat available from other systems is relatively insensitive to the temperature requirement over a rather wide range. The temperatures at which steam was required for the selected processes are plotted in figure 7 as a function of E/Q. The great majority of the requirements are for process steam between 250° and 500° F. A number of the processes also required hot water at 140° to 170° F, and several processes exhibited a requirement for direct heat. (Where practical, UTC configured their cogeneration systems to fulfill all process heat requirements; GE provided only steam and hot water requirements in their configurations.)

The annual hours of plant operation and the frequency of shutdown can have a significant effect on the economic attractiveness of installing a cogeneration system and on the relative attractiveness of various types of energy conversion systems. Most of the process plants considered in CTAS operate three shifts per day, 5 to 7 days per week (roughly 6000 to 8000 hr/yr), as shown in figure 8. Average steady-state electric power and process heat requirements were used in CTAS to characterize the processes for the calculation of fuel energy savings, emissions savings, etc. This level of detail was appropriate for the rather broad evaluation of systems intended in CTAS.

In addition to the specific plant-site energy consumption data, each contractor also projected the national energy consumption for each process to the 1985-2000 time period in order to estimate the potential national benefits of the advanced energy conversion systems.

3.3 Energy Conversion Systems, Fuels, and Ranges of Parameters

3.3.1 Energy Conversion System and Fuel Combinations

The combinations of energy conversion system types and fuels or combustion approaches considered by each contractor are shown in table 4. The petroleum- and coal-derived fuels are listed either as distillate or residual grade. The coal-fired cases are separated according to whether the coal was fired in an atmospheric fluidized bed (AFB) or in a pressurized fluidized bed (PFB) with in-bed desulfurization; whether it was fired directly and first-generation lime or limestone scrubbers were used for flue gas desulfurization (FGD); or whether the system included an integrated low- or intermediate-Btu coal gasifier with fuel gas desulfurization.

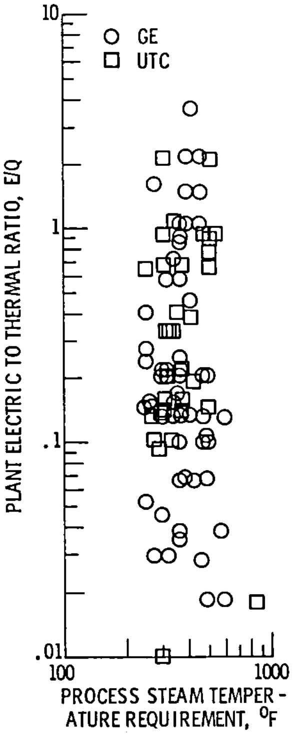


Figure 7. - Process steam temperature requirements of CTAS processes.

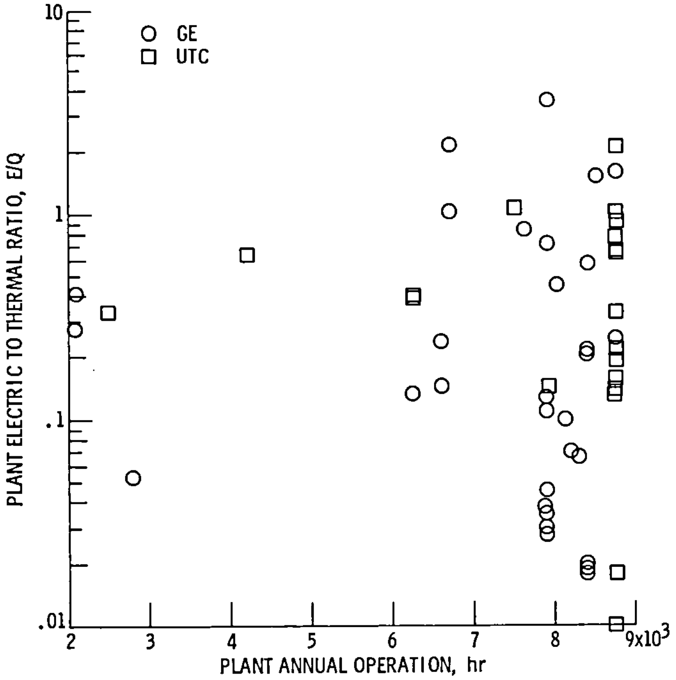


Figure 8. - Load factors for CTAS processes.

Since the objective of the study was to examine advanced energy conversion systems with minimally processed fuels, cases that used a high-Btu gaseous fuel, either natural or coal derived, were not selected. Any conversion system could use such a fuel more easily than the fuels that were considered, and inclusion of such natural-gas-fired cases would not have significantly altered the overall conclusions of the study.

The combinations of energy conversion systems and fuels analyzed with state-of-the-art design parameters are footnoted in table 4. These combinations served as a baseline for the comparison with advanced-technology cases. Note that most of the cases that use a petroleum-based fuel were state-of-the-art systems. The use of coal or coal-derived fuels was emphasized for the advanced-technology cases. Any of the advanced-technology cases that use coal-derived fuels could also of course use a petroleum-based fuel, probably with some improvements in performance, emissions, and cost.

3.3.2 Energy Conversion System Parameters

For the combinations of conversion systems and fuels listed in table 4, a range of parameters or some variation in system configuration was studied. The ranges of parameters used for the advanced-technology cases are summarized in table 5 for each type of system. Those used for the state-of-the-art baseline cases are summarized in table 6.

Steam turbines. - For steam turbine systems, the advanced technology studied was mainly concerned with the boiler type. Both contractors studied advanced systems with coal-fired, fluidized-bed boilers to compare with the state-of-the-art cases shown in table 6. UTC included consideration of 1800 psig/1050° F throttle conditions, which are beyond current practice in the United States for small industrial turbines.

As indicated in these tables the contractors used different steam turbine approaches. GE chose a noncondensing turbine with back pressure corresponding to the average pressure of the process steam required on site. UTC chose a condensing steam turbine with single extraction.

Open-cycle gas turbines and combined cycles. - Both contractors assumed the use of coal-derived, residual-grade fuel for most of the liquid-fired, open-cycle gas turbine systems. GE analyzed advanced systems with turbine inlet temperatures of 2200° F with air-cooled turbine blades and 2600° F with water-cooled blades. UTC analyzed advanced systems with a 2500° F turbine inlet temperature and air-cooled blades. GE included recuperated cycles using distillate-grade fuel. Both contractors considered combined-cycle configurations using the same gas turbine inlet temperatures assumed for the simple cycles. Both also analyzed configurations with steam injection to the combustor where the steam is generated in a heat exchanger in the gas turbine exhaust.

Both contractors included gas turbine systems with an integrated, entrained-bed gasifier and cold fuel gas cleanup. GE used a combined-cycle configuration and an oxygen-blown gasifier for this case; UTC used a simple cycle and an air-blown gasifier. In addition, UTC included gas turbines using a coal-fired PFB combustor and indirectly fired gas turbines using an AFB combustor. In both these situations they assumed the use of air tubes in the fluid bed, with the heated, pressurized air ducted to the turbine inlet.

As shown in table 6 both contractors studied state-of-the-art gas turbines with a 2000° F inlet temperature that used a distillate-grade petroleum fuel. In

TABLE 4. - CONVERSION SYSTEM - FUEL COMBINATIONS

System	Fuel							
	Petroleum		Coal-derived liquids		Coal			
	Distillate	Residual	Distillate	Residual	Flue gas desulfurization	Atmospheric fluidized bed	Pressurized fluidized bed	Gasifier
Steam turbine	----------	[a]GE, [a]UTC	--------	GE, UTC	[a]GE, [a]UTC	GE, UTC	GE	--------
Open-cycle gas turbine:								
Simple	[a]GE, [a]UTC	[a]GE, UTC	--------	GE, UTC	----------	UTC	UTC	UTC
Recuperated	----------	----------	GE	--------	----------	--------	----	--------
Steam injection	----------	UTC	--------	GE, UTC	----------	UTC	UTC	--------
Combined gas turbine/ steam turbine	[a]UTC	UTC	--------	GE, UTC	----------	UTC	UTC	GE
Diesel:								
Low speed	----------	[a]UTC	--------	UTC	UTC	--------	----	--------
Medium speed	[a]GE	[a]GE	--------	GE	----------	--------	----	--------
High speed	[a]UTC	----------	UTC	--------	----------	--------	----	--------
Closed-cycle gas turbine	----------	----------	--------	UTC	----------	GE, UTC	----	--------
Stirling engine	----------	----------	GE	GE, UTC	GE	UTC	----	--------
Fuel cell:								
Phosphoric acid	UTC	----------	GE, UTC	--------	----------	--------	----	--------
Molten carbonate	UTC	----------	GE, UTC	--------	----------	--------	----	GE, UTC
Molten carbonate/ steam	----------	----------	--------	--------	----------	--------	----	GE
Thermionic	----------	----------	--------	GE, UTC	GE	--------	----	--------
Thermionic/steam	----------	----------	--------	GE, UTC	GE	--------	----	--------

[a]Case analyzed with current commercially available technology.

TABLE 5. - MAJOR PARAMETERS STUDIED FOR ADVANCED ENERGY CONVERSION SYSTEMS

System	Parameter	General Electric Co.	United Technologies Corp.
Steam turbine	Turbine configuration	Noncondensing with back pressure at process required pressure	Condensing with single extraction at 50 or 600 psig
	Throttle pressure/temperature, psig/°F	1450/1000 850/825	1200/950 1800/1050
	Boiler type	AFB, PFB	AFB
Open-cycle gas turbine:			
Liquid fueled	Turbine inlet temperature, °F	2200, 2600	2500
	Pressure ratio	8 to 16	10 to 18
	Recuperator effectiveness:		
	With residual fuel	0	0
	With distillate fuel	0, 0.6, 0.85	----------------
	Ratio of steam injection rate to airflow	0, 0.1, 0.15	0, 0.05, 0.1
	Bottoming cycle	None, steam	None, steam
Coal fired	Turbine inlet temperature, °F:		
	With coal - gasifier	2200	2400, 2500
	With coal - PFB	----------------	1600
	With coal - AFB	----------------	1500
	Pressure ratio:		
	With gasifier	10	17, 18
	With coal - PFB	----------------	6 to 10
	With coal - AFB	----------------	10
	Gasifier type	Entrained bed	Entrained bed
	Bottoming cycle	Steam	None, steam
Diesel:			
Low speed (2 cycle)	Speed, rpm	----------------	120
	Jacket coolant temperature, °F	----------------	266
	Unit size, MWe	----------------	8 to 29
Medium speed (4 cycle)	Speed, rpm	450	----------------
	Jacket coolant temperature, °F	250	----------------
	Unit size, MWe	0.3 to 15	----------------
High speed (4 cycle)	Speed, rpm	----------------	1800
	Jacket coolant temperature, °F	----------------	Adiabatic
	Unit size, MWe	----------------	0.2 to 15
Closed-cycle gas turbine	Working fluid	Helium	Air, helium
	Turbine inlet temperature, °F:		
	With AFB	1500	1500
	With liquid fuel	----------------	2200

TABLE 5. - Concluded.

System	Parameter	General Electric Co.	United Technologies Corp.
Closed-cycle gas turbine (concluded)	Pressure ratio:		
	With helium	2.5	3 to 6
	With air	----------------	3 to 14
	Recuperator effectiveness	0,0.6,0.85	0,0.85
	Compressor inlet temperature, °F	80	190, 300
Stirling engine	Fluid	Helium	Helium
	Maximum fluid temperature, °F:		
	With coal - flue gas desulfurization	1390	----------------
	With coal - AFB	----------------	1450
	With liquid fuel	----------------	1600
	Heat input configuration:		
	With coal fuel	Intermediate heat-transfer gas loop	Intermediate heat-transfer gas loop
	With liquid fuel	Heater head in combustion zone	Intermediate heat-transfer gas loop
	Engine coolant temperature, °F	As required by process up to 500	150
	Unit size, MWe	0.5 to 2	0.5 to 30
Fuel cell:			
Phosphoric acid	Stack temperature/pressure, °F/psia	375/15	400/120
	Fuel processing:		
	With petroleum-derived fuel	Steam reformer	Steam reformer
	With coal-derived fuel	Steam reformer	Adiabatic reformer
Molten carbonate	Cell stack temperature, °F	1000 to 1300	1100 to 1300
	Cell stack pressure, psia	147	120
	Cell stack temperature control configuration:		
	With distillate-grade fuel	Cathode recycle	Anode recycle
	With gasifier	Excess cathode air	Anode recycle
	Gasifier type (coal-fired case)	Entrained bed	Entrained bed
	Bottoming cycle	None, steam with gasifier	None
Thermionics	Emitter collector temperature, °F	2420/710 1880/900	2400/763 2400/1113
	Configuration	Modular array	Thermionic heat exchanger (THX)
	Air preheat temperature, °F	1000	2200, 1000
	Bottoming cycle	None, steam	None, steam

TABLE 6. - MAJOR PARAMETERS OF STATE-OF-THE-ART ENERGY CONVERSION SYSTEMS

System	Parameter	General Electric Co.	United Technologies Corp.
Steam turbine	Configuration	Noncondensing with back pressure at process required pressure	Condensing with single extraction at 50 or 600 psig
	Throttle pressure/temperature, psig/^{o}F	1450/1000 850/825	1200/950 ----------------
	Fuel	Pulverized coal with flue gas desulfurization, petroleum residual	Pulverized coal with flue gas desulfurization, petroleum residual
Gas turbine:			
Petroleum distillate fired	Turbine inlet temperature, ^{o}F	2000	2000
	Pressure ratio	10	10 to 14
Petroleum residual fired	Turbine inlet temperature, ^{o}F	1750	----------------
	Pressure ratio	10	----------------
Diesel			
Petroleum distillate fired	Type	Medium speed, 4 cycle	High speed, 4 cycle
	Speed, rpm	450	1800
	Jacket coolant temperature, ^{o}F	180	200
	Unit size, MWe	0.3	0.4 to 1.5
Petroleum residual fired	Type	Medium speed, 4 cycle	Low speed, 2 cycle
	Speed, rpm	450	120
	Jacket coolant temperature, ^{o}F	155	158
	Unit size, MWe	1 to 10	8 to 29

addition, GE included a state-of-the-art gas turbine at 1750° F that used a residual-grade petroleum fuel.

Diesel engines. - GE studied four-stroke-cycle, medium-speed diesels using distillate- or residual-grade liquid fuels. UTC studied high-speed diesels using distillate-grade liquid fuel and a low-speed, two-stroke-cycle diesel using residual-grade liquid fuel or pulverized coal. Both contractors assumed the use of coal-derived liquid fuels for the advanced-technology diesel configurations. The UTC coal-fired case assumed a floatation process for desulfurization (but no cost or performance penalty for this was included by UTC for this system). In the advanced-technology version of the high-speed diesel, UTC assumed the use of ceramic parts in high-temperature areas in order to completely eliminate the jacket coolant. GE assumed advancements including higher brake mean effective pressure (BMEP), reductions in losses to the jacket coolant, higher coolant temperatures, and larger unit sizes. Both contractors also assumed a reduction in NO_x emissions although in their judgment the reduction would not be enough to bring the diesel engine emissions down to the limits set for the study. GE also considered the use of an open-cycle steam heat pump integrated with the jacket-coolant water loop in order to produce useful process steam from this waste heat.

Closed-cycle gas turbines. - Both contractors studied 1500° F closed-cycle gas turbine systems using an atmospheric-fluidized-bed, coal-fired furnace. In addition, UTC analyzed a 2200° F closed-cycle gas turbine system using a residual-grade-fuel-fired furnace with ceramic heat exchangers. Both contractors included both recuperated and unrecuperated cycles. In a cogeneration application an unrecuperated cycle would allow recovery of a greater fraction of waste heat as steam, which is the dominant form required by the processes studied. The electrical efficiency, however, is of course lower for the unrecuperated version. Also, to improve heat recovery at the expense of some loss in electrical efficiency, UTC considered cases with 190° F and 300° F compressor inlet temperatures rather than the lower temperatures that would be more appropriate for power generation only.

Stirling engines. - As indicated in table 5 both contractors studied Stirling engines using helium as the working fluid. For the liquid-fired case GE assumed that the heater-head tubes were located directly in the combustion zone. In the coal-fired case, they used an intermediate helium gas loop to transfer heat from the pulverized coal furnace to the engine heater-head tubes. GE did not use an AFB because they considered the temperature difference between the nominally uniform 1550° F fluid bed and the selected 1470° F engine heater tube surfaces to be too small to be practical for such a gas loop. UTC did use an AFB furnace, but their engine configuration was much different. They studied a two-stage configuration with heat input to the engine at the peak value shown in table 5 and at nominally 500° F. They therefore used an intermediate air heat-transfer loop that exited the AFB at 1500° F, or the liquid-fuel-fired furnace at 1800° F, and returned at 500° F.

Most of the process heat provided by this Stirling engine as configured in the UTC study was 500° F steam generated by using heat transferred from the intermediate air loop between the high-temperature input to the engine and the lower temperature input to the engine. Hot water at 140° F was obtained from engine heat rejection. GE, however, obtained most of their process heat in the form of steam from the engine by raising the heat rejection temperature to higher levels. They obtained a smaller amount of steam from the furnace loop in order to avoid either the use of a high-temperature air preheater or high stack losses.

Phosphoric acid and molten carbonate fuel cells. - UTC studied only pressurized phosphoric acid fuel cells; GE considered only atmospheric cells. Both contractors used a conventional steam reformer for the fuel processing. UTC also considered an advanced adiabatic reformer to produce the hydrogen-rich gas required. The adiabatic reformer, unlike the steam reformer, uses neither a separate combustion of fuel nor heat transfer to the gasification reaction zone through the heat-exchanger surface. Instead, all the fuel together with air and steam is mixed and reacted in the presence of a nickel catalyst. In one design option with the adiabatic reformer, UTC used the cathode exhaust, which contains unreacted oxygen and water vapor from fuel oxidation, as an input to the reformer instead of separate air and steam flow. This allowed production of a larger amount of steam for process use.

In the high-temperature fuel cell cases UTC used a configuration in which heat is removed from the molten carbonate fuel cell stacks by recirculating anode gas. GE used recirculated cathode gas for the liquid-fired case and excess cathode air for the integrated gasifer case. Both used an entrained-bed, air-blown gasifier with cold-gas desulfurization in the coal-fired case. In the liquid-fired case, both GE and UTC used an adiabatic reformer.

Thermionics. - As indicated in table 5, for the thermionic system GE assumed the use of planar, modular arrays of small converters lining the surfaces of the furnace. UTC used what is known as the THX approach, which involves larger converters mounted on large heat pipes, with the heat pipes extending into the furnace.

The two sets of emitter-collector temperatures shown in table 5 for GE are used for temperature staging within the furnace. GE used air to cool the collectors and then used this 1000° F air in the furnace for combustion. In UTC's case the collectors were steam cooled. In the UTC configuration the combustion air was heated by using furnace exit gases. They examined a 2200° F air preheat with a ceramic heat exchanger and a 1000° F air preheat with a metallic heat exchanger. The higher collector temperature shown in table 5 was used to generate steam turbine throttle steam in the UTC configuration that included the bottoming cycle. The lower temperature collector was used in the configuration without a bottoming cycle, where only process steam was generated.

3.4 Limitations of Scope

The prime consideration in setting the scope of CTAS was to enable comparisons and evaluations of the advanced energy conversion systems studied to be made for industrial cogeneration applications. The potential process plant applications included in the study convered a large fraction (i.e., 50 percent) of the energy used by industry and included a wide diversity of process requirements. This enabled valid and meaningful comparisons of the advanced systems to be made both for representative plants and on a national basis. Of course not all applications could be included and other potentially attractive applications may exist. Further, although process requirements for each application were those projected by the contractors for the 1985-2000 time period, changes in processes to make them more amenable to cogeneration were not considered in the study.

A wide, but certainly not exhaustive, range of advanced energy conversion system configurations and parameter variations was studied. More optimum configurations than those studied probably exist, particularly for those systems not previously studied for industrial cogeneration applications. However, it is believed that for the purposes of the study enough options were considered for each system to enable the relative merit of the various types of systems to be evaluated. More detailed studies are required for the attractive systems to more precisely define the best configurations and to investigate those technical, economic, and other aspects of cogeneration beyond the scope of the CTAS effort.

Many institutional, regulatory, and market considerations will affect the ultimate implementation and acceptance of industrial cogeneration either with current or advanced-technology systems. Although these considerations were recognized, no attempt was made in the study to provide solutions to any institutional or regulatory problems that may exist. Rather, where possible, results are presented in a way that can provide useful information to those charged with the responsibility for addressing these issues.

Finally, the study was concerned only with industrial cogeneration at individual plant sites. The evaluations of the systems therefore apply only to that application, and no inference should be drawn as to the relative merit of the systems for any other application.

4.0 STUDY METHODOLOGY

This section discusses the major assumptions used in the study and the screening process used by Lewis in its evaluation of results for the various advanced energy conversion systems. Section 4.1 describes the common ground rules established for use in the study. Section 4.2 describes the major assumptions made by the contractors, which are specific to each contracted study. Section 4.3 defines some of the output parameters specified for common use in the study. Section 4.4 describes the process used by Lewis in its evaluation of study results.

4.1 Common Ground Rules

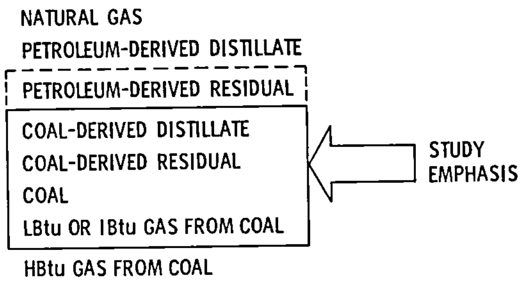
A set of ground rules was established by NASA in cooperation with DOE and the contractors in order to ensure that the contractors' results could be compared on a consistent basis and that differences that occurred would not be attributable to arbitrary differences in the basic study assumptions. The major areas where common ground rules were established are

(1) Fuel characteristics
(2) Utility characteristics
(3) Fuel and electricity prices
(4) Emissions guidelines
(5) Capital costing approach and economic methodology
(6) Output parameters

A number of the most significant ground rules are discussed in the following paragraphs.

4.1.1 Fuel Characteristics and Price

Figure 9 shows the fuels considered for use in CTAS. The emphasis, as indicated in figure 9, was on the use of high-sulfur coal, minimally processed coal-derived liquid fuels, and low- or intermediate-Btu (LBtu or IBtu) gas obtained through on-site gasification of coal. Residual-grade petroleum oil was considered



CS-79-938

Figure 9. - CTAS fuels.

TABLE 7. - FUEL SPECIFICATIONS

Content	Petroleum derived		Coal derived		Coal
	Distillate	Residual	Distillate	Residual	
Sulfur, wt%	0.5	0.7	0.5	0.7	3.9
Nitrogen, wt%	0.06	0.25	[a]0.8	[a]1.0	1.0
Hydrogen, wt%	12.7	10.8	[a]9.5	[a]8.5	5.9
Ash, wt%	Negligible	0.03	0.06	0.26	9.6
Trace elements[b]	Low	High	Moderate	High	High

[a]Nominal value.
[b]Vanadium, sodium, potassium, calcium, and lead.

TABLE 8. - FUEL PRICES BASED ON DOE INPUT

Fuel	1985 Base year price, 1978 $/MBtu	Escalation of price above inflation, percent/yr
Distillate oil[a]	3.80	1.0
Residual oil[a]	3.10	1.0
Coal	1.80	1.0
Natural gas	2.40	4.6 (1985-2000)
		1.0 (after 2000)

[a]Prices for petroleum- and coal-derived liquid fuels of similar grades are assumed to be the same.

as an intermediate step from the clean fuels in use in most currently available systems toward the use of coal-derived fuels. A small number of systems (primarily state-of-the-art configurations) using petroleum distillate fuel were also examined. The fuel specifications provided to the contractors are summarized in table 7. The specifications shown for the petroleum distillate fuel and the petroleum residual-grade fuel represent characteristics near the upper limits of current specifications for #2 diesel oil and #5 boiler-grade fuel, respectively, and are not necessarily typical of the fuels being used today. The coal-derived liquid fuels specified are not the outputs of any particular liquefaction process but represent what might be future characteristics of minimally processed coal-derived liquid fuels in grades similar to the specified petroleum fuels. Characteristics of the low- or intermediate-Btu gas were not specified but depended on the specific gasifier concepts selected by the respective contractor.

Prices assumed for the fuels are given in table 8. Prices for the petroleum-based fuels and coal were based on projections for industrial uses made by the DOE Energy Information Administration. These data were provided to NASA by DOE for use in CTAS. Prices for coal-derived liquid fuels were assumed to be the same as the prices for petroleum-based fuels of comparable grades, based on the assumption that for coal-derived liquid fuels to achieve a significant degree of usage in industry, the effective price to the user would have to be competitive with petroleum fuels. The prices shown are projected national averages. The impact of regional differences in fuel prices (and electricity prices) was examined by Lewis.

In some industrial processes included in the study byproduct fuels were available. The characteristics of byproduct fuels and the amounts of byproduct fuels available were determined by the contractors from their data for the industrial processes. When byproduct fuels were used, they were assumed to be available at no charge.

4.1.2 Utility Characteristics and Electricity Price

Electric power purchased from a utility was assumed to be baseload power generated by a coal-fired steam powerplant at an efficiency of 32 percent including transmission and distribution losses. The utility was assumed to exactly meet the emissions guidelines for coal-fired systems as described here. The prices assumed for electricity (in 1978 dollars) were as follows:

(1) Purchase price for utility electricity in 1985 is 3.3¢/kWhr (based on DOE input).

(2) Electricity purchase price escalates at 1 percent above inflation (based on DOE input).

(3) Price received by a cogenerator for electricity exported to the grid is 60 percent of the purchase price.

The purchase price and escalation rate were based on the same DOE Energy Information Administration data as the fuel prices. Electricity prices were based on projected prices for industrial customers. Average demand charges were assumed to be included in the price of electricity. Standby charges for electric power were not considered. Although standby charges can be significant in any given application being considered for implementation, they are highly variable. For this broad screening study of advanced energy conversion systems, the effect of these charges was not addressed. As in the case of the fuel prices the electricity prices were national average values. Further a flat electricity rate was assumed, that is, no variation in price with size of electrical demand.

The sale price of exported electricity was established by Lewis, with DOE approval, after discussion with several utilities and the CTAS contractors. The 60 percent value is roughly equivalent to the cost of fuel required by a utility to generate a like amount of electricity.

4.1.3 Emissions Guidelines

A set of emissions guidelines was established by Lewis to provide the contractors with a common level that should not be exceeded in formulating their cogeneration system designs. These guidelines were based on the 1971 Federal New Source Performance Standards (NSPS) for steam powerplants, which were in effect at the start of this study, and on NSPS that were proposed in 1977 for stationary gas turbines. The guidelines, presented in table 9, are fuel dependent and are based on the fuel energy input to the powerplant. Note that the guidelines for solid coal were also applied to cases where on-site gasification is used. The emissions guidelines were reviewed by both DOE and the Environmental Protection Agency (EPA), prior to their use in CTAS, for appropriateness in a study such as this, which is aimed at comparing a wide variety of advanced energy conversion systems. Conversion systems that did not meet the guidelines were not eliminated from further study but were flagged for their failure to meet the guidelines. It is important to note that some states have more stringent standards for steam powerplants than those delineated in the 1971 NSPS. State-by-state emissions standards and data on nonattainment areas were cataloged by JPL in support of CTAS and are included in the detailed NASA report (see appendix A).

4.1.4 Capital Costing Approach

All capital costs are given in 1978 dollars, and interest during construction was included when the capital costs were used in the economic analyses. Capital costs were estimated for all on-site equipment associated with the generation of electric power and process heat. Capital costs for distribution of power or heat, condensate return systems, and process-related equipment were not included in the cost estimates since the same equipment would be used with or without cogeneration.

An "island" approach to capital costing was specified by Lewis for use by both CTAS contractors. Each total cogeneration system was made up of a number of major subsystems (e.g., fuel handling, furnace, and conversion systems). Each major subsystem and the balance of plant equipment associated directly with that subsystem make up a cost "island." The major cost islands used by the two CTAS contractors are shown in table 10. Costs were estimated by the contractors for the equipment, installation material, and labor for each island from inputs generated by the conversion system consultants on their CTAS team and/or from cost models based on experience with existing similar equipment or previous studies. All equipment, material, and labor required to tie together the separate subsystem islands into a total cogeneration system, and which cannot be conveniently allocated to a specific subsystem island, were accounted for in a balance-of-plant (BOP) island.

TABLE 9. - EMISSIONS GUIDELINES BASED ON PROPOSED NSPS FOR STEAM POWERPLANTS (1971) AND ON PROPOSED NSPS FOR STATIONARY GAS TURBINES (1977)

Pollutant	Fuel type		
	Solid	Liquid	Gaseous[a]
NO_x, lb/MBtu	0.7	[b]0.5	0.2
SO_x, lb/MBtu	1.2	0.8	0.2
Particulates, lb/MBtu	0.1	0.1	0.1

[a]Solid-fuel standards apply to systems using gas produced on site from integrated coal gasifiers.
[b]NO_x guideline for petroleum distillate is 0.4 lb/MBtu input.

TABLE 10. - CAPITAL COST ACCOUNTING CATEGORIES (ISLANDS)

General Electric Co.		United Technologies Corp.	
Item	Island name	Item	Island name
1	Fuel handling	1	Fuel and waste handling and storage
2	Fuel utilization and cleanup	2	Conversion system heat source
3	Energy conversion system	3	Energy conversion system
4	Bottoming cycle	4	Thermal storage
5	Heat sink	5	Supplementary heat
6	Balance of plant	6	Heat rejection
		7	Balance of plant

TABLE 11. - COST ADDERS

	General Electric Co.	United Technologies Corp.
Indirect labor, percent of direct labor	90	75
Contingency, percent	15	20
Engineering and fees, percent	11	15

TABLE 12. - MAJOR ASSUMPTIONS FOR CTAS ECONOMIC ANALYSIS

Inflation rate	All economic calculations are inflation free[a]
Income tax rate, including federal, state, and local income taxes, percent	50
Other local taxes and insurance, percent of capital investment per year	3
Investment tax credit (assumed to reduce tax liability in first year of operation)	10
Depreciation	Sum of year's digits; 15-year tax life
Cost of capital (after taxes), percent	5.4
Capital cost escalation above general inflation	0
Startup date (all systems assumed to start operation in that year; capital investment assumed to occur in single cash flow at that time)	1990

[a]Gives conservative results.

The contractors' cost categories were reviewed and coordinated early in the study, in order to achieve, where practical, consistency between the contractors in the level of breakdowns and in the equipment included in the various islands. The contractors reported costs at one level of detail greater than that shown in table 10. Because of the diversity of data sources and the methodologies used by the two contractors in developing cost estimates, it was not always possible to establish directly comparable cost islands. For example, in the UTC cost breakdown, costs for the heat source and associated cleanup equipment for the energy conversion system were in their item 2. Costs for a supplementary furnace and associated equipment, when required, were reported under their item 5. In the GE cost breakdown, costs for the energy conversion system heat source and the supplementary furnace, when required, were both reported under GE's item 2. Sufficiently detailed cost data were reported to allow Lewis to compare costs and to evaluate differences where they occurred.

The total installed costs for the appropriate subsystem islands were summed together with the balance-of-plant island. Cost adders such as indirect labor costs, contingency, engineering services, and fees were then included to obtain the total cogeneration system capital costs. Each contractor used cost adders consistent with his data sources and costing methodology. The cost adders used are given in table 11.

4.1.5 Economic Assumptions

A wide variation is possible in the methodology and assumptions used in the economic analyses of a proposed venture. To facilitate the comparison of results generated by the two contractors, NASA, after consultation wih the contractors and DOE, specified a set of ground rules to be followed in the CTAS economic analyses. Two primary parameters that were used in CTAS as measures of economic attractiveness were levelized annual energy cost and return on investment. They are defined in Section 4.3.

Several of the more important assumptions used in the economic analyses are listed in table 12. The values were specified by Lewis after consultation with the contractors, and the assumptions were provided to DOE for review before being incorporated into the study.

4.2 Contractor-Specific Assumptions

There were a number of important areas where it was decided not to establish common ground rules but to allow the contractors to incorporate their individual philosophies, design approaches, and methodologies. A number of these areas where the contractor-specific assumptions have a significant effect on the study results are discussed briefly here.

4.2.1 Noncogeneration Case

The noncogeneration case was the baseline against which all cogeneration system energy costs and emissions savings were measured. Thus the assumptions that were made in defining the noncogeneration case could, in some cases, have a significant effect on the absolute value of the results. The noncogeneration cases established by both contractors differed only in their philosophies on the fuel that was assumed for the on-site furnaces producing process heat. UTC assumed that noncogeneration plants built from 1985 to 2000 would predominantly use liquid fuels in their process heat furnaces, similar to current practice. UTC assumed that whatever liquid fuel was available for the cogeneration system could also be available for use with the noncogeneration system. Therefore, when cogeneration systems based on commercially available or advanced-technology systems were examined with petroleum-based fuels, the noncogeneration fuel was residual-grade petroleum oil. When UTC was considering an advanced cogeneration system fueled by coal or coal-derived liquid fuel, the noncogeneration fuel was assumed to be a residual-grade, coal-derived liquid. The GE approach was to assume that for noncogeneration plants built from 1985 to 2000 coal would be the predominant fuel for the on-site furnaces when the plant size was sufficient to support the equipment required (process heat required, $>30\times10^6$ Btu/hr). In smaller plants the noncogeneration fuel was assumed to be coal-derived residual oil.

This difference in noncogeneration fuel had a significant effect on the absolute values of the results, especially energy cost savings and ROI for the cogeneration systems. This effect is discussed in appendix B. To obtain data that permitted a more direct comparison between the two contractors' results, GE was requested to provide computer data for all their cases for a noncogeneration fuel consistent with that assumed by UTC, in addition to data based on their assumption. The liquid-fueled noncogeneration case, for which data are available from both contractors, will be used throughout this report for comparisons of results.

4.2.2 Process Heat Requirements

The two CTAS contractors chose different methods of defining and matching the process requirements and conversion system capabilities in the area of process heat. The significant differences are discussed briefly in this section.

UTC elected to specify five "bins" into which all process heat requirements were categorized in order to enable them to proceed with their system designs independently of the industrial process data. The bins were specified as 140° F hot water, 300° F (50 psig) saturated steam, 500° F (600 psig) saturated steam, 700° F (600 psig) superheated steam, and direct heat. In some cases direct-heat requirements can be satisfied through the direct use of the gaseous exhaust from an energy conversion system. The energy conversion system design options were configured to provide recoverable heat for one or more of these bins. UTC and Gordian Associates examined the process requirements and, using their judgment, placed them in the appropriate bins. This technique for matching the system capability with the process requirements enabled UTC to then satisfy multiple-temperature process heat requirements. In general a process heat requirement was placed in the next higher temperature bin (e.g., a 375° F requirement would be placed in the 500° F bin). When the energy conversion system capability was determined, it was typically adjusted to the next lower temperature bin (e.g., if the maximum temperature a system could provide was 400° F, it was adjusted to the 300° F bin). This methodology allowed consideration of multiple-temperature process heat requirements. In some cases (especially where only relatively low-grade heat is available from the system) it yielded conservative results.

GE developed a characteristic for each conversion system that expressed the electric output and the amount of recoverable waste heat available from that system as a function of the temperature at which the process heat was required. This characteristic assumed that for a given plant all process heat was provided at one temperature. When GE identified an industrial process with multiple-temperature process heat requirements, they combined the multiple-heat streams into a single representative requirement roughly equal to the total heat energy requirement of the multiple streams and generally at the highest temperature required by the process. They then matched the performance characteristic of the conversion system with the single representative requirement. This methodology tends to yield conservative results for those processes requiring multiple process heat streams at different temperatures, since all the process heat energy is generated at the highest temperature required. The approach of generating steam at one temperature when the process needs steam at more than one temperature is often used in industry today.

The effects of the GE and UTC assumptions on the results have been examined by Lewis. In general the methodology used by each contractor yielded results of sufficient accuracy for the screening purposes of CTAS. In some instances Lewis and/or the contractors recalculated the results where the assumptions may have inadvertently penalized one or more systems.

4.2.3 Energy Conversion System Unit Sizing

The philosophies of the two contractors differed somewhat in their sizing of energy conversion system units to meet the total power requirements determined by the cogeneration matching strategy. GE established a maximum unit size limit for each system. If the total power requirements could be satisfied by a unit smaller than the maximum size, a single unit was used. If the total power requirement was greater than the maximum unit size for the system being considered, the minimum number of equal-sized units of that type was used to satisfy the requirement. At the small end, if the size of the unit required was smaller than the lower end of the range covered by the GE cost model, the model was extrapolated and the results flagged as being outside the range of available data and probably optimistic. In selecting cases for detailed economic study the flagged cases were not considered.

The primary difference between the GE and UTC approaches in this area was that UTC felt that in order to increase the flexibility of the cogeneration systems and to insure a capability to shut down the industrial process without damage to process equipment, multiple units of energy conversion systems should always be used. Therefore all the UTC cogeneration systems used at least two equal-sized units until the maximum unit size was reached. Then the minimum number of equal-sized units was used to meet the requirements. UTC also flagged those cases that were smaller than the minimum practical size, and they were not considered in selecting cases for detailed economic study.

Equipment to provide additional electrical or thermal capacity for standby purposes to be used in the event of failure of the primary equipment so that full production capability could be maintained was not included as part of the cogeneration systems. Examination of the consequences or economics of forced outages versus having standby electrical or thermal capacity was beyond the scope of this broad screening study. Of course it can be an important consideration in the design of a cogeneration system for a specific application and can have a significant influence on the final economic attractiveness of a proposed venture.

4.3 Definition of Evaluation Parameters

A large variety of parameters can be used to characterize cogeneration system performance and economics. Lewis specified a basic set of output parameters to be used by both contractors not only so that numerical results would be directly comparable, but also because the parameters defined were felt to be particularly suitable for use in a study such as this one.

Each contractor was also permitted to use other output parameters in addition to the ones specified. Four parameters specified by Lewis and used extensively in this report are fuel energy savings ratio (FESR), emissions savings ratio (EMSR), levelized annual energy cost savings ratio (LAECSR), and rate of return on investment (ROI). These are defined in the following paragraphs. The factors affecting results for these and other evaluation parameters are discussed in appendix B.

4.3.1 Fuel Energy Savings

The fuel energy savings ratio (FESR) parameter specified to measure cogeneration system performance is the savings of fuel energy as compared with that required to meet the site requirements without cogeneration.

$$\text{FESR} = \frac{(\text{Fuel energy})_{\text{noncogen}} - (\text{Fuel energy})_{\text{cogen}}}{(\text{Fuel energy})_{\text{noncogen}}}$$

The fuel energy in the cogeneration case includes that used by the cogenerating energy conversion system plus that required at the utility if additional electricity is required and/or the fuel energy required by an on-site furnace or boiler if additional process heat is required. In the noncogeneration case the fuel energy is the sum of that used at the utility site to produce electric power and that used at the industrial site to produce heat. To be consistent, when the cogeneration case involves electricity exported back to the utility, the fuel energy at the utility in the noncogeneration case is adjusted to account for electricity production equal to the cogeneration case.

4.3.2 Emissions Savings

Because of the fuel savings there is usually a reduction in overall emissions, considering both the utility and industrial sites. The parameter used to measure this was analogous to the fuel energy savings ratio, that is, an emissions savings ratio (EMSR).

$$\text{EMSR} = \frac{(\text{Emissions})_{\text{noncogen}} - (\text{Emissions})_{\text{cogen}}}{(\text{Emissions})_{\text{noncogen}}}$$

The emissions include those at the utility site and those at the industrial site. This emissions savings ratio was calculated individually for sulfur dioxide, oxides of nitrogen, and particulates, as well as for the sum of all three. In this summary report only values for the sum of all three emissions are presented. In addition to emissions where the plant site and utility were included together, each contractor cataloged the plant-site emissions by species for both the noncogeneration and cogeneration cases since on-site emissions can be a crucial factor for implementation of a congeneration system.

4.3.3 Levelized Annual Energy Cost Savings

Levelized annual energy cost (LAEC) is defined as the minimum constant net revenue required each year of the economic life of the project to meet the expenses for energy (electric power and process heat) of the industrial plant including fuel, electricity and operating costs, the cost of money, and the recovery of the initial investment. A levelized annual energy cost savings ratio (LAECSR) was used in the study and is defined

$$\mathrm{LAECSR} = \frac{(\mathrm{LAEC})_{\mathrm{noncogen}} - (\mathrm{LAEC})_{\mathrm{cogen}}}{(\mathrm{LAEC})_{\mathrm{noncogen}}}$$

Items considered in the annual energy cost include fixed capital charges (including cost of debt and return on equity), fuel costs, operating and maintenance costs, the costs for purchased electricity (if required), and credits for the sale of electricity (if excess is generated by the system). This is an investment analysis approach commonly used by electric utilities; however, the methodology is also applicable to industrial firms.

4.3.4 Return on Investment

Return on investment (ROI) is defined as the rate that equates the present value of all future cash flows with the initial capital investment. The ROI's calculated were based on the incremental investment required for a cogeneration system relative to the noncogeneration case. Cash flows were also incremental values relative to noncogeneration. The ROI's were calculated on an inflation-free, after-tax basis and as such represent a conservative estimate of the economic attractiveness of the cogeneration systems. ROI is frequently used by industry as one of the prime measures of the economic merit of a proposed venture.

4.4 NASA Evaluation Approach

4.4.1 Plant-Basis Evaluation

The Lewis project team felt that all the output parameters used in CTAS should be considered in identifying the most attractive advanced energy conversion systems. Further it decided to avoid the use of fixed, explicit weighting factors for the various parameters, which would have allowed a mathematical selection of the best alternative. Such a set of weighting factors would depend on site- and industry-specific considerations; on societal, political, and judgmental considerations that are difficult to quantify; and on considerations in system design or optimization that were beyond the scope and purpose of CTAS. Instead, a detailed screening method, which was less formal mathematically but did consider all the output parameters, was used to select a relatively small group of the most attractive conversion systems from the CTAS results.

For the plant-basis results, the detailed screening method used by Lewis consisted of examining all the cogeneration results in terms of one output parameter at a time to identify a group of energy conversion systems that yielded the higher values of that parameter. This detailed screening was done for nine representative industries included by both contractors in their studies. The processes used for this purpose are identified in figure 10. The axes of figure 10 are identical to those of figure 6. The solid lines in figure 10 represent an envelope around the total set of processes selected by the contractors and plotted in figure 6. Each set of two symbols connected by a dashed line represents the characteristic of the same SIC four-digit industrial plant as used by the two contractors. Although in the cases plotted in figure 10 the contractors studied the same generic process, each had projected data on a different specific plant. It is not unusual that variations in characteristics of the magnitude shown occur between two plants selected from the same four-digit industry group. Figure 10 shows that the nine industries selected as a subset provide a good representation of the total envelope of size and E/Q characteristics of the total set of processes considered by the two contractors. Specific details on the size, E/Q, and temperature of the process heat required are shown in table 13 for the nine representative process plants.

The parameters included in the detailed plant-basis screening were fuel energy savings ratio, emissions savings ratio, return on investment, and levelized annual energy cost savings ratio. From the original set of energy conversion systems a smaller group was arrived at by considering which systems did well in terms of all the parameters. The attractive cases identified in terms of each parameter were not restricted to a fixed number of cases nor restricted to include cases only with values above some predetermined cutoff value. The size of the list of attractive systems and the cutoff values were determined after considering such things as the number of attractive cases, the spread in the data, and the comparison of the advanced conversion systems to the state-of-the-art conversion systems. The specific approach used in the detailed screening is illustrated in appendix C.

4.4.2 National-Basis Evaluation

Although the emphasis in the study was on the development of data on a plant basis, relative comparisons of the various advanced systems in terms of potential benefits on a national scale were also viewed as important by Lewis. For this reason, included in each contractor's effort was the task of aggregating his plant-basis results to the national scale by using simple, straightforward techniques. Included in the estimates made by the contractors for each system were the potential energy savings, emissions savings, and annual cost savings. To obtain relative comparisons among the various advanced systems, each system was considered individually and applied to every process studied without competition, and then these results were extrapolated to all the processes of the manufacturing sector not specifically included in the study. The methodology for a NASA

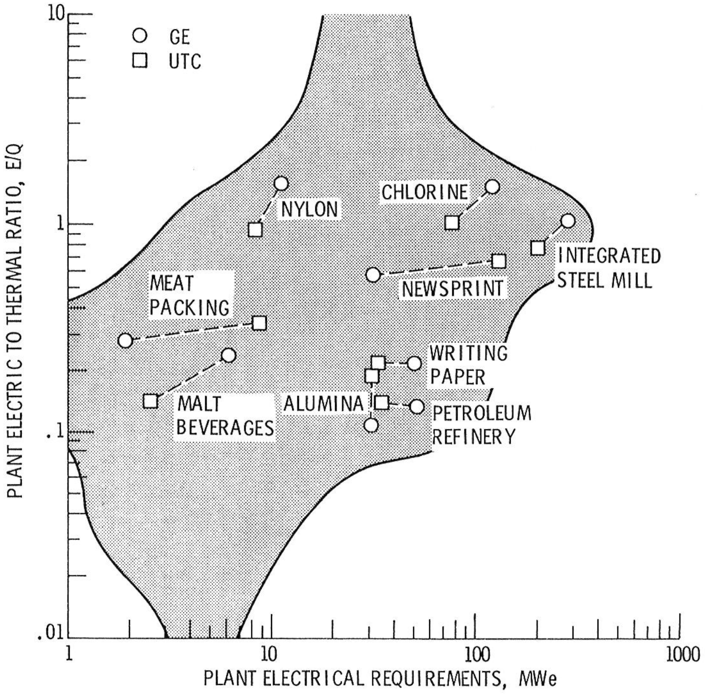


Figure 10. - Process plant electric-to-thermal energy ratio as function of plant electrical requirement for representative processes common to both contractors.

TABLE 13. - CHARACTERISTICS OF REPRESENTATIVE PROCESS PLANTS COMMON TO BOTH CONTRACTS

Process plant	Size, MWe		Power-to-heat ratio[a]		Process temperature, °F	
	GE	UTC	GE	UTC	GE	UTC
Meat packing	1.9	8.7	0.28	0.34	Hot water; 250° F steam	Hot water; 300° F steam
Malt beverages	6.0	2.6	.24	.14	Hot water; 250° F steam	300° F Steam
Nylon	11.0	8.2	1.63	.94	274° F Steam	300°, 500°, 700° F Steam
Chlorine	120.0	77.0	1.55	1.03	338° F Steam	300°, 500° F Steam
Alumina	30.3	31.0	.11	.19	495° F Steam	500° F Steam
Writing paper	50.0	33.0	.22	.22	366° F Steam	Hot water; 300°, 500° F steam
Newsprint mill	31.3	130.0	.58	.68	366° F Steam	Hot water; 300°, 500° F steam
Petroleum	52.0	34.6	.13	.14	470° F Steam	500° F Steam
Steel	280.0	200.0	1.05	.78	448° F Steam	500° F Steam

[a]For steam and hot water.

aggregation to a national scale that was used in evaluating and screening the advanced energy conversion systems is presented in this subsection. This was done independently of the contractors' efforts, but used the contractors' plant-basis results as the input to the analysis.

For simplicity Lewis considered only those processes specifically included in the contractors' studies without extrapolating to other processes. The Lewis analyses used ROI parametrically as a factor in assessing the relative aggregated savings for the various systems in order to include industrial economics more strongly in the analyses. This turned out to be a significantly more stringent and discriminating factor than was used in the contractors' studies. Overall, this approach yielded savings of from a factor of nearly 2 to a factor of more than 10 lower than the contractors' results in terms of the absolute magnitude of the savings estimated. These differences resulted from differences in the specific assumptions made as well as from the more limited objective and scope of the Lewis extrapolations. These calculations provide a nearly direct comparison of the contractors' cogeneration system results. Only the potential national savings calculated by Lewis are presented in this report.

The potential market assumed by Lewis for each process was estimated as indicated in figure 11. It corresponds to projected new expansions for each process in the 1985-1990 period plus projected replacement of retired units. The retirement rate was assumed to be 2 percent of installed capacity. Data for energy consumption as projected by each contractor were used to estimate the size of the potential market in each process included in his study. Results for an aggregated market that included 40 GE processes and for an aggregated market that included 26 UTC process were then developed for each type of energy conversion system studied.

The specific approach used by Lewis to compare the advanced energy conversion systems on a national basis is illustrated in appendix C.

5.0 RESULTS AND EVALUATIONS

This section compares the advanced energy conversion systems studied, presents the results of the evaluation process used by Lewis to identify the most attractive advanced systems for industrial cogeneration, and discusses the benefits of the advanced-technology systems as compared with systems employing current commercially available technology.

In Section 5.1 plant-basis results from the study are presented with emphasis on results for the systems that were found attractive by using the Lewis screening methodology. Results on a national basis are presented in Section 5.2. Section 5.3 identifies the most attractive advanced energy conversion systems based on Lewis' evaluation of both plant- and national-basis results. Also presented in Section 5.3 is an identification of potentially attractive industrial process applications found in the study. Section 5.4 illustrates some of the potential benefits of advanced-technology systems as compared with today's commercially available technology.

5.1 Plant-Basis Results

The most attractive systems found for the nine representative industrial process plants used by Lewis in their detailed screening of plant-basis results are

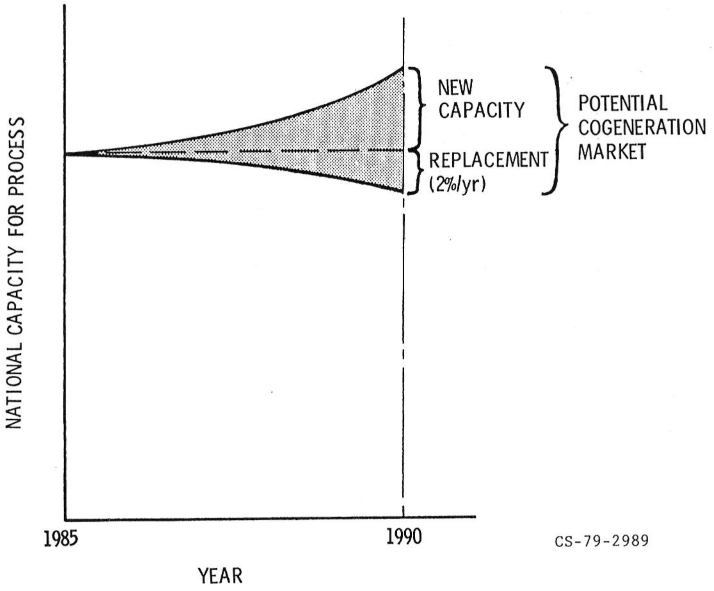


Figure 11. - Procedure used by Lewis for estimating potential fuel savings due to cogeneration in process.

X = LEWIS SELECTION BASED ON CONTRACTOR RESULTS

SYSTEM	INDUSTRY								
	PETROLEUM	ALUMINA	MALT BEVERAGES	WRITING PAPER	MEAT PACKING	NEWSPRINT MILL	STEEL	NYLON	CHLORINE
STEAM TURBINE - AFB	X	X	X	X					
STEAM TURBINE - PFB	X	X		X		X	X		
GAS TURBINE - AFB	X			X					
GAS TURBINE - PFB	X		X			X			X
GAS TURBINE - INTEGRATED GASIFIER				X					
CLOSED-CYCLE GAS TURBINE - AFB				X		X			
HIGH-TEMPERATURE FUEL CELL - INTEGRATED GASIFIER	X	X				X			X

(a) Advanced systems using coal.

SYSTEM	PETROLEUM	ALUMINA	MALT BEVERAGES	WRITING PAPER	MEAT PACKING	NEWSPRINT MILL	STEEL	NYLON	CHLORINE
GAS TURBINE - RESIDUAL	X	X	X	X	X	X	X	X	X
COMBINED CYCLE - RESIDUAL				X		X	X	X	X
HIGH-TEMPERATURE FUEL CELL - DISTILLATE				X			X	X	X

(b) Advanced systems using coal-derived liquid fuels.

Figure 12. - Applicability of selected advanced systems to representative industries.

shown in figure 12. The coal-fired systems are shown in part (a), and the systems using coal-derived liquid fuels are shown in part (b). For each industrial process, results from each contractor were screened individually and independently, and then judgment was applied in deciding whether or not to identify a system as among the most attractive for that industry. Analyses performed by Lewis to supplement or confirm the contractors' results or to reconcile differences in them were used as a guide in these decisions, particularly when there were differences in the contractors' results. In those cases where contractors' results differed enough to make one contractor's results for some system attractive enough to survive the screening process while the other contractor's results did not, the results were examined to determine the reason for the differences before it was decided whether to include that system in figure 12.

As discussed in Section 4.4 the nine industry processes in figure 12 cover a wide range of sizes, power-to-heat ratios, and steam temperature (and pressure) requirements. They are arranged in figure 12 roughly from the lowest to the highest power-to-heat ratio E/Q (with heat being in the form of steam and hot water). The figure indicates the range of industries in which each system was able to attain results attractive enough to survive the screening. Systems not listed in the figure may have achieved attractive results in some industries in terms of one or more of the output parameters but were not among the overall most attractive cases.

At least one cogeneration case survived the screening process for each of the nine industry processes considered. Also each process except meat packing and nylon had attractive cases that used both coal and coal-derived liquid fuels. In these two industry cases, the plant-site data used resulted in coal-fired cases with relatively poor economics. Both the meat packing plant and the nylon plant required relatively small amounts of electric power, and this resulted in higher power system specific cost. In addition, the meat packing plant operated for a relatively few number of hours per year. Since the annual operating cost savings relative to the capital investment are directly proportional to the hours of operation per year, the economics of cogeneration are more attractive when the hours of operation per year are high. Further the nylon process requires a ratio of power to heat that is higher than the ratio produced by most of the coal-fired energy conversion systems studied. In such a case either the power system produces only part of the power needed, or only part of the heat potentially recoverable from the power system is actually usefully recovered. In either case the fuel savings are relatively low, and hence the yearly operating cost savings are relatively low.

The ranges of output parameters for each system in figure 12 are listed in table 14. These values assume the use of a residual-grade, coal-derived liquid fuel in the on-site boiler for the noncogeneration situation. Again, the cogeneration cases using coal and coal-derived liquid fuels are listed separately. In general the ranges shown for each parameter are high since they correspond only to the most attractive cases identified in the screening process. The values given for the steam turbine - PFB system correspond only to GE's results since UTC did not study this configuration. Similarly the values given for the coal-fired, open-cycle gas turbines correspond only to the UTC results since GE did not study such cases.

For the closed-cycle gas turbines and coal-derived-distillate-fueled molten carbonate fuel cell systems, the ranges shown in table 14 correspond only to UTC results, even though both contractors analyzed these systems. The contractors' results differed enough in these systems that UTC's results survived the screening process and GE's did not. In these cases the specific system configurations,

TABLE 14. - RANGES OF RESULTS IN NINE REPRESENTATIVE INDUSTRIES

[All values relative to noncogeneration boiler burning residual-grade, coal-derived liquid fuels and coal-fired utility.]

(a) Most attractive advanced systems using coal

System	Contractor	Return on investment, percent	Fuel energy savings, percent	Levelized annual energy cost savings, percent	Emissions savings, percent
Steam turbine - AFB	GE, UTC	17 - 54	15 - 29	25 - 41	25 - 37
Steam turbine - PFB	GE	27 - 39	24 - 36	33 - 42	34 - 51
Gas turbine (coal fired):					
AFB	UTC	17 - 18	23 - 44	32 - 38	30 - 54
PFB	UTC	12 - 20	17 - 34	10 - 37	27 - 50
Gasifier	UTC	19	20	30	36
Closed-cycle gas turbine - AFB	UTC	18 - 20	27 - 38	28 - 35	38 - 48
Molten carbonate fuel cell - gasifier	GE, UTC	11 - 15	30 - 38	19 - 33	72 - 91

(b) Most attractive advanced systems using coal-derived liquid fuels

System	Contractor	Return on investment, percent	Fuel energy savings, percent	Levelized annual energy cost savings, percent	Emissions savings, percent
Advanced gas turbine - residual	GE	19 - 37	14 - 31	10 - 21	6 - 20
	UTC	19 - 50	26 - 37	8 - 34	35 - 57
Advanced combined cycle - residual	GE	17 - 28	18 - 22	12 - 21	13 - 24
	UTC	21 - 31	23 - 38	13 - 27	42 - 56
Molten carbonate fuel cell - distillate	UTC	16 - 20	34 - 41	11 - 15	72 - 79

design-point parameters, and assumptions made by UTC were more optimal for the required process conditions (power-to-heat ratio and process temperatures) of the industries studied in CTAS. In both cases the energy conversion system configuration and design-point parameters used by UTC resulted in much better heat recovery, at the expense of system electrical efficiency, than the approach used by GE.

For the closed-cycle gas turbine, UTC used a 190° or 300° F compressor inlet temperature; GE used 80° F. This considerably reduced the amount of heat rejected by cooling towers to the atmosphere in the UTC case. The resulting power-to-heat ratio was a much closer match to the requirements of the two paper industries, where the system looked most attractive, and resulted in higher fuel savings and higher annual operating cost savings. The configuration used by GE would look relatively better in situations where heat is recovered by water. In the case of the molten carbonate fuel cell system using distillate-grade, coal-derived liquid fuel, the configuration studied by UTC, which gave the attractive results indicated in figure 12, was one in which a portion of the anode exhaust was fed to the adiabatic fuel reformer. The water vapor in this gas eliminated the need for a separate steam input. The configuration studied by GE used a portion of the generated process steam for the reformer; this resulted in less steam available for process use and consequently much lower fuel and operating cost savings. Also for both systems, the UTC capital cost estimates were lower than those of GE. This together with the higher annual operating cost savings and fuel energy savings achieved by the UTC configurations resulted in the UTC cogeneration results being more attractive.

For those systems for which table 14 shows ranges of parameters based on both contractors' results, the agreement was generally good. Differences followed not only from different judgments concerning cost and performance, but also from differences in the detailed parameters studied for both the energy conversion system and the industry process data. The biggest noticeable difference was in the emissions savings ratio for gas turbines burning distillate-grade, coal-derived liquid fuel. UTC assumed the development of NO_x-limiting combustors including reduction of NO_x from fuel-bound nitrogen consistent with DOE development goals. NO_x emission values used by UTC met the emission limit set for the study. GE assumed a substantial reduction in NO_x formation as compared with what would be produced if all the fuel-bound nitrogen were converted to NO_x, but the NO_x emission values they estimated for the coal-derived fuels exceeded the emission limit set for the study.

Results in this section have thus far been given only for those systems found attractive on the basis of the Lewis screening. An important concern at this point is to convey briefly how the other advanced systems compared with those identified in figure 12. In fact, the various other advanced systems often showed attractive results in a number of process applications. However, it was found that, in general, wherever one of the other advanced systems showed attractive results one or more of those systems identified in figure 12 (and also in the table on page 3) showed superior results. This fact is illustrated in tables 15 and 16 for the GE and UTC results, respectively. In part (a) of each table the most attractive application for each of the other advanced systems is identified along with the ROI and fuel energy savings estimated by the contractor. Part (b) of each table gives the results achieved by the most attractive system in the corresponding process applications identified in part (a). Where both a coal-fueled and a coal-derived-liquid-fueled system appear in part (a), the most attractive coal-fueled and coal-derived-liquid-fueled systems are each included in part (b). In

TABLE 15. - COMPARISON OF GE RESULTS FOR MOST ATTRACTIVE APPLICATIONS OF OTHER ADVANCED SYSTEMS WITH RESULTS IN SAME INDUSTRIES FOR ADVANCED SYSTEMS SELECTED BY LEWIS SCREENING APPROACH

[All values relative to noncogeneration boiler burning residual-grade, coal-derived liquid fuels and coal-fired utility.]

(a) Results for most attractive application of other advanced systems

System	Most attractive application	Return on investment, percent	Fuel energy savings, percent
Diesel (residual-grade, coal-derived liquid fuels)	Chlorine	14.7	21.7
Stirling engine (coal with flue gas desulfurization)	Petroleum refining	18.7	11.5
Closed-cycle gas turbine - AFB (coal fired)	Integrated chemical	15.0	11.0
Thermionics - steam (coal with flue gas desulfurization)	Petroleum refining	15.3	16.7
Phosphoric acid fuel cells (distillate-grade, coal-derived liquid fuels)	Malt beverages	(a)	20.0
Molten carbonate fuel cells (distillate-grade, coal-derived liquid fuels)	Chlorine	(a)	35.0

(b) Results in same industries for advanced systems selected by Lewis screening approach

Industry	System	Return on investment, percent	Fuel energy savings, percent
Chlorine	Combined cycle (residual-grade, coal-derived liquid fuels)	31.2	29.5
Petroleum refining	Steam turbine - AFB	50+	18.9
Integrated chemical	Steam turbine - PFB	41.0	27.4
Malt products	Advanced gas turbine (residual-grade, coal-derived liquid fuels)	12.0	31.0

TABLE 16. - COMPARISON OF UTC RESULTS FOR MOST ATTRACTIVE APPLICATIONS OF OTHER ADVANCED SYSTEMS WITH RESULTS IN SAME INDUSTRIES FOR ADVANCED SYSTEMS SELECTED BY LEWIS SCREENING APPROACH

[All values relative to noncogeneration boiler burning residual-grade, coal-derived liquid fuels and coal-fired utility.]

(a) Results for most attractive application of other advanced systems

System	Most attractive application	Return on investment, percent	Fuel energy savings, percent
Low-speed diesel (residual-grade, coal-derived liquid fuels)	Corrugated paper	10.5	20.4
High-speed diesel (distillate-grade, coal-derived liquid fuels)	Chlorine	11.5	47.6
Stirling engine (residual-grade, coal-derived liquid fuels)	Boxboard mill	11.0	22.0
Stirling engine 0 AFB (coal)	Corrugated paper	24.3	16.6
Thermionics (residual-grade, coal-derived liquid fuels)	Corrugated paper	9.9	24.3
Phosphoric acid fuel cell (distillate-grade, coal-derived liquid fuels)	Boxboard mill	14.0	31.0

(b) Results in same industries for advanced systems selected by Lewis screening approach

Industry	System	Return on investment, percent	Fuel energy savings, percent
Corrugated paper	Advanced gas turbine (residual-grade, coal-derived liquid fuels)	30.3	37.3
Corrugated paper	Steam turbine - AFB	37.0	43.0
Chlorine	Advanced gas turbine (residual-grade, coal-derived liquid fuels)	41.4	35.4
Boxboard mill	Advanced gas turbine (residual-grade, coal-derived liquid fuels)	34.8	37.2

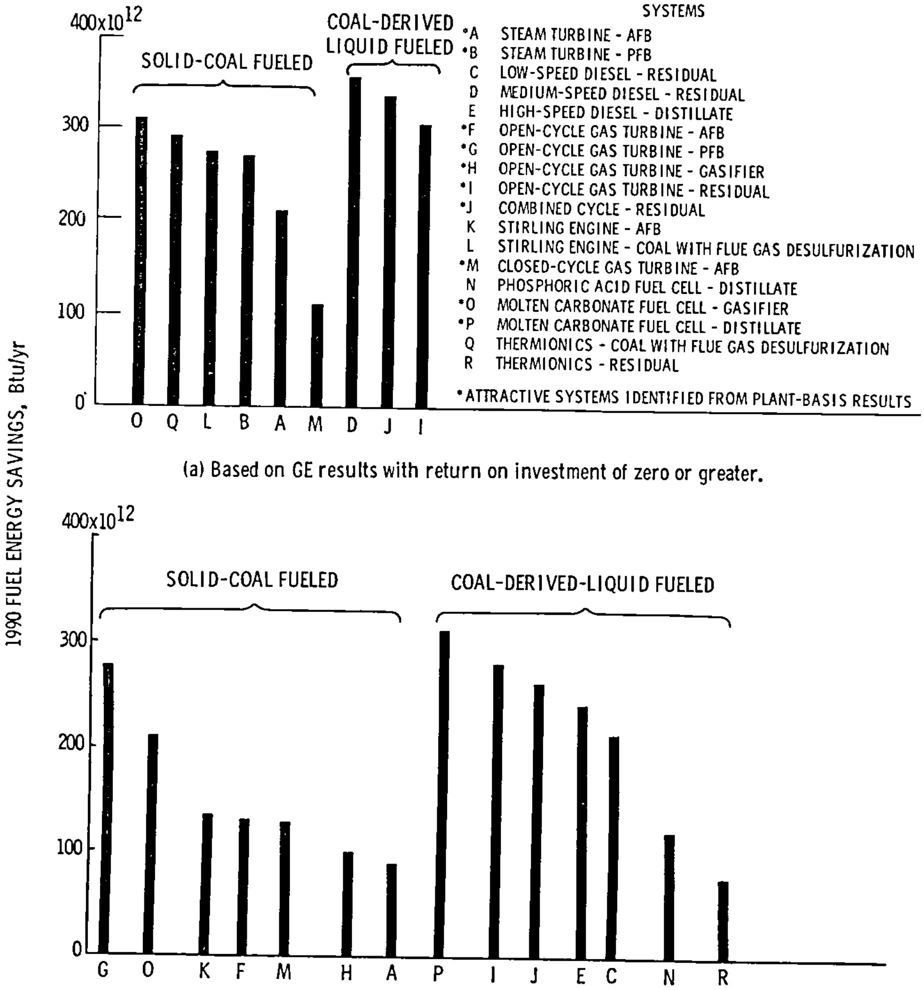
almost all cases both the ROI and fuel energy savings were higher for the advanced systems shown in figure 12.

The sensitivity of results to changes in ground rules and assumptions was examined by each contractor and by Lewis. The variables examined included fuel prices, the price of purchased electricity, the price received for exported electricity, capital costs, investment tax credit, tax life, inflation rate, and the escalation rate of fuel and electricity prices relative to the general inflation rate. Of prime consideration was whether changes in the ground rules and assumptions would affect the relative comparisons of the advanced energy conversion systems.

Changes in such parameters as investment tax credit, tax life, and inflation rate and across-the-board changes in fuel and electricity prices changed the absolute values of the results but did not significantly alter the comparisons of the advanced systems. Changes in the relative price of the different fuels or changes in the relationship between the prices of exported and purchased electricity had a more significant effect on the comparison of systems, particularly the comparison of coal-fueled and coal-derived-liquid-fueled systems. In addition to having a more pronounced effect on the relative results for the various advanced systems, future fuel and electricity prices have a great uncertainty associated with their values. This is one reason why the results presented in this report have been placed into two groups according to whether the system uses coal or coal-derived liquid fuels. Within these two groups relative comparisons of the various systems were not significantly altered over wide changes in value for fuel and electricity prices. Appendix D illustrates the sensitivity of results to changes in fuel and electricity prices.

5.2 National-Basis Results

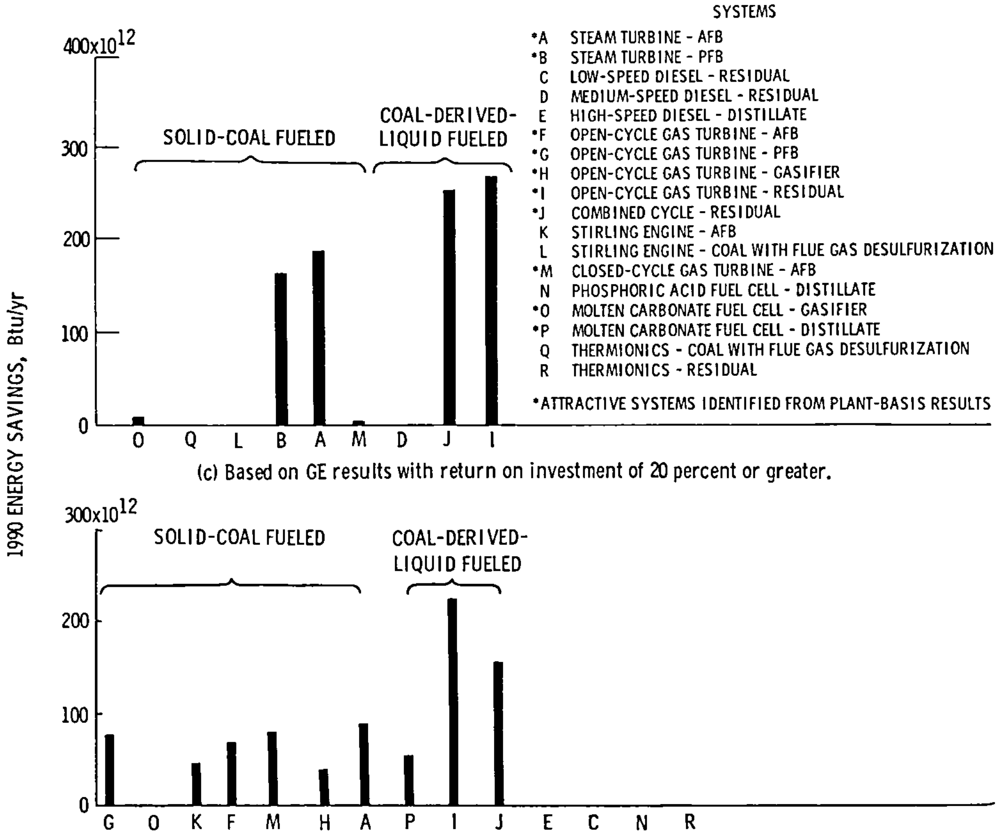
Figure 13 shows relative energy savings for the advanced systems under the constraint of no export of electricity to the utility, using the approach described in Section 4.4. (In examining these results keep in mind that the relative comparison of advanced systems was the prime consideration in formulating the approach used to estimate the values shown. The absolute magnitude of the results could be significantly lower or higher depending on the scenario used for the potential market and the criteria assumed for the systems to penetrate that market.) In figure 13 the cogeneration system results have been grouped according to fuel type (i.e., solid coal and coal-derived liquids) and arranged in descending order of fuel energy savings for ROI greater than zero. Parts (a) and (b) show results for an ROI hurdle of zero; parts (c) and (d) show results for an ROI hurdle of 20 percent (appendix C). For an ROI of zero or greater many energy conversion systems showed relatively high energy savings. The results based on both contractors' data showed high savings for the molten carbonate fuel cell systems, the liquid-fueled advanced gas turbine and combined-cycle systems, and the advanced diesel systems. Although included in the GE study no results are shown for the phosphoric acid fuel cell or molten carbonate fuel cell using coal-derived liquid fuels since no cases resulted in an ROI of zero or greater. As shown in parts (c) and (d), the potential savings with the molten carbonate fuel cell and diesel systems went to zero or near zero if an ROI of 20 percent or greater was required. In fact, the potential energy savings for many systems disappeared, and in general the magnitude of the savings for all systems decreased significantly when it was assumed that the ROI must be greater than 20 percent before cogeneration is used with a system. As indicated in figure 13 the systems showing the greatest relative



(a) Based on GE results with return on investment of zero or greater.

(b) Based on UTC results with return on investment of zero or greater.

Figure 13. - Potential national energy savings for advanced systems if no export of electricity is allowed. (All values relative to noncogeneration boiler burning residual-grade, coal-derived liquid fuels and coal-fired utility.)



(c) Based on GE results with return on investment of 20 percent or greater.

(d) Based on UTC results with return on investment of 20 percent or greater.

Figure 13. - Concluded.

savings in parts (c) and (d) were predominantly the systems identified as attractive in the Lewis plant-basis screening.

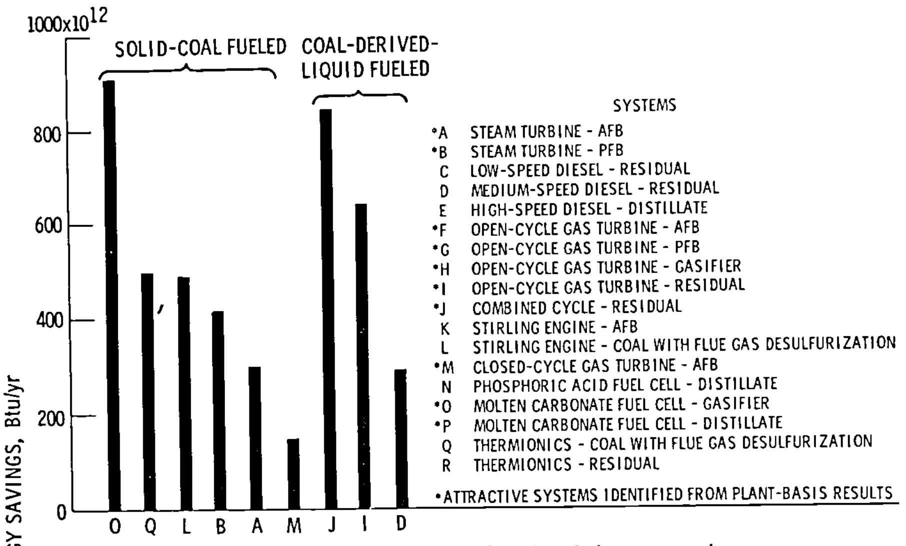
Figure 14 shows the same type of national-basis results but allows the consideration of export of electricity. In parts (a) and (b), where it was required only that the ROI be zero or greater, energy savings typically were from 1.5 to 2.5 times as great as those shown in figure 13. For the GE molten carbonate fuel cell system and the UTC gas turbine with integrated gasifier, the relative energy savings increased by factors of approximately 3 and 4, respectively. For the gas turbine with integrated gasifier the increase was due mainly to savings in the petroleum industry. As shown in parts (c) and (d), where it was required that the ROI be greater than 20 percent before it was assumed that a system is used in cogeneration, the reduction in magnitude of estimated energy savings was greater than it was in figure 13 for the no-export case. This was largely due to the assumed ground rule that the selling price of electricity exported to the utility would be 60 percent of the price paid by the industry for purchased power. A higher value would substantially increase the economic attractiveness of the systems in the export situation.

In many situations where export was allowed, the on-site power system produced 2 to 4 times as much power as needed on site. In a number of cases the on-site power system produced 5 to 10 times as much power as needed on site. These situations might logically be considered as candidates for utility ownership both from economic and practical considerations.

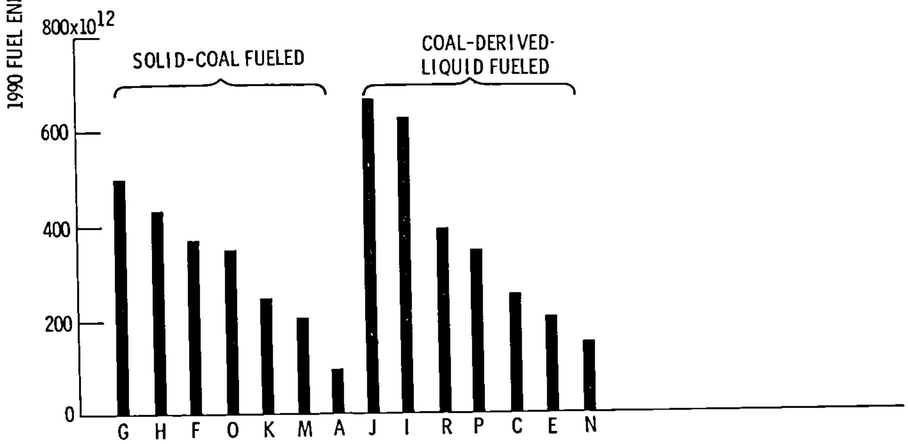
5.3 Identification of Most Attractive Advanced Energy Conversion Systems and Potential Applications

From the contractors' results and independent in-house analyses an evaluation was made by Lewis to identify the most attractive advanced systems for industrial cogeneration using coal or coal-derived fuels. As discussed and summarized in Sections 5.1 and 5.2 the results were screened, analyzed, and evaluated both on an individual plant basis and on a national basis. Factors included in the evaluations were fuel energy savings, annual energy cost savings, emissions reductions, incremental capital costs, rate of return on incremental investment, applicability to a wide variety of industrial process requirements, and potential relative national impact. The attractive advanced energy conversion system and fuel combinations identified by Lewis are shown in the table on page 3. The most attractive advanced energy conversion systems with the greatest potential for widespread implementation in industrial cogeneration were found to be the coal-fueled steam turbine systems using AFB or PFB furnaces and the open-cycle gas turbine and combined-cycle systems burning residual-grade, coal-derived liquid fuel. Additional attractive systems included several gas turbine and fuel cell systems concepts. These were open- and closed-cycle gas turbine systems with a high-temperature coal-fueled AFB heater, an open-cycle concept employing a high-temperature, coal-fueled PFB heater, open-cycle gas turbines (or combined cycles) burning with low- or intermediate-Btu gas from a coal gasifier integrated with the gas turbine system, and molten carbonate fuel cell systems using low-Btu gas from an integrated gasifier or a distillate-grade, coal-derived liquid fuel.

Tables 17 and 18 present ranges of results for the combinations of advanced energy conversion systems and fuels identified as attractive by Lewis. Results are given for each of the five major industry groups appropriate for topping

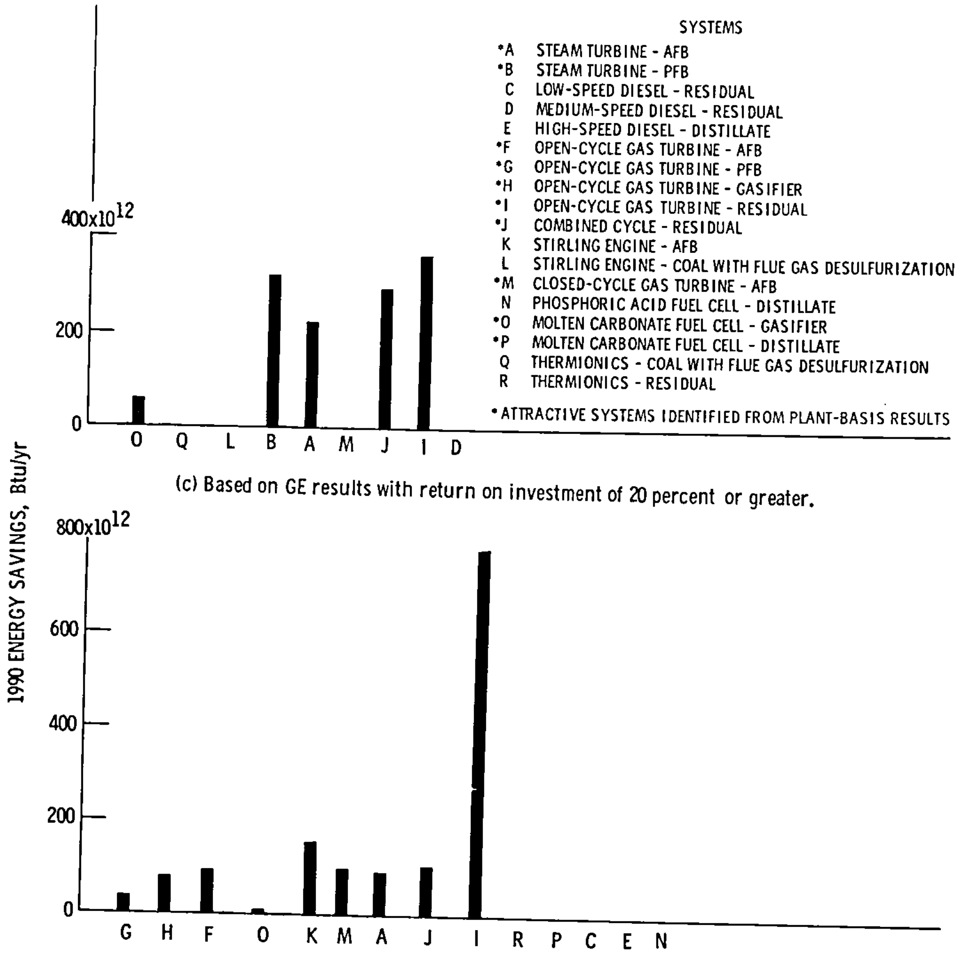


(a) Based on GE results with return on investment of zero or greater.



(b) Based on UTC results with return on investment of zero or greater.

Figure 14. - Potential national energy savings for advanced systems if export of electricity is allowed. (All values relative to noncogeneration boiler burning residual-grade, coal-derived liquid fuels and coal-fired utility.)



(c) Based on GE results with return on investment of 20 percent or greater.

(d) Based on UTC results with return on investment of 20 percent or greater.

Figure 14. - Concluded.

TABLE 17. - RANGES OF RESULTS FOR ATTRACTIVE PROCESSES - NO EXPORT OF ELECTRICITY ALLOWED

[All values relative to noncogeneration boiler burning residual-grade, coal-derived liquid fuels and coal-fired utility. Heavy box includes cases with ROI ≥20 percent and fuel energy savings ≥10 percent.]

(a) Advanced systems using coal

System	Contractor	Industry									
		Foods		Paper		Chemicals		Petroleum		Metals	
		Return on investment, percent	Fuel energy savings, percent	Return on investment, percent	Fuel energy savings, percent	Return on investment, percent	Fuel energy savings, percent	Return on investment, percent	Fuel energy savings, percent	Return on investment, percent	Fuel energy savings, percent
Steam turbine - AFB	GE	10 - 29	18 - 24	26 - 50+	12 - 29	39 - 50+	13 - 16	33 - 50+	16 - 17	40	6
	UTC	9	10	20 - 40	22 - 46	50+	8	-------	------	------	------
Steam turbine - PFB	GE	20	17	19 - 22	20 - 30	25 - 42	13 - 26	19 - 41	15 - 17	24	11
Gas turbine - AFB	UTC	9	13	18 - 20	35 - 44	-------	------	42	6	------	------
Gas turbine - PFB	UTC	6 - 11	13 - 21	17 - 24	21 - 32	13	15	50+	5	12	20
Gas turbine - integrated gasifier	UTC	7 - 8	13 - 20	19 - 22	20 - 33	-------	------	-------	------	------	------
Closed-cycle gas turbine - AFB	GE	------	------	-------	------	-------	------	-------	------	------	------
	UTC	8 - 9	10 - 25	17 - 26	22 - 38	50+	9	50+	3	------	------
Molten carbonate fuel cell - gasifier	GE	12	16	9 - 11	21 - 34	15 - 16	12 - 30	15	20	12	21
	UTC	5	10 - 26	11 - 15	23 - 38	-------	------	-------	------	------	------

(b) Advanced systems using coal-derived liquid fuels

System	Contractor	Foods ROI	Foods FES	Paper ROI	Paper FES	Chemicals ROI	Chemicals FES	Petroleum ROI	Petroleum FES	Metals ROI	Metals FES
Gas turbine - residual	GE	20 - 22	10 - 15	17 - 35	19 - 32	20 - 37	11 - 32	17 - 38	13 - 14	21 - 29	13 - 28
	UTC	18 - 22	11 - 17	32 - 50+	24 - 30	22 - 41	10 - 38	14	7	25 - 44	5 - 30
Combined cycle - residual	GE	6 - 18	14 - 19	20 - 28	18 - 30	17 - 31	10 - 30	14 - 29	12 - 13	18 - 25	17 - 35
	UTC	6	21	21 - 28	20 - 34	13 - 31	29 - 39	-------	------	12 - 27	5 - 29
Molten carbonate fuel cell - distillate	GE	------	------	-------	------	-------	------	-------	------	------	------
	UTC	9	31	20	26 - 34	12 - 15	37 - 41	13	7	13 - 19	6 - 25

TABLE 18. - RANGES OF RESULTS FOR ATTRACTIVE PROCESSES - EXPORT OF ELECTRICITY ALLOWED

[All values relative to noncogeneration boiler burning residual-grade, coal-derived liquid fuels and coal-fired utility. Heavy box includes cases with ROI ≥20 percent and fuel energy savings ≥10 percent.]

(a) Advanced systems using coal

System	Contractor	Industry									
		Foods		Paper		Chemicals		Petroleum		Metals	
		Return on invest-ment, percent	Fuel energy savings, percent	Return on invest-ment, percent	Fuel energy savings, percent	Return on invest-ment, percent	Fuel energy savings, percent	Return on invest-ment, percent	Fuel energy savings, percent	Return on invest-ment, percent	Fuel energy savings, percent
Steam turbine - AFB	GE	12 - 38	28 - 32	33 - 50+	20 - 30	24 - 50+	15 - 32	19	23	40	6
	UTC	7	12	14 - 25	22 - 46	27 - 50	7 - 8	------	------	------	------
Steam turbine - PFB	GE	9 - 23	33	18 - 27	20 - 36	15 - 42	24 - 38	10	29	24	11
Gas turbine - AFB	UTC	------	------	17 - 20	19 - 44	9 - 20	6 - 13	17	23	21	20
Gas turbine - PFB	UTC	5	23 - 26	17 - 18	28 - 34	7 - 46	4 - 23	18	30	12 - 22	8 - 21
Gas turbine - integrated gasifier	UTC	7 - 9	21 - 23	21 - 22	22 - 33	9 - 23	6 - 21	16	27	15	21
Closed-cycle gas turbine - AFB	GE	------	------	-------	------	-------	------	------	------	------	------
	UTC	7	28	19 - 25	27 - 38	18 - 49	3 - 16	45	4	------	------
Molten carbonate fuel cell - gasifier	GE	8	42	8 - 9	33 - 40	15	30 - 38	2	40	7 - 12	21 - 39
	UTC	------	------	10 - 13	27 - 38	13	25	------	------	7	23

(b) Advanced systems using coal-derived liquid fuels

System	Contractor	Foods ROI	Foods FES	Paper ROI	Paper FES	Chemicals ROI	Chemicals FES	Petroleum ROI	Petroleum FES	Metals ROI	Metals FES
Gas turbine - residual	GE	11 - 16	34	15 - 27	33	10 - 37	21 - 34	17 - 22	33	20 - 29	13 - 28
	UTC	13	37	31 - 36	27 - 37	33 - 37	32 - 37	23	32	25 - 29	21 - 38
Combined cycle - residual	GE	------	------	12 - 17	36 - 37	10 - 31	23 - 37	10 - 13	35 - 36	17 - 25	18 - 36
	UTC	------	------	8 - 27	35	10 - 31	18 - 39	13	27	10	31
Molten carbonate fuel cell - distillate	GE	------	------	-------	------	-------	------	------	------	------	------
	UTC	------	------	9 - 10	33 - 43	12 - 41	37 - 41	------	------	------	------

cogeneration applications that were emphasized for selection of representative process plants. Table 17 shows results without export of electricity to the utility grid; table 18 allows consideration of the export of electricity. In both tables the system configuration and cogeneration strategy were selected to maximize fuel energy savings. The ranges given are not for all the industrial processes included in the study but rather summarize results for the attractive applications found in each of the five major industry groups. Applications were selected as attractive primarily on the basis of reasonably good combinations of fuel energy savings and ROI. These parameters, it was felt, would be strong indicators of overall attractiveness when considering other parameters as well. Although only ROI and energy savings are summarized in these tables, insight into results for the other parameters can be inferred from the material presented in appendix B. In tables 17 and 18 systems having applications with fuel energy savings greater than 10 percent and ROI greater than 20 percent have been identified to indicate where the greatest potential for the systems exists. Comparing these tables shows that the ranges for fuel energy savings generally increase when export of electricity is allowed, while the ranges of ROI generally go down.

In a number of cases differences between results from the two contracted efforts are evident. These differences resulted from differences in the configurations studied by the contractors as well as from differences in the advancements in technology assumed, in the estimates for electrical efficiency, recoverable heat, and capital cost of the equipment, and in analytical procedures. Differences such as those shown were anticipated, and detailed examination of the results has provided added insight into the merits of the various systems. The differences and their impact on the results are discussed in the detailed NASA report.

Tables 19 to 23 show potentially attractive industrial applications for the attractive advanced systems identified in the table on page 3. Each table shows where attractive results were obtained for processes included in the study in one of five major industry groups appropriate for topping-cycle cogeneration. The selection of the system configuration and cogeneration strategy used in preparing these figures was aimed at maximizing fuel energy savings and actually formed the basis for preparation of tables 17 and 18. Applications with ROI greater than 20 percent and fuel energy savings greater than 10 percent are identified. An ROI greater than 20 percent was selected to indicate those cases with the greatest relative potential for industrial interest on economic grounds. It is not intended to imply that an ROI greater than 20 percent is required for implementation by industry or that all cases with ROI greater than 20 percent would be attractive to a potential industrial owner.

In tables 19 to 23 differences in attractive applications among systems are evident. This is due to differences in the characteristics of the various systems, which affect how well they can satisfy the different process requirements. As discussed in Section 3.2, Industrial Process Plant Requirements, there is a great diversity of requirements in industry. Those systems that can satisfy a broad spectrum of requirements will have an advantage in the degree of implementation that can be achieved. From consideration of tables 17 to 23 the systems having the widest applicability are the advanced steam systems using AFB or PFB furnaces and the advanced open-cycle gas turbine and combined-cycle systems burning residual-grade, coal-derived liquid fuels.

TABLE 19. - SYSTEM APPLICABILITY - FOOD INDUSTRY

[X indicates attractive results; dashes indicate that system was studied but not found attractive.]

(a) Advanced systems using coal

System	Contractor	Attractive application if no export of electricity is allowed				Attractive application if export of electricity is allowed			
		Malt beverage	Meat packing	Wet corn milling	Others	Malt beverage	Meat packing	Wet corn milling	Others
Steam turbine - AFB	GE	X	---	X[a]	---	X	---	X[a]	X
	UTC	X	---	(b)	---	X	---	(b)	---
Steam turbine - PFB	GE	---	---	X[a]	---	X	---	X[a]	---
Gas turbine - AFB	UTC	X	---	(b)	---	---	---	(b)	---
Gas turbine - PFB	UTC	X	X	(b)	---	X	X	(b)	---
Gas turbine - integrated gasifier	UTC	X	X	(b)	---	X	X	(b)	---
Closed-cycle gas turbine - AFB	GE	---	---	---	---	---	---	---	---
	UTC	X	X	(b)	---	---	X	(b)	---
Molten carbonate fuel cell - integrated gasifier	GE	---	---	X	---	---	---	X	---
	UTC	X	X	(b)	---	---	---	(b)	---

(b) Advanced systems using coal-derived liquid fuels

System	Contractor	Malt beverage	Meat packing	Wet corn milling	Others	Malt beverage	Meat packing	Wet corn milling	Others
Gas turbine - residual	GE	X[a]	---	X[a]	---	X	---	X	---
	UTC	X[a]	X	(b)	---	X	X	(b)	---
Combined cycle- residual	GE	---	X	X	---	---	---	---	---
	UTC	---	X	(b)	---	---	---	(b)	---
Molten carbonate fuel cell - distillate	GE	---	---	---	---	---	---	---	---
	UTC	---	X	(b)	---	---	---	(b)	---

[a]Results with ROI ≥20 percent and fuel energy savings ≥10 percent relative to noncogeneration boiler burning residual-grade, coal-derived liquid fuels and coal-fired utility.
[b]Not studied.

TABLE 20. - SYSTEM APPLICABILITY - PAPER INDUSTRY

[X indicates attractive results; dashes indicate that system was studied but not found attractive.]

(a) Advanced systems using coal

System	Contractor	Attractive application if no export of electricity is allowed					Attractive application if export of electricity is allowed				
		Writing paper	Corru-gated paper	Box-board	News-print	Others	Writing paper	Corru-gated paper	Box-board	News-print	Others
Steam turbine - AFB	GE	X[a]	X[a]	X[a]	X[a]	X[a]	X[a]	X[a]	X[a]	----	X[a]
	UTC	X[a]	X[a]	X[a]	----	----	X	X[a]	X[a]	----	----
Steam turbine - PFB	GE	X[a]	X	X	X	----	X[a]	X[a]	X[a]	X	----
Gas turbine - AFB	UTC	X	X	X[a]	----	----	X	X	X[a]	X	----
Gas turbine - PFB	UTC	X	X[a]	X[a]	X	----	X	X	X	X	----
Gas turbine - integrated gasifier	UTC	X	X[a]	X[a]	----	----	X[a]	X[a]	X[a]	X[a]	----
Closed-cycle gas turbine - AFB	GE	----	----	----	----	----	----	----	----	----	----
	UTC	X	X[a]	X[a]	X	----	X	X[a]	X[a]	X[a]	----
Molten carbonate fuel cell - integrated gasifier	GE	----	X	----	X	----	X	X	----	X	X
	UTC	X	X	X	X	----	X	X	X	X	----

(b) Advanced systems using coal-derived liquid fuels

System	Contractor	Writing paper	Corru-gated paper	Box-board	News-print	Others	Writing paper	Corru-gated paper	Box-board	News-print	Others
Gas turbine - residual	GE	X[a]	X[a]	X[a]	X[a]	X	X[a]	X[a]	X[a]	X[a]	X
	UTC	X[a]	X[a]	X[a]	X[a]	----	X[a]	X[a]	X[a]	X[a]	----
Combined cycle - residual	GE	X[a]	X[a]	X[a]	X[a]	----	X	X	X	X	----
	UTC	X[a]	X[a]	X[a]	X[a]	----	X	----	----	X[a]	----
Molten carbonate fuel cell - distillate	GE	----	----	----	----	----	----	----	----	----	----
	UTC	X[a]	X[a]	X[a]	----	----	X	----	X	X	----

[a]Results with ROI ≥20 percent and fuel energy savings ≥10 percent relative to noncogeneration boiler burning residual-grade, coal-derived liquid fuels and coal-fired utility.

TABLE 21. - SYSTEM APPLICABILITY - CHEMICAL INDUSTRY

[X indicates attractive results; dashes indicate that system was studied but not found attractive.]

(a) Advanced systems using coal

System	Contractor	Attractive application if no export of electricity is allowed					Attractive application if export of electricity is allowed				
		Alumina	Styrene	Ethylene	Chlorine	Others	Alumina	Styrene	Ethylene	Chlorine	Others
Steam turbine - AFB	GE	X^{a}	----	----	----	X^{a}	X^{a}	X^{a}	----	----	X^{a}
	UTC	----	----	----	----	X	----	X	X	X	----
Steam turbine - PFB	GE	X^{a}	----	----	----	X^{a}	X^{a}	X	----	----	X^{a}
Gas turbine - AFB	UTC	----	----	----	----	----	----	X^{a}	X	X^{a}	----
Gas turbine - PFB	UTC	----	----	----	X	----	----	X^{a}	X	X^{a}	X
Gas turbine - integrated gasifier	UTC	----	----	----	----	----	----	----	----	X^{a}	X
Closed-cycle gas turbine - AFB	GE	----	----	----	----	----	----	----	----	----	----
	UTC	----	----	----	----	X	----	X	X	X	----
Molten carbonate fuel cell - integrated gasifier	GE	----	----	----	X	X	X	----	----	X	----
	UTC	----	----	----	----	----	----	----	----	X	----

(b) Advanced systems using coal-derived liquid fuels

System	Contractor	Attractive application if no export of electricity is allowed					Attractive application if export of electricity is allowed				
		Alumina	Styrene butadiene	Chlorine	Nylon	Others	Alumina	Styrene butadiene	Chlorine	Nylon	Others
Gas turbine - residual	GE	X^{a}	X^{a}	X^{a}	X^{a}	X^{a}	X	X^{a}	X^{a}	X^{a}	X^{a}
	UTC	X^{a}	X^{a}	X^{a}	X^{a}	X^{a}	X	X	X^{a}	X^{a}	X^{a}
Combined cycle - residual	GE	X^{a}	----	X^{a}	X	X^{a}	X	X	X^{a}	X	X^{a}
	UTC	----	----	X^{a}	X	X	----	----	X^{a}	X	X
Molten carbonate fuel cell - distillate	GE	----	----	----	----	----	----	----	----	----	----
	UTC	----	----	X	X	X	----	----	X	X	X

[a]Results with ROI ≥20 percent and fuel energy savings ≥10 percent relative to noncogeneration boiler burning residual-grade, coal-derived liquid fuels and coal-fired utility.

TABLE 22. - SYSTEM APPLICABILITY - PETROLEUM INDUSTRY

[X indicates attractive results; dashes indicate that system was studied but not found attractive.]

(a) Advanced systems using coal

System	Contractor	Attractive application if no export of electricity is allowed	Attractive application if export of electricity is allowed
Steam turbine - AFB	GE	X[a]	X
	UTC	----	----
Steam turbine - PFB	GE	X[a]	X
Gas turbine - AFB	UTC	X	X
Gas turbine - PFB	UTC	X	X
Gas turbine - integrated gasifier	UTC	----	X
Closed-cycle gas turbine - AFB	GE	X	----
	UTC	----	X
Molten carbonate fuel cell - integrated gasifier	GE	X	X
	UTC	----	----

(b) Advanced systems using coal-derived liquid fuels

System	Contractor	Attractive application if no export of electricity is allowed	Attractive application if export of electricity is allowed
Gas turbine - residual	GE	X[a]	X[a]
	UTC	X	X[a]
Combined cycle - residual	GE	X[a]	X
	UTC	----	X
Molten carbonate fuel cell - distillate	GE	----	----
	UTC	X	----

[a]Results with ROI ≥20 percent and fuel energy savings ≥10 percent relative to noncogeneration boiler burning residual-grade, coal-derived liquid fuels and coal-fired utility.

TABLE 23. - SYSTEM APPLICABILITY - METALS INDUSTRY

[X indicates attractive results; dashes indicate that system was studied but not found attractive.]

(a) Advanced systems using coal

System	Contractor	Attractive application if no export of electricity is allowed			Attractive application if export of electricity is allowed		
		Integrated steel	Copper	Others	Integrated steel	Copper	Others
Steam turbine - AFB	GE	X	----	----	X	----	----
	UTC	----	----	----	----	----	----
Steam turbine - PFB	GE	X	----	----	X[a]	----	----
Gas turbine - AFB	UTC	----	----	----	----	----	X[a]
Gas turbine - PFB	UTC	----	X	----	----	X	X
Gas turbine - integrated gasifier	UTC	----	----	----	----	X	----
Closed-cycle gas turbine - AFB	GE	----	----	----	----	----	----
	UTC	----	----	----	----	----	----
Molten carbonate fuel cell - integrated gasifier	GE	X	----	----	X	X	X
	UTC	----	----	----	----	X	----

(b) Advanced systems using coal-derived liquid fuels

System	Contractor	Integrated steel	Copper	Others	Integrated steel	Copper	Others
Gas turbine - residual	GE	X[a]	X[a]	X[a]	X[a]	X[a]	X[a]
	UTC	X	X[a]	X[a]	----	X[a]	X[a]
Combined cycle - residual	GE	X[a]	X	X	X[a]	X	X
	UTC	X	X	X[a]	----	X	----
Molten carbonate fuel cell - distillate	GE	----	----	----	----	----	----
	UTC	X	X	----	----	----	----

[a]Results with ROI ≥20 percent and fuel energy savings ≥10 percent relative to noncogeneration boiler burning residual-grade, coal-derived liquid fuels and coal-fired utility.

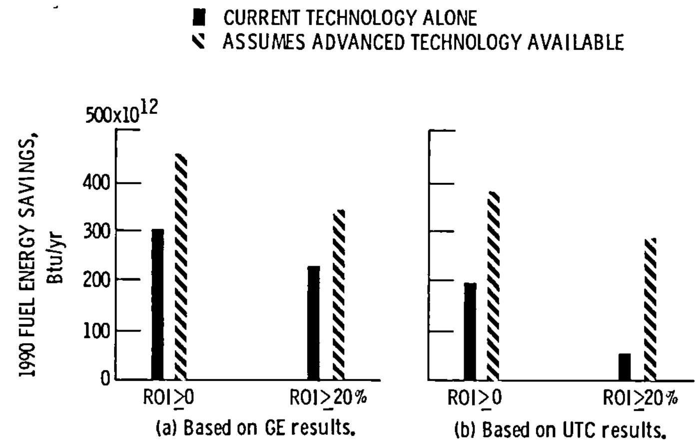
5.4 Benefits of Advanced Technology

The benefits of advanced technology in industrial cogeneration as compared with the use of equipment with current commercially available technology are discussed primarily from a national perspective although some observations on plant-basis benefits are also made. As discussed in Section 4.4, quantification of potential national benefits by Lewis was done only for the industrial processes explicitly included in the study.

Figure 15 compares national energy savings for two assumptions: that all the advanced- and current-technology cogeneration systems were available for selection, and that only current-technology systems were available. For each assumption Lewis obtained the results shown by adding together the energy savings in 1990 for each process, using the cogeneration system with the highest fuel energy savings in that process. Two constraints were imposed on the selection process; namely, that the cases selected did not export electricity from the plant site and that there were not emission increases over those for the noncogeneration situation when considering both the plant site and the utility site together. Also two different economic constraints were considered: that only cases with ROI greater than zero were included, and that only cases with ROI greater than 20 percent were included. Assuming the availability of the advanced-technology systems in addition to the current systems resulted in fuel energy savings more than 40 percent higher than with the current systems alone for the GE-based results and in fuel energy savings approximately 80 percent to nearly four times higher for the UTC-based results. If only those advanced systems identified in the table on page 3 were considered to be available, the values for fuel energy savings for advanced-technology systems in figure 15 would be reduced by only approximately 5 percent. The major difference between the contractors' results shown in figure 15 was in the economics of current-technology cogeneration systems. The GE results for the current-technology systems had many more applications with ROI greater than zero and ROI greater than 20 percent than did the UTC results primarily because of their different results for steam turbine systems.

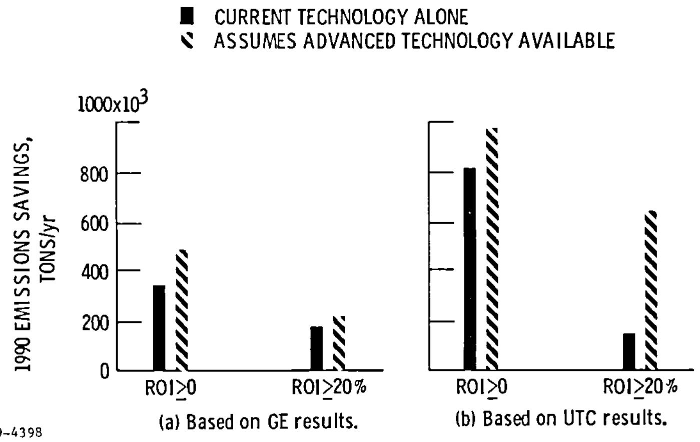
Figure 16 compares the emissions savings if advanced technology were available with the emissions savings when only current-technology cogeneration systems are used. The emissions savings are for the same cases used in the energy savings comparisons made in figure 15. The GE-based results show emissions savings increases from approximately 20 percent to more than 50 percent higher when the advanced-technology systems are assumed to be available. The UTC-based results show emissions savings from approximately 20 percent to more than four times higher with the availability of the advanced-technology systems. The differences between emissions savings based on the two contractors' results had a variety of causes. Among them were the differences in estimated ROI of the current systems, the mix of advanced systems that resulted in maximizing the energy savings for each contractor; the "market" size of the particular processes in which each system produced maximum savings; and differences in assumptions for technological advances that can reduce emissions.

Both the GE and UTC results show the potential for significant energy savings and emissions reductions when advanced-technology systems are included in the mix of available systems. Recall that figures 15 and 16 illustrate the potential from a national perspective with the constraint of no export of electricity to the utility grid. Even larger savings with advanced-technology cogeneration systems can be shown when the opportunity to export is included.



CS-79-4399

Figure 15. - Potential national fuel energy savings of current- and advanced-technology cogeneration systems. (All values relative to noncogeneration boiler burning residual-grade, coal-derived liquid fuels and coal-fired utility.)



CS-79-4398

Figure 16. - Potential national emissions savings for current- and advanced-technology cogeneration systems. (All values relative to noncogeneration boiler burning residual-grade, coal-derived liquid fuels and coal-fired utility.)

From the viewpoint of a potential industrial owner, plant-basis savings are of course more important than these national-basis savings. Many factors would be important including the system economics, the plant-site emissions, and the type of fuel required for the cogeneration system. On the basis of ROI alone the advanced-technology systems showed benefits over the current-technology systems in a majority of applications. Also, as a consequence of superior energy savings and in many cases lower capital costs, annual energy cost reductions were shown for the advanced-technology systems in many applications. Any plant-site emissions reductions resulting from the use of advanced technology as compared with current technology would be a major benefit. In fact, for a few of the advanced-technology cases plant-site emissions were even lower than those for the on-site, liquid-fueled noncogeneration boiler. These were cases where distillate-grade fuels were used with the fuel cell systems.

Finally, of concern to a potential industrial owner is the type of fuel used to provide heat and electric power for industrial plants. The industrialist is concerned about dependence on oil from the standpoint of both assured availability and cost. The ability to displace the use of oil in industrial applications, where about 20 percent of all oil consumed is used today, is of course also crucial to our nation. In this study a strong emphasis was placed on advanced-technology cogeneration systems that permit economically and environmentally acceptable use of coal, minimally processed coal-derived liquid fuels, and low- or intermediate-Btu gas made from coal. Table 24 shows the applicability of the most attractive advanced systems to the 10 highest oil-consuming industries studied by both contractors. The applications were selected from those identified as attractive in tables 19 to 23. The widespread applicability of these advanced energy conversion systems to the major oil-consuming industries is evident from table 24.

6.0 CONCLUDING REMARKS AND PERSPECTIVES ON STUDY RESULTS

The Cogeneration Technology Alternatives Study (CTAS) was a broad study aimed at identifying the most attractive advanced energy conversion systems that could significantly advance the use of coal or coal-derived fuels for industrial cogeneration applications. As such, the study was concerned exclusively with the potential technical, economic, and environmental merits of advanced-technology cogeneration systems. The study provided relative comparisons and evaluations of the advanced energy conversion system candidates studied. This was done through a government/industry team approach. The majority of the basic data was provided through contracted studies with teams of industrial concerns knowledgeable in each of the various energy conversion systems studied, balance-of-plant equipment, industrial process requirements, and other elements necessary for establishing the technical, economic, and environmental characteristics of complete cogeneration systems. In addition to the contractor results the NASA Lewis Research Center provided further analyses of the data developed by the contractors and made an independent evaluation of the advanced systems, the results of which are presented as part of this report.

Although cases for systems using technology representative of current commercially available equipment were carried through the study to serve as a baseline for assessing the benefits of technological advancements, the study did not attempt to compare these current-technology systems or to assess the benefits of the cogeneration concept itself. Further no attempt was made to propose solutions

TABLE 24. - APPLICABILITY OF ADVANCED SYSTEMS TO HIGH OIL-CONSUMING INDUSTRIES[a]

[X indicates attractive results; dashes indicate systems were studied but not found attractive.]

(a) Advanced systems using coal

Industrial process	Projected 1990 annual oil consumption,[b] Btu	System				
		Steam turbine - AFB	Steam turbine - PFB	Gas turbine[c]	Closed-cycle gas turbine	Molten carbonate fuel cell with integrated gasifier
Petroleum refineries	936×10^{12}	X	X	X	---	X
Integrated steel mills	299	X	X	X	---	X
Ethylene	251	X	---	X	X	---
Corrugated paper	97	X	X	X	X	---
Styrene	43	X	---	X	X	---
Alumina	38	X	X	---	---	---
Boxboard	28	X	X	X	X	---
Writing paper	23	X	X	X	X	X
Chlorine	21	---	---	X	---	X
Malt beverages	15	X	---	---	---	---

(b) Advanced systems using coal-derived liquid fuels

Industrial process	Projected 1990 annual oil consumption, Btu	System		
		Gas turbine - residual	Combined cycle - residual	Molten carbonate fuel cell - distillate
Petroleum refineries	936×10^{12}	X	X	---
Integrated steel mills	299	X	X	---
Ethylene	251	---	---	---
Corrugated paper	97	X	X	X
Styrene	43	---	---	---
Alumina	38	X	X	---
Boxboard	28	X	X	X
Writing paper	23	X	X	X
Chlorine	21	X	X	X
Malt beverages	15	X	---	---

[a]Noncogeneration consumption for highest oil-consuming industries included in GE and UTC studies.
[b]Taken from Gordian Associates' data prepared as part of UTC contracted study. The estimates were made before enactment of National Energy Act legislation.
[c]AFB, PFB, and integrated-gasifier systems.

to institutional or regulatory barriers currently inhibiting more widespread use of industrial cogeneration.

On the basis of Lewis' evaluation of the overall study results, attractive advanced energy conversion systems were identified and placed into two groups as indicated in the following table:

Most attractive advanced systems	
Steam turbines	Coal, atmospheric-fluidized-bed furnace (AFB) Coal, pressurized-fluidized-bed furnace (PFB)
Open-cycle gas turbines	Coal-derived liquid fuel, residual grade
Combined cycles	Coal derived liquid fuel, residual grade
Additional attractive advanced systems	
Open-cycle gas turbines	Coal, atmospheric-fluidized-bed furnace (AFB) Coal, pressurized-fluidized-bed furnace (PFB) Integrated coal gasifier
Closed-cycle gas turbines	Coal, atmospheric-fluidized-bed furnace (AFB)
Molten carbonate fuel cells	Integrated coal gasifier Coal-derived liquid fuel, distillate grade

The other advanced systems studied did have attractive cogeneration results in one or more industrial process plant applications; however, in almost all cases, at least one of the systems in the preceding table had superior results in those applications. An important result of the study was that as a class the advanced-technology energy conversion systems showed significant advantages over systems using current commercially available technology in terms of energy savings, emissions reductions, and economics.

Although the study did not provide estimates of R&D costs or assess development risks for the various systems, the identification of the research and development needed to bring the various technologies to commercial fruition was an important product of the CTAS effort. The technological advancements required to achieve the performance, economic, and environmental results calculated for those systems identified as the most attractive advanced systems studied are therefore discussed here to give perspective to the study results.

For the advanced steam systems the development and commercialization of the atmospheric- and pressurized-fluidized-bed (AFB and PFB) furnaces were the principal advancements assumed. For the PFB furnace subsystem this includes development of effective particulate removal systems with moderate costs and/or the development of approaches to turbine protection that would enable the gas turbine downstream of the PFB to operate reliably and with acceptable life in the erosive and corrosive effluent from the fluidized-bed furnace. The principal advancements for the open-cycle gas turbine and combined-cycle systems burning coal-derived liquid fuels are in the gas turbine component. These are the development of gas turbines with the capability for long-lived and environmentally acceptable operation while using the minimally processed coal-derived liquid fuels.

Advancements in materials (particularly erosion- and corrosion-resistant coatings) and combustion concepts that limit oxides-of-nitrogen formation from the high-fuel-bound-nitrogen, coal-derived liquids are required. In addition, higher turbine inlet temperatures than those characteristic of current commercially available engines were found to be of benefit. Most of the benefits can be obtained through modest increases in turbine inlet temperature. Finally, the option of steam injection was found to be beneficial in a number of industrial process applications.

For the open-cycle and closed-cycle gas turbine systems using an AFB or PFB furnace, the principal additional technological advancement over the steam systems using these advanced furnaces is a higher temperature heat exchanger with air or helium as a working fluid rather than steam. For the open-cycle gas turbine (or combined cycle) burning low- or intermediate-Btu gas produced in an integrated gasifier, the major requirement is demonstration of the complete system including integration and control. In addition, higher gas turbine inlet temperatures were found to be beneficial. As for the coal-derived-liquid-fueled turbines, modest increases in turbine inlet temperature can provide most of the benefits. For the molten carbonate fuel cell systems, development of long-lived fuel cells and related subsystems including reformers and the like was the principal technological advancement assumed. For the fuel cell system using low- or intermediate-Btu gas produced by an integrated gasifier, demonstration of the complete system including integration and control is also required.

Although a broad range of options was considered for each type of advanced system, all possible configurations of the various systems could not of course be covered in the study. The configurations studied were those felt by the various industrial team members to be most appropriate for industrial cogeneration applications for the 1985-2000 time period. Improvements in results, particularly for those advanced systems not previously studied in detail for industrial cogeneration applications, could be expected. On the other hand, estimated capital cost often increases as more detailed studies are performed and the technology proceeds toward commercial fruition, particularly for the more advanced systems. For those systems identified as attractive more detailed studies are required to more precisely evaluate their potential benefits. Finally, it is important to keep in mind that the relative comparisons and evaluations of the systems made in CTAS apply only to industrial cogeneration applications. Different relative attractiveness could very well be found for other applications such as utility (power only) applications, commercial and residential total energy applications, or institutional and governmental installation applications, where the technical and economic requirements can be significantly different from those studied here.

APPENDIX A

DESCRIPTION OF REPORTS ON THE COGENERATION TECHNOLOGY ALTERNATIVES STUDY

This NASA summary report presents the objective, scope, approach, and major results from the entire CTAS effort, including both the contractor and in-house analyses. In addition, NASA is preparing a more detailed report that compares and evaluates the study results. Each contractor is preparing a multivolume report that presents the specific scope, detailed approach, and results of their contracted study. The first volume of each set of contractor reports is a summary of the contracted study. A complete listing of planned reports for CTAS is as follows:

(1) Cogeneration Technology Alternatives Study (CTAS)
  Volume I - Summary. NASA TM-81400, 1980.
  Volume II - Comparison and Evaluation of Results.
    NASA TM-81401, to be published.

(2) Cogeneration Technology Alternatives Study (CTAS) - General Electric Company Final Report
  Volume I - Summary Report. DOE/NASA/0031-80/1, NASA CR-159765, 1980
  Volume II - Analytical Approach. DOE/NASA/031-80/2, NASA CR-159766, to be published
  Volume III - Industrial Process Characteristics. DOE/NASA/0031-80/3, NASA CR-159767, to be published
  Volume IV - Energy Conversion System Characteristics. DOE/NASA/0031-80/4, NASA CR-159768, to be published.
  Volume V - Cogeneration System Results. DOE/NASA/0031-80/5, NASA CR-159769, to be published.
  Volume VI - Computer Data. DOE/NASA/0031-80/6, NASA CR-159770, to be published

(3) Cogeneration Technology Alternatives Study (CTAS) - United Technologies Corporation Final Report
  Volume I - Summary Report. DOE/NASA/0030-80/1, NASA CR-159759, 1980.
  Volume II - Industrial Process Characteristics. DOE/NASA/0030-80/2, NASA CR-159760, to be published.
  Volume III - Energy Conversion System Characteristics. DOE/NASA/0030-80/3, NASA CR-159761, to be published.
  Volume IV - Heat Sources, Balance of Plant, and Auxiliary Systems. DOE/NASA/0030-80/4, NASA CR-159762, to be published.
  Volume V - Analytical Approach and Results. DOE/NASA/0030-80/5, NASA CR-159763, to be published.
  Volume VI - Computer Data. DOE/NASA/0030-80/6, NASA CR-159764, to be published.

The NASA and contractor summary reports will provide a sufficient level of detail for many readers. However, for other readers more detail in one or more aspects of the study may be of interest. The more detailed NASA and contractor reports address the needs of those readers.

APPENDIX B

DISCUSSION OF EVALUATION PARAMETERS

A number of parameters were used in CTAS to characterize the cogeneration system results. They are defined in Section 4.3 and were used in common by the contractors. The parameters that were emphasized in CTAS in evaluating the plant-site results are as follows:

(1) Fuel energy savings, percent
(2) Emissions savings, percent
(3) Operating savings, dollars/year
(4) Incremental capital cost, dollars
(5) Levelized annual energy cost savings, percent
(6) Return on investment, percent

Note that these parameters are a measure of the performance and economics of a complete cogeneration system and that the energy conversion system is configured for cogeneration and matched to the requirements of a particular industry process according to one of the matching strategies defined in Section 3.1. Comparing two cogeneration systems using two different energy conversion systems in terms of one of these parameters might be very different from comparing the energy conversion systems themselves in terms of such parameters as system electrical efficiency or capital cost. The cogeneration parameters in the preceding list depend very heavily on cogeneration strategy, the cost and/or performance of the supplementary boiler and heat-recovery heat exchanger, the cost and/or performance of the noncogeneration boiler, the relative costs of fuels and purchased or sold electricity, etc., in addition to the energy conversion system characteristics.

Fuel Energy Savings

Because of the recovery of waste heat from the on-site power system, there is usually a savings in total fuel use when cogeneration is employed as compared with the noncogeneration case, where all the power is generated at the utility site without waste heat recovery. Therefore it is understandable that the maximum fuel savings would be achieved when all the site process heat is obtained by waste heat recovery from the energy conversion system. However, it might not be obvious that there would be a fuel savings if the conversion system electrical efficiency had to be drastically spoiled in order to recover the amount of "waste" heat needed for the process. In the detailed NASA report (see appendix A), the relationship between the conversion system efficiency and the heat-recovery fraction, the resulting power-to-heat ratio obtained from the conversion system, the cogeneration matching strategy used, and the fuel savings obtained are examined parametrically. That parametric analysis was done at the start of the CTAS effort, not only to display these relationships but to aid in the selection of the parameters used to measure cogeneration fuel savings. For CTAS a fuel savings parameter was needed that could provide a consistent and valid comparison of the cogeneration performance of the energy conversion systems with a wide range of characteristics matched to a wide range of processes.

The parameter specified in CTAS to measure cogeneration performance is the percentage savings of fuel energy over that required to meet the site requirements without cogeneration, as defined in Section 4.3.

In the parametric analysis summarized in the detailed NASA report, the conversion system was characterized by its electrical efficiency and a heat-recovery factor AR defined as the heat actually recovered divided by the total system heat rejected; that is,

$$AR = \frac{Q_{recovered}}{Q_{rejected}} \tag{B1}$$

The heat rejected from an energy conversion system is

$$Q_{rejected} = \frac{(1 - \eta)P}{\eta}$$

where P is the electric power output. So

$$AR = \frac{Q_{recovered}}{P(1 - \eta)/\eta}$$

Or for the energy conversion system, the ratio of power produced to heat recovered is

$$\frac{P}{Q_{recovered}} = \frac{\eta}{(1 - \eta)AR} \tag{B2}$$

Various strategies were considered to match this ratio to that required by the process. The fuel energy savings achieved is very dependent on the strategy used and hence on the relationship between these two power-to-heat ratios. Often for advanced systems the ratio of power to recovered heat exceeds the ratio of power to the heat required by many processes. In such a case, an increase in system efficiency, as can be seen in the preceding equation, leads to a higher power-to-heat ratio and to the requirement for more heat from a supplementary boiler if the match-electricity strategy is used or for more excess power, which must be sold, if the match-heat strategy is used. In the former case the fuel energy savings is often reduced, and in the latter case (for the CTAS economic ground rules) the economics are often less attractive. So the higher electrical efficiencies of some of the advanced energy conversion systems will probably be of advantage mainly for higher-power-to-heat-ratio industries or if excess electricity can be exported economically.

In addition to the efficiency, the conversion system heat-recovery factor defined previously is an important characteristic in determining cogeneration performance. It can easily be determined from the form and temperature of the conversion system waste heat and from the form and temperature of the heat required by the process. Since fuel energy savings are basically the result of heat recovery, the higher the heat-recovery factor the better the cogeneration performance possible. Some types of energy conversion systems such as recuperated gas turbines, diesels, and low-temperature fuel cells that have part or all of their heat rejection at relatively low temperatures were able to achieve a high heat-recovery factor only for processes requiring hot water or low-pressure steam. Since such processes were in the minority, these systems did not achieve attractive fuel savings for many processes. Those conversion systems that achieved attractive fuel energy savings for broad ranges of industry requirements in CTAS were those that were able to achieve a high heat-recovery factor for a broad range of process steam temperatures and pressures and that could be configured in a number of ways to achieve either low or high system electrical efficiency for low or high power-to-heat ratios (eq. (B2)) to match process requirements.

Emissions Savings

Because of the fuel savings there is usually a reduction in overall emissions with cogeneration, considering both the utility and industrial sites. In addition to the amount of fuel energy saved, the emissions savings ratio obviously depends on the characteristics of the fuels used at the utility, in the on-site boilers with or without cogeneration, and in the on-site energy conversion system. Because it was assumed that the utility used coal, many of the cogeneration cases calculated in CTAS that used liquid fuels yielded impressive emissions savings ratios. Those cases that used distillate-grade fuels generally yielded the highest values. Note that the emissions savings ratio depends heavily on the assumptions concerning the type of fuel used in the noncogeneration on-site boiler.

The emissions savings ratio also is very dependent on the combustion or fuel utilization characteristics of the cogeneration energy conversion system. The fuel cell systems yielded very high emissions savings ratios. On the other hand, diesels, which were estimated to emit high levels of oxides of nitrogen, in many cases yielded negative emissions savings ratios, even though there was a positive fuel energy savings.

An important point to note is that even though there is an overall reduction in emissions, the increased fuel consumption at the industrial site with cogeneration usually results in an increase in industrial site emissions (i.e., the fuel and emissions savings occur at the utility site). This will obviously be an important factor in cogeneration implementation. In some cases, however, (e.g., distillate-grade-fueled fuel cells) there was still a reduction in on-site emissions in spite of the increased fuel use because of the low specific emissions of the fuel cell as compared with those of the residual-grade-fueled or coal-fired noncogeneration process steam boiler.

Operating Cost Savings

Operating cost is defined here as the sum of yearly expenditures for fuel, electricity, and other expendables such as water, lime, or limestone and operating labor and maintenance costs. The operating cost savings due to cogeneration are dominated by the relative cost of the fuel required for the cogeneration energy conversion system, the cost of the boiler fuel saved because of conversion system waste heat recovery, and the cost of the electricity that no longer is purchased from the utility. In addition to being sensitive to the same things to which the fuel savings are sensitive, the operating cost savings depend on the fuel and electricity prices. In general those systems that used coal achieved the highest operating cost savings in CTAS for any specific process and those that used distillate-grade fuel resulted in the lowest operating cost savings. Note that the operating cost savings depend on the contractor-specific assumption of the type of fuel used in the process steam boiler in the noncogeneration case. In some industry processes with a very low required power-to-heat ratio, when it was assumed that the noncogeneration on-site boiler used residual-grade fuel, some coal-fired conversion systems yielded positive operating cost savings even though the fuel energy savings were very low or even negative. These operating cost savings were not the result of cogeneration and heat recovery but resulted from the switch to the use of lower price coal in the cogeneration case rather than the residual fuel used in the noncogeneration case.

Because the operating cost savings depend on the relative fuel and electricity costs, they depend heavily on which cogeneration strategy is used since this affects the amount of imported or exported electricity involved. This is particularly true for export situations since one CTAS ground rule was that electricity exported to the grid would yield an income equal to 60 percent of the purchase price of a corresponding amount of power.

In comparing the yearly operating cost savings achieved in different processes, it is important to note that the level achievable depends on the site power-to-heat ratio and load factor. The higher the power-to-heat ratio, the larger the relative amount of relatively expensive electricity purchased in the noncogeneration situation. And obviously the greater the hours of operation per year, the greater the yearly savings. In CTAS those processes that indicated operation during only one shift per day, 5 days per week, generally did not yield attractive cogeneration economic results.

Incremental Capital Cost

Two of the parameters listed on page 68 (levelized annual energy cost savings and return on investment) involved combining the effects of initial capital investment and operating cost savings. In both cases the capital cost of the cogeneration system enters as the incremental cost of the cogeneration system as compared with the capital cost of the on-site boiler in the noncogeneration case. A comparison of two different energy conversion systems configured for cogeneration for a particular process in terms of cogeneration incremental capital cost might yield a much different impression than would a comparison of the corresponding conversion system specific costs. The cogeneration cost depends not only on the specific costs of the conversion system and boiler, but on their relative sizes, which in turn are determined by the cogeneration matching or sizing strategy used. (The cogeneration cost also includes heat-recovery heat exchangers.) Since it depends on the matching strategy, the cogeneration cost therefore strongly depends on the relationship between the power-to-recovered-heat ratio of the conversion system and the power-to-heat ratio required by the process. It also depends on the site power-to-heat ratio since this determines the relative size of the noncogeneration on-site boiler. And of course it depends on the type of fuel assumed for the noncogeneration boiler since this affects the boiler specific cost.

Levelized Annual Energy Cost Savings

In most cases the levelized annual energy cost was dominated by operating costs, with fixed capital charges amounting to less than 20 percent of the total levelized annual energy cost. The levelized annual energy cost savings therefore are generally sensitive to the same factors as are the operating cost savings. In comparing alternative energy conversion systems, however, capital cost is still an important factor. For example, for a particular process, a steam system with a pulverized-coal-fired boiler and flue gas desulfurization yields about the same operating cost savings as a steam system with an AFB boiler but has higher capital cost. It would therefore have lower levelized annual energy cost savings. Or in many cases a coal-fired thermionic/steam system yielded about the same operating cost savings as a coal-fired steam system. But the addition of the high-temperature thermionic converters raised the capital cost and hence lowered levelized annual energy cost savings.

Because it includes the effects of capital costs, the levelized annual energy cost sometimes yields a different comparison of cogeneration strategies than does the operating cost savings. The most obvious examples are where cases involving sizing the conversion system to match site power are compared with cases involving sizing the conversion system to match required site heat and to export excess power. Even with the CTAS ground rule that exported power is sold for 60 percent of the purchase price, the export case often still yields higher operating cost savings. However, since the incremental capital cost is higher when the energy conversion system is sized larger to make excess power, the levelized annual energy cost savings may decrease even though the operating cost savings are increased.

Return on Investment

The return on investment is much more sensitive to incremental capital cost than is the levelized annual energy cost savings ratio. In fact, a comparison of alternative cogeneration cases on the basis of ROI often yields much different results than a comparison on the basis of levelized annual energy cost savings. The levelized annual energy cost savings are proportional to the sum of the levelized incremental capital cost and the levelized annual operating cost savings. The return on investment is roughly proportional to the operating cost savings divided by the incremental capital cost (or the inverse of the payback period).

An example of a type of plot used by Lewis in comparing and screening the cogeneration results in terms of ROI is shown in figure 17. The coordinates are incremental capital cost and annual operating cost savings relative to a noncogeneration situation in which an on-site boiler using residual-grade, coal-derived liquid fuel is used to provide the required steam and the required electric power is purchased from a utility. Several cogeneration cases based on the GE results for a writing-paper plant are shown in the figure. The slope of a line from the origin to some cogeneration case (i.e., the incremental capital cost divided by the annual operating cost savings) represents a payback period. The ROI's for a large number of CTAS cases were plotted against the reciprocal of this payback period to demonstrate that all fell closely on a single line. Thus a line through the origin of figure 17 is also approximately a line of constant ROI. In fact, as shown in this figure, two of the example cases have 24 percent ROI, and both are on the same line through the origin. The shallower the slope of a line from the origin to a cogeneration case, the shorter the payback period or the higher the ROI.

A second set of axes is shown in figure 17 that corresponds to a noncogeneration situation in which a coal-fired, on-site boiler with flue gas desulfurization is used. The distance between the two horizontal axes is the difference in capital cost of the two types of boiler systems, and the distance between the two vertical axes is the yearly operating cost savings due to the lower price of coal. Note that the ROI of the coal-fired noncogeneration case relative to the residual-fuel-fired noncogeneration case is 14 percent. This is higher than for

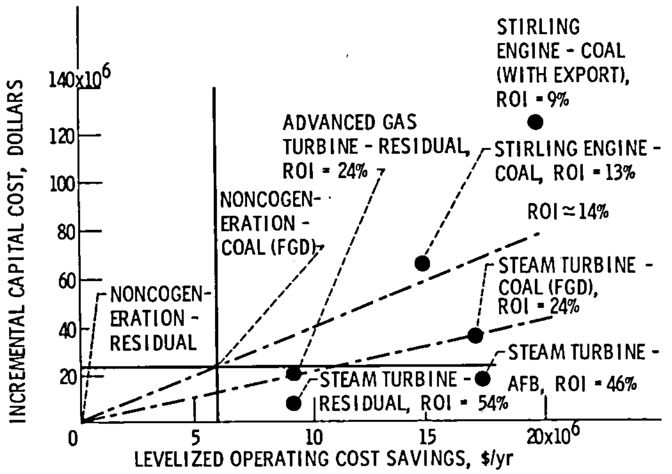


Figure 17. - Incremental capital cost as function of levelized operating cost savings and return on investment. Writing paper mill; electrical requirement, 50 MWe.

many of the cogeneration cases calculated for this process. (All cases are not shown in the figure for simplicity.)

Note that the slope of a line from the origin of one set of axes to a cogeneration case can be much different from the slope of a line from the origin of the other set of axes to the same cogeneration case. Thus the ROI is very sensitive to the type of noncogeneration boiler assumed to be used. Note also that in some cases the ROI relative to the coal-fired noncogeneration case could be higher than that relative to the residual-fuel-fired noncogeneration case; in other cases the opposite is true.

Some of the example cogeneration cases shown in figure 17 have lower capital costs than the coal-fired noncogeneration boiler with flue gas desulfurization. Since they have a relative operating cost savings and lower capital investment, these cases are obviously an attractive investment alternative. But the ROI is not calculable in such a situation. This type of plot, however, still provides a graphical comparison of such cases.

For the particular set of example cases shown in figure 17, the steam system using coal-derived, residual-grade fuel had the highest ROI relative to the residual-fired noncogeneration case. However, its levelized annual energy cost saving was 22 percent, and the highest achieved by the steam system with a coal-fired AFB was 41 percent. Also, the levelized annual energy saving of the steam system with coal-derived, residual-grade fuel (22 percent) was about the same as that for the coal-fired Stirling engine (21 percent). The former system had an ROI of 54 percent, and the latter system had an ROI of only 13 percent. Thus comparing systems on the basis of ROI could lead to different conclusions than comparing them on the basis of levelized annual energy cost savings.

Potential National Fuel Energy Savings

The most attractive energy conversion systems on a plant-site basis in terms of such parameters as fuel energy savings ratio or ROI vary from process to process. The processes considered in CTAS cover a wide range of sizes or represent a wide range of potential cogeneration markets in terms of national energy consumption. It is therefore also desirable to compare the alternative systems by taking into consideration the national energy consumption in processes where the systems appear attractive on a plant-site basis. For example, a system that achieves a moderate fuel energy savings ratio in cogeneration in several industries that consume large amounts of energy might be more desirable from the national perspective than a system that might achieve high fuel energy savings ratios in industries that consume small amounts of energy. Therefore in CTAS the energy conversion systems were also compared on the basis of potential national fuel savings by assuming that each system was implemented, one at a time, in 100 percent of the potential market in each industry process.

APPENDIX C

EXAMPLES OF THE APPLICATION OF LEWIS' EVALUATION APPROACH

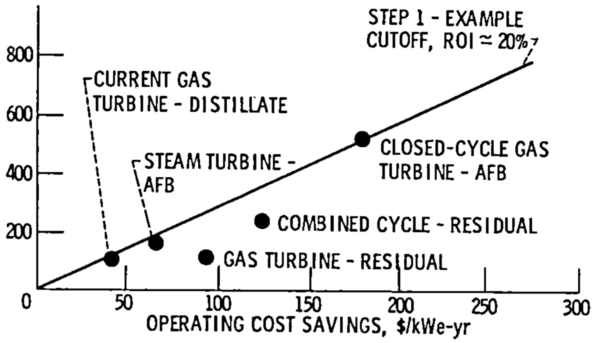
Plant-Basis Screening of Results

The specific approach used in Lewis' detailed plant-basis screening is illustrated in figure 18. The data shown in this example consist of results generated by UTC for the newsprint process. The screening method consisted of a sequential consideration of each evaluation parameter as indicated in the various parts of the figure. Each part consists of a plot of the incremental capital investment required for cogeneration versus some return obtained. The return is in the form of operating cost savings, fuel energy savings, levelized annual energy cost savings, or emissions savings.

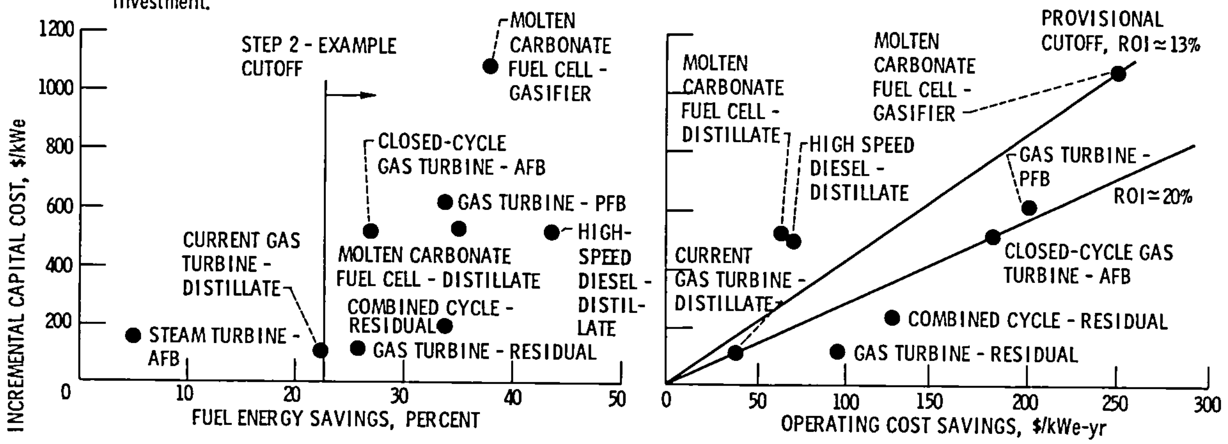
In the first step, figure 18(a), the incremental capital cost and annual operating cost savings are considered. In this case, both of these parameters are referenced to the noncogeneration situation in which an on-site boiler burning coal-derived, residual-grade liquid fuel is used to provide the required process steam and electricity is purchased to meet power requirements. A line from the origin to some cogeneration case is roughly a line of constant ROI (appendix B). The shallower the slope of a line from the origin to a cogeneration case, the higher the ROI for that case. As shown in figure 18(a), four advanced-technology cogeneration cases achieved an ROI about equal to or greater than the highest ROI achieved by a state-of-the-art technology cogeneration case. (Actually a variation of the advanced gas turbine case, involving steam injection, had results very similar to those for the gas turbine case shown and was omitted from the figure for simplicity.) Many other cases also had good ROI, but they were lower than the 20 percent for the state-of-the-art gas turbine and were not included in this figure. For this industrial process, in this step in the screening, a cutoff of 20 percent was used. However, as shown in other parts of the figure, some cases with lower ROI were eventually included. In other industrial processes, other cutoff values were used that were not necessarily associated with the results of a state-of-the-art case. Also, it is important to note that no restrictions were placed on cogeneration strategy or on whether electricity would be exported to the utility.

In the second step of the screening, shown in figure 18(b), incremental capital cost versus fuel energy savings ratio was considered. The five cases identified in the previous step as having the highest ROI are shown. Four additional cases, together with the advanced combined cycle burning coal-derived, residual-grade fuel, are the top five in terms of fuel energy savings ratio. Note that all the advanced-technology systems shown, except the steam turbine - AFB system, have fuel energy savings greater than that for the state-of-the-art gas turbine. The fuel energy savings for the steam turbine - AFB system were low because the power-to-heat ratio of that system did not match the ratio of power to process heat required for this industry. This particular cogeneration system was configured to produce the amount of process steam needed but produced only 13 percent of the required power. Therefore only limited benefits of cogeneration were realized.

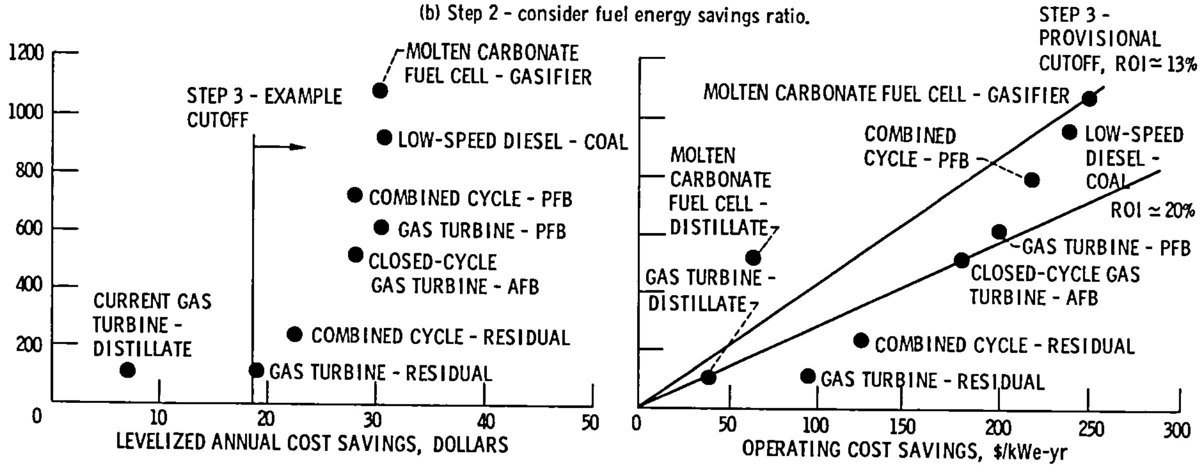
It is emphasized that figure 18(b) contains only the five cases with highest ROI and the five cases with highest fuel energy savings ratio (a total of nine distinct cases). The cutoff shown in the figure applies only to these cases; it does not imply that all cases with higher than 22 percent fuel savings are included. For example, a Stirling engine using coal-derived, residual-grade fuel achieved a fuel energy savings in this industry of 28 percent with an ROI of 6 percent. It is not shown in



(a) Step 1 - consider incremental capital cost and return on investment.

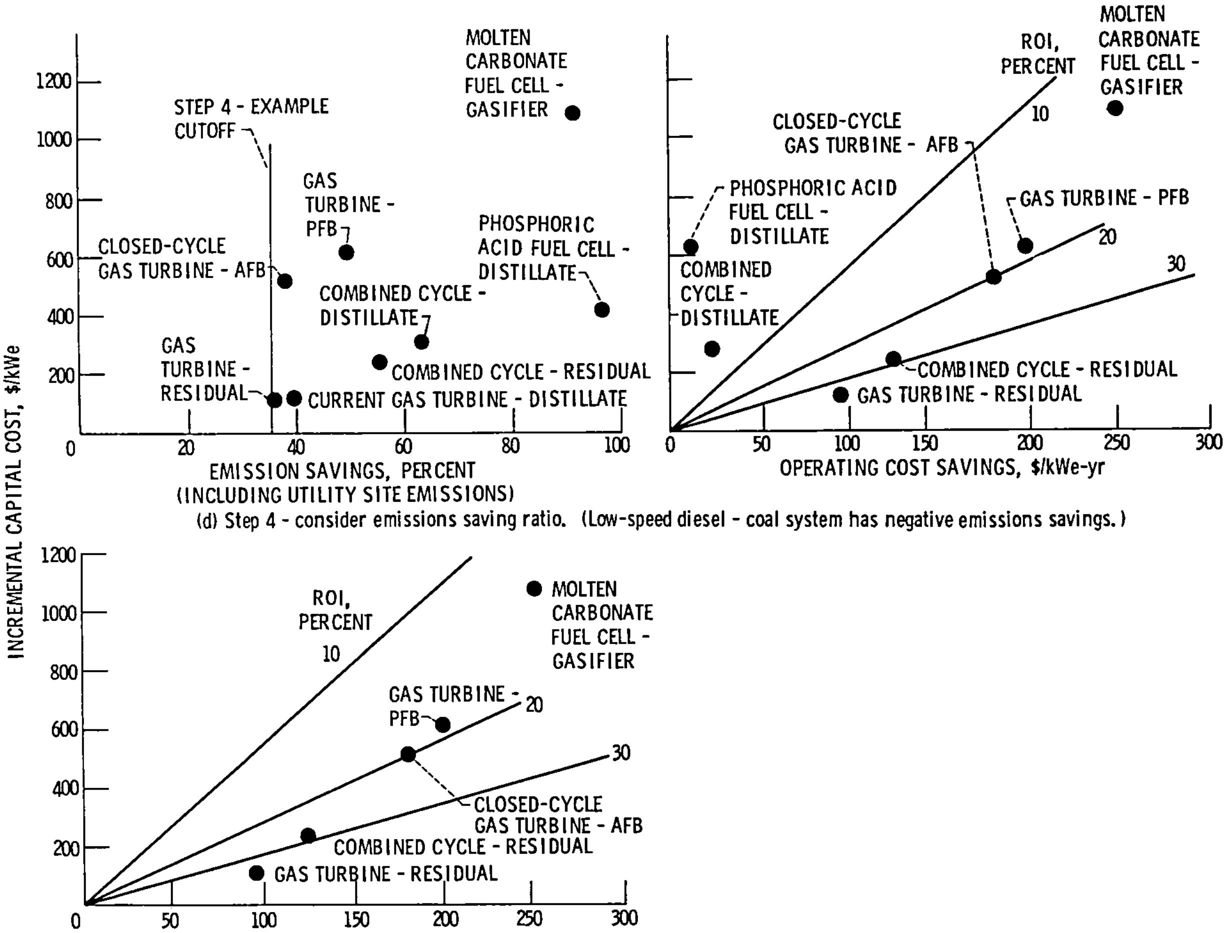


(b) Step 2 - consider fuel energy savings ratio.



(c) Step 3 - consider levelized annual energy cost savings ratio.

Figure 18. - Example of screening process: newsprint industry. (All values relative to noncogeneration boiler burning residual-grade, coal-derived liquid fuels and coal-fired utility.)



(d) Step 4 - consider emissions saving ratio. (Low-speed diesel - coal system has negative emissions savings.)

(e) Final step - choose most attractive cases.

Figure 18. - Concluded.

this figure since it is not among the most attractive cases in terms of either parameter.

The next part of step 2, shown on the right side of figure 18(b), is to reconsider the incremental capital cost versus the annual operating cost savings. The gas turbine - PFB case has an ROI just below the previous 20 percent cutoff, and the molten carbonate fuel cell - gasifier has an ROI of 13 percent. Since both these cases have high fuel energy savings, they were provisionally retained at this point. The other two cases that were identified as having high fuel energy savings have much lower annual operating cost savings (due to the higher price of their distillate-grade fuel). Therefore they have much lower ROI and were dropped from further consideration at this point. Again it should be clear that the cutoff shown in this figure (i.e., ROI $\geq$13 percent) does not mean that all cases with higher than 13 percent ROI are included.

The third step of the screening, figure 18(c), considers the levelized annual energy cost savings. Included are all the cases that were retained from the previous figure plus two additional cases, a low-speed diesel and a combined cycle - PFB. The two additional cases plus the steam turbine - AFB, gas turbine - PFB, and molten carbonate fuel cell - gasifier systems are the top five cases in terms of the levelized annual energy cost savings. All the advanced cases have higher fuel energy savings and use a lower price fuel than the state-of-the-art gas turbine and hence show much higher levelized annual energy cost savings. In this particular step no systems were dropped.

The incremental capital cost versus annual operating cost savings is again considered on the right side of figure 18(c). Both new cases in this figure have ROI above the 13 percent cutoff adopted previously. However, at this point, the combined cycle - PFB was dropped from further consideration because it showed no advantage over the gas turbine - PFB (which is the same system but without the steam bottoming cycle) in terms of any of the parameters considered here.

In step 4, figure 18(d), the emissions savings ratio is considered. Two new cases appear in this figure, a distillate-fueled phosphoric acid fuel cell system and a distillate-fueled combined cycle. These, together with three of the cases carried over from the previous figure, make up the top five cases in terms of emissions savings ratio. The coal-fired diesel that was identified in figure 18(c) as having the highest levelized annual energy cost savings was dropped from figure 18(d) since its emissions savings ratio was negative. The other cases shown have very attractive emissions savings ratios, particularly the fuel cell systems.

Finally, on the right side of figure 18(d) the incremental capital cost versus annual operating cost savings is again considered. As shown, the two cases that use coal-derived, distillate-grade fuel have low annual operating cost savings and hence low ROI. The other four advanced systems have survived this step of the screening and are retained as the most attractive cases for this particular industrial process. These cases are shown in figure 18(e).

National-Basis Evaluations

Figure 19 is an example of the type of data that were prepared by Lewis in evaluating potential national benefits of the advanced systems. Shown are the potential fuel energy savings for the advanced steam turbine system with a coal-fired AFB furnace aggregated over 40 processes included by GE in their contracted study. The GE data for the advanced steam turbine system were used as input to the analysis as were the GE projections of the growth of the various

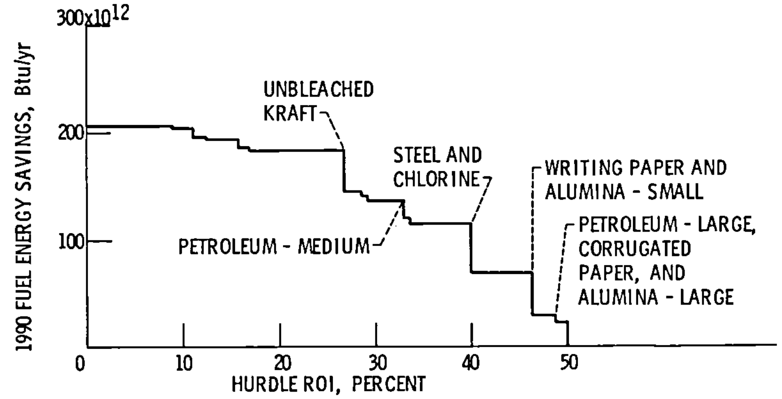


Figure 19. - Example of potential fuel energy savings in 40 General Electric processes for cogeneration with steam turbine burning coal in an atmospheric fluidized bed. (All values relative to noncogeneration boiler burning residual-grade, coal-derived liquid fuels and coal-fired utility.)

industries. Energy savings are shown as a function of a "hurdle" ROI required for an industrial investment in the cogeneration system. At any value of hurdle ROI in this figure it was assumed that all processes for which the steam turbine - AFB system achieved higher ROI would use the system in cogeneration and would achieve the plant-basis fuel energy savings calculated. The value on the ordinate of the figure shows the accumulated fuel energy savings for all such processes.

The hurdle ROI is the minimum rate of return on an investment needed for a decision by an industrial concern to make the investment. Of course other factors would also likely be used in coming to a decision. Even though a hurdle ROI may actually vary from industry to industry, within companies in a given industry, and even from time to time within the same company, for simplicity the same value was assumed by NASA to be applicable to all potential industrial applications. It was felt this approach would factor industrial economics into the national-scale results while stopping short of a detailed market analysis, which was beyond the scope of the study.

The effect of hurdle ROI on potential energy savings can be seen from figure 19. If only an ROI ≥ 0 is assumed to be required, the potential national energy savings in 1990 for the steam turbine - AFB system applied to these 40 processes would be slightly greater than 200×10^{12} Btu/yr. If an ROI ≥ 10 percent were assumed to be required, only a slight reduction in potential savings would result. However, if an ROI ≥ 20 percent or ≥ 30 percent were assumed to be required, the potential savings would drop to approximately 180×10^{12} and 140×10^{12} Btu/yr, respectively.

Different energy conversion systems have a different sensitivity of energy savings to required ROI. Displays such as that shown in figure 19 were prepared for each of the advanced systems by using each contractor's plant-basis results and industrial growth projections. Figures for national savings in this report show results for slices through ROI ≥ 0 and ROI ≥ 20 percent in order to illustrate the effect of required ROI on the comparisons of advanced systems on a national scale. The methodology described provided not only a way of comparing and screening the advanced energy conversion systems, but also a way of further identifying industries where the various advanced energy conversion systems could make a significant impact on industrial energy consumption. For example, identified in figure 19 are industrial processes where large potential savings resulted for the steam turbine - AFB system in the GE study.

APPENDIX D

SENSITIVITY OF RESULTS TO CHANGES IN FUEL AND ELECTRICITY PRICES

Sample results for two conversion systems in two processes will be used in this appendix to illustrate the effects of variations in fuel and electricity prices on the relative economics of different cogeneration systems. These parameters represent the area where the greatest uncertainty is believed to exist in the CTAS ground rules, and it is these parameters that were found in the sensitivity analyses to have the greatest effect on the study results. Keep in mind that the sensitivities are strongly dependent on the characteristics of the particular process plant, the energy conversion system being considered, the cogeneration strategy employed, and other factors. The results presented here are only for illustration. Results for the detailed sensitivity analyses performed are presented in the detailed NASA and contractor CTAS final reports.

The writing-paper mill and the chlorine plant defined by GE (as shown in table 13) are the two industrial processes that are used in the examples. The E/Q for the writing-paper mill is relatively low (0.22) and as a result, when many of the advanced energy conversion systems are matched to that process by using the match-heat strategy, excess electricity is generated. An advanced gas turbine burning coal-derived residual fuel is one example of such a system. That case is plotted in figure 20(a), as is the case for the same conversion system applied to the same writing-paper mill by using the match-electricity strategy. In the match-electricity case of course a supplementary boiler is required to make up the deficit in process heat from the conversion system. Also plotted in figure 20(a) is a coal-fired steam system using an AFB. The E/Q of this system at the required conditions is slightly lower than the E/Q of the writing-paper mill. In this instance the heat requirement is matched and a small amount of electricity is purchased from a utility.

The coordinates of figure 20 are incremental capital cost and annual operating cost savings. The use of plots on these coordinates to compare the economic attractiveness of cogeneration systems is discussed in appendix B. The various types of horizontal lines shown going both left and right from each of the base points represent the changes in operating cost savings for specific variations in fuel and electricity prices.

Looking first at the gas turbine without export, note that the ROI for the base case is 30 percent. As the price of purchased electricity is increased, the operating savings increase, as shown by the horizontal solid lines, and result in an increase in ROI. This change is due to the operating costs for the noncogeneration case increasing with the electricity price increase while the operating costs for the cogeneration case, which neither imports nor exports electricity, are unaffected by the price change. As the price of liquid fuel is varied, as represented by the horizontal short-dashed lines, operating cost savings vary inversely since more liquid fuel is being used on site in the cogeneration case (both in the conversion system and the supplementary boiler) than in the noncogeneration case. For this particular combination of conversion system, fuel, and process, the change in operating cost savings for a given percentage variation in liquid-fuel price is about half the change resulting from the same percentage variation in electricity price and is in the opposite direction. Since both the noncogeneration and cogeneration cases use liquid fuel, variations in solid-coal price have no direct effect.

Next we look at the same liquid-fueled gas turbine, but this time in a match-heat strategy allowing the export of electricity. Because the gas turbine

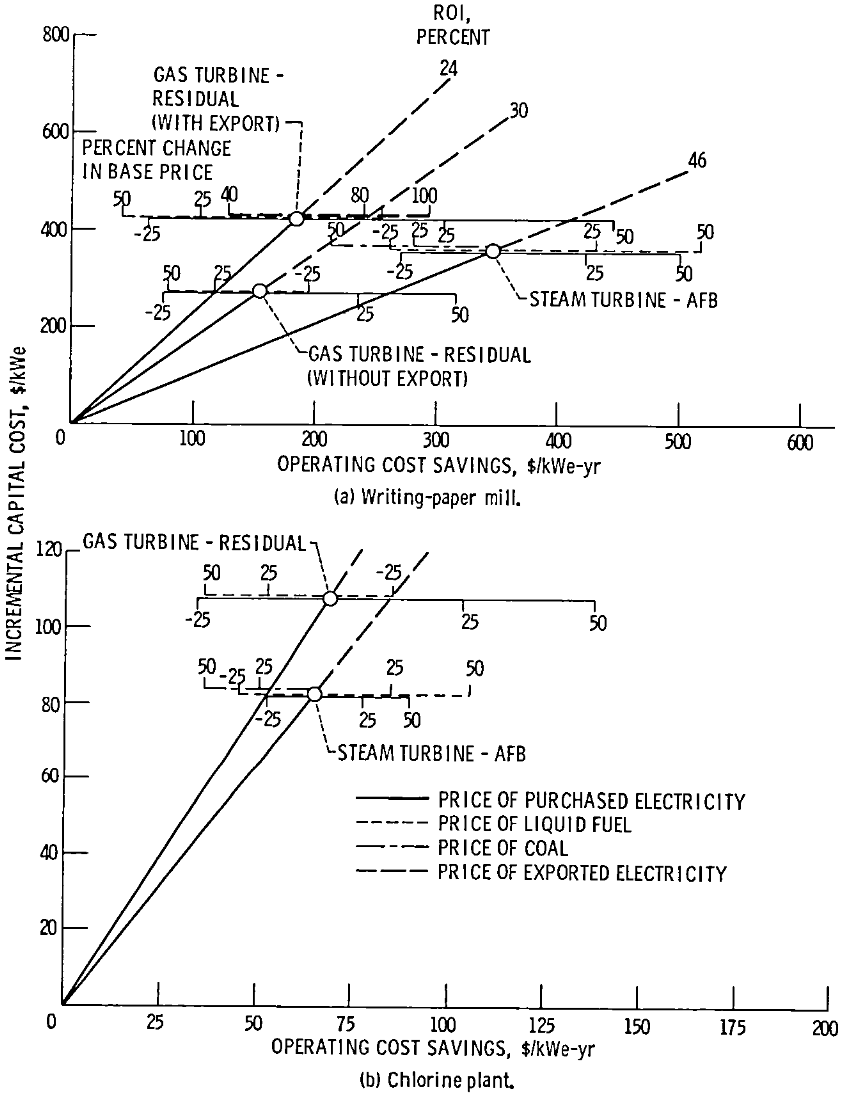


Figure 20. - Examples of sensitivity of cogeneration system economics to variations in fuel and electricity prices. (All values relative to noncogeneration boiler burning residual-grade, coal-derived liquid fuels and coal-fired utility.)

has a much higher E/Q ratio than that required by the process, a large amount of electricity is available for export when the process heat demand is met by heat recovery from the turbine. Note that the ROI for this base case is 24 percent as compared with 30 percent for the nonexport case. The effects of variations in liquid-fuel prices and purchased electricity prices are larger in absolute magnitude because of the increased size of the cogeneration system, but the effect of ROI is very similar to that in the nonexport case. An additional sensitivity parameter, the price received by the cogenerator for exported electricity, is introduced in this case. The base export price used in CTAS was 60 percent of the price paid by the industrial owner to purchase electricity from the utility grid. There is considerable uncertainty in this value, and the sensitivity of results for this case to variations in the export price are indicated by the heavy, long-dashed horizontal line. If the export price was increased to about 80 percent of the purchase price of electricity, the ROI for the export case would equal the ROI for the nonexport case. Above the 80 percent value, the export case would have a higher ROI than the nonexport case. Export generally resulted in increased energy savings, but at the 60 percent export sale price it reduced the ROI. The economics are significantly improved as the export price approaches the purchase price of electricity.

The remaining case plotted in figure 20(a) is the steam system using an AFB furnace. The effect of varying the purchase price of electricity is very similar to that in the previous two cases. However, the effect of variations in the liquid-fuel price is the opposite of that for the liquid-fired systems. The operating costs vary with the liquid-fuel price for the noncogeneraton case, which burns liquid fuel, but the operating costs do not change for the coal-burning cogeneration case. The result is that, when different liquid-fuel prices are assumed, the relative comparison of coal-fired and liquid-fired systems can change significantly. The effects of variations in the assumed coal price are shown by the dot-dashed line in figure 20(a) for the steam turbine - AFB system. The effect is similar in magnitude but opposite in direction to the effect of the same percentage change in liquid-fuel price.

The effects of combinations of the changes shown in figure 20(a) can be evaluated by vectorially adding the effects of the individual changes.

Figure 20(b) displays similar data for the chlorine plant, which has a higher E/Q (1.55) than the writing-paper mill. Again the liquid-fired gas turbine and the steam turbine - AFB system are used as example conversion systems. Note that, for the base case, again the steam turbine - AFB system yields the higher ROI. If the liquid fuel price were assumed to be higher relative to coal and electricity than was assumed for CTAS, the advantage of the steam turbine - AFB system would be even greater. However, an increase of 25 percent or more in electricity price and/or coal price with no change in liquid fuel price would result in the liquid-fueled gas turbine yielding the higher ROI.

As indicated earlier the sensitivity results presented here are intended as examples, and the magnitudes of the changes shown apply only to the particular processes and systems specified. However, a few general trends from the broader sensitivity analyses performed should be noted:

(1) An increase in the assumed purchase price of electricity improves the economics of all cogeneration systems.

(2) Increasing the price of all energy (electricity and all fuels) does not significantly affect the relative comparison of systems.

(3) Changes in the relative fuel prices can significantly affect the relative comparison of systems that use different fuels.

(4) The attractiveness of export is highly dependent on the price received for electricity sold to the utility.

(5) Other economic variables showed lesser effects over the ranges studied.

The base fuel and electricity prices used in CTAS were based on national average prices provided by DOE. However, the relative fuel and electricity prices vary in different regions throughout the United States due to availability, transportation costs for fuel, etc. In many cases certain industrial processes are concentrated in particular regions because of the availability of raw materials, the availability of transportation, the convenience to the market place, etc. It is possible that in the region where a particular industry is concentrated, such things as fuel prices, electricity prices, and environmental restrictions may be much different from those assumed in CTAS. The Jet Propulsion Laboratory gathered data on regional characteristics throughout the United States that might affect the comparison of advanced cogeneration systems. A few cases were examined in CTAS to determine the effect of fuel prices in regions where selected industries are concentrated. The effect on the comparison of systems was small for the cases examined. However, a case-by-case study would be required to evaluate the impact of regional and/or local characteristics on the relative attractiveness of different advanced systems for specific applications. The information gathered by JPL on the regional concentration of industries and the regional characteristics are included in the NASA final report on CTAS.

1. Report No.	2. Government Accession No.	3. Recipient's Catalog No.
NASA TM-81400		

4. Title and Subtitle	5. Report Date
COGENERATION TECHNOLOGY ALTERNATIVES STUDY (CTAS) VOLUME I - SUMMARY	January 1980
	6. Performing Organization Code
7. Author(s)	8. Performing Organization Report No.
Gerald J. Barna, Raymond K. Burns, and Gary D. Sagerman	E-312
9. Performing Organization Name and Address	10. Work Unit No.
National Aeronautics and Space Administration Lewis Research Center Cleveland, Ohio 44135	11. Contract or Grant No.
	13. Type of Report and Period Covered
12. Sponsoring Agency Name and Address	Technical Memorandum
U.S Department of Energy Fossil Fuel Utilization Division Washington, D.C. 20545	14. Sponsoring Agency ~~Code~~ Report No. DOE/NASA/1062-80/4

15. Supplementary Notes

Prepared under Interagency Agreement EC-77-A-31-1062.

16. Abstract

CTAS compared and evaluated various advanced energy conversion systems that can use coal or coal-derived fuels for industrial cogeneration applications. The study was sponsored by the Department of Energy (DOE). Project management of the overall effort was delegated to NASA's Lewis Research Center. Most of the data were developed under contracts with two industrial teams led by the General Electric Co. and the United Technologies Corp. In addition to study management Lewis also performed in-house analyses of the advanced systems. The Jet Propulsion Laboratory supported Lewis in selected areas. The principal aim of the study was to provide information needed by DOE to establish research and development (R&D) funding priorities for advanced-technology systems that could significantly advance the use of coal or coal-derived fuels in industrial cogeneration. Steam turbines, diesel engines, open-cycle gas turbines, combined cycles, closed-cycle gas turbines, Stirling engines, phosphoric acid fuel cells, molten carbonate fuel cells, and thermionics were studied with technology advancements appropriate for the 1985-2000 time period. The various advanced systems were compared and evaluated for a wide diversity of representative industrial plants on the basis of fuel energy savings, annual energy cost savings, emissions savings, and rate of return on investment (ROI) as compared with purchasing electricity from a utility and providing process heat with an on-site boiler. Also included in the comparisons and evaluations were results extrapolated to the national level. This report summarizes the results of the CTAS effort, including the contractors' and Lewis in-house results.

17. Key Words (Suggested by Author(s))	18. Distribution Statement
Coal; Cogeneration; Electric powerplants; Energy conversion; Energy conversion efficiency; Cost estimates	Unclassified - unlimited STAR Category 44 DOE Category UC-93

19. Security Classif. (of this report)	20. Security Classif. (of this page)	21. No. of Pages	22. Price*
Unclassified	Unclassified		

* For sale by the National Technical Information Service, Springfield, Virginia 22161

☆ U. S. GOVERNMENT PRINTING OFFICE: 1980-660-257 Region No. 5-II