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COGENERATION TECHNOLOGY ALTERNATIVES STUDY (CTAS) UNITED TECHNOLOGIES CORPORATION FINAL REPORT

VOLUME V – ANALYTIC APPROACH AND RESULTS

Power Systems Division
United Technologies Corporation

January 1980

Prepared for
NATIONAL AERONAUTICS AND SPACE ADMINISTRATION
Lewis Research Center
Under Contract DEN3-30

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

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Volume V

Analytic Approach and Results

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Lewis Research Center
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16. Abstract

The Cogeneration Technology Alternatives Study (CTAS) provides data and information in the area of advanced energy conversion systems for industrial cogeneration applications in the 1985-2000 time period. Six current and thirty-six advanced energy conversion systems were defined and combined with appropriate balance-of-plant equipment. Twenty-six industrial processes were selected from among the high energy consuming industries to serve as a frame work for the study. Each conversion system was analyzed as a cogenerator with each industrial plant. Fuel consumption, costs, and environmental intrusion were evaluated and compared to corresponding traditional values. Various cogeneration strategies were analyzed and both topping and bottoming (using industrial by-product heat) applications were included.

The advanced energy conversion technologies indicated reduced fuel consumption, costs, and emissions. Typically fuel energy savings of 10 to 25 percent were predicted compared to traditional on-site furnaces and utility electricity. With the variety of industrial requirements, each advanced technology had attractive applications. Overall, fuel cells indicated the greatest fuel energy savings and emission reductions. Gas turbines and combined cycles indicated high overall annual cost savings. Steam turbines and gas turbines produced high estimated returns. In some applications, diesels were most efficient. The advanced technologies used coal-derived fuels, or coal with advanced fluid bed combustion or on-site gasification systems.

This volume presents a description of the analysis employed and the results obtained.

17. Key Words (Suggested by Author(s)) Cogeneration, Fuel Conversion, Energy Conversion, Steam Turbines, Gas Turbines, Combined Cycles, Diesels, Fuel Cells, Stirling Engines, Thermionic Power Plants, Organic Rankine Cycles, Industrial Energy Requirements	18. Distribution Statement Unclassified – Unlimited STAR Category 44 DOE Category UC093

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VOLUME V

PREFACE

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

This document describes the work conducted by Power Systems Division of United Technologies Corporation under National Aeronautics and Space Administration contract DEN3-30. This United Technologies contractor report is one of a set of reports describing CTAS results. The other reports are the following: Cogeneration Technology Alternatives Study (CTAS) Volume I - Summary NASA TM 81400, Cogeneration Technology Alternatives Study (CTAS) General Electric Final Report NASA CR 159765-159770 and Cogeneration Technology Alternatives Studies (CTAS) Volume II - Comparison and Evaluation of Results, NASA TM 81401.

This United Technologies contractor report for the CTAS study is contained in six volumes:

Volume I	-	Summary Report, DOE/NASA/0030-80/1 NASA CR 159759
Volume II	-	Industrial Process Characteristics, DOE/NASA/0030-80/2 NASA CR 159760
Volume III	-	Energy Conversion System Characteristics, DOE/NASA/0030-80/3 NASA CR 159761
Volume IV	-	Heat Sources, Balance of Plant, and Auxiliary Systems, DOE/NASA/0030-80/4 159762

Volume V - Analytic Approach and Results, DOE/NASA/
0030-80/5 159763
Volume VI - Computer Data, DOE/NASA/0030-80/6 NASA CR 159764

The cogeneration analysis presented in this Volume V was developed by United Technologies Research Center, East Hartford, Connecticut.

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INTRODUCTION

This volume describes the analyses which were employed to evaluate the energy savings, environmental impact, and economic viability of cogeneration using advanced energy conversion systems to provide on-site electrical power and thermal energy for industrial process needs. For this study 37 different energy conversion systems and 26 different industries were combined to formulate candidate cogeneration plants. For each of these combinations, the energy conversion system output was matched to the industrial process needs by four different strategies. In order to evaluate this large number of systems, two computer programs were developed to calculate the various parameters which describe the system performance. In the first program, the industrial data, the energy conversion system data, and the heat-source and balance-of-plant data are combined to formulate a cogeneration system and calculate the energy utilization, cost, and emission characteristics of that system. The same characteristics for a non-cogeneration system are determined and the performance improvements which could be realized through cogeneration are analyzed. In the second program, the output of the first program is utilized to calculate various economic parameters which can be used to evaluate the economic viability of cogeneration. This program was used to evaluate the economics for 120 selected cogeneration systems which have attractive energy conservation and cost savings potential.

This Volume V describes the data base, the analyses, and the results obtained in the conduct of the study. It is divided into two major parts: the first concerns the analyses and the second, results.

The first part of the Analyses section describes the data base for the analyses. The industrial data base was extracted from the detailed description of the industrial processes provided by Gordian Associates and reported in Volume II. A discussion of the energy conversion system data base follows. These data were provided by the advocates for the various energy conversion systems and are presented in Volume III. Next, the heat source data is summarized. These data were used in conjunction with certain energy conversion systems and for auxiliary boilers. They were provided by Bechtel National, Incorporated, and reported in

Volume IV. A description of the balance-of-plant data is included. These data were also provided by Bechtel National, Incorporated, and reported in Volume IV. A brief description follows of heat pump data which was developed in consultation with Westinghouse Electric Company and presented in Volume IV.

The next section of this volume defines a cogeneration system and its component parts, followed by a description of the cogeneration performance analysis which was used to calculate the energy characteristics, emissions, and costs of cogeneration and non-cogeneration systems. A description of the computer printouts from the performance analysis is also included. The final section of the Analyses section describes the economic analysis which was used to evaluate the economic viability of cogeneration with advanced energy conversion systems.

The second part of this volume presents a summary of the results of the analysis. Detail computer printouts are included in Volume VI.

ANALYSES

INDUSTRIAL DATA BASE

Twenty-six industries were chosen for evaluation in this study. Gordian Associates provided industrial process data which characterized each industry. These data were reduced to a standard format and stored in the computer file to provide a common data base for the subsequent cogeneration performance calculations.

The selection of industrial processes for inclusion in the study was based on the following considerations. The industrial processes should be energy intensive, have cogeneration applicability (primarily for utilizing topping cycles, although two industries were chosen for bottoming cycles), provide a wide range of overall industry electrical-to-thermal ratios, provide a wide range of plant sizes, be large oil and natural gas consumers, and represent industrial processes expected to be used in the 1975-2000 time period. The 1975 energy consumption data for the 20 two-digit Sector D, Manufacturing, classifications are shown in Figure V-1. To meet the energy intensiveness criteria, most of the industries were chosen from the six two-digit classifications having the highest energy consumption; however, some industries were chosen from four of the next seven two-digit classifications which have lower, but significant levels of energy consumption. The selection of industries within this second group was made by reviewing the available literature and choosing those which best met the above criteria and had sufficient and reliable data available. The ten two-digit classifications represented in this study consume over 80 percent of the energy used by the industrial sector. Twenty-six industrial processes meeting the above criteria were chosen for this study. These twenty-six industrial processes represent approximately 50 percent of the industrial energy consumed. A discussion of their characteristics is contained in Volume II of this report. A list of the industries chosen for this study along with their annual energy requirements is given in Table V-1.

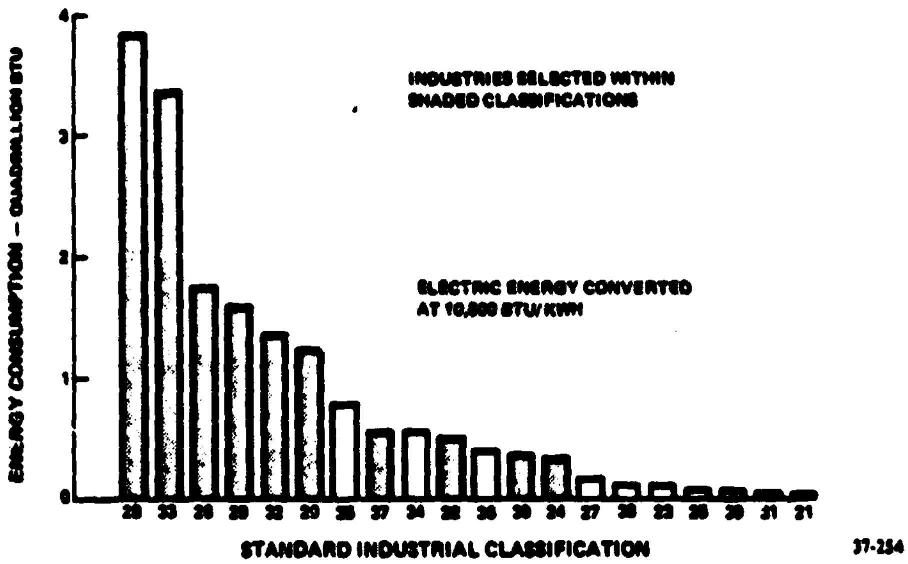


Figure V-1. Industrial Energy Consumption Two-Digit Classification in 1975

TABLE V-1

INDUSTRIES REPRESENTED IN CTAS STUDY

No.	Industry Name	Four-Digit SIC Code	Total* Energy Consump. 10^{12} Btu
1	Meat Packing	2011	70.6
2	Baking	2051	41.3
3	Malt Beverage	2082	46.75
4	Fabric Mills	2221	49.49
5	Sawmills	2421	72.01
6	Newsprint	2621	67
7	Writing Paper	2621	105.6
8	Corrugated Paper	2631	498.6
9	Folding Boxboard	2631	109.1
10	Chlorine/Caustic	2812	128.6
11	Alumina	2819	70.5
12	LDPE	2821	28.27
13	HDPE	2821	15.72
14	PVC	2821	18.8
15	SB Rubber	2822	12.28
16	Nylon	2824	13.17
17	Styrene	2865	90.96
18	Ethylene	2869	250.[illegible]
19	Petroleum Refining	2911	2854.8
20	Tires	3011	76.11
21	Glass Containers	3221	140.0
22	Cement	3241	413.8
23	Steel	3312	3140.6
24	Gray Iron Foundries	3321	103.1
25	Copper-Arbiter Process	3331	0.7
26	Motor Vehicles	3711	103.71

* National Data 1975

Industrial Characterization

o Plant Data

The cogeneration analysis program required the development of an industrial data base to store the pertinent information for each of the industrial processes. The specific plant characterizations stored in the data base were developed from detailed reports of each of the industrial processes provided by Gordian Associates and reported in Volume II. The typical plant characterization was intended to represent a plant which is expected to be manufacturing goods by a specified processing method in the 1985 to 2000 time period. The annual production level of the typical plant was projected by Gordian Associates.

The type of information stored for each industrial process is illustrated in Figure V-2 which contains data for a typical chlorine plant. The data in Figure V-2 are for the year 1985. Data were also stored for the years 1978 and 2000.

In developing a general data base for the industrial processes, certain assumptions were made to limit the quantity of data required without sacrificing overall accuracy. One such assumption was the use of two types of days in the characterization. Each plant is represented by its energy consumption on productive days (workdays) and, if necessary, nonproductive days (weekends, holidays, shutdowns).

The electrical requirements of the typical plant are summarized by several factors. The unit electrical consumption (kWh/unit produced) indicates the electrical energy intensiveness of the process. The unit electrical consumption as well as unit thermal consumption on nonproductive days has been adjusted by the ratio of nonproductive days to productive days. Thus, the addition of the two-unit consumption values, when multiplied by the annual production, will yield the annual electrical energy used by the process.

NO.10 SIC 2812 CHLORINE/CAUSTIC PRODUCTION

TIME FRAME 19[illegible]5.

TYPICAL PLANT DATA

ANNUAL PLANT PRODUCTION(TONS)		220000.	
DAILY PLANT PRODUCTION(TONS)		603.	
PRODUCTIVE DAYS PER YEAR		365.	
NON-PRODUCTIVE DAYS PER YEAR		0.	
ELECTRICAL REQUIREMENTS		**PROD**	**NON-PROD**
UNIT ELECTRIC CONSUMPTION(KWH/TON)		2919.7	0.0
PEAK ELECTRICAL DEMAND(MW)		77.186	0.0
AVERAGE ELECTRICAL DEMAND(MW)		73.[illegible]97	0.0
ELECTRIC LOAD FACTOR(TYPICAL DAY)		0.950	0.0
AVERAGE THERMAL REQUIREMENTS(MILLION BTU/TON)			
HOT WATER	150.F	0.0	0.0
300 F STEAM	274.F	1.914	0.0
500 F STEAM	3[illegible]2.F	7.749	0.0
700 F STEAM	700.F	0.0	0.0
DIRECT HEAT(CLEAN=1.00,FUEL=0.0)	0.F	0.0	0.0
USEABLE PROCESS HEAT	0.F	0.0	0.0
BY-PRODUCT FUEL AVAILABLE(TYPE=1.0)		[illegible].400	0.0
AVERAGE ANNUAL E/T		1.0[illegible]2	0.0
		LOW	**HIGH**
DAILY COINCIDENCE FACTOR RANGE		1.000	1.000
SEASONAL VARIATION OF DAILY AVERAGE E/T		1.032	1.032
NATIONAL ANNUAL CRUDE RUNS(TONS)		0.144E+08	
FUEL BREAKDOWN FRACTIONS			
COAL		0.570	
OIL		0.020	
NATURAL GAS		0.410	
OTHER		0.0	
OTHER		0.0	
% OF SIC REPRESENTED BY PRODUCT		95.200	

Figure V-2. Industry Energy Requirements Printout

The average electrical demand listed on this summary was established using the annual energy consumption and the working hours. The electric load factor for a typical day is also listed; it can be used to determine the peak electrical demand for a typical day (i.e., average demand/load factor = peak demand).

The average thermal requirements of the various processes were defined in terms of temperature as well as heat requirements (Btu/unit production). This diversity of thermal requirements increases the complexity of matching the waste heat from a given energy conversion system with the requirements of the various industries because the energy conversion system must be designed differently to supply the different thermal requirements of the various industries. In order to reduce the number of energy conversion system design variations required, the thermal requirements were generalized into five thermal categories: hot water, low temperature steam, medium temperature steam, high temperature steam, and direct heat. Direct heat denotes thermal requirements met by direct combustion or other specific source of hot gas. Thermal needs met by steam and hot water are denoted as indirect heat. The nominal temperatures and pressures established for the thermal categories were: (1) hot water at 140°F, (2) 50 psig steam at 300°F, (3) 600 psig steam at 500°F, and (4) 600 psig superheated steam at 700°F. The actual bookkeeping procedure was to characterize all hot water requirements at the nominal temperature (140°F), all steam requirements from 212°F to 315°F in the 300°F category, all 315°F-515°F steam requirements in the 500°F category and all steam requirements over 515°F in the 700°F category. The thermal categories generalize the hot water and steam requirements only; the direct heat requirement is defined at a specific input temperature.

The unit thermal requirements (millions Btu/unit produced) for productive and nonproductive days are shown in Figure V-2. The actual temperature of the thermal requirement is indicated for reference only.

Associated with the hot water and steam requirements are the amount of hot water and/or steam condensate returned to the boiler. The assumptions were made that the condensate was returned at 130°F and make-up water was supplied at 60°F. Boiler blow-down of 10 percent was included. If hot water was returned after use, its temperature was assumed to be 130°F. The amount of water returned has an obvious impact on the energy required to heat make-up water for the process. In many cases, return water temperatures were not available, but the fuel consumption to provide hot water was known. Therefore, Gordian Associates defined the thermal requirement to provide the 140°F hot water for the actual situation in the representation. For example, the energy requirements for hot water in the meat packing industry include the total heat required to heat room-temperature water to 140°F. Thus, even though all this hot water is thrown away, there is no additional energy requirement to preheat the make-up water to 130°F, the normal hot water return temperature assumed for the study. To make the energy utilization correct, all hot water for this industry was listed as being returned. The actual temperatures, pressures, and hot water and/or condensate return fractions for the 24 processes requiring hot water and/or steam are presented in Table V-2 in the assigned bins. Glass and cement are not included in this list because they require only direct heat.

TABLE V-2

HOT WATER AND STEAM REQUIREMENTS IN THE ASSIGNED BINS

	Temperature (F)				Pressure (PSIG)			Fraction Returned			
Industry	HW	300 F	500 F	700 F	300 F	500 F	700 F	HW	300 F	500 F	700 F
Meat Packing	140	315			15			1.0	1.0		
Baking	180	250			15			0.1	0.77		
Malt Beverages		300			53				0.9		
Fabric Mills			338			100				0.9	
Saw Mills			331		90				0.7		
Newsprint	140	307	371		60	160		1.0	0.9	0.9	
Writing Paper	140	307	371		60	160		1.0	0.9	0.9	
Corrugated Paper	140	307	371		60	160		1.0	0.9	0.9	
Boxboard	140	307	371		60	160		1.0	0.9	0.9	
Chlorine/caustic		274	332		30	90			0.9	0.9	
Alumina			442			200				0.9	
LDPE		300	500		53	600			0.9	0.9	
PVC			500			600				0.9	
S.B. Rubber		267	371		25	160			0.9	0.9	
Nylon		300	470	532	53	495	885		0.9	0.9	0.9
Styrene		300			53				0.74		
Ethlyene				850			1500				0.9
Petroleum			500			385				0.9	
Tires			406			250				0.9	
Steel			500			600				0.9	
Gray Iron		300			53				0.9		
Copper			338			100				0.9	
Motor Vehicles			353			125				0.9	

The direct heat thermal category represents heat currently supplied to the process by burning a specified fuel (such as natural gas for hog hair singeing in a meat packing plant) or burning (of various types of fuel) to provide hot gases for the process. Therefore, the characterization of the direct heat necessitates the specification of: (1) the temperature, (2) the specific fuel, if necessary, and (3) any specific level of cleanliness required by the process. The exhaust gas from a conversion system was used to meet direct heat needs when that gas satisfied the required characteristics. For this study both direct heat requirements and exhaust gas characteristics were classified and only appropriate combinations were analyzed. Of the 26 industrial processes considered in the study, 14 had direct heat requirements and 10 of these required a specific fuel. A summary of direct heat requirements for these 14 processes is presented in Table V-3. The chlorine process, as indicated in Figure V-2, does not require any direct heat.

TABLE V-3

DIRECT HEAT, BY-PRODUCT FUEL, AND WASTE HEAT CHARACTERISTICS

	Direct Heat Requirements			By-Product Fuel Characteristics			Waste Heat
	Temp (F)	Fuel	Cleanliness**	Description***	% Used	Thermal Eff. %	Temp (F)
Meat Packing	2000	Nat. Gas	1.0				
Baking	500	Nat. Gas	1.0				
Malt Beverages	300	Nat. Gas	1.0				
Fabric Mills	400	Nat. Gas	1.0				
Saw Mills				5	65	60	
Newsprint				4	100	63	
Writing Paper				4	100	63	
Corrugated Paper				4	100	62	
Boxboard				4	100	62	
Chlorine				1	25	85	
Alumina	2100	Pet. Dist.	2.0				800
S.B. Rubber	2000	Pet. Dist.	2.0				
Styrene	1400	Nat. Gas	1.0	1	100	85	500
Ethylene	2000		1.0	1	100	85	
Petroleum	960		2.0				
Glass	2800	Pet. Dist.	2.0				1000*
Cement (Dry)	2900		2.0				1100*
Steel	3000	Coal	3.0	1	100	85	
Gray Iron	3000		3.0				
Motor Vehicles	3000	Nat. Gas	1.0				

* Usable only for bottoming

** 1.0 = clean
2.0 = moderately clean
3.0 = dirty

*** 1.0 = gaseous fuel
4.0 = black liquor
5.0 = solid fuel, only usable in auxiliary furnace

In certain processes, there is waste heat which may be used to reduce some of the process thermal requirements. The ability to use the waste heat will depend upon its temperature and state (steam or hot gas). Waste heat steam may be used to reduce a steam requirement directly, if the temperature is sufficient to match a thermal category requirement, or it can be used to preheat make-up water. A gas stream may be used to reduce a direct-heat requirement if it meets the criteria for direct heat discussed previously or it may be used as preheat. Additionally, process waste heat can be used in bottoming applications to generate some or all of the electrical requirements of the process if the waste heat is of sufficient temperature. Waste heat availability and temperature are also indicated in Table V-3.

In nine of the twenty-six processes, a by-product fuel was available for on-site use in providing some of the plant thermal requirements. This fuel may be used either in the energy conversion system directly, or burned in an auxiliary furnace to provide thermal energy where appropriate. One factor defines the physical characteristic of the fuel, such as solid (i.e., saw dust, wood chips, and bark in the saw mill and paper industry) or gaseous (i.e., hydrogen gas in the chlorine/ caustic industry). A second factor specifies the fraction of by-product fuel which is currently used in the industry. Most of the nine industries currently use 100 percent of their by-product fuel. Only two, saw mills and chlorine, use less than 100 percent. Currently, because of environmental reasons, saw mill operators burn approximately 65 percent of the saw dust generated during operation, with the remainder sold. In chlorine production, some plants utilize the hydrogen gas while others simply flare it. However, on the average, only 25 percent of the hydrogen gas is used as fuel, industry wide.

Overall plant energy parameters can be defined from the electrical and thermal energy characteristics discussed previously. One such parameter is the electrical to thermal ratio of the industry which may be used as a rough indicator for estimating which energy conversion systems may be best for cogeneration applications. For example, an industry with an E/T of 0.6 would be better matched to a gas turbine-generator power plant having an E/T of 0.6 than to a diesel power plant having an E/T at 1.0. Many energy conversion systems can be designed to produce different proportions of electrical and thermal energy, thereby permitting some flexibility for industrial process cogeneration matching.

The electrical-to-thermal coincidence factor is included in Figure V-2. This factor is defined as the variation of the hourly E/T normalized to the plant average E/T. The coincidence factor can point out those processes which may show promise for utilizing thermal storage devices. The high and low range of E/T which occurs during a typical production day is indicated in Figure V-2.

o National Data

In order to estimate the national benefits of various cogeneration applications, it is necessary to scale the results generated at the plant level to the national level for each industrial process. For each of the twenty-six industries, Gordian Associates has estimated the current (1978) and future production requirements for the various processes. Estimation of future requirements is based upon identifying those industry specific factors which control or influence the production levels. For example, the current and future output of the meat packing industry is logically related to the present population level and its anticipated growth to the year 2000. The production requirements of the saw mill industry are likely to be highly dependent upon the number of anticipated housing starts. Other industries may be dependent on other factors such as gross national product or possibly a combination of factors. Gordian Associates has identified those particular factors which, in their opinion, establish the production requirements at the national level.

In order to estimate the fuel usage and savings due to cogeneration, an estimate of current and future fuel utilization by type was made by Gordian Associates. This estimate is shown as fuel breakdown fractions in Figure V-2. Three specific categories of fuel type are defined. These are coal, oil, and natural gas. Other fuels used by an industry, but not identified as a specific type, would be categorized in the "other" categories. Changes in fuel fractions due to expected shifts from one fuel to another due to internal (fuel costs) or external (Government regulations) factors were included in the Gordian Associates estimates.

Each of the industries characterized represents a specific processing method for producing the product. For example, 75 percent of the chlorine currently produced is made with the diaphragm cell. The remainder is made using mercury cells. Diaphragm cells are more energy intensive than mercury cells and therefore account for more than 75 percent of the energy consumed in the chlorine industry. This percentage (85 percent) is indicated in Figure V-2. The percentage of energy consumed in the 4-digit classification by the specific process is indicated in the summary data to permit the evaluation of the national benefits of cogeneration.

Summary of Industrial Data

A complete set of summary data for the twenty-six industries for the years 1978, 1985, and 2000 is presented in Volume VI. Table V-4 presents a summary of the estimated production and energy requirements for typical plants in 1985. Electrical demand varies from 0.32 MW in baking to 200 MW in steel production, and electrical to thermal ratios vary from 0.002 in ethylene to 2.17 in low density polyethylene. A review of the thermal requirements in Table V-4 indicates that the majority of the thermal requirements are found in the 300°F, 500°F, and direct-heat categories with very little in the 700°F steam requirement.

The estimated national production, fuel breakdown fraction, and energy consumption (as percent of the 4-digit classification) in 1985 are presented in Table V-5. Many of these industries are expected to consume large quantities of oil and gas in the time period starting in 1985. Thus, the adoption of cogeneration by these industries, especially with advanced energy conversion systems employing coal or coal-derived fuels, could provide substantial resource savings.

TABLE V-4

SUMMARY OF REPRESENTATIVE PLANTS 1985

Industry	Annual Plant Production	Plant E (MWe)	E/T	Thermal Requirements (Million Btu/Unit) HW	300F	500F	700F	Direct
Meat Packing	200,000 tons	8.7	.32	1.22	.82	0	0	.14
Baking	15,000 tons	.32	.24	.03	.66	0	0	1.18
Malt Beverages	2,000,000 barrels	2.4	.13	0	.21	0	0	.01
Broad Woven Fabrics	6,000 tons	4.1	.95	0	0	15.2	0	1.46
Saw Mills	12,000 M bd. ft	.38	.10	0	0	6.3	0	0
Newsprint	620,000 tons	130.0	.68	.64	2.5	5.7	0	0
Writing Paper	207,000 tons	33.0	.22	.9	7.0	12.6	0	0
Corrugated Paper	775,000 tons	82.0	.14	1.5	9.4	10.2	0	0
Boxboard	517,000 tons	70.0	.16	1.8	9.6	12.8	0	0
Chlorine/Caustic	220,000 tons	77.0	1.03	0	1.9	7.7	0	0
Alumina	900,000 tons	31.0	.11	0	0	4.8	0	3.4
LDPE	190,000 tons	40.0	2.17	0	.33	2.4	0	0
HDPE	140,000 tons	20.4	.89	0	0	4.6	0	0
PVC	120,000 tons	13.7	.67	0	0	4.9	0	0
S. B. Rubber	128,000 tons	2.9	.10	0	1.3	3.4	0	1.6
Nylon	57,000 tons	8.2	.94	0	.43	2.7	1.4	0
Styrene	500,000 tons	4.3	.01	0	23.8	0	0	4.5
Ethylene	652,000 tons	2.8	.002	0	0	0	6.9	50.
Petroleum	63.9×10^6 crude runs	34.6	.03	0	0	.10	0	.41
Tires	100,000 tons	14.3	.38	0	0	6.9	0	0
Glass	125,000 tons	4.7	.11	0	0	0	0	8.6
Cement (Dry)	725,000 tons	11.8	.08	0	0	0	0	5.3
Steel	5,000,000 tons	200.0	.07	0	0	1.2	0	13.2
Gray Iron	400,000 tons	25.7	.35	0	.06	0	0	6.5
Copper	36,000 tons	11.1	.34	0	0	24.7	0	0
Motor Vehicles	210,000 autos	21.0	.31	0	0	4.7	0	1.7

TABLE V-5

NATIONAL INDUSTRY DATA
1985

Industry	National Production	Fuel Breakdown (%) Coal	Oil	Nat. Gas	Other	% 4-digit SIC Represented
Meat Packing	20.9×10^6 tons	20.5	13.4	62.6	3.6	100
Baking	10.85×10^6 tons		11.4	61.5	27.1	100
Malt Beverages	178.6×10^6 barrels		30	60.3	9.7	100
Broad Woven Fabrics	1.52×10^6 tons	22.3	30.4	40.2	7.1	100
Saw Mills	43.7×10^9 board feet	7.5	21.2	38.3	33	100
Newsprint	4.1×10^6 tons	16	42	42		4.8 *
Writing Paper	3.6×10^6 tons	26.2	45.6	28.2		8.1 *
Corrugated Paper	18.45×10^6 tons	19.2	32.7	48.1		38.5 *
Boxboard	4.86×10^6 tons	18.2	34.1	47.7		8.4 *
Chlorine/caustic	14.4×10^6 tons	57	2	41		85.2
Alumina	9.7×10^6 tons		39	61		18.5
LDPE	5.95×10^6 tons	20	18	52	10	17.33
HDPE	3.26×10^6 tons	20	18	52	10	9.64
PVC	5.11×10^6 tons	20	18	52	10	11.54
S. B. Rubber	1.86×10^6 tons	8.5	5.6	63.8	17.1	39.3
Nylon	1.2×10^6 tons	34.7	41.7	19.1	4.6	70
Styrene	5.19×10^6 tons	8.3	23.6	63.2	4.9	54.3
Ethylene	20.2×10^6 tons		20.6	79.4		26
Petroleum	6.14×10^9 crude runs	2	26	55	17	100
Tires	5.5×10^6 tons	21.6	32.7	44	1.7	81
Glass	15.6×10^8 tons		19.3	80.7		100
Cement (Dry)	40×10^6 tons	63	7.8	29.2		43.3
Steel	155×10^6 tons	65.3	7.4	18.9	8.4	100
Gray Iron	9.76×10^6 tons	1.2	2.5	45.9	50.4	100
Copper	2.7×10^6 tons			100		100
Motor Vehicles	13.73×10^6 autos	24.4	12.2	52.8	10.6	100

* % of 2-Digit Represented

ENERGY CONVERSION SYSTEMS

The energy conversion systems used in the study were each characterized by the advocates identified in Volume III.

The energy conversion systems included seven generic types having various configurations and design options. Energy conversion system designations were assigned to represent a specific conversion system and fuel combination. Further definition was indicated by the design option. The data base used in this study comprised 37 conversion system-fuel combinations with a total of 131 design options. Table V-6 presents a listing of the 37 energy conversion systems used in this analysis.

Energy Conversion System Characterization

In this study numerals were assigned to represent a specific conversion system-fuel combination as indicated in Table V-6. Implicit in each numeral is a definition of the state-of-the-art (current or advanced), the type of conversion system, and the fuel used. The energy conversion systems included in this study were: steam turbines, diesels, gas turbines, steam injected gas turbines, combined cycles, fuel cells, Stirling engines, thermionics and organic Rankine cycles. Within each technology type, further definition was sometimes necessary to identify the conversion system. Diesels were classified as high speed or low speed units. Gas turbines had three classifications: direct fired, indirect fired, or closed cycle. Combined cycles were either direct or indirect fired. Fuel cells considered were low-temperature acid cells and high-temperature molten carbonate cells. Thermionic systems were simple and compounded with steam turbines.

Six fuels were considered in the study. They were petroleum distillate, petroleum boiler fuel, coal-derived distillate, coal-derived boiler fuel, coal, and coal gas (gasified on site).

TABLE V-6

ENERGY CONVERSION SYSTEMS

ECS No.	No. of Design Options	State Of the Art	Technology Type		Fuel
1	10	Current	Steam Turbine		Petroleum Boiler Fuel
2	10	Current	Steam Turbine		Coal
3	2	Current	Diesel, High Speed		Petroleum Distillate
4	1	Current	Diesel, Low Speed		Petroleum Boiler Fuel
5	4	Current	Gas Turbine		Petroleum Distillate
6	1	Current	Combined		Petroleum Distillate
7	10	Advanced	Steam Turbine		Coal Derived Boiler Fuel
8	10	Advanced	Steam Turbine		Coal (AFB)
9	1	Advanced	Diesel, High Speed		Coal Derived Distillate
10	2	Advanced	Diesel, Low Speed		Coal Derived Boiler Fuel
11	1	Advanced	Diesel, Low Speed		Coal (pulverized)
12	5	Advanced	Gas Turbine		Petroleum Boiler Fuel
13	5	Advanced	Gas Turbine		Coal Derived Boiler Fuel
14	2	Advanced	Gas Turbine		Coal (gasifier)
15	4	Advanced	Gas Turbine		Coal (PFB)
16	3	Advanced	Gas Turbine, Indirect		Coal (AFB)
17	5	Advanced	Gas Turbine, Closed Cycle		Coal Derived Boiler Fuel
18	5	Advanced	Gas Turbine, Closed Cycle		Coal (AFB)
19	2	Advanced	Steam Injected Gas Turbine		Petroleum Boiler Fuel
20	2	Advanced	Steam Injected Gas Turbine		Coal Derived Boiler Fuel
21	2	Advanced	Steam Injected Gas Turbine		Coal (PFB)
22	2	Advanced	Steam Injected Gas Turbine, Indirect		Coal (AFB)
23	3	Advanced	Combined Cycle		Petroleum Boiler Fuel
24	3	Advanced	Combined Cycle		Coal Derived Boiler Fuel
25	1	Advanced	Combined Cycle		Coal (PFB)
26	2	Advanced	Combined Cycle, Indirect		Coal (AFB)
27	2	Advanced	Fuel Cell, Low Temperature		Petroleum Distillate
28	2	Advanced	Fuel Cell, Low Temperature		Coal Derived Distillate
29	2	Advanced	Fuel Cell, High Temperature		Petroleum Distillate
30	4	Advanced	Fuel Cell, High Temperature		Coal Derived Distillate
31	1	Advanced	Fuel Cell, High Temperature		Coal (Gasifier)
32	2	Advanced	Stirling		Coal Derived Boiler Fuel
33	2	Advanced	Stirling		Coal (AFB)
34	2	Advanced	Thermionics		Coal Derived Boiler Fuel
35	3	Advanced	Thermionics (compound cycle)		Coal Derived Boiler Fuel
36	10	Current	Steam Turbine	Bottoming	By Product Heat
37	3	Advanced	Organic Rankine	Bottoming	By Product Heat

The industrial process energy requirements vary over a wide range; some require low temperature heat (usually hot water or low pressure steam), and others require substantial amounts of intermediate or high temperature heat. Also, the ratio of thermal to electric energy varies from one industrial process to another. The choice of energy conversion system design conditions can emphasize heat recovery at one temperature or another, or electricity. The advocates for each advanced technology recognized the variability in application and provided data and information for a number of designs to provide broad cogeneration potential.

The type of design information stored for each conversion system is summarized in Figure V-3 which contains data for an advanced technology combined cycle.

```
NO.26 ADVANCED TECHNOLOGY,COMBINED CYCLE,INDIRECT FIRED,COAL(AFB)

                                          DESIGN OPTION
                                  1        2        3        4        5
                               ------   ------   ------   ------   ------
ENERGY CONVERSION SYSTEM.
  MAXIMUM POWER (MW)           150.00   150.00   0.0      0.0      0.0
  MINIMUM POWER (MW)            10.00    10.00   0.0      0.0      0.0
  NOMINAL POWER (MW)            45.00    45.00   0.0      0.0      0.0

ENERGY FRACTION - NOMINAL SIZE
  ELECTRICITY                  0.2450   0.2470   0.0      0.0      0.0
  HOT WATER                    0.1597   0.1050   0.0      0.0      0.0
  300 F STEAM                  0.0430   0.0      0.0      0.0      0.0
  500 F STEAM                  0.0      0.0      0.0      0.0      0.0
  700 F STEAM                  0.1920   0.3480   0.0      0.0      0.0
  IRRECOVERABLE LOSSES         0.0852   0.0853   0.0      0.0      0.0
  SENSIBLE HEAT                0.0696   0.0677   0.0      0.0      0.0
  DIRECT HEAT AVAILABLE        0.5144   0.5702   0.0      0.0      0.0
    CLEANLINESS INDICATOR         1.0      1.0      0.0      0.0      0.0
    DIR. HEAT TEMPERATURE(F)    794.3    794.0      0.0      0.0      0.0

HEAT SOURCE NO.=12.
HEAT REJECTION NO. = 2.
  HEAT REJECTION FRACTION      0.1550   0.1000   0.0      0.0      0.0

EMISSIONS DATA(LBS/MILLION BTU)
  SO2 OUTPUT                   1.200
  NOX OUTPUT                   0.200
  CHX OUTPUT                   0.0
  PARTICULATE OUTPUT           0.100
  SOLID WASTES                42.000

COST DATA AT   45.0MW ($/KW)   EQUIPMENT  INSTALLATION
  2.4 GASIFIER                    0.0          0.0
  3.1 PRIMARY CONVERTER          54.93        14.57
  3.2 PRIMARY GENERATOR          22.14         0.0
  3.3 SECONDARY CONVERTER        41.14        16.61
  3.4 SECONDARY GENERATOR        16.36         0.0

  3.6 HEAT RECOVERY              44.57         0.0

O & M COSTS (CENTS/KWH)      0.10

SPACE DATA AT  45.0MW
  SPECIFIC AREA   (FT2/KW)       0.17
  SPECIFIC VOLUME (FT3/KW)       9.82
  SPECIFIC WEIGHT (LBS/KW)      71.00

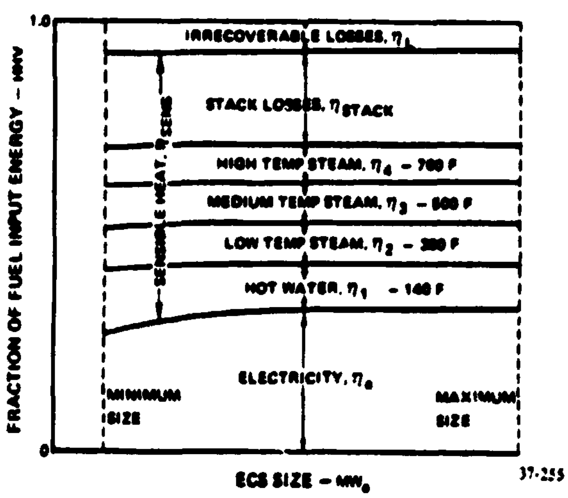
INSTALLATION TIME (YEARS)        1.
```

Figure V-3. Energy Conversion System Characteristics Printout

Each energy conversion system was limited by a maximum and minimum rated power and a nominal power condition. The data presented in Figure V-3 is at the nominal rated power and serves as an indication of the level of performance; however, the actual performance may vary over the range from the minimum to maximum power output. While not shown in the summaries, the ratio of the maximum steady-state power to rated power (i.e., overload capability) is stored in the data base.

o Performance

The performance of each energy conversion system design option was defined in terms of the fraction of energy available relative to the higher heating value of the fuel, as illustrated in Figure V-4. The energy fractions specifically defined were: electrical (ηe), hot water (η_1), low temperature steam (η_2), medium temperature steam (η_3), high temperature steam (η_4), stack sensible heat loss (η_{stack}), and irrecoverable losses (η_L). The irrecoverable losses include the latent heat of vaporization in the exhaust gases (equal to the difference between the higher and lower heating value of the fuel), the electrical generation losses and heat leaks from the conversion system to the surrounding atmosphere. The sensible heat content of the exhaust is defined as the theoretical amount of heat energy which could be recovered without condensing exhaust products. It is equal to the total heat rejected minus the irrecoverable losses.



$$\eta_{sens} = 1 - \eta_e - \eta_L$$

Figure V-4.
Energy Conversion System Energy Characteristics

The fraction of fuel energy which is available for direct heat is also listed.

$$\eta_{DH} = \zeta \eta_{sens}$$

ζ is the fraction of the sensible heat available as direct heat.

The cleanliness and temperature is noted for the direct heat available from the conversion system.

Some of the energy conversion systems require a separate source to heat the working fluid. The heat sources include steam generators, hot-gas generators, and waste-heat boilers. The heat sources were assigned numerals for simplicity and those conversion systems requiring a heat source are indicated on the summary sheets (i.e., heat source number 12 in Figure V-3). Heat source number 12 is a coal-fired, atmospheric fluidized bed, 1500°F, hot-gas generator. The conversion system is a combined cycle and requires a condenser indicated by the heat rejection number 2 for the steam turbine portion of the cycle. The condenser for design option number 1 must remove 15 percent of the fuel energy input as indicated in the example, Figure V-3. The heat is removed from the condenser by a cooling tower, a balance-of-plant item.

Three different numbers are assigned to identify the three heat rejection methods used in the study. Method number 1 applies to those systems where the rejected heat can be recovered and used in industrial processes. If the thermal energy by the process used is less than the heat rejected by the conversion system, then the balance must be removed by the cooling tower. This approach applies to closed-cycle gas turbines, Stirling cycles, and thermionic converters. Heat rejection method number 2 applies to those systems which require condensers and the cooling tower is sized to accept all of the condenser heat, i.e., 15 percent for design option number 1 in Figure V-3. This applies to steam turbines, combined cycles, and the compound thermionics device having a steam bottoming cycle. Rejection method number 3 applies to diesels only. For this case, some of the cooling-jacket water heat must be rejected through a cooling tower if the hot water requirement of the process is less than the hot water available from the jacket cooling. If the heat rejection code number is "0", there is no need to use a heat rejection system. This mode applies to open-cycle gas turbines for which the exhaust gases can be discharged directly to the atmosphere. Fuel cells also fall into this category, not because they do not need to reject heat, but because the fuel cell design already contains an integrated heat exchanger for rejecting waste heat to the atmosphere.

For bottoming cycle applications, the temperature of the usable process heat must be high enough to operate the bottoming cycle. The minimum temperature for operating the bottoming cycles is stored with each bottoming conversion system data set. This information is used to determine the applicability of bottoming to the specific industrial process considered.

o Emissions Data

The burning of fuels results in the release of various pollutants. The emissions data stored in the conversion system data file permits an estimation of the amount of each pollutant and solid waste generated at the site from the various installations. These emissions were defined in four categories: sulfur oxides, nitrogen oxides, hydrocarbons, and particulates. The emissions depend on both the conversion system and fuel type. The levels of emission are expressed in lbs/million Btu fuel input. In certain applications, the burning of fuel results in a solid waste being formed. The amount of solid wastes (bottom ash and stack-gas clean-up residues) produced is defined relative to the fuel input energy. For the example shown in Figure V-3, a large amount of solid waste (42 lbs/million Btu fuel input) is produced from the burning of the coal in the atmospheric fluidized bed. This waste includes ash and the spent limestone used to absorb the sulfur dioxide released during combustion. The handling of the waste is accomplished by the solids disposal systems which are part of the balance-of-plant.

o Cost Data

A cost accounting system was defined to provide visibility for the various elements. The complete system is presented in Table 15, "Definition of Cost Elements," in Volume I - Summary Report. The principal cost elements for energy conversion systems are identified in Figure V-3. They include the energy conversion equipment and installation costs and the operating and maintenance costs (excluding fuel). They are broken down to show the conversion equipment, the electric generator or power conditioner (such as an inverter) and the heat recovery equipment. In compound or combined systems, each conversion device and the corresponding electric generator are defined.

The advocates provided cost estimates for the energy conversion system design options and one set of data for each conversion system was included in the analysis. The summary data in Figure V-3 are for the nominal design rating. Further data were included in the computer analysis for each conversion system to evaluate various system sizes.

The cost estimates for the heat sources, balance-of-plant, and other items were treated separately from the energy conversion system and are reported in Volume IV. Condenser costs are reported in Figure III-13 of Volume III.

The installation elapsed time and costs were provided by the advocates or by Bechtel National, Incorporated as reported in Volume IV. The installation costs for the converter/generator sets are not separately defined since they are usually installed simultaneously and are, therefore, combined into the installation cost of the converter alone. The installation costs for the heat-recovery equipment, however, are indicated separately.

The operating and maintenance costs of each conversion system were also provided by the advocates and were applied at a flat rate (cents/kWh) which was not a function of the size of the system.

The physical specifications of the energy conversion system included the specific areas (ft^2/kW), the specific volume (ft^3/kW) and the specific weight (lb/kW) at the energy conversion system nominal size. The area and volume is used to estimate the size of the building required to house the conversion equipment. The determination of the area, volume and weight is made by utilizing the general relationships below.

$$\text{SPECIFIC} \begin{Bmatrix} \text{AREA} \\ \text{VOLUME} \\ \text{WEIGHT} \end{Bmatrix} = C\left(\frac{MW}{MW_{nom}}\right)^m$$

where C is the specific physical factor (ft^2/kW, ft^3/kW, lbs/kW) at the nominal or design power level (MW_{nom}) and m is the size variation exponent. The physical specifications shown in the summary data are given at the nominal size and, therefore, are equal to the specific physical factor (C).

Summary of Energy Conversion System Data

Volume VI presents the summary data for the 37 energy conversion systems and their design options used in the study. Figures V-5 and V-6 present a breakdown of the electric energy and the thermal energy available in the steam and hot water categories for the 37 configurations. These data are presented for the design option giving the highest electrical efficiency (Figure V-5), and for the design option giving the highest thermal output in the combined hot water and steam categories (Figure V-6). These charts provide an indication of the ranges covered in the available electrical and thermal energies as well as the overall fuel utilization of the energy conversion system. Table V-7 gives the emissions data at the nominal power point in pounds per million Btu of fuel input. Table V-8 presents the physical specifications for each ECS which include the specific area, volume, and weight factors at the nominal design power and the size scaling exponent. Table V-9 presents the capital and installation costs along with the operating and maintenance costs and installation time.

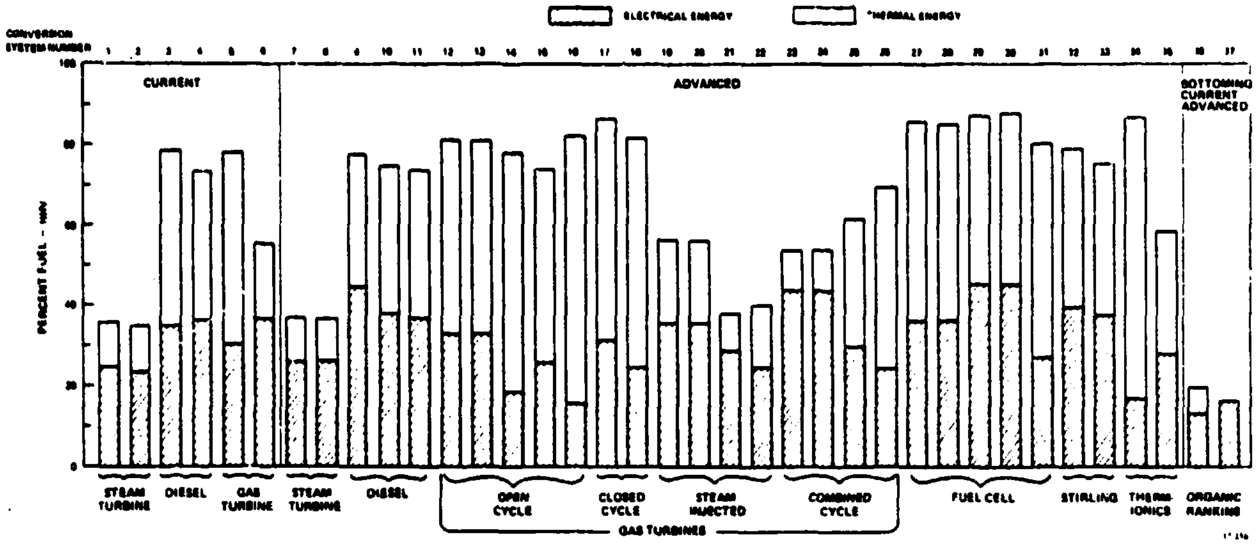


Figure V-5. Energy Conversion Systems Available Electrical and Thermal Energy- Maximum Electrical Efficiency Design Option

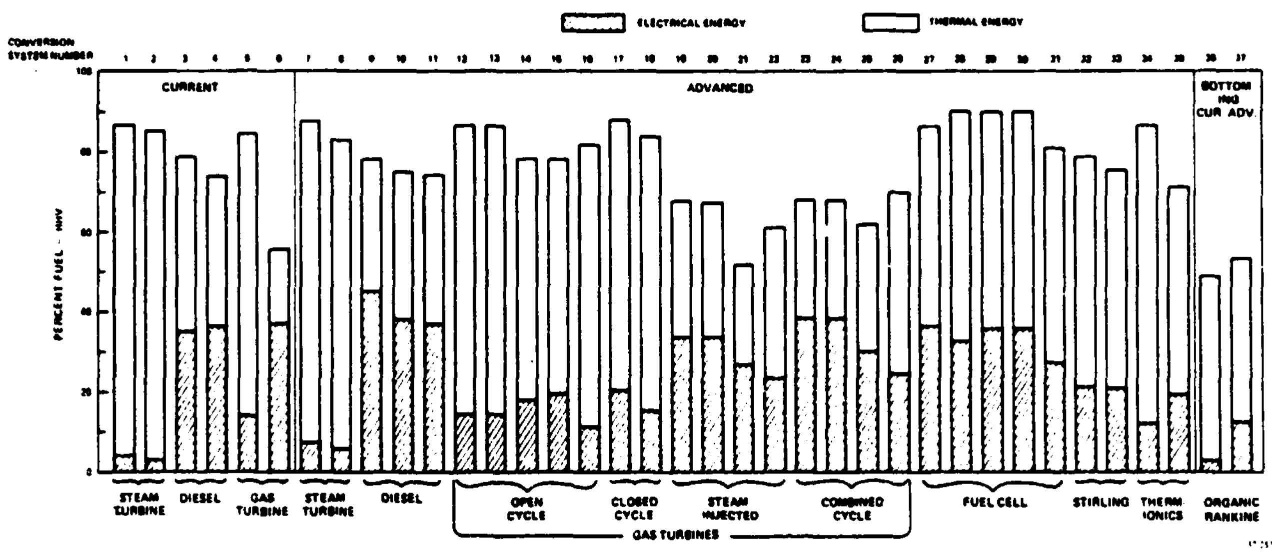


Figure V-6. Energy Conversion Systems Available Electrical and Thermal Energy for Maximum Thermal Energy Design Option

TABLE V-7
ENERGY CONVERSION SYSTEM
EMISSIONS DATA

Conversion System Number	Nominal Power (MW)	Emissions (lbs/million Btu input)				
		SO_2	NO_x	CH_x	Particulates	Solid Waste
1	18.0	0.76	0.50	0.02	0.016	0
2	18.0	1.2	0.70	0.014	0.10	6.76
3	0.6	0.516	4.0	0.04	0.02	0
4	18.0	0.757	3.68	0.17	0.012	0
5	30.0	0.52	0.4	0.02	0	0
6	30.0	0.52	0.4	0.02	0	0
7	18.0	0.824	0.5	0.02	0.10	0.053
8	18.0	1.2	0.2	0	0.10	36.0
9	2.0	0.565	4.0	0.04	0.02	0
10	20.0	0.824	3.68	0.17	0.012	0
11	20.0	1.2	3.5	0	0.10	0
12	30.0	0.76	0.5	0.02	0.03	0
13	30.0	0.82	0.5	0.02	0.10	0
14	30.0	0.82	0.5	0.02	0	0
15	30.0	1.2	0.2	0	0.001	33.0
16	30.0	1.2	0.2	0	0.1	42.0
17	30.0	0.824	0.5	0.02	0.1	0.053
18	30.0	1.2	0.2	0	0.1	42.0
19	45.0	0.76	0.50	0.02	0.03	0
20	45.0	0.82	0.5	0.02	0.10	0
21	45.0	1.2	0.2	0	0.001	33.0
22	45.0	1.2	0.2	0	0.10	42.0
23	45.0	0.76	0.5	0.02	0.03	0
24	45.0	0.82	0.5	0.02	0.10	0
25	45.0	1.2	0.2	0	0.001	33.0
26	45.0	1.2	0.2	0	0.10	42.0
27	12.0	0	0.016	0	0	0
28	12.0	0.57	0.042	0	0.034	0
29	12.0	0.51	0.083	0	0	0
30	12.0	0.57	0.087	0	0.034	0
31	100.0	0.07	0.201	0	0	0
32	30.0	0.824	0.50	0.02	0.10	0.053
33	30.0	1.2	0.2	0	0.10	42.0
34	7.2	0.824	0.50	0.02	0.10	0.053
35	12.1	0.824	0.50	0.02	0.10	0.053
36	18.0	0	0	0	0	0
37	0.8	0	0	0	0	0

TABLE V-8
ENERGY CONVERSION SYSTEM
PHYSICAL SPECIFICATIONS*

Conversion System Number	Nominal Power (MW)	Area		Volume		Weight	
		C	m	C	m	C	m
1	18.	0.054	-0.56	0.90	-0.37	15.27	-0.31
2	18.	0.054	-0.56	0.90	-0.37	15.27	-0.31
3	0.6	1.50	0	18.	0	20.	0
4	18.	0.40	0	25.0	0	100.	0
5	30.	0.045	0	1.57	0.20	15.	0
6	30.	0.20	0	12.6	0.20	90.	0
7	18.	0.054	-0.56	0.90	-0.37	15.27	-0.31
8	18.	0.054	-0.56	0.90	-0.37	15.27	-0.31
9	2.	1.50	0	18.0	0	20.	0
10	20.	0.40	0	25.0	0	100.	0
11	20.	0.40	0	25.0	0	100.	0
12	30.	0.03	0	1.05	0.20	10.	0
13	30.	0.03	0	1.05	0.20	10.	0
14	30.	0.03	0	1.05	0.20	10.	0
15	30.	0.07	0	2.28	0.20	21.	0
16	30.	0.07	0	2.28	0.20	21.	0
17	30.	0.03	0	1.05	0.20	10.	0
18	30.	0.03	0	1.05	0.20	10.	0
19	45.	0.03	0	1.14	0.20	10.	0
20	45.	0.03	0	1.14	0.20	10.	0
21	45.	0.07	0	2.47	0.20	21.	0
22	45.	0.07	0	2.47	0.20	21.	0
23	45.	0.125	0	8.52	0.20	60.	0
24	45.	0.125	0	8.52	0.20	60.	0
25	45.	0.165	0	9.82	0.20	71.	0
26	45.	0.165	0	9.82	0.20	71.	0
27	12.	1.50	0	24.0	0	-	-
28	12.	1.50	0	24.0	0	-	-
29	12.	1.50	0	24.0	0	-	-
30	12.	1.50	0	24.0	0	-	-
31	100.	1.50	0	24.0	0	-	-
32	30.	0.062	-0.10	1.0	0	50.	0
33	30.	0.062	-0.10	1.0	0	50.	0
34	7.2	0.04	0	0.56	0	62.	0
35	12.	0.13	0	0.56	0	46.	-0.07
36	18.	0.054	-0.56	0.90	-0.37	15.27	-0.31
37	0.8	0.313	-0.56	2.87	-0.37	40.	-0.31

* General Relationship

$$\left.\begin{array}{l}\text{Specific Area}\\ \text{Specific Volume}\\ \text{Specific Weight}\end{array}\right\} = C\left(\frac{MW}{MW_{nom}}\right)^m \quad \text{where } C = \frac{ft^2}{kW},\ \frac{ft^3}{kW},\ \frac{lbs}{kW}$$

TABLE V-9
ENERGY CONVERSION SYSTEM
COST DATA

$/kW at Nominal Power

Conversion System Number	Nominal Power (MW)	Equipment					Installation					O&M	Inst. Time
		3.1	3.2	3.3	3.4	3.6	3.1	3.2**	3.3	3.4	3.6	(¢/kWh)	(Yrs)
1	18.	118.4	49.2	0	0	0	6.9	0	0	0	0	.06	1
2	18.	118.4	49.2	0	0	0	6.9	0	0	0	0	.06	1
3	0.6	121.0	24.0	0	0	18.0	93.0	0	0	0	0	.70	1
4	18.	376.7	85.0	0	0	36.7	8.0	0	0	0	0	.15	1
5	30.	64.0	36.0	0	0	5100.*	24.0	0	0	0	1800.*	.25	1
6	30.	54.0	21.0	35.0	9.0	22.0	21.0	0	14.0	0	8	.20	2
7	18.	122.6	52.6	0	0	0	6.9	0	0	0	0	.06	2
8	18.	122.6	52.6	0	0	0	6.9	0	0	0	0	.06	1
9	2.	129.0	24.0	0	0	22.0	85.0	0	0	0	0	.70	1
10	20.	370.0	85.0	0	0	67.0	8.0	0	0	0	0	.15	1
11	20.	369.9	85.0	0	0	67.0	8.0	0	0	0	0	.15	2
12	30.	56.0	36.0	0	0	5100.*	24.0	0	0	0	1800.*	.28	1
13	30.	56.0	36.0	0	0	5100.*	24.0	0	0	0	1800.*	.28	1
+14	30.	54.0	36.0	0	0	5100.*	24.0	0	0	0	1800.*	.30	3
15	30.	91.0	36.0	0	0	5100.*	24.0	0	0	0	1800.*	.30	1
16	30.	91.0	36.0	0	0	5100.*	24.0	0	0	0	1800.*	.10	1
17	30.	27.0	36.0	0	0	5100.*	24.0	0	0	0	1800.*	.12	1
18	30.	38.0	36.0	0	0	5100.*	24.0	0	0	0	1800.*	.08	1
19	45.	51.1	34.7	0	0	22.6	23.1	0	0	0	7.74	.26	1
20	45.	51.1	34.7	0	0	22.6	23.1	0	0	0	7.74	.26	1
21	45.	84.7	34.7	0	0	27.3	23.1	0	0	0	9.43	.28	1
22	45.	84.7	34.7	0	0	29.0	23.1	0	0	0	9.50	.12	1
23	45.	40.4	26.1	35.1	13.1	18.1	17.7	0	14.4	0	6.52	.24	2
24	45.	40.4	26.1	35.1	13.1	18.1	17.7	0	14.4	0	6.52	.24	2
25	45.	73.1	28.9	30.9	9.6	25.2	19.2	0	11.9	0	8.68	.26	1
26	45.	54.9	22.1	41.1	16.4	44.6	14.6	0	16.6	0	0	.10	1
27	12.	226.7	50.0	0	0	12.0	10.0	0	0	0	0	.22	1
28	12.	302.8	50.0	0	0	40.0	10.0	0	0	0	0	.29	1
29	12.	276.2	50.0	0	0	10.0	10.0	0	0	0	0	.27	1
30	12.	218.5	50.0	0	0	20.0	10.0	0	0	0	0	.23	1
+31	100.	150.0	50.0	0	0	20.0	10.0	0	0	0	0	.30	3
32	30.	164.0	21.8	0	0	55.5	5.9	0	0	0	0	.45	1
33	30.	128.0	21.8	0	0	46.0	5.9	0	0	0	0	.45	1
34	7.2	432.0	51.1	0	0	0	22.2	4.4	0	0	0	.18	1
35	12.	266.4	31.0	83.8	35.7	0	13.9	2.7	3.6	0	0	.13	1
36	18.	118.4	49.2	0	0	0	6.9	0	0	0	0	.06	1
37	0.8	166.1	34.8	0	0	147.4	49.9	10.5	0	0	44.2	.50	1

Cost accounting categories
- 3.1 Primary converter
- 3.2 Primary generator
- 3.3 Secondary converter
- 3.4 Secondary generator
- 3.6 Heat Recovery equipment

* $/MBtu @ 100 MBtu/HR
**Generator installation included in 3.1.
+ Has coal gasifier equipmnet
ECS No. 14 - 415 Equip. - 115 INST
ECS No. 31 - 350 Equip. - 120 INST

HEAT SOURCES

The study employed 14 heat-source designs which were characterized by Bechtel National, Incorporated for use in various plant and conversion systems. Four were boilers for providing steam and hot-water needs, nine were used to provide the thermal input for various energy conversion systems, and one was a waste-heat-recovery boiler. These designs were differentiated by the type of fuel burned, the form of the thermal energy, the technology status, and the temperature of the thermal energy output. These heat sources are described in Volume IV of this report series. Their key characteristics, which were stored in the computer data file, are described herein.

Heat Source Characterization

The 14 heat sources employed in this study are listed in Table V-10. Heat sources numbered 1 through 4 provide hot water or steam for the cases without cogeneration and also provide auxiliary thermal energy required with some cogeneration situations. When a cogeneration plant consumes coal or coal derived fuel, the auxiliary heat source consumes coal-derived boiler grade fuel.

Heat sources number 5 and number 10 are current technology oil- and coal-fired 1200 psi steam boilers which are used with current technology steam turbines.

Heat source number 6 is an advanced technology 1800 psi steam boiler using coal-derived residual oil which is used with an advanced steam turbine.

Heat sources numbered 7 and 8 are advanced technology, hot-gas generators used with Stirling engines and advanced, indirect-fired gas turbines.

Heat source number 9 is designed specifically as a heat source for a thermionic converter operating at 2400°F.

TABLE V-10

HEAT SOURCES

No.	Description	Fuel
1	140 F water heater	Petroleum Boiler Grade
2	300 F steam generator	"
3	500 F steam generator	"
4	700 F steam generator	"
5	950 F steam generator	"
6	1050 F steam generator	Coal Derived Boiler Grade
7	1800 F hot gas generator	"
8	2200 F hot gas generator	"
9	2400 F thermionic heat source	"
10	950 F steam generator	Coal
11	1050 F steam generator (AFB)*	"
12	1500 F hot gas generator (AFB)*	"
13	1600 F hot gas generator (PFB)**	"
14	950 F waste heat recovery unit	

* Atmospheric Fluidized Bed
** Pressurized Fluidized Bed

Heat sources 11 and 12 use coal fired atmospheric fluidized bed combustion. Heat source number 11 provides high temperature steam to advanced steam turbines and heat source number 12 provides high temperature gas to advanced, indirect-fired, gas turbines, and Stirling engines.

Number 13 involves a coal-fired pressurized fluidized bed heat source for advanced, direct-fired gas turbines.

o Performance

Each heat source was characterized by a thermal efficiency (heat energy output/ fuel input) and all associated electrical and/or thermal parasitic losses. The thermal efficiency of the heat sources which were used for auxiliary furnaces was established by the study ground rules. The thermal efficiencies used for the other heat sources were the design point values developed by Bechtel National, Incorporated.

The auxiliary electrical power required for the peripheral equipment necessary for the operation of the heat source includes such items as induced draft fans and feedwater pumps. The thermal parasitic requirements for heat sources 1 through 9 were in the form of low pressure steam (50 psig, 300°F) which was used in the fuel atomizing system. No thermal parasitic requirement was needed for the remaining heat sources. The balance of plant equipment has parasitic requirements discussed in the next major section of this Volume V.

o Cost Data

Costs for the heat sources were broken down into equipment and installation. These costs were stored in the data base as a function of thermal output and, in some cases, the costs were also a function of fabrication techniques. For example, Figure V-7 indicates the estimated cost of heat source 6 is dependent upon the construction practice which is dictated by the source rating. Large size dictates field assembly because of transportation, special design, or logistics problems.

These units are generally more expensive than smaller units which are preassembled in the shop. The installation cost for each heat source includes the direct installation labor cost at $14.00 per manhour plus a 75 percent surcharge on the direct labor cost for indirect costs.

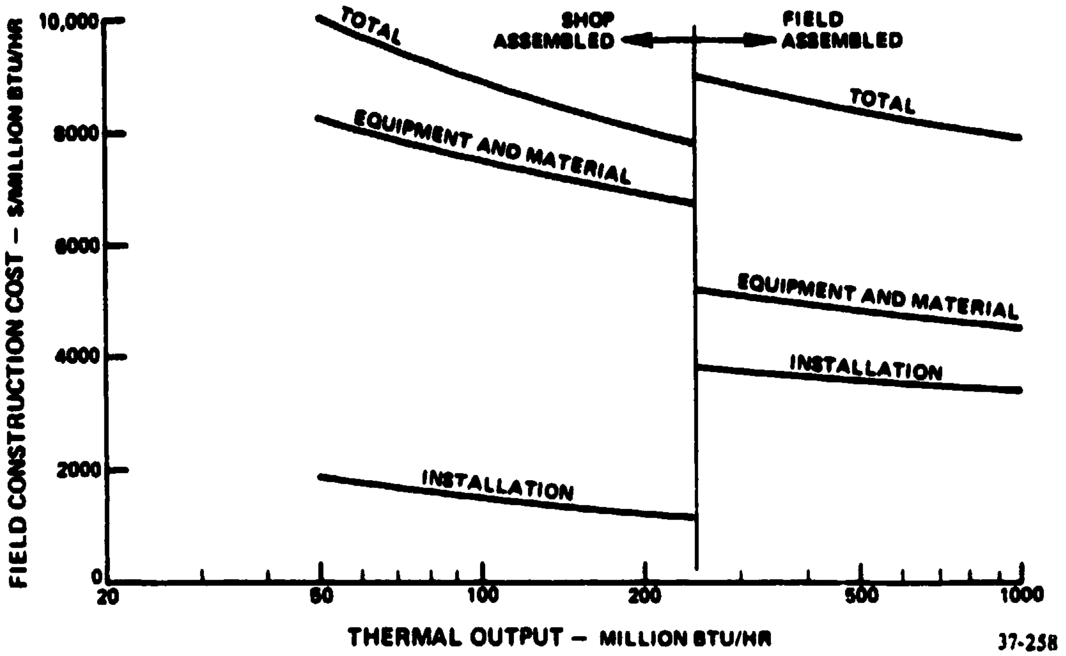


Figure V-7. Coal Derived Residual Oil Fired 1050 Steam Generator Costs

In addition to the capital equipment costs and installation fees, each heat source will have a recurring annual operating and maintenance cost reported in Volume IV.

The overall cogeneration analysis includes the evaluation of all materials discharged by the complete system. The heat source data base used in this analysis includes all materials discharged from the heat sources. The design of the heat sources includes provision to limit nitrogen oxide emissions and, in many cases, sulfur dioxide. In some cases, balance-of-plant equipment is necessary to meet the emission requirements and the appropriate data are included in the balance-of-plant data base. For example, a flue gas desulfurizer is a balance-of-plant item which limits the sulfur dioxide emitted by a coal fired heat source.

Summary of Heat Source Data

The thermal efficiencies and parasitic electric and thermal requirements for the heat sources are presented in Table V-11. A summary of the heat source equipment, installation, and operating and maintenance cost for nominal size units is presented in Table V-12. Table V-13 shows the emissions and wastes discharged for each of the systems considered. Physical space requirements (area and volume) and estimated construction time are presented in Table V-14 for the nominal size units only.

TABLE V-11

HEAT SOURCE ENERGY CHARACTERISTICS

Heat Source Number	Nominal Size (Million Btu/hr)	Efficiency(%)	Parasitic Requirements Electrical (kWh/Million Btu)	Parasitic Requirements Thermal (Btu/ Btu)
1	150	88	2.8	.020
2	150	88	1.3	.020
3	150	88	2.3	.020
4	150	88	2.3	.020
5	500	88	3.0	.020
6	500	88.5	4.1	.020
7	125	88.3	1.85	.020
8	125	88.3	2.34	.020
9	125	88.3	1.3	.020
10	500	85	3.5	0
11	250	84	5.9	0
12	250	84	3.9	0
13	250		0.55	0
14	250	53	3.4	0

TABLE V-12

HEAT SOURCE COST SUMMARY

Heat Source Number	Nominal Size Million Btu/hr	Cost at Nominal Size ($/MBtu/hr) Equipment	Installation	Total	Operating and Maintenance $/year/Million Btu/hr
1	150	2950	1050	4000	175
2	150	2450	1050	3500	175
3	150	3450	1050	4500	175
4	150	3300	1000	4300	175
5	500	4400	3400	7800	175
6	500	4800	3580	8380	175
7	125	19500	2200	21700	234
8	125	29500	2000	31500	234
9	125	16000	6000	22000	234
10	500	10300	7900	18200	292
11	250	11800	5100	16900	380
12	250	17000	9000	26000	380
13	250	15000	9600	24600	350
14	250	6940	2200	9140	175

TABLE V-13

HEAT SOURCE EMISSIONS AND WASTES

Heat Source Number	Emissions (lbs/million Btu Fuel) SO_2	NO_x	CH_x	CO	Particulates	Wastes Discharged (lbs/million Btu/Fuel) Blowdown	Dry Solids	Wet Solids
1	0.76	0.5	0.02	0.027	0.016	9.3	0	0
2	0.76	0.5	0.02	0.027	0.016	9.3	0	0
3	0.76	0.5	0.02	0.027	0.016	7.9	0	0
4	0.76	0.5	0.02	0.027	0.016	7.9	0	0
5	0.76	0.5	0.02	0.027	0.016	7.1	0	0
6	0.824	0.5	0.02	0.027	0.10	6.9	0.053	0
7	0.824	0.5	0.02	0.027	0.10	0	0.053	0
8	0.824	0.5	0.02	0.027	0.10	0	0.053	0
9	0.824	0.5	0.02	0.027	0.10	1.3	0.053	0
10	7.2	0.7	0.046	0.093	0.10	6.8	1.87*/4.98	6.23*/1.78
11	1.2	0.2	0	0.04	0.10	6.9	36.0	0
12	1.2	0.2	0	0.04	0.10	0	42.0	0
13	1.2	0.2	0	0.04	0.001	0	33.0	0
14	x	x	x	x	x	4.7	0	0

x - dependent upon the process hot-gas source

* - left values for systems below 150 x 10^6 Btu/hr

TABLE V-14

HEAT SOURCE SPACE REQUIREMENTS

Heat Source Number	Nominal Size (Million Btu/hr)	Space Requirements Area (Ft^2)	Volume (Ft^3)	Construction Time (Months)
1	150	2680	94500	2
2	150	2040	73500	2
3	150	2235	79500	2
4	150	2235	79500	2
5	500	6500	425000	25
6	500	6500	425000	25
7	125	4500	212500	18
8	125	4500	212500	18
9	125	4000	240000	24
10	500	9500	1275000	31
11	250	8500	630000	25
12	250	8500	630000	28
13	250	1750	98500	28
14	250	6250	350000	20

BALANCE-OF-PLANT SYSTEMS

The balance-of-plant systems used in this study were developed by Bechtel National, Incorporated and reported in Volume IV. These systems complement the basic energy conversion systems and heat sources and are necessary for their operation. The fourteen Balance-of-Plant items used in this study are listed in Table V-15.

All cogeneration systems require one or more balance-of-plant subsystems. All facilities require one of the fuel storage and distribution systems (1-3). Fluidized bed coal combustion requires the limestone/dolomite storage and distribution systems (4) and the dry-solids disposal system (5). The conventional coal fired boiler requires the wet-solids disposal system (6) and the sulfur dioxide scrubber system (7). The pressurized fluidized bed combustor also requires the hot-gas cleanup system (8). All steam and hot water systems require a feedwater system

(9). Most systems would require a heat-rejection system (10) to dispose of the excess thermal energy. All systems require an electrical conditioning and control system (11). Most energy conversion systems required buildings (12) and all systems required site preparation and development (13). Installation costs for static and rotating equipment are presented under Balance-of-Plant number 14. This information was used in determining the energy conversion system installation cost except in those cases where more directly applicable data was available.

TABLE V-15. BALANCE-OF-PLANT SYSTEMS

Number	System Description
1	Distillate Oil Storage and Distribution System
2	Residual Oil Storage and Distribution System
3	Coal Storage and Distribution System
4	Limestone Storage and Distribution System
5	Dry Waste Solids Disposal System
6	Wet Waste Solids Disposal System
7	Sulfur Dioxide Scrubber System
8	Hot Gas Cleanup System
9	Boiler Feedwater System
10	Heat Rejection System
11	Electrical Conditioning and Control System
12	Energy Conversion System Building
13	Site Preparation and Development
14	Energy Conversion Equipment Installation

<u>Balance-of-Plant Data Base</u>

o Energy Requirements

Most balance-of-plant systems require electrical and thermal energy for their operation. Electrical parasitic power was defined in terms of KWe expended per unit of resource or material handled. Thermal parasitic energy was defined in terms of millions of Btu of steam expended per unit of resource or material handled. In addition to the electrical and thermal parasitics, three systems required additional resources such as make-up water for the scrubber, heat rejection, and wet-waste solids disposal systems and chemicals for the scrubber systems. Table V-16 shows the parasitic requirements, additional resources, and wastes generated for balance-of-plant systems 1-10. Items 11-14 have no parasitic power requirements.

TABLE V-16

BALANCE OF PLANT REQUIREMENTS

Balance-of-Plant Number	Units	Resource or Material Handled	Parasitic Power Electric (kWe/unit)	Parasitic Power Thermal (MBtu/hr/unit)	Make-up Water (lbs/hr/unit)	Limestone (lbs/hr/unit)	Wastes (lbs/hr/unit)
1	Million Btu/hr	fuel	0.009	0	0	0	0
2	Million Btu/hr	fuel	0.2	0.007	0	0	0
3	Million Btu/hr	fuel	0.07	0	0	0	0
4	lbs/hr	limestone	0.45	0	0	0	0
5	Thousand lbs/hr	dry solids	0.002	0	0	0	0
6	lbs/hr	wet solids	0.005	0	0.5	0	0
7	Million Btu/hr	flue gas	0.20	0.050	100	6.5	11.0
8	Thousand lbs/hr	flue gas	0.67	0	0	0	0
9	Thousand lbs/hr	feedwater	0.054	0*	0	0	0
10	Thousand lbs/hr	reject heat (steam)	3.25	0	1350	0	0

* The feedwater system uses 0.11 lb. steam per lb. of water heated. This requirement is included in the energy requirement for making steam and hot water. It is not included here to avoid double bookkeeping.

o Cost Data

The capital costs for balance-of-plant systems included equipment and installation costs. These costs were dependent upon the size of the system as illustrated in Figure V-8 for the Coal Storage and Distribution System. Table V-17 presents the capital equipment and installation costs for systems 1-11 at the indicated system sizes.

The annual operating and maintenance costs of the balance-of-plant systems were correlated with the type and size of the heat source used in the conversion system. These costs are presented in Table V-18.

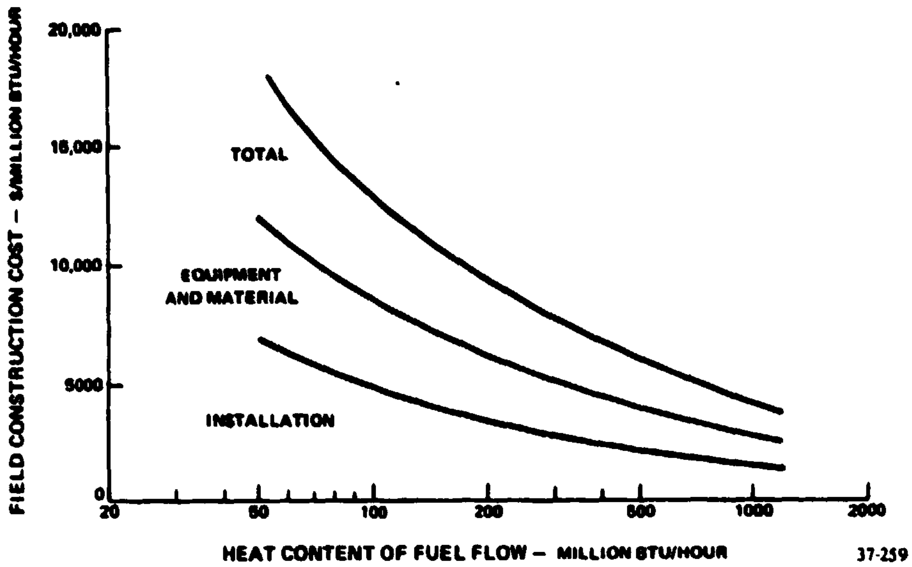


Figure V-8. Coal Storage and Distribution System Costs

TABLE V-17

BALANCE OF PLANT COSTS

Balance-of-Plant Number	System Size	Units	Resources or Material Handled	Costs ($/Unit) Equipment	Installation	Total
1	100	Million Btu/hr	Fuel	910	150	1060
2	100	Million Btu/hr	Fuel	1180	160	1340
3	100	Million Btu/hr	Fuel	8500	4800	13300
4	20	Thousand lbs/hr	Limestone	4550	4200	8750
5	1000	Lbs/hr	Dry Solids	83	13	96
6	1000	Lbs/hr	Wet Solids	37	15	52
7	100	Million Btu/hr	Flue gas	15500	260	15760
8	100	Thousand lbs/hr	Flue gas	2960	1000	3960
9	100	Thousand lbs/hr	Feedwater	680	250	930
10	100	Million Btu/hr	Reject Heat	4700	2500	7200
11	1000	kWe	Auxiliary Power	117	81	198

TABLE V-18

BALANCE OF PLANT OPERATING AND MAINTENANCE COSTS

	Annual Cost ($/Million Btu/hr)
Oil Fired Heat Source	117
Coal Fired Heat Source	204
Coal Fired Heat Source with Sulfur Dioxide Scrubber	554
Coal Fired Heat Source with Hot Gas Cleanup System	258

The cost of the energy conversion system building was determined by applying the following relationship:

$$\text{Building field construction cost} = 1.2\ K_{ECS}\ A_{ECS} + K_{HS}\ A_{HS}$$

where K_{ECS} = conversion system building specific cost ($/ft^2) (the factor 1.2 accounts for the cost of the crane)

A_{ECS} = conversion system footprint area (ft^2)

K_{HS} = heat source building specific cost ($/ft^2)

A_{HS} = heat source foot print area (ft^2)

Diesel engines, Stirling engines, steam turbines, and organic Rankine cycle conversion systems were housed in a building. The gas turbine costs included housing and silencing. The fuel cells were designed for outside installation.

The cost of site preparation and development was estimated to be 1 percent of the total cogeneration plant direct cost.

TABLE V-19

BUILDING COSTS

Building Height (ft)	K_{ECS} ($\$/ft^2$)	K_{HS} ($\$/ft^2$)
0 - 20	50	30
20 - 40	70	42
40 - 60	95	57
60 - 80	125	75

where Height $= \frac{\text{Volume}}{\text{Area}}$

HEAT PUMP

The heat pump performance used in the study was developed in consultation with Westinghouse Electric Company. Figure V-9 shows the coefficient of performance as a function of the normalized temperature lift for single- and two-stage units. This performance was developed from published data for heat pumps with outlet temperatures in the range from 140°F to 220°F. Although there are no current heat pumps which are designed to operate in the 300°F to 500°F temperature range, it was assumed for this study that such heat pumps could be developed, and that they would have normalized performance curves similar to that presented in Figure V-9. Heat pumps with higher outlet temperatures were not considered in this study.

Figure V-10 presents the heat pump cost (\$/million Btu/hr output) as a function of heat output (million Btu/hr). The cost of heat pump installation was estimated to be equal to the equipment cost.

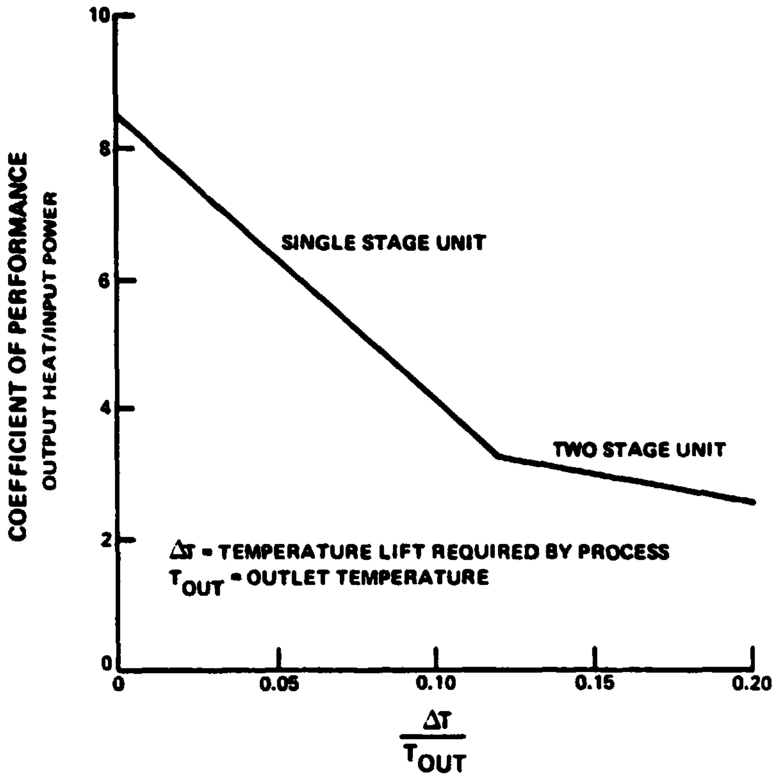


Figure V-9.
Normalized Heat Pump Performance

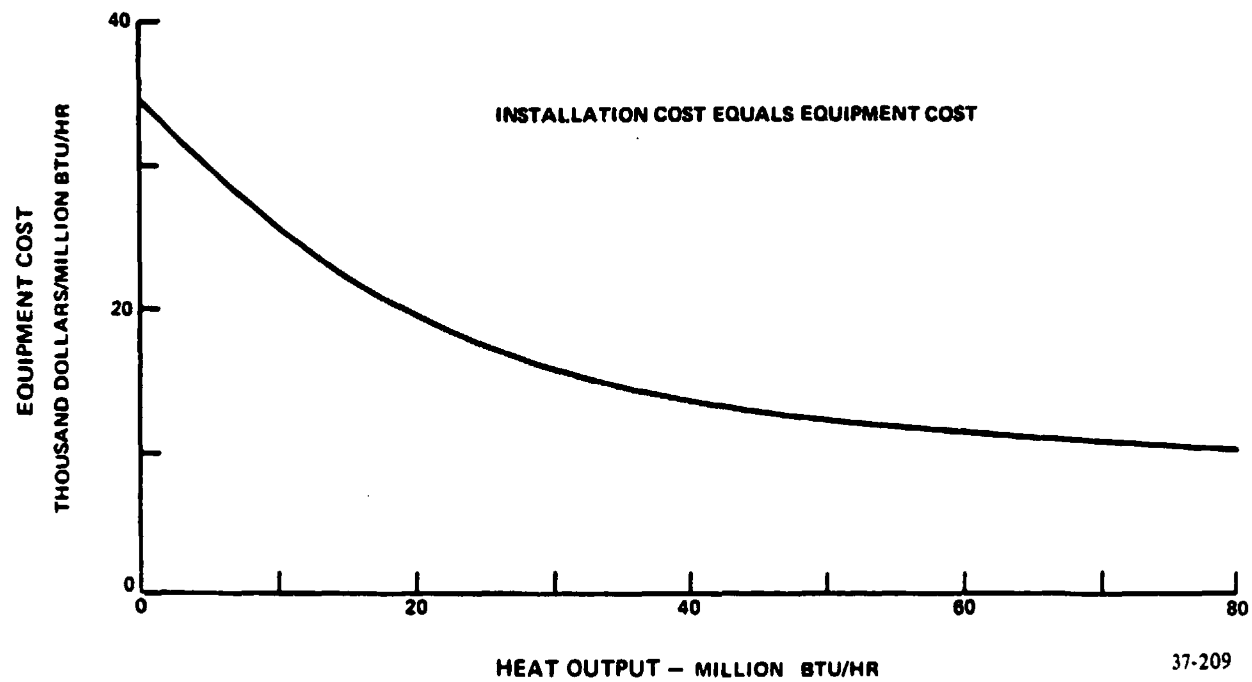


Figure V-10. Heat Pump Equipment Cost

COGENERATION SYSTEMS

A cogeneration system is an integration of the various components (energy conversion system, balance-of-plant systems, heat source, heat pump, etc.) into a total system which provides the electrical and thermal requirements of a specified industrial process. The overall cogeneration system model used in this study is illustrated in Figure V-11. Fuel is provided to the conversion system and any on-site furnace. Electricity is produced for the process and, if there is a surplus or a deficit, electrical energy can be bought from or sold to the electric utilities. The cogeneration system also provides thermal energy in appropriate categories for the industrial process. If the process produces a by-product fuel, that fuel is used in the conversion system, if possible. Also, if the process produces surplus heat, that energy could be used in a bottoming cycle.

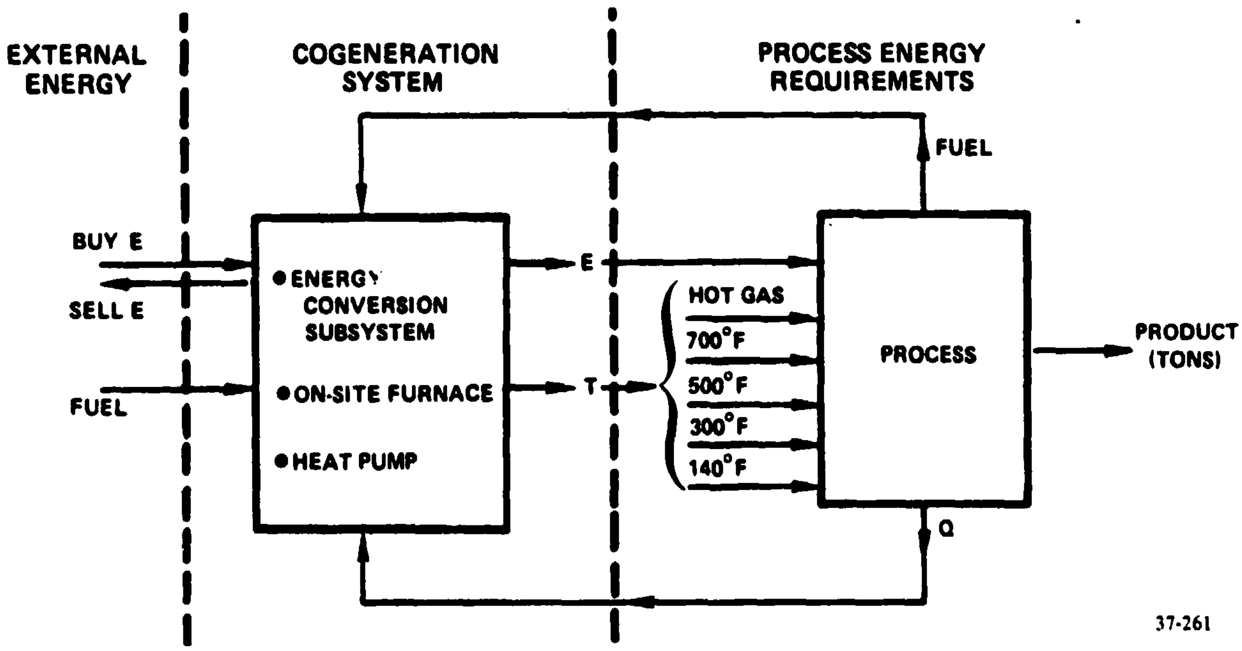


Figure V-11. Cogeneration System Model

A diagram showing the relationship of the various components which may comprise a topping-cycle cogeneration system is shown in Figure V-12. All of these elements would not appear for every system. The specific components comprising a cogeneration plant will depend upon the industry, the energy conversion system, and the strategy picked for sizing the energy conversion system. For example, if an open-cycle gas turbine were sized to meet the energy requirements of an industrial process, there would be no need for a separate heat source, waste disposal or cleanup system, condenser, or heat rejection system. Depending on the industrial requirements and matching strategy used, the auxiliary furnace or heat pump may not be used, i.e., if the gas turbine system were sized so that the waste heat recovered from its exhaust met the thermal requirements of the industrial process, no additional heat, nor heat pumping of the waste heat to a higher temperature would be required.

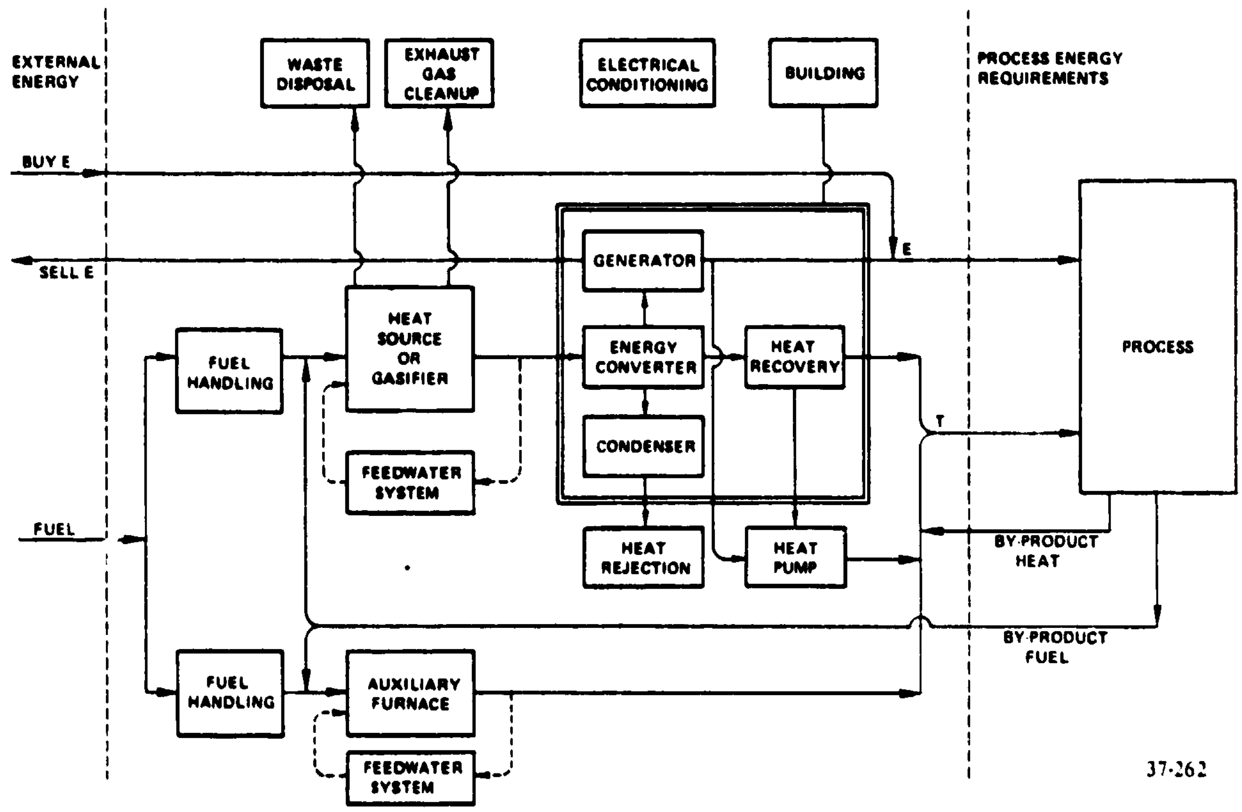


Figure V-12. Cogeneration Plant — Topping Cycle

Other energy conversion systems would require a heat source and some of these heat sources would require waste disposal and exhaust cleanup systems. All systems would require a fuel handling system, generator, heat recovery equipment, feedwater heater, and electrical conditioning equipment. Many systems require buildings.

A similar diagram for a bottoming cycle cogeneration plant is shown in Figure V-13. In this system, the vapor generator replaces the heat source. Neither a furnace nor cleanup system is needed in the cogeneration system.

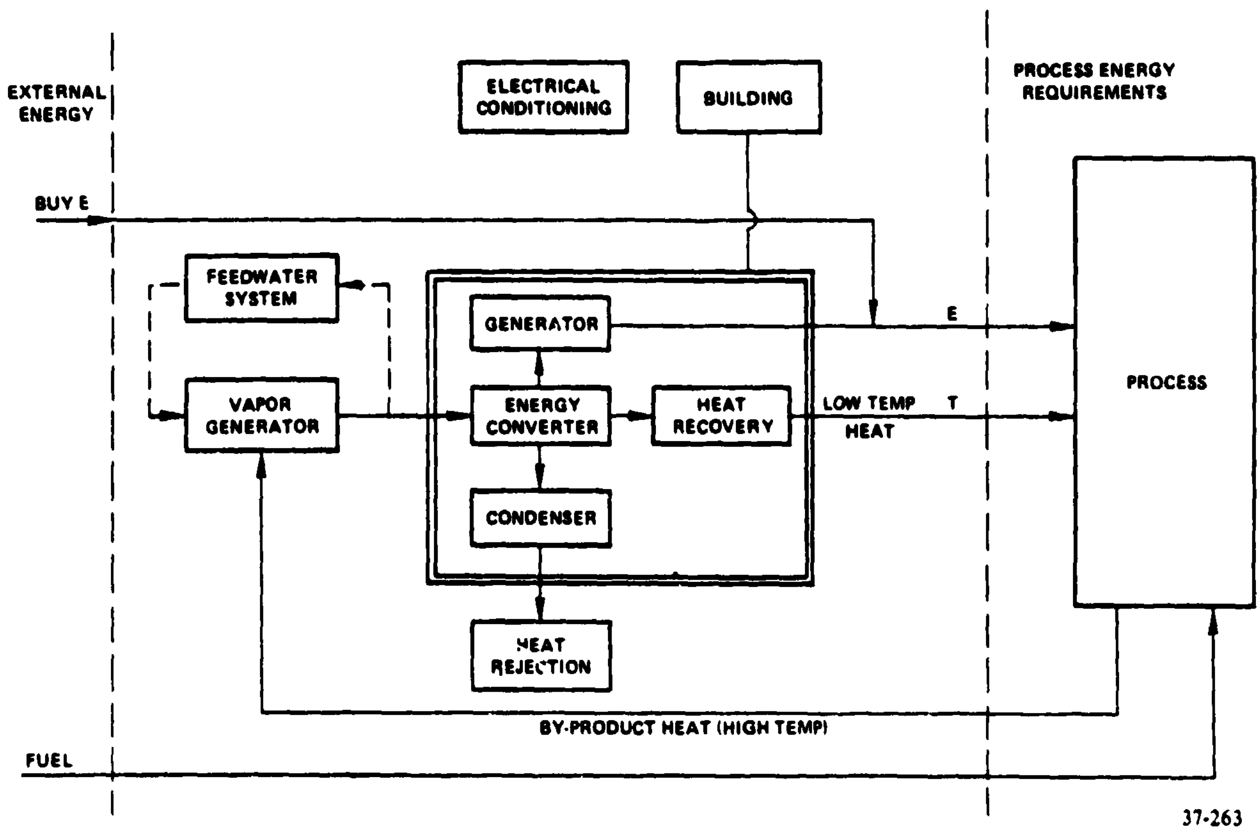


Figure V-13. Cogeneration Plant — Bottoming Cycle

Table V-20 lists the required heat source and balance-of-plant systems for each of the 37 energy conversion systems based on the identification numbers defined in Tables V-6, V-10, and V-15. To these systems are added any additional systems (such as an auxiliary furnace) which may be required as a result of applying a specific conversion system and matching strategy to a given industrial process.

TABLE V-20

COGENERATION PLANT COMPONENTS

Conversion System Number	Heat Source Number	Balance of Plant*			
		Fuel/Waste Handling	Clean Up	Heat Rejection	Building
1	5	2		10	12
2	10	3,6	7	10	12
3	-	1		10	12
4	-	2		10	12
5	-	1			
6	-	1		10	12
7	6	2		10	12
8	11	3,4,5		10	12
9	-	1		10	12
10	-	2		10	12
11	-	3		10	12
12	-	2			
13	-	2			
14	Gasifier	3			
15	13	3,4,5	8		
16	12	3,4,5			
17	8	2		10	
18	12	3,4,5		10	
19	-	2			
20	-	2			
21	13	3,4,5	8		
22	12	3,4,5			
23	-	2		10	12
24	-	2		10	12
25	13	3,4,5	8	10	12
26	12	3,4,5		10	12
27	-	1			
28	-	1			
29	-	1			
30	-	1			
31	Gasifier	3			
32	7	2		10	12
33	12	3,4,5		10	12
34	9	2		10	12
35	9	2		10	12
36	14	-		10	12
37	-	0			12

* All systems use BOP No. 9 - Boiler Feedwater System
11 - Electrical Conditioning and Control System
12 - Site Preparation and Development

COGENERATION PERFORMANCE ANALYSIS

A computer program was developed to assemble the appropriate data and calculate energy consumption, costs, and environmental impact of cogeneration systems. These calculations used the data base contained in the industry, energy conversion system, heat source, and balance-of-plant data files.

Overview

To analyze a particular cogeneration system, it is necessary to prescribe the (1) industry, (2) energy conversion system, (3) year, and (4) cogeneration strategy. Specification of the industry and conversion system allows selection of the data sets from the 26 industry and 131 conversion system data files. Although there were only 37 different energy conversion systems, each had several design options such that the total number of conversion system data files was 131. These data contain codes defining which heat sources and balance-of-plant items must be included. The appropriate data from the heat-source and balance-of-plant data files are selected for use.

Definition of the year to be studied establishes the industrial requirements and certain economic factors (such as the cost of fuel).

Various strategies may be used to match a conversion system to an industry: (1) Meet the electrical requirement exactly and use all the heat possible for meeting thermal needs. A supplemental furnace provides additional heat for larger thermal requirements. Excess heat is rejected if the thermal requirement is smaller than that provided by the conversion system. (2) Meet the electrical requirement and meet the thermal requirement by using high temperature heat directly and by heat pumping low temperature waste heat to suitable temperatures for process needs. (3) Meet the thermal requirements with conversion system heat, and buy or sell electricity as required. (4) Select the system which optimizes fuel energy utilization.

The computer program was used to calculate the fuel use, costs, and emissions for both a single cogeneration plant and for the entire industry as typified by the representative plant. The same characteristics were calculated for a conventional plant and for the entire industry without cogeneration. These non-cogeneration results were used as a basis for subsequent comparisons. The total number of cases analyzed by the computer was more than 11,000. The first step in reducing the number of cases was to select the best conversion system design option for each cogeneration system. The performance for each design option was calculated and the design option with maximum fuel savings was chosen for each matching strategy. These results were stored in a master output data file. The master data file was subsequently used to retrieve data and print it out in various formats in order to make additional comparisons, eliminate cases which did not conserve fuel energy or were economically unattractive, and select 120 cases for more detailed economic studies.

Energy Consumption Without Cogeneration

In a conventional, non-cogeneration industrial process electricity is bought from a utility and thermal requirements are met with on-site furnaces. To evaluate the energy consumption for a typical industrial situation, the necessary information for that industry is gathered from the industrial data file described previously.

Among the data gathered are the following: product output, normalized temporal energy requirements per unit production, by-product fuel and heat availability, temperatures and pressures for thermal requirements, specified fuels and cleanliness requirements, national fuel breakdowns for the industry, and information allowing projection of the 1978 data to 1985-2000.

To find the energy requirements for a typical plant, the normalized temporal profiles are scaled up to annual requirements by multiplying by the annual plant production. The energy requirements are divided up into six categories: (1) electricity, (2) hot water, (3) low temperature steam, (4) medium temperature steam, (5) high temperature steam, and (6) direct heat (i.e., a hot gas).

The energy requirements given in the industrial data base are gross energy requirements needed by the actual manufacturing process; they are independent of any requirements to preheat make-up water or any parasitics associated with the equipment (furnaces, etc.) used to supply energy to the process and they do not include the use of any by-product heat or fuel from the process that could be used to reduce the requirements.

The fraction of steam condensate and hot water returned is included in the industrial data base and presented in Table V-2. If all of the steam or hot water is not returned for re-use in the process, it must be replaced by ambient water at 60°F. The fractions to be made up are stored in the industry data file. Thus, the total amount of makeup water required can be calculated and used to find the additional energy needed to heat it to the proper temperature. That value is added to the calculated hot-water requirement.

If an industrial process generates waste heat, this by-product process heat could be used to reduce the thermal requirements that have been specified. The computer program is based on using that available by-product heat whenever possible. The available by-product heat is given in terms of its temperature, and its Btu content referenced to ambient condition (i.e., 60°F). There is also an indicator telling whether the heat is available in the form of steam or hot gas. If it is steam, it can be applied directly to meet thermal requirements. If the heat is in the form of hot gas, only that portion with temperature greater than the exhaust stack temperature is available for use. The by-product heat is used to its fullest extent. Thus, it can be applied against thermal requirements in any category having a lower temperature, or to preheat higher temperature requirements up to the temperature of the by-product heat.

For those industries having direct heat requirements, there are special restrictions regarding how these requirements may be met. A particular fuel may be specified or a minimum cleanliness required of the hot gas. In cases where use of process by-product heat would be inappropriate, by-product heat is applied to the steam and hot water requirements.

After using the by-product heat to meet thermal needs in accordance with the above restrictions, the net thermal and electrical requirements, except for parasitic effects, are specified. These values are the starting point for both non-cogeneration and cogeneration calculations. The final requirements will differ in each case only by the differences in the parasitics.

Thermal parasitics in a conventional plant come primarily from two sources: fuel storage and handling, and operating the furnaces. Thermal energy (usually low temperature steam) is used to heat boiler grade oil in order to transport it and atomize it in the furnace. The parasitic requirement for fuel handling is proportional to the amount of fuel consumed by the furnace. Thus:

$$Q_P = (\alpha_{FH} + \alpha_{Furn})\, Q_F^{tot}$$

where Q_P = thermal parasitic (Btu)

Q_F^{tot} = quantity of fuel (Btu)

α_{FH} = fuel handling parasitic thermal factor

α_{Furn} = furnace parasitic thermal factor

The parasitic factors α_{FH} and α_{Furn} are calculated from balance-of-plant data for the fraction of fuel that is boiler grade. If Q_N is the net thermal requirement except for parasitics, the total fuel consumption can be written as:

$$Q_F^{tot} = (Q_N + Q_P)/\eta_F$$

where η_F is the average furnace efficiency. This can be rewritten as

$$Q_F^{tot} = (Q_N + (\alpha_{FH} + \alpha_{Furn})\, Q_F^{tot})/\eta_F$$

After some algebraic manipulation

$$Q_F = \frac{(\alpha_{FH} + \alpha_{Furn})}{\eta_F - (\alpha_{FH} + \alpha_{Furn})}\, Q_N$$

Hence, once the net thermal requirement except for parasitics, Q_N, is known, the parasitic requirement is also known. This requirement is considered to be for 300°F steam referenced to ambient conditions (60°F).

The electrical parasitic requirements are equally straightforward to calculate. Contributions arise from fuel handling, furnace operation, and the boiler feedwater system. Once the on-site fuel requirements are known, the fuel handling parasitics are calculated. The furnace parasitic is proportional to the furnace output (i.e., $Q_N + Q_P$) and thus is directly calculable. Finally, the water flow associated with the total thermal requirement is evaluated from data in the heat-source file and used to calculate a feed-water supply electrical parasitic. These parasitics are added to the nominal electrical requirement to find the total electrical requirements.

Once the total thermal and electrical requirements are known we can calculate the amount of fossil fuels that must be burned to meet them. Fuel burned at the plant site is calculated by dividing the total requirement ($Q_N + Q_P$) by the average furnace efficiency η_F. If there is any by-product fuel available from the process, Q_F^{BP}, it can displace fuel for the furnaces by the amount

$$Q_F^{Disp} = Q_F^{BP}\, \eta_{BP}/\eta_F$$

where η_{BP} is the efficiency with which the by-product fuel may be burned. Thus the net fuel consumed at the industrial site without cogeneration is

$$Q_F^{Net} = \frac{Q_N + Q_P - Q_F^{BP}\eta_{BP}}{\eta_F}$$

Here, Q_N, Q_P and η_F are previously calculated values, and Q_F^{BP} and η_{BP} are given in the industrial data base.

All electricity used in a non-cogeneration plant is bought from a utility. The fuel required to generate that electricity is found by dividing the requirement by the utility efficiency, η_u, which was specified to be 0.32.

The total fuel consumption associated with a single industrial process is found by adding the fuel consumption at the utility to the fuel burned at the site.

The total national annual fuel usage for the industry is evaluated by the following procedure. The fuel consumption at the industrial site is scaled up by the ratio of national production to the representative plant production. This national consumption is broken down by fuel type using the breakdown percentages given in the data base. National utility fuel consumption associated with the industry in question is also found by scaling plant-level utility fuel consumption by the ratio of national-to-plant production. This fuel consumption is assumed to be all coal, and is added to the coal consumed at the plant to give the overall national breakdown of fuel usage for the industry.

Energy Consumption with Cogeneration

A cogeneration plant differs from a conventional plant in that all or part of the required electricity is provided by an on-site energy conversion system, and the heat from the cogeneration system is used to help meet the plant thermal requirements.

The industry information required to calculate performance for a cogeneration system is the same as used for the non-cogeneration case. Energy requirements are the same except for parasitics, which must be specifically calculated for each conversion system - industry combination. The conversion system information required is retrieved from the data file. Among the data retrieved are the following: maximum and minimum sizes per unit, the relationship of normal operating power and peak power to rated power, exhaust temperature and cleanliness, emissions data, the type fuel used, the type of heat source needed, and provisions for rejecting excess heat. Also provided in the data set are tables telling what fractions of the fuel energy input to the conversion system are recovered in the various thermal categories (hot water, low temperature steam, medium temperature steam, high temperature steam, and direct heat) as described previously. Along with these, the fraction of the input energy that cannot be recovered (irrecoverable losses) is also given. These tables are presented as a function of rated output. Separate tables of data are given for each design option of interest.

o Conceptual Approach

Given the industrial process requirements and breakdown of available energy from the conversion system, a cogeneration energy calculation can then be made. By varying the conversion system size, the performance of any cogeneration system of interest can be evaluated. If the selected electrical output falls short of the industrial process requirement, E_p, the difference must be made up by electricity purchased from a utility. If there is excess electricity, it can be sold to the utility. Corresponding to a given electrical output there is a thermal output. If more thermal energy is provided than is required by the process, the excess must be thrown away. On the other hand, if the conversion system cannot meet all the process thermal requirements, the shortfall must be made up with an auxiliary furnace.

When dealing with more than one category of thermal energy, the matter of meeting all thermal requirements introduces some complications. Thus a basic set of ground rules has been applied. In matching a conversion system to an industrial process thermal requirement, higher temperature needs are considered first. If there is an excess of available thermal energy, it can be used to meet lower temperature thermal needs (i.e., the energy can "cascade" downwards). Any excess low temperature thermal energy may be applied against higher temperature needs by using that energy to provide preheating for the higher temperature requirement; i.e., 300°F steam may be applied to preheat the water for a 500°F steam boiler.

With that general approach, consider some simple examples of the consequences of gradually increasing the output of the conversion system in a cogeneration system from zero to an arbitrarily large size.

First, assume an industrial process with an electrical requirement, E_p, and a single thermal requirement, θ_p. Assume also that there is a conversion system design option that has a thermal output in the same temperature category as the requirement. When the conversion system electric output is E, the corresponding thermal output is $\theta = \mu E$. For simplicity let μ, the thermal-electric ratio, be constant, independent of the conversion system size. Similarly let the electrical efficiency, η_e, remain constant.

The total fuel consumption includes contributions from three sources: the conversion system, the utility, and the auxiliary furnaces. The fuel consumption contribution from the conversion system is:

$$Q_{ECS} = E/\eta_e$$

The utility fuel consumption depends on the difference between the electricity provided by the conversion system, E, and that required by the process, E_p. If E is greater than E_p, electricity is sold to the utility and utility fuel is saved that normally would have been burned to provide electricity to other customers. The net utility fuel consumption is:

$$Q_u = \frac{E_p - E}{\eta_u}$$

The fuel consumption of the furnaces is:

$$Q_F = \Delta\theta/\eta_F$$

where

$$\Delta\theta = Q_p - \theta = Q_p - \mu E \quad \text{if } Q_p > \theta$$
$$\Delta\theta = 0 \quad \text{if } Q_p < \theta$$

The net fuel consumption thus can be written as

$$Q = Q_{ECS} + Q_u + Q_F$$

$$Q = \frac{E}{\eta_e} + \frac{E_p - E}{\eta_u} + \frac{Q_p - \mu E}{\eta_F}, \quad \text{for } Q_p > \mu E$$

or

$$Q = \frac{E}{\eta_e} + \frac{E_p - E}{\eta_u} \quad \text{for } Q_p < \mu E$$

Consider a case where the conversion system electrical efficiency, η_e, is less than that for the utility, η_u. This is illustrated in Figure V-14. When E=0, the non-cogeneration case applies and the fuel consumption is that for a conventional situation:

$$Q_{Noncogen} = \frac{E_P}{\eta_u} + \frac{Q_P}{\eta_F}$$

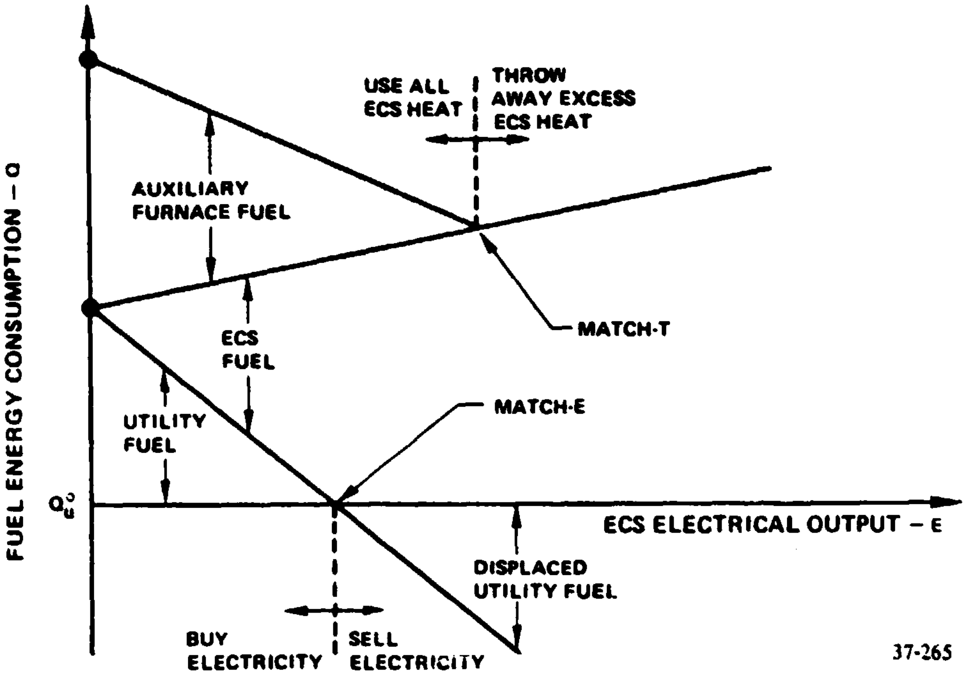


Figure V-14. Variation of Fuel Energy Consumption with Conversion ECS Efficiency Less Than Utility

As E increases the conversion system replaces some of both the electrical and the thermal requirements. In a efficient system, the quantity of fuel required to run the conversion system is smaller than that required by the utility and by the furnaces. Thus the total fuel consumption decreases. This trend continues until the point at which the thermal requirement is matched. Beyond that point excess thermal energy is being thrown away and the net fuel consumption starts to rise again. Note that the electrical requirement is met (Match-E point) before the thermal requirement is met (Match-T point). Thus at the Match-T point electricity is being sold back to the utility. It is also possible for the Match-T point to occur before the Match-E point, in which case electricity would be bought, but the basic shape of the curves would not change.

In a case where the conversion efficiency, η_e, is greater than that of the utility, Figure V-15, the fuel consumption continues to decrease, even after the Match-T point has been reached. Although heat is being thrown away, less heat is being thrown away by the cogeneration system than would have been rejected by the utility when generating that electricity.

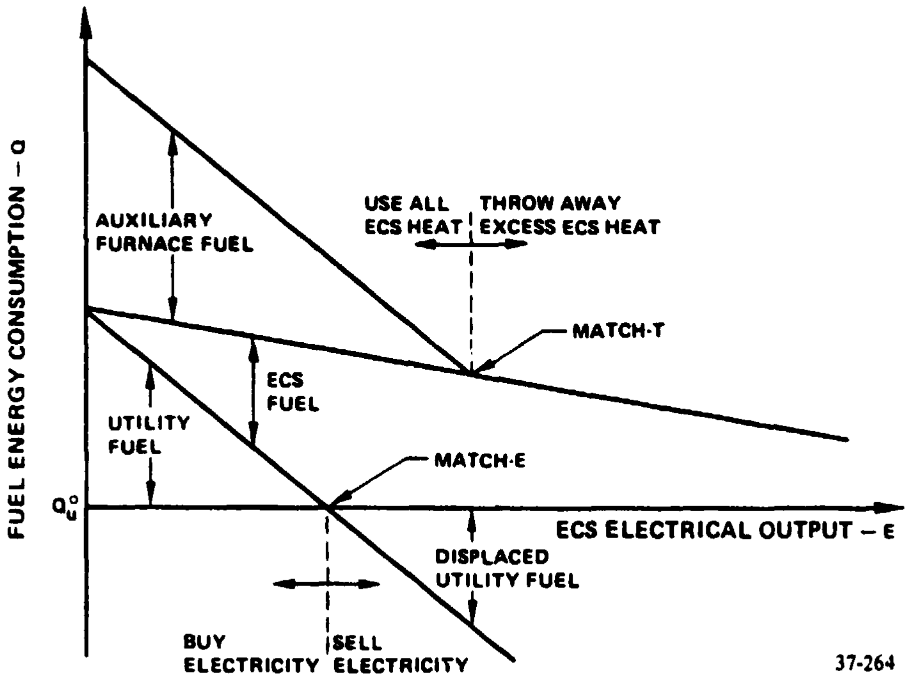


Figure V-15. Variation of Fuel Energy Consumption with Conversion ECS Efficiency Greater Than Utility

Consider next the situation when there are two categories of thermal energy: high temperature and low temperature. The energies required by the process are θ_H and θ_L respectively; and the available thermal energies provided by the conversion system are $\mu_H E$ and $\mu_L E$ respectively.

If $\frac{\mu_H}{\mu_L} > \frac{\theta_H}{\theta_L}$, the high temperature requirement would be met first as the conversion system size increases. Then any additional available high temperature energy would be applied towards the low temperature thermal requirement. No heat would be thown away until all the thermal requirements are met. This situation is effectively the same as that described previously.

If $\frac{\mu_H}{\mu_L} < \frac{\theta_H}{\theta_L}$, then the low temperature requirement will be met first (match Point 1, Figure V-16). Beyond that point, available low temperature energy can be used to preheat the high temperature requirement until all the possible preheating (i.e., the water for the high temperature steam is preheated up to the temperature of the low temperature stream) has been achieved (Match Point 2, Figure V-16). The energy consumption up to this point is represented by the equation:

$$Q = \frac{E}{\eta_e} + \frac{E_p - E}{\eta_u} + \frac{(\theta_H + \theta_L) - (\mu_H + \mu_L) E}{\eta_F}$$

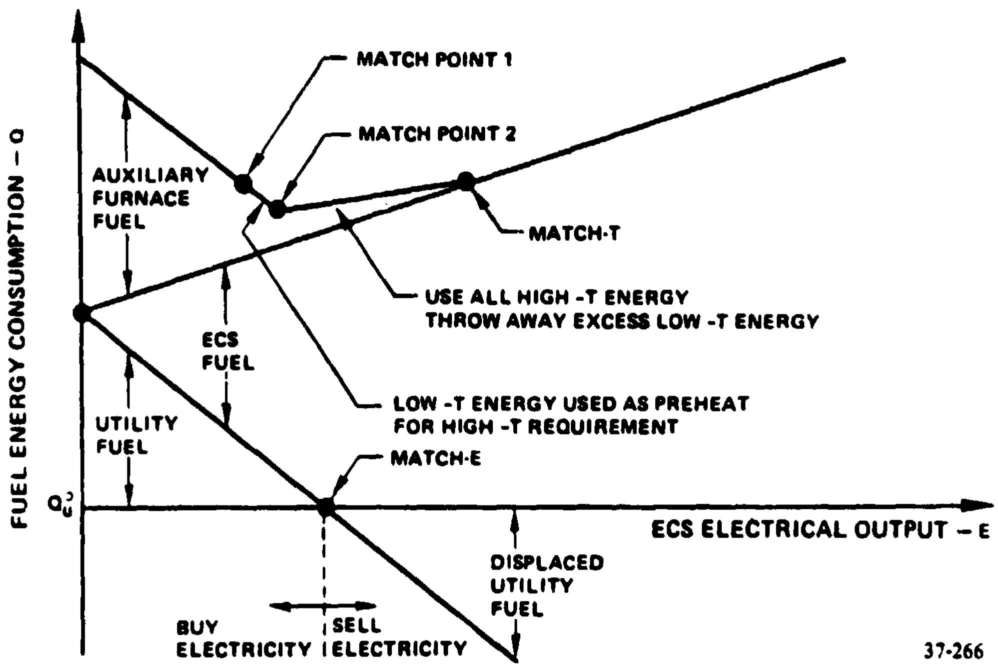


Figure V-18. Variation of Cogeneration Fuel Energy Consumption for an Industry Having High and Low Temperature Requirements

Beyond Match Point 2, Figure V-16, the excess available low temperature heat must be thrown away, although all the available high temperature heat is used. This causes a break in the curve as shown. This continues as the conversion system output increases until all thermal requirements are met (Match-T Point, Figure V-16). The energy consumption in this range is presented by the equation.

$$Q = \frac{E}{\eta_e} + \frac{E_P - E}{\eta_u} + \frac{(\theta_H - \theta_{PH}) - \mu_H E}{\eta_F}$$

where θ_{PH} is the amount of preheat possible with the low temperature recovered heat.

Finally, beyond the Match-T point excess high temperature energy, as well as low-temperature energy, is thrown away and a second break in the curve occurs. The energy consumption for this region is just

$$Q = \frac{E}{\eta_e} + \frac{E_P - E}{\eta_u}$$

as was true for the previous examples.

The case shown in Figure V-16 is for $\eta_e < \eta_u$. Further, μ_H and μ_L are of such magnitude that Match Point 2 is lower than the Match-T point. It is equally possible to have a situation in which the Match-T point is lower than Match Point 2. The slope of the curve beyond the Match-T point will be positive or negative depending on whether $\eta_e < \eta_u$ or $\eta_e > \eta_u$ respectively.

In the general case with an arbitrary number of thermal energy categories, it is possible to have as many breaks in the curve as there are categories. Which point will represent the minimum energy consumption depends on the interrelationship between all the efficiencies and electrical-thermal ratios involved. Further complications arise from two other considerations. First, it is possible that there is a thermal requirement (e.g., direct heat from a specified fuel) that can never be met by the conversion system no matter how large. The fuel consumed for such requirements will simply be a constant value added. Second, the electrical efficiencies and electric-thermal ratios generally vary with conversion system size and output. Thus, each segment on the curve will typically not be a straight line. The essential features of the curves presented will be maintained, however.

o Matching Strategies

The cogeneration performance curves just discussed are useful in describing possible matching strategies that might be employed in a cogeneration scheme. Two matching strategies that are obvious in the previous examples are: (1) Exactly match the electrical requirement and either supplement thermal needs with auxiliary furnaces or throw away excess heat. This is known as the Match-E strategy. (2) Meet all thermal requirements that can be met by the conversion system and buy or sell electricity, as needed. This is known as the Match-T strategy.

For the Match-E strategy, the industrial process could, in principle, be disconnected from the utility electrical grid. If all thermal requirements have not been met, additional fuel is required to fire the auxiliary boilers. If all thermal requirements have been met, the only fuel requirement is for the conversion system.

For the Match-T strategy, no auxiliary furnaces are required, except for thermal requirements that can't possibly be met by the conversion system. With this strategy, the plant must be connected to the utility electrical grid since electricity must either be bought or sold. The Match-T point does not necessarily correspond to an exact match of all available and required thermal energies. For example in Figure V-16, some low temperature energy is thrown away when the high temperature requirement is met. If there is a high-temperature requirement that the conversion system cannot ever meet (e.g., a conversion system that can only provide 500°F heat when 800°F heat is required), then an auxiliary furnace would be needed at the Match-T point.

Figure V-16 illustrates a case where neither the Match-E nor the Match-T strategy results in the minimum fuel energy consumption. A third strategy that might be employed does not dictate that any particular requirement be met. The conversion system size is selected at a value that corresponds to the minimum energy consumption. This is called the Optimum Energy strategy.

One possible definition of the optimum point might be the point corresponding to the minimum total consumption of fuel at the industrial plant and the utility. With this definition, the optimum in Figure V-16 occurs at Match Point 2. An auxiliary furnace is needed to meet part of the high temperature requirement, and some electricity must also be purchased from the utility grid.

For the example shown in Figure V-15, which is representative of a case where $\eta_e > \eta_u$, the total energy consumption decreases indefinitely as the conversion system size increases. The minimum energy consumption would occur when the conversion system completely replaces the utility. To restrict considerations to more realistic configurations, certain ground rules were established. The maximum conversion system size is limited to the larger size for the Match-E or Match-T strategy. In addition, in no case is the conversion system electrical size allowed to exceed ten times the process electrical requirement, E_p.

It is also possible to specify different criteria to define the optimum fuel utilization. In the discussion above, the total cogeneration system plus utility fuel energy savings was the criterion. In cases where the fuel has been converted from its natural form to a more convenient state (e.g., liquefaction of coal), the fuel energy used at the industrial site would correspond to more energy of the raw fuel; i.e., in its natural form at the source where it comes out of the ground. For example, the conversion efficiency for producing a coal-derived boiler-grade fuel is 0.70; thus for every Btu of fuel energy used at the plant, 1.43 Btu of coal energy was consumed. Using these conversion factors, the energy content of the fuel in its natural form can be calculated for both cogeneration and non-cogeneration cases. The figure of merit could then be the minimum consumption of fuel in its natural form.

In this study, the "optimum" strategy was chosen as providing the maximum fuel energy savings ratio (FESR) which is defined as:

$$FESR = \frac{Q_{Noncogeneration} - Q_{Cogeneration}}{Q_{Noncogeneration}}$$

The cogeneration fuel includes the fuel consumed by the conversion system, the fuel required by any auxiliary furnace, and the fuel consumed by the electric utility to provide any imported electricity. The non-cogeneration fuel consists of the fuel used by on-site furnaces and by the electric utility to meet the process electric requirements. For consistancy, when the cogeneration system exports electricity to the utility, the non-cogeneration fuel includes the additional utility fuel necessary to provide the exported electricity in the absence of the cogeneration equipment.

An example of different types of conclusions that might be drawn by using the fuel energy savings ratio as the criterion for picking the optimum strategy is shown in Figure V-17 for the examples discussed previously. The curve labeled Case 1 corresponds to the cogeneration system shown on Figure V-14. For this case, the maximum energy savings occurs at the Match-T point and corresponds exactly to the point of minimum energy consumption. The curve labeled Case 2 corresponds to the case shown in Figure V-15, which has maximum fuel energy savings ratio at the Match-T point. Finally the curve labeled Case 3 corresponds to Figure V-16. The optimum occurs at a point which is neither Match-T or Match-E. Usually the optimum will occur at the breaks in the curve corresponding to the matching of some need (either a particular thermal requirement or the electrical requirement) but in the most general case, with multiple requirements and efficiencies that vary with size, the optimum might occur at any converstion system size.

There is another matching strategy of potential interest, namely, the Heat-Pump strategy. This strategy is basically a variation on the Match-E strategy with an additional piece of equipment. In some cases, when a conversion system is sized to match the process electric requirement, E_p, there will be surplus low temperature energy available while there remains a higher temperature energy requirement. The conversion system size could be increased beyond E_p and the additional electricity could be used to drive a heat pump that would transform low temperature energy to the higher temperature required.

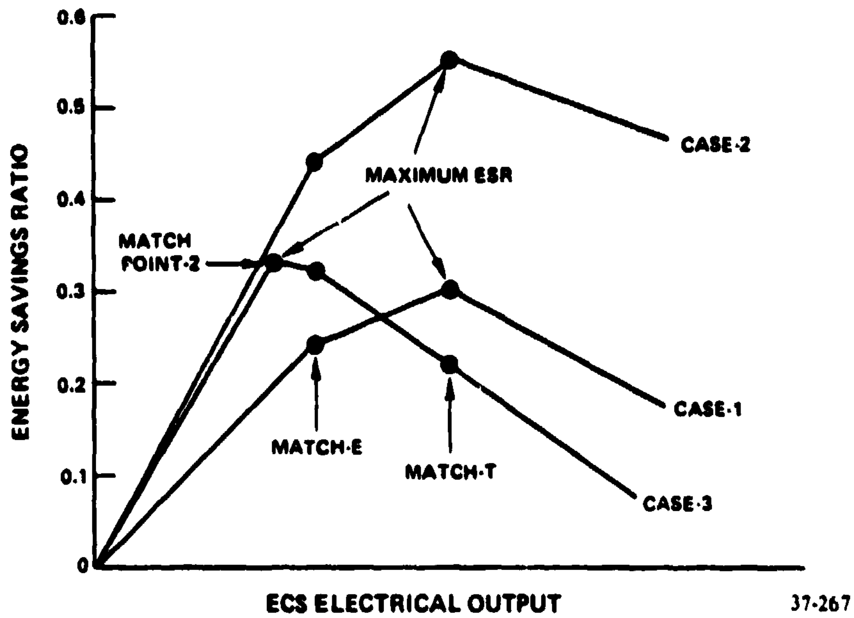


Figure V-17. Variation of Energy Savings Ratio with Conversion System Size

A sample heat pump case is illustrated in Figure V-18 with two thermal requirements --high temperature and low temperature. The low temperature requirement is met first (Point 1), before the electrical or high temperature requirements are met. As the conversion system size increases, additional low-temperature energy is used for preheating up to point 2. Beyond point 2, additional low temperature energy is discarded. High temperature energy is still being used to reduce the high temperature requirement. At point 3, the electrical requirement is met, but there is still a shortfall of high temperature heat. For a larger conversion system, the excess electricity is not sold to the utility; instead it is used to drive a heat pump which converts surplus low temperature heat to high temperature heat. This helps reduce the remaining thermal requirement. Eventually the heat pump is large enough (Point 4) to reduce the high temperature requirement to zero. This is the Heat Pump Match Point.

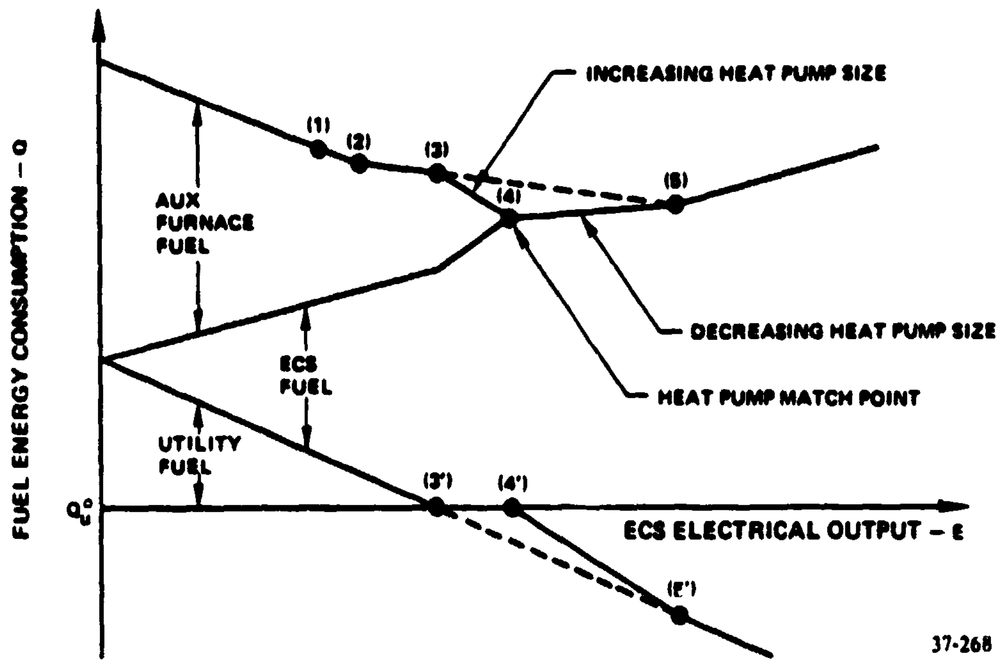


Figure V-18. Variation of Fuel Energy Consumption with Heat Pump Strategy

As the size increases beyond the match point, the conversion system can meet more and more of the high temperature requirement directly, thus reducing the heat pumping requirement and the heat pump size. As the heat pump size is reduced, its electrical requirement is reduced. This additional electricity can be sold to the utility. Eventually the normal Match-T point (5) is reached. At point 5, the heat pump size has been reduced to zero. The dashed lines 3-5 and 3'-5' represent the performance curves for a case without a heat pump. Beyond the Match-T point, performance is the same as for a case without a heat pump.

This section outlined a general method of evaluating performance for cogeneration systems and described four potentially attractive matching strategies: (1) Match-E, (2) Match-T, (3) Optimum-Energy, (4) Heat Pump. The following sections describe how the calculations are actually implemented.

o Energy Utilization and Fuel Consumption

The first major segment of the analysis is the computation of the fuel consumption for each industrial process - energy conversion system - cogeneration strategy combination. Certain calculations are employed regardless of cogeneration strategy.

They include: establishing the industrial process energy requirements and the conversion system characteristics from the data base; determining the by-product heat and by-product fuel situation; examining the direct heat question; determining the steam and hot water requirements; and calculating the parasitic losses. With this information the analysis of fuel consumption for a specific strategy can be performed.

The overall fuel and auxiliary furnace requirements are determined when a conversion system of a specified size and electrical output is used to help meet given process thermal requirements for hot water, low-temperature steam, medium-temperature steam, high-temperature steam, and direct heat. These requirements are denoted as Q_1^R, Q_2^R, Q_3^R, Q_4^R, and Q_{DH}^R respectively.

When the size is known, the conversion system data file can be used to calculate the available energy in each category. The type of data stored in the data file is illustrated graphically in Figure V-19A. For a specific conversion system size, the fraction of the fuel input energy that is output as electricity (η_e), hot water (η_1), low-temperature steam (η_2), medium-temperature steam (η_3), and high-temperature steam (η_4) are given. Also given is the fraction of energy trapped as irrecoverable losses (η_L). Any remaining fraction is assumed to be stack losses

$$\eta_{Stack} = 1 - (\eta_e + \eta_1 + \eta_2 + \eta_3 + \eta_4 + \eta_L)$$

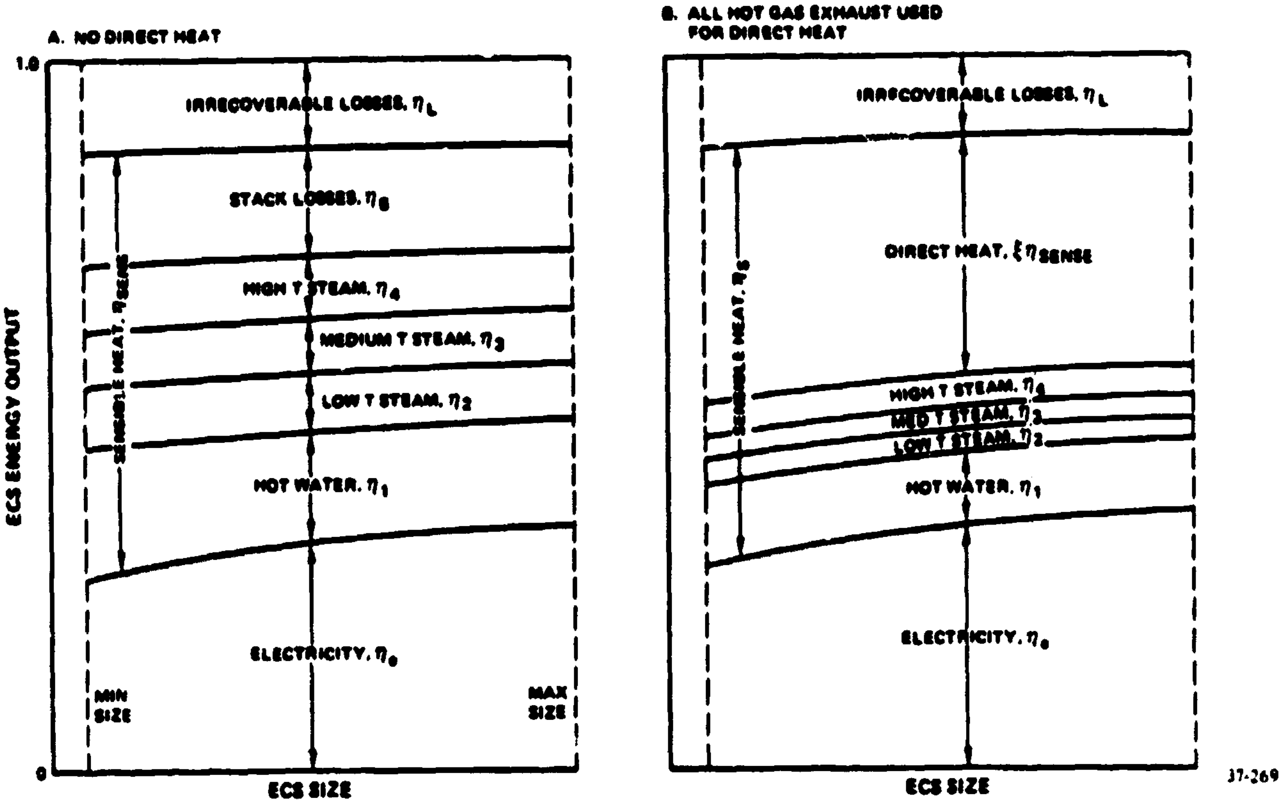


Figure V-19. Energy Conversion System Output with and without Direct Heat

These data represent a case for which all of the conversion system heat has been used to generate steam and hot water. To calculate the available thermal energy in any category we use the equation

$$Q_i^A = \eta_i \, (E/\eta_e)$$

where the superscript "A" represents the case where all possible rejected heat is used to generate steam and hot water, the subscript i may be 1,2,3 or 4 and E is the conversion system electrical output.

Industrial process heat is normally dealt with prior to any actual cogeneration calculations. The thermal requirements used in the cogeneration calculations are net requirements reflecting the use of by-product heat to reduce actual process requirements whenever possible.

If an industrial process generates a useable by-product fuel, that fuel is used to replace fuel that would otherwise be purchased. The by-product fuel is first used to provide direct heat needs requiring supplementary firing (except for those cases where a particular fuel is specified for direct heat). If there is any by-product fuel remaining, it can be used, without restriction, to fire auxiliary boilers for steam and hot water. If there is still by-product fuel remaining, it can be used in the conversion system provided that it is compatible. Compatibility is determined by comparing fuel quality parameters specified in the industry and conversion system data files. The requirements met with by-product fuel represent a savings of purchased fossil fuel. This saving is subtracted from the total fuel requirement to give the net fuel requirement for the cogeneration plant.

The thermal energy supplied by the conversion system is typically in two forms: hot exhaust gases or hot water. Some systems also produce steam directly but, in most cases, the steam is produced from the hot exhaust gases. Since some industrial processes require heat in the form of hot gases, direct use of hot exhaust gases is examined first.

If all the hot exhaust gas were to be used as direct heat, there might still be hot water and/or steam available that was generated from sources other than the hot exhaust (e.g., jacket cooling water in diesels). Another parameter given in the conversion system data file is ξ the fraction of the sensible heat that is available as direct heat. Then the amount of sensible heat that is available for meeting the heat needs is

$$Q^{a}_{DH} = \xi \eta_{sens} (E/\eta_e)$$

where the superscript "a" indicates that all of the hot-gas exhaust was used directly, and the subscript DH indicates the energy available as direct heat. η_{sens} is the fraction of conversion system fuel energy available as sensible heat.

$$\eta_{sens} = 1 - (\eta_e + \eta_L)$$

The remaining energy is available in the form of lower quality heat, i.e., steam or hot water as shown in Figure V-19B. The distribution of this energy is established according to an algorithm depending upon the type of conversion system and sensible heat fraction, ξ. For example, diesels which require cooling jacket water must retain that fraction of the hot water which is used for cooling. New efficiencies, η', can be calculated to give the available heat as

$$Q_i^a = \eta_i^1 (E/\eta_e)$$

where the superscript "a" indicates that minimum available steam and hot water remaining after all available conversion system exhaust gases are used for direct heat. The subscript "i" may take on the values 1 through 4.

In summary, there are two sets of values for the available thermal energy in the data base. The first set comprises the available steam and hot water if no direct heat is used: Q_1^A, Q_2^A, Q_3^A, and Q_4^A . The second set applies when all the direct heat that can possibly be used is so used: Q_1^a, Q_2^a, Q_3^a, Q_4^a, and Q_{DH}^a.

The next step is to determine the amount of direct heat used in meeting the industrial process requirement and then to convert the remaining conversion system exhaust energy to useful steam to meet further industrial requirements. All of the exhaust energy can be converted to steam if 1) there is no direct heat requirement; 2) there is specified fuel for the industrial requirement and the need is met by a separate furnace, and 3) the direct heat available from the conversion system is at lower temperature than the highest temperature steam. None of the conversion system exhaust heat can be used as steam if it all is used for direct heat. In some cases a portion of the conversion system exhaust heat is used as direct heat leaving the remaining fraction, χ, to be converted to steam

$$\chi = \frac{Q_{Avail} - Q_{DH}^{Acess}}{Q_{Avail}}$$

The energy available from the conversion system in any given category is equal to the energy available from sources other than the exhaust (e.g., jacket cooling water) plus the energy in that category that can be obtained from the remaining exhaust (i.e., the part not used for direct-heat needs). This contribution is assumed to be directly proportional to the fraction of the exhaust still available for use (x). Thus,

$$Q_i^{Avail} = Q_i^a + \chi \left(Q_i^A - Q_i^a\right)$$

where the subscript i may take the values, 1, 2, 3, or 4.

The requirements against which these available energies may be applied are the hot water and steam, Q_1^R through Q_4^R, and any remaining direct heat, Q_{DH}^{Rem}. To gain maximum benefit from the available energy, energy available at a given temperature T is used for any lower temperature thermal requirements or to preheat up to T for higher temperature requirements. An approach that automatically accounts for preheating involves redistributing the available and required energies in each category into bins with specified temperature ranges. The temperature ranges chosen are:

Bin	Temp Range (°F)
1	<140
2	140 - 300
3	300 - 500
4	500 - 700
5	>700

To redistribute the energy from the steam categories to the steam bins, standard steam tables are used. An example of the 700°F steam category is shown in Figure V-20, which is a plot of temperature versus specific enthalpy for water at 600 psig. Each pound of the 700°F steam represents 1242 Btu of energy based upon a 140°F reference temperature. Of that total, 162 Btu are required to raise the temperature of the water from 140°F to 300°F. This amount is assigned to Bin 2. An additional 943 Btu are required to raise the water temperature to 489°F, vaporize the liquid and superheat the steam to 500°F. This amount is added to Bin 3. Finally, 137 Btu's are required to raise the 500°F steam to 700°F. This is added to Bin 4. The hot water and other steam categories are treated in similar fashion. The breakdown of energy from each category is given in Table V-21.

The breakdown for any remaining direct heat requirement is simply calculated by assuming the specific heat of the hot gas to be constant. The breakdown is then just a ratio of temperature differences. There can be a contribution to Bin 5 (T>700°F) depending upon the temperature required for the direct heat. There will be no remaining available energy above 700°F, however, since that has all been previously accounted for.

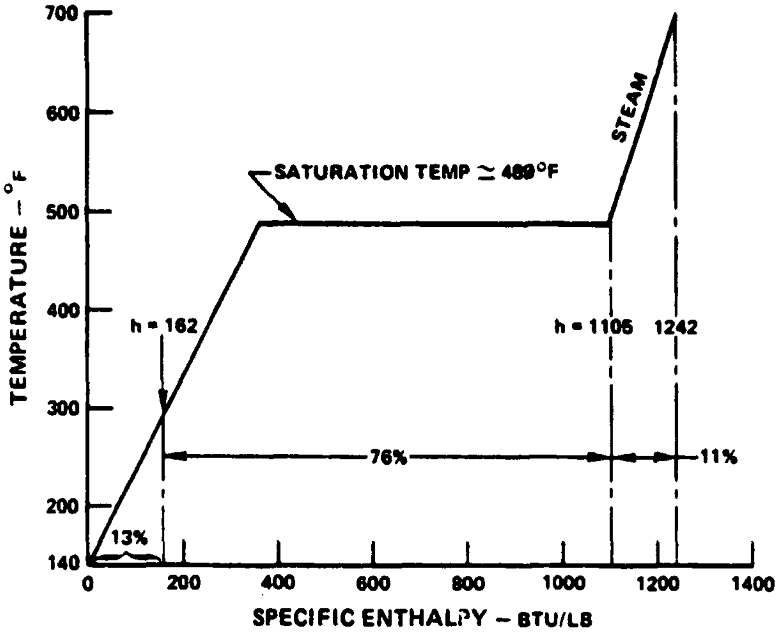


Figure V-20. Distribution of Required Energy – 700° Steam Category P = 600 psig

TABLE V-21

REDISTRIBUTION OF REQUIRED THERMAL ENERGY

Category	Fraction into Each Bin			
	Bin 1 T<140	Bin 2 140<T<300	Bin 3 300<T<500	Bin 4 500<T<700
Hot Water (140°F)	1.0	0.0	0.0	0.0
Low T Steam (300°F, 50 psig)	0.0	1.0	0.0	0.0
Medium T Steam (500°F, 600 psig)	0.0	0.15	0.85	0.0
High T Steam 700°F, 600 psig)	0.0	0.13	0.76	0.11

The distribution of available thermal energy into bins is essentially the same as the distribution for required energy but with one basic difference. The thermal output from a conversion system is described in terms of Btu of steam that has been generated via heat exchange with a hot source. Of interest is the breakdown of this thermal energy as a function of the actual temperature at which it is available. Unfortunately, the temperature and characteristics of this source are not always well known. A reasonable approximate breakdown can be obtained by envisioning a counterflow heat exchanger with the hot source flowing opposite the water. Consider the situation for 700°F steam as illustrated in Figure V-21. The lines labeled I and II represent the range of possible variations of the hot-source energy content with different exhaust weight flows. The "low flow" line (I) implies high temperature conversion system exhaust heat, 1350°F. Note that for virtually any curve one might use to describe the hot source, the energy of vaporization for the steam (between specific enthalpy 367 and 1094 in Figure V-21) actually came from energy above 519°F available in 500°F - 700°F temperature range. Thus, it seems reasonable to include the heat of vaporization in the 500 - 700°F bin rather than the 300 - 500°F bin, as was done for the required energy. The energy breakdown in the 140 and 300°F bins is calculated by using the enthalpy changes associated with preheating water.

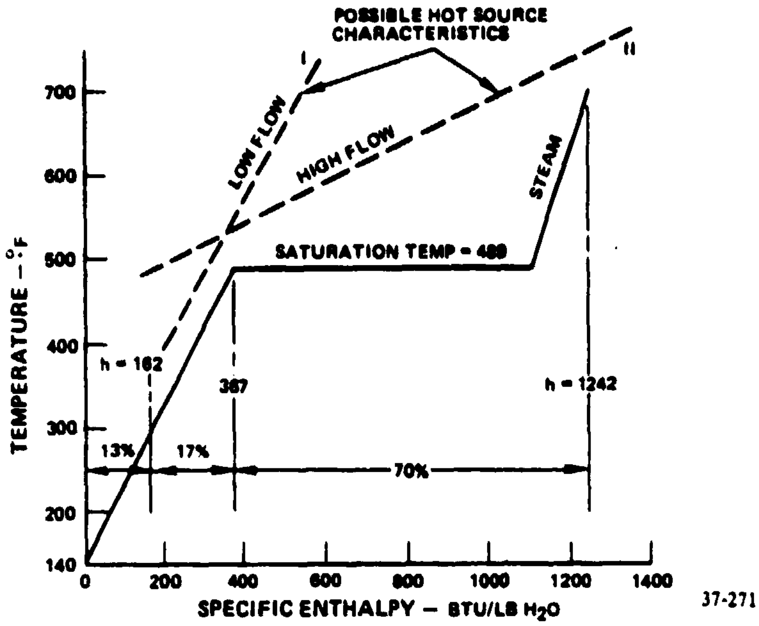


Figure V-21.
Distribution of Available Energy — 700° Steam Category P = 600 psig

When dealing with the 500°F and 300°F steam categories, the breakdowns are the same as for the required energy. The heat of vaporization is assigned to the 300 - 500 and 140 - 300°F bins, respectively. This is illustrated in Figure V-22. The breakdown for all the categories of available energy is summarized in Table V-22.

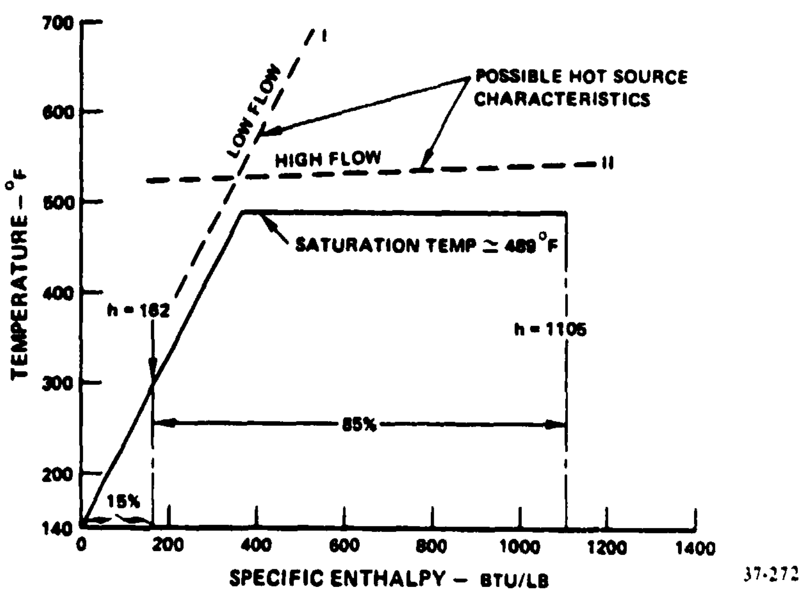


Figure V-22.
Distribution of Energy — 500° Steam Category P = 600 psig

TABLE V-22

REDISTRIBUTION OF AVAILABLE THERMAL ENERGY

Category	Bin 1 T<140	Fraction into Each Bin Bin 2 140<T<300	Bin 3 300<T<500	Bin 4 500<T<700
Hot Water (140°F)	1.0	0.0	0.0	0.0
Low T Steam (300°F, 50 psig)	0.0	1.0	0.0	0.0
Medium T Steam (500°F, 600 psig)	0.0	0.15	0.85	0.0
High T Steam 700°F, 600 psig)	0.0	0.13	0.17	0.70

Once the available and required energies are distributed within their respective bins, the application of the available energy to the industrial requirements can be calculated. Starting with the highest bin (i.e., Bin 5), the required energy is compared with the available energy. If the available is smaller than required, there is a net deficit, Δq, equal to the difference between them. This deficit is met by auxiliary burning of fuel. The fuel burned is just $\Delta Q_F = \Delta q/\eta_F$, where η_F is the burner efficiency which is a function of the specified fuel type ($\eta_F = 0.85$ for coal and natural gas; $\eta_F = 0.88$ for liquid fuels).

If the available energy in a given bin is greater than the required energy, there is no deficit to be met by supplemental firing. Instead, the surplus can be cascaded down to the next lower bin to meet needs in that temperature range. This is effected by adding the surplus to the available energy in that bin.

The above procedure is followed for each bin in order, from highest to lowest temperature, until all bins have been considered.

The total fuel requirement and its breakdown by application are then found. The conversion system fuel requirement is simply the electrical output divided by the electrical efficiency. The boiler fuel requirement is the sum of the requirements calculated for Bins 1 through 4. The fuel used is boiler grade liquid, either oil or coal-derived depending on the conversion system fuel. One exception to this is a conversion system with a coal-fired heat source, in which case coal is used for auxiliary heat by increasing the size of the heat source.

Finally, the fuel requirement for meeting direct heat needs is the sum of the requirement from Bin 5 and/or fuel used to provide direct heat independent of the conversion system.

$$Q_F^{DH} = Q_{DH}^R / \eta_F$$

In the evaluation of direct heat requirements certain details have to be considered. Normally, the direct heat requirement is stated in reference to ambient conditions, 60°F, and the conversion system energy available is based on the same reference condition. If the conversion system exhaust is clean enough, the available hot gas temperature is the exhaust temperature ($T_{Avail} = T_{exh}$), and the energy available is all the energy in the exhaust, $Q_{Avail} = Q_{DH}^a$. If the exhaust is not clean enough, it must first go though a heat exchanger. Then the available temperature is given by

$$T_{Avail} = T_{Exh} - T_{Pinch}$$

where the pinch temperature, ΔT_{pinch}, is 50°F. The available energy must now have stack losses subtracted from it. Thus,

$$Q_{Avail} = Q_{DH}^a - Q_{Stack}$$

where

$$Q_{Stack} = \eta_{Stack} (E/\eta_e)$$

The available temperature, T_{Avail}, is compared with the temperature needed for direct heat, T_{DH}. If $T_{Avail} > T_{DH}$, the available energy can be applied toward the direct heat requirements over the entire temperature range. If $T_{Avail} < T_{DH}$, only that portion of the direct heat requirement up to T_{Avail} can be met by the conversion system. In that case

$$Q_{DH}^{Access} = \left(\frac{T_{Avail} - T_{Ref}}{T_{DH} - T_{Ref}}\right) Q_{DH}^{R}$$

The inaccessible part of the requirement is just

$$Q_{DH}^{Inacc} = \left(\frac{T_{DH} - T_{Avail}}{T_{DH} - T_{Ref}}\right) Q_{DH}^{R}$$

This part of the requirement must be met via auxiliary burning. The fuel required is

$$Q_{F}^{DH} = Q_{DH}^{Inacc} / \eta_F$$

The accessible direct heat requirement is compared against the available energy. If $Q_{DH}^{Access} > Q_{Avail}$, all of the available energy is assumed to be used and the remaining direct heat requirement becomes

$$Q_{DH}^{Rem} = Q_{DH}^{Access} - Q_{Avail}$$

This remaining energy is treated with the steam and hot water requirements because some preheating of the hot gases could be done with the steam or hot water.

If the direct heat is not the highest temperature requirement, a different procedure is used. The conversion system exhaust is first used to produce steam that is used for high temperature needs and then cascaded down as required for lower temperature needs. All the energy that would normally go up the stack is not necessarily lost, however, if steam is made. If the exhaust meets the cleanliness standard for use as direct heat, it can be diverted prior to entering the stack and used as gas which is preheated to the stack temperature T_{stack} for the direct-heat requirement. Then further heating would only be required from T_{stack} to the required temperature T_{DH}. The maximum amount of preheat that is allowable is determined from

$$Q_{DH}^{PH} = Q_{DH}^{R} \frac{T_{Stack} - T_{Ref}}{T_{DH} - T_{Ref}}$$

Generally, T_{stack} = 280°F and T_{ref} = 60°F. The energy available in the stack gases, Q_{stack}, is the energy from the exhaust not converted to steam or hot water. The amount of energy provided from the stack gases, Q_{OH}^{Prov}, is the smaller of Q_{DH}^{PH} and Q_{stack}. The remaining direct heat requirement is then

$$Q_{DH}^{Rem} = Q_{DH}^{R} - Q_{DH}^{Prov}$$

This quantity of energy is included with the steam requirements since the energy available as high temperature steam could be made available to preheat the hot gases. This approach provides a calculation technique insuring the maximum utilization of the available energy. An actual cogeneration system might be set up somewhat differently to accomplish the same results.

o Parasitic Requirements

In order to compute the energy consumption for any particular case, it is necessary to know the parasitic electrical and thermal requirements. These are added to the industrial requirements to get overall requirements. The parasitics for any given case are evaluated by an iterative approach. Estimated values for the electric and thermal parasitics are used for the first pass. These are added to the nominal process energy requirements. Calculations to evaluate the utilization of the conversion system output are performed as described previously. The results of these calculations are used to evaluate balance-of-plant needs that lead to a calculation of the system parasitics. These parasitics are used for another pass through the calculations. This process continues until the parasitics calculated on consecutive passes fall within a prescribed tolerance.

Sources of parasitic requirements are heat sources, furnaces, pollution control equipment (scrubbers, hot-gas cleanup), waste handling and removal, limestone handling and storage, fuel handling and storage, boiler feed water supply systems, and heat-rejection equipment. These parasitics are generally calculated as the product of a parasitic factor and the capacity of the system under consideration. The factors used in this study for the parasitics were summarized previously in Tables V-11 and 16. The calculation of parasitic requirements from these sources is described below.

Parasitics related to heat sources and furnaces are computed first. The heat source which is associated with each conversion system is listed in Table V-20. If a conversion system has an internal heat source (e.g., diesel, gas turbine, etc.), these calculations are not applicable. The fuel consumption is multiplied by the heat-source efficiency (available from the heat-source data file) to find the heat-source output. This output is multiplied by factors obtained from the heat-source data file to give the heat-source contribution to the electrical and thermal parasitic requirements. In addition, there are factors which, when multiplied by fuel requirement, indicate the heat-source output of solid and liquid waste and its requirement for limestone and boiler feed water.

Auxiliary furnace parasitic requirements must also be calculated if applicable. There are several possible furnaces that might be used. If the conversion system has a heat source that burns coal, heat source is sized to accommodate the auxiliary furnace requirements as well. In that case, the parasitic, waste, limestone and cost factors are the same as for the heat source. For all other conversion systems, the auxiliary furnaces are separate units that burn boiler grade liquid fuel. Four furnaces were included in the study: (1) a 140°F water heater, (2) a 300°F steam generator, (3) a 500°F steam generator, and (4) a 700°F steam generator. The furnace picked is the one corresponding to the highest bin for which there is a net energy deficit. The appropriate parasitic, waste, limestone, and feedwater factors are selected from the heat-source data file. The furnace contributions to the parasitics are calculated by multiplying the appropriate factors by the furnace fuel requirements.

Certain heat sources require the use of a sulfur dioxide scrubber. This information is stored in the heat-source data file (see Table V-20). If a scrubber is required, factors for the electric and thermal parasitics, for solid wastes and for required limestone are obtained from the balance-of-plant data file. These factors are multiplied by the heat-source fuel consumption to give the scrubber contribution to the parasitics, the solid waste output, and the limestone requirement.

In similar fashion some heat sources require the use of a hot-gas cleanup system. This requirement is indicated in the heat-source data file. If hot gas cleanup is required, factors for the electric and thermal parasitics are obtained from the balance-of-plant data. These are multiplied by the weight flow of exhaust gases from the heat source. A conversion factor from fuel consumption to exhaust gas weight flow is available in the heat source data. This is used along with the heat-source fuel requirement to calculate the hot-gas cleanup system contribution to the parasitics.

The parasitics associated with limestone handling are calculated next. The limestone consumption from all sources (heat source, furnace, scrubber) is summed up to give a total limestone usage. Parasitic factors are available from the balance-of-plant data file. Simple multiplication by the usage yields the electric and thermal parasitics.

Similarly, the parasitics for the boiler feedwater system and for solid and liquid waste handling and removal are calculated by summing all contributions for each and multiplying by the appropriate factors obtained from the balance-of-plant data.

To calculate fuel handling and storage parasitics it is necessary to know the breakdown of fuel usage by type--distillate, boiler grade, or coal. The fuel type is determined from the conversion system data file. Auxiliary furnace fuel is boiler grade unless there is a heat source which burns coal, in which case coal is used. The fuel for direct heat is the same as for the furnaces unless otherwise specified. Once the usage of each type of fuel is known, it is multiplied by the appropriate parasitic factors from the balance-of-plant data. The total fuel handling parasitics are the sums of the parasitics for each type of fuel.

Finally, the parasitics associated with heat rejection equipment are calculated. The requirement for heat rejection varies according to the system. Whether heat rejection is required and what type of heat must be rejected is described by a parameter contained within the conversion system data file. The magnitude of the heat rejection is multiplied by the heat rejection electrical parasitic factor, available in the balance-of-plant data.

All contributions to the electrical and thermal parasitics are added together and the results used for the next pass through the iterative procedure.

o Match Electric Strategy

For the Match-Electric strategy it is presumed that all the electrical requirements of the plant are met by the energy conversion system which must be large enough to accommodate the peak electrical demand of the plant which is given in the industry data file, and also the parasitic electrical requirement, which is dependent upon the particular conversion system industry combination. To estimate the total peak demand, an industry sizing factor, r_s, was defined as the ratio of the peak process electrical demand to the average process electrical demand. Then the average parasitic demand is added to the average process electrical demand and the sum is multiplied by the industry sizing factor, r_s:

$$
\begin{aligned}
E_{peak}^{tot} &= \left(\langle E \rangle_{process} + \langle E \rangle_{parasitic} \right) r_s \\
&= E_{peak}^{process} + r_s \langle E \rangle_{parasitic}
\end{aligned}
$$

Implicit in the use of r_s is the assumption that the temporal variation of the parasitic demand is coincident with that of the process electrical demand.

The number and size of conversion units necessary to meet the peak demand are determined according to the relationship

$$E_{MAX} = \frac{E_{peak}^{tot}}{N_{ECS}}$$

where N_{ECS} is the smallest integer greater than or equal to two that gives a value for E_{MAX} less than or equal to the maximum allowed conversion system output. Then N_{ECS} represents the number of units to be used. The rated size of each unit should be

$$E_{Rated} = kE_{MAX}$$

where k is the ratio of the rated to maximum steady state power for the specified conversion system.

There generally is a restriction on the number of conversion units that may be used. In this study a minimum number of 2 units and a maximum of 12 units was selected. If more than 12 units are needed, the conversion system is not suited for application to the given industry and no further calculations are performed. If, on the other extreme, it is found that the rated size is smaller than the allowed minimum size, even when only two units are used, the calculation is still performed. However, a flag is set to indicate that the conversion system is smaller than the minimum practical size indicated in the file.

Once the energy conversion system size and number of units has been selected, the associated electrical and thermal efficiencies can be evaluated from the data file. Then the standard calculations related to energy utilization and fuel consumption are performed. The iterative procedure to find the appropriate parasitics is employed and the conversion system size modified to reflect the latest value for the electrical parasitics. On successive iterations when the newly calculated parasitics are within 2 percent of their previous value, the solution is deemed converged.

Calculations of this type are performed for each design option of the conversion system being studied. The results for each option are compared and those for the most conserving design option are saved for display and for subsequent cost and emissions calculations. The selection criteria for the best design option used for this study is the highest energy savings ratio.

o Heat Pump Strategy

The heat pump strategy involves sizing the energy conversion system such that power produced meets the process electrical requirements and also provides electricity to operate a heat pump. The process thermal needs are met by heat recovered from the energy conversion system supplemented by heat output from the heat pump. A simple schematic diagram of this system is shown in Figure V-23. In this study, the heat pump operates directly with the cogeneration system utilizing it as a sole source of heat for the industrial process.

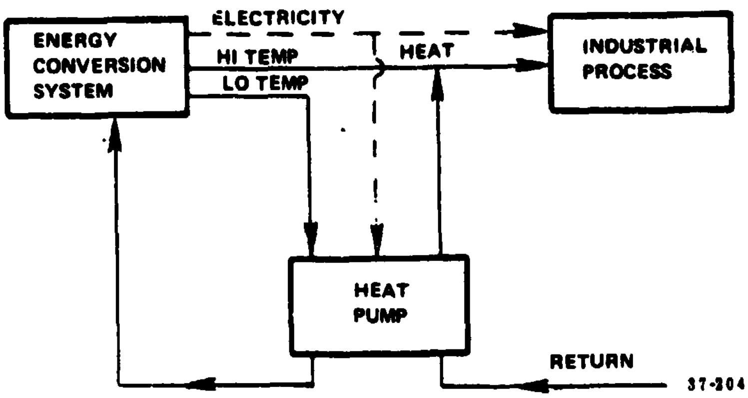


Figure V-23. Heat Pump Strategy Schematic Diagram

After the match-electric calculation has been made for a given design option, the results are used to see if a heat pump would be appropriate. If the match-electric results are such that there is a surplus of energy in Bin Number 1 (140°F) and a deficit in Bin Number 2 (300°F), or a surplus in Bin Number 2 and a deficit in Bin Number 3 (500°F), then heat pump strategy is investigated.

An initial heat pump size is selected based on the thermal deficit. A preliminary calculation is made based on Figure V-9 using the temperature of the conversion system available heat and the temperature to which the energy must be pumped. The amount of heat to be pumped is divided by the coefficient of performance to give the estimated electric requirement for the heat pump and iterative procedure is then employed to select the heat pump size and performance. A new total electric requirement is taken to be the sum of the process electric requirement including parasitics and the estimated heat pump electrical requirements. The conversion system size is modified based on the new total electric requirement. As a result there is a reduced thermal deficit that must be pumped and the low temperature available is increased. An iterative procedure is employed to bring the heat being pumped from the conversion system to within 5 percent of the available heat. If this match is not achieved, the strategy is abandoned.

The heat pump calculation incorporates a futher iteration procedure to establish the parasitics. Each conversion system design option is analyzed and the data for the most conserving are used in subsequent cost and emissions calculations.

o Matched Thermal Strategy

For the match thermal strategy, thermal requirements which can be met with the heat recovered from the conversion system are met. For example, if a conversion system can only provide heat up to 500°F, an auxiliary furnace will be used for higher temperature requirements and the matched-thermal strategy is satisfied in this study when all requirements from 500°F and lower are satisfied. The analysis establishes the size of the energy conversion system to achieve this condition. The calculation procedure involves selection of a conversion system size and evaluation of the heat recovered in relation to the thermal requirements. If the thermal situation does not match, electrical output is increased and the calculation repeated. This procedure continues until a conversion system size is selected that matches the thermal requirements within one percent. A limit to the size of the cogeneration system of 10 times the size necessary to meet the process electrical requirements was imposed in this study. If the thermal requirements were not met with such a large size power plant, the match thermal strategy was deemed not practical. Also, if twelve energy conversion systems of the maximum allowed size could not satisfy the thermal requirements, the strategy was considered impractical and abandoned.

o Optimum Strategy

In the optimum strategy, the size of the energy conversion system is selected to provide the greatest fuel energy savings ratio. In the calculations for the match thermal strategy, the performance of the full range of conversion systems sizes was evaluated in finding the appropriate size to meet the thermal requirements.

Figure V-16 illustrates fuel consumption with varying conversion system size and the match thermal point is identified. In the optimum strategy, the fuel consumption data are reviewed and the most conserving size selected. The fuel energy savings ratio with the match electric and the heat pump strategies are also included in the review. Thus, all points of interest are covered and the highest energy savings ratio is retained. As in the other strategies, all design options are considered and the results for the most conserving one are saved for further calculations.

o Bottoming Configurations

The majority of cogeneration systems considered in this study are front-end or topping configurations. However, some back-end or bottoming configurations are included. in these, by-product heat available from the industrial process is used to generate electricity for the industrial process and/or for export to the electric utility. Two of the industries in the study--glass containers and cement--have ample high temperature by-product heat for use with bottoming configurations.

Certain procedures are followed when evaluating the performance of a bottoming cycle. The industry data must be examined to insure that there is available heat of sufficiently high temperature. The required temperature is found in the conversion system data file. The conversion system fuel consumption is automatically set to zero. The size of the conversion system is limited by the amount of by-product heat available. The calculation procedure is similar to the calculations for the optimum strategy in that the performance of the system for various sizes up to the limiting size is evaluated. Then the most conserving size is chosen. Note that electricity may be imported or exported to the electric utility depending upon industrial requirements.

o Fuel Consumption Evaluation

The primary reason for performing the energy consumption calculations described previously is to evaluate the fuel consumption for cogeneration plants and compare with the fuel that would be used in non-cogeneration plants in order to determine which advanced systems promise the greatest potential national benefit. In addition to the basic calculation of the total fuel consumption the results are broken down by fuel use and fuel type to aid evaluation.

The cogeneration fuel use is separated into four functional categories: the energy conversion system, the utility (both credit and debit), the auxiliary furnace, and specified special fuels for direct heat. With the fuel separated according to function, a further breakdown by fuel type is possible in accordance with the study groundrules. Conversion system fuel is specified as part of the data file. The utility fuel is coal. In a cogeneration plant, the auxiliary furnace fuel is the same fuel as used by the conversion system. The study includes various boiler grade liquid fueled furnaces for supplemental heating. These furnaces are also capable of using distillate fuels. When the conversion system uses a coal-fired heat source, that source is expanded in size to provide supplemental heat when required. Thus, the conversion system and supplemental requirements are met with a single fuel. The special fuel requirements for direct use are met with the appropriate fuel.

The calculations are performed for a representative industrial facility typical of the 1985-2000 period. To evaluate potential national results, the fuel consumption for the cogeneration system was scaled from the representative industrial plant to the national level for the product or process based on the production level expected in the 1985-2000 period. The type of fuel used by the cogeneration system was not varied in the scale-up. Normally, an individual industrial plant would use one or two fuels. However, with many plants in the nation a variety of fuels would be used. Therefore, the noncogeneration fuel use by type was based on projections of national fuel use by Gordian Associates (Volume II) for the particular product or process. These data, at the national level, permit evaluation of the move from light oil and natural gas towards heavy oil, coal and coal-derived fuels. As a result of cogeneration with advanced energy conversion systems, savings of natural gas, oil, and coal were calculated on a national basis.

When the cogeneration system consumed coal-derived fuels, the assumption was made that the noncogeneration furnace would also use coal-derived fuels. Based on the assumption that coal could be converted to coal-derived fuel with an efficiency of 70 percent evaluations of coal consumption were made on a national basis assuming either coal or coal-derived fuels were used in the cogeneration energy conversion systems.

Costs

While the motivation for installing a cogeneration system in an industrial plant is to save energy, such an installation should also appear to be economically practical. Thus, calculations of capital, fuel, and operating costs associated with a cogeneration system and the comparable costs of an equivalent non-cogeneration plant are necessary. For comparative purposes only the costs of items that are likely to be different between cogeneration and non-cogeneration cases are included in the calculations. Three sets of costs are calculated for each case: the capital costs, the annual operating costs, and the levelized annual cost.

The equipment and facilities required at the industrial site to meet the process energy needs without cogeneration include: fuel storage and handling equipment, furnaces, feed-water system, electrical control equipment, and special buildings.

The capital and installation costs for this equipment are included in the balance-of-plant data file and the heat source data file. In order to use these data, the size of the various elements must be selected.

To evaluate the size of the equipment, the total required capacity for the particular item is multiplied by the standard sizing factor, r_s. This factor is the ratio of the peak hourly electric requirment to the total average electric requirement. There is an implicit assumption that the demand for any system varies roughly as does the demand for electricity. The item size, X, is used with cost data file to find the specific cost, C_s, associated with that size. The total item capital cost, C_c, is then $C_c = XC_s$.

Both equipment cost and installation cost are determined and included in the total capital cost.

The cost for the fuel handling and storage system is dependent on the rate of fuel consumption. In this study, natural gas handling involves no capital costs. The cost of handling of by-product fuels was assumed to be equivalent to the cost of the system to handle the displaced fuel. Once the requirement and type of fuel are known, the cost is determined from the fuel handling and storage data file.

A furnace type is chosen from the heat-source data file that can provide the highest quality steam required by the process and the size of the furnace is selected to provide all of the industrial process thermal requirements. Furnace size is limited (specified in the data file). For a total furnace output, O_F, then the size per furnace, X, is $X = O_F/N_F$ where N_F, the number of furnaces, is the smallest integer that that gives a size smaller than the maximum allowed. The cost calculation is used based upon the unit size, X, and the total furnace capital costs found by multiplying by N_F.

The basis for the cost for the boiler feedwater system is similar. Sizing is based on the total requirement for feedwater. This is calculated by multiplying the furnace size by a feedwater factor for that furnace available in the heat-source data. The standard cost calculation is used and the total costs found by multiplying by N_F.

In the case of electrical conditioning and control, only the incremental cost for the equipment to service the furnaces and balance-of-plant are included since the electrical conditioning for the industrial process needs is the same for both the non-cogeneration and cogeneration plants.

The special buildings in a non-cogeneration plant are those to house the furnaces. To size the building, the area and volume of the furnaces are calculated according to the formulas.

$$A_{HS} = C_1 + C_2 X$$
$$V_{HS} = C_3 + C_4 X$$

where X is the total furnace output capacity and C_1, C_2, C_3 and C_4 are parameters stored in the heat source data file. These parameters may have different values depending on the size range in which the furnace falls. The furnace height is estimated by dividing the area, A_{HS}, into the volume V_{HS}. The cost of the building is then evaluated from the formula

$$C_c = K_{HS} A_{HS}$$

where K_{HS} is the unit cost factor given in Table V-19.

The site preparation cost is one percent of the total direct capital costs. The engineering and contingency fees are 0.15 and 0.20 of the total capital cost, respectively.

Summation of all the items is the total capital cost. The actual expense involved will be somewhat higher due to interest charges during the time required for construction. The construction time for the furnaces is calculated according to the formula

$$t = A + (B\chi)^{0.2}C$$

where A, B, and C are parameters whose values are stored in the heat source data file for the furnace of interest, and X is the size for one furnace. The total expense is found by multiplying the capital costs by the factor $e^{\alpha t}$ where t is time in years. The factor α accounts for interest cost during construction. For the economic ground rules used in this study, $\alpha = 0.024$.

The annual operating costs for a typical noncogeneration case are the costs for fuel, electricity, and operation and maintenance expenses. Fuel costs are based upon actual fuel consumption. The cost for by-product fuel is considered to be zero. The costs are then determined by multiplying the price of each fuel by the fuel consumed that year. Electricity costs are calculated in a similar fashion. The 1985-2000 prices are in 1978 dollars. These prices are assumed to escalate at a specified annual rate above the inflation rate. Thus to find the price for the particular year of interest the 1985 price is multiplied at $e^{\beta t}$ where β is the escalation rate, and t is the difference in years between 1985 and the year of interest. The fuel prices and escalation rates specified in the ground rules are listed in Table V-23.

TABLE V-23

FUEL COSTS
(In 1978 Dollars)

Fuel	1985 Cost	Escalation Rate, β
Natural Gas	\$2.40/MBtu	0.0362
Distillate	\$3.80/MBtu	0.0100
Residual	\$3.10/MBtu	0.0100
Coal	\$1.80/MBtu	0.0100
Electricity	3.3¢/kWh	0.0100

The operation and maintenance costs are directly related to the furnace and the balance-of-plant. The specific costs are obtained from the heat source and balance of plant data files. The operating and maintenance costs do not escalate; they remain constant in terms of 1978 dollars.

Since capital costs and operating costs cannot be combined directly, all costs are spread over the economic life of the installation, considering the time value of money, to produce a levelized annual cost. The levelized annual costs of different systems can be compared directly.

The levelized fuel and electricity costs are found by multiplying the respective annual costs by the appropriate levelizing factors determined from the economic ground rules. For natural gas the levelizing factor is 1.470; for all other fuels and electricity it is 1.123. The levelized fixed charge for capital expenses is the product of the total capital cost and the fixed charge levelizing factor of 0.101 based upon the economic groundrules.

o Cogeneration System Costs

The conversion system related items comprise gasifier systems, primary and secondary energy converters, primary and secondary generators, heat recovery equipment, condensers, and heat pumps. The cost data for these items for one design option are in the data file. The design option was selected on the bases of greatest fuel conservation potential. Since the size of conversion system is known from the energy consumption calculations, it is used to determine equipment costs, (i.e., interpolation to find specific costs per unit size and multiplication to find total costs) for each item. These costs are then multiplied by the number of conversion systems, N_{ECS}, to find the overall capital costs.

In some cases, the cost of the heat recovery equipment is given as a function of the heat recovered rather than the conversion system size.

Condenser cost data is stored in the computer program and condenser requirements are defined in the conversion system data file. The total condenser cost is found by multiplying by N_{ECS}.

When heat pumps are used, the cost is based on the amount of heat pumped which is known from the energy consumption calculations. Heat pump cost data are stored in the computer program.

If a heat source is required in conjunction with the energy conversion system, the thermal output is calculated in the course of the performance analysis. Assuming that there is one heat source for each conversion system, the size of one heat source is

$$X_{HS} = O_{HS} r_s / N_{ECS}$$

where O_{HS} is the heat source thermal output and N_{ECS} is the number of conversion systems. The heat source size is used to determine equipment costs based on the data file. The resultant costs are multiplied by N_{ECS} to yield the overall heat-source capital costs.

For all cogeneration systems using liquid fuels, the auxiliary furnace costs are calculated in the same manner as non-cogeneration systems. If the conversion system uses a heat source that burns coal, auxiliary furnace requirements are met by expanding the size of the heat source. In this case, the costs calculated are incremental costs in excess of the cost of the basic heat source. The incremental size is

$$X_{inc} = O_F r_s / N_{ecs}$$

where O_F is the required furnace output. A size equal to $S_{HS} + S_{inc}$ is used to find the specific furnace costs which are multiplied by X_{Inc} N_{ECS} to yield the incremantal furnace costs.

The balance-of-plant capital cost items are fuel storage and distribution systems, limestone storage and distribution systems, waste disposal systems, emission-control systems, boiler feedwater systems, heat-rejection systems, electrical conditioning and control systems, and buildings. The cost analysis for the balance-of-plant items is the same as the analysis without cogeneration.

The capital cost data for installation and equipment are all found in the balance-of-plant data file. The appropriate system size for each item is the product of the respective total capacity and the sizing factor, r_s.

Buildings may be required to house the conversion system, the heat source, or auxiliary furnace. The calculations are similar to the computation for the furnaces used in the non-cogeneration cases. There are some minor differences. The area and volume of the conversion system are calculated according to the formulas

$$A_{ECS} = N_{ECS}\, C_A\, MW_R\, \left(MW_R/MW_c\right)^{m_A}$$

$$V_{ECS} = N_{ECS}\, C_V\, MW_R\, \left(MW_R/MW_o\right)^{m_V}$$

where MW_R is the rated unit output, MW_o is a reference unit size, and C_A, C_V, m_A and m_V are parameters stored in the conversion system data file. Another parameter in the data file tells whether a building is required. If it is, the building height is

$$h_{ECS} = V_{ECS}/A_{ECS}$$

and the building cost calculated from the formula

$$C_c = 1.2\, K_{ECS}\, A_{ECS}$$

where K_{ECS}, the unit cost given in Table V-19, is a function of the building height. The factor 1.2 is used to account for the cost of a crane.

The area and volume occupied by the heat source are determined according to the formulas

$$A_{HS} = (C_1 + C_2 X_{HS})\, N_{ECS}$$

$$V_{HS} = (C_3 + C_4 X_{HS})\, N_{ECS}$$

where C_1 through C_4 are parameters presented in Volume IV which are appropriate to the heat source in question; X_{HS} is the total output of each heat source (including output used for process thermal requirements); and N_{ESC} is the number of heat sources (which is equal to the number of conversion systems). The parameters C_1 through C_4 are constants having different values over different size ranges. The set of parameters corresponding to the converter size is used in the calculation. The set of parameters is set up so that when X_{HS} is zero, the area and volume go to zero also. If auxiliary furnaces are required, they are treated exactly the same fashion as other furnaces. The assumption was made that the heat sources and furnaces are housed in the same building, where appropriate. The building height is approximated as the maximum of the ratios V_{HS}/A_{HS} and V_F/A_F. The area is just the sum $A = A_{HS} + A_F$. The building cost is then

$$C_c = K_{HS} A$$

where the values for K_{HS} are the same as for non-cogeneration cases (see Table V-19). Total building costs are the summation of the costs of the conversion system building and the cost for heat source and furnace buildings.

Site preparation costs are assumed to be one percent of the total direct system capital cost.

As in the non-cogeneration case, engineering and contingency fees are assumed to be 15 percent and 20 percent, respectively. The total expense is somewhat higher depending on construction time which is the maximum installation time for the conversion system, the heat source or the furnace. The total expense is then found by multiplying the total capital cost by the factor $e^{0.024t}$ to account for the interest expense during construction.

Operating costs for cogeneration systems consist of the annual cost of consumables, electricity (credit or debit) and operation and maintenance.

Fuel costs are based on actual annual fuel usage by type, which is determined from the energy consumption calculations. The fuel prices are the same as non-cogeneration fuel prices. The cost of limestone is $10 per ton and the cost of dolomite is $12.50 per ton in 1978 dollars. The type of limestone required is defined by the heat source data file. No escalation in the price of limestone was assumed.

If electricity is purchased, the cost is determined in the same manner as non-cogeneration case. If electricity is exported to the utility, the selling price or credit is assumed to be 60 percent of the buying or import price.

The economic and physical groundrules for the study are defined in Volume I, pages 27 through 40.

The operating and maintenance costs have contributions from the conversion system heat source, furnace and balance-of-plant. The contribution from the conversion system is determined by the annual electrical output and the operation and maintenance cost factor obtained from the data file. For the heat source and/or the furnace, operation and maintenance costs are determined by the capacity of the equipment and the specific operation and maintenance cost factor contained in the data file. The similar costs for the balance of plant are determined from the data file.

The levelized annual cost for the cogeneration cases is determined in the same manner as in the noncogeneration case. The levelizing factors for fuels, electricity, capital and operation and maintenance are identical to those used in the conventional system. The prices of limestone and dolomite were assumed to be stable in 1978 dollars and a levelizing factor of unity was used.

For one comparative evaluation, the levelized cost savings ratio is calculated. This ratio is defined as

$$CSR = \frac{LAC_{Noncogen} - LAC_{Cogen}}{LAC_{Noncogen}}$$

Emissions and Wastes

Cogeneration systems can emit pollutants which could be a detriment to acceptability. Curtailment rules in some areas are concerned with emissions discharged at the industrial plant. The nation, as a whole, is concerned with the total amount of pollutants discharged to meet the energy requirements of the industrial process. In this study, amounts of pollutants discharged to the atmosphere were estimated both at the industrial site and including the electric utility. Specifically, discharges of sulfur oxides, nitrogen oxides, hydrocarbons and particulates were determined. Emission guidelines were established (Table 12, Volume I) based on the type and amount of fuel consumed by the energy conversion system to serve as a design objective and as an evaluation measure.

Solid material wastes (such as ash) were assumed to be trucked away and were not considered pollutants. Waste water or other liquids (such as spent lubricants) were assumed to be handled by the industrial plant waste system in an environmentally acceptable manner. In computing total or national emissions, the electric utilities were assumed to burn coal and operate within the emission guidelines. Heat rejection from cogeneration energy conversion systems was handled by wet cooling towers.

o Noncogeneration Emissions

In the conventional situation, the emissions from the industrial plant boilers and the emissions from the electric utility comprised the total emissions. The calculations are performed separately. The utility coal consumption is determined in the performance calculations. The factors for the amounts of pollutants emitted per unit fuel consumed for the utility are obtained from the heat source data file for heat source Number 10, a coal-fired steam generator which includes the sulfur dioxide scrubber equipment to meet the emission guidelines.

The industrial plant traditionally includes furnaces or boilers to provide the process heat. These are fueled with boiler-grade oil and the emission factors are determined from the heat source data file for heat sources one through four. If the cogeneration conversion system used coal-derived fuel, the emission factors are obtained from the data file for heat source Number 6. The difference in emissions per unit of fuel consumed is small - principally, higher particulates due to the ash content in the coal-derived fuel. Direct heat furnaces using liquid fuel are assumed to emit pollutants consistent with the emission guidelines. Since none of the conversion systems used natural gas, there is no difference in direct heat emissions between the cogeneration and the non-cogeneration cases when natural gas is the specified fuel.

o Cogeneration

Emissions in the cogeneration case can come from four sources--the utility, the conversion system, furnaces, and direct heating. The utility emissions are calculated separately in the same fashion as in the non-cogeneration case.

The conversion systems emissions are calculated in one of two ways. If a heat source is required, the emission factors appropriate to that heat source are multiplied by the heat-source fuel consumption. If the conversion system does not require a separate heat source, the emission factors used are obtained directly from the conversion system data file and multiplied by the appropriate fuel consumption.

To find furnace related emissions for auxiliary furnaces, the fuel consumption is multiplied by the emission factors for boiler grade oil or coal derived boiler grade depending on conversion system fuel. Direct heat related emissions are the product of the fuel consumed for direct heat and the emission factors appropriate to that fuel.

The industrial plant emissions for each pollutant are the sum of the conversion system, auxiliary furnace, and direct heat contributions. Total emissions are the sum of the plant and utility emissions.

o Emission Comparisons

To compare the environmental merits of cogeneration plants, the predicted emissions can be compared by species or in total. These comparisons can be made at the industrial plant site or they can include the electric utility emissions. To assist in comparisons, the emissions savings ratio is useful.

$$\text{Emissions Savings Ratio} = \frac{\text{Noncogeneration Emissions - Cogeneration Emissions}}{\text{Noncogeneration Emissions}}$$

For this ratio the emissions are the arithmetic sum of the various species and include both on-site and utility emissions. As with the fuel energy savings ratio, when the cogeneration system exports electricity to the utility, the non-cogeneration emissions include the additional utility emissions associated with the exported electricity.

COGENERATION PERFORMANCE OUTPUT FORMATS

The performance and costs of the various cogeneration applications studied with the computer program are presented in two different output formats: a summary for each energy conversion system which gives the performance and cost savings when used with all twenty-six industries and a five page cogeneration printout for each cogeneration system which presents detailed performance at the national level and costing at the plant level.

Each summary printout presents information for a selected conversion system installed in the year 1990 in each of the 26 industries for one of the four matching strategies. These summaries are included in Volume VI.

Each detailed five page cogeneration printout present data for a specific combination of conversion system industrial process-cogeneration strategy. A sample cogeneration printout for a gas turbine - chlorine and match-electric strategy is presented in Figure V-24. The industry, the energy conversion system and the matching strategy are indicated on the first page. The model industrial plant size and the national annual production are listed in Table VI-II of Volume VI.

Page 1 AVERAGE ENERGY REQUIREMENTS

NO.10 SIC 2812 CHLORINE/CAUSTIC PRODUCTION

TIME FRAME = 1990.

STRATEGY : MATCH-E

SELECTED TECHNOLOGY = NO.13 ADVANCED TECHNOLOGY,GAS TURBINE,DIRECT FIRED,COAL DER.BLR GRD

Page 2

	SELECTED TECHNOLOGY	NON COGENERATION
FUEL UTILIZATION (10**12 BTU)		
NATURAL GAS	0.0	46.39
PETROLEUM DISTILLATE	0.0	0.0
PETROLEUM RESIDUAL	0.0	20.93
COAL GAS	0.0	0.0
COAL DERIVED DISTILLATE	0.0	0.0
COAL DERIVED RESIDUAL	432.36	0.0
COAL	0.0	601.53
OTHER	0.0	0.0
TOT FUEL CONSUMPTION(10**12 BTU)		
SITE	432.36	668.86
SOURCE	617.84	668.86
IND BYPRODUCT FUEL (10**12 BTU)	48.72	12.18
TOTAL ELECTRIC CONSUMPTION		
(10**9 KWH)	46.52	46.80
(10**12 BTU) FUEL ENERGY	432.36	499.13
ELECTRICITY PURCHASED		
(10**9 KWH)	0.0	46.80
(10**12 BTU) FUEL ENERGY	0.0	499.13
TOT FUEL ENERGY SAVE (10**12 BTU)		
SITE	236.50	0.0
SOURCE	51.02	0.0
TOT OIL AND GAS SAVE(10**12 BTU)	67.33	0.0
NATURAL GAS SAVINGS		
(10**12 BTU)	46.39	0.0
(10**9 CU FT)	49.87	0.0
OIL SAVINGS		
(10**12 BTU)	20.93	0.0
EQUIV. BBLS	3.61	0.0
COAL SAVINGS (SOURCE)		
(10**12 BTU)	-16.31	0.0
(10**6 TONS)	-0.76	0.0

Figure V-24. Cogeneration Printout for Gas Turbine — Chlorine Industry and Match E Strategy

Page 3

	SELECTED TECHNOLOGY	NON COGENERATION
FUEL ENERGY UTILIZATION RATIOS		
FUEL ENERGY SAVINGS RATIO		
SITE	0.3[illegible]4	0.0
SOURCE	0.076	0.0
U/U(0)	0.0	1.000
ECS FUEL/U(0)	0.866	0.0
F/U(0)	0.0	0.340
SPECIFIED FUEL/U(0)	0.0	0.0
ENERGY CONVERSION SYSTEM DATA		
DESIGN OPTION	3.0	0.0
ECS SIZE (MW)	44.64	0.0
NO. OF UNITS	2.0	0.0
ECS ELECTRICAL EFF-ETAE	0.330	0.0
SENSIBLE WASTE HEAT RATIO--A	0.923	0.0
AVBL WASTE HEAT RATIO,R'--HG (NON ADDATIVE)	1.000	0.0
AVBL WASTE HEAT RATIO,R'-700	0.539	0.0
AVBL WASTE HEAT RATIO,R'-500	0.136	0.0
AVBL WASTE HEAT RATIO,R'-300	0.101	0.0
AVBL WASTE HEAT RATIO,R'--HW	0.008	0.0
TOTAL R	0.784	0.0
RECOV WASTE HEAT RATIO,R--HG	0.0	0.0
RECOV WASTE HEAT RATIO,R-700	0.0	0.0
RECOV,WASTE HEAT RATIO,R-500	0.353	0.0
RECOV WASTE HEAT RATIO,R-300	0.173	0.0
RECOV WASTE HEAT RATIO,R--HW	0.005	0.0
TOTAL R	0.531	0.0
AUXILIARY POWER REQUIRED(KW)	184.	727.
AUX THERMAL REQ(10**6 BTU)	6.	1.
COP OF HEAT PUMP	0.0	0.0

U = UTILITY FUEL U(0) = UTILITY FUEL (NON-COGENERATION)
F = AUXILIARY FUEL (INCLUDES SPECIFIED FUEL)

Figure V-24. Cogeneration Printout for Gas Turbine – Chlorine Industry and Match E Strategy (continued)

Page 4

CAPITOL COST ACCOUNTING FOR TYPICAL PLANT
($ 000)

COST CATEGORY	***** SELECTED TECHNOLOGY *** EQUIPMENT	INSTALLATION	TOTAL	NON-COGEN TOTAL
1. FUEL/WASTE HANDLING AND STORAGE				
1.1 FUEL STORAGE AND RETRIEVAL	722.	94.	815.	353.
1.2 LIMESTONE STORAGE AND RETRIEVAL	0.	0.	0.	0.
1.3 WASTE HANDLING SYSTEMS	0.	0.	0.	0.
SUB-TOTAL	722.	94.	815.	353.
2. ECS HEAT SOURCE				
2.1 HEAT SOURCE	0.	0.	0.	0.
2.2 SPECIAL EMISSIONS CONTROLS	0.	0.	0.	0.
2.3 FEED WATER SYSTEMS	0.	0.	0.	263.
2.4 GASIFIER(ECS)	0.	0.	0.	0.
SUB-TOTAL	0.	0.	0.	263.
3. ENERGY CONVERSION SYSTEM(ECS)				
3.1 PRIMARY ENERGY CONVERTER	4925.	2068.	6993.	0.
3.2 PRIMARY GENERATOR/INVERTER	3102.	0.	3102.	0.
3.3 SECONDARY ENERGY CONVERTER	0.	0.	0.	0.
3.4 SECONDARY GENERATOR	0.	0.	0.	0.
3.5 BOTTOMING CYCLE VAPOR GENERATOR	0.	0.	0.	0.
3.6 HEAT RECOVERY EQUIPMENT	1442.	460.	1902.	0.
3.7 CONDENSERS	0.	0.	0.	0.
3.8 HEAT PUMP	0.	0.	0.	0.
SUB-TOTAL	9469.	2528.	11997.	0.
4. THERMAL STORAGE	0.	0.	0.	0.
5. SUPPLEMENTARY HEAT(FURNACE,BOILER)	0.	0.	0.	1351.
6. HEAT REJECTION	0.	0.	0.	0.
7. OTHER BALANCE OF PLANT ITEMS				
7.1 SITE PREPARATION	0.	128.	128.	22.
7.2 STRUCTURES	0.	0.	0.	211.
7.3 ELECTRICAL CONDITIONING & CONTROL	2.	3.	4.	16.
SUB-TOTAL	2.	131.	132.	249.
8. INDIRECT COSTS				
8.1 CONTINGENCY	2039.	550.	2589.	443.
8.2 ENGINEERING AND FEES	1529.	413.	1942.	332.
SUB-TOTAL	3567.	963.	4531.	776.
TOTAL CAPITAL COST ESTIMATE	13760.	3716.	17476.	2992.
CONSTRUCTION TIME(YEARS)	0.	1.	1.	0.
CAPITAL COST EXPENDITURE	14094.	3806.	17900.	3004.

Figure V-24. Cogeneration Printout for Gas Turbine — Chlorine Industry and Match E Strategy (continued)

Page 5

	SELECTED TECHNOLOGY	NON COGENERATION
ANNUAL COSTS		
OPERATING COSTS 1990. (K$/YR)		
NATURAL GAS	0.	0.
PETROLEUM DISTILLATE	0.	0.
PETROLEUM RESIDUAL	0.	0.
COAL GAS	0.	0.
COAL DERIVED DISTILLATE	0.	0.
COAL DERIVED RESIDUAL	22505.	8571.
COAL	0.	0.
OTHER	0.	0.
LIMESTONE/DOLOMITE	0.	0.
TOTAL FUEL COST	22505.	8571.
ELECTRICITY	0.	25933.
STAND-BY CHARGE	0.	0.
O & M COST	2080.	87.
TOTAL OPERATING COSTS	24586.	34591.
LEVELIZED OPERATING COSTS	27354.	38835.
LEVELIZED FIXED CHARGES	1808.	303.
LEVELIZED ANNUAL COST	29162.	39138.
COST SAVINGS	9976.	0.
COST SAVINGS RATIO	0.255	0.0
ENVIRONMENTAL IMPACT		
PLANT EMISSIONS(TON/YR)		
SULFUR DIOXIDE	2831.357	1083.537
NITROGEN OXIDES	1726.437	657.486
HYDROCARBONS	69.057	26.299
PARTICULATES	345.288	131.497
SUBTOTAL	4972.133	1898.820
UTILITY EMISSIONS(TON/YR)		
SULFUR DIOXIDE	0.0	4783.328
NITROGEN OXIDES	0.0	2790.276
HYDROCARBONS	0.0	558.055
PARTICULATES	0.0	398.611
SUBTOTAL	0.0	8530.266
TOTAL	4972.133	10429.082
EMISSIONS SAVINGS RATIO		
SULFUR DIOXIDE	0.517	0.0
NITROGEN OXIDES	0.499	0.0
HYDROCARBONS	0.882	0.0
PARTICULATES	0.349	0.0
TOTAL	0.523	0.0
SOLID WASTES	0.0	0.0

Figure V-24. Cogeneration Printout for Gas Turbine — Chlorine Industry and Match E Strategy (continued)

Page two presents the energy consumption at the national level for the cogeneration and non-cogeneration cases. Fuel consumption at the site by type is given for both the cogeneration and conventional cases.

The total fuel consumption is given at the site (plant and utility) and source (coal mine). The differences in consumption are due to processing energy losses in converting the coal to a useable liquid. If a specific industry produces a by-product fuel which can be utilized, the extent of utilization will be indicated in the by-product fuel column. The total electric consumption for the national level is presented in kWh and equivalent Btu of fuel converted at the electrical generation efficiency of the conversion system electricity and 32 percent efficiency for the purchased electricity. The total fuel energy saved at the site (or source) will equal the difference between the fuel energy used in the non-cogeneration case and the fuel used in the cogeneration case. The total natural gas and oil saved is defined in the same manner as total fuel saved. Additionally, natural gas savings is given in Btu and cubic feet (converted at 930 Btu/ft^3), oil savings is given in Btu and equivalent barrels (converted at 5.80 million Btu/bbl) and coal savings is given in Btu and equivalent tons (converted at 21.5 million Btu/ton of coal).

Page three presents energy utilization ratios and plant level energy data. The fuel energy savings ratio is given for site and source. Strategies which do not produce an answer are indicated by a -1000.0. The cogeneration fuel use is listed by function: the utility consumption (debit or credit), the conversion system fuel use, the sum of the auxiliary furnace fuel and specified fuel, and the specified fuel separately. Each of the fuel consumptions is stated as a ratio of the fuel energy used to the energy used at the utility to supply the industrial process without cogeneration.

The next section of page 3 presents the conversion system related data: the design option, the size in MWe, the number of units installed, and the electrical efficiency. The electrical efficiency is the electrical output divided by the higher heating value of the input. The following parameter, the sensible waste heat ratio, (A), is defined as the sensible heat available divided by the total heat rejected by the conversion system.

$$A = \frac{\eta_{sens}}{1-\eta_e} = \frac{1-\eta_e-\eta_L}{1-\eta_e}$$

where η_L = irrecoverable losses,
η_e = electrical efficiency

The next group of parameters is the available waste heat ratio (R') by thermal category.

The waste heat ratio for a given thermal category R_i is defined as

$$R'_i = \frac{\eta_i}{\eta_{sens}}$$

The available waste heat ratios (R') in this printout reflect the redistribution of the conversion system available thermal energies into the various thermal bins. The waste heat ratio for hot gases (HG), represents the fraction of the sensible heat (ξ) which is available for direct-process heating. The total R' is the summation of the individual available waste-heat ratios R_i', excluding hot gas, and represents the maximum available thermal energy as steam and hot water.

The next section presents the recovered waste heat ratios (R) relative to the specific industrial application. This section indicates how much and in which thermal categories the available waste heat was utilized. At the bottom of the page, the parasitic requirements (electrical and thermal) are given along with the coefficient-of-performance of the heat pump, if utilized.

Page four presents the capital cost accounts in 1978 dollars. Cogeneration system costs are broken into equipment and installation costs.

The summation of the individual components of the system gives the total capital cost estimate shown at the bottom of the page. The cost of borrowing money during the construction period adds to the total indebtedness and is reflected in the capital cost expenditure.

Page five gives the annual operating costs (in 1978 dollars) and environmental impact of the installation for the typical plant. The operating fuel costs are listed by fuel type for the year 1990. Any purchased electricity and system operation and maintenance cost is presented in this section. For this study, no stand-by charge was assessed. If the cogeneration matching strategy results in the sale of electricity to the utility grid, the cost credit to the industry will appear as a negative number. The credit for selling electricity to the utility would be 60 percent of the purchase price of electricity. The levelized costs over the economic life of the system consists of the levelized fixed charges and the levelized operating cost.

The environmental impact data are presented for the plant and utility. The pollutant species are given in tons emitted per year for the typical plant. The emissions savings ratio is based on the summation of emissions at the plant and utility for the cogeneration and non-cogeneration case. The tons per year of solid wastes produced by the operation of the non-cogeneration and cogeneration plants are listed. This value reflects solid wastes from the operation of coal-fired heat sources and waste disposal systems.

COGENERATION ECONOMIC ANALYSIS

The purpose of the economic analysis is to provide a format to evaluate the cost effectiveness of alternative energy systems. To this end, the methodology must be not only appropriate, but it must be based on accepted practices. In addition, the methodology should be as comprehensive as is practical in order that any differences in the results can be traced to the data rather than to peculiarities in the method of approach.

The performance and cost data provided for the advanced energy conversion systems were estimates based on the experience of experts in each technical area. Consequently, the results produced in the economic analysis are dependent upon the implied accuracy of these input data. Regardless, an economic model was developed which is comprehensive in nature and is able to provide detailed results.

Since all input data are based on the same set of economic ground rules, the relative differences in results should be reliable. When a system characteristic, such as discounted-cash-flow rate-of-return which is calculated in this economic model, is significantly above or below a target industry rate, the attractiveness or unattractiveness of the venture is apparent. When the calculated rate-of-return falls near an assumed industry or company target, other factors, such as cash flow profiles, investment magnitude, and degree of financial uncertainty, (which are not included in this study) must be considered in judging a system in addition to the results produced by this analysis.

The results calculated in the economic rate-of-return analysis are based on a discounted factor which takes into account the time value of cash flows into and out of a selected venture. The levelized annual costs and life-cycle costs follow typical public utility analysis practices except for the fact that this basic approach has been modified to eliminate the effect of inflation (where appropriate) on the forecast levels of future cash flows. The practice followed in this analysis follows directly the methodology outlined in a 1976 Jet Propulsion Laboratory study for the Electric Power Research Institute. (Reference 1).

The overall objective of this task was to estimate the economic characteristics of cogeneration and non-cogeneration systems. All of the input data required in this economic task were obtained from the cogeneration performance analysis described previously in this report. The following sections of the economic analysis present descriptions of the relevant industry (internal) and national (external) factors affecting each of the cogenerations systems, the economic parameters calculated, samples of typical program results, and sensitivities to change in input data for selected case studies.

Internal and External Factors

Industrial organizations within the private business sector establish criteria, herein called internal factors, which are used to guide and monitor the performance of their businesses. At the same time, there are generally a set of external factors which represent conditions of the business environment outside the confines of the firm which also affect the manner by which these firms conduct their business. Internal factors are defined as those industry-related criteria involving policies, practices, constraints, and other conditions specific within each industry or to the individual firms within that industry which influence industry capital investment decisions. The specific internal factors used in this study are the cost-of-capital to the firm and the rate-of-return (which is intended to be compared with an established "target"). External factors are defined as those conditions prevalent throughout the business community which are imposed on all industrial firms but also which influence the capital investment decisions of individual firms. The external factors, which generally are beyond the control of any firm or group of industrial firms, cover political, environmental, regulatory, and economic areas, some of which are under partial or direct control of the government. Examples of external factors are the federal income tax rate, investment tax credit, cost of purchased fuels and electricity, and relevant institutional and environment regulations. These conditions are specified by the economic ground rules.

Of the internal and external factors affecting business investment decisions in this study, the cost of capital, the rate-of-return, depreciation method, effective federal tax rate, investment tax credit, and costs of purchased fuels and electricity can be quantified explicity. Political, regulatory, and environmental factors must be considered in qualitative terms, and as such, were only considered implicitly in the economic analysis. These latter factors were assumed to be satisfied by the cogeneration systems and sufficient capital allowances were assumed to have been made in each of the subject conversion systems to assure their compliance with the regulations as foreseen for the 1985-2000 period.

o Cost-of-Capital

A series of economic ground rules and assumptions were made to provide a framework for the study. To assist in establishing these ground rules, historical data were analyzed and reviewed for firms with twenty-two industrial classifications in this study. These results, calculated for a large number of firms in each industry were based on 1978 economic data from Reference 2.

The after-tax cost-of-capital is an important internal factor for the industrial and utility-oriented firms which would consider the installation of cogeneration energy systems in the future. It is expressed as:

$$\text{Cost of Capital} = (1-Tr)\,(CD)\,\frac{D}{TC} + (CC)\,\frac{CE}{TC} + (CP)\,\frac{PE}{V}$$

where: $TC = D + CE + PE$

In this relationship, Tr is the effective tax rate; CD is the cost of debt to the firm; CC is the effective cost of common equity to the firm (here expressed as the earnings-to-price-ratio); and CP, the cost of preferred equity. The total firm capitalization, TC, and the individual components, (the debt portion of total capital, Di the common stockholders equity, CE; and the preferred stock-holders equity, PE) are used to weight the various costs components of the overall cost-of-capital.

As shown in Table V-24, the average value of the cost-of-capital calculated across all firms is slightly in excess of 10 percent, and the range of values within each of the industrial categories is small as indicated by the standard deviations. These historical values include an average inflation rate of 5 percent. If inflation for the noted period were removed from the results, the cost of capital on a non-inflated basis would be approximately 5 percent.

In setting the economic ground rules, a cost of capital (after taxes) of 5.35 percent was established for this study.

o Achieved Rate-of-Return

In assessing the merits of a cogeneration system, some decision makers would consider the estimated rate-of-return as an important parameter. Therefore, historical business data were analyzed to provide background and perspective on achieved rate of return.

Different methods of calculating the achieved rate-of-return on prior capital investment have been proposed over the years, but none of the methods investigated were considered to provide results consistent with the rates-of-return calculated by the discounted cash flow model used in this study. Therefore, a derivation was undertaken in order to provide insight into historical results which could be compared directly with the results forecast for the cogeneration systems considered in this study.

TABLE V-24

HISTORICAL DATA ON INDUSTRIAL AFTER TAX COST-OF-CAPITAL

SIC	Category	Cost of Capital	Standard Deviation
2011	Meat Packing	11.0	4.1
2051	Bread and Other Bakery Products	9.0	2.1
2082	Malt Beverages	8.5	---
2221	Broad Woven Fabric Mills	---	---
2621	Paper Mills Except Building Paper Mills	---	---
2631	Paperboard Mills	11.5	2.1
2812	Alkalies and Chlorines	10.0	2.0
2819	Ind. Inorganic Chemicals Not Elsewhere Classified	10.1	2.1
2821	Plastic Materials, Synthetic Resins, and Non-Vulc. Elastomers	---	---
2822	Butadiene Rubber	9.6	2.1
2824	Synthetic Organic Fibers Except Cellulosic (Nylon)	9.0	1.9
2865	Cyclic Crudes, Cyclic Intermediates, and Organic Pigments (Styrene)	9.2	1.5
2869	Ind. Organic Chemicals Not Elsewhere Classified (Ethylene)	9.3	2.3
2911	Petroleum Refining	10.6	1.6
3011	Tires and Inner Tubes	10.2	2.7
3221	Glass Containers	10.7	1.5
3241	Cements, Hydraulic	11.5	3.9
3312	Blast Furnace (Including Coke Ovens), Steel Works and Rolling Mills	8.9	1.8
3321	Gray Iron Foundries	12.3	3.3
3331	Primary Smelting and Refining of Copper	9.7	6.2
3711	Motor Vehicles and Passenger Car Bodies	12.3	3.9
3714	Motor Vehicle Parts and Acessories	11.6	2.4

If, over a short period of industrial experience (2-5 years), incremental profit can be related to incremental sales, then

$$\Delta\text{Profit} = (\text{Margin}) \times (\Delta\text{Sales Volume})$$

If capital investment is proportional to sales in the same period (that is, there is a representative capital-output ratio, CO, for the firm) then sales and investment, INV, can be related by:

$$(\Delta\text{Sales}) \times (\text{CO}) = (\Delta\text{INV})$$

Therefore, in the short-run, profit is proportional to investment:

$$(\Delta\text{Profit}) = (\text{Margin}) \times (\Delta\text{INV})/(\text{CO})$$
$$(\Delta\text{Profit}) = (K) \times (\Delta\text{INV})$$

In other words, profit is a fixed return on investment where

$$K = (\text{Margin})/(\text{CO})$$

ΔINV is the incremental gross investment before depreciation since production output does not decrease with the book value of an investment. Further, in order to support a given level of sales, another investment in nondepreciable assets must be made. This additional investment is generally defined as working capital, WC, and is assumed to be related to investment, INV, by:

$$\text{WC} = (J) \times (\text{INV})$$

Therefore, total assets may be defined as:

$$\text{Total Assets} = (\text{WC}) + (\text{INV}) = (1+J) \times (\text{INV})$$

The net present value, NPV_I, of a series of annual investments may be written as:

$$NVP_I = (1+J)\left[INV_1 + INV_2/(1+r) + INV_3/(1+r)^2 \ldots\ldots\ldots + INV_n/(1+r)^{n-1}\right]$$
$$-J/(1+r)^n\left[INV_1 + INV_2/(1+r) \ldots\ldots\ldots + INV_n/(1+r)^{n-1}\right]$$

The assumption is made that the firm will operate over a long period, in years, but that the capital equipment has a finite life, N. Since working capital is not needed when capital equipment is retired, the second major term represents the return of that working capital. Any new equipment purchased to replace returned equipment and the working capital associated with such purchases are already taken into account in the first major bracketed term. In a similar manner, the net present value of the earnings cash flow NPV_{ECF}, comprised of the net present value of the after-tax profit (net income) plus the net present value of the depreciation cash flow (based on the straightline approach) becomes:

$$NPV_{ECF} = NPV_{ATP} + NPV_{DEP}$$

where

$$NPV_{ATP} = K\left[\sum_{1}^{N} \frac{INV_1}{(1+m)^i} + \sum_{2}^{N+1} \frac{INV_2}{(1+m)^i} + \sum_{3}^{N+2} \frac{INV_3}{(1+m)^i} \ldots\ldots\ldots + \sum_{\eta}^{N-\eta-1} \frac{INV_\eta}{(1+m)^i}\right]$$

$$NPV_{DEP} = \frac{1}{N}\left[\sum_{1}^{N} \frac{INV_1}{(1+m)^i} + \sum_{2}^{N+1} \frac{INV_2}{(1+m)^i} + \sum_{3}^{N+2} \frac{INV_3}{(1+m)^i} \ldots\ldots\ldots + \sum_{\eta}^{N-\eta-1} \frac{INV_\eta}{(1+m)^i}\right]$$

which can be transformed to:

$$NPV_{ECF} = \left(K+\frac{1}{N}\right) \sum_{1}^{N} \frac{1}{(1+M)^i}\left[INV_1 + \frac{INV_2}{(1+m)} \ldots\ldots + \frac{INV_\eta}{(1+m)^{\eta-1}}\right]$$

where m is the rate-of-return and N is the tax life of the capital investment. In the long run, using the approach that the discount factor for investments, r, equals the internal rate-of-return, m, and the investment criterion that the net present value of future investments is equal to the net present value of future earnings

$$NPV_I = NPV_{ECF}$$

However, the summation terms inside the brackets on both sides of expanded verion are equal. Therefore;

$$(1+J) - \frac{1}{(1+r)^N} = \left(K + \frac{1}{N}\right)\left(\sum_{1}^{N} \frac{1}{(1+r)^i}\right)$$

However, the term:

$$\sum_{1}^{N} \frac{1}{(1+r)^i} = \frac{(1+r)^N - 1}{(r)\ (1+r)^N} \longrightarrow \frac{1}{r}$$

as N becomes large.

Therefore, the rate-of-return can be transformed into

$$r = \frac{KN + 1}{N(1+J)}$$

The terms of the right hand side of this relationship can be obtained directly from a firm's balance sheets over a selected time period, and for that period, the internal rate-of-return achieved by that firm can be estimated. Of course, the accuracy of the approximation increases as N, the depreciation period, increases; this accuracy also depends on the relative values of the working capital ratio, J, and the (margin-to-capital output ratio) term, K. For most values of J and K used in this study, the rate-of-return calculated by using this simplified approach tended to overestimate by less than 10 percent the value which would have been calculated directly.

Based on this approach, the calculated rates-of-return identified by four digit standard industrial classification numbers are shown in Table V-25. The values include the effects of inflation. With a few exceptions, the rates-of-return exceed the cost-of-capital for the respective categories. The overall (unweighted) average aftertax rate-of-return calculated for these twenty-two industrial groupings is slightly less than 13 percent compared to an average cost-of-capital of 10 percent. This indicates that for the subject firms (industrial groupings), the rates-of-return historically have exceeded the costs of capital by approximately three percentage points.

Since most firms cannot plan for all events affecting their future sales, target rates-of-return may be established in excess of their historically-achieved rates-of-return. In fact, information presented in Reference 3 indicates that target rates-of-return in excess of 15 percent, aftertax, are not uncommon in industry.

TABLE V-25

INDUSTRIAL COMPOSITE RETURN RATES

SIC	Industry	Average Rate of Return	Standard Deviation
2011	Meat Packing	7.7	11.0
2051	Bread and Other Bakery Products	17.3	10.0
2082	Malt Beverages	7.5	8.8
2221	Broad Woven Fabric Mills	18.7	13.7
2621	Paper Mills Except Building Paper Mills	14.4	6.0
2631	Paperboard Mills	12.5	5.0
2812	Alkalies and Chlorines	14.7	2.6
2819	Ind. Inorganic Chemicals Not Elsewhere Classified	14.1	3.1
2821	Plastic Materials, Synthetic Resins, and Non-Vulc. Elastomers	12.0	4.5
2822	Butadiene Rubber	7.7	2.6
2824	Synthetic Organic Fibers Except Cellulosic (Nylon)	9.4	3.5
2865	Cyclic Crudes, Cyclic Intermediates, and Organic Pigments (Styrene	13.3	4.3
2869	Ind. Organic Chemicals Not Elsewhere Classified (Ethylene)	13.1	4.1
2911	Petroleum Refining	12.5	1.9
3011	Tires and Inner Tubes	9.0	3.45
3221	Glass Containers	10.0	4.0
3241	Cements, Hydraulic	19.9	19.8
3312	Blast Furnace (Including Coke Ovens), Steel Works and Rolling Mills	10.4	3.2
3321	Gray Iron Foundries	13.9	5.0
3331	Primary Smelting and Refining of Copper	10.8	11.0
3711	Motor Vehicles and Passenger Car Bodies	14.3	8.8
3714	Motor Vehicle Parts and Acessories	16.5	4.7

In a business climate facing a 6 percent to 7 percent inflation rate (which was typical of firms in the mid-1970's), a target rate of return of 15 percent (including the effect of inflation) would be reasonable. When the inflation factor is removed from this estimate, a target, constant-dollar rate-of-return of 8 to 9 percent (above the inflation rate) should be considered typical of most industrial firms which consider a low-risk venture. It was thought that in as much as this value exceeds the estimated average industrial firm cost of capital by approximately 3 to 4 percentage points, it is in line with historical data and therefore could be used. Consequently, when estimating the attractiveness of a cogeneration system from the viewpoint of an industrial firm, target rate-of-return of 8 percent above the inflation rate was considered to be the minimum value which would be acceptable.

Assumptions and Ground Rules

For consistency in the overall study, a set of economic ground rules, assumptions, and methods were established. These ground rules affect the industrial- and utility-related capitalization and capital equipment depreciation life, the economic life, the escalation rates of the fuels, the tax rates, the date on which the costing is based, and the date of introduction for a given technology. In addition, all costs and investments were expressed in 1978 dollar values, an assumption equivalent to assuming an inflation rate of zero.

Because all base-case economic analyses were calculated in the absence of inflationary effects, this effect was also removed from the cost of capital. For the average industrial firm, the before-tax cost of debt was assumed at 3 percent, while the cost of equity was assumed to be 7 percent. Of the total capitalization, that portion from debt funding was assumed to be 30 percent and that from equity funding was assumed to be 70 percent. No preferred equity financing was considered. The after-tax cost-of-capital was 5.35 percent. In those cases where utility type financing was considered, the inflation-free cost of debt was assumed to be 2 percent (before-tax), and that for equity funding was 6 percent. With a 50 percent capitalization ratio for debt and equity financing, the after-tax cost-of-capital for utility-type cogeneration system operators became 3.5 percent (at a zero inflation rate).

Although capital and operating costs for both the cogeneration and non-cogeneration systems were expressed in 1978 dollars and there was no effect of inflation, there were escalation factors which were assumed to affect the costs of fuels and electricity because of their increasing scarcity. For all fuels and electricity except for natural gas, it was assumed that the real cost (in constant 1978 dollars) increased at an escalation rate of 1 percent per year throughout the term of the analysis. During this same period, natural gas was assumed to escalate in price (also expressed in constant 1978 dollars) at an average rate of 4.6 percent per year until 2000 when the escalation rate would reduce to 1 percent. All other charges (e.g., operating and maintenance, capital, taxes, insurance, etc., affecting the base cases) were assumed to include neither an inflation factor nor an escalation factor.

For industrial firms, the rapid return of capital through depreciation cash flow is beneficial to both their cash positions and their rates-of-return. Therefore, to match as closely as possible the economic policies of such firms, the sum-of-the-years digits, accelerated depreciation method was used, and all capital investments were assumed to have a depreciation life of 15 years. For those firms where utility-type financing was considered, it was believed that regulations by public utility commissions would be applicable. Although the accelerated, sum-of-the-years-digits depreciation method was still assumed in these latter cases, the depreciation lifetime for these capital investments was extended to 30 years. In every case considered, the effective economic lifetimes of the systems considered were assumed to be 30 years. Calculations were performed to obtain cash flows from both the noncogeneration and cogeneration systems for each year throughout their entire economic lifetimes.

For purposes of this analysis, the federal income tax and the state income tax were combined (recognizing that state taxes are deductible expenses on federal tax returns). The effective income tax rate is approximately 50 percent and this value was used. Tax concessions in the form of an investment tax credit from the federal government have long been an incentive device to stimulate capital investment on the part of industrial firms. Although several government plans considering this incentive have been discussed for cogeneration, none were in effect at the time of the study. As a result, both the cogeneration and noncogeneration systems were considered to be eligible for only a 10 percent investment tax credit. However, the effect of varying this highly visible incentive was considered in the sensitivity analysis. Finally, although not strictly a tax factor, an allowance for insurance premium on the capital equipment, ad valorum taxes, and other miscellaneous state and municipal taxes was estimated to be 3 percent of the capital equipment cost for firms where industrialtype financing was assumed.

For all cases, the initial year of operation of the cogeneration systems was selected to be 1990; and the economic lifetimes extended 30 years to the end of the year 2019. This start-date is important in that it establishes the target year for which the escalated fuel and electricity charges must be established (albeit in terms of 1978 dollar values). Although it could be argued that several of the technologies could be made available before that time, some of the developing technologies may not be available until a later time. By establishing a single base year for system start-up, and by using a 1978-cost base for capital and expense charges, all systems become comparable on a common basis, unaffected by the time value of money which would otherwise accompany differing technology availability dates.

Calculation of Major Economic Parameters

There are several economic parameters which are generally of significance to the management of a firm considering a new venture. Among the more important of these are the discounted-cash-flow rate-of-return, the payback period, the net present value of the venture, its levelized annual cost, and its life-cycle cost. The definitions of each of these parameters, along with the methodology exercised in the analysis to calculate the values of these parameters are presented in the following section. However, before these individual factors are discussed, background on some of the major underlying components affecting the cash flows of a typical venture should be introduced.

Specifically, the cash flow from operations is the summation of after-tax profit plus the depreciation expense. This is illustrated in Table V-26 where operating expenses, allowable depreciation, and federal and state income taxes are subtracted from sales to product net income from operations. However, as noted, since depreciation is a non-cash operating expense, its value must be added to the net income to produce earnings cash flow for the subject period of examination.

Table V-26

SAMPLE COMPONENTS OF EARNINGS CASH FLOW

Sales Receipts
(minus)
Operating Expenses
(minus)
Depreciation
equals

Taxable Profit
(minus)
Federal, etc. Income Taxes
equals

Net Income
plus
Depreciation
equals

Earnings Cash Flow

In an effort to further assist in visualizing the manner by which the major economic parameters of the analysis were calculated, Figure V-25 shows the initial capital investment and the annual earnings cash flow values in each subsequent year of a venture. The investment is shown below the base line to indicate a cash outflow, whereas, the earnings cash flows are shown above the base line indicating inflows of cash. The total heights of each earnings cash flow column are meant to represent the actual values of the cash flows. The cross-hatched values in each column represent the discounted values of each annual cash flow.

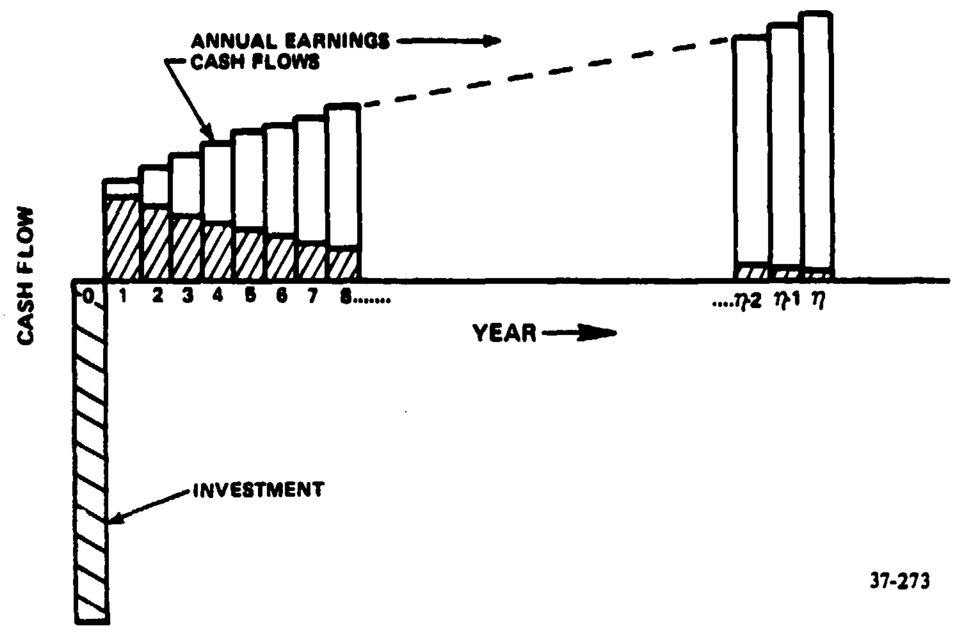


Figure V-25. Schematic Diagram of Investment and Earnings Cash Flows for a Typical Venture

o Rate-of-Return

The rate-of-return is a measure of the interest returned on the invested capital through a series of future cash flows resulting from the operation of a venture requiring that capital. The rate-of-return is a unique characteristic of a business venture and in financial terms is analogous to the interest rate paid on an annuity.

In the study, the method used to calculate rate-of-return was as follows: The annual costs for fuel, electricity, operation and maintenance, depreciation, taxes, insurance, and other related items were estimated separately for the cogeneration and noncogeneration systems. Since it was rate-of-return on the incremental capital investment (cogeneration minus noncogeneration) which was of importance, the incremental earnings cash flows between systems were then determined. When this difference was calculated for each year, the implicit estimates for sales disappear and all that remained were differences in system costs. The future annual after-tax earnings cash flow differences were then discounted on a trial-and-error basis until the sum of their present values matched the value of the incremental capital investment. Referring to Figure V-25, each future annual cash flow has a discounted present value proportional to the cross-hatched area at its base, and there is only one interest rate (discount factor) which, when applied to these actual cash flows produces a series of (discounted) flows whose summed value equals that of the investment. This discount factor is defined as the discounted-cash-flow rate-of-return for the capital investment undertaken. Expressed in equation form:

$$INV = \sum_{i=1}^{30} \frac{ECF_i}{(1+r)^i}$$

where r is the rate-of-return

INV is the incremental capital investment

ECF_i is the annual, incremental, after-tax earnings cash flow in year "i".

o Simple Payback Period

Payback period is that amount of time until the summation of annual (incremental) after tax earnings cash flows are sufficient to return the capital required in the investment. Referring to Figure V-25, when the sum of the annual earnings cash flows starting with year 1, equals the initial investment, the payback period has been reached. The methodology used to calculate payback period does not consider the time value of money nor the earnings cash flow profile beyond the payback period. Nevertheless, payback period does serve as a simple and convenient figure of merit of how rapidly a program returns its initial investment.

o Net Present Value

The term "net present value" refers to the sum of discounted incremental annual earnings cash flows (between cogeneration and non-cogeneration systems), using the cost-of-capital as the discount factor, minus the incremental capital investment. Net present value is calculated using a method analogous to that used for the rate-of-return. The cross-hatched areas in Figure V-25 are the present values of the annual earnings cash flows using the cost-of-capital as the discount factor. Their (positive) sum, when added to the (negative) value of the investment produces the net present value of the venture. Stated differently, the net present value is the difference between the present value of a future stream of earnings and the net investment required. A venture is generally considered attractive for investment if its net present value is positive, and when choices among ventures must be made, those with the highest net present value are the most attractive. Because the same discounting method is used to calculate the rate-of-return and the net present value, any cogeneration system whose incremental capital investment produced a rate-of-return greater than the cost-of-capital also produced a positive net present value.

Expressed in equation form:

$$NPV = \sum_{1}^{n} \frac{ECF_i}{(1+COC)^i} - CI$$

where: NPV is the net present value;

ECF is the annual, after-tax earnings cash flow;

COC is the after-tax cost-ofcapital;

CI is the capital investment

o Levelized Annual Cost

The levelized annual cost is that cost which when distributed annually over the lifetime of a system would have the same present value as the actual stream of costs when both are discounted at the cost-of-capital. The levelized cost is comprised of numerous component factors including those related to the invested capital, operating and maintenance charges, fuel costs, electricity costs, and miscellaneous other system charges. Since this sum comprises system costs, the levelized value which is the lowest among systems being compared represents the most attractive system on a relative basis. Expressed in closed form, the levelized annual cost, LAC is:

$$LAC = (FCR)\ (CI) + (CRF)\ (OC_{PV})$$

when: FCR is the fixed charge rate;
CI is the capital investment;
CRF is the capital recovery factor;
OC_{PV} is the present value of the system operating costs.

The methodology used to calculate the FCR and CRF factors of the levelized costs for the cogeneration and non-cogeneration systems are based on Reference 1.

o Life-Cycle Cost

The life-cycle cost of a system is defined as the net present value (discounted at the cost-of-capital) of the sum of the system related costs, and where there is no net investment outside of a given project, it represents the present value of the reveneu stream (which includes appropriate returns to the bondholders and stockholders) associated with that program. The ratio of the levelized annual cost to the life-cycle cost is directly proportional to the capital recovery factor, a term used to spread a given present value equally over each of a future set of years. As was the case for levelized annual costs where the analyses of both the cogeneration and noncogeneration systems are concerned only with system costs, that system with the lowest life-cycle cost would be the most attractive in a relative sense. The methodology and equations for the life-cycle cost used in the CTAS economic analyses were taken from Reference 1. The equation for life-cycle cost, LCC is: LCC = LAC/CRF

where: LAC is the levelized annual cost
CRF is the capital recovery factor

Economic Output Format

An example of the output results for a typical CTAS economic analysis is shown in Figure V-26. This is the case for the chlorine industry with advanced-technology gas turbines for the optimum cogeneration strategy. The start up year (1990) and base year of cost estimates appear first in the results followed by an indication of the depreciation methodology, the after-tax cost-of-capital, annual fixed charge rate (on invested capital), and the general inflation rate assumed. The subsequent columnar data present specific information about the cogeneration and non-cogeneration systems with respect to their capital costs, life-cycle costs, and annularized (levelized) costs. The levelized annual cost savings ratio represents the difference in annularized costs divided by the non-cogeneration system costs and is expressed as a decimal value. For the annual output level of 268,333 tons shown, the annual cost per ton is simply the annularized cost divided by this annual output capacity. For this installation, the cogeneration system has a payback period of 2.3 years as noted and a discounted-cash-flow rate-of-return of 41.2 percent (after taxes). Since this rate of return far exceeds the cost-of-capital, the net present value based on the incremental cash flow differences between the non-cogeneration and cogeneration systems is positive. Finally, the major economic input data for this case is noted at the bottom of this figure for ready reference or for use when making comparisions among system results.

Economic analyses were conducted for 120 cogeneration systems using the baseline economic ground rules described previously.

Sensitivity Analyses

In order to investigate the effect of changes in the values of several of the major economic variables affecting the results of the study, sensitivity analyses were conducted wherein the select variables are varied individually within prescribed ranges. The primary objective of this activity was to determine the level of these individual variables at which the minimum acceptable corporate rate-of-return (previously selected to by 6 percent above the general inflation rate) would be achieved. A further purpose of this activity was to determine the trend relationships between the rate-of-return and the variable selected. Such calculations not only define the trends but also help to identify those variables which have the greatest effect on the overall results. Different cases were selected for detailed sensitivity studies. These cases covered a representative set of industries, including firms producing newsprint paper, corregated paper, chlorine, and textiles; and examinations were made of the effect created by variations in capital costs, investment tax credit, tax life, electric utility rate, fuel (coal and oil) prices, fuel escalation rate, and general inflation rate. The computer model which generated the results represented by the sample shown in Figure 26 was made versatile in order to accept the changes in the industrial variables as noted. The output format for the results of the sensitivity case examinations is identical to that presented in Figure V-26, and for all cases studied the input data format at the page bottom was generally sufficient, in addition to the title, to identify the specific cases and variables considered in these analyses.

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CASE  53 INDUSTRY-CHLORINE                STRATEGY-OPTIMUM   OWNERSHIP--INDUSTRIAL
NO.13 ADVANCED TECHNOLOGY,GAS TURBINE,DIRECT FIRED,COAL DFR,BLR GRD

START-UP DATE = 1990.
BASE YEAR OF COST ESTIMATES = 1978.

DEPRECIATION=SUM-OF-THE-YEARS DIGITS METHOD

AFTER-TAX COST-OF-CAPITAL =  5.3%
FIXED CHARGE RATE ON INVESTMENT CAPITAL = 10.1%
GENERAL INFLATION RATE= 0.0%

                                                      NONCOGEN      COGEN

CAPITAL COST (THOUSANDS OF DOLLARS)                     3004.       17900.

LIFE-CYCLE COST (THOUSANDS OF DOLLARS)                980770.      432405.

ANNUALIZED COSTS (THOUSANDS OF DOLLARS)
  FIXED PORTION                                          302.        1800.
  NATURAL GAS        (ESCALATION RATE= 3.4%                0.           0.
  DISTILLATE         (ESCALATION RATE= 1.0%                0.           0.
  RESIDUAL           (ESCALATION RATE= 1.0%             9666.       25380.
  COAL               (ESCALATION RATE= 1.0%                0.           0.
  COAL GAS & OTHER   (ESCALATION RATE= 1.0%                0.           0.
  ELECTRICITY        (ESCALATION RATE= 1.0%            29246.           0.
  OEM,INS,ETC.       (INFLATION RATE = 0.0%               87.        2080.

  TOTAL SYSTEM                                         39301.       29261.

  LEVELIZED ANNUAL COST SAVINGS RATIO = 0.255

ANNUAL OUTPUT      268333.(TONS)
LEVELIZED ENERGY COST($/TON)   *                      146.46       109.05
UNIT ENERGY COST($/TON)        **                     146.46       109.05

UNDISCOUNTED PAYBACK PERIOD              =   2.3   YEARS

DISCOUNTED CASH FLOW RATE OF RETURN      =  41.2   %

NET PRESENT VALUE OF INCREMENTAL CASH FLOW
(COGEN. VERSUS NONCOGEN. - (THOUSANDS OF DOLLARS)) =      73116.

*   BASED ON ANNUAL OUTPUT OF PRODUCT

**  HAS AN UNCHANGING VALUE IN TERMS OF CONSTANT PURCHASING
    POWER AND GROWS ANNUALLY AT THE GENERAL INFLATION RATE

COST OF DEBT                  =    3. %   EFFECTIVE TAX RATE          =   40. %
COST OF COMMON EQUITY         =    7. %   ECONOMIC LIFE               =   30. YRS
COST OF PREFERRED EQUITY      =    0. %   TAX LIFE                    =   15. YRS
DEBT CAPITALIZATION           =   30. %   INVESTMENT TAX CREDIT       =   10. %
COMMON STOCK CAPITALIZ.       =   70. %   INSURANCE & OTHER TAXES     =    3. %
PREFERRED STOCK CAPITALIZ.    =    0. %   INCREMENTAL CAPITAL INV.    =    0. %
```

Figure V-26. Economic Evaluation Printout

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OF POOR QUALITY

RESULTS

The energy conversion system characteristics, heat source data, and balance-of-plant information were combined to define cogeneration systems which were applied, consistent with the assumptions and groundrules, to satisfy the requirements of the various industrial processes. For each strategy-conversion technology-fuel-industry combination, fuel consumption, cost, and emission data were compiled for the most energy conserving conversion system design option. Summary data including fuel savings, fuel energy savings ratio, cost savings, cost savings ratio, capital costs, emissions savings ratio, and emission savings (on-site and total) for each of these 3,364 cases are presented in Volume VI of this report.

In the following sections the results for these cases are summarized in three ways:

First, a series of matrix charts are presented indicating the results for each energy conversion system - fuel- industry combination. Second, the energy and cost savings ratio for each energy conversion system are summarized statistically for the various industrial applications. Third, an extrapolation to national consumption levels is introduced to aid in evaluating and comparing energy conversion systems. Extending the results to the national level is not intended as a prediction of future events; rather it is a simplified means examining the relative merits and advantages of the various advanced energy conversion technologies.

DETAIL RESULTS

Figure V-27 indicates that the energy costs and emission savings were computed for each intersection of the matrix of industrial applications and energy conversion systems. One method of presenting the results of the analysis is to indicate the savings in each industry - conversion system box in the matrix. A series of charts have been prepared for that purpose. Figure V-28 is one such matrix chart. In this figure each of the 26 industrial processes occupies a vertical column. The energy conversion systems both current and advanced are included as horizontal rows.

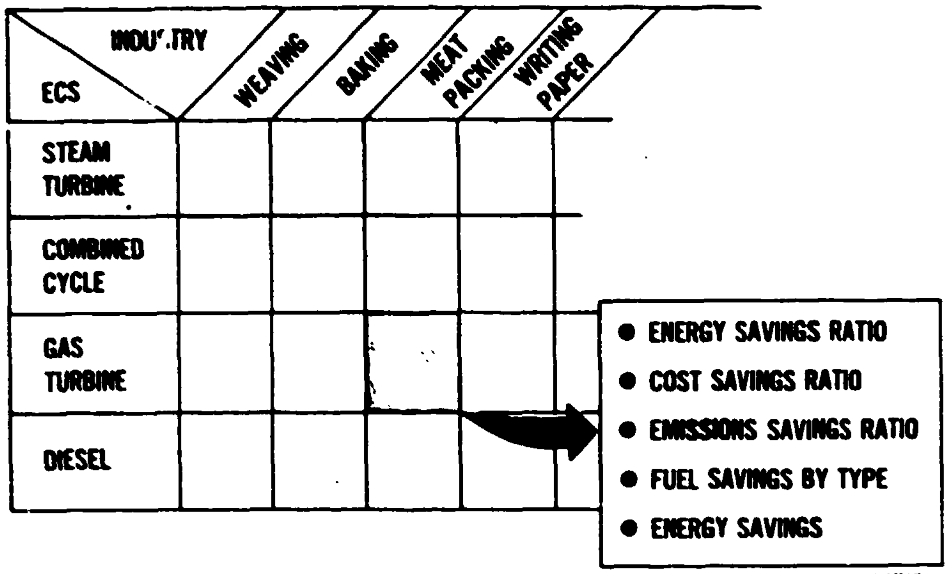

Figure V-27. Technology Data Base for Each Cogeneration Strategy

The fuel energy savings ratios for a match electric strategy are presented in Figure V-28. Fuel energy saving ratios greater than 30 percent are represented by the darker shading while savings less than 10 percent are not shaded. A review of the chart will indicate some of the more conserving energy conversion systems: the gas turbine with coal derived boiler fuel; the combined cycle with coal derived boiler fuel, and the high temperature fuel cell with coal derived distillate fuel. In certain cases, the results include energy conversion systems designs which were outside the range considered practical. For example, the results shown for the advanced technology high speed diesel engine are not limited by powerplant size considerations. As a result, this conversion technology appears attractive in certain large industries where a sizeable number of units would be required. In practice, the high speed diesel engine is limited to about 1½ megawatts electric output. Its application in a paper mill requiring 90 megawatts might be considered too complex. However, the results are included here for completeness but were not carried forward to the detail economic analysis. The matrix chart, Figure V-28, also indicates industrial processes which are good cogeneration candidates with the advanced energy conversion systems.

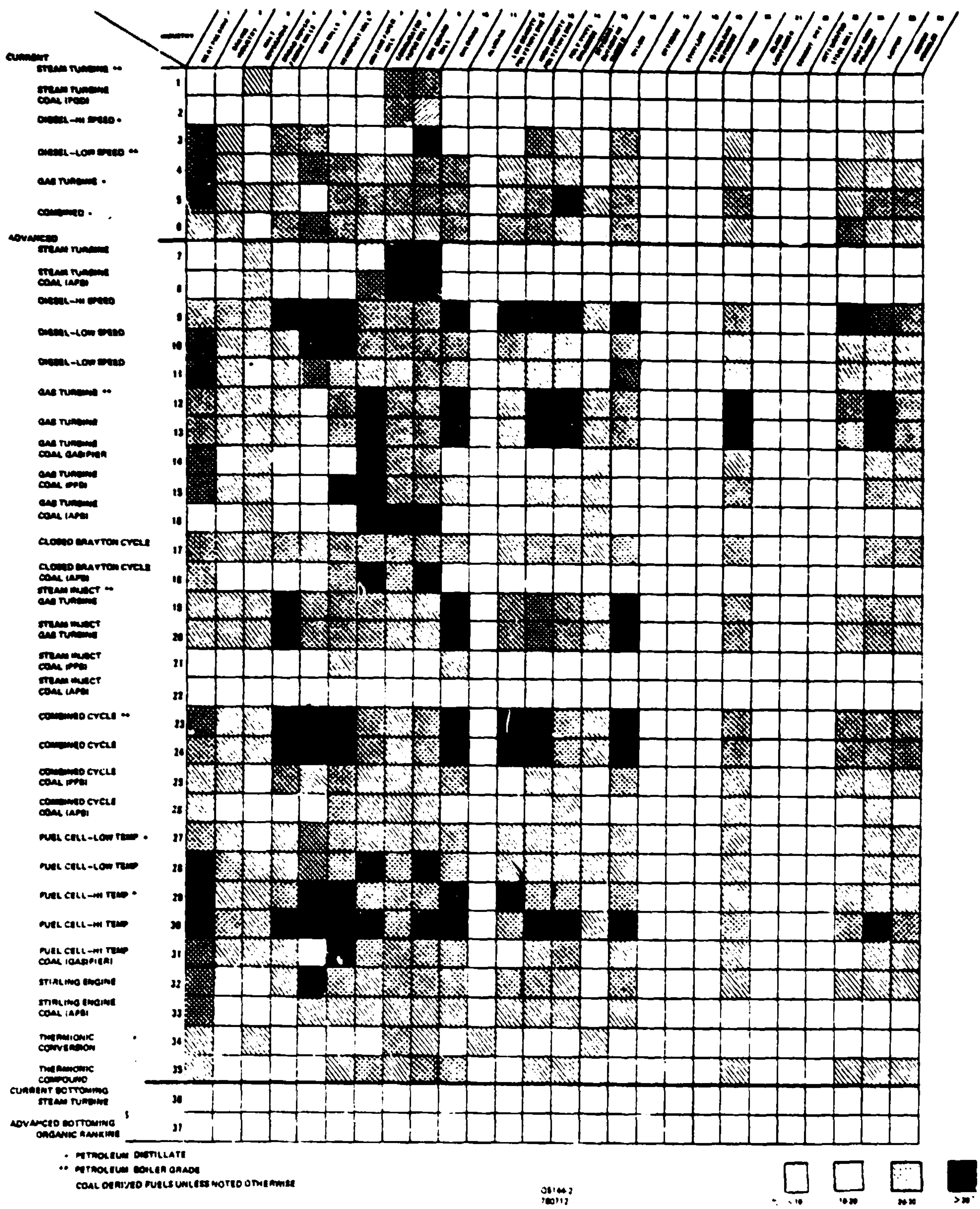

Figure V-28. Fuel Energy Savings Ratio Results, Match Electric Strategy

Some industries which are significant energy consumers do not indicate fuel energy saving ratios above 10 percent; for example, petroleum refining. However, substantial fuel savings are possible. In the second matrix chart, Figure V-29, the absolute magnitude of the fuel savings is indicated for each industrial process - conversion system combination. In this figure the fuel savings for the representative industrial plant have been extended to the national level for the particular product produced assuming that similar percentage savings could be obtained in all other plants producing the same product. Petroleum refining is an interesting prospect for cogeneration because it offers high fuel savings even though the percentage savings may be less than 10 percent. For the match electric strategy, national fuel savings are not as strong a discriminator between advanced energy conversion systems as the fuel energy savings ratio.

Economics is an important element in the acceptability of cogeneration. Figure V-30 presents the matrix of the cost savings ratios based upon levelized annual costs. Conversion systems which exhibited high fuel savings generally provide economically attractive situations. Again, in this chart the highest savings (greater than 20 percent) are achieved with the darker shading. A second influence can be seen in Figure V-30: The type of fuel is a factor in the cost savings ratio. For example, the gas turbine energy conversion systems using coal (on-site gasified coal, atmospheric fluid bed coal combustion, or pressurized fluid bed coal combustion) present a number of economically attractive circumstances compared to the conventional gas turbine.

While the high temperature fuel cell with coal derived liquid fuel presents a number of attractive fuel energy savings ratio cases, the high temperature fuel cell operating with an on-site coal gasification plant appears to provide the more dramatic cost savings.

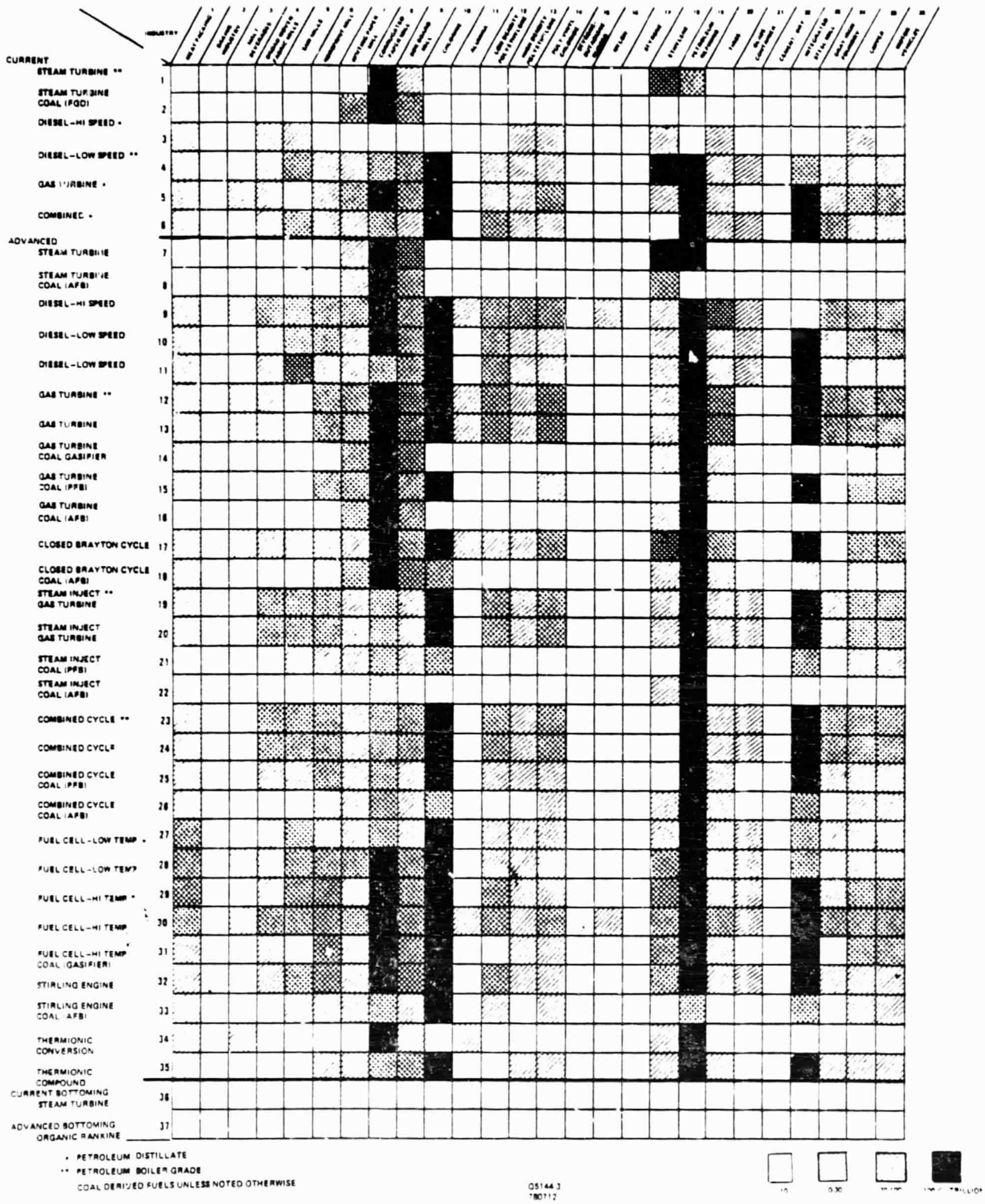

Figure V-29. Fuel Energy Savings, Match Electric Strategy

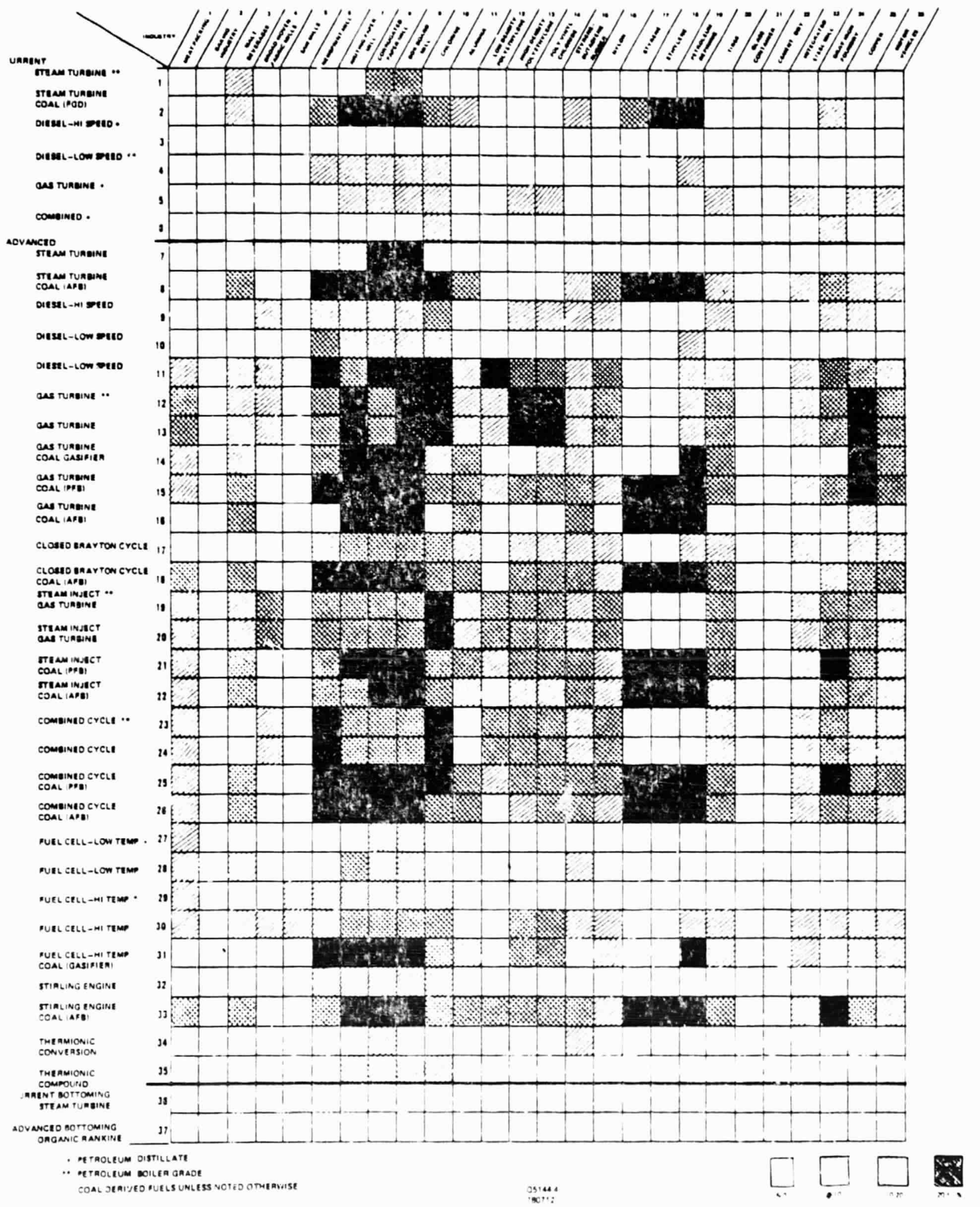

Figure V-30, Cost Savings Ratio Results, Match Electric Strategy

The pollutants emitted by cogeneration plants can be an important factor in their acceptability. Figure V-31 presents the emission savings ratios for the match electric strategy. Again, the darkest squares are the most attractive. The most significant conclusion of this chart is that the diesel powerplants offer the least attractive emission characteristics. The emissions savings ratios presented in Figure V-31 represent the total emissions including the emissions from electric utilities.

These matrix charts, taken simply, do not indicate strong discriminating factors which would recommend one energy conversion system over another. Two factors are combined in Figure V-32. This chart presents the energy savings ratio for only those cases which are economically attractive, that is, have positive cost savings ratios. The gas turbine is most commonly represented in Figure V-32. The high speed diesel, gas turbine combined cycle and high temperature fuel cell also appear to have many attractive cases for the match electric strategy.

The cogeneration strategy can affect the results and conclusions. A second set of matrix charts are included for the strategy which maximizes the energy savings ratio. In some cases this strategy will match the electrical requirements. In others the thermal requirements will be satisfied without an auxiliary furnace. In most cases the maximum fuel energy savings ratio occurs at a power level between the match electric and the match thermal situation.

Figure V-33 presents the energy saving ratio for the maximum savings strategy. The darkest cases are the most conserving. With this strategy there are more attractive energy conversion systems than appeared with the match electric situation. In addition to the high speed diesel, gas turbine, combined cycle, and high temperature fuel cell; the low speed diesel, closed cycle gas turbine and steam injected gas turbine also appear promising for this strategy. In addition, some industries, which produced low percentage savings with the match electric situation, produce significantly higher fuel energy savings ratios with this most conserving strategy.

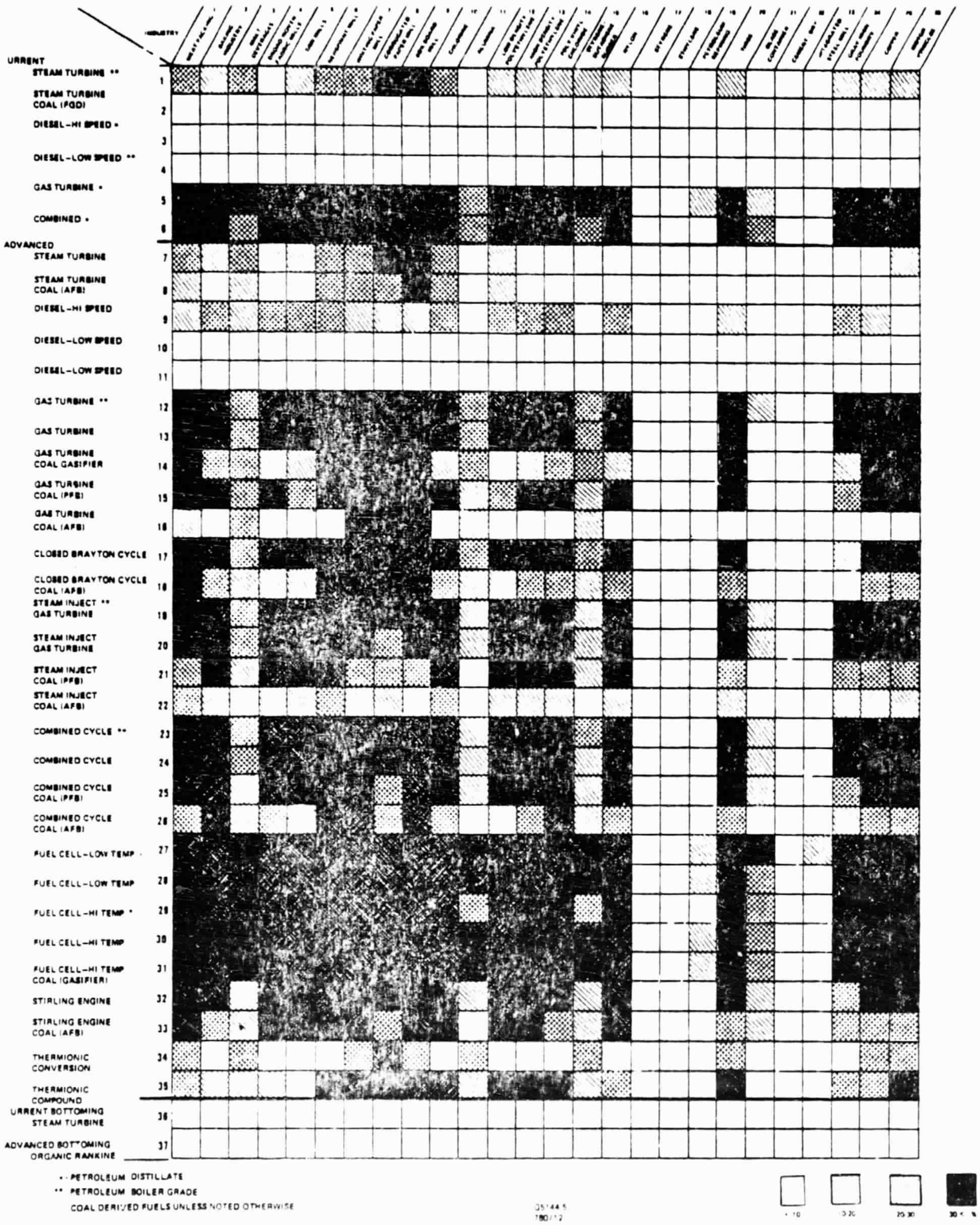

Figure V-31. Emission Savings Ratio Results, Match Electric Strategy

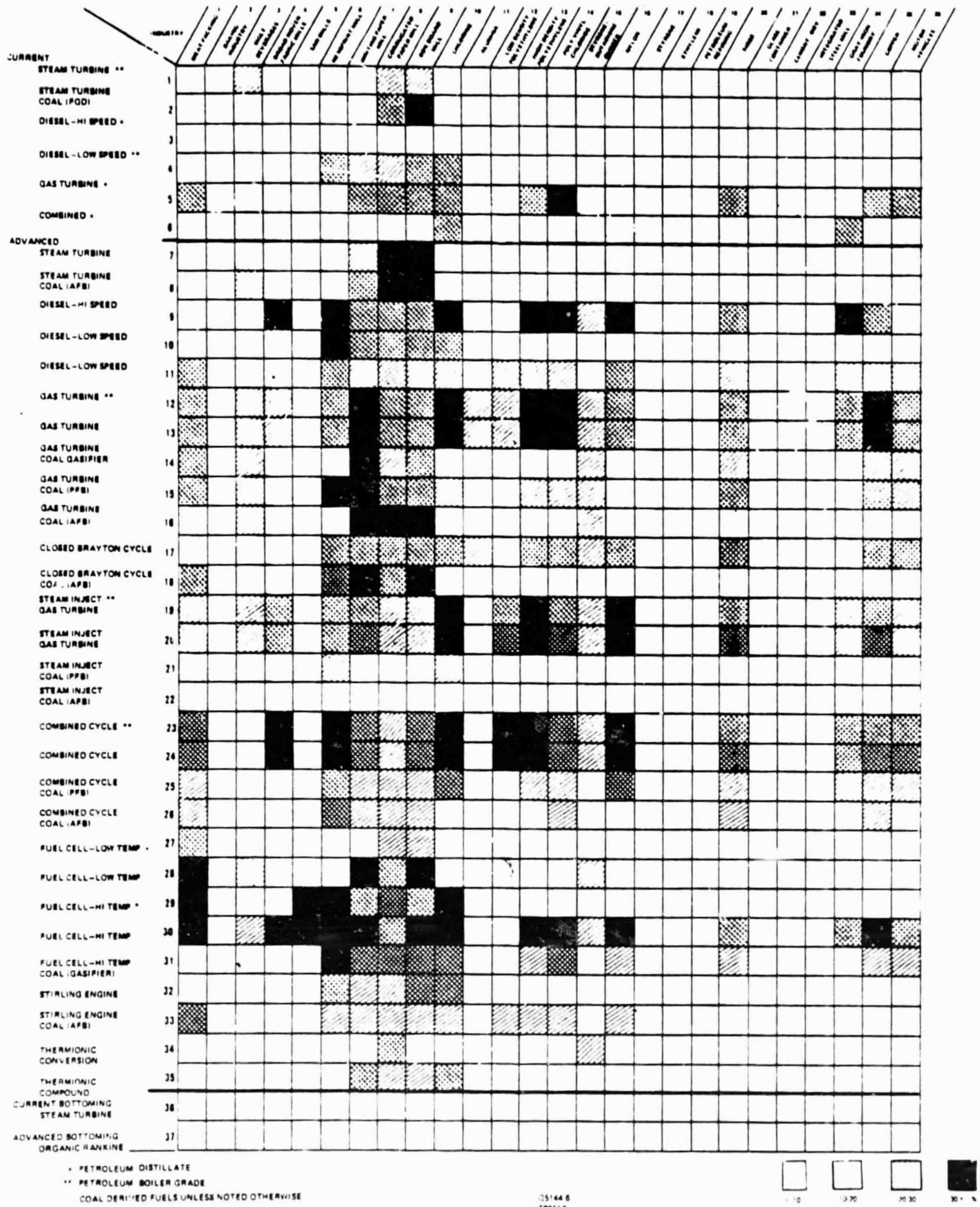

Figure V-32. Fuel Energy Savings Ratio Results for Cases with Positive Cost Savings Ratio, Match Electric Strategy

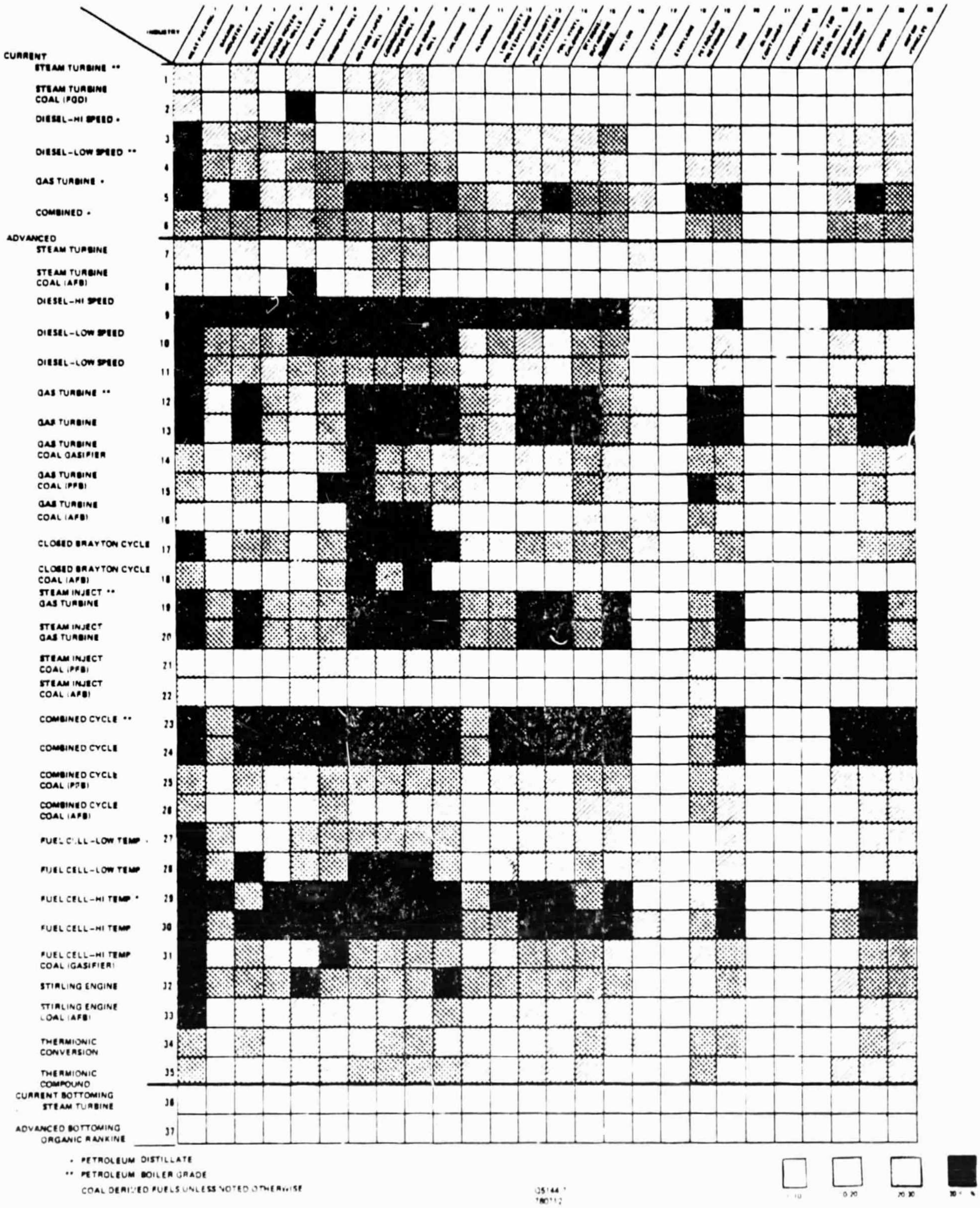

Figure V-33. Fuel Energy Savings Ratio Results, Maximum Fuel Savings Strategy

The fuel savings scaled to a national level are presented in Figure V-34. The patterns are similar to those with the match electric strategy. The cost savings ratio is presented in Figure V-35 and the emission savings are indicated in Figure V-36. The last chart with this maximum energy savings ratio strategy Figure V-37 indicates the energy savings ratio for only those cases which have positive cost savings ratios. Again, the gas turbine, combined cycle, and high temperature fuel cell are the dominant technologies.

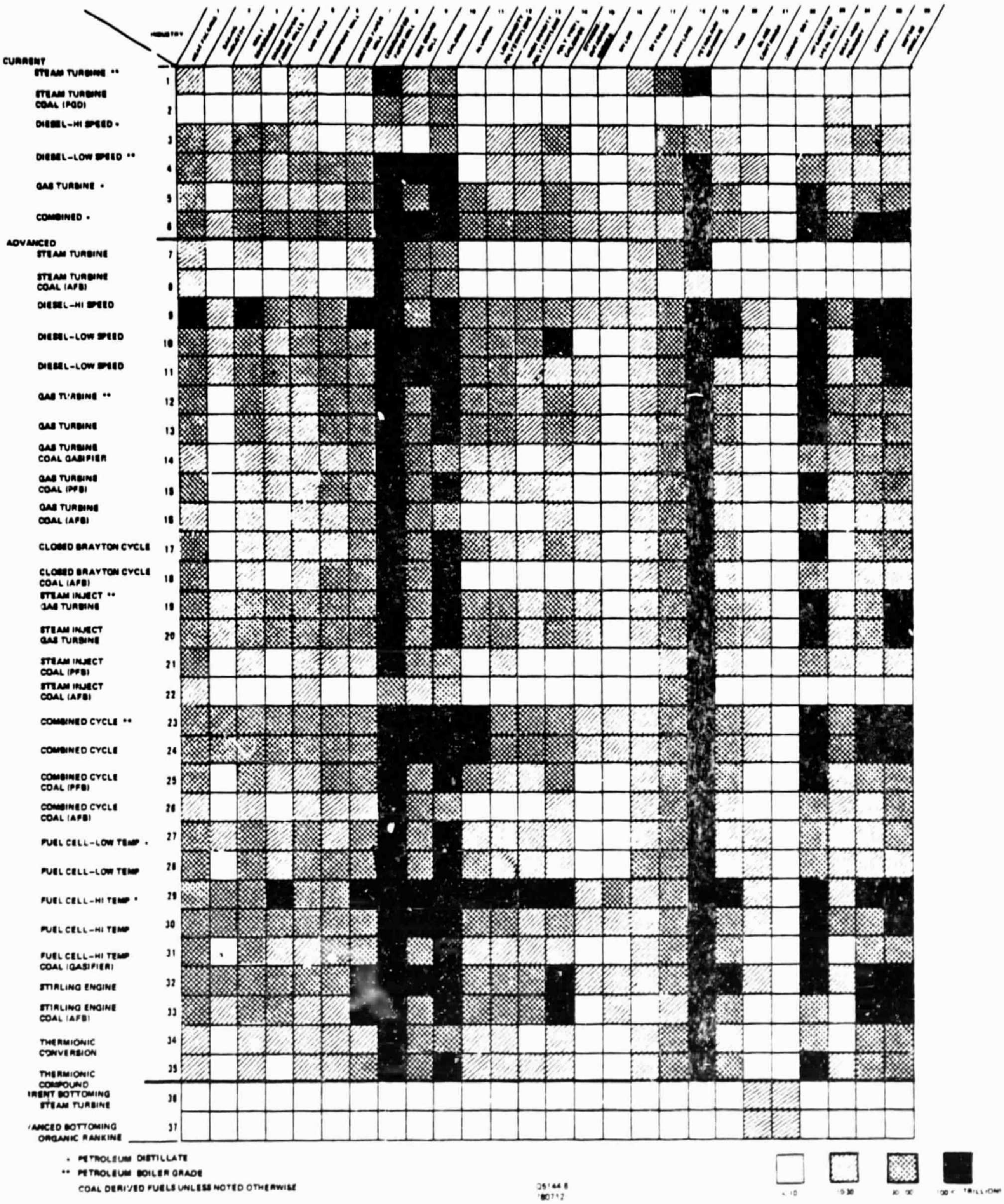

Figure V-34. Fuel Energy Savings, Maximum Fuel Savings Strategy

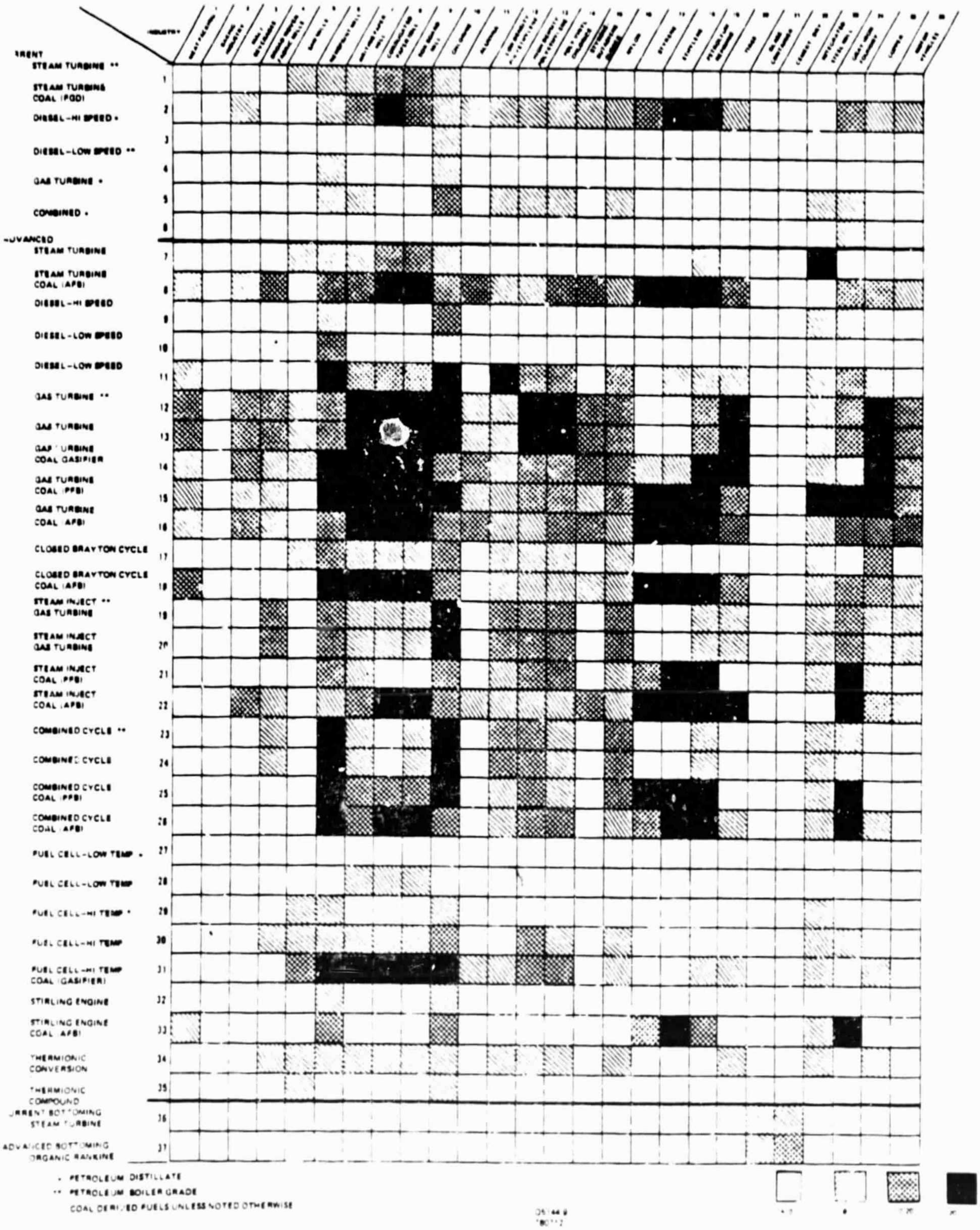

Figure V-35. Cost Savings Rati Results, Maximum Energy Savings Strategy

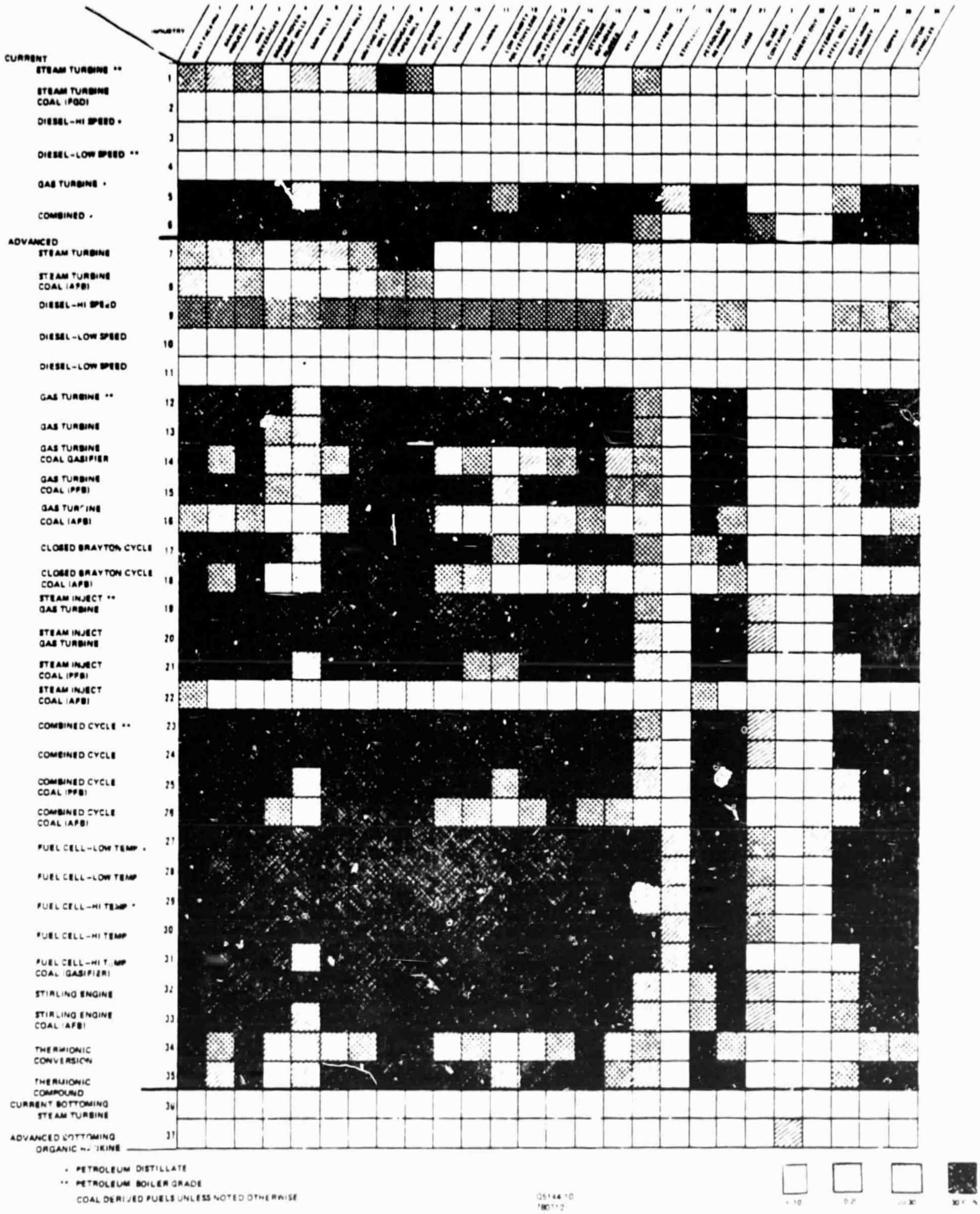

Figure V-36. Emissions Savings Ratio Results, Maximum Energy Savings Strategy

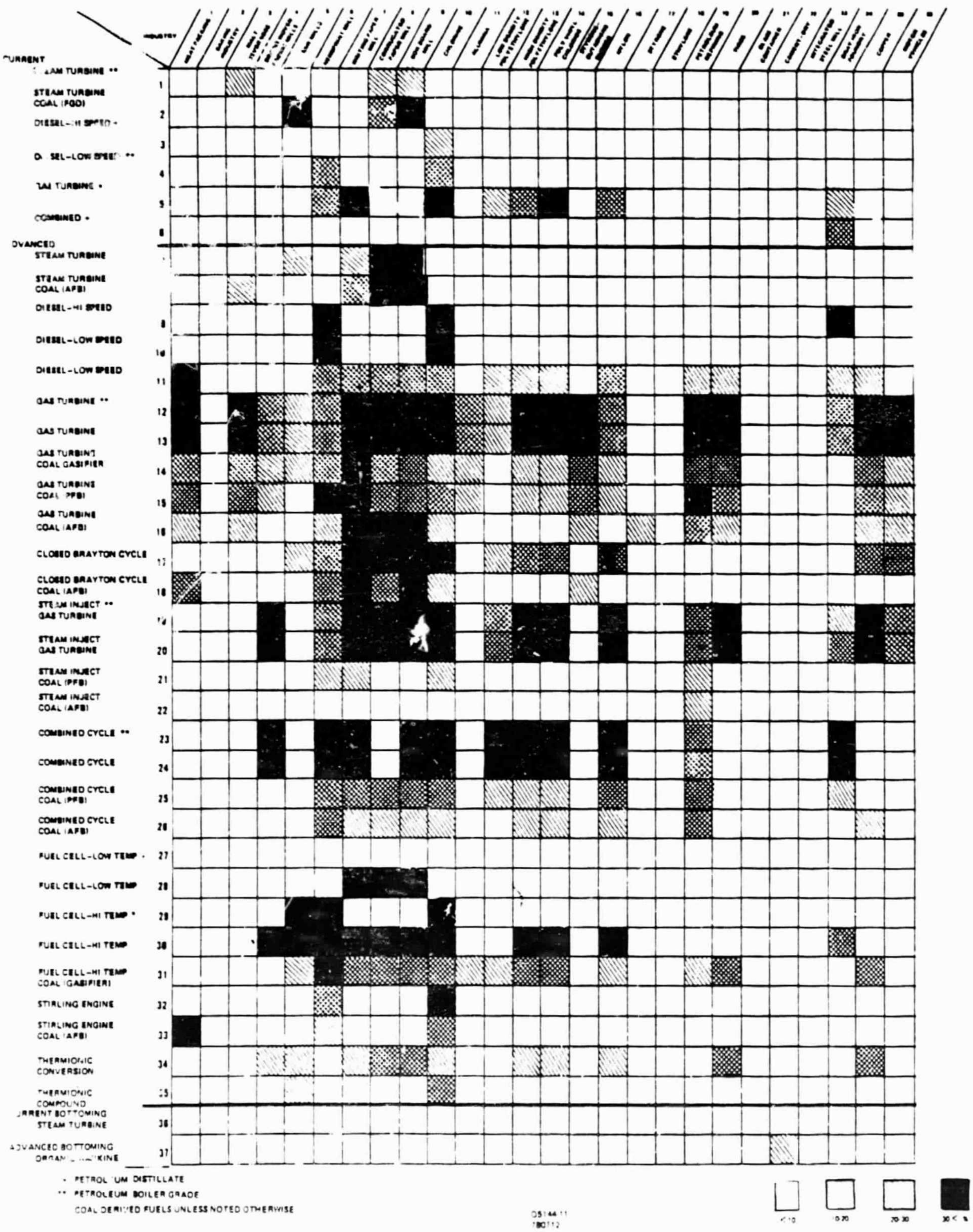

Figure V-37. Fuel Energy Savings Ratio Results for Cases with Positive Cost Savings Ratio, Maximum Energy Savings Ratio Strategy

STATISTICAL RESULTS

There is a significant variability from one cogeneration application to another. Figure V-38 indicates the statistical distribution of the fuel energy savings ratio for the advanced gas turbine with coal-derived boiler fuel in the various industrial applications. These data can be represented by a normal distribution shown as a straight line in Figure V-38. The average value of the fuel energy savings ratio is a general figure-of-merit for each energy conversion system.

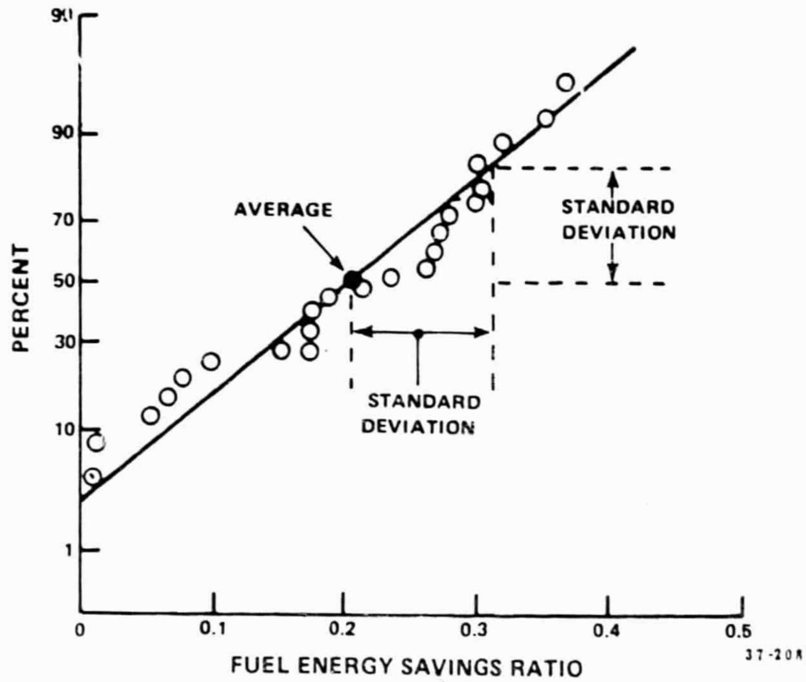

Figure V-38. Distribution of Fuel Energy Savings Ratio for Advanced Gas Turbine — Match Electric Strategy

Figure V-39 presents the average fuel energy savings ratio for the liquid fueled advanced technologies. In developing the data for Figure V-39, applications with negative fuel energy savings ratios were eliminated. While some technologies provide higher average savings ratios than others, all technologies had some applications of high potential savings. The best application is shown for each technology and marked "highest" in Figure V-39. The spread of one standard deviation above and below the average is included as an indication of the variability for each technology (16 percent of the data would fall above and 16 percent would be expected to fall below this range). The large standard deviation for the high-speed diesel systems is in part due to the fact that these systems are limited in applicability to about half the industrial processes because of size restrictions.

Figure V-39 represents the data for liquid fueled cases. All of these advanced technology conversion systems used coal-derived boiler fuels except the fuel cells and the high speed diesel which used coal-derived distillate.

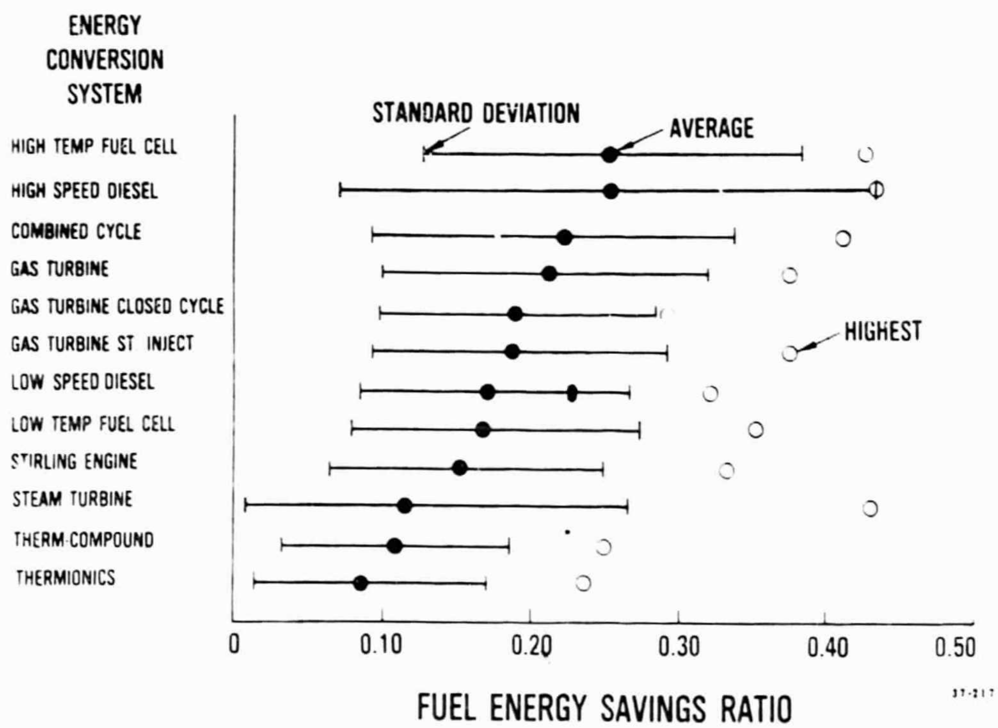

Figure V-39. Summary of Advanced Technology Conservation Potential — Liquid Fuels

Since comparisons of liquid fueled and coal-fired systems lead to difficulties, the fuel energy savings ratio data for coal-fired systems are included in Figure V-40. For summary purposes, not all of the coal-fired cases are included. For those technologies where there was more than one type of coal-fired technology, the system with the largest overall fuel savings potential has been presented. For example, the gas turbine with a pressurized fluidized bed is presented in Figure V-40 and the other two coal-fired gas turbines (atmospheric fluidized bed and coal gasifier) are not plotted. The gas turbine with the coal gasifier produced practically the same average fuel energy savings ratio and standard deviation as the pressurized fluidized bed gas turbine, although the number of industrial applications was smaller with the gasifier. The atmospheric fluidized bed gas turbine applied in a papermill provided the highest fuel energy savings ratio of any coal-fired system sized to match the electric requirements. However, this conversion system was fuel energy conserving in only nine industrial applications compared to 22 process possibilities with the pressurized fluidized bed system.

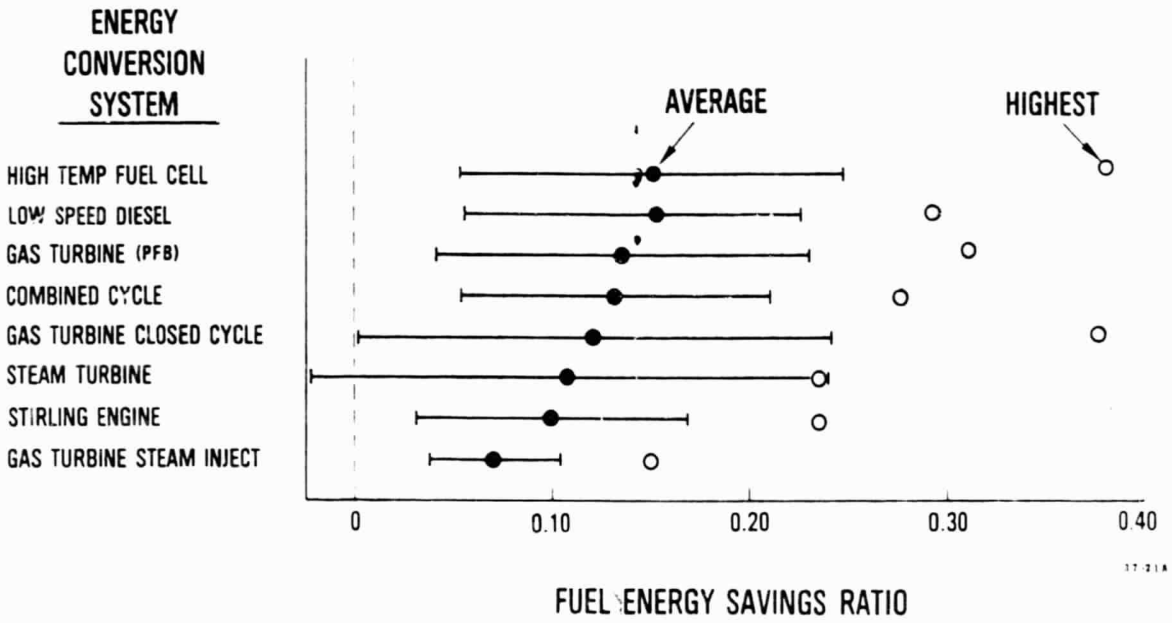

Figure V-40. Summary of Advanced Technology Conservation Potential – Coal

For the atmospheric fluidized bed the spread in the data is very large; the standard deviation is about three times the standard deviation of the other systems. If a line indicating the range of data was presented for the atmospheric fluidized bed gas turbine, it would extend beyond the scale in both directions in Figure V-40.

With steam-injected gas turbines and combined cycles, the pressurized bed configurations had higher fuel energy savings ratios and greater overall savings potential than the corresponding atmospheric fluidized bed cases.

The results presented in Figures V-39 and 40 were developed for conversion systems sized to match the electrical energy requirements with auxiliary furnaces for any additional thermal needs. If a thermal matching strategy were adopted, the data are summarized in Figures V-41 and V-42. The liquid fuel high speed diesel engine applied to only three industrial processes of the 24 topping possibilities because of size limitations. Those three applications are all very favorable so the average fuel energy savings ratio is high. The indicated range of data for the steam turbine is very wide due to two industrial applications: corrugated paper and boxboard, which had very high fuel energy savings ratios. In all of the steam turbine cases with positive fuel energy savings ratios, 76 percent fell below 0.1 fuel energy savings ratio.

In the coal-fired cases, Figure V-42, the gas turbine and combined cycle cases include the pressurized fluidized bed coal combustion system. In each case the average and maximum fuel energy savings ratio is superior with the pressurized fluidized bed compared to the atmospheric fluidized bed.

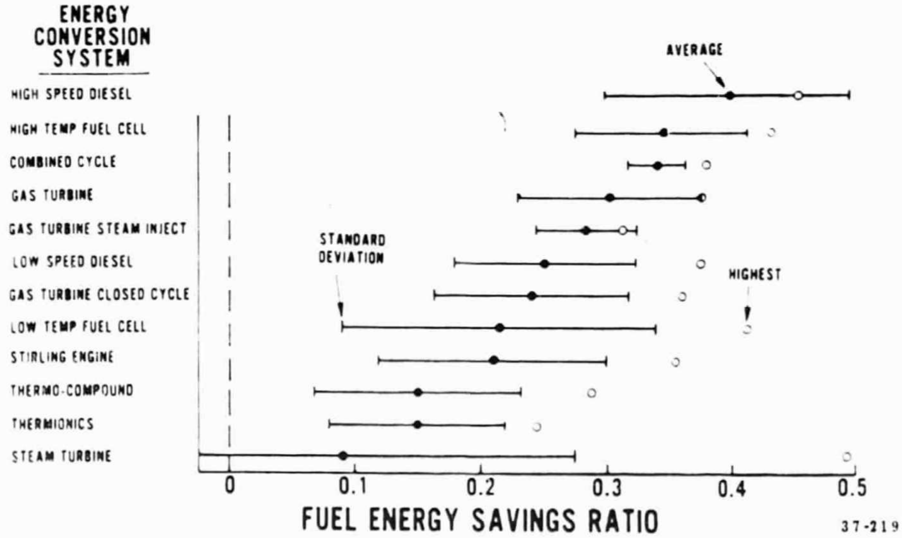

Figure V-41. Advanced Technology Conservation Potential – Match Thermal Strategy – Liquid Fuels

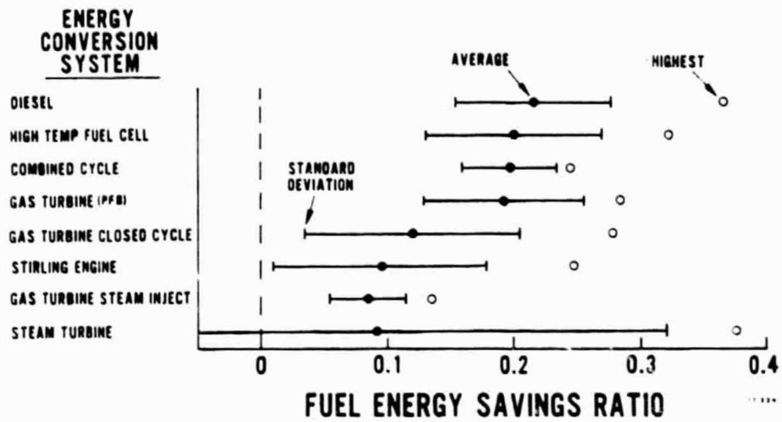

Figure V-42.

Advanced Technology Potential – Match Thermal Strategy – Coal

To summarize the emissions savings possibilities, similar simple averages were developed and presented in Figures V-43 and V-44 for the match electric strategy. Fuel cells offer the greatest environmental benefits. In fact, in some cases the on-site emissions are reduced compared to the on-site emissions from the conventional furnaces.

The diesel engines produce nitrogen oxides in excess of the guidelines and, on the average, do not reduce pollutants compared to the non-cogeneration configuration.

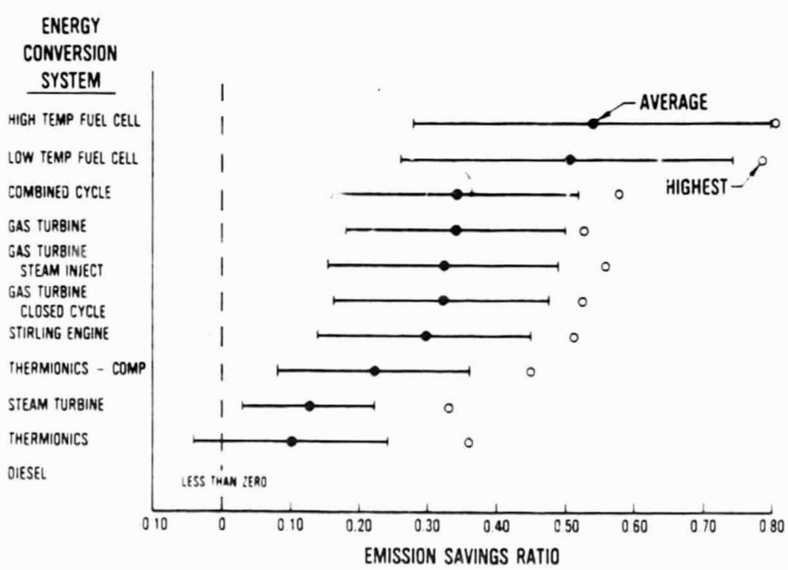

Figure V-43. Advanced Technology Emissions Savings – Liquid Fuel

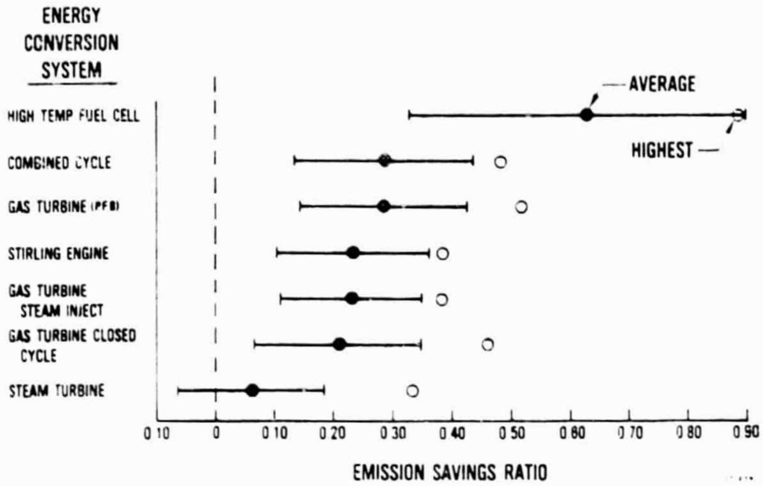

Figure V-44. Advanced Technology Emissions Savings – Coal

The potential cost savings based on levelized annual costs to the industrialist are presented in Figures V-45 and V-46. In summarizing the fuel energy savings ratios, only the positive savings were considered. The emissions savings summary in Figures V-43 and V-44 included those applications with positive fuel energy savings ratios. This same approach was used in summarizing the data in Figures V-45 and V-46, which indicate the cost savings ratio data for those situations which conserve fuel.

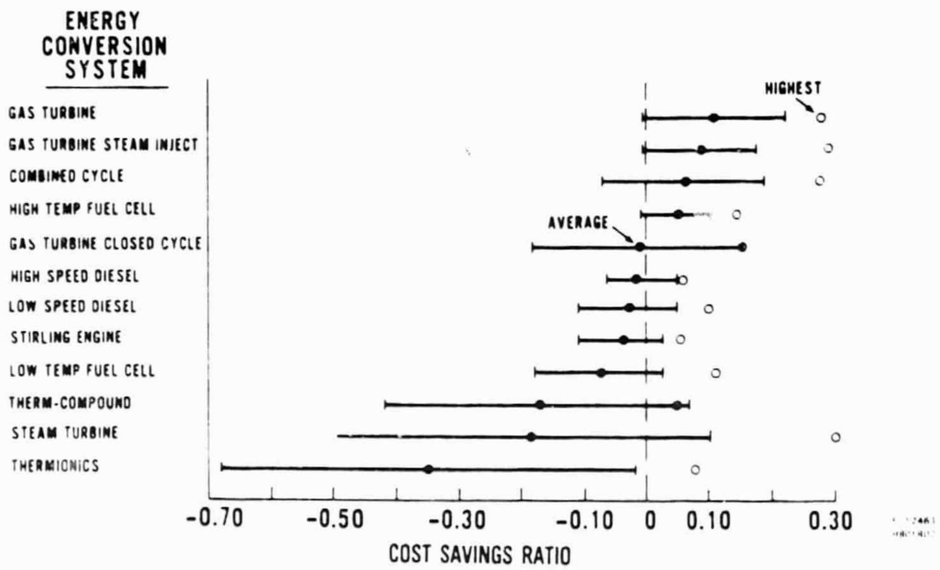

Figure V-45. Advanced Technology Cost Savings Ratio – Liquid Fuels

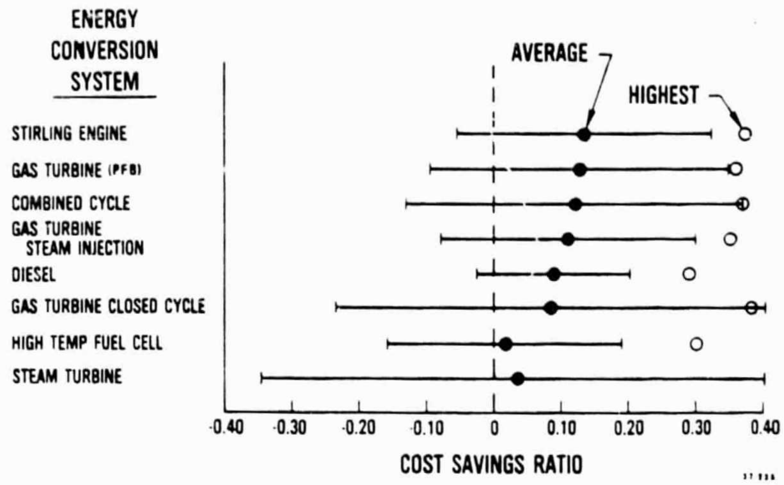

Figure V-46. Advanced Technology Cost Savings Ratio – Coal

With the economic assumptions adopted for this study, coal-fired systems generally offer higher average savings. In fact, in many cases the liquid fuel systems do not provide economic savings. Of particular interest are those cases which conserve fuel and indicate levelized annual cost savings to a potential industrial plant owner. Therefore, the data were analyzed to determine the relative number of cases with indicated annual cost savings and the results are presented in Figure V-47 for the liquid fueled conversion systems. The various gas turbines and the high temperature fuel cells have the highest proportion of cost saving cases.

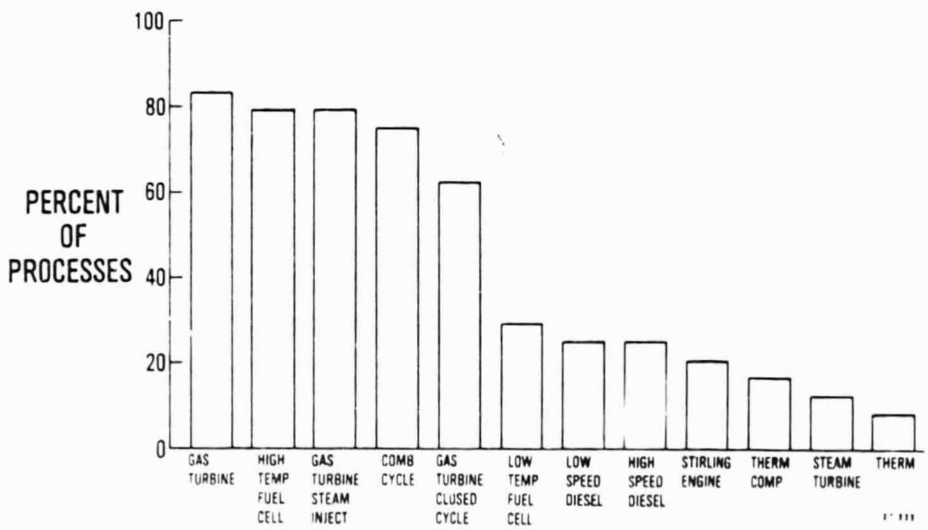

Figure V-47. Fraction of Industrial Processes with Positive Annual Cost Savings – Liquid Fuels

If only the cost savings and fuel savings cases are considered for an energy conversion system, the average cost savings ratio is positive. The average cost savings ratio data for the liquid-fueled cases for the match electric strategy limited to the conserving and cost savings cases are presented in Figure V-48. This result can be compared with Figure V-45 where the cost savings ratio for all cases is presented. A similar improvement in the average cost savings ratio situation occurs with the coal fired conversion systems.

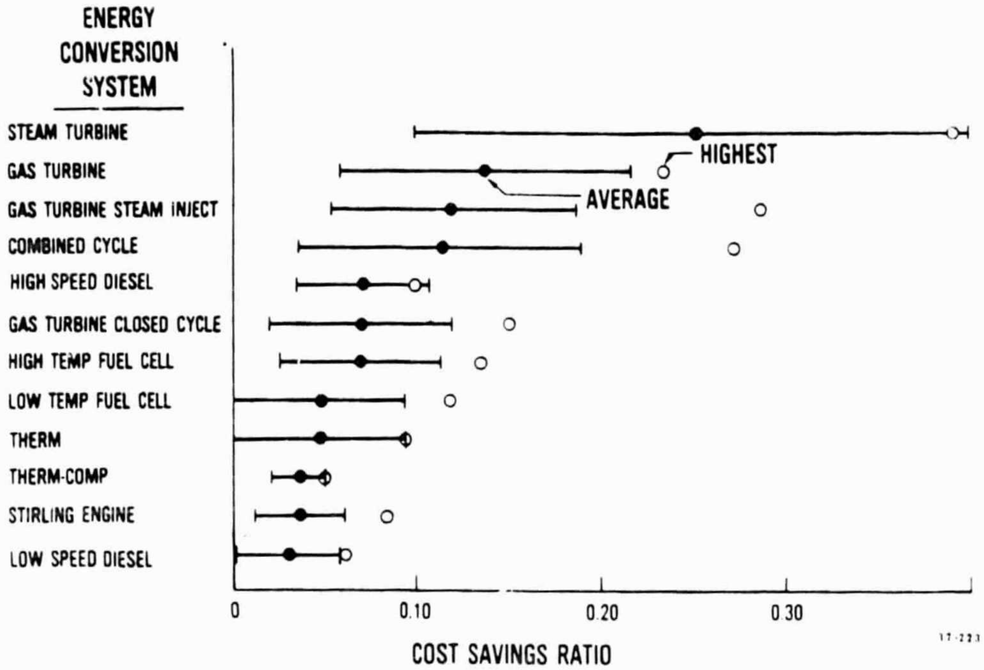

Figure V-48. Advanced Technology Cost Savings Ratio – Cost Savings Cases Only – Liquid Fuels

INTEGRATED RESULTS

The data discussed thus far have been simple arithmetic averages of fuel, emission, and cost ratios. The variation in the data is substantial indicating that there are good cogeneration prospects for each of the conversion technologies in certain specific industrial process applications. In calculating the averages, the savings ratios for industrial processes with small fuel savings were given the same weight as the ratios for processes with large overall savings.

A system is needed to summarize the fuel, cost, and emissions savings whereby the size of the potential savings as well as the savings ratios are considered. For example, the fuel energy savings ratios for the petroleum refining industry are typically less than 10 percent, Figure V-28. However, cogeneration with most of the advanced energy conversion systems could produce significant savings in absolute terms, Figure V-29. In order to develop a relative comparison and evaluation of the advanced energy conversion systems, a projection of the potential savings to the national level is needed.

The basic analyses were conducted for typical industrial plants. In order to develop projections to the national level, major assumptions are required. The first is that all industrial plants are candidates for cogeneration, both new and old. Second, the assumption is made that all plants fitting the appropriate criteria install cogeneration equipment. For example, if positive fuel energy savings were the criteria, all plants with predicted fuel energy savings would be included.

Assuming that the typical plants are representative of the manufacture of the product in the 1985-2000 period, the fuel consumption can be scaled based on the production level expected in 1985-2000 and the energy consumption per unit of product produced, as indicated in Figure V-49. In order to assess the potential of each conversion technology for savings at the national level, the assumption was made that the data for the process or product are representative of the potential savings in the four-digit industrial classification. Some four-digit classifications contain more than one of the study processes. Double accounting was avoided by summing the savings and then scaling to the four-digit level using the projected industry data presented in Volume II of this report. Bureau of Census data were used to scale from the four-digit level to the national level again assuming that the savings estimated in the study industries are representative of the possible savings in other industries not studied. The whole analysis is depicted in Figure V-49. The data presented in Volume VI includes the total fuel savings, the utility fuel savings, and the fuel use by type--oil, gas or coal for each technology based on the assumptions outlined.

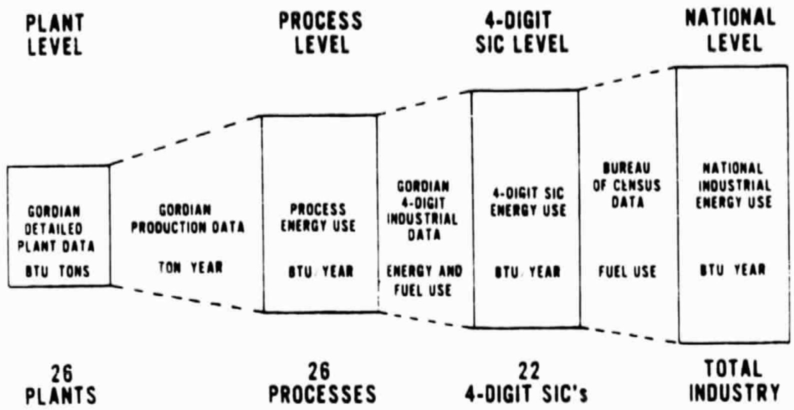

Figure V-49. National Impact Evaluation

The same assumptions for extention of the data to the national level were applied to all of the technologies to provide a basis for comparison. The fuel savings were summarized for all cases with positive fuel savings, for cases with economic savings, cases with emissions savings, the combination of cost and fuel savings cases and the combination of fuel, cost, and emissions savings. These data are presented in tabular form in Volume VI. A summary is presented here in graphic form. Figure V-50 presents the potential fuel energy savings, including the effect of utility fuel consumption, scaled to the national level assuming cogeneration with each current energy conversion technology.

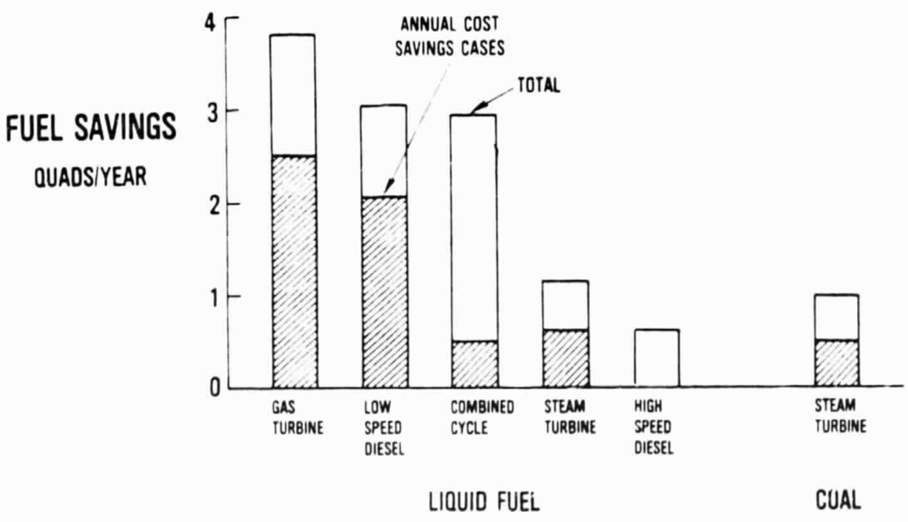

Figure V-50. Current Technology Potential Fuel Savings

Also included are the fuel savings for those situations where both fuel and levelized cost savings estimates are positive.

Figure V-51 presents the advanced liquid fueled conversion systems and Figure V-52 presents the estimated national data for coal-fired systems. This analysis indicates that cogeneration offers the possibility of substantial fuel energy savings and that the advanced technologies are estimated to provide greater fuel savings and superior economics.

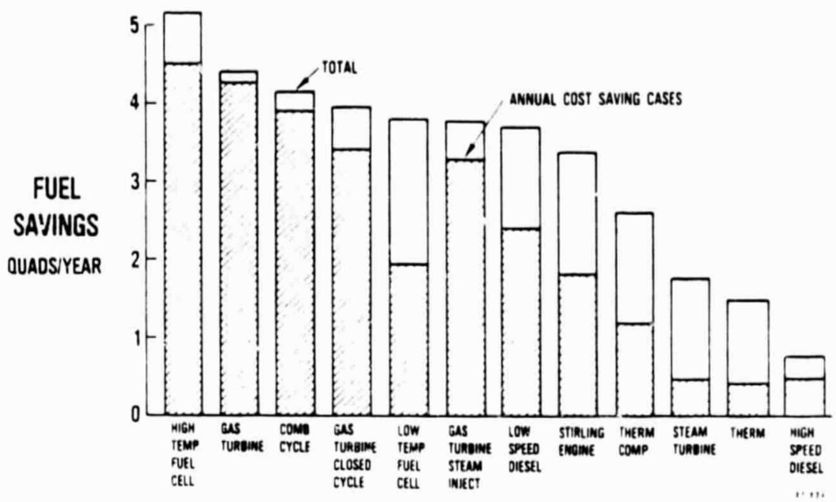

Figure V-51. Liquid Fueled Advanced Technology Potential Fuel Savings

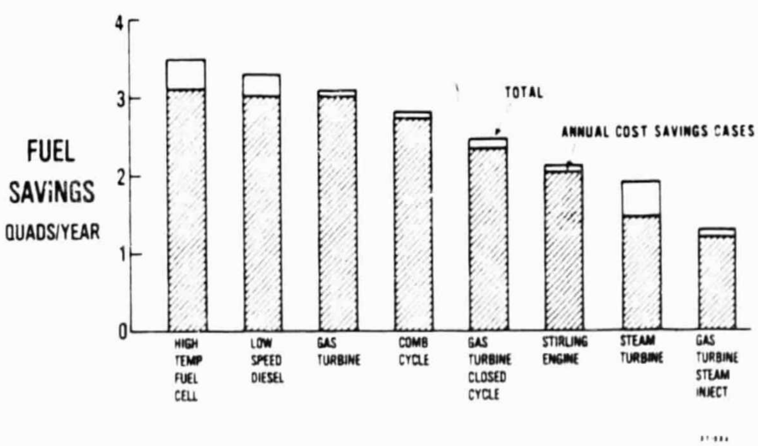

Figure V-52. Coal Fired Advanced Technology Potential Fuel Savings

The potential emissions at the national level are presented in Figures V-53 and V-54. These data include the emissions from the conversion system and any auxiliary furnaces required. These data were developed for a match electric strategy and, as a result, there were no utility emissions.

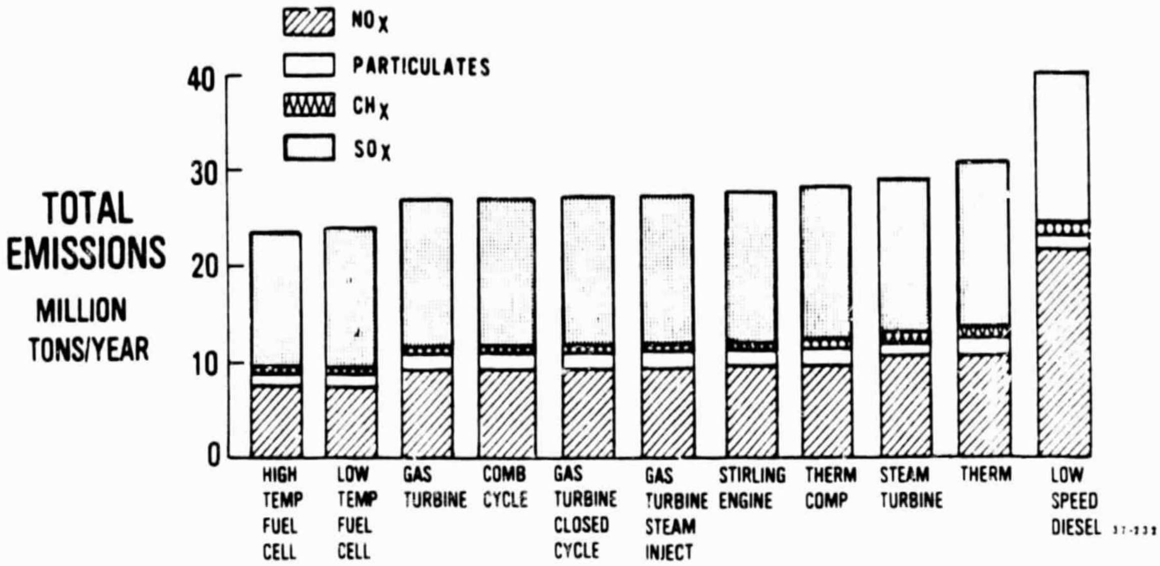

Figure V-53. Advanced Technology Emissions – Liquid Fuels

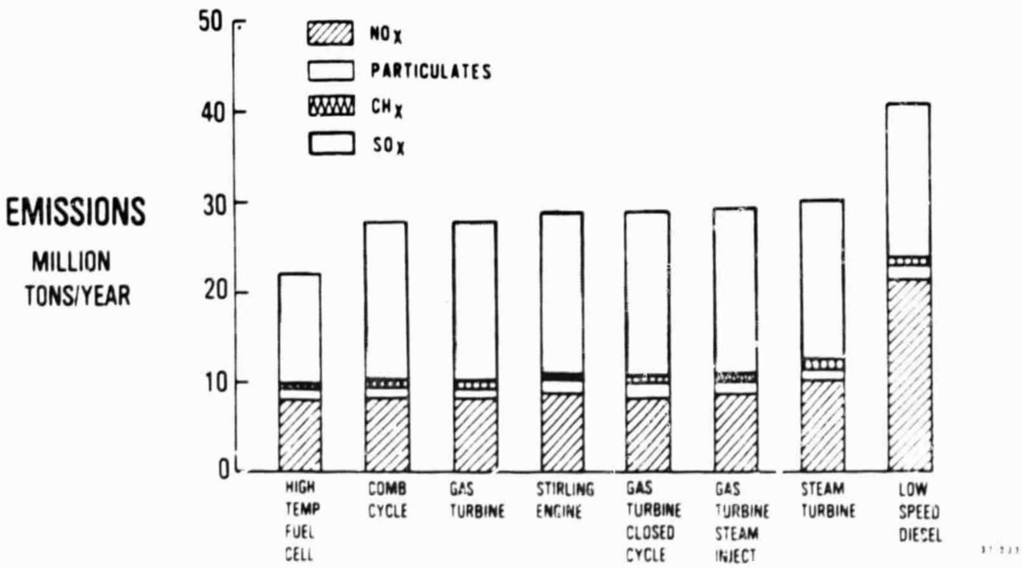

Figure V-54. Advanced Technologies Emissions – Coal

The estimated nitrogen oxide emissions by the diesel engines exceeded the guidelines. Methods of reducing NO_x emissions from diesel engines need to be developed.

The fuel cell is an electro-chemical conversion device and the pollutants associated with combustion are minimized. The sulphur in the fuel is removed in fuel cell powerplants. Various methods of sulphur removal are employed and some are regenerative. In these cases, the sulphur is absorbed on a material and then discharged as sulphur dioxide or elemental sulphur when the material is restored to its original condition. The data presented in Figures V-53 and V-54 are based on the assumption that regenerative type absorbtion is used and sulphur is discharged in the oxide form at the plant site.

In order to evaluate the environmental impact of cogeneration systems nationally, the emissions data are presented in Figures V-55 and V-56 in relation to the emissions from conventional furnaces traditionally located at the industrial plant and the total emissions including the electric utility. The assumptions were made that the conventional furnaces met the pollution guidelines for liquid fueled systems and that the utilities consumed coal and met the pollution guidelines for coal-fired systems. All cogeneration systems with the exception of diesels are estimated to reduce the total pollutants emitted nationally.

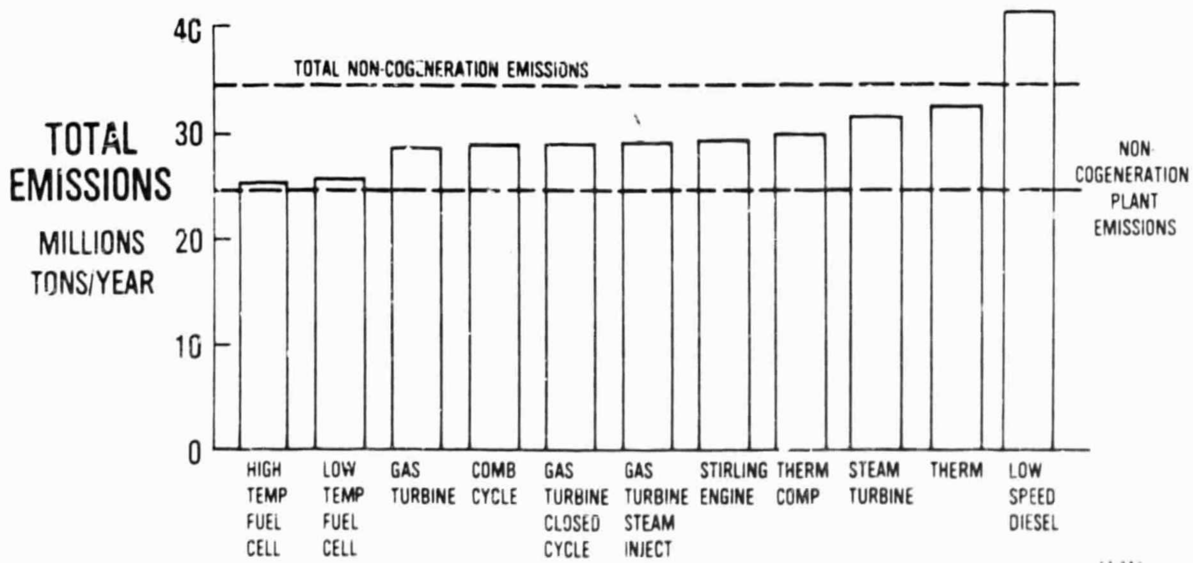

Figure V-55. Emissions Impact – Liquid Fuels

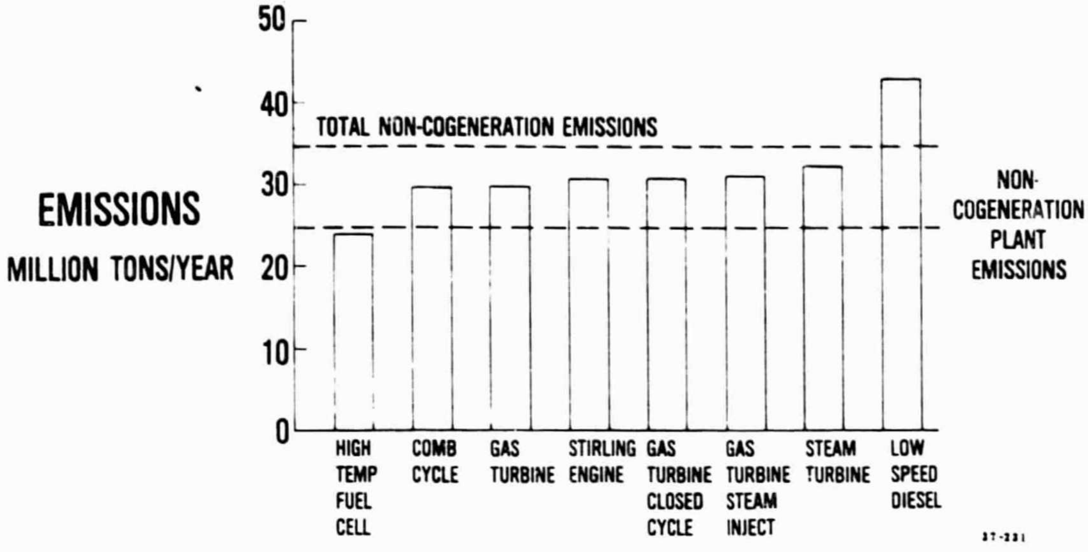

Figure V-56. Emissions Impact – Coal

A potential constraint on the application of cogeneration at industrial locations is the environmental rules which could be applied locally. In comparing to the non-cogeneration emissions at the industrial plant, the fuel cell systems offer the most promising situation.

The summation and scale-up of the data to a potential national level have been based on fuel energy saving cases. An alternate economic criteria could be applied. In Figure V-57, the potential annual cost savings (levelized) are presented regardless of fuel energy savings for liquid fueled conversion systems. The corresponding data for coal-fired systems is included in Figure V-58.

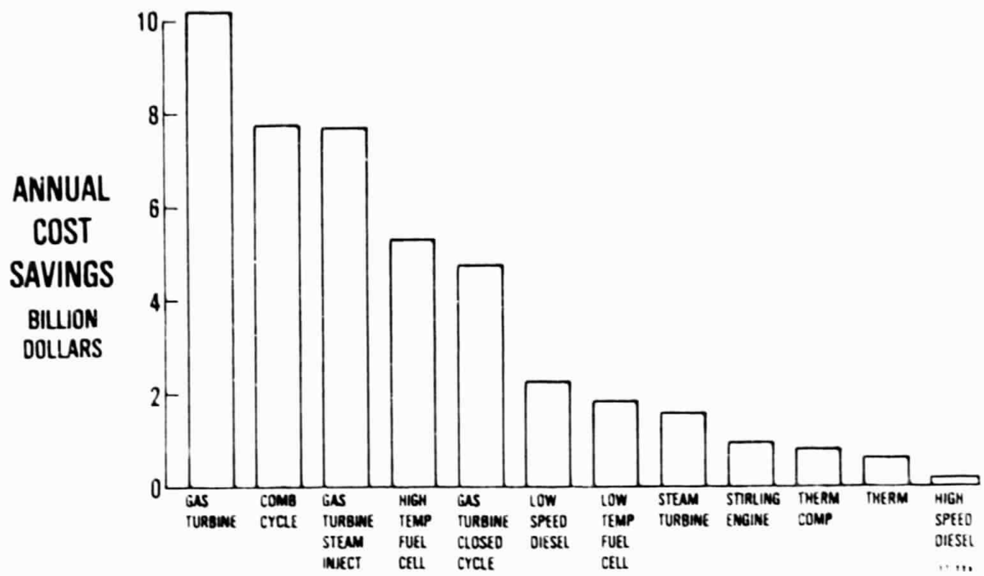

Figure V-57. Estimated Potential Annual Cost Savings – Liquid Fuels

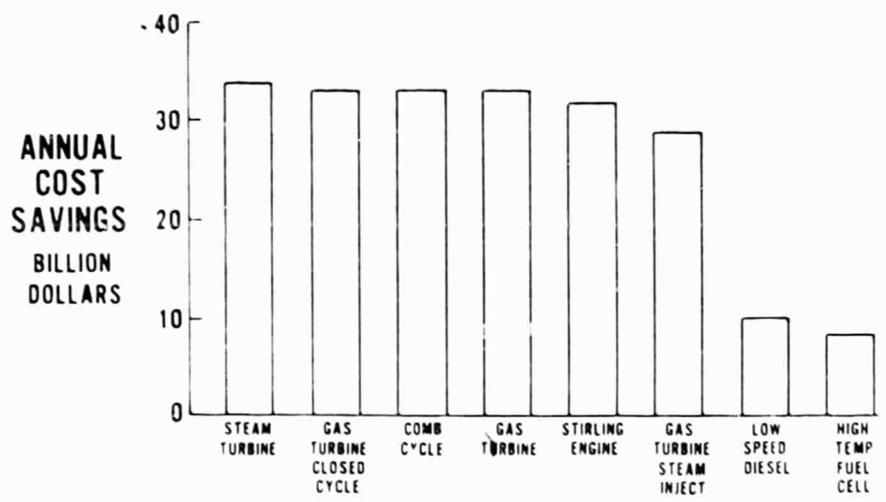

Figure V-58. Estimated Potential Annual Cost Savings – Coal

Of particular interest are situations which indicate both economic and fuel energy savings. For the cases with liquid fuel, the data presented in Figure V-57 are also all fuel savings cases. With coal-fired systems there are conversion system-industrial process combinations where there are levelized annual cost savings, but fuel energy is not conserved. Figure V-59 presents the estimated potential national annual cost savings for the coal-fired conversion technologies which have both fuel energy conservation and levelized annual cost savings.

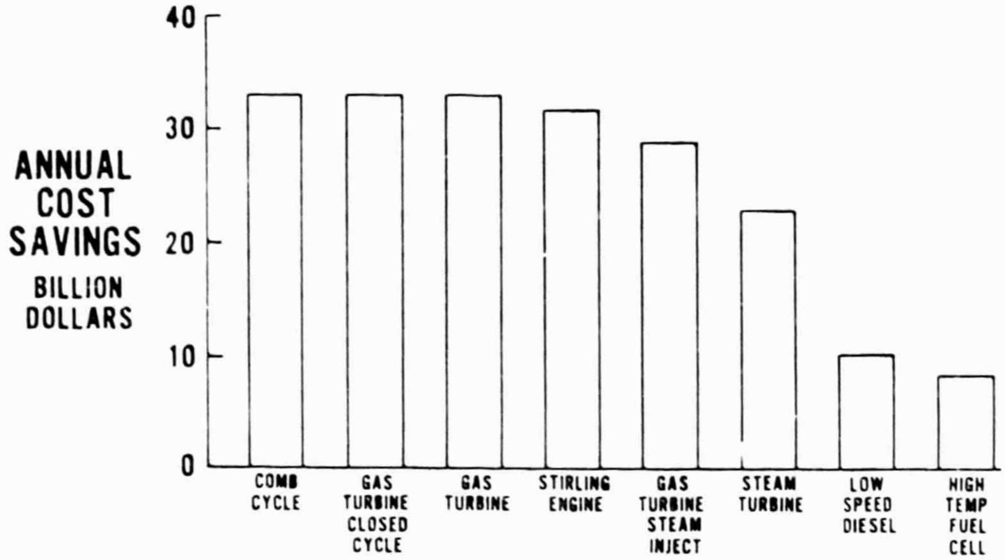

Figure V-59. Estimated Potential Annual Cost Savings with Fuel Energy Savings — Coal

The only cases with industrial plant site emission savings, annual cost savings, and fuel energy savings involved fuel cells. At the estimated national level for these cases fuel energy savings were in the range of 2 - 3 quadrillion BTU. Levelized annual cost savings had a potential of over $2 billion with liquid fuel and a potential of over $7 billion with coal fuel.

The national scale-up has been summarized for cogeneration systems meeting the industrial electrical requirements. The data in Volume VI include national summaries using the same scale-up techniques and coefficients for the other strategies. However, the scale-up systems which imported or exported electricity with the utility present difficulties in expanding the possibilities to the national level. Situations in which significant quantities of electricity are exported to the electric utility may be questionable when expanded nationally. Exported electrical energy in some conversion system-industrial process combinations would amount to eight times the electricity traditionally provided to the industrial plant. For the advanced gas turbine technology with a matched thermal requirements strategy, 19 industries produced positive conservation results. Of these, 12 would export electricity to the utilities. Scaling to the national level by the techniques used in the study, without cogeneration the utilities would have supplied 820 billion kilowatt-hours of electricity to industry in 1990. If the advanced gas turbine were used throughout industry and the assumptions, techniques and coefficients for scale-up were applied overall, industry would export 470 billion kilowatt-hours. Since the utilities would not be required to provide industry and would accept this exported energy, the net effect would be a reduction of 1290 billion kilowatt-hours generated by the utilities. For individual applications, the matched thermal strategy can provide conservation benefits to society and economic benefits to the industrialist. Therefore, such applications are an important element of the study, and the data are included in Volume VI. However, the national benefits with the matched thermal or optimum strategies printed in Volume VI can only be considered broad indications of the possibilities.

The fourth strategy addressed in the study involved a limited analysis utilizing a heat pump to improve the quality of the heat recovered to provide better matching between the conversion system and the industrial process. The results are included in Volume VI. In general, this strategy is of interest with conversion systems with low temperature recovered heat (some diesels, fuel cells and Stirling engines) and with industries with high electrical usage in relation to the thermal requirements (textiles, newsprint, chlorine, low density polyethylene, nylon). As an example, the low-speed diesel engine applied in the chlorine plant would improve fuel energy savings with the heat pump compared to the matched electric strategy. However, the economic comparison would not be quite as favorable.

In addition to the topping cogeneration applications, steam and advanced organic Rankine cycle bottoming systems were evaluated in cement plants and glass making. The fuel savings results are summarized in Figure V-60 and the estimated levelized annual cost savings are included in Figure V-61. These results are scaled from the representative plants to the four digit industrial classification levels to indicate potential national benefits.

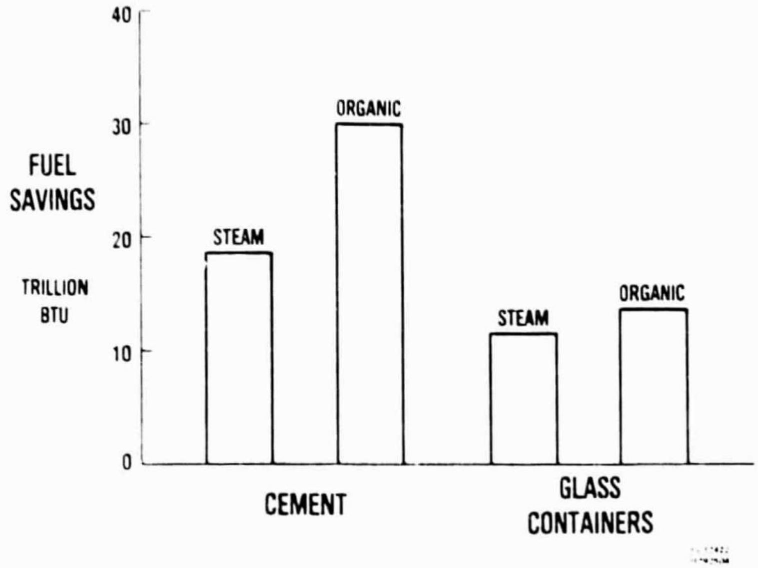

Figure V-60. Bottoming Applications Fuel Savings

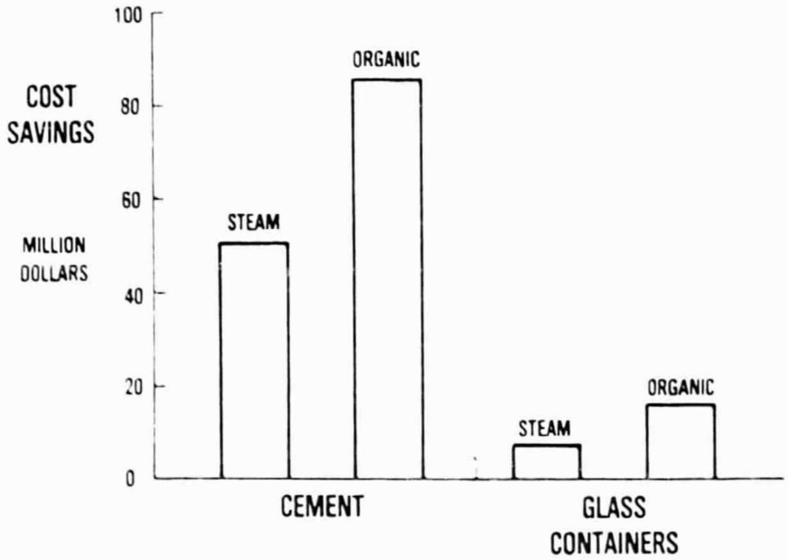

Figure V-61. Bottoming Applications Estimated Annual Cost Savings

The evaluation of advanced energy conversion techniques to determine the potential for transition from the use of oil and natural gas to coal or coal-derived or alternate fuels in the 1985-2000 time period is complicated. Qualitatively all of the advanced energy technologies are able to use coal or coal-derived liquid fuels.

The diesel engines exceed the NO_x emissions guidelines primarily due to the nature of the combustion process. The additional nitrogen in the coal-derived fuel is a secondary factor in this case.

Quantitatively, the fuel consumption for the non-cogeneration situation was projected by Gordian Associates to the time period of interest. While a representative plant would normally consume only one or two fuels, the consumption of all fuels was determined at the process level and scaled up to the national level. The advanced conversion technology used one fuel and the auxiliary furnace used the same fuel or another. The consumption of fuels by type was determined for the conversion system and scaled-up to the national level. The resulting fuel savings are tabulated in Volume VI.

If coal-derived fuels are available for cogeneration, then a reasonable assumption would be to expect such fuels to be available for non-cogeneration industrial furnaces. For the purposes of this study, if coal-derived fuels are available, the assumption is made that all systems, cogeneration and non-cogeneration, use the coal-derived fuels. Assuming a conversion efficiency from coal to coal-derived fuel of 70%, and assuming the coal conversion plant did not introduce pollutants, the relative merits of the various conversion system cogeneration applications can be estimated based on a single fuel--coal. Figure V-62 indicates the estimated coal consumption on a national basis, assuming either coal or a coal-derived liquid is used in cogeneration energy conversion systems installed in all appropriate industrial plants. This extention to the national level is based on the same set of assumptions outlined on pages and in Figure V-49.

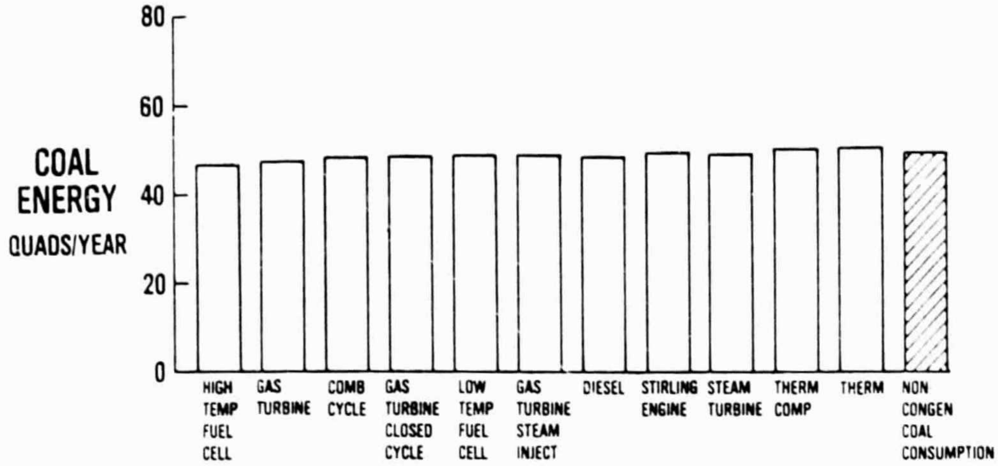

Figure V-62. Coal Requirements Including Coal for Conversion to Coal-Derived Fuels

SPECIAL COMPARISONS

In addition to the representative industrial plants which served as the basis for the study, two additional fictitious plants were defined to permit comparison of capital costs of the energy conversion cogeneration plants. The electrical demands were 10 and 30 megawatts for these industries. The thermal requirements were four times the electrical requirements and the plants operated continuously. The results of these calculations are presented in Figures V-63, V-64, and V-65. The installed costs include the balance-of-plant and the auxiliary furnaces as well as the energy conversion systems. Generally the coal-fired systems are significantly more capital intensive than the liquid fueled technologies.

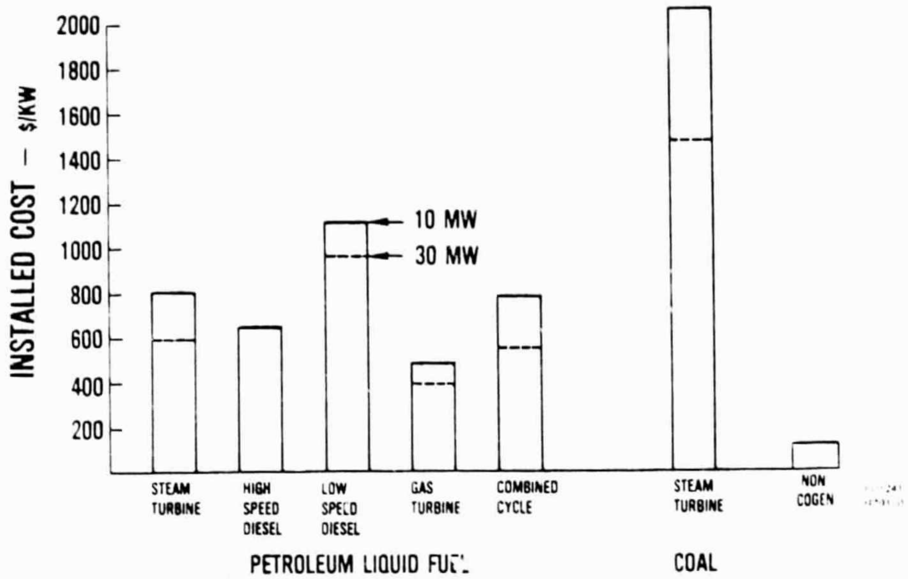

Figure V-63. Current Technology Estimated System Installed Cost for Special Industries

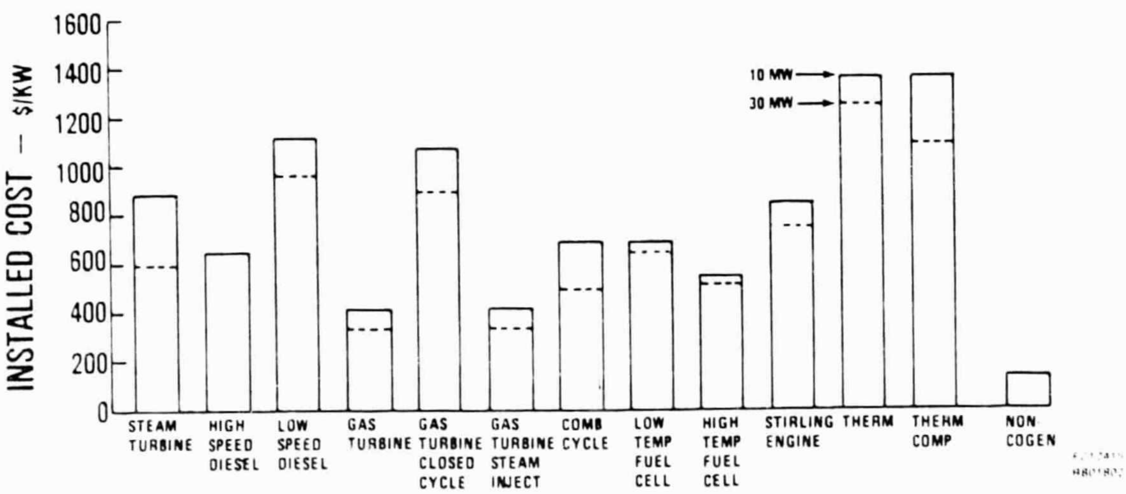

Figure V-64. Advanced Technology Estimated System Installed Costs for Special Industries — Liquid Fuels

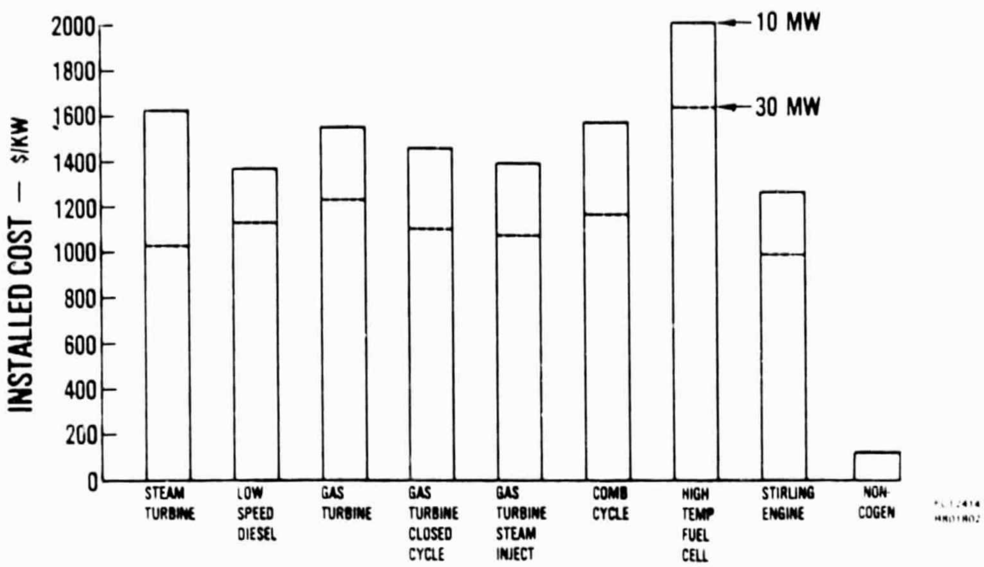

Figure V-65. Advanced Technology Estimated System Installed Cost for Special Industries — Coal

ECONOMICS

Economic Results

Based on the results of the analysis of the 3,364 strategy-conversion system - fuel-industry cases, 120 were selected for more detailed economic analysis. In order to conduct this evaluation both internal and external factors which could influence an industrialist's decision concerning cogeneration were identified. Internal factors are defined as those industry-related criteria involving policies, practices, and constraints specific to a particular industry or individual firm which influence capital investment decisions. In this study, significant internal factors were selected for evaluation including: discounted cash flow rate-of-return, payback period, net present value, levelized annual cost, and life cycle cost. One or more of these factors could be the critical measure of a capital investment attractiveness to the industrialist. The estimated rate-of-return in relation to the perceived risk may be the most important or most commonly used criteria in industry. Of course, the magnitude of the investment, the exposure and competing investment opportunities are also significant factors. Utilities often use levelized annual cost or life cycle cost as an investment criteria. If generalization were possible, the levelized annual cost factor tends to be affected more by operating costs and the rate-of-return factor tends to be influenced more by the capital requirements.

External factors are those conditions prevalent throughout the business community which are imposed on all industrial firms which influence the capital investment decisions of the industrialist. External factors which are generally beyond the control of any firm or group of industrial firms include political, environmental, regulatory and economic areas some of which are under partial or direct control of the government. Examples of external factors are the general Federal income tax rate, investment tax credit, cost of purchased fuels and electricity and relevant institutional and environmental regulations. These factors have been addressed and included in the Principal Assumptions and Ground Rules section of Volume I. To summarize, the economic evaluations are based on the ground rules presented in Table V-27.

TABLE V-27

SUMMARY OF ECONOMIC GROUND RULES

Cogeneration Plant Startup Date	1980
Base Year For Dollar	1978
Inflation Free Analysis	
Cost of Debt	3% above inflation
Cost of Equity	7% above inflation
Debt Capitalization	30%
Equity Capitalization	70%
Effective Tax Rate (Federal & State)	50%
Insurance and Other Taxes	3%
Economic Life	30 Years
Tax Life	15 Years
Depreciation	Sum-of-Years Digits
Investment Tax Credit	10%
Fuel Escalation Rate (1985 Base)	1%
Electricity Escalation Rate (1985 Base)	1%
1985 Distillate Fuel Price	$3.80/million BTU
1985 Liquid Boiler Fuel Price	$3.10/million BTU
1985 Coal Price	$1.80/million BTU
1985 Electricity Price	3.3¢/kWh

A summary of the inflation-free return on investment results for the liquid fueled conversion systems of the 120 cases evaluated are presented in Figure V-66. While there is significant variability for a conversion system from one application to another, on the average, the systems with the relatively low capital investment offer the highest rate-of-return prospects.

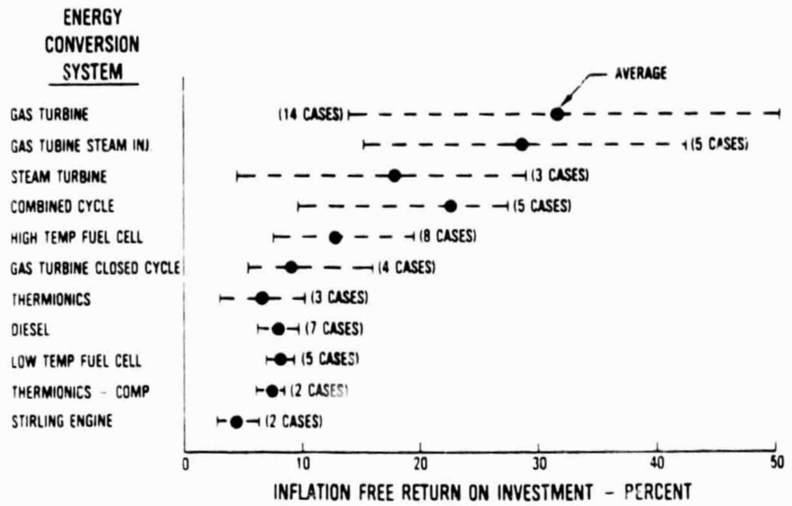

Figure V-66. Advanced Technology Return-on-Investment – Liquid Fuels

The corresponding coal-fired cases are included in Figure V-67. The coal-fired systems with large capital requirements and lower operating (fuel) costs generally do not provide as high returns as the liquid fueled systems. For example, on the average, the simple gas turbine provides the highest rate of return and the lowest installed equipment costs. The closed cycle gas turbine, with expensive heat exchangers, has about three times the equipment cost of the gas turbine and the rate-of-return is depressed accordingly. The data presented in Figures V-66 and V-67 are developed without inflation and should be examined in that light. With the ground rules used in this study, the inflation-free cost of capital is 5.4 percent so an inflation-free rate-of-return above 8 percent might be considered favorably.

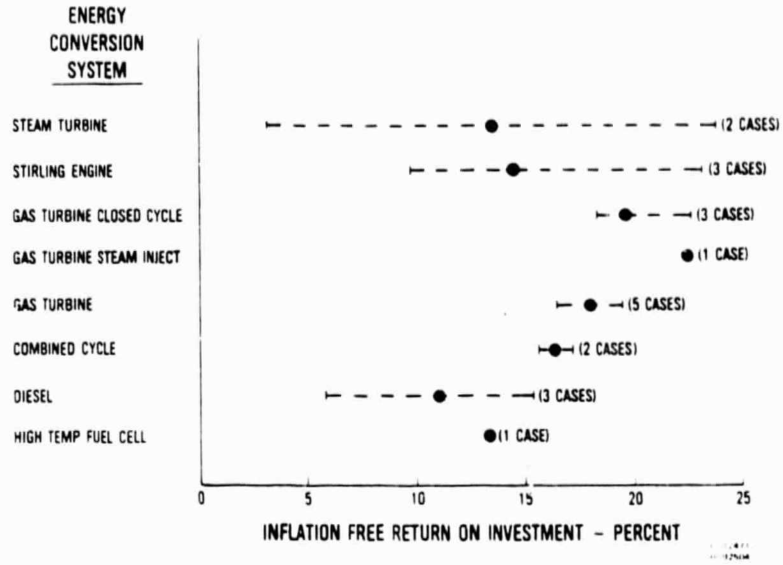

Figure V-67. Advanced Technology Return-on-Investment – Coal

Sensitivity

In order to investigate the effect of changes in the values of several of the major economic variables affecting the results of the study, sensitivity analysis were conducted where selected variables are varied individually within prescribed ranges. The objective of this activity was to determine the trend relationships between the rate-of-return and the variable selected and identify those variables which have the greatest effect on the overall results. Sixty different cases were selected for detailed sensitivity studies. These cases covered a representative set of industries, including firms producing newsprint, corrugated paper, chlorine , and textiles; and examinations were made of the effect created by variations in capital costs, investment tax credit, tax life, electric utility rates, fuel (coal and oil) prices, fuel escalation rates, and general inflation rate. The results are summarized in Table V-28 which indicates the consequences of a 1 percent variation in the factor on the rate of return. For example, a 1 percent increase in the electric rate (from 3.30 to 3.33 cents per kilowatt hour in 1985) would increase the rate-of-return by 0.53 percent. Also a one percent increase in capital cost would cause the rate of return to be reduced by 0.21 percent. The results of this analysis indicate that projected escalation rates for fuels and utility electricity have the strongest influence on the overall results of the study.

Assumed fuel prices and electric rates in 1990 have important bearing on these results. Capital equipment cost and investment tax credits appear to have modest influence.

TABLE V-28

ECONOMIC SENSITIVITY

Factor	Average Rate of Return Slope Negative	Average Rate of Return Slope Positive
Fuel Escalation	1.25	
Fuel and Electric Rate Escalation		1.09
Inflation		0.90
Coal Escalation	0.85	
Electric Rate		0.53
Fuel Price	0.30	
Non-Cogeneration Fuel Price		0.25
Capital Cost	0.21	
Investment Tax Credit		0.20
Coal Price	0.15	
Tax Life	0.04	

TIME-OF-DAY VARIATIONS

A broad analysis of the type conducted for this study of necessity involves assumptions or approximations. To better evaluate the degree of approximation, the consequences of energy variations in the course of the day were evaluated.

Many of the industrial processes are operated continuously with annual shutdowns for maintenance. In several cases, however, the energy requirements vary in the course of the day, week, or season. The industrial process selected to illustrate these variations was meat packing. The representative plant, defined by Gordian Associates and described in detail in Volume II of this report, is an integrated plant engaged in slaughter for meat as a product and the production of meat products. The principal uses of energy in the meat packing plant include electricity for refrigeration, lighting, and cutting; hot water for clean up and processing; and steam for processing, cleaning, and cooling.

Typical daily variations in steam demand are presented in Figure V-68, and electrical demand in Figure V-69. Refrigeration is the dominant electric load, so even on weekends the electrical needs do not fall below half the peak electrical load in the middle of the work day. The needs for hot water and steam vary since most killing occurs in the morning and the following evisceration generally occurs in the middle of the day. With a five day work week, need for thermal energy is reduced during the weekends.

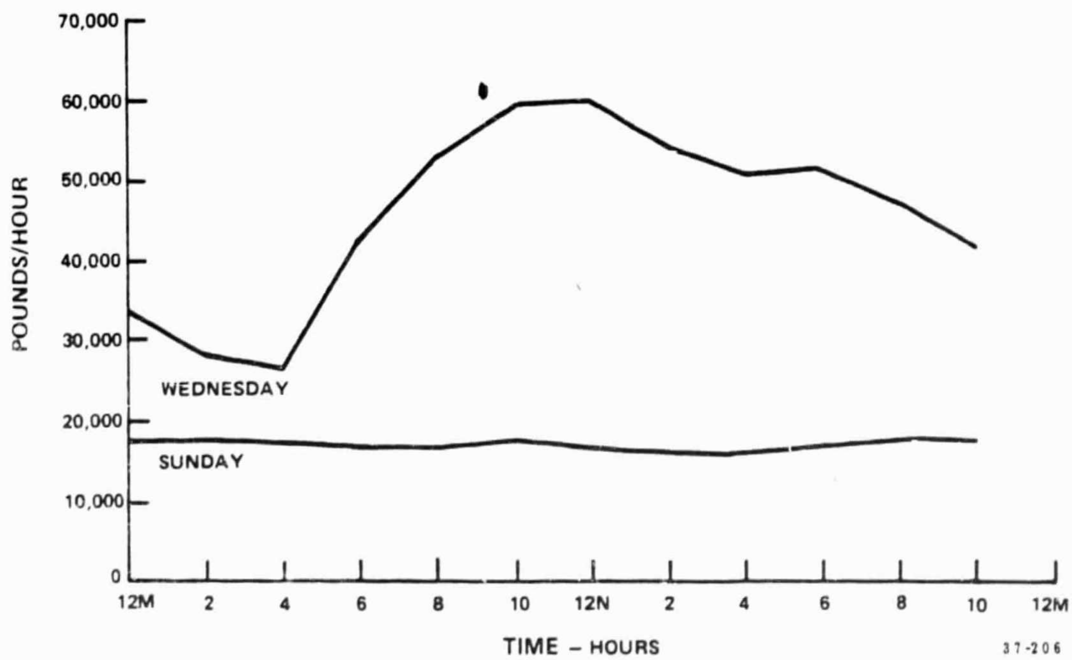

Figure V-68. Steam Demand Profiles for Representative Meat Packing Plant

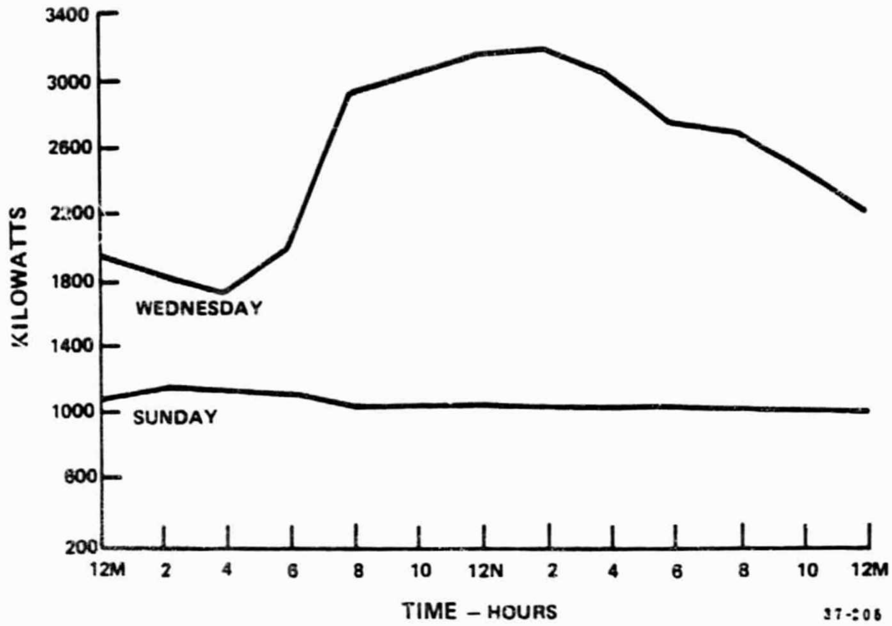

Figure V-69. Electric Demand Profile for Representative Meat Packing Plant

In addition to the hourly and daily energy use variations, there are seasonal variations. For example, many cattle are brought to slaughter in the late summer and fall when they are heavier and when the expense of winter feeding can be avoided.

The energy consumption of the meat packing plant was analyzed accounting for the hourly and seasonal variations. For this analysis, the daily electrical and thermal energy requirement profiles were simplified. The low temperature fuel cell conversion system described in Volume III, was selected for this analysis. The off-design performance of this system is presented in Figure V-70.

The refrigeration electric load must be satisfied at night and during the weekends while the thermal load primarily occurs during the working day. Therefore, an alternate cogeneration configuration, including a hot water thermal storage system, was introduced based upon the data developed by Rocket Research Company and presented in Volume IV. The round trip efficiency of this thermal storage system is 98 percent. The size of the storage system was chosen to recover the maximum amount of heat from the energy conversion system during nights and weekends.

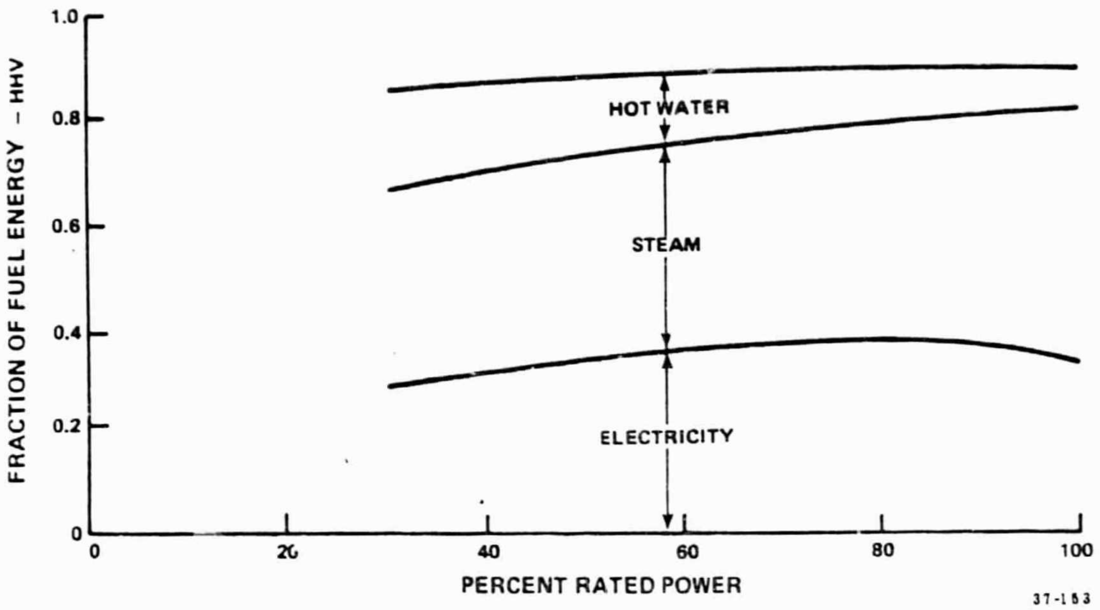

Figure V-70. Off-Design Performance of Low Temperature Fuel Cell Power Plant

The fuel energy savings, cost savings, and emission savings were estimated recognizing the daily and seasonal variations. The results are presented in Table V-29.

TABLE V-29

ESTIMATED COGENERATION RESULTS IN MEAT PACKING PLANT WITH FUEL CELL

	Steady-State Analysis	Time-of-Day Analysis Storage	Time-of-Day Analysis No Storage
Fuel Energy Savings Ratio	0.3130	0.3234	0.2934
Cost Savings Ratio	0.0180	0.0271	-0.0307
Emissions Savings Ratio	0.6510	0.6726	0.6102

Using the time-of-day variation analysis, the fuel energy savings ratio was reduced by 0.02 compared with the steady-state analysis. The levelized annual cost savings were reduced by 0.05 and the estimated economic advantage with the steady-state analysis became negative with the time-of-day analysis.

With thermal storage the detailed analysis indicated improvements over the results of the steady-state analysis from a conservation, cost, and environmental standpoint. The steady-state analysis appeared to be a reasonable initial evaluation for general purposes.

REFERENCES

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ADDENDUM

LIST OF SYMBOLS

A_{ECS}	Energy conversion system area requirement
A_F	Auxiliary furnace area requirement
A_{HS}	Heat source area requirement
C	Specific area, volume, or weight
C_c	General capital cost term
C_s	Specific cost per unit size
CC	Cost of common equity
CCRAT	Capital cost ratio
CD	Cost of debt
CE	Cost of common equity
CI	Capital investment
CO	Capital-output ratio
COC	Cost of capital
COP	Heat pump coefficient of performance
CP	Cost of preferred equity
CRF	Capital recovery factory
CSR	Cost savings ratio
C_i	General sizing parameters
D	Debt
E	Energy conversion system electrical output
ECF	Earnings cash flow
E_{LIM}	Limiting size on ECS output for bottoming cycle
E_{MAX}	Maximum ECS output

LIST OF SYMBOLS (Continued)

E_p	Process electric requirement
E_{peak}	Peak hourly electric requirement
$E_{peak}^{process}$	Peak hourly electric requirement for process alone without parasites
$\langle E \rangle_{parasitic}$	Avg. parasitic electric requirement
$\langle E \rangle_{process}$	Avg. process electric requirement
E_{Rated}	Rated ECS electric output
FCR	Fixed charge rate
INV	Investment
J	Ratio of working capital to investment
k	Ratio of E_{Rated}/E_{max}
K	Ratio of profit to investment
K_{ECS}	ECS building cost factor
K_{HS}	Heat source building cost factor
kWH	Kilowatt hours
LAC	Levelized annual cost
LFC	Levelized fixed charge
m	Rate-of-return
MBtu	Millions of Btu's
MWe	Megawatts of electrical power
m	Exponent for specific area, volume, or weight
N_{ECS}	Number of ECS's
N_F	Number of furnaces
NPV	Net present value

LIST OF SYMBOLS (Continued)

OC_{pv}	Present value of operating costs
OF	Furnace output
OHS	Heat source output
PE	Preferred stockholders equity
PSR	Pollution savings ratio
Q_{Avail}	Available thermal energy
$Q_{Displaced}$	Fuel energy for fuel displaced at the utility
Q^{access}_{DH}	The portion of the direct heat requirement at temperatures less than the available temperature from the ECS
Q^{Inacc}_{DH}	The portion of the direct heat requirement at temperature higher than available from the ECS
Q^{Rem}_{DH}	The remaining direct heat requirement after ECS exhaust gas has been used
Q_{ECS}	ECS fuel consumption
Q^{BP}_{F}	By-product fuel energy content
Q^{tot}_{F}	Total fuel consumption
Q_N	Nominal thermal requirement
Q_P	Parasitic thermal requirement
Q_{stack}	Stack losses
Q_u	Utility fuel consumption
$Q_{noncogen}$	
Q^{a}_{i}	Available thermal energies for hot water, low temperature steam, medium temperature steam, high temperature steam, and direct heat when all hot ECS exhaust is used for direct heat

LIST OF SYMBOLS (Continued)

Q_{stack}	Stack losses
Q_i^A	Maximum available thermal energies for hot water, low temperature steam, medium temperature steam, and high temperature steam when no energy is used for direct heat
Q_i^R	Required thermal energies for hot water, low temperature steam, medium temperature steam, high temperature steam, and direct heat
r	Discount factor
r_s	Standard industry sizing factor
t	Time required for building construction
T	Temperature
T_{Avail}	Available temperature of ECS exhaust
T_{exh}	ECS exhaust temperature
T_{out}	Heat pump outlet temperature
T_{pinch}	Heat exchanger pinch temperature
T_r	Tax ratio
T_{ref}	Reference temperature
T_{res}	Reservoir temperature for heat pump
T_o	Initial reservoir temperature for heat pump
TC	Total capitalization of the firm
ΔT	Heat pump temperature rise
V_{ECS}	Required volume for ECS
V_F	Required volume for furnace
V_{HS}	Required volume for heat source
WC	Working capital

LIST OF SYMBOLS (Continued)

x, X	General sizes used in cost calculations
X_{inc}	Incremental size
α	Factor to account for the cost of interest on borrowed money
α_{FH}	Fuel handling thermal parasitic factor
α_{Furn}	Furnace thermal parasitic factor
β	Price escalation factor
ΔE_{HP}	Heat pump electrical requirement
ΔQ_{Avail}	Reservoir heat available for pumping
ΔQ_{HP}	Quantity of heat to be pumped by heat pump
ΔQ_{pumped}	Actual quantity of heat pumped
Δq_{tot}	Difference between required and available heat
η_{BP}	Efficiency at which by-product fuel is burned
η_{DH}	Fraction of ECS fuel energy that is available for direct heat
η_e	ECS electrical efficiency
η_F	Furnace efficiency
η_L	Fraction of ECS fuel energy that becomes irrecoverable losses
η_{stack}	Fraction of ECS fuel energy that becomes stack losses
η_{sens}	Fraction of ECS fuel energy available as sensible heat
η_i	Fraction of ECS fuel energy available as hot water, low temperature steam, medium temperature steam, and high temperature steam, respectively
θ	General ECS thermal energy available
θ_P	Process thermal requirement
θ_H	Process high-temperature requirement

LIST OF SYMBOLS (Continued)

θ_L	Process low-temperature requirement
μ	General ECS thermal to electric ratio
μ_H	ECS high-temperature thermal to electric ratio
μ_L	ECS low-temperature thermal to electric ratio
ζ	Fraction of sensible heat available as direct heat