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ASSESSMENT OF TOTAL ENERGY SYSTEMS FOR THE DEPARTMENT OF DEFENSE - VOLUME 2

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The purpose of this study is to assess the potential applicability of various types of total energy systems to military installations. This appendix volume of the final report contains (1) engineering performance characteristics and costs of fossil fuel system elements, (2) energy consumption data for military bases and derivation of the energy load profiles used in the study, (3) description of the fuel consumption model and summaries of the fuel consumption and total system costs for the various cases

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ASSESSMENT OF TOTAL ENERGY SYSTEMS FOR THE DEPARTMENT OF DEFENSE

Volume II

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ABSTRACT

The purpose of this study is to assess the potential applicability of various types of total energy systems to military installations. This appendix volume of the final report contains (1) engineering performance characteristics and costs of fossil fuel system elements, (2) energy consumption data for military bases and derivation of the energy load profiles used in the study, (3) description of the fuel consumption model and summaries of the fuel consumption and total system costs for the various cases, (4) characteristics and costs of geothermal systems, and (5) description of solar energy systems.

PREFACE

This study was conducted in the Operations Evaluation Department, George D. Hopkins, Director, of the Engineering Systems Division. The program manager was Robert M. Rodden, and the project leader was Richard L. Goen.

Volume I of this report contains the results and conclusions of the study. The present Volume II contains the appendices with backup information.

Appendix A was prepared by L. O. Beaulaurier and Gordon Stout of Bechtel Corporation. Appendix B was prepared by Jack E. Van Zandt, of the Institute's Urban and Social Systems Division, with the assistance of Ellis E. Pickering and Frank C. Allen. Appendices C and F were prepared by John W. Ryan. Appendix D was prepared by Dr. Richard A. Schmidt (Characteristics of Geothermal Resources) and Ronald K. White (Costs of Geothermal TE Systems). Appendix E was prepared by Dr. Edwin M. Kinderman of the Institute's Physical Sciences Division.

The study was conducted for ARPA under the cognizance of Mr. R. A. Black. Mr. Richard G. Donaghy of the U.S. Army Construction Engineering Laboratory was the authorized representative of the contracting officer and Mr. John Pollock was the contract monitor.

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Appendix A

PERFORMANCE CHARACTERISTICS AND ELEMENTS OF COSTS OF FOSSIL FUEL SYSTEMS

Introduction

This Appendix presents the performance characteristics, installed costs, and operating costs (excluding fuel) of the fossil fuel systems considered for total energy systems. The systems discussed are: (1) diesel, (2) gas turbine, (3) steam turbine, and (4) conventional heating systems; there is limited discussion also of (5) combined cycle, and (6) nuclear systems. The performance characteristics and costs are given separately for each of four equipment groups: (1) electric generating plant, (2) heating plant, (3) heat transmission lines, and (4) air conditioning. In most cases the characteristics and costs are given as functions of unit capacity. From this information the system elements can be sized and combined to cover the many variations in base size, climate, and energy system configuration. The performance characteristics provide the information necessary for calculating fuel consumption.

The wide scope of the study in terms of system capacities, configuration, fuels, and geographic location precludes great precision in performance data and, especially, cost data. The results of this study should, therefore, be taken as first approximations to indicate whether more detailed study of particular cases is justified.

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Cases and Ranges of Capacities

Generating Station Cases

(1) Single central plant consisting of enough diesel engines or gas turbines to provide all standby requirements, with central heating plant and dispersed cooling plants.

(2) Single central steam turbine plant having no standby requirement (tied to electric utility for downtime), with central heating plant and dispersed cooling plants.

(3) Several (five or more) separate plants of up to 5 MWe each on one military base, electrically interconnected.* Separate plants need not have their own standby capacity; there could be a single generating unit at each plant, with dispersed heating and cooling plants.

(4) Conventional central or dispersed heating plants and dispersed cooling plants but without electric generation.

Electric Plant Capacities

	Range of Unit Capacities (MWe)	Range of Plant Capacities (MWe)
Diesel engines	0.5 to 8	0.5 to 50
Gas turbines	2 to 100	2 to 100
Steam turbines	25 to 100	25 to 100
Nuclear	25 to 100	25 to 100

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*Early in the study, the simplifying assumption was made that the costs of the electric distribution network would be the same for the central and dispersed cases. In view of the possible need for protective relaying in the dispersed cases, this may not be a completely accurate assumption; an engineering and cost analysis of the electrical distribution systems would be necessary to resolve the issue precisely.

Heating Plant Capacities

Range: 10 to 1000 MWt

Cooling Plant Capacities

Range: 50 to 10,000 tons, absorption and vapor compression chillers

Heat Transmission

The model base is divided into four or more complexes, each with its own central heating and cooling distribution system. The distribution systems within each complex are not analyzed in this study.

The heating medium is assumed to be high temperature water. For the single central plant cases, the hot water is transmitted to a single point in each complex through a two-pipe (supply and return) system.

Heat Transmission Lines

Line Capacity (MWt)	Line Length (miles)
3 to 25	1/4 to 2
25 to 100	1/2 to 4

Each line will have two or three use points having equal demand equally spaced along the line.

Gas Turbines

Industrial type open cycle gas turbines with waste heat recovery directly by high temperature water (HTW)* were considered in the size

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*Hereafter high temperature water will be called HTW, whether it is on the supply side or the relatively cold return side of the HTW circulation system.

range from 2 to 70 MWe. The net electric generation heat rate is given in Figure A-1 as a function of unit size; Figure A-2 shows a multiplier to adjust the heat rate for operation at less than rated load. The heat rates given are for intake air conditions of 59°F, 14.7 psia. Degradation of both heat rate and output occur with higher temperatures and lower pressures at the intake.

The HTW enters the exhaust heat recovery unit of the gas turbine at 220°F and exits at the HTW supply temperature of 380°F; it is fully pressurized so that it remains in the liquid phase. Heat recovery was calculated assuming a 950°F turbine exhaust temperature and a 300°F stack temperature, the latter being the approximate minimum temperature to preclude moisture condensation in the stack. The unfired waste heat recovery rate at full load, expressed in megawatts thermal (MWt) per rated megawatt electric (MWe) capacity, is given in Figure A-3. Figure A-4 shows a multiplier that converts the full load heat recovery rate to the

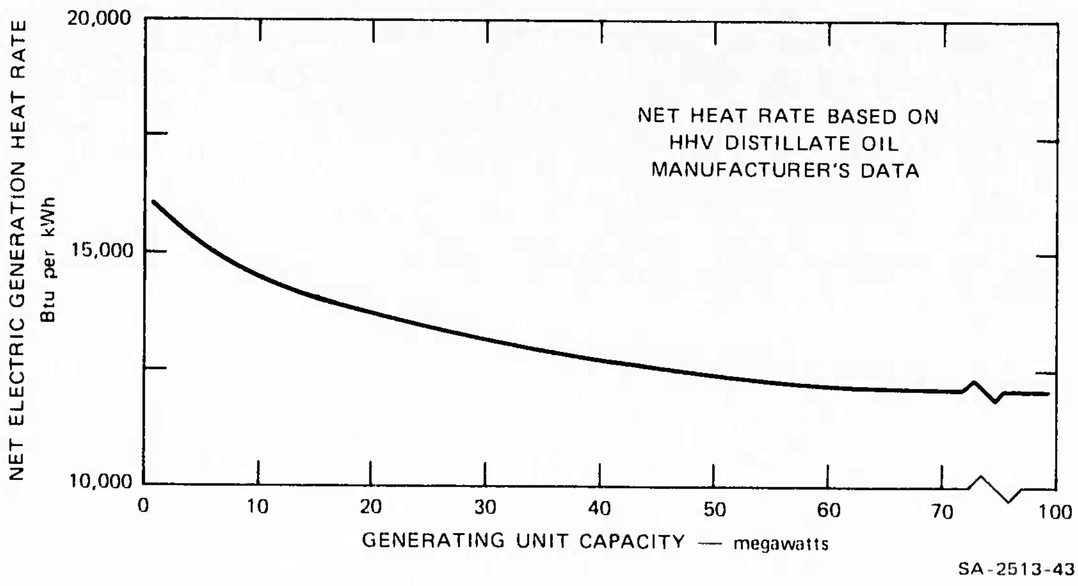


FIGURE A-1 GAS TURBINE NET ELECTRIC GENERATION HEAT RATE AT RATED LOAD AS A FUNCTION OF GENERATING UNIT CAPACITY

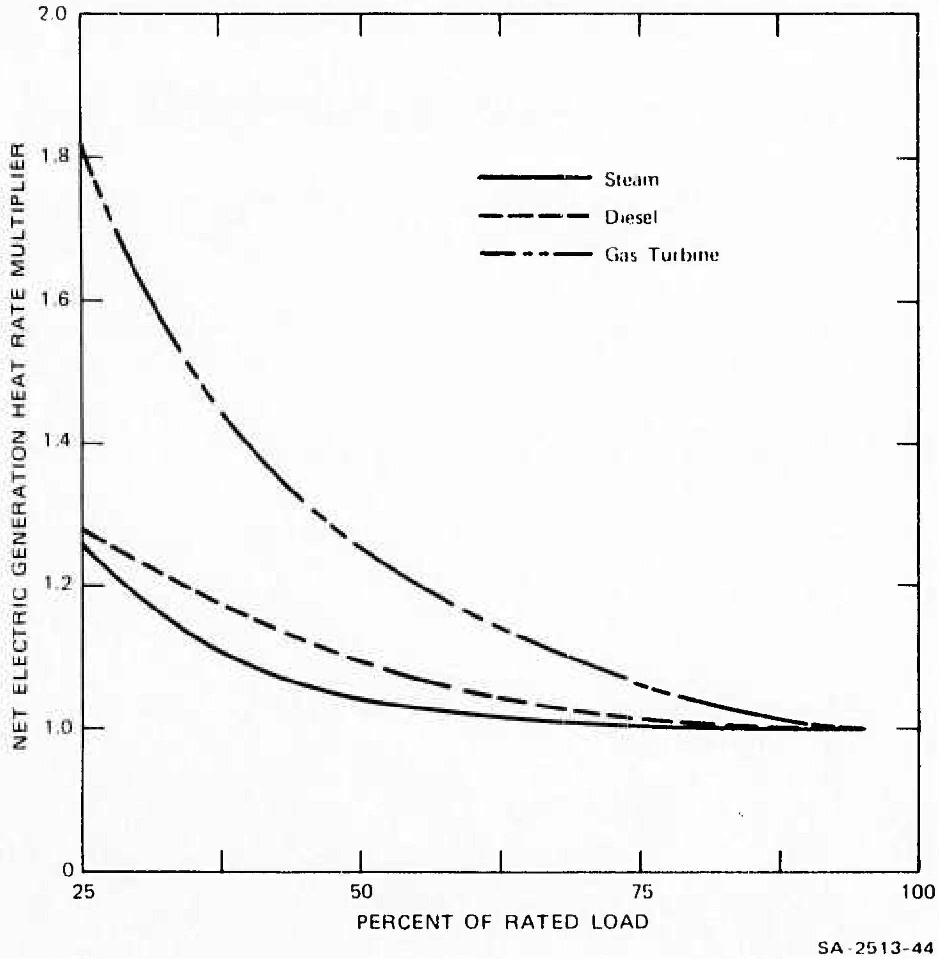


FIGURE A-2 HEAT RATE MULTIPLIER TO ACCOUNT FOR PERCENT OF RATED LOAD

heat recovery rate at partial load in MWt per actual net electric generation in MWe.

Additional heat can be generated in the heat recovery unit by supplemental firing of the turbine exhaust from 950°F to 1400°F. This supplemental firing can be modeled as a 90 percent efficient HTW generator operating on the same fuel as the gas turbine, and can be used up to the maximum heat duty shown in Figure A-5 as heat recovered in MWt per rated electric generation capacity in MWe.

Maintenance and operating cost (exclusive of fuel costs) for natural gas or distillate oil should run about 1.1 mills per kWh, including

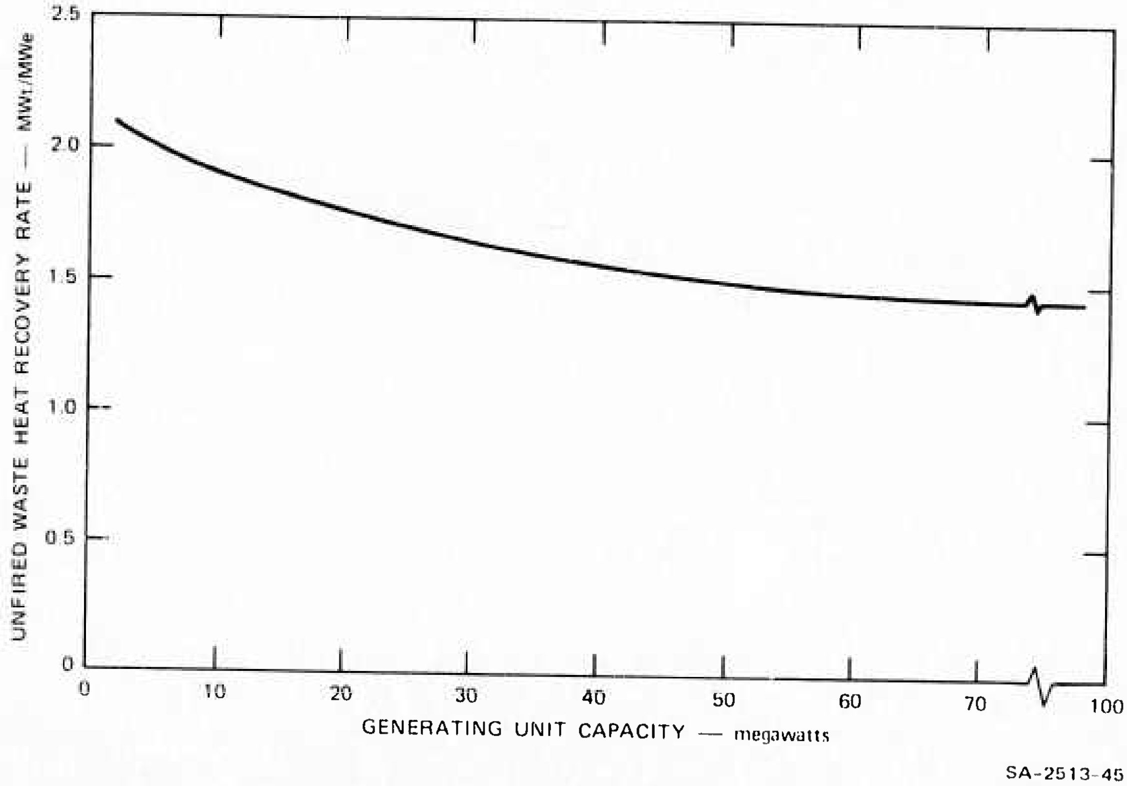
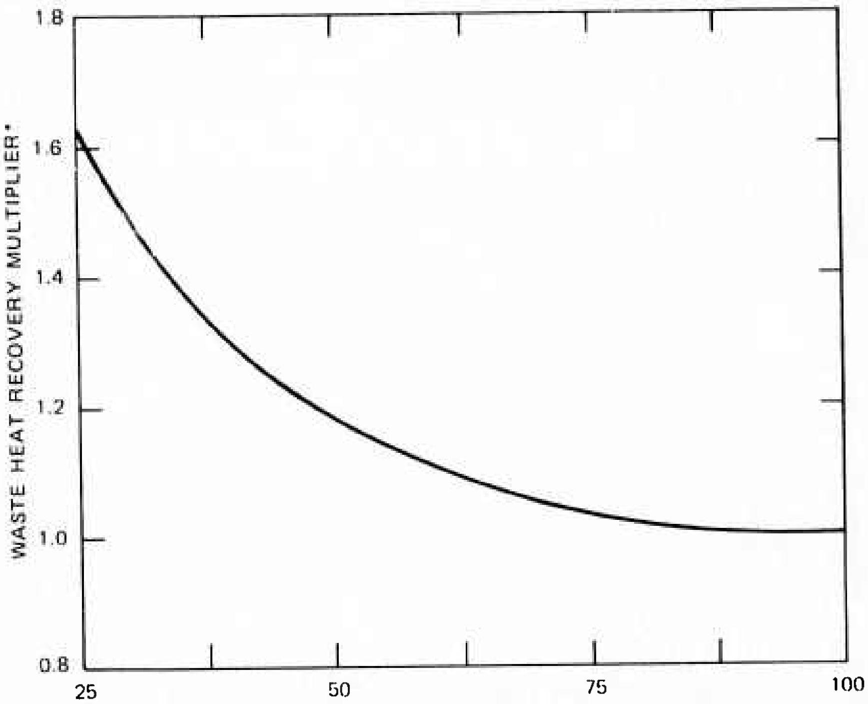


FIGURE A-3 GAS TURBINE UNFIRED WASTE HEAT RECOVERY RATE AT RATED LOAD AS A FUNCTION OF GENERATING UNIT CAPACITY

operating personnel and supervision. High maintenance costs for heavy oil roughly double this figure. Installed capacity costs are given as a function of generating plant capacity in Figure A-6; two curves are shown, one for multi-unit plants and one for single-unit plants. These costs include the waste heat recovery unit but do not include a heavy fuel treatment system; otherwise the costs are representative of conventional utility gas turbine plants. Approximate costs for the heavy fuel treatment system are shown in Figure A-7.

An approximation of total annual cost versus generating unit size was made, considering only fuel and annualized capital costs as affected by variations in heat rate and installed capacity cost. Sufficient standby capacity was assumed to be provided by having one unit in excess



*Corrects heat recovery at rated load to heat recovered/actual electric generation.

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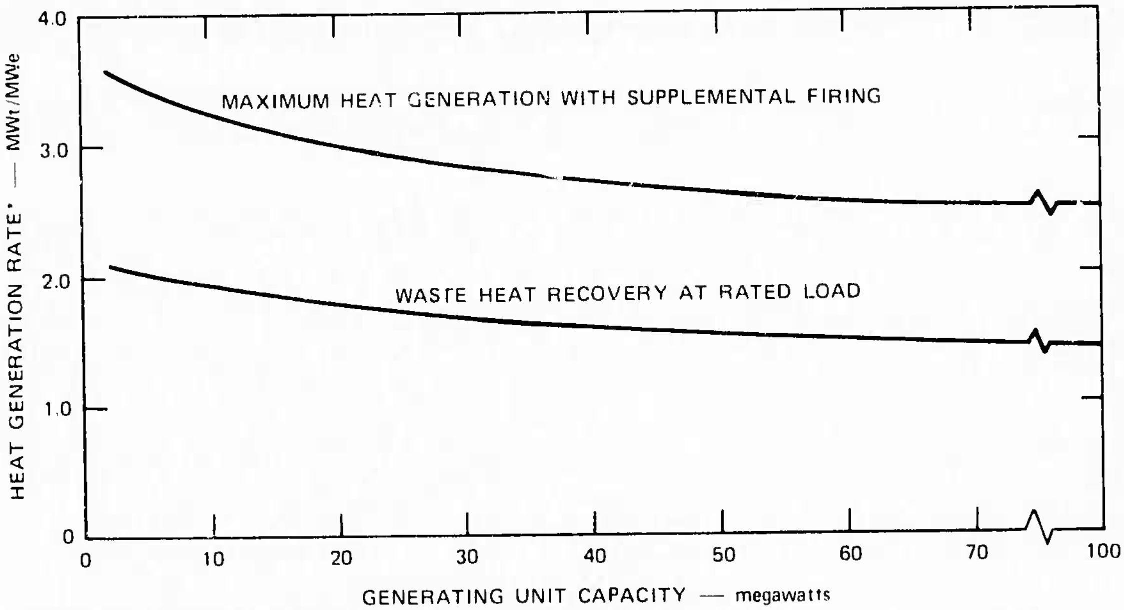
FIGURE A-4 GAS TURBINE WASTE HEAT RECOVERY MULTIPLIER* TO ACCOUNT FOR PERCENT OF RATED LOAD

of the rated plant capacity. The plant composition chosen was seven equally sized units, six of which make up the rated capacity of the plant, with the seventh as standby. The difference in total annual cost between plants with various numbers of units was not high, however, which suggests that other plant compositions might well be competitive.

As with the other cost and performance data, the results for gas turbines have been presented as curves that are continuous over unit size. Gas turbines, however, are available in fewer discrete sizes than either diesels or steam turbines, and the desired size of gas turbine for a given application may not be available. Since the total generation costs are not strongly affected by unit size, however, ignoring the discontinuities in available capacities should not endanger the accuracy of the study.



*Maximum heat generation (MWt)/generating unit capacity (MWe).

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FIGURE A-5 GAS TURBINE MAXIMUM HEAT GENERATION* WITH SUPPLEMENTAL FIRING AS A FUNCTION OF GENERATING UNIT CAPACITY

Steam Turbines

The steam system consists of a conventional steam power plant with a single turbine capable of high rates of extraction, oversized boilers, and indirect (closed) heaters that transfer heat from the extracted steam to the HTW. The size range considered is from 25 to 100 MWe generating capacity, with standby capacity provided by a tie to an electric utility network or by other means not considered in this study.

Cycle efficiency and heat recovery were evaluated assuming the following throttle state points and a nonreheat cycle:

25 MW	750 psia	800°F
50 MW	1250 psia	850°F
100 MW	1800 psia	900°F

Steam at 220 and 82 psia is extracted at approximately equal mass flow rates at each extraction point to two steam/HTW heat exchangers. These

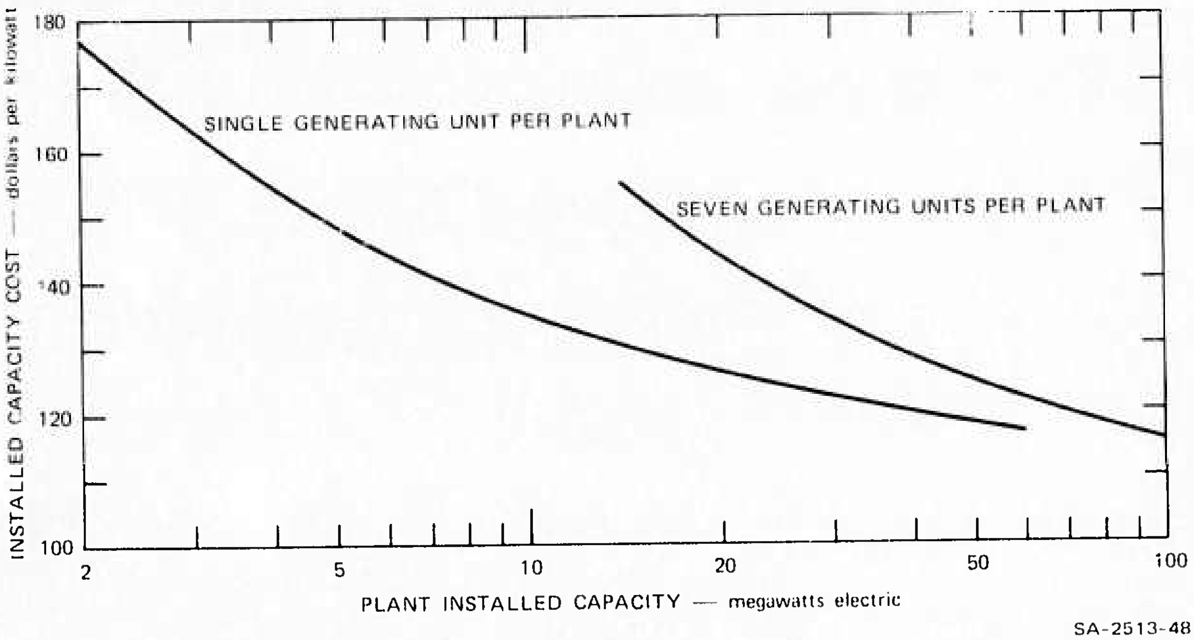


FIGURE A-6 GAS TURBINE INSTALLED CAPACITY COST AS A FUNCTION OF GENERATING PLANT CAPACITY

extraction points and two additional ones are also used for heating the boiler feedwater, which is hydraulically isolated from the HTW system. The net electric generation heat rate was calculated for two idealized modes of operation: (1) full condensing, where no steam is extracted except for feedwater heating; and (2) back-pressure operation, where the first three extraction points claim virtually all of the steam flow. Heat rates for these two modes are given in Figure A-8 as a function of plant generating capacity; heat recovery rates for the back-pressure mode are given in Figure A-9 as heat recovery in MWt per actual electrical generation in MWe.

The suggested method of computing fuel consumption and heat recovery is to model the plant as containing two turbines--one fully condensing machine and one back-pressure machine side by side--with efficiencies

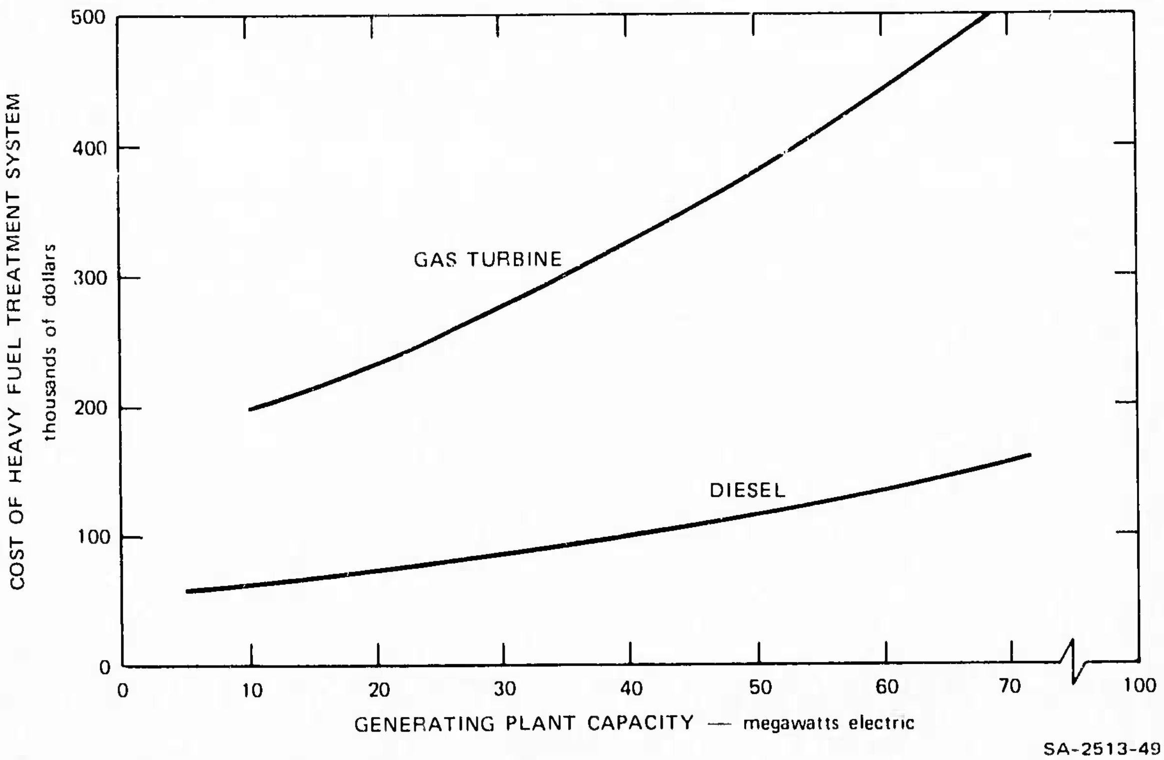


FIGURE A-7 APPROXIMATE COST OF HEAVY FUEL TREATMENT SYSTEMS AS A FUNCTION OF GENERATING PLANT CAPACITY

and heat recovery corresponding to the condensing and back-pressure modes above. Operation would then be as follows:

(1) If the ratio of thermal to electric demand were greater than the heat recovery rate of the back-pressure cycle, the back-pressure turbine would be run up enough to meet the electrical demand. The remaining thermal demand would be met by an independent auxiliary HTW generator.

(2) If the ratio of thermal to electric demand were less than the back-pressure heat recovery rate, the output of the back-pressure turbine would be set at the level necessary to meet the thermal load. Then the condensing turbine would be brought on to meet the balance of the electric load.

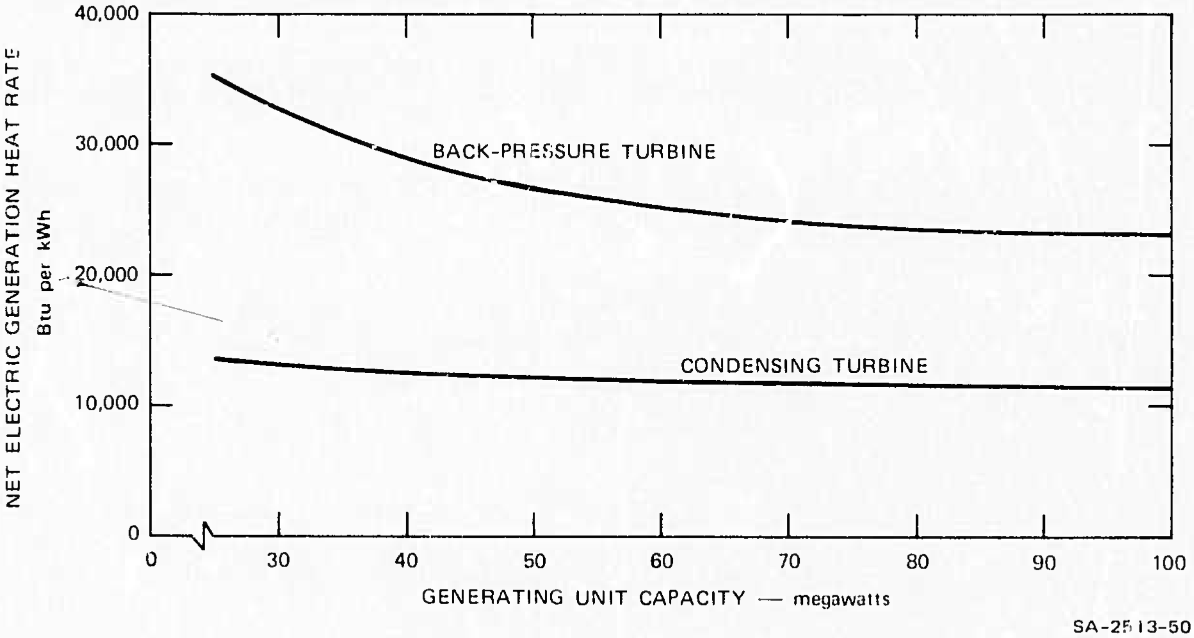
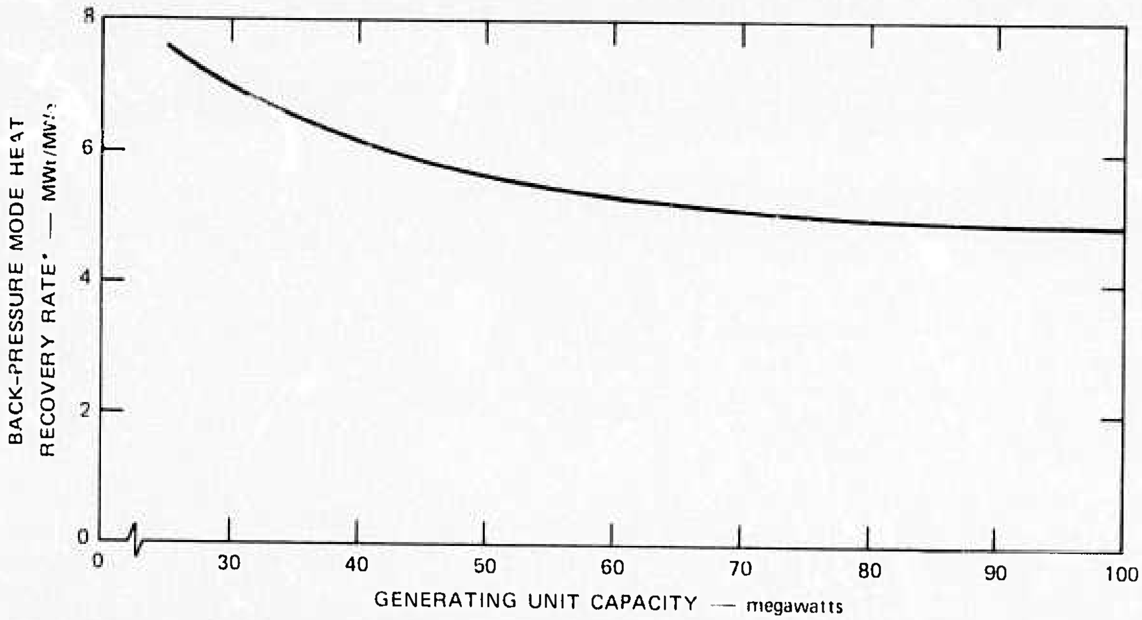


FIGURE A-8 STEAM TURBINE NET ELECTRIC GENERATION HEAT RATE AS A FUNCTION OF GENERATING UNIT CAPACITY

While this modeling is attractively simple, it ignores the fact that there is actually only one turbine, and that a single turbine is not capable of such wide flexibility in extraction rates without losses in efficiency. The modeling should, however, be reasonably accurate over a wide range of thermal/electric demand ratios, though a more refined analysis would consider the effect of thermal electric demand ratio fluctuation on turbine efficiency.

The steam system installed capacity costs, which are shown in Figure A-10 for gas, oil, and coal fired plants, include enough boiler and steam/HTW heat exchanger capacity for full extraction mode operation at the plant rated electric output. For plants with a lower thermal output capability, the cost deduction shown in Figure A-11 may be subtracted from the basic plant cost shown in Figure A-10 to give the cost of a plant with a smaller thermal capacity.



*Maximum heat recovery (MWt)/actual electric generation (MWe)

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FIGURE A-9 STEAM TURBINE BACK-PRESSURE MODE HEAT RECOVERY RATE* AS A FUNCTION OF GENERATING UNIT CAPACITY

Operating and maintenance costs are different for the condensing and back-pressure modes because of differences in steam flows. The following operating and maintenance cost figures, in mills per kWh, were derived from data on small utility steam power plants:

	Condensing Mode	Back-Pressure Mode
Gas fired	1.0	2.1
Oil fired	1.3	2.8
Coal fired	1.6	3.4

Diesel Engines

Low to medium speed diesel engines ranging in size from 500 kW to 8 MW were considered. Net electric generation heat rates were obtained from manufacturer's data and checked against operating data for a large

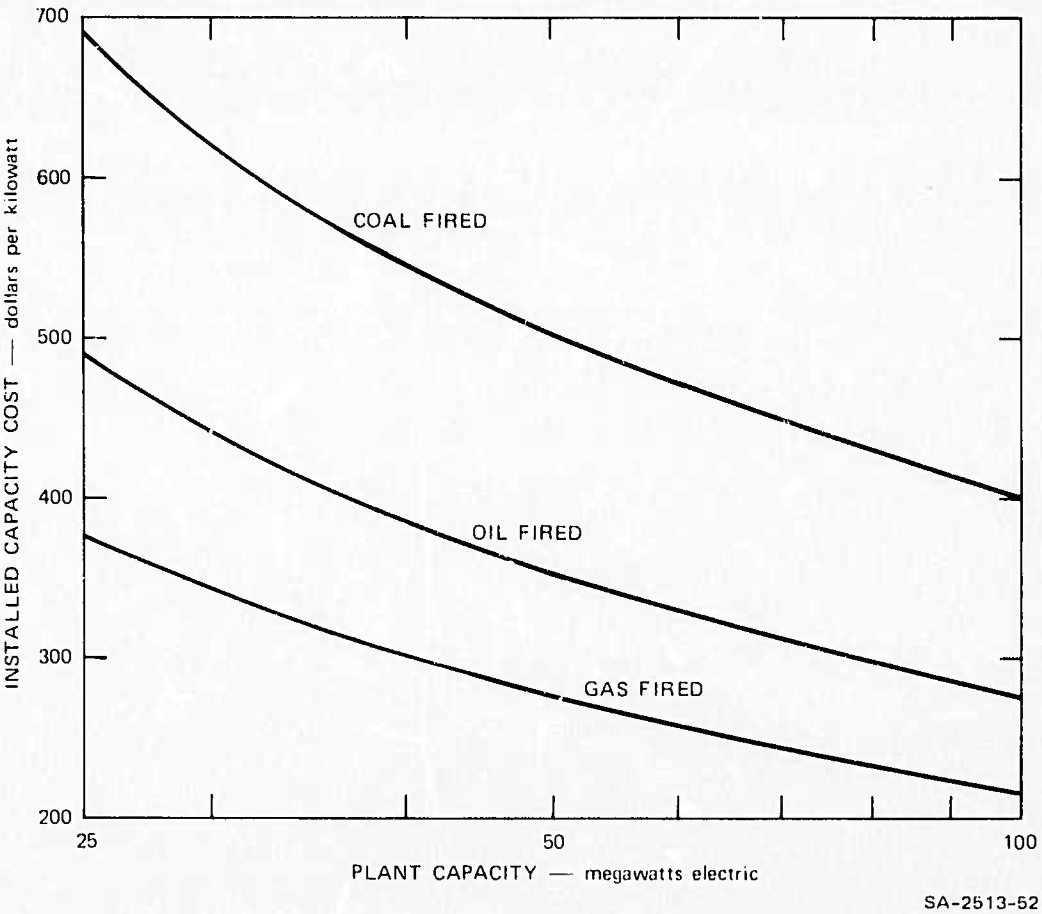


FIGURE A-10 STEAM POWER PLANT INSTALLED CAPACITY COST WITH MAXIMUM HEAT GENERATION CAPACITY AS A FUNCTION OF PLANT CAPACITY

sample of diesel power plants. Heat rate is shown as a function of generating unit size in Figure A-12 (Figure A-2 gave a multiplier that accounts for the effect on heat rate of operation at other than peak capacity).

Heat is recovered both from the engine exhaust by an exhaust-air-to-water waste heat recovery silencer and from the jacket water by a water-to-water heat exchanger that isolates the high pressure HTW system from the low pressure engine cooling system. The HTW enters the jacket water heat exchanger at the 220°F return temperature of the HTW system,

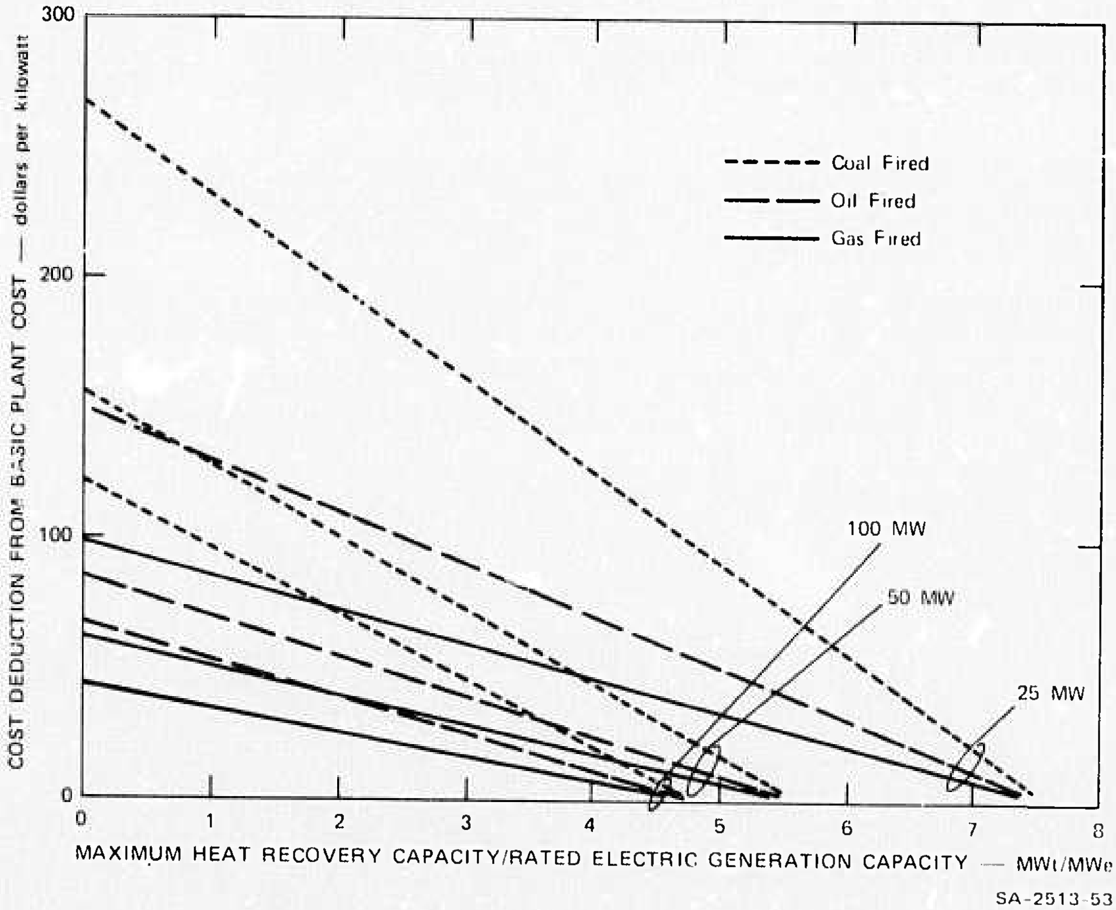


FIGURE A-11 STEAM PLANT COST DEDUCTION FOR LESS THAN FULL HEAT GENERATION CAPACITY

is heated to 240°F (10° below the assumed jacket temperature of 250°F), and then enters the exhaust recovery unit where it is further heated to about 276°F. The HTW then flows to a conventional HTW generator, where it is topped up to the design HTW supply temperature of 380°F. For the calculated diesel heat recovery rate of 0.9 MWt per MWe, this means that about 1.6 MWt per MWe will have to be added by the conventional HTW generator to achieve the desired transmission temperature. This scheme was adopted because the two constraints--HTW return temperature (220°F) and jacket water temperature (250°F)--limit the temperature rise of the HTW to 20°F in the jacket water heat exchanger, thus fixing the minimum HTW

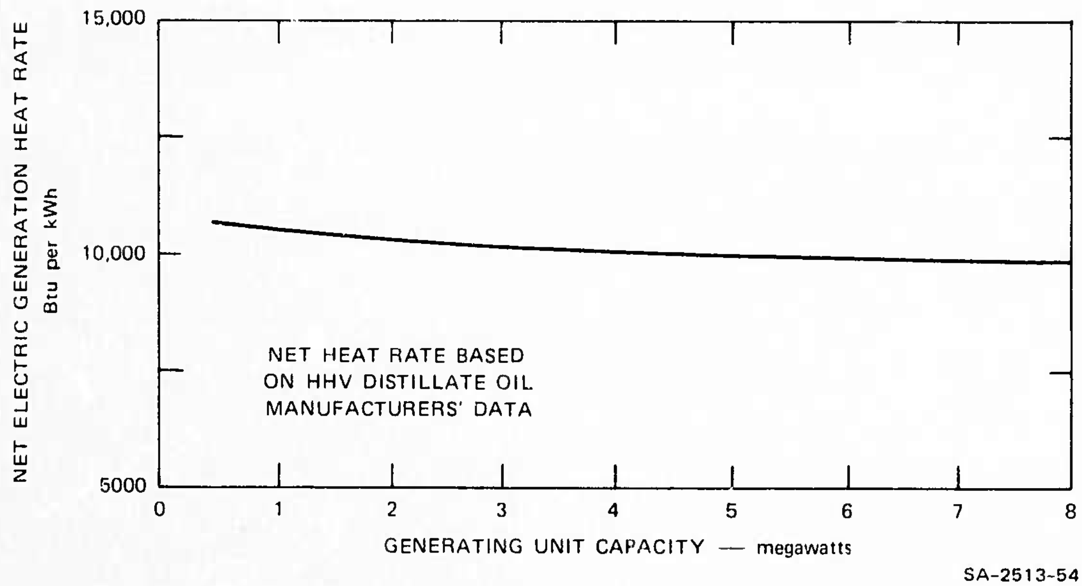


FIGURE A-12 DIESEL POWER PLANT ELECTRIC GENERATION HEAT RATE AT RATED LOAD AS A FUNCTION OF GENERATING UNIT CAPACITY

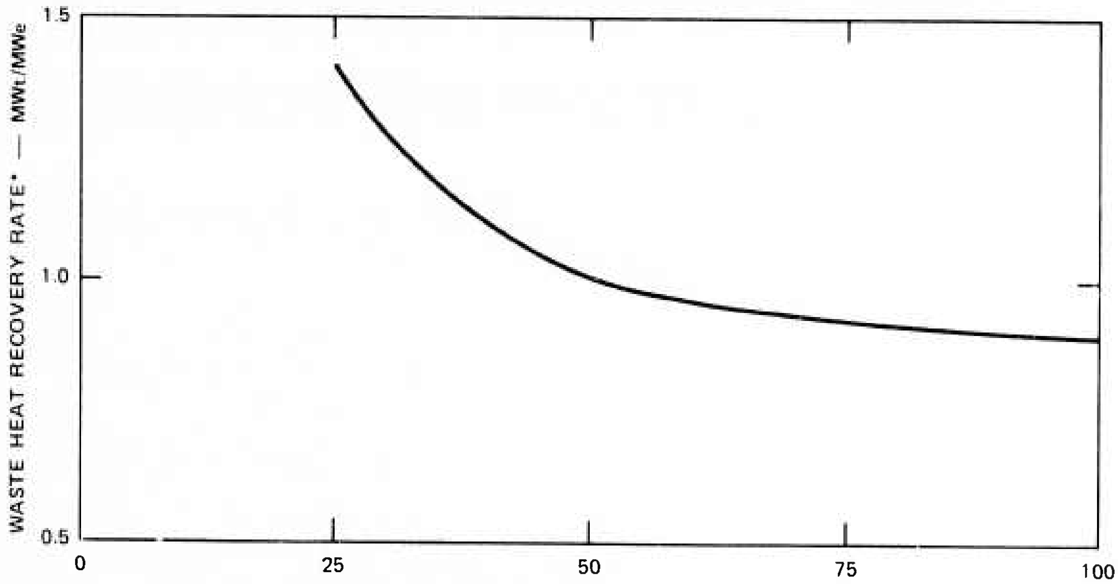
flow rate needed to carry off all of the jacket heat. The outlet temperature from the exhaust heat recovery unit could be increased by reducing the HTW flow rate, but because of the temperature constraints discussed above, the excess jacket heat would have to be rejected elsewhere and would thus be lost to the system. The temperature topping scheme, which avoids losing any of the jacket heat, was felt to be justified in view of the fact that the anticipated high thermal demands (ranging from 5 to 15 MWt per MWe) would normally require additional heat from a conventional HTW generator in any case.

The amount of temperature topping required could be reduced by lowering the return temperature of the HTW system; for a 200°F return temperature, the HTW undergoes a 40°F rise in the jacket exchanger, and (assuming a slightly increased heat transfer area in the exhaust heat recovery unit to make up for the lower LMTD), the HTW exits the exhaust heat recovery unit at 312°F. This reduces the heat required for temperature topping from 1.8 to 0.55 MWt per MWe for a 380°F transmission temperature and to no topping at all if transmitting directly at 312°F is chosen.

Another factor suggests that the HTW supply and return temperatures might well be chosen lower for the diesel than for the other prime movers. The study has assumed engines designed for ebullient cooling, which can tolerate 250°F water (and associated 15 psig pressure) in their jackets, and also higher than average exhaust heat rejection rates and temperatures. Not all engines are designed for ebullient cooling, however, and of those that are, some reject a substantial proportion of heat to the lube oil at too low a temperature for recovery (about 180°F) rather than to a hot exhaust. These two assumptions taken together limit the number of appropriate engines, so that it might be impossible to cover the size range specified. This problem is less acute with a lower temperature HTW system because the jacket heat can then be recovered at a temperature low enough for most diesel engines to attain.

The HTW design temperature for the diesel system would have been reduced for these reasons except that (1) there was time to consider only one transmission temperature in the study, and (2) a lower temperature system would have been uneconomic for the gas turbine and steam options. For the diesel option, then, in cases either of low thermal/electric load ratios or of engines without the happy combination of ebullient cooling and plentiful exhaust heat, the HTW transmission system described probably has understated capital cost and pumping power, and overstated heat losses. A more detailed study would tailor the HTW transmission and distribution system to the characteristics of the various prime movers available.

Figure A-13 gives the heat recovery rate for the diesel system (in MWt per actual net electric generation in MWe) as a function of percent of rated load.



*Waste heat recovered (MWt)/actual electrical generation (MWe).

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FIGURE A-13 DIESEL POWER PLANT WASTE HEAT RECOVERY RATE* AS A FUNCTION OF PERCENT OF RATED LOAD

The diesel operating and maintenance costs have been broken down into fixed and variable costs (not including fuel costs). The variable costs are taken at 1.4 mills per kWh for No. 2 diesel fuel or natural gas, and roughly double this for heavy oil. Fixed costs are $23,800 per year plus $5,000 per year per installed MWe of operating capacity, with a $47,600 minimum annual operating cost. The fixed costs reflect the manning scales found in the sample of diesel utility power plants studied, which are considerably more heavily manned than gas turbines of equal capacity.

Diesel installed capacity costs for single-unit and multi-unit plants, are given in Figure A-14 as a function of generating plant size. They include a building with overhead crane, waste heat recovery equipment, a 30-day fuel capacity tank farm, and all plant equipment including 4600-volt switchgear. They do not include a heavy fuel treatment system (the approximate cost of which was shown in Figure A-7).

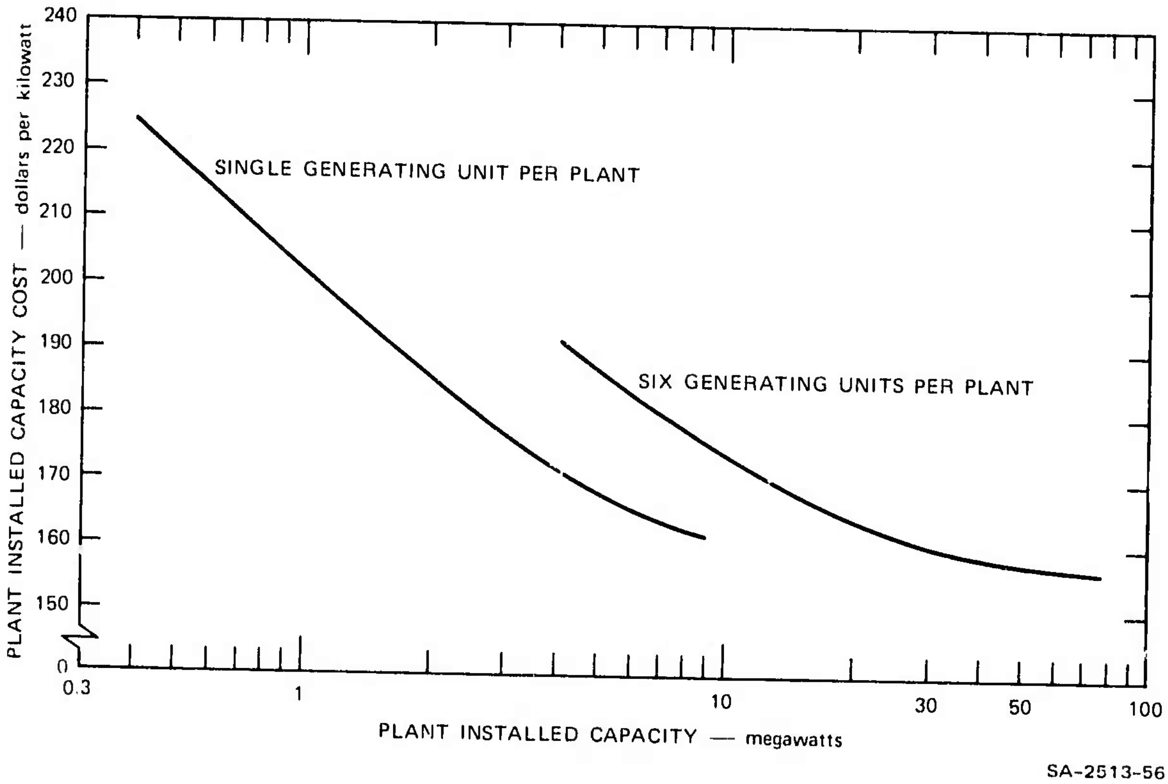

FIGURE A-14 DIESEL POWER PLANT INSTALLED CAPACITY COST AS A FUNCTION OF PLANT INSTALLED CAPACITY

The recommended plant composition for diesels is six equally sized units, with five units making up the plant rated capacity and the sixth serving as a standby unit.

Gas Turbine/Steam Turbine Combined Cycle (GT/ST)

GT/ST combined cycles were the subject of preliminary study only because they did not appear suited to the special demands of the problem. While a GT/ST properly tailored to a given thermal/electric load pattern allows flexible variation of thermal/electric load ratios, it was felt that for the high thermal loads expected, the system would not be a good candidate. In the form in which the GT/ST is used in the utility industry, the electric generation heat rate is attractive but there is no waste heat generation at usable temperatures. However, with sufficient waste heat recovery to meet the high thermal/electric ratios specified in this study, the steam turbine becomes so small that the system virtually degenerates into the previously considered option of an open cycle gas turbine with waste heat recovery for heating only. There may be cases where the thermal/electric ratio is low enough for a sufficient proportion of the time that the GT/ST system might appear attractive and therefore worthy of a more detailed study.

Nuclear Heat Source

It is technically feasible to employ relatively low capacity high temperature gas cooled reactors (HTGR) or light water reactors (LWR) as the heat source for electric power generation and district heating on U.S. military bases. However, licensable commercial reactors in capacities of 25 MWe to 100 MWe do not exist at the present time. Further, there is no known current program, either in the United States or abroad, for developing these types of reactors in the above capacity range. While their use may be technically feasible, they are at present underdeveloped and economically unfeasible.

With respect to technical feasibility, the HTGR has a thermodynamic advantage over the LWR reactors because of its inherently higher initial steam temperature--approximately 1000°F compared with 520°F to 580°F for the LWRs. While the HTW can be raised to the assumed 380°F supply temperature by extraction from the LWR turbine, the ratio of shaft work (MWe) to recovered heat (MWt) would be low because of the relatively low throttle temperature of the LWR.

Because typical turbine throttle steam conditions of the HTGR closely match the assumed throttle conditions for fossil fired plants in this study, reference can be made to Figure A-9 to determine waste heat recovery and to Figure A-8 for the heat rate for the HTGR. However, for the LWRs, a separate study would have to be undertaken and different curves developed.

In the plant circuitry, the nuclear plant steam generator simply replaces the boiler of the fossil-fueled plant. Transfer of thermal energy to the HTW loop is accomplished through indirect heat exchange, there being no contact between the primary or secondary circulants and the HTW. It should be noted that since the PWR inherently includes a primary and a secondary circulating loop, whereas the BWR has only one loop, the latter would have one level less isolation from the HTW and therefore a smaller margin of safety with respect to possible cross contamination of the HTW by the primary coolant.

HTW Generators

HTW generators were used both for supplementing the waste heat recovery and for the conventional heating comparison. Steam pressurized HTW systems were assumed for the study, with a 380°F supply and a 220°F return temperature. The transmission temperatures chosen profoundly affect the design of the system--pump power consumption, heat loss, and capital investment in heat exchangers, expansion tanks, and piping. No one choice of temperatures is optimal over the large size range specified (from 8.5 to 1000 million Btu per hr); and indeed, in the lower size ranges, it is not clear that a conventional HTW system would necessarily be the most economic choice. For the purposes of this study, however, the temperature and system chosen should give sufficiently accurate results, even if they are not optimal for very small or very large distribution systems. Further analysis is needed to evaluate accurately systems for the high and low end of the capacity range.

Installed costs as a function of plant capacity are given in Figure A-15. These include the HTW generation unit, plant piping and auxiliaries, and enough expansion tank capacity to account for the volume of water in the generating plant itself. Expansion tank capacity for the distribution

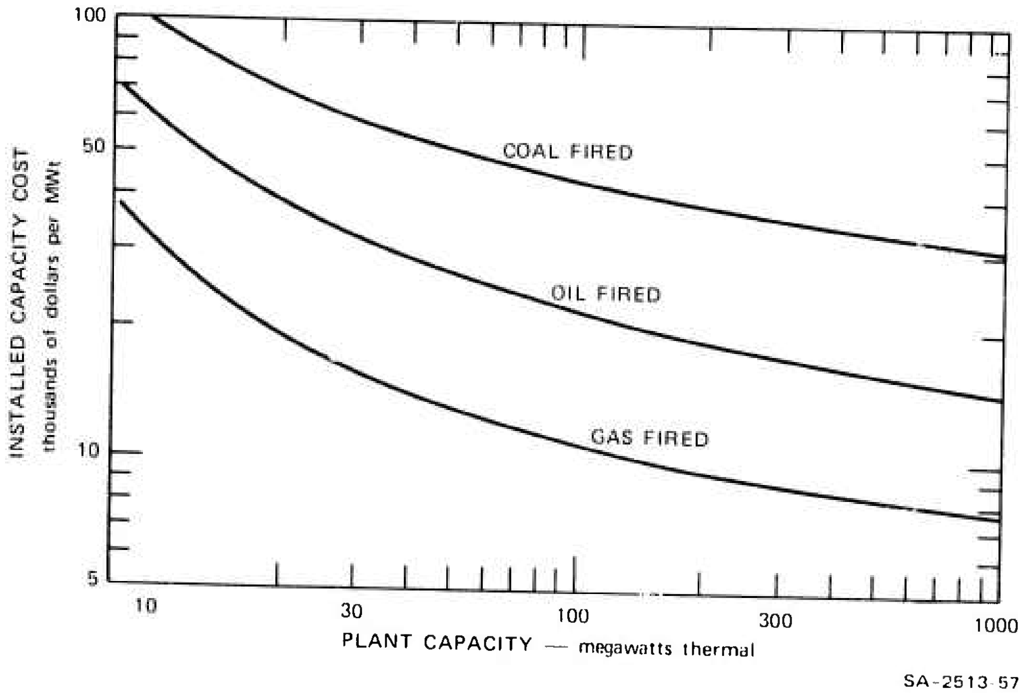

FIGURE A-15 HIGH TEMPERATURE WATER GENERATOR INSTALLED COSTS AS A FUNCTION OF PLANT CAPACITY

lines is included in the HTW transmission line costs, as are costs for the system circulation pumps.

The heating efficiency for an oil fired system is 83 percent, and for gas and coal fired systems, 80 percent.

High Temperature Water Transmission System

The HTW transmission system consists of supply and return pipes buried in an insulated trench with rated heat transmission capacities varying from 1 to 300 MWt. The transmission pipes were sized for an 0.1-inch water gauge pressure drop per foot of single pipe run when operating at rated capacity with a 380°F supply and a 220°F return temperature. Figure A-16 gives the resulting pipe diameters as a function of the rated thermal transmission capacity of the line. Figure A-17 shows the pump power required at peak load per 100 feet of rur of combined

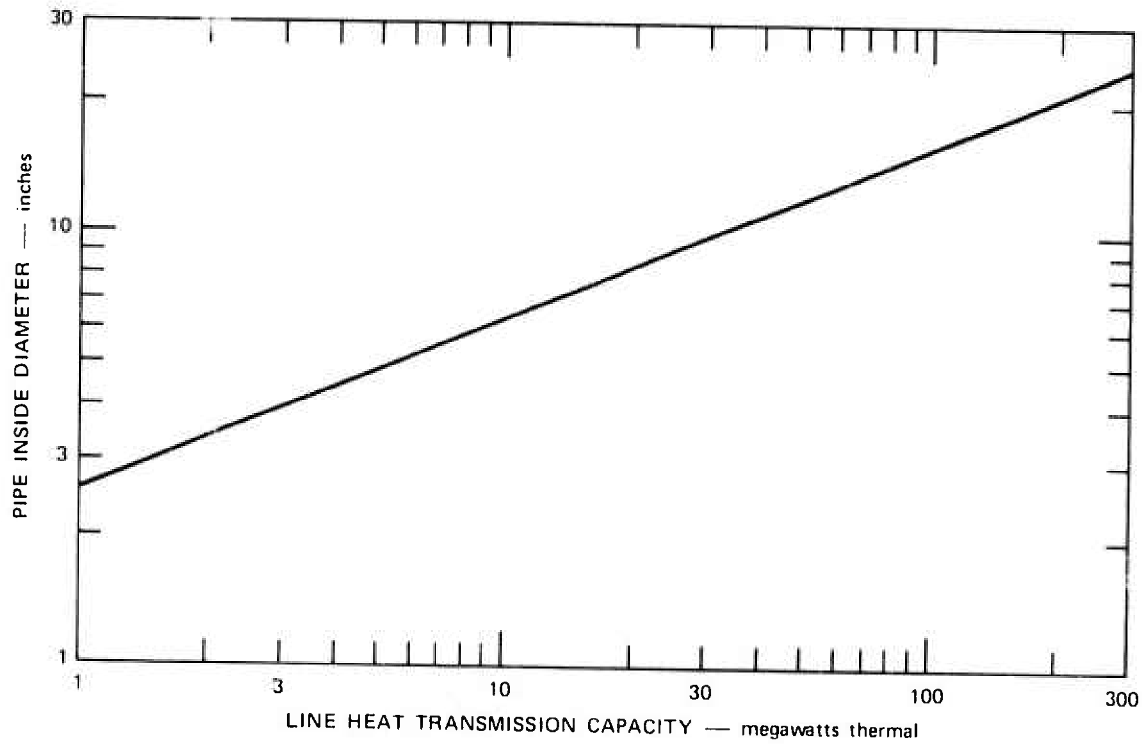

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FIGURE A-16 PIPE INSIDE DIAMETER AS A FUNCTION OF LINE HEAT TRANSMISSION CAPACITY

supply and return pipes as a function of line heat transmission capacity. To obtain power requirements for less than peak loads, read the power required at peak load for the rated capacity of the line in question, and apply the following formula:

$$P' = P_{nom} \left(\frac{q' \; \Delta T_{nom}}{q_{nom} \; \Delta T'} \right)^{2.96}$$

where:

q_{nom} = rated heat transmission capacity of the line

q' = actual heat demand

ΔT_{nom} = design temperature difference (160°F)

$\Delta T'$ = actual operating temperature difference

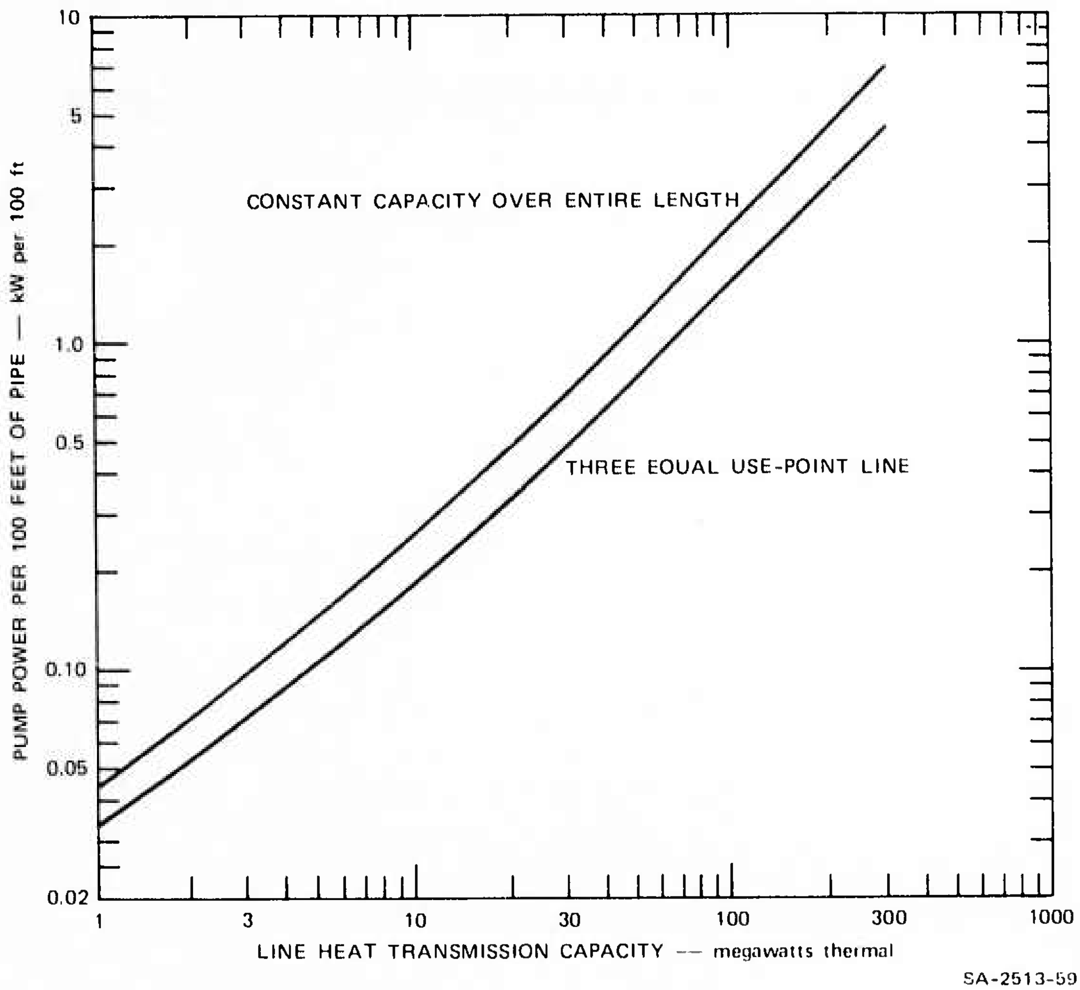

FIGURE A-17 PUMP POWER PER 100 FEET OF SUPPLY AND RETURN PIPE AT RATED CAPACITY AS A FUNCTION OF LINE HEAT TRANSMISSION CAPACITY

For winter operation, the system can be assumed to be operating at design conditions, i.e., with $\Delta T' = \Delta T_{nom} = 160°F$. Summer operation (defined as an extended period of relatively low thermal load) would use lower operating temperatures, for instance, a supply temperature of 320°F and a return temperature of 200°F, with $\Delta T' = 120°F$.

Heat loss was computed assuming poured-in-place insulation around the buried supply and return pipes, with an insulation envelope sized for a pipe temperature 20°F higher than the design temperature, in the interest of obtaining a more favorable heat loss picture at some increase in capital cost. Depth of burial ranged from three to five feet (for the smallest and largest lines respectively) of cover over the top of the insulation envelope. A soil conductivity of 1.0 Btu per hr ft°F was taken as representative of reasonably dry soil.* The heat loss computed on this basis is given in Figure A-18, along with the summer operation correction factor of 0.74 to account for the lower heat loss at the assumed lower summer transmission temperatures.

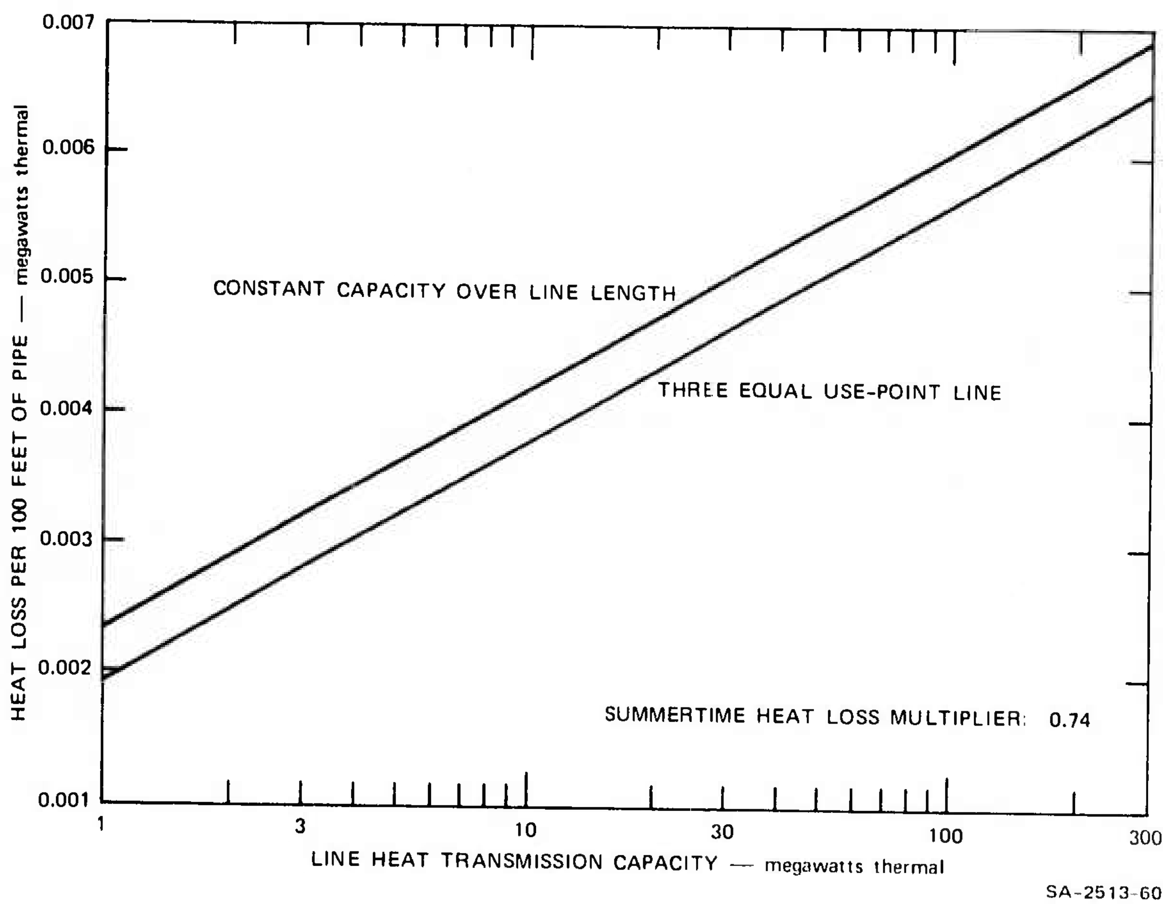

FIGURE A-18 HEAT LOSS PER 100 FEET OF BURIED SUPPLY AND RETURN PIPE AS A FUNCTION OF LINE HEAT TRANSMISSION CAPACITY

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*Btu per hour per square foot per degree fahrenheit per 1-inch thickness.

Installed costs for the transmission piping are given in Figure A-19 in dollars per 100 ft of combined supply and return pipe as a function of the design heat transmission capacity in MWt. These installed costs include a prorated share of the central plant expansion tank and pump costs, along with the costs of excavation, pipe, anchors, expansion loops, and insulation. The excavation costs are based on good conditions; upward adjustments would be required to account for rocky soil or for work in the rainy season.

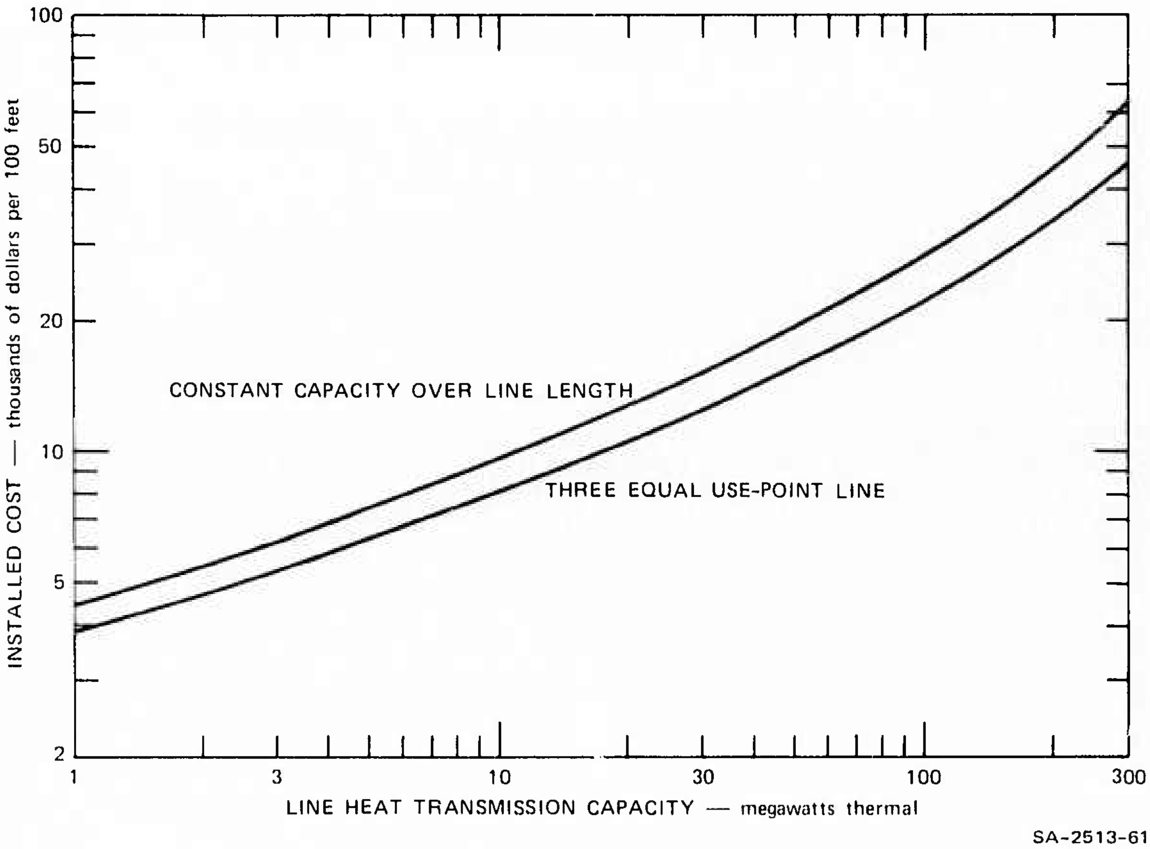

FIGURE A-19 INSTALLED COSTS PER 100 FEET OF BURIED SUPPLY AND RETURN PIPE AS A FUNCTION OF LINE HEAT TRANSMISSION CAPACITY

Air Conditioning Chillers

Absorption and electrically driven vapor compression chillers were considered, varying in capacity from 50 tons to the maximum available. Chiller performance is affected by ambient conditions, desired chilled air temperature, and load factor, making the parametric representation of performance a complicated matter. For the purposes of this study, sufficient accuracy should be obtained by using the following energy requirements for the types of chillers considered:

Vapor Compressor	Simple Absorption	Double Effect Absorption
0.83 kWe per ton	5.3 kWt per ton	3.2 kWt per ton

Annual maintenance costs for vapor compression and simple absorption chillers are given in Figure 20. The costs for double effect absorption units (which are new to the market, only one product line being available at present) should run about the same as simple absorption units.

Installed capacity costs are given in Figure 21 as a function of unit capacity for the three chiller types. The costs include the installed cooling tower and chilling machine but no circulation system piping or pumps and no building. These latter items were not priced because they are about the same for all three systems and hence will not affect cost comparisons of the options considered in this study.

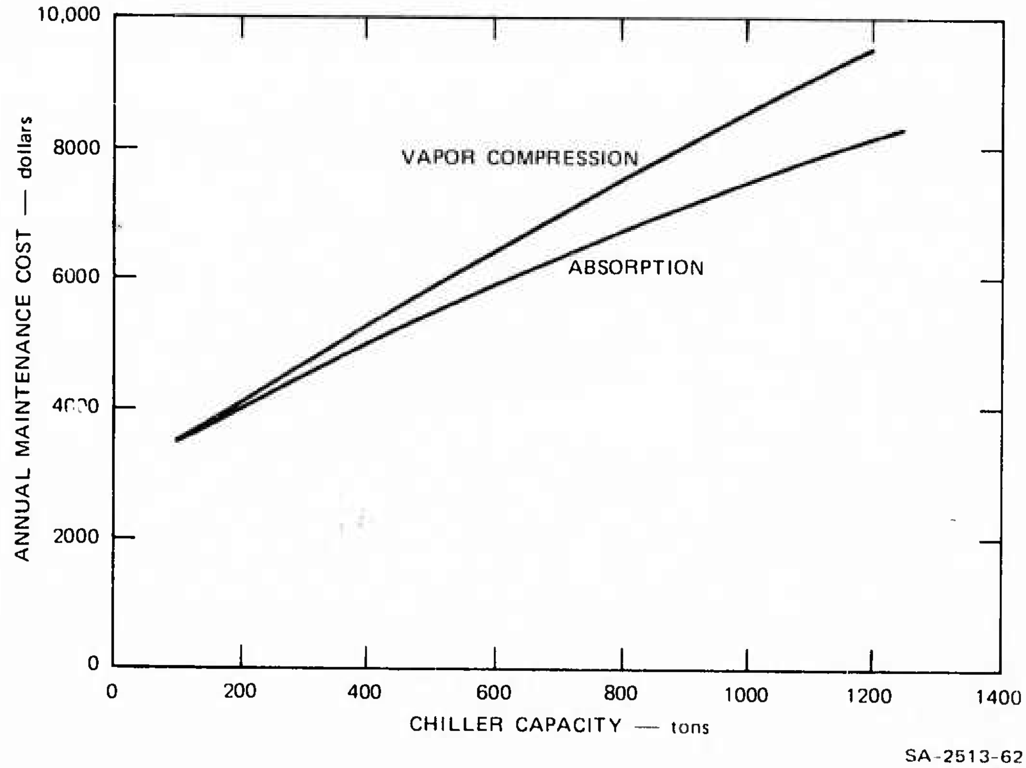

FIGURE A-20 ANNUAL MAINTENANCE COSTS AS A FUNCTION OF CHILLER CAPACITY

Design Life

The following values of "design life" may be taken as typical for the types of facilities enumerated

Diesel: 30 years

Gas turbine: 25 years

Steam plant: 30 years

HTW transmission: 25 years

HTW generator: 30 years

Absorption chiller: 35 years

Vapor compression chiller: 30 years

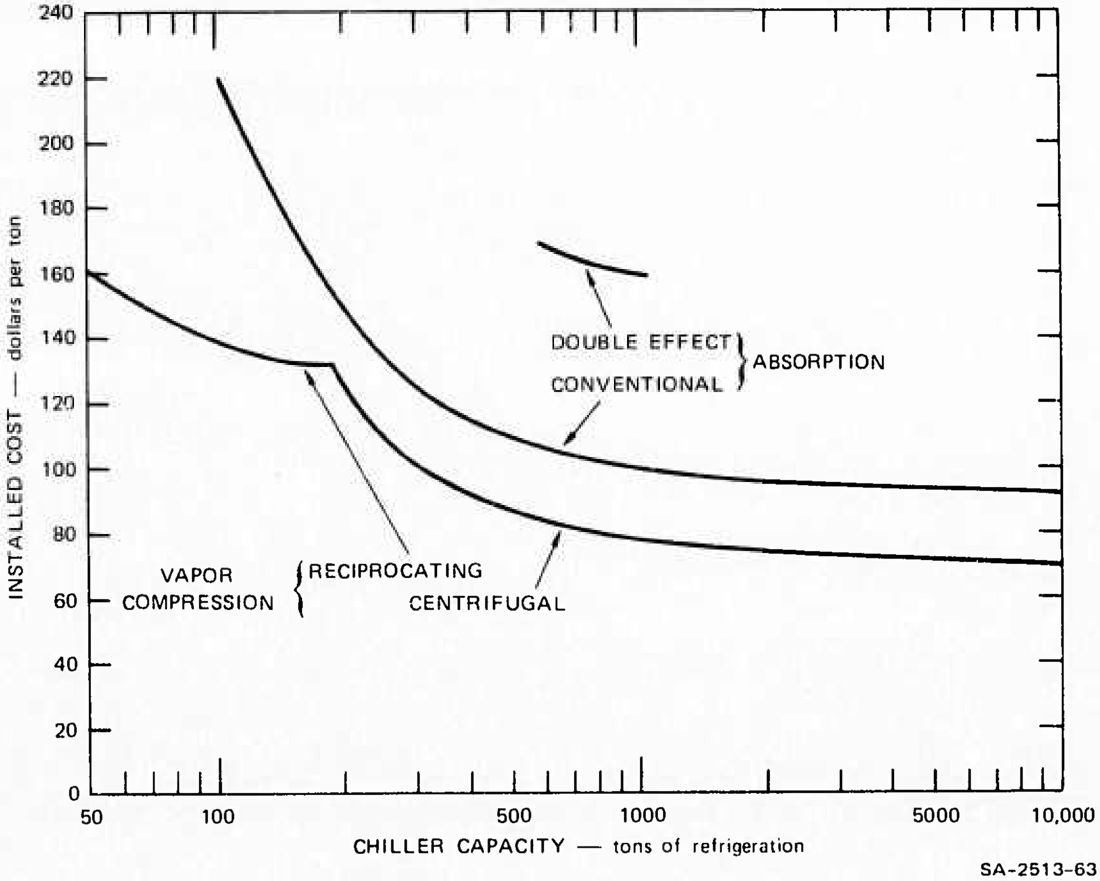

FIGURE A-21 AIR CONDITIONING CHILLER INSTALLED COST AS A FUNCTION OF CHILLER CAPACITY

Appendix B

ENERGY LOAD DATA FOR MILITARY INSTALLATIONS

Introduction

This appendix presents the derivation of the energy load patterns used in Volume I for the evaluation of fuel consumption and costs of the different types of energy systems. The load patterns were derived from data on utility use on military installations. Although primary emphasis was directed toward military bases of the U.S. Army and the U.S. Air Force, those of the U.S. Navy were also considered. Unless otherwise noted, data collected was based on FY72, the last full year compiled at the time of the field investigation.

Two primary means of obtaining utility data were conducted: (1) annual reports by the headquarters of each of the three services; and (2) interviews with base engineering and utility personnel at several military installations.

Source one (annual reports) was useful in evaluating the broad spectrum of utility use and services on large numbers of military installations across the country. These reports included:

Army

Facilities Engineering, Annual Summary of Operations
(Summary of DA 2788 reports, 1972)

Air Force

USAF Cost Standards Development
(Summary of AF-C128 reports, FY 1972)
(Summary of AF-C172 reports--SAC--to March 1972)

Pages 31-32 blank

Navy

Cost of Utility Services, NAVFAC, Western Division
(Summary of UCAR's FY 1970)*

However, as only annual data was shown in these reports, this source had to be supplemented by actual visits to individual military bases.

Source two (on-base interviews) provided the monthly, daily, and hourly information on utility consumption and utility services that was necessary both for correlation to the annualized data and for the development of utility load factors used in the analysis of the Total Energy concept. The installations visited included:

Ft. Ord, California
Ft. Knox, Kentucky
Minot AFB, North Dakota
Travis AFB, California
Nellis AFB, Nevada
Defense Construction Supply Center (DCSC), Ohio
Mare Island Naval Shipyard, California

In addition to the Director of Facilities Engineering, the Base Civil Engineer, or the Public Works Officer for each base, from three to six individuals within each base's utilities office were interviewed.

Even though considerable utility data were available within the files of the base utility offices (even, in some cases, to 15-minute electrical consumption and peak loads), the biggest problem encountered was that of centralized metering. That is, most of the bases had single electrical and gas meters "at the gate" only, without submetering or separate metering of even major component functions on the base. In effect, this meant that energy consumption and peaking data for electrical, heating, and cooling requirements associated with troop housing, family housing, administrative and industrial functions, hospitals, water supply

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*Not required in subsequent years.

development, sewage treatment, and so forth were for the most part aggregated into single meter recordings. Where multiple metering did occur, such was mainly used to separate family housing from other base functions.

Energy Load Model

Hour-by-hour energy loads were derived for five representative days of the year; these were thermal, electric, and air conditioning loads. The five representative days are:

- High heating day, i.e., a cold midwinter day.
- Moderate heating day.
- Day with no space heating (there is still a thermal load for other purposes) or air conditioning, i.e., a mild spring or fall day.
- Moderate air conditioning day.
- High air conditioning day, i.e., a hot midsummer day.

Each of the five days represents a certain number of days of the year, varying with the climate. Three climates were included: Northcentral (NC), Southeast (SE), and Southwest (SW).

The number of days of the year of each type and the average temperature for each type of day are given in Table B-1. These figures are based on FY72 temperature data, adjusted for historical norms.*

General Base Description

Table B-2 gives the resident and nonresident populations for the bases visited. For the purpose of utility analysis, an "effective" population was used; this was derived by combining 100 percent of the resident and one-third (eight twenty-fourths of the day) of the nonresident populations.

*Climatological Data National Summary, U.S. Department of Commerce, National Oceanic and Atmospheric Administration.

Table B-1

HEATING AND COOLING DAYS AND AVERAGE TEMPERATURES

	Days per Year			Average Temperature (°F)		
Type of Day	NC	SE	SW	NC	SE	SW
High heating	91	56	40	11°F	40°F	41°F
Moderate heating	180	116	79	41	53	54
No space heating or cooling	54	71	70	70	70	70
Moderate cooling	27	82	116	75	75	79
High cooling	13	40	60	84	84	95

As indicated, 44 to 63 percent of the base residents live in on-base family housing;* the remainder were quartered in troop/dormitory housing, BOQ, NCO, hospital, and other smaller facilities. The nonresident population, of course, live off-base in neighboring communities.

In order to gain an impression of likely TE system transmission distances from, say, a central plant to the farthest energy-using structure, a simplified boundary analysis was made. In effect, this boundary replaces the actual physical, and often random, configuration of the total base (including all open areas) with a rectangular boundary that most nearly encompasses only the built-up areas of energy consuming structures. As noted in Table B-4, runways, taxiways, and peripheral open training areas are excluded in the simplified boundary. Its use then is limited to heat (or cooling) transmission considerations only. For electrical transmission, all types of areas would, of course, have to be considered even though they may be open and space-intensive; e.g., runway lighting and security lighting.

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*Table B-3 illustrates average family housing unit size.

Table B-2

BASE POPULATION AND FAMILY HOUSING

Base	Population			Family Housing Units (Fhu)					
	Resident	Non-Resident	Effective	Number	Occupancy Rate (percent)	Occupied Fhu	Family Density	Population Housed	Percent of Resident Population
Ft. Knox	32.800	12,900	37,100	4,370	92%	4,020	4.7	18,800	57%
Ft. Ord	31,000	5,200	32,700	3,264	98	3,200	3.8	12,000	40
Minot AFB	13,400	4,000	14,700	2,462	99	2,440	3.45	8,500	63
Travis AFB	13.300	9.500	16,500	2,169	98	2.120	3.55	7,550	57
Nellis AFB	8,800	4,400	10,200	1,297	99	1,285	3.5	4,500	51
Mare Is. Shipyard	4,000	7,900*	11,000 (8 hr)*	481	100	481	3.5	1,700	44
DCSC†	200	4,200	4,400 (8 hr)	12	--	--	--	--	--

*Approximately 900 on swing and graveyard shifts.

†Defense Construction Supply Center, Columbus, Ohio.

Table B-3

FAMILY HOUSING UNIT SIZE

Base	Unit Size (ft^2)	Number of Housing Units*
Grand Forks AFB	1,520	600
Carswell AFB	1,500	154
Minot AFB	1,490	999
Ft. Knox	1,420	4,370
Ft. Ord	1,400	3,264
Pease AFB	1,380	13
Whiteman AFB	1,370	488
Beale AFB	1,310	342
Loring AFB	1,260	240
Nellis AFB	1,250	1,297
Average	1,400	

*Does not include all units on base in some cases.

Table B-4

DEVELOPED AREA CONFIGURATION*

Base	Width (miles)	Length (miles)	Width to Length Ratio
Ft. Knox	2.6	2.9	1:1.1
Ft. Ord	1.6	3.6	1:2.2
Minot AFB	1.5	1.9	1:1.3
Travis AFB	1.2	1.75	1:1.5
Nellis AFB	0.64	1.67	1:2.6
DCSC	0.45	1.25	1:2.8
Mare Island	0.75	2.5	1:3.3

*Spatial configurations are based on area of building concentration (including family housing)--exclusive of runways, taxiways, golf courses, open training areas, and other peripheral open spaces--and therefore the indicated figures should not be used as a measure of overall base size.

Table B-5 gives the distribution of floor space by type of building for Ft. Ord and Ft. Knox. The figure of 25 percent for family housing was used in cases where family housing floor space was missing.

Table B-5

DISTRIBUTION OF FLOOR SPACE
BY TYPE OF BUILDING

	Percent of Floor Space	
	Ft. Ord	Ft. Knox
Troop housing	26%	24%
Family housing	24	25
Community services	6	6
Administration	3	3
Storage	4	5
Hospital/medical	4	2
Other	33	35
	100%	100%

Electrical Consumption and Peak Electric Loads

Electrical consumption data are shown in Tables B-6 and B-7 for the bases visited. Table B-6 gives the total electrical energy consumed by the base and the peak demands. Table B-7 is limited to family housing on a sample basis where separate metering existed.

The peak kW demand was determined by first finding the peak month of consumption, then the day of maximum demand of that month, and finally, by examining automatic recording meter tapes, the peak one-half hour during that day. Similarly, the minimum day peak kW demand was found by seeking the minimum month, its minimum day (excluding Saturdays and Sundays), and the maximum one-half hour peak during that day.

Table B-6

ANNUAL ELECTRICAL CONSUMPTION AND PEAK DEMAND--
TOTAL BASE

Base	Annual Electrical Consumption (thousands of kWh)	Peak Demand			
		Maximum Day		Minimum Day	
		kW	Ratio kW/kWh	kW	Ratio kW/kWh
Knox	137,420	30,800	0.00022	21,500	0.00015
Ord	79,500	13,780	0.00017	12,100	0.00015
Minot	65,290	12,700	0.00019	8,400	0.00013
Travis	74,700	12,570	0.00017	10,900	0.00015
Nellis	65,280	13,320	0.00020	8,460	0.00013
Mare Is.	127,250	24,000	0.00019	17,000	0.00013
DCSC	33,760	7,300	0.00022	6,650	0.00020

Figure B-1 presents a graphical plot of the foregoing electrical consumption and peak demands. The curves show a reasonably straight line relationship between consumption and peak power demand.* Accordingly, the slope of the curves can be used for approximating peak load requirements for bases where only annual electrical consumption is known. Multiplying the total annual electricity consumed in kWh by 0.0002 approximates the peak kW demand required by the base. By multiplying the total annual kWh by 0.00014, the minimum daily peak demand (exclusive of Saturdays and Sundays) can be approximated. For example, for a 100,000,000 kWh annual consumption, the daily peak loads will vary between 14 and 20 MW over the 261 work days of the year.

Slightly over one hundred military installations were first reviewed from information contained in the Source One reports referred to previously.

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*Peak power demand is a measure of total instantaneous watts of power "on the line" as recorded, say, during a certain 15 to 30 minute period, and is not necessarily a measure of total connected capacity.

Table B-7

ANNUAL ELECTRICAL CONSUMPTION AND PEAK DEMAND--
FAMILY HOUSING UNITS ONLY

Base	Units in Sample	Thousands of kWh	Peak Demand Maximum Day		kWh/Person	kW/Person	kWh/Fhu	Peak kW/Fhu
			kW	kW/kWh				
Ord	900	5,527	1,225	0.00022	1,600	0.4	6,100	1.4
Minot	2,440	22,200	6,000	0.00027	2,600	0.7	9,100	2.5
Travis	900	7,490	1,640	0.00022	2,300	0.5	8,300	1.8
Nellis	1,285	13,583	3,230	0.00023	3,000	0.7	10,500	2.5
Mare Is.	400	3,607	--	--	2,600	--	9,000	--

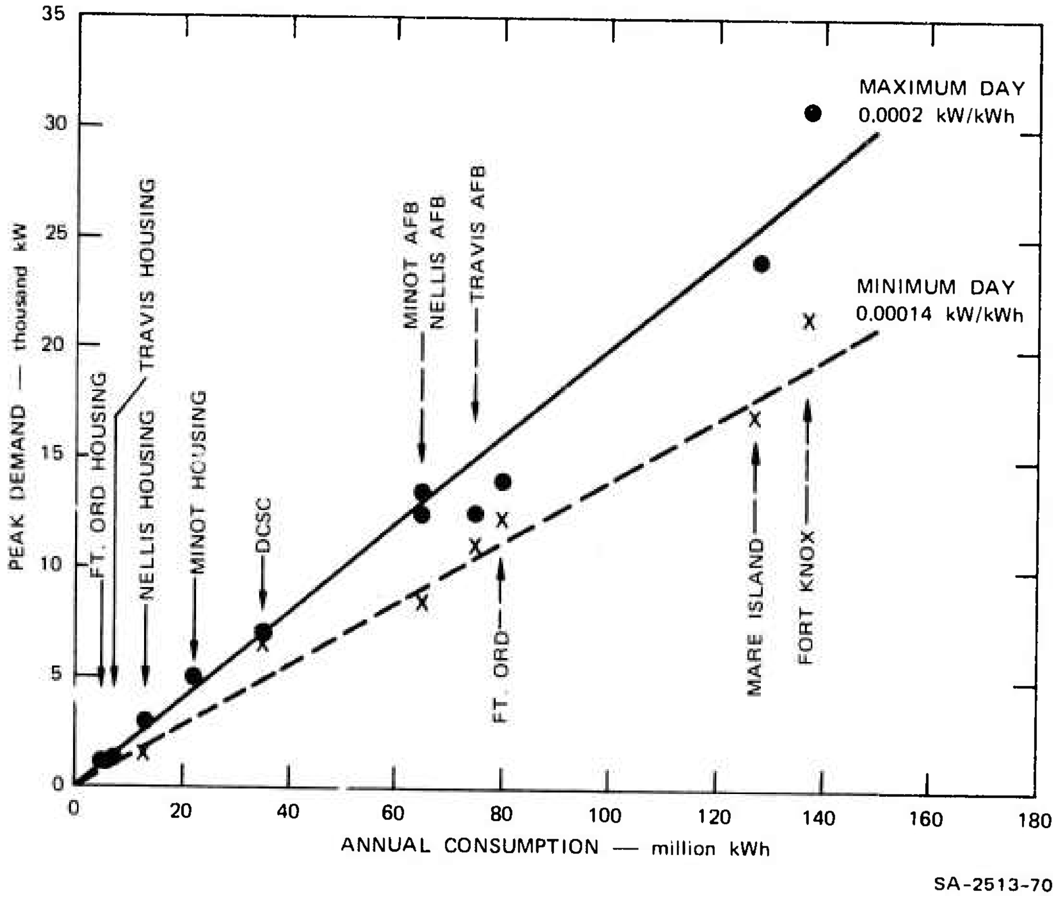

FIGURE B-1 ANNUAL ELECTRICAL CONSUMPTION VERSUS PEAK DEMAND

The basis of this preliminary review centered around size (utilizing water as well as electricity consumption as parameters), geographic location, function, and special considerations such as on-site power generation, sanitary sewage, and water treatment. From this initial screening a sample of seventy representative installations was selected, with peak demands ranging from one to fifty MW, calculated from the annual consumption on the basis of 0.0002 kW/kWh.

First, however, for comparability, it was necessary to adjust upwards the USAF annual electrical consumption (as reported in their C128 Summaries) by the electrical energy consumed by on-base family housing. (USAF family housing data is reported separately from that of actual base operations and complete family housing data was not readily available.) Table B-8 presents typical relationships between the electrical consumption of family housing and that of the base itself.

Table B-8

PERCENT OF TOTAL USAF BASE
ANNUAL ELECTRICAL CONSUMPTION
APPLICABLE TO FAMILY HOUSING UNITS

Base	Percent
Minot	34%
Travis	24
Offutt	20
Nellis	20
Beale	21
Westover	24
Loring	29
Castle	17
Carswell	24
Average	24% (of total base kWh)

After making the appropriate adjustments to USAF installations, the ranking as shown on Table B-9 could then be established. Based on this sample, peak demand is 17 MW and the median is 14 MW.

These peak demands include air conditioning requirements as they existed in FY72. Downward adjustment of electrical load requirements to exclude air conditioning is shown later.

Table B-9

PEAK ELECTRICAL DEMANDS FOR SELECTED BASES IN FY72*

Base	Peak Demand (MW)	Base	Peak Demand (MW)
Wright Patterson (AFLC)	51.4	Randolph AFB	13.6
Ft. Bragg	43.8	Nellis AFB (TAC)	13.3
Ft. Meade	42.2	Ft. Devens	12.8
Tinker AFB (AFLC)	40.6	Minot AFB (SAC)	12.7
Kelley AFB (AFLC)	36.0	Lemore NAS	12.6
Ft. Hood (HQ)	33.5	Griffiss AFB (AFLC)	12.6
Keesler AFB (ATC)	32.6	Travis AFB (MTC)	12.6
Ft. Benning	31.3	Ft. Lee	11.5
Ft. Knox	30.8	Ft. Sheridan	11.4
Ft. Lewis	29.6	Ft. Carson	11.3
Bremerton NSY	28.2	Presidio of S.F. (HQ)	11.1
McClellan AFB (AFLC)	25.5	Ft. Polk	11.1
Robbins AFB (AFLC)	25.2	Loring AFB (SAC)	11.0
Offutt AFB (HQ)	24.6	Westover AFB (SAC)	10.8
Mare Island NSY	24.0	Dover AFB (MAC)	10.4
Ft. Bliss	23.6	Lowry AFB (ATC)	10.0
Ft. Leonard Wood	23.3	Altus AFB (MTC)	9.0
Hill AFB (AFLC)	22.3	George AFB (TAC)	8.6
Ft. Sill	22.2	Forbes AFB (TAC)	8.4
Ft. Campbell	20.9	Ft. Benj. Harrison	8.4
Alameda NAS	19.4	Carswell AFB (SAC)	7.8
Ft. Gordon	19.1	Columbus DCSC	7.3
Ft. Dix	18.9	Castle AFB (SAC)	7.2
Ft. Rucker	18.9	Moody AFB (TAC)	7.2
Ft. Belvoir	18.4	Columbus AFB (TAC)	6.6
Ft. Riley	18.3	Pope AFC (TAC)	5.2
McDill AFB (TAC)	17.2	Moffett Field NAS	5.0
Ft. Jackson	16.6	Vance AFB (ATC)	4.6
Ft. Monmouth	15.7	Ft. McPherson	3.9
Langley AFB (TAC)	15.6	Ft. Monroe	3.6
Luke AFB (TAC)	15.2	Ft. Wolters	3.6
Ft. Stewart	15.1	Carlisle Barracks	3.0
Ft. Eustis	14.9	Ft. Lawton	2.9
Chanute AFB (ATC)	14.6	Camp Drum	2.5
Ft. Ord	13.8	Camp Pickett	1.0

*Median, 14 MW; average, 17 MW.

Hourly Electric Demands

Typical diurnal cycles of electric demands were developed from the limited data collected on hourly electric demands for a few selected days of the year for a few bases.

The typical peak electric demands for each of the five representative days of the year are given in the following tabulation as a percent of the peak demand for the year.

Type of Day	Percent
High heating	95%
Moderate heating	85
No space heating or cooling	75
Moderate cooling	85
High cooling	95

Table B-10 gives the hourly electric demands for each type of day as a percent of the peak demand for the day. Since data were not available on the electric demands exclusive of the air conditioning load, the same diurnal pattern was used for the moderate cooling and high cooling days as for the no space heating or cooling day. The figures for the high heating day are based on data from Minot AFB in January 1972. Those for the moderate heating day are based on Ft. Ord, December 1971; for the nonspace heating days, on Ft. Ord, April and May of 1973, and on Ft. Knox, April 1972.

Table B-10

HOURLY ELECTRIC DEMANDS

Hour of Day	Percent of Daily Peak Demand		
	High Heating Day	Moderate Heating Day	No Space Heating Day
M	80%	66%	56%
1	79	62	54
2	77	60	51
3	76	59	50
4	78	60	51
5	80	62	52
6	83	70	55
7	90	77	63
8	93	85	78
9	94	90	87
10	95	92	90
11	96	92	90
12	95	92	88
13	94	90	87
14	93	88	85
15	93	88	84
16	94	89	82
17	97	92	82
18	100	97	84
19	100	100	90
20	99	99	100
21	96	95	97
22	92	89	86
23	86	77	75

Comparison of Electrical and Thermal Loads

Table B-11 gives the annual consumption of fuel for heating energy (including that used for cooking) and the annual electricity consumption. Also shown in the table is the ratio of the annual consumption of thermal and electrical energy.

Table B-11

ANNUAL ELECTRICITY AND FUEL CONSUMPTION AND AIR CONDITIONING CAPACITY

Base	Annual Consumption		Ratio of Electric to Thermal Energy	Air Conditioning (tons)	Floor Space (millions of ft^2)	kWh/ft^2	Btu/ft^2	Electricity for Air Conditioning as Percent of Electricity Consumption	Annual Electricity Consumption Excluding Air Conditioning (millions of kWh)
	Electricity (millions of kWh)	Fuel (billions of Btu)							
Ft. Bragg	219	3,146	4.2	7,500	29.0	7.5	108	5.1%	207
Ft. Hood	167	1,589	2.8	16,000	21.5	7.8	74	28.6	119
Ft. Benning	156	2,295	4.3	8,300	28.8	5.4	80	12.2	137
Ft. Lewis	148	2,873	5.7	270	26.0	5.7	110	0.1	147
Ft. Knox	138	2,913	6.2	7,600	25.2	5.5	115	7.6	127
Ft. Bliss	117	1,713	4.3	3,800	22.5	5.3	76	5.9	110
Ft. Leonard Wood	116	1,859	4.7	7,200	16.8	6.9	110	10.0	104
Ft. Sill	110	1,340	3.5	7,700	17.2	6.5	78	13.3	96
Ft. Campbell	104	1,504	4.2	3,900	17.2	6.1	87	5.2	99
Alameda NAS	97	1,620	4.9	n.a.*	--	--	--	n.a.	--
Ft. Gordon	95	1,435	4.4	8,900	11.9	8.0	120	16.4	79
Ft. Rucker	94	818	2.5	8,000	10.4	9.0	78	20.9	74
Ft. Belvoir	92	1,471	4.6	7,200	12.1	7.5	121	11.3	82
Ft. Jackson	83	1,201	4.2	6,500	12.9	6.4	93	16.4	69
Ft. Ord	80	1,731	6.3	300	17.7	4.5	98	0.1	79
Ft. Monmouth	78	1,177	4.4	3,900	9.2	8.5	128	7.7	72
Travis AFB	74	1,020	4.0	2,300	--	--	--	4.6	71
Ft. Eustis	74	1,049	4.1	4,100	9.2	8.1	114	9.3	67
Minot AFB	65	1,125	5.0	1,300	6.2	10.5	180	1.2	64
Ft. Devens	64	1,300	5.9	1,800	13.2	4.9	98	1.9	63
Ft. Lee	57	1,009	5.1	3,900	10.9	5.3	93	9.9	51
Ft. Sheridan	56	1,016	5.2	2,700	8.8	6.5	115	5.8	53
Presidio of S.F.	55	784	4.1	600	9.7	5.7	81	0.3	55
Ft. Polk	55	975	5.2	3,400	11.7	4.7	83	14.9	47
Loring AFB	55	1,457	7.7	n.a.	n.a.	--	--	---	--
Westover AFB	54	1,116	6.0	n.a.	n.a.	--	--	--	--
Ft. B. Harrison	42	723	5.0	2,700	6.9	6.1	105	7.8	38
Carswell AFB	39	403	3.0	3,100	n.a.	--	--	19.2	29
Ft. McPherson	19	216	3.2	1,600	2.8	7.0	77	14.4	16
Average					6.6				

*Not available.

For reasons of comparability, the prior sample of 70 bases was reduced to 29. Atypical bases such as logistic bases, shipyards, supply depots, and school- and prison-oriented bases have been eliminated. Where the total floor space of family housing was not readily available, an allowance of 24 percent of the total base floor space for family housing was made, on the basis of Table B-5. Table B-8 shows the basis for this adjustment.

In a total energy system the air conditioning might be operated by heat rather than electricity. Therefore, the electrical consumption for air conditioning was estimated for each of the bases using recorded degree day (cooling) data, assumed temperature gradient, base-installed air conditioning capacity, and appropriate conversior factors. The estimated electrical consumption, excluding air conditioning, is also given in Table B-11.

The ratio of annual fuel consumption to electricity consumption, excluding air conditioning, is given in Table B-12. Since the fuel consumption is dependent on climate, the ratios have been grouped by climate.

Heating Loads

Table B-12 provides a relationship between the annual fuel consumption for heat needs and the annual electricity consumption. The next steps are to break down the annual heating loads into the heat loads for each of the five representative days of the year, and then to break down those daily heat loads into the hourly heat loads.

The heat demands of the bases include, besides space heating, hot water, cooling, industrial, and other miscellaneous uses. The heat load for hot water is estimated in Table B-13 for five bases. The estimates are based on 18 gallons per day for the resident population (adjusted for differences in hot water consumption between family housing, and barracks

Table B-12

RATIO OF ANNUAL FUEL CONSUMPTION
TO ELECTRICITY CONSUMPTION,
EXCLUDING AIR CONDITIONING

Base	Thousands of Btu/kWh						
	NC NE	EC	SE	SC	SW	W	NW
Ft. Bragg			15				
Ft. Hood				13			
Ft. Benning			16				
Ft. Lewis							19
Ft. Knox				22			
Ft. Bliss					15		
Ft. Leonard Wood				17			
Ft. Sill				14			
Ft. Campbell		15					
Alameda NAS						16	
Ft. Gordon			18				
Ft. Rucker			11				
Ft. Belvoir		18					
Ft. Jackson			17				
Ft. Ord						21	
Ft. Monmouth		16					
Travis AFB						14	
Ft. Eustis		17					
Minot AFB	17						
Ft. Devens	20						
Ft. Lee		19					
Ft. Sheridan		18					
Presidio of S.F.						14	
Ft. Polk			20				
Loring AFB	26						
Westover AFB	20						
Ft. Benjamin Harrison		18					
Carswell AFB				12			
Ft. McPherson			13				
Averages	21	17	16	16	15	16	19

Table B-13

ANNUAL ENERGY FOR DOMESTIC HOT WATER

Base	Billions of Btu	Percent of Total Heating Energy Consumption
Ft. Knox	221,000	7.5%
Ft. Ord	206,000	11.9
Travis AFB	96,000	9.4
Minot AFB	91,000	8.1
Nellis AFB	62,000	15.0

and dormitories) and three gallons per day for the nonresident population. The population figures were given in Table B-12.

Table B-13 indicates that the energy demand for hot water heating can vary between 8 and 15 percent, depending upon climate (i.e., subject to the magnitude of the space heating requirement). On average, the hot water heating requirement can be considered to be 1 percent of the annual consumption per month. Using national averages, the cooking requirement for thermal energy is estimated to be approximately one-half percent per month.

The heating loads by month for the five bases are shown in Figure B-2 as a percent of the annual heating load. The minimum monthly heating load during the months with little or no space heating is about 3 percent of the annual heating load, which suggests that the monthly heating load for hot water, cooking, and other nonspace heating uses is about 3 percent of the total annual heating load.

The derivation of the daily heating loads for a base with a 10 MW peak electric demand is shown in Table B-14. From Figure B-1, the annual electricity consumption is 10,000 kW/(0.0002 kW/kWh) = 50 million kWh.

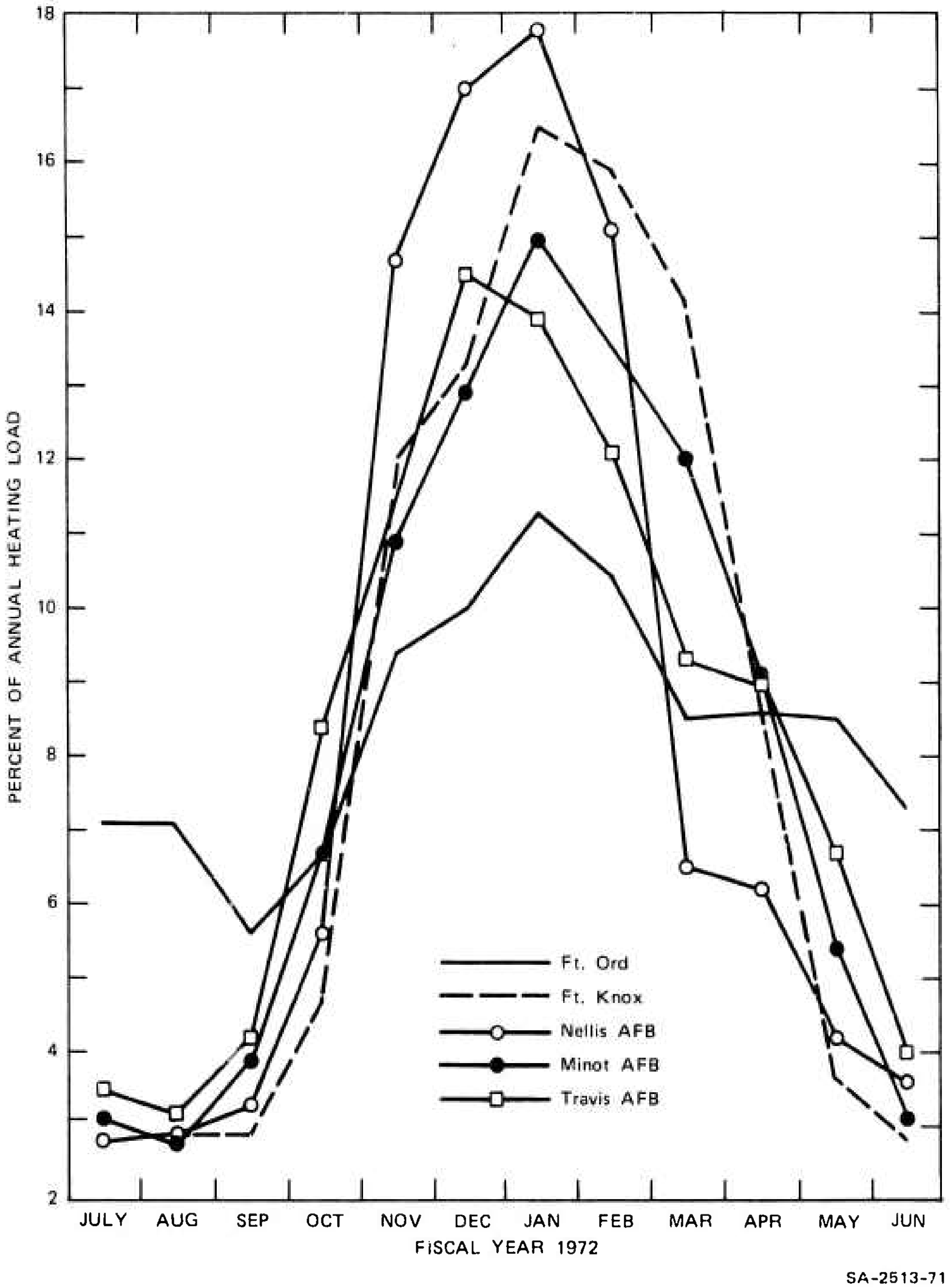

FIGURE B-2 HEATING LOADS BY MONTH

Table B-14

DERIVATION OF DAILY HEATING LOADS FOR A 10 MW BASE

	NC	SE	SW
Annual electricity consumption (millions of kWh)	50	50	50
Ratio of annual heating load to electricity (thousands of Btu/kWh)	25	15	10
Annual heating load (billions of Btu)	1,250	750	500
Monthly heating load, excluding space heating, as percent of annual	2	3	3
Space heating load (billions of Btu)	950	480	320
Number of high heating days per year	91	56	40
Number of moderate heating days per year	180	116	79
Ratio of space heating loads: high heating day to moderate heating day	70/30	70/30	70/30
Space heating load (millions of Btu)			
High heating day	5,647	4,538	4,331
Moderate heating day	2,423	1,947	1,858
Daily heating load excluding space heating (millions of Btu)	833	750	500
Total daily heating load (millions of Btu)			
High heating day	6,480	5,288	4,831
Moderate heating day	3,256	2,697	2,358

Ratios of the annual heating load to electricity consumption from 10,000 to 25,000 Btu per kWh were selected to cover the range indicated in Table B-12, and multiplied times the annual electricity consumption to give the total annual heating load. The nonspace heating load was subtracted from the total to give the annual space heating load. From the average temperature in Table B-1, a 70/30 ratio of heating loads for high heating days and moderate heating days was estimated. With this ratio, and the number of days in the year of each type, also from Table B-1, the daily heating loads were determined for each type of day.

The hourly heating loads for each type of day are given in Table B-15 as a percent of the daily heating load. The figures for the space heating days are based on data for Ft. Knox in January 1972. The figures for the nonspace heating days are based on data for Ft. Knox in June 1972.

Table B-15

HOURLY HEATING LOADS

Hour of Day	Percent of Daily Heating Load	
	High or Moderate Heating Day	No Space Heating Day
M	4.2%	2.7%
1	4.1	2.6
2	4.0	2.5
3	4.1	2.6
4	4.2	2.7
5	4.2	3.0
6	4.3	3.5
7	4.4	4.0
8	4.5	4.7
9	4.5	5.0
10	4.4	5.3
11	4.3	5.5
12	4.2	5.3
13	4.0	5.1
14	3.9	5.0
15	3.8	4.9
16	3.9	4.8
17	4.0	4.9
18	4.1	5.1
19	4.1	5.2
20	4.2	4.7
21	4.2	4.2
22	4.2	3.6
23	4.2	3.1

Air Conditioning

Required air conditioning capacities for the various types of buildings on military installations, based on U.S. averages, are given in Table B-16. The weighted average of 2.81 tons per 1,000 ft^2 were modified for each of the three climates on the basis of the following design criteria:

	Climate		
	NC	SE	SW
Design temperature (°F)			
Dry bulb	91	95	106
Wet bulb	72	77	76
Dew point (°F)	64	70	63

Table B-16

AIR CONDITIONING CAPACITY REQUIREMENTS
BY BUILDING TYPE
(U.S. Average)

	Tons per 1,000 Ft^2	Fraction of Total Base Floor Space	Weighting Factor
Barracks/dormitories	3	0.25	0.75
Family housing	2	0.24	0.48
Administration	2.3	0.03	0.07
Storage	0.1	0.05	0.01
Hospital/medical	4	0.03	0.12
Community services	6	0.06	0.36
Other (such as mess halls, training, shops)	3	0.34	1.02
Weighted average 2.8 tons/1,000 ft^2		1.00	2.81

The derivation of the total air conditioning capacity and the daily air conditioning loads for a 10 MW base is shown in Table B-17.

Table B-17

DERIVATION OF AIR CONDITIONING CAPACITY AND DAILY LOADS

	Climate		
	NC	SE	SW
Total floor space* (10^6 ft^2)	7.6	7.6	7.6
Air conditioning capacity			
Tons per 1,000 ft^2	2.0	2.7	3.9
Total capacity† (tons)	7,600	10,250	14,800
Load factors‡			
High cooling day	0.56	0.70	0.62
Moderate cooling day	0.30	0.37	0.29
Daily air conditioning load (ton-hrs)			
High cooling day	102	172	220
Moderate cooling day	55	91	103

*Annual electricity consumption of 50 million kWh divided by 6.6 kWh per ft^2 from Table B-11.

†Air conditioning of 80 percent of the floor space, and load diversity factor of 62.5 percent.

‡Load factor multiplied by 24 hours equals number of equivalent full load operating hours.

The hourly air conditioning loads are given in Table B-18 as a percent of the air conditioning load for the day.

Table B-18

HOURLY AIR CONDITIONING LOADS AS PERCENT OF DAILY LOAD

Hour of Day	Moderate Cooling Day			High Cooling Day		
	NC	SE	SW	NC	SE	SW
M	1.5%	3.0%	2.2%	2.9%	3.2%	3.6%
1	0.7	2.6	1.6	2.5	2.9	3.3
2	0	2.0	0.8	2.0	2.5	3.1
3	0	1.4	0.2	1.7	2.2	2.8
4	0	1.0	0	1.4	1.9	2.6
5	0	0.8	0	1.1	1.8	2.5
6	0	0.8	0	1.1	1.8	2.5
7	0	0.8	0	1.2	1.9	2.5
8	0	1.0	0.2	1.7	2.2	2.6
9	0.7	2.2	1.4	2.5	2.8	3.2
10	2.8	3.4	3.2	3.6	3.7	3.8
11	5.2	4.6	5.6	4.9	4.7	4.4
12	6.8	5.8	6.2	5.8	5.4	5.0
13	8.3	6.6	7.8	6.6	6.0	5.4
14	9.0	7.3	8.2	7.0	6.4	5.7
15	9.8	7.7	9.2	7.4	6.7	5.9
16	9.8	7.9	9.2	7.4	6.7	6.0
17	9.8	7.9	9.2	7.4	6.7	6.0
18	9.1	7.7	8.8	7.0	6.5	5.9
19	8.1	6.9	7.8	6.5	6.0	5.5
20	6.5	6.0	6.2	5.6	5.4	5.1
21	5.2	5.0	5.2	4.9	4.7	4.6
22	3.9	4.2	4.2	4.2	4.2	4.2
23	2.8	3.4	3.2	3.6	3.7	3.8
	100.0%	100.0%	100.0%	100.0%	100.0%	100.0%

Hourly Energy Loads

The hourly energy loads--electricity, heating, and air conditioning--for a 10 MW base in each of the three climates are given in Tables B-19 to B-21. The electricity loads were obtained by multiplying the hourly electric demands given as a percent of the peak daily demand in Table B-10, times the peak electric demand for the respective type of day. The heating and air conditioning loads were obtained by multiplying the hourly loads given as a percent of the total daily load in Table B-15 for heating, and Table B-18 for air conditioning, times the total heating or air conditioning load for the respective type of day.

The loads for the other base sizes--5, 20, and 40 MW peak electric demand--were assumed to be proportional to the peak electric demand.

Table B-19

HOURLY ENERGY LOADS BY TYPE OF DAY--
NORTH CENTRAL, 10 MW BASE

Hour of Day	High Heating Day		Moderate Heating Day		No Space Heating or Cooling Day		Moderate Cooling Day			High Cooling Day		
	Electric (MW)	Heating (millions of Btu/hr)	Electric (MW)	Heating (millions of Btu/hr)	Electric (MW)	Heating (millions of Btu/hr)	Electric (MW)	Heating (millions of Btu/hr)	Cooling (thousands of tons)	Electric (MW)	Heating (millions of Btu/hr)	Cooling (thousands of tons)
0	7.600	272.2	5.610	136.8	4.200	22.5	4.760	22.5	0.8	5.320	22.5	3.0
1	7.505	265.7	5.270	133.5	4.050	21.7	4.590	21.7	0.4	5.130	21.7	2.5
2	7.315	259.2	5.100	130.2	3.825	20.8	4.335	20.8	0.0	4.845	20.8	2.0
3	7.220	265.7	5.015	133.5	3.750	21.7	4.250	21.7	0.0	4.750	21.7	1.7
4	7.410	272.2	5.100	136.8	3.825	22.5	4.335	22.5	0.0	4.845	22.5	1.4
5	7.600	272.2	5.270	136.8	3.900	25.0	4.420	25.0	0.0	4.940	25.0	1.1
6	7.885	278.6	5.950	140.0	4.125	29.2	4.675	29.2	0.0	5.225	29.2	1.1
7	8.550	285.1	6.545	143.3	4.725	33.3	5.355	33.3	0.0	5.985	33.3	1.2
8	8.835	291.6	7.225	146.5	5.850	39.2	6.630	39.2	0.0	7.410	39.2	1.7
9	8.930	291.6	7.650	146.5	6.525	41.6	7.395	41.6	0.4	8.265	41.6	2.5
10	9.025	285.1	7.820	143.3	6.750	44.1	7.650	44.1	1.5	8.550	44.1	3.7
11	9.120	278.6	7.820	140.0	6.750	45.8	7.650	45.8	2.9	8.550	45.8	5.0
12	9.025	272.2	7.820	136.8	6.600	44.1	7.480	44.1	3.7	8.360	44.1	5.9
13	8.930	259.2	7.650	130.2	6.525	42.5	7.395	42.5	4.6	8.265	42.5	6.7
14	8.835	252.7	7.480	127.0	6.375	41.6	7.225	41.6	4.9	8.075	41.6	7.1
15	8.835	246.2	7.480	123.7	5.300	40.8	7.140	40.8	5.4	7.980	40.8	7.5
16	8.930	252.7	7.565	127.0	6.150	40.0	6.970	40.0	5.4	7.790	40.0	7.5
17	9.215	259.2	7.820	130.2	6.150	40.8	6.970	40.8	5.4	7.790	40.8	7.5
18	9.500	265.7	8.245	133.5	6.300	42.5	7.140	42.5	5.0	7.989	42.5	7.1
19	9.500	265.7	8.500	133.5	6.750	43.3	7.650	43.3	4.5	8.550	43.3	6.6
20	9.405	272.2	8.415	136.8	7.500	39.2	8.500	39.2	3.6	9.500	39.2	5.7
21	9.120	272.2	8.075	136.8	7.275	35.0	8.245	35.0	2.9	9.215	35.0	5.0
22	8.740	272.2	7.565	136.8	6.450	30.0	7.310	30.0	2.1	8.170	30.0	4.3
23	8.170	272.2	6.545	136.8	5.625	25.8	6.375	25.8	1.5	7.125	25.8	3.7

Table B-20

HOURLY ENERGY LOADS BY TYPE OF DAY--
SOUTHEAST, 10 MW BASE

Hour of Day	High Heating Day		Moderate Heating Day		No Space Heating or Cooling Day		Moderate Cooling Day			High Cooling Day		
	Electric (MW)	Heating (millions of Btu/hr)	Electric (MW)	Heating (millions of Btu/hr)	Electric (MW)	Heating (millions of Btu/hr)	Electric (MW)	Heating (millions of Btu/hr)	Cooling (thousands of tons)	Electric (MW)	Heating (millions of Btu/hr)	Cooling (thousands of tons)
0	7.600	222.1	5.610	113.3	4.200	20.2	4.760	20.2	2.7	5.320	20.2	6.2
1	7.505	216.8	5.270	110.6	4.050	19.5	4.590	19.5	2.4	5.130	19.5	5.7
2	7.315	211.5	5.100	107.9	3.825	18.7	4.335	18.7	1.8	4.845	18.7	5.3
3	7.220	216.8	5.015	110.6	3.750	19.5	4.250	19.5	1.3	4.750	19.5	4.8
4	7.410	222.1	5.100	113.3	3.825	20.2	4.335	20.2	0.9	4.845	20.2	4.5
5	7.600	222.1	5.270	113.3	3.900	22.5	4.425	22.5	0.7	4.940	22.5	4.3
6	7.885	227.4	5.950	116.0	4.125	26.2	4.675	26.2	0.7	5.225	26.2	4.3
7	8.550	232.7	6.545	118.7	4.725	30.0	5.355	30.0	0.9	5.985	30.0	4.3
8	8.835	238.0	7.225	121.4	5.850	35.2	6.620	35.2	0.9	7.410	35.2	4.5
9	8.930	238.0	7.650	121.4	6.525	37.5	7.395	37.5	2.0	8.265	37.5	5.5
10	9.025	232.7	7.820	118.7	6.750	39.7	7.650	39.7	3.1	8.550	39.7	6.5
11	9.120	227.4	7.820	116.0	6.750	41.2	7.650	41.2	4.2	8.550	41.2	7.6
12	9.025	222.1	7.820	113.3	6.600	39.7	7.480	39.7	5.3	8.360	39.7	8.6
13	8.930	211.5	7.650	107.9	6.525	38.2	7.395	38.2	6.0	8.265	38.2	9.3
14	8.835	206.2	7.480	105.2	6.375	37.5	7.225	37.5	6.6	8.075	37.5	9.8
15	8.835	200.9	7.480	102.5	6.300	36.7	7.140	36.7	7.0	7.980	36.7	10.1
16	8.930	206.2	7.565	105.2	6.150	36.0	6.970	36.0	7.2	7.790	36.0	10.3
17	9.215	211.5	7.820	107.9	6.150	36.7	6.970	36.7	7.2	7.790	36.7	10.3
18	9.500	216.8	8.245	110.6	6.300	38.2	7.140	38.2	7.0	7.980	38.2	10.1
19	9.500	216.8	8.500	110.6	6.750	39.0	7.650	39.0	6.3	8.550	39.0	9.5
20	9.405	222.1	8.415	113.3	7.500	35.2	8.500	35.2	5.5	9.500	35.2	8.8
21	9.120	222.1	8.075	113.3	7.275	31.5	8.245	31.5	4.5	9.215	31.5	7.9
22	8.740	222.1	7.565	113.3	6.450	27.0	7.310	27.0	3.8	8.170	27.0	7.2
23	8.170	222.1	6.545	113.3	5.625	23.2	6.375	23.2	3.1	7.125	23.2	6.5

Table B-21

HOURLY ENERGY LOADS BY TYPE OF DAY--
SOUTHWEST, 10 MW BASE

Hour of Day	High Heating Day		Moderate Heating Day		No Space Heating or Cooling Day		Moderate Cooling Day			High Cooling Day		
	Electric (MW)	Heating (millions of Btu/hr)	Electric (MW)	Heating (millions of Btu/hr)	Electric (MW)	Heating (millions of Btu/hr)	Electric (MW)	Heating (millions of Btu/hr)	Cooling (thousands of tons)	Electric (MW)	Heating (millions of Btu/hr)	Cooling (thousands of tons)
0	7.6[illegible]	202.9	5.610	99.0	4.200	13.5	4.760	13.5	2.3	5.320	13.5	7.1
1	7.505	198.1	5.270	96.7	4.050	13.0	4.590	13.0	1.6	5.130	13.0	6.4
2	7.315	193.2	5.100	94.3	3.825	12.5	4.335	12.5	0.8	4.845	12.5	5.5
3	7.220	198.1	5.015	96.7	3.750	13.0	4.250	13.0	0.2	4.750	13.0	4.9
4	7.410	202.9	5.100	99.0	3.825	13.5	4.335	13.5	0.0	4.845	13.5	4.2
5	7.600	202.9	5.270	99.0	3.900	15.0	4.420	15.0	0.0	4.940	15.0	4.0
6	7.885	207.7	5.950	101.4	4.125	17.5	4.675	17.5	0.0	5.225	17.5	4.0
7	8.550	212.6	6.545	103.8	4.725	20.0	5.355	20.0	0.0	5.985	20.0	4.2
8	8.835	217.4	7.225	106.1	5.850	23.5	6.630	23.5	0.2	7.410	23.5	4.9
9	8.930	217.4	7.650	106.1	6.525	25.0	7.395	25.0	1.4	8.265	25.0	6.2
10	9.025	212.6	7.820	103.8	6.750	26.5	7.650	26.5	3.3	8.550	26.5	8.2
11	9.120	207.7	7.820	101.4	6.750	27.5	7.650	27.5	5.8	8.550	27.5	10.4
12	9.025	202.9	7.820	99.0	6.600	26.5	7.480	26.5	6.4	8.360	26.5	11.9
13	8.930	193.2	7.650	94.3	6.525	25.5	7.395	25.5	8.0	8.265	25.5	13.3
14	8.835	188.4	7.480	92.0	6.375	25.0	7.225	25.0	8.4	8.075	25.0	14.1
15	8.835	183.6	7.480	89.6	6.300	24.5	7.140	24.5	9.5	7.980	24.5	14.8
16	8.930	188.4	7.565	92.0	6.150	24.0	6.970	24.0	9.5	7.790	24.0	14.8
17	9.215	193.2	7.820	94.3	6.150	24.5	6.970	24.5	9.5	7.790	24.5	14.8
18	9.500	198.1	8.245	96.7	6.300	25.5	7.140	25.5	9.1	7.980	25.5	14.4
19	9.500	198.1	8.500	96.7	6.750	26.0	7.650	26.0	8.0	8.550	26.0	13.3
20	9.405	202.9	8.415	99.0	7.500	23.5	8.500	23.5	6.4	9.500	22.5	11.9
21	9.120	202.9	8.075	99.0	7.275	21.0	8.245	21.0	5.4	9.215	21.0	10.4
22	8.740	202.9	7.565	99.0	6.450	18.0	7.310	18.0	4.3	8.170	18.0	9.3
23	8.170	202.9	6.545	99.0	5.625	15.5	6.375	15.5	3.3	7.125	15.5	8.2

Appendix C

FUEL CONSUMPTION AND COSTS FOR FOSSIL FUEL SYSTEMS

Fuel Consumption Model

A fuel consumption model was developed to calculate annual fuel usage of the alternative total energy systems considered. For a typical base, the model calculates the total required to meet the electric, heating, and cooling loads using descriptors of an assumed total energy system. The major inputs, computations, and outputs are outlined in Figure C-1. A flow diagram, program listing, and user instructions for the fuel consumption program are given in Appendix F.

Inputs

The base size was defined in terms of the peak electric load. To cover a representative range of base sizes, four peak electric loads were used: 5, 10, 20, and 40 MW. The electric, heating, and air conditioning loads were input hourly for each of the five representative days: high heating, moderate heating, and minimum heating; and cooling, moderate cooling, and high cooling. These loads for a 10 MW base were given in Appendix B.

Equipment installed at a base was sized to meet the peak loads for the base size and geographic region, as well as for standby capacity for maintenance periods. For the independent, centralized TE systems, the diesel installations had five units to meet peak loads and a sixth on standby. However, as the largest diesel unit considered was 8 MW, the larger base sizes had more than six units. Gas turbine systems consisted of seven units of equal size with sufficient capacity so that any six

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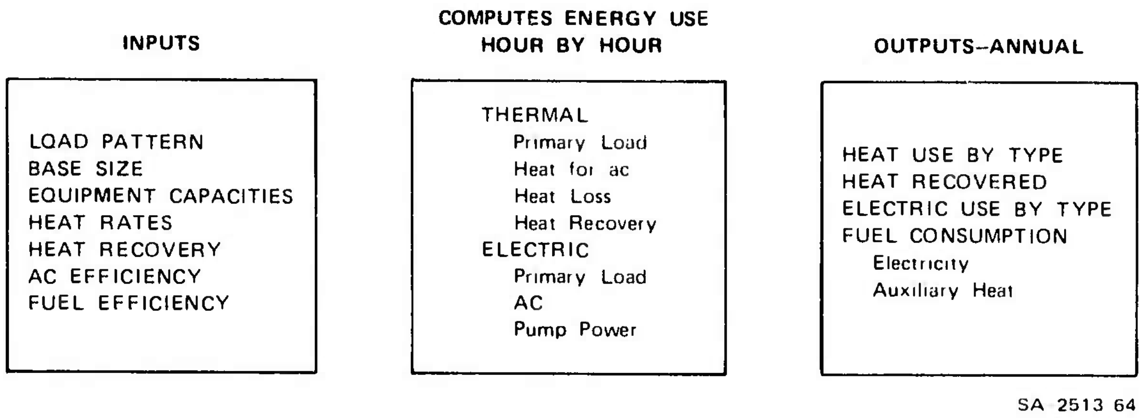

FIGURE C-1 FUEL CONSUMPTION MODEL

could meet the peak load. Electrical generation capacities are displayed in Table C-1 for selected base sizes and regions. The required generating capacities are larger than the peak loads (which exclude air conditioning) because of the standby requirement and the electric load for air conditioning. The air conditioning for these cases is 50 percent absorption and 50 percent electric.

Table C-1

ELECTRIC GENERATING CAPACITIES
FOR SELECTED TOTAL ENERGY SYSTEMS

TE System	Climate	Base Size (MW)	Unit Capacity (MW)	Total Capacity (MW)
Diesel	NC	5	1.3	7.9
	NC	40	7.5	60.1
	SW	5	1.6	9.1
	SW	40	8.0*	72.7
Gas Turbine	NC	5	1.1	7.7
	NC	40	8.8	61.4
	SW	5	1.3	9.4
	SW	40	10.8	75.4

*Maximum size for diesel units in this study.

Hot water generators were installed so that two units, with a third on standby, could meet maximum heat loads plus line losses. Because of the higher heat recovery with gas turbine systems, compared with diesel systems, the hot water generators for gas turbine systems are smaller than those for diesel systems with the same loads. Table C-2 compares the hot water generator capacities for diesel and gas turbine systems.

Table C-2

HOT WATER GENERATOR CAPACITIES
(Millions of Btu)

Climate	Base Size (MW)	Diesel	Gas Turbine
NC	5	203	132
	40	1,620	1,120
SE	5	162	92
	40	1,296	810
SW	5	147	75
	40	1,170	684

The hot water lines for a base were designed to deliver the peak heat demand plus the line losses as determined from Figure A-18. The lowest heat loads were in the Southwest and were approximately 75 percent of the North Central bases of comparable size. The highest heat loads occurred at North Central bases; the hot water transmission capacity for that region is tabulated below:

Base Size (MW)	Heat Transmission Capacity (million Btu/hr)	
	Per Line	Total
5	73.7	147.4
10	98.5	295.5
20	147.6	590.3
40	188.4	1,130.4

The heat loss in transmission was a function of line length and time of year. The heat loss per 100 feet of pipe in summer was taken as 74 percent of the winter heat loss. The heat losses were greatest at North Central bases since they have the largest heat loads; as a percent of the heat load the line losses were 2 to 2.5 percent depending on base size. In the Southwest, line losses were 4.5 to 5.5 percent of the heat load, since the heat loads were about 60 percent lower than North Central bases, while the line losses in the Southwest were only 15 percent lower than those in the North Central.

Electric powered pumps were assumed to circulate the hot water to the individual base complexes. The pump power required for each distribution line was calculated using Figure A-17 and multiplied by the number of lines to get the total pumping capacity needed for the whole base. The electric load for the heat transmission pumps was less than 1 percent of the total electric load. Pump capacity and electric use at North Central bases are shown in Table C-3.

Table C-3

PUMP CAPACITY AND ELECTRIC USAGE IN NORTH CENTRAL

Base Size (MW)	Pump Capacity (KW)	Pump Electricity as Percent of Annual Electric Load
5	43.3	0.3%
10	123.6	0.4
20	283.0	0.5
40	689.0	0.5

The peak cooling load of a single base complex determined the size of air conditioning units. Table C-4 gives the number of complexes, the capacity per unit, and total air conditioning capacity for bases in the Southeast. In those cases that assumed a division of air conditioning between absorption and electric compression air conditioning, some complexes had absorption air conditioning and the remaining complexes had electric air conditioning.

Table C-4

AIR CONDITIONING CAPACITY AT SOUTHEAST BASES

Base Size (MW)	Number of Complexes	Unit Capacity (tons)	Total Base Capacity (tons)
5	4	1,300	5,100
10	6	1,700	10,300
20	12	1,700	20,500
40	18	2,300	41,000

Major Calculations in Fuel Consumption Model

The model calculated the energy required to meet the electric, heating, and cooling loads for each hour of the day.

The electricity required is the sum of three components:

- Base electric load
- Electricity for heat transmission pumps
- Electricity for compression air conditioners (if any).

The model totals the hourly heat requirement by summing the base heat load, the heat loss in transmission, and the heat (if necessary) used in absorption air conditioning. When the heat load was greater than could be recovered from the electrical generation process, the model calculated the fuel necessary from auxiliary heat sources.

Air conditioning loads were met by some combination of absorption and compression chillers. The absorption chillers received heat from either electric generation or auxiliary heat sources. The compression air conditioning was operated by electricity. In those cases where both absorption and compression air conditioning existed, it was necessary that they both operate whenever air conditioning was required, since each complex was assumed to have only one type of air conditioning. The operating rate of each type was determined by its share of the total air conditioning capacity. Thus if the air conditioning was 50 percent absorption and 50 percent compression, the air conditioning load was divided half and half.

Fuel consumption was measured in Btu and occurred in two processes:

- Electric generation
- Auxiliary heating.

Fuel consumed in electrical generation depended on the heat rate of the generating system as determined by Figure A-1 for gas turbine units, Figure A-8 for steam turbines, or Figure A-12 for diesel units.

Fuel consumed in auxiliary heating was determined by dividing the required auxiliary heat by the fuel efficiency. Fuel efficiencies used were:

Natural gas	80%
Oil	83%

Fuel Consumption

The primary output of the model was a summary of annual fuel usage by function: electrical generation and auxiliary heating. The annual data calculated by the program are printed to provide detailed breakdowns of the electricity usage, air conditioning ton-hours by type of chiller, and sources and uses of heat.

For each case, equipment capacities and system parameters, such as electric generation heat rate and waste heat recovery rate, are printed along with a description of base size, location, electric generation system, and fuel burned.

Table C-5 gives the total annual fuel consumption for the centralized multiple generating unit, diesel and gas turbine TE systems and for the three climates and four base sizes. Fuel consumption for various mixes of absorption and electric compression air conditioning is shown in the table. Three cases assume use of the conventional type of absorption air conditioning, and the remaining cases assume the more efficient double effect type.

Table C-5

ANNUAL FUEL CONSUMPTION FOR CENTRALIZED, MULTIPLE GENERATING UNIT, DIESEL AND GAS TURBINE TE SYSTEMS
(Billions of Btu)

TE System	Climate	Absorption Air Conditioning (percent)	Base Size (MW)			
			5	10	20	40
Diesel	SE	10%	733	1,449	2,867	5,702
	SE	50	778	1,549	3,054	6,081
	SE	10*	727	1,438	2,843	5,656
	SE	50*	747	1,488	2,931	5,835
	SE	100*	777	1,548	3,044	6,061
	NC	50*	1,005	2,004	3,977	7,928
	SW	50*	644	1,273	2,514	4,998
Gas turbine	SE	50	791	1,586	3,132	6,168
	SE	50*	774	1,548	3,048	5,983
	SE	100*	780	1,560	3,109	6,137
	NC	50*	1,010	2,027	4,015	7,948
	SW	50*	713	1,420	2,779	5,405

*Double effect type.

The steam turbine TE systems have a single electric generating unit and are dependent on utility electricity during downtime. The fuel consumption includes the fuel used by the utility to generate the electricity for the base during the steam turbine downtime, based on 10,000 Btu/kWh. The air conditioning is all double effect absorption. The annual fuel consumption for the steam turbine TE systems is given in billions of Btu in the following tabulation.

Climate	Base Size (MW) 25	40
NC	5,094	7,814
SE	4,089	6,163
SW	3,738	5,609

Table C-6 gives the fuel consumption for a single generating unit gas turbine TE system. The turbine has larger capacity than the peak electric load, and the excess electricity is sent off base. The fuel consumption figures include credit for the excess electricity at 10,000 Btu/kWh. The air conditioning is double effect absorption.

Table C-6

ANNUAL FUEL CONSUMPTION FOR SINGLE UNIT
GAS TURBINE TE SYSTEMS

Climate	Base Size (MW)	Turbine Capacity (MW)	Fuel Consumption (Btu $\times$ 10^9)
SE	10	20	1,364
SE	20	30	2,815
SE	20	40	2,717
SE	20	50	2,889
SE	40	80	5,178
NC	20	40	3,441
SW	20	40	2,396

The following tabulation gives the annual fuel consumption in billions of Btu for TE systems with dispersed electric generating units in each complex. (The units are electrically interconnected but there are no hot water lines connecting the complexes. The air conditioning is double effect absorption.)

	Base Size (MW)			
	5	10	20	40
Diesel	777	1,548	3,110	6,171
Gas turbine	799	1,592	3,194	6,345

Fuel consumption was also calculated for TE systems with heat transmission only to 25 percent or 50 percent of the base, for diesel and gas turbine systems, respectively. The annual fuel consumption, in billions of Btu, for a 20 MW base in the Southeast, with double effect absorption air conditioning is:

Diesel	3,031
Gas turbine	3,204

The effect of variations in the heating and cooling load on fuel consumption was calculated for a 20 MW base in the Southeast, with a gas turbine TE system and double effect absorption air conditioning. The annual fuel consumption is tabulated below:

Percent of Base Case Load		Billions
Heat	Air Conditioning	of Btu
100%	0%	2,888
100	50	2,939
50	50	2,162

A breakdown of fuel consumption between electric generation and auxiliary heating is shown in Table C-7 for diesel and gas turbine TE systems at 10 MW bases. The major difference is the amount of fuel needed for auxiliary heating. The higher heat recovery available with gas turbine systems lessens the need for auxiliary heat. Table C-7 compares the utilization of the recoverable heat for the diesel and gas turbine systems. Heat recovery in diesel systems is so low that all available heat can be used. In the case of gas turbines some excess heat is generated.

Table C-7

HEAT RECOVERY FOR TE SYSTEMS AT 10 MW BASES

System	Climate	Fuel Consumpsion (billions of Btu)			Recoverable Heat (billions of Btu)	Percent of Recoverable Heat Utilized
		Electric Generation	Auxiliary Heating	Total		
Diesel	NC	679	1,325	2,004	186	100%
	SE	703	785	1,488	192	100
	SW	734	539	1,273	203	100
Gas turbine	NC	1,067	960	2,027	500	97
	SE	1,104	444	1,548	517	92
	SW	1,163	257	1,420	545	82

Costs of Total Energy Systems

Evaluating total energy systems required that annual costs of such systems be determined. The total annual cost is the sum of three components:

- Annualized capital costs
- Operating and maintenance costs
- Fuel costs.

All cost information except fuel cost was supplied by Bechtel (Appendix A).

Capital Costs

Capital costs for a total energy system were the sum of costs for electrical generation, heat generation, heat transmission, and air conditioning.

In order to demonstrate the costing method used in this study, annual costs of a 10 MW base in the Southeast will be derived step by step. This demonstration base was assumed to have a diesel generation system and 50 percent conventional absorption air conditioning.

The total capacity necessary at the base was derived from the peak electrical demand (10 MW) plus the electricity necessary for electric compression air conditioning, which was 4.3 MW. The peak demand of 14.3 MW was multiplied by 6/5 to arrive at the total capacity of 17.1 MW, consisting of six units of approximately 2.9 MW each. The peak demand can be met by any five units. Using Figure A-14, the cost per kilowatt for a 2.9 MW diesel unit is $165.9. Multiplying 17,100 kW times $165.9 per kW resulted in a total installed cost of $2,837,000.

Oil-fired generator costs are given in Figure A-15 using plant capacities expressed in megawatts thermal (MWt). The necessary heating capacity is 324 million Btu, or 94.9 MWt. From Figure A-15, the unit cost was found to be $22,300 per MWt; this results in a total cost of $2,116,000 for an oil-fired hot water generator.

The installed cost of hot water transmission lines was based on Figure A-19. The line length and number of use-points used in deriving capital costs depended on the assumed configuration of complexes on the base. The capital costs used in this study are shown in Table C-8.

Table C-8

INSTALLED COSTS FOR HOT WATER TRANSMISSION LINES
(Millions of Dollars)

Climate	Base Size (MW)			
	5	10	20	40
NC	$1.2	$3.1	$6.1	$13.5
SE	1.1	2.8	5.6	12.0
SW	1.1	2.7	5.5	11.5

Capital costs for air conditioning equipment were based on Figure A-21. The example chosen has both conventional absorption and compression air conditioning chillers. The unit size, unit cost, and total cost for each were:

	Unit Size (tons)	Installed Cost per Ton	Total Capacity (tons)	Total Cost (thousands of dollars)
Absorption	1,700	$97.0	5,100	$494.7
Compression	1,700	75.9	5,100	387.0
Total				$881.7

In summary, the capital costs are:

	Thousands of Dollars
Electric generation	$2,837
Hot water generation	2,116
Hot water transmission	2,838
Air conditioning	882
Total	$8,674

In order to make comparisons among alternative total energy systems, the capital costs had to be expressed as a uniform annual cost. This was done following procedures outlined in AR37-13 "Economic Analysis of Proposed Army Investments," 22 January 1970. The discount rate used in present value calculations was 6-1/8 percent, and the economic life used was 25 years.

The uniform annual capital costs were obtained by dividing the installed costs by the present value factor for $1 invested annually at 6-1/8 percent for 25 years.

$$\text{Present value} = \frac{1 - (1.06125)^{-25}}{0.06125} = 12.6329$$

The uniform annual capital cost of the example detailed above is:

$$\frac{\$8,674,000}{12.6329} = \$686,000$$

Operating and Maintenance Costs

The operating and maintenance costs for each total energy system component were calculated individually, based on Bechtel-supplied data, and then summed to obtain an annual total.

Electrical generator maintenance costs were dependent on the type of generator and fuel used. For gas and steam turbines the costs were expressed simply as a cost per kilowatt-hour.

Maintenance costs for diesel generators were expressed as a sum of a fixed cost based on capacity and a variable cost dependent on fuel and kilowatt generated.

For the 10 MW diesel base, the operating and maintenance costs for the generating system were calculated as follows:

Fixed cost:

$$\$23,800 + \$5,000/\text{MW} \times 17.1 \text{ MW} = \$109,300$$

Variable cost:

$$1.4 \text{ mills/kWh} \times 66.315 \times 10^6 \text{ kWh} = \underline{\quad 92,840}$$

$$\text{Total} \qquad \$202,140$$

The annual operating and maintenance cost of a hot water generator of 324 million Btu capacity was $36,000.

Annual operating and maintenance costs for air conditioning were expressed in Figure A-20 as a function of chiller capacity. The cost for 1,700 ton absorption units was $10,000 per year, and for compression units $12,200 per year. Since there were three units of each type on the example base, the total is:

$$3 \times \$10,000 + 3 \times \$12,200 = \$66,600 \quad .$$

In summary, annual operating and maintenance costs were:

Electric generation	$202,140
Hot water generation	36,000
Air conditioning	66,600
Total	$304,740

Excluding fuel costs, the annual cost of a diesel total energy system at a 10 MW base in the Southeast was estimated to be $686,000 plus $305,000 for a total of $991,000.

A summary of annualized capital costs and annual operating and maintenance costs (excluding fuel) for diesel, gas turbine, and steam turbine TE systems is presented in Table C-9. The diesel and gas turbine systems are centralized, multiple generating unit systems, while the steam turbine systems are single generating units.

Table C-9

ANNUAL COSTS, EXCLUDING FUEL, FOR DIESEL, GAS TURBINE, AND STEAM TURBINE TE SYSTEMS
(Thousands of Dollars)

TE System	Climate	Percent Absorption Air Conditioning	Base Size											
			5 MW			10 MW			20 MW			40 MW		
			Annualized Capital Cost	O&M Cost	Total	Annualized Capital Cost	O&M Cost	Total	Annualized Capital Cost	O&M Cost	Total	Annualized Capital Cost	O&M Cost	Total
Diesel	SE	50	$345	$178	$523	$686	$305	$ 991	$1,297	$565	$1,862	$2,533	$1,054	$3,587
	SE	50*	357	178	535	710	305	1,015	1,344	565	1,909	2,628	1,054	3,682
	NC	50*	362	170	532	721	288	1,009	1,364	533	1,897	2,692	984	3,676
	SW	50*	376	187	563	759	341	1,100	1,449	637	2,086	2,801	1,183	3,984
Gas turbine	SE	50	310	138	448	603	209	812	1,117	358	1,475	2,191	641	2,832
	SE	50*	322	138	460	626	209	835	1,165	358	1,523	2,286	641	2,927
	NC	50*	327	134	461	614	200	814	1,194	340	1,534	2,374	598	2,972
	SW	50*	344	144	488	666	232	898	1,252	405	1,657	2,597	728	3,325
	SE	100*	309	132	441	611	196	807	1,136	332	1,468	2,210	588	2,828
									25 MW					
Steam turbine	SE	100*							$2,111	$531	$2,642	3,057	854	3,911
	NC	100*							2,142	562	2,704	3,124	894	4,018
	SW	100*							2,217	607	2,824	3,230	953*	4,183

*Double effect type.

Table C-10 gives the annual costs, excluding fuel, for single gas turbine TE systems, and Table C-11 gives the same information for dispersed diesel and gas turbine TE systems.

The annual costs for a 20 MW base in the Southeast, excluding fuel for the cases with heat transmission only to part of the base (25 percent for the diesel; 50 percent for the gas turbine), are given in the following tabulation:

	Annual Costs (thousands of dollars)		
	Capital	Operating	Total
Diesel	1,250	505	1,755
Gas turbine	1,120	392	1,512

The effect of variations in the heating and cooling load on the annual costs, excluding fuel, for a gas turbine TE system as a 20 MW base in the Southeast is shown in the following tabulation:

Percent of Base Case Load		Annual Costs (thousands of dollars)		
Heat	Air Conditioning	Capital	Operating	Total
100%	0%	$ 883	$212	$1,095
100	50	1,014	298	1,312
50	50	652	281	933

Fuel Costs

The total annual cost of a TE system includes fuel costs as well as capital and operating costs. Future fuel costs are uncertain, and also vary greatly from region to region in the United States, so the effect of fuel costs on the annual cost of TE systems was treated parametrically. The uniform annual cost of fuel was assumed to vary between $1 and $3 per million Btu. Thus the total annual costs used in this study were the sum

Table C-10

ANNUAL COSTS, EXCLUDING FUEL,
FOR SINGLE GAS TURBINE TE SYSTEMS
(Thousands of Dollars)

Climate	Base Size (MW)	Gas Turbine Capacity (MW)	Total Installed Costs	Annual Costs		
				Capital	Operating	Total
SE	10	20	$ 8,648	$ 685	$236	$ 921
SE	20	30	15,207	1,204	416	1,620
SE	20	40	16,327	1,293	468	1,761
SE	20	50	17,422	1,379	503	1,882
SE	40	80	32,354	2,561	872	3,443
NC	20	40	16,571	1,312	499	1,811
SW	20	40	17,430	1,380	472	1,852

Table C-11

ANNUAL COSTS, EXCLUDING FUEL, FOR DISPERSED TE SYSTEMS
(Thousands of Dollars)

TE System	Base Size (MW)	Annual Costs		
		Capital	Operating	Total
Diesel	5	$ 372	$163	$ 535
	10	656	266	922
	20	1,281	477	1,758
	40	2,305	764	3,069
Gas turbine	5	369	136	505
	10	647	204	851
	20	1,268	348	1,616
	40	2,268	619	2,887

of the capital and operating costs, excluding fuel, plus the fuel consumption times the assumed fuel cost for a particular case. For the example developed above, the fuel consumed in one year was 1,549 billion Btu; if fuel is $1 per million Btu, then the total annual cost was $1,549,000 for fuel plus the annual capital and operating costs of $991,000, or $2,540,000.

Fuel Consumption for Conventional Systems

Conventional systems consume fuel on base for heating water and space heating, and electricity is purchased from a utility. For comparison with the fuel consumption of TE systems, the fuel consumption of the conventional system includes, in addition to the fuel consumed on base, the fuel (or energy equivalent) consumed by the utility to generate the electricity for the base, assuming a heat rate of 10,000 Btu/kWh. Table C-12 gives the fuel consumption of the conventional system for different climates and base sizes. The heating efficiency on base is 83 percent for an oil-fired system.

The effect of load variations on the fuel consumption for conventional systems is shown in Table C-13.

Costs of Conventional Systems

Costs for conventional systems were estimated using the methods described above for total energy systems; however, conventional systems had only two major capital items:

(1) Hot water generators

(2) Electric compression air conditioning.

Without a heat transmission system, each complex needs a hot water generator; therefore, the individual units are smaller and have a higher cost per MWt of capacity (see Figure A-15). Likewise the operating and

Table C-12

FUEL CONSUMPTION FOR CONVENTIONAL SYSTEMS

Type of Air Conditioning	Climate	Base Size (MW)	Fuel Consumption (billions of Btu): On-Base Heating	Fuel Consumption (billions of Btu): Off-Base Electric Generation	Fuel Consumption (billions of Btu): Total
Electric air conditioning	NC	5	755	325	1,080
	NC	10	1,511	659	2,170
	NC	20	3,022	1,318	4,340
	NC	40	6,043	2,637	8,680
	SW	5	302	401	703
	SW	10	606	802	1,408
	SW	20	1,211	1,603	2,814
	SW	40	2,422	3,207	5,629
	SE	5	454	361	815
	SE	10	908	722	1,630
	SE	20	1,817	1,422	3,259
	SE	40	3,632	2,885	6,517
Double effect absorption air conditioning	SE	5	548	301	849
	SE	10	1,098	602	1,700
	SE	20	2,194	1,203	3,397
	SE	40	4,389	2,407	6,796

Table C-13

FUEL CONSUMPTION FOR SELECTED LOAD VARIATIONS FOR 20 MW CONVENTIONAL SYSTEMS IN THE SOUTHEAST

Percent of Base Case Load		Fuel Consumption (billions of Btu)		
Heat	Air Conditioning	On-Base Heating	Off-Base Electric Generation	Total
100%	0%	1,817	1,203	3,020
100	50*	1,817	1,323	3,140
50	50*	908	1,323	2,231
50	50+	1,097	1,203	2,300

*Electric air conditioning.

+Double effect absorption air conditioning.

maintenance costs for several small units were higher than for a single large installation.

Annual costs, excluding fuel, for conventional systems are shown in Table C-14. As with the TE systems, the fuel cost was taken as a parameter.

The cost of electricity for conventional systems was calculated in two parts: a demand charge and an energy charge. The demand charge is based on the peak electric demand at a base. For example, a 10 MW base in the Southeast has a peak demand of 18.5 MW; if the demand charge is assumed to be $15,000 per year per MW, then the annual cost is $277,500. The energy charge portion of the electric cost is based on the total kWh used, and was also treated parametrically. Continuing the above example, the total electricity used was 72.2 million kWh. At 1.5¢ per kWh the energy charge is $1,083,000. The total electric cost for one year is $1,360,500.

Total annual costs for a conventional system at a 10 MW base in the Southeast were calculated as summarized in Table C-15.

Table C-14

ANNUAL COSTS, EXCLUDING FUEL, FOR CONVENTIONAL SYSTEMS
(Thousands of Dollars)

	Base Size											
	5 MW			10 MW			20 MW			40 MW		
Climate	Annualized Capital Cost	O&M Cost	Total	Annualized Capital Cost	O&M Cost	Total	Annualized Capital Cost	O&M Cost	Total	Annualized Capital Cost	O&M Cost	Total
NC	$252	$ 99	$351	$430	$134	$564	$859	$209	$1,068	$1,517	$337	$1,854
SE	247	117	364	426	168	594	853	274	1,127	1,490	467	1,957
SW	238	106	344	410	145	555	819	229	1,048	1,433	377	1,810

Table C-15

ESTIMATION OF TOTAL ANNUAL COST OF CONVENTIONAL
10 MW SYSTEM IN SOUTHEAST
(Thousands of Dollars)

Capital costs		
Hot water generator	\$4,393	
Compression air conditioning	782	
Total	\$5,175	
Uniform annual cost (× 0.07916)		\$ 410
Annual operating and maintenance costs		
Hot water generator	72	
Compression air conditioning	74	
Total		145
Fuel		
Heat load-Btu x 10^9	\$ 754	
Fuel demand-Btu × 10^9 (@ 0.83 efficiency)	908	
Annual cost @ \$1.00/Btu × 10^6		908
Electricity cost		
Peak load (MW)	18.5	
Annual demand charge @ \$15,000/MW		278
Electric load (millions of kWh)	72.2	
Annual energy charge @ 1.5¢/kWh		1,083
Total annual cost		\$2,824

Appendix D

GEOTHERMAL ENERGY

Introduction

Projected shortages in supplies of the fossil fuels have prompted renewed attention to the possible use of less conventional sources of energy, such as geothermal resources. The natural steam and hot water occurring near the earth's surface has, in fact, been employed for production of electric power since 1904 in Italy and since 1960 in the United States. Moreover, geothermal waters have been used for space heating in Iceland for an extensive period of time. Attempts to use geothermal resources are thus not an entirely new undertaking. What is new is the interest in use of georthermal resources on a scale and in an integrated fashion not previously contemplated.

This appendix describes the characteristics of geothermal resources, and presents estimates of the costs of geothermal energy applications to military installations.

Characteristics of Geothermal Resources

Geothermal resources may be defined legally as being " ... the natural heat of the earth, the energy ... which may be extracted from such natural heat and all minerals--or other products obtained from naturally heated fluids--but excluding oil, hycrocarbon gas or other hyd carbon substances."[1] In a technical sense, geothermal resources are ous rocks

[1] Section 6903, Chapter 3, Division 6, Public Resources Code of California.

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containing water or steam at temperatures from 150°C to 650°C. The heat energy stored in these rocks may be conveyed to the surface by extraction of the associated liquids. Thus, there are two basic components to a geothermal system:

- A source of heat (regional heat flow or local igneous intrusion).
- Circulating water.[2]

Rocks constituting geothermal reservoirs can be of practically any type or age if they are relatively porous and permeable and "preferably sufficiently brittle to sustain open fractures at elevated temperatures."[3] Although no specific petrological association has been established, acidic volcanic rocks seem to be more closely associated with certain geothermal prospects than are the more basic rocks. These acidic rocks include rhyolite and dacite, which occur in some abundance in the contiguous states west of the 100th meridian, along the region of the western mountain states, and especially along the continental margin.

Four types of geothermal systems have been recognized:[3]

(1) Normal geothermal gradient and heat flow, such as occur on continental masses and in most ocean basins. The geopressured systems occurring in the Gulf Coast area are of this type.

(2) Higher than normal geothermal gradient and conductive heat flow, such as along the world rift zone. The Gulf of California area is of this type as are the dry, hot rock areas.

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[2] D. E. White, L.J.P. Muffler, and A. H. Truesdell, "Vapor-Dominated Hydrothermal Systems Compared with Hot-Water Systems," Economic Geology, V. 66, pp. 75-97 (1971).

[3] L. T. Grose, "Geothermal Energy: Geology, Exploration, and Developments," Parts I and II; Colorado School of Mines, Mineral Industries Bulletin, Vol. 14, No. 6 (November 1971) and Vol. 15, No. 1 (January 1972).

(3) Hot spring areas with convective transfer of most of the total heat flow in shallow depths by circulating water and dry steam. The Geysers area is of this type.

(4) Composite hydrothermal systems with both convective and conductive heat transfer, representing a combination of types (2) and (3) and emphasizing hot water. Heat flow to the surface is appreciably lower from these systems than from hot springs. The Salton Sea-Imperial Valley system is of this type.

A more detailed description of each of the above systems is presented to better illustrate the characteristics of the principal geothermal resource areas of the United States, drawn largely from the work of White et al.[2]

Dry Steam Systems

These systems are vapor-dominated and are exemplified by The Geysers area. (Actually, the name "The Geysers" is an unfortunate misnomer. The area has never had true geysers, which are restricted to hot water systems.) Near surface rocks at this area are relatively tight and incompetent, but still allow quantities of meteoric or near surface ground water to penetrate to some depth and saturate the rocks. Heat is transferred by conduction and circulating water into surrounding rocks that have some permeability. Because of the initial thermal expansion and resulting decrease in density of the heated water, a hot water convection system is initiated. The water flow rate, rock temperature, and depth below the surface all determine whether boiling occurs. To a certain extent, the system is self-regulating in heat removal. Where there is a substantial heat supply or decreasing rate of water supply, a hot water system of limited permeability may start to boil off more water than inflow can replace, and a vapor-dominated or "dry-steam" system may form.

Pressures throughout the geothermal reservoir will be controlled by the total vapor pressure at the boiling water table, modified by frictional resistance to the upward flow of vapor and by the weight of the vapor itself. Near the top of the reservoir, some steam may condense and other gases (e.g., CO_2, H_2S) having different vapor pressures may be residually concentrated. A general model of vapor-dominated geothermal systems is illustrated in the work of White et al.[2]

At The Geysers, temperatures of shallow wells (<350 m) show a rather close relationship to the reference boiling curve for hydrostatic pressure of pure water, according to White et al. This lends support to the interpretation that most water in the system is of meteoric origin. Also, it suggests that pure, liquid water condenses from rising steam at the boiling water table level and fills most of the pore spaces. This condensed water provides a buffering control over temperatures and pressures in the zone of upflowing fluids. Although temperatures at The Geysers increase irregularly with depth, they are probably along or near the hydrostatic boiling point curve (dissolved solids or gases may cause temperatures or pressures to exceed the limits for pure water). Typical wells at The Geysers produce dry or superheated steam containing 1% to 5% CO_2 and normally less than 1 ppm chloride.

Hot Water Systems

These systems are generally found in permeable sedimentary or volcanic rocks in which meteoric water penetrates to considerable depths and are exemplified by the Imperial Valley region. Temperatures of many explored hot water systems increase with depth to a base temperature that varies with each system. The meteoric water is heated to its base temperature by rock conduction. The heated water may rise in the system according to the water circulation pattern. As the water rises, hydrostatic pressure decreases, and eventually a level may be attained at which pressure is low enough for boiling to take place. A range of temperatures and water chemistry may be associated with hot water geothermal systems many occurring in the same general area; such systems are quite complex.

Hot water systems have high contents of salts such as alkali chlorides, SiO_2, and boron and arsenic compounds. They have a high potential for self-sealing by means of deposition of minerals in outlet channels. SiO_2 is the most important constituent for the self-sealing of high temperature systems because quartz is so abundant and its solubility increases so much with temperature. Quartz dissolves rapidly at high temperatures, and when quartz-saturated waters are cooled, the quartz precipitates readily to about 180°C. Calcite, zeolites, and other minerals are also effective to a lesser degree in producing self-sealing. Self-sealing is likely to be most extensive where temperatures decrease most rapidly. In this regard, it was suggested[4] that the microearthquake movements in geothermal areas were necessary to keep the channels open and prevent mineral deposits from curtailing water circulation needed to make the system function. Clearly, however, further work is required on this aspect of research into geothermal mechanisms.

The foregoing brief description of the mechanisms of typing geothermal reservoirs may be synthesized to indicate characteristics of potentially commercial reservoirs as listed below:[5]

- Reservoir or base temperature of 200°C, necessary to sustain power generation of 100 MW or more in conventional steam plants. Temperature greater than 300°C lead to waters with too high chemical content.

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[4] A. L. Lange, and W. H. Westphal, "Microearthquakes Near the Geysers, Somona County, California," J. Geophysical Research, Vol. 74, No. 17, pp. 4377-4378 (1969).

[5] J. W. Feiss, "Geothermal Energy: A Summary of Current Status and Future U.S. Potential," Manuscript (1970).

- Reservoir volume of several tens of cubic km.
- Rock permeability (or fractures) sufficient to permit water/ steam flow.
- Reservoirs at moderate depths, accessible to drilling.
- Low permeability reservoir cap rock with low thermal conductivity to prevent loss of fluids and heat.
- Sufficient long term fluid recharge into the system.
- Low quantities of dissolved solids.
- Large heat source to maintain high temperatures for at least 20 to 30 year life.

Clearly, these characteristics will not be present at each prospective geothermal site, and it will be necessary to conduct systematic exploration programs to identify the sites that warrant further development.

Geopressured Systems

The term "geopressure" was coined by Stewart[6] to describe abnormally high subsurface fluid pressure, and was later defined by Dickenson[7] as:

> Any pressure which exceeds the hydrostatic pressure of a column of water extending from the stratum tapped by the well to the land surface containing 80,000 mg/l total solids.

Jones has pointed out that geopressure may also be expressed in terms of the geostatic ratio, which is the observed fluid pressure in aquifer due to weight of overlying deposits at aquifer depth. Because the average density of all rocks in the stratigraphic column changes slowly with depth, the geostatic load at any given depth is approximately equal to 1.0. Therefore, any observed subsurface fluid pressure for which the

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[6] Cited in: P. H. Jones, "Hydrodynamics of Geopressure in the Northern Gulf of Mexico Basin," Jour. Petroleum Technology, pp. 803-810 (July 1969).

[7] G. Dickenson, "Reservoir Pressures in Gulf Coast Louisiana,: Bull. Am. Assoc. Petroleum Geologists, Vol. 37, pp. 410-432 (1953).

geostatic ratio is between the pressure exerted by a water column of appropriate depth (0.465 psi/ft) and the pressure exerted by a column of sedimentary rocks at that depth (1.0 psi/ft), is by the above definition, a geopressure reservoir.

The geopressured resources therefore differ from the previously described types in both the source of thermal waters and in the hydrology of the systems.[8] Thermal waters of this type do not occur in volcanic regimes but in deep sedimentary basins far from zones of active volcanism. The geopressure reservoirs are not dependent on recharge, deep circulation, and heating of meteoric water; rather, their thermal waters are derived from the sediments themselves. Although fluid depletion will occur upon development, the large amount of water in storage offers the prospect for continuing development at substantial scales.

The geochemical and geophysical features of geopressure reservoirs may be summarized as follows:

- Salinity--usually decreases within the reservoirs with increasing depth.
- Geotemperature regime--no apparent relationship between the average geothermal gradient and the geostatic ratio. However, localized relations between reservoir temperature and geostatic ratio have been observed, emphasizing the need for data over short depth intervals in particular localities.
- Clay-mineral abundance--the clay mineral abundance ratio is markedly dependent on temperature. The content of montmorillonite sharply decreases in geopressured zones. Heating of fine-grained sediments that promotes diagensis of montmorillonite yields free pore water in an amount equal to about half the volume of the clay altered, and thereby increases the fluid content of the sediments.

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[8] P. H. Jones, "Geothermal Resources of the Northern Gulf of Mexico Basin," Geothermics, Special Issue No. 2, Vol. 2, pp. 14-26 (1970).

The basic sequence of events leading to geopressure development was described by Jones:[8]

- Rapid deposition of deltaic sediments composed largely of montmorillonite (80 percent or more) was accompanied by contemporaneous faults that compartmentalized the strata prior to escape of their interstitial saline water.
- Fluid pressures in these compartmentalized reservoirs increased with deepening burial, and heating of the deposits accompanied such burial.
- Undercompacted clay beds subjected to increasing overburden load lost water to interbedded sands, in which case the water flowed in the direction of pressure release. Closure of avenues of exit for this water through faulting led to a rapid rise in fluid pressures in the compartmentalized reservoirs.
- As geopressure increased, water escaped initially through the clay beds overlying sandstone aquifers. However, osmotic forces developed as clay beds served as semipermeable membranes and salinity increases in the zone of escape occurred. Osmotic forces opposing water escape from the reservoir increased until an equilibrium with geopressure was achieved and flow ceased.
- Thermal dehydration and diagensis of montmorillonite produced interstitial fresh water in substantial amounts, markedly increasing fluid pressure and decreasing salinity while at the same time reducing the bulk density load-bearing strength and thermal conductivity of the clay beds.
- As upward water flow was restricted, the rate of heat flow was greatly reduced, and the geopressured reservoirs became overheated. As reservoir temperature rose, the vapor pressure increased, water became less dense, osmotic forces were strengthened, and reservoir pressure increased further.
- These stages took place in a dynamic environment, in which structural deformation, flow, and precipitation of dissolved solids took place. Precipitation of mineral matter at the upper parts of clay beds or along faults further helped to isolate the geopressured reservoirs.
- Production of geothermal reservoirs will be a depletion process. However, the volume of geothermal fluids (heated water containing dissolved gases) is substantial. The

amount of depletion and the rate with which it is practiced will depend on the character of individual reservoirs.

Dry, Hot Rock Systems

The possibility of recovering geothermal energy from dry, hot rock systems has received increasing attention in recent years.* There are numerous regions of the earth's crust containing hot rocks† without any significant quantities of recoverable hot water or steam that occur at moderate depths. The basic principle of the method is to emulate the main heat transfer mechanism existing in natural vapor-dominated geothermal systems, where heat is transferred from permeable hot rocks at depth to near-surface reservoirs by the convective flow of water.

The concept of the prospective dry hot rock system is to create fractures in such rock masses, either by hydrofracturing, conventional explosives, or nuclear explosives. Water would be introduced into these fractures, where it would be heated by the surrounding rocks. The heated water could be tapped, it is postulated, in a manner similar to that used in either dry steam or hot water geothermal systems.

This approach to geothermal resource development is at a very early experimental stage. The first drilling work into dry, hot rocks remains to be conducted. It remains to be demonstrated that fractures can be

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*See, for example, Brown, D. W. et al., "A New Method for Extracting Energy from 'dry' Geothermal Reservoirs," Los Alamos Scientific Laboratory, Report LA-DC-72-115, September 20, 1972; and D. D. Blackwell and C. Baag, "Heat Flow in a Blind Geothermal Area near Marysville, Montana," in press for Geophysics.

†Identifiable by regions of high geothermal gradient or heat flow.

induced and sustained in such material. It is not clear that water introduced into fractures will be contained in any cavity without continued recharge to replace that which leaks out along joints and cleavage planes. Finally, it is not clear that the proposed mechanism for extraction of energy from dry, hot rocks will resemble the natural vapor-dominated geothermal systems it seeks to duplicate, even if the above uncertainties prove to be no problem, because in fact natural vapor-dominated geothermal systems are not at all well understood. If successful at all, it appears that dry, hot rock geothermal systems will not provide benefits until far in the future.

Exploration

Delineation of geothermal resources requires a systematic exploration program that integrates geological, geophysical, and geochemical techniques. An appropriate program should determine with reasonable accuracy the existence, extent, and character of the geothermal fields. Systematic exploration work is required. At present, geothermal exploration is analogous to the early days of oil exploration when attention was concentrated in areas of oil seeps--efforts are focused on areas of surface heat leakage such as thermal springs. One unresolved problem in geothermal resource development is the means to discover large hidden heat reservoirs in which surface manifestations are not obvious. Not until then does it appear that geothermal resources can become other than locally attractive.

Exploration methods for geothermal resources are summarized as follows:

- Geological methods
  - Types of geometry of structural features
  - Lithology and character of porous/permeable rocks

- Nature and extent of hydrothermal alteration and mineral deposition
- Modern thermal springs

- Geophysical methods
  - Surface temperature and heat flow measurements
  - Electrical resistivity measurements
  - Gravity methods
  - Magnetic surveys
  - Seismic methods
- Geochemical methods
  - Chloride content
  - Silica content
  - Na/K ratio.

Geologic methods reveal the thermal history and evolution of the area, give clues as to how the thermal activity relates to basic geology, and enable interpretation of how long the system has been active. Geophysical methods seek to measure the principal relationships between physical parameters of the site and geothermal phenomena--e.g., electrical resistivity measurements give the direct relationship between fluid content, temperature, and electrical conductivity. Geochemical methods attempt to determine the chemical character of the heated waters to use these data as indicators of the likely range of subsurface conditions in the geothermal reservoir (e.g., size, extent, volume, and permeability character).

When exploration methods reveal promising geothermal indications, a program of drilling is usually undertaken, much the same as in exploration for petroleum or natural gas. Furthermore, the equipment and procedures used in this work are closely related (if not entirely identical) to that used in development of oil and gas. However, it was noted[10] that basic differences do exist between petroleum and geothermal fluid reservoirs, although they are similar in many respects. Some key differences[11] are:

- Geothermal systems are single component systems in contrast to multicomponent hydrocarbon systems.
- Heat effects are much larger for water than for hydrocarbon systems.
- Natural steam may or may not be isothermal, while petroleum is normally considered to be isothermal.
- Two-phase geothermal reservoirs should follow nonisothermal paths during fluid depletion.
- Liquids at pore volume saturations less than or equal to those for isothermal reservoirs can boil in geothermal reservoirs and be recovered as steam, unless suppressed by surface tension effects. This situation is complicated by dissolved salts that lower the vapor pressure, leading to very complex phase equilibria whose characteristics are imperfectly understood.
- Water influx may vary from steady to unsteady.
- Complete thermodynamic equilibrium may not be a reasonable assumption for an entire reservoir.
- The temperature-depth profile in reservoirs would be time-dependent and a function of specific reservoir geometry and degree of filling.

Finally, Whiting and Ramey note that:

> Geothermal fluid systems should exist at thermal and hydraulic equilibrium. The heat conduction to the bottom of the reservoir should essentially equal the heat loss by conduction from the

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[10] G. V. Cady, H. L. Bilhartz, Jr., and H. J. Ramey, Jr., "Model Studies of Geothermal Steam Production," Presented at AICLE 71st National Meeting, Dallas, Texas, February 20-23, 1972.

[11] R. L. Whiting and H. J. Ramey, Jr., "Application of Material and Energy Balances to Geothermal Steam Production," J. Petroleum Technology, pp. 893-900 (July 1969).

top of the reservoir. This balance could be upset only if production results in significant reservoir temperature change. Even in this event, terrestrial heat conduction takes place at such a slow rate that reservoir performance should not be affected over time periods involved in normal forecasting (50 years).

This lends encouragement that, recognizing the complexity of the systems and the need to arrive at a better understanding of their characteristics, geothermal resources can be used to sustain developments for considerable periods of time.

Costs of Geothermal TE Systems

System Descriptions

To arrive at cost estimates for a base using a geothermal power source, short of an exhaustive design study, one typical base size and location were selected and two different types of geothermal sources were considered.

A base was selected in the "southeast" climate type, having a peak electrical load of 20 MW and a peak thermal load of about 4.8×10^8 Btu/hr. The corresponding annual loads are 1.2×10^8 kWh electric and about 1.8×10^{12} Btu thermal. Thus, the annual thermal load in this case is about 4-1/2 times the annual electric load.

Both dry steam and "steam plus water" type sources were considered. The dry steam was assumed to be provided at 355°F and 144 psia at the plant. The steam plus water source was assumed to yield 29 percent saturated steam and the rest water, all at 355°F and 144 psia from an underground reservoir at 572°F. Explicit consideration was not given to extreme cases of corrosives, or presence of large amounts of salts or solids. Individual consideration is always required for each specific well to estimate the importance of these effects.

Individual systems were considered for the two geothermal source types, as shown in Figures D-1 and D-2. Each system uses a 20 MW turbine/condenser/generator subsystem designed for low pressure geothermal sources. The heat exchangers for each system are designed to feed high temperature water (HTW) base systems operating between 330°F and 170°F. Flow rates and water return temperatures shown on the figures correspond to peak load conditions. The heat exchangers for the water plus steam system are sized to accommodate the necessary variations in the ratio of electric to thermal demand and the ratio of water to steam under changing load conditions.

To estimate the well output necessary to provide the required peak loads, typical values of 18 pounds of steam per kW and heat exchanger efficiency of 92 percent were assumed. From the considerations above, the flows required from the geothermal source are calculated and presented in Table D-1. Here, well lifetimes of about 8 years and well success rates of 75 percent are assumed in the estimates given; the flows per well shown are typical.

Costs

There are four major categories of capital costs,[12] exploration, drilling, wellhead equipment, and collection pipework.

There is no real upper limit to the amount that may be spent on exploration, but $3 million is a typical figure that is spent in areas where prospects are likely. The bulk of this is spent at the start.

The cost of drilling is about $60 thousand per production bore for typical geothermal depths. At the assumed 75 percent success rate, the estimate would be $80 thousand per successful production bore.

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[12] H. Christopher H. Armstead, "Geothermal Economics," in Geothermal Energy, Earth Sciences 12, Unesco (1973).

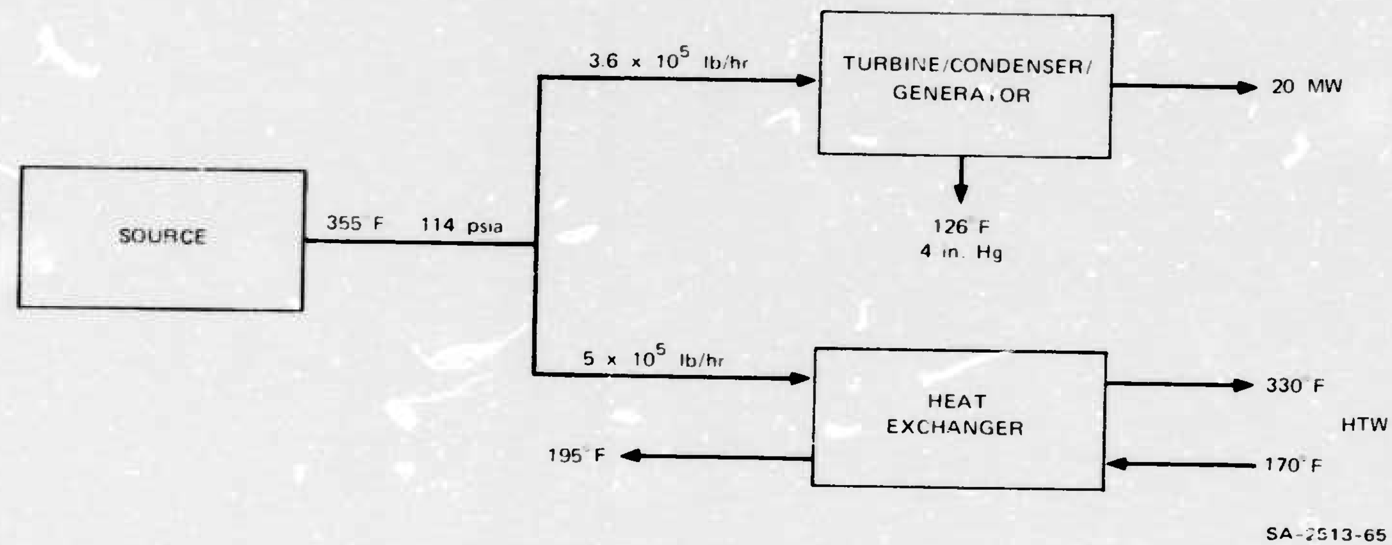

FIGURE D-1 DRY STEAM SYSTEM

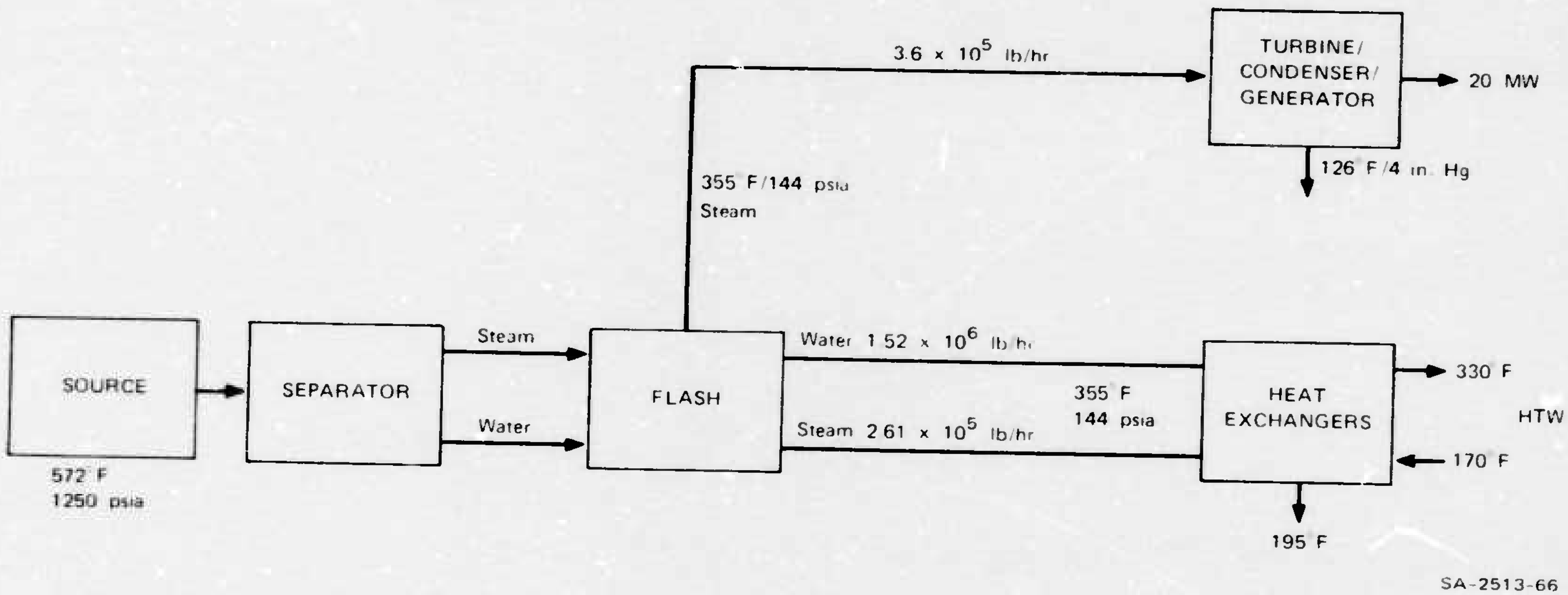

FIGURE D-2 WATER PLUS STEAM SYSTEM

Table D-1

WELL REQUIREMENTS

	Dry Steam	Water Plus Steam
Flow required lb/hr	8.6×10^5	2.2×10^6
Flow per well lb/hr	10^5	2×10^5
Average number of wells operating at one time	9	11
Number of wells required over 25-year span	27	33
Number of wells to drill at 75 percent success rate	36	44

The wellhead equipment, consisting of separator, silencer, valving, integral pipework, and instrumentation, is typically about $35 thousand per (successful) production bore.

The collection pipework estimate is based on a maximum steam velocity of 150 ft/sec and a maximum water velocity of 10 ft/sec. Table D-2 gives

Table D-2

COLLECTION PIPEWORK REQUIREMENTS

	Water	Wet Steam	Dry Steam
Inside diameter (inches)	12	18	27
Number of pipes required	1	1	1

the resulting requirements. Using $90/ft for steam pipe installed above ground and $120/ft for water pipe installed above ground and allowing 40 percent of the main line estimate for branch lines, the cost for one mile would be $887 thousand for the water lines and $665 thousand for the steam pipework. The steam pipework estimate includes lagging, expansion facilities, traps, and suitable valving. The water pipework estimate must include $600 thousand for terminal equipment, consisting of pumps, head tank, flash equipment and control gear.

Recurring costs[13] are estimated as follows: Capital charges are based on an 8-year life for bores and 25 years for wellhead gear and collection pipework. Bore replacement cost, including moving wellhead gear and extending collection pipework, is estimated at $15 thousand. Operation, repairs, and maintenance on wellhead equipment and bores is estimated at 2 percent per annum of the total cost of wellhead equipment plus drilling cost for the operating bores.

The capital cost of the power plant is based on $200/kW, which includes buildings, cooling water facilities and an allowance for the heat exchangers. The operating cost is based on 2.5 mills/kWh and the 1.2×10^8 kW-hr annual load.

Heat exchangers meeting the specifications shown can be built and installed[13] for approximately $225 thousand for the dry steam system, and $390 thousand for the water plus steam system.

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[13] G. Phillips, South West Engineering Co., Los Angeles, California Personal Communication (1973).

Appendix E

SOLAR ENERGY

Introduction

In considering solar applications, the objective was to find the extent that the sun could be used to supplant conventional fuels as a source of electric power and heat for such purposes as space heating and cooling for homes, barracks, offices, operations building and the other buildings in a military base. The military base has a need for energy or heat at various intensity or temperature levels. The highest temperature is needed for production of electric power. The next highest levels are needed for hospital sterilization, laundry, and kitchen applications. Heat energy at this level or below can be used for space conditioning if absorption refrigerators are used to replace compression ones. Hot water and space heating represent the lowest end use temperatures required.

Various schemes can be used to apply solar energy to produce the various temperatures needed. Several of these, which are applicable for use in "Solar Communities," have been recently described by Pope, et. al.[1] In this paper and a companion one,[2] the conclusion was reached that a cascaded system that used heat energy inefficiently for electric generation

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[1] R. B. Pope, W. P. Schimmel, Jr., D. O. Lee, W. H. McCullock, and B. E. Bader, "A Combination of Solar Energy and the Total Energy Concept--The Solar Community," Sandia Laboratories SLA-73-5318. Presented at the 8th Intersociety Energy Conversion Engineering Conference, August 13-17, 1973.

[2] R. B. Pope, and W. P. Schimmel, Jr., "The Solar Community and the Cascaded Energy Concept Applied to a Single House and a Small Subdivision," a Status Report, Sandia Laboratories SLA-73-0357 (May 1973).

Pages 107-108 Blank

in a turbine but which used the turbine "waste" heat for space conditioning and water heating was optimum. Except for small differences in load patterns and ratios of heat to electricity demand, military bases can be expected to resemble the solar community considered by Pope.

This cascade approach was also chosen for the case in the present study that used solar energy for electric generation as well as for space conditioning and hot water. Rather than using the combination selected by Pope--focusing devices to collect solar energy and "low efficiency" absorbers--this study used flat plate collectors with "high efficiency" absorbers. Flat plate collectors use both diffuse and direct radiation and thus use more of the available solar energy. Even in the clear sky areas of the southwest, 10 to 20 percent of the total radiation is diffuse (see p. 344 of Ref. 3). A second case used a flat plate collector with "low efficiency" only for space conditioning and hot water. As shown later, the conversion of solar energy by the two collectors is about the same in the two cases.

In testing the suitability of solar energy systems for military bases, the variable nature of solar radiation must be considered. Sunlight is an effective energy source from 8 to 10 hours per day in good weather. In addition to the hourly variations, its intensity varies with season, latitude, and the various factors that influence cloud cover. The latitude and seasonal (declination of the sun) variations can be partially compensated for by adjustment of collector tilt.

Data on solar insolation indicate that large contiguous areas have similar quantities of available sunlight. Inspection of solar insolation maps leads to the conclusion that the southwestern region--encompassing

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[3]H. C. Hottel, and J. B. Howard, "New Energy Technology--Some Facts and Assessments," MIT Press, Cambridge, Massachusetts (1971).

western Texas, New Mexico, Arizona, southern Nevada, and the desert regions of California--is the most favorable. Other regions of apparently favorable solar insolation include a southern and an upper central states region. The former includes the southern portions of eastern Texas, Louisiana, Mississippi, Alabama, Georgia, and North and South Carolina. The latter includes eastern Montana and Wyoming, North and South Dakota. Nebraska, Kansas, and western Iowa and Minnesota. The insolation on these regions was used as the basis of the analyses of solar energy use on military bases.

The analysis considered the primary isolation, its conversion into heat through use of the two collectors mentioned above, heat storage, and the use of that heat either through a combined electric power-heat distribution system or through a simple, heat-only system.

Collectors

The basic factors determining collector performance are the solar input and output (waste heat) radiation rates. Input factors that can be influenced by collector design are the transmission through the cover to the absorber unit, and the absorber's ability to retain the radiation. Output is dominated by the temperature of the absorber and its emissivity. Commonly accepted transmission factors were chosen for incoming radiation and absorptivity, two operating temperatures for absorbers (namely 325° F and 207° F) and collector emissivities of 0.05 and 0.20. Single transmission and absorption factors were used, thereby neglecting the effects of the angle of solar incidence on these quantities. An emissivity of 0.05 has been achieved with specially manufactured films. The same overall efficiency may be reached through a combination of higher emissivity films and one-way transmission glass coatings. Emissivities of 0.20 to 0.35 have been demonstrated by certain oxide coatings and such surfaces as flame-sprayed tungsten carbide containing some cobalt. Overall coefficients of 0.15 and 0.30 were used in the calculations in order to account for convection and conduction losses.

Efficiencies under a range of daily insolation conditions of the two collectors were calculated using the simplified equations of Hottel and Howard (see pp. 348-349 of Ref. 3). The daily average insolation was assumed in each case to be distributed over 8 hours, with hourly variations corresponding to those of a typical El Paso June day. This efficiency of collection is slightly overstated because the entire insolation was assigned to 8 productive hours. Some of this would be delivered at low rates and thus not collected. On the other hand, the collector efficiency will be understated because the temperature at the collector output is assumed to pertain over the entire collector surface when in fact it does not. The input heat exchange fluid will be at a temperature below that assumed (and desired) at the output, and thus, the input end of the collector will lose heat through radiation at a lower rate than calculated.

The results of the calculations are shown in Figure E-1.

Energy Collected

The solar collectors were assumed to be tilted to an angle with the horizon of 10° more than the latitude. The collector efficiency varies with the amount of solar insolation. The efficiency of the collectors as a function of the daily solar insolation is shown in Figure E-1.

The calculations of solar energy collection for this study were based on daily solar insolation data from a few stations in each of the three climatic regions--North Central, Southeast, and Southwest. Table E-1 gives the average daily heat collection and annual totals by the two types of collectors for each of the five representative days of the year.

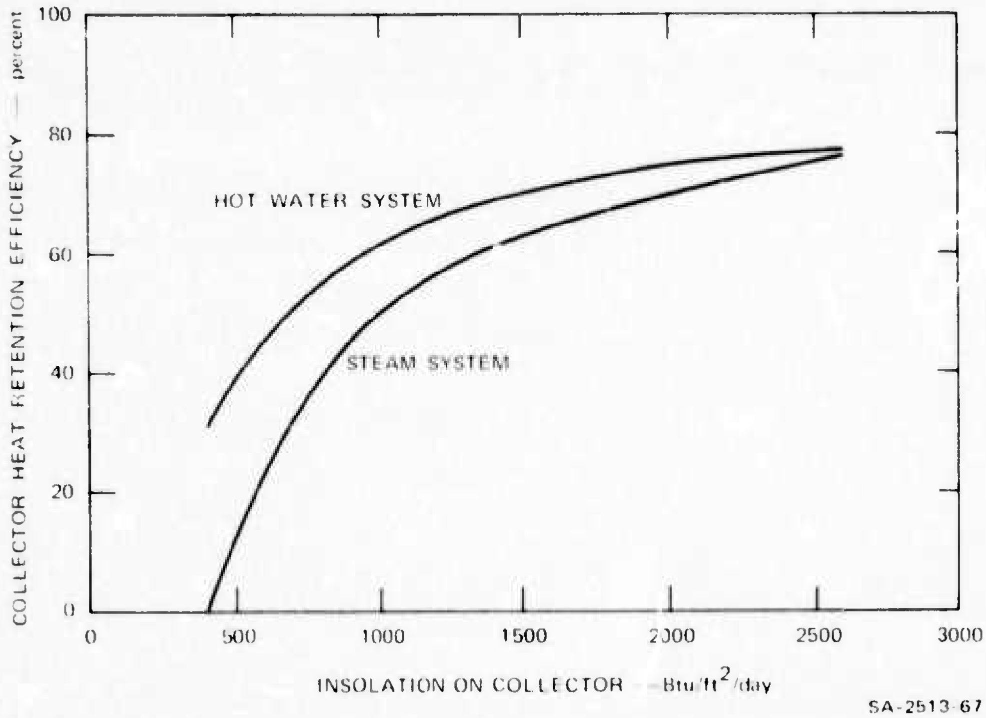

FIGURE E-1 HEAT COLLECTION EFFICIENCY AS A FUNCTION OF DAILY INSOLATION

Table E-1

AVERAGE DAILY HEAT COLLECTION OF SOLAR COLLECTORS
(Btu/sq ft)

	Heating and Cooling System			Electric Generation System		
	NC	SE	SW	NC	SE	SW
Type of day						
High heating	1,015	1,107	1,476	904	996	1,384
Moderate heating	1,292	1,107	1,660	1,181	996	1,587
No space heating or cooling	1,660	1,292	1,753	1,587	1,181	1,697
Moderate cooling	1,476	1,384	1,753	1,384	1,292	1,697
High cooling	1,753	1,476	1,753	1,697	1,384	1,697
Annual total	477,000	455,000	621,000	440,000	416,000	598,000

Two sizes of collector were used for the solar energy system for heating and cooling only. In one case (medium collector) the collector was sized to meet the thermal load on a moderate heat day with average insolation. The second case (small collector) assumes collectors half that size. For the electric generation case, the collector was sized to meet the thermal load on a no space heating or cooling day, with average insolation. The resulting collector sizes to meet these heat demands for a 10 MW base are shown in the following tabulation:

Solar Energy System	Collector Size (millions of ft^2)		
	NC	SE	SW
Heating and cooling only			
Medium collector	2.52	2.44	1.42
Small collector	1.26	1.22	0.71
Electric generation	2.44	3.29	2.29

Supplementary energy is required during periods when the energy loads exceed the energy obtained from the collectors or available from the thermal storage. When energy collected exceeds the demands and the capacity of the thermal storage, the excess energy cannot be utilized. The energy collected by the system but not utilized was determined by relating the daily variations in solar insolation to the heat demands on the representative days.

The amount of solar heat utilized annually for each of the cases is given in the following tabulation:

Solar Energy System	Solar Heat Utilized Annually (billions of Btu)		
	NC	SE	SW
Heating and cooling only			
Medium collector	877	[illegible]7	714
Small collector	535	496	390
Electric generation	1,002	1,229	1,283

Thermal Storage

The limited availability of solar energy (about 8 hours per day) and the variability of the quantity collectable make energy storage an essential part of any solar system. Two storage systems were chosen, operating around 200°F and 350°F, to mate with the two energy utilization systems (and collectors).

Thermal storage at around 200°F can be achieved most simply by using the heat capacity of water or crushed rock. Storage at 325°F or above could use the heat changes accompanying phase transitions or heat capacity effects in rocks.

High boiling organic materials (such as Santowax M) and liquid metals (such as mercury or sodium) can be used for storage at the higher temperatures necessary to produce steam and drive a steam turbine. However, the storage system should produce steam at nearly constant temperature to simplify the turbogenerator design and operation. A phase change system using a simple metal or salt or an eutectic mixture might be found for the temperature range desired. (Organic materials of appropriate characteristics might be found.) Particularly, salt mixtures with the approximate temperature requirements should be available. These might have heat storage capacities (fusion only) of 25 to 50 Btu per pound. The heat capacity of such salt mixtures should range between 0.25 and 0.50 Btu per pound. Thus an eutectic mixture could supply as much as 75 Btu per pound with a 50°F temperature differential.

A rock heat storage system can be used to produce a uniform exit temperature for most of its available heat capacity. Heat is added to the storage bin when the heat exchange medium moves in a forward direction; heat is extracted from the storage bin by reversing the direction of the heat exchange fluid. This is in contrast to the performance available from liquid storage systems. The rocks are fixed and have low heat conductivity. Flow of a heat exchange fluid across the rocks heats successive layers to the temperature of the incoming fluid that is bringing in heat or heats of outgoing fluid that is extracting heat from storage to the temperature of the hottest point (that nearest the exit in the heat extraction case).

Rock systems are not as efficient as most of the other types of storage systems in heat storag in a volume or weight sense, but they require less expensive containers and contents. A rock system might have a heat capacity of 0.2 Btu per pound per $^{\circ}$F (20 Btu per cubic foot per $^{\circ}$F). If the rock system is operative with an overall temperature drop of 50°F and this full drop is effective for 80 percent of the total system, then the capacity would be 800 Btu per cubic foot without substantial temperature change.

Rock systems can be used for the low temperature system (200°F) as well as for the 350°F system. Water systems have capacities of 1 Btu per pound per $^{\circ}$F. A 50 degree drop permits storage of 50 Btu per pound or over 3,000 Btu per cubic foot. In usual applications, the temperature of each part of the water storage tank will be covered simultaneously because convection currents will tend to keep the temperature uniform. Thus the temperature achievable by the output heat exchange fluid will drop as heat is extracted.

Energy Use

The output from the collector or storage subsystem can be delivered as hot water (approximately 200°F) directly to a complex of buildings. It can also be delivered as low temperature steam (approximately 325°F to 350°F) to a turbogenerator. The turbogenerator, operating between 325°F and 190°F, will have a practical efficiency of about 12 percent in converting heat energy to electricity. The residual heat energy, in the form of hot water, can be pumped throughout the building complex. This water is sufficiently hot to drive absorption refrigerators or air chillers for refrigeration and air-conditioning needs.

Costs of Components

The solar heating systems will be constructed of a mixture of common and unique components. Solar collectors of any kind are not available commercially. Detailed designs for the conceptual systems used as the basis of the calculations of solar heat availability have not been made so the cost estimates offered here must be viewed as preliminary and uncertain.

Heat storage using rocks or water as the primary storage element has been practiced on a small scale and the costs of concrete vaults or tankage and their construction and installation are well established.

Production of a few thousand units of household-size water-heaters by several manufacturers in the United States and Israel in the period immediately preceding 1962 was reported to cost from \$5.95 to \$8.90 per square foot of collector surface for the entire system of collector, storage tank, and auxiliary piping.[4] From this data and their own experience, Tybot and Löf suggest that \$2.00 to \$4.00 per square foot should be the cost of manufacture of collectors alone. They quote materials costs ranging from \$0.90 to \$1.90 per square foot of collector for a simple glass-covered black metal absorber collector.

Currently, a small scale manufacturer of plastic solar heaters for swimming pool application sells his product for \$1.75 per square foot.* This price includes a minimum amount of auxiliary plastic piping. The

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[4] R. A. Tybot, and G.O.G. Löf, "Solar House Heating," Natural Resources Journal, Vol. 10, No. 2, pp. 284-6, April 1970.

*Information quotation, FAFCO, Redwood City, California.

heater is not covered, as would be required for most applications, and is made of low density polyethylene, a material unsuited for hot water or steam use. A recent undocumented statement places current costs for collectors capable of producing hot water for domestic purpose (140°F to 150°F range probably) at $18 per square meter ($1.67 per square foot), and project costs of $15 per square meter ($1.40 per square foot) or less.[5]

In the present study, the materials cost of the unit shown in Figure E-2, which represents a possible configuration for the low efficiency-low temperature collector, was estimated to range from a low of $1.69 to a high of $1.99 per square foot, with the materials of construction being limited to aluminum, glass, and plastic. Delivered costs might be approximately $2.55 to $4.00 per square foot--about 50 to 100 percent above the materials cost.

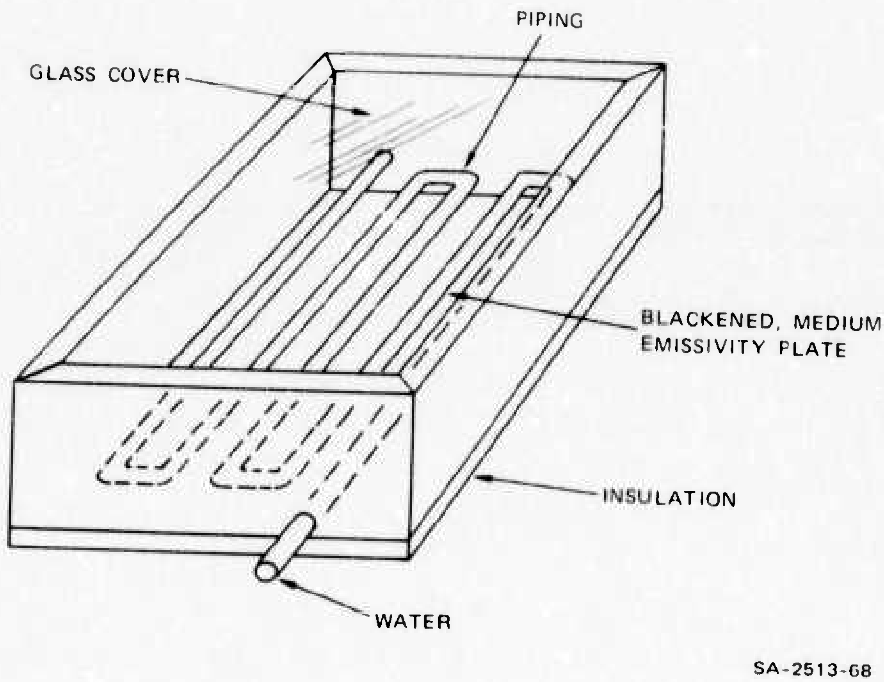

FIGURE E-2 LOW TEMPERATURE COLLECTOR SCHEMATIC FOR HOT WATER SYSTEM

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[5] R. S. Godfrey, ed., "Building Construction Cost Data 1972," Robert Snow Construction Company, Duxbury, Massachusetts.

These units must be installed on some inclined frame. A simple metal frame field-installed is estimated to cost approximately \$0.20 to \$0.25 per square foot of collector supported. Installation of collectors on the frame will probably cost a minimum of \$0.10 to \$0.25 per square foot of collector. If allowance is made for normal overhead and profit (25 percent) on the total value, costs of this installed collector can run from \$3.56 to \$5.63 per square foot. (The costs quoted are based primarily on costs and prices applicable in 1971 or early 1972).

Considering the current price of the solar pool unit at \$1.75 per square foot, a price of perhaps \$2.50 per square foot for an all-plastic heating system capable of operation at 200°F might be attainable. This price would pertain only if the manufacturing operations were large volume ones. The plastic cover would require periodic replacement, perhaps every five years if the collector efficiency were to be maintained. The installation, including frame, of the plastic collectors could add \$0.40 per square foot to the base cost and a 25 percent overhead would bring the installed cost to \$3.00.

To bracket the range of possible costs for the low temperature system, collector costs of \$3.00 and \$6.00 per square foot were used in the analysis of Chapter VII of Volume I.

Figure E-3 represents a potential configuration for a low emissivity collector for the electric generation system. Cost estimates for this system are also uncertain. However, it might be possible to build such systems with the costs indicated below (in dollars per square foot):

Collector components and piping, materials only	\$2.26	
Total for collector, including coating costs and labor		\$4.40
Coolant (Santowax @ \$0.05 per lb)		0.25
Frame and supports		0.10
Field installation, including evacuation		0.20
Constructor's O.H. fee and contingency @ 25%		1.24
		\$6.19

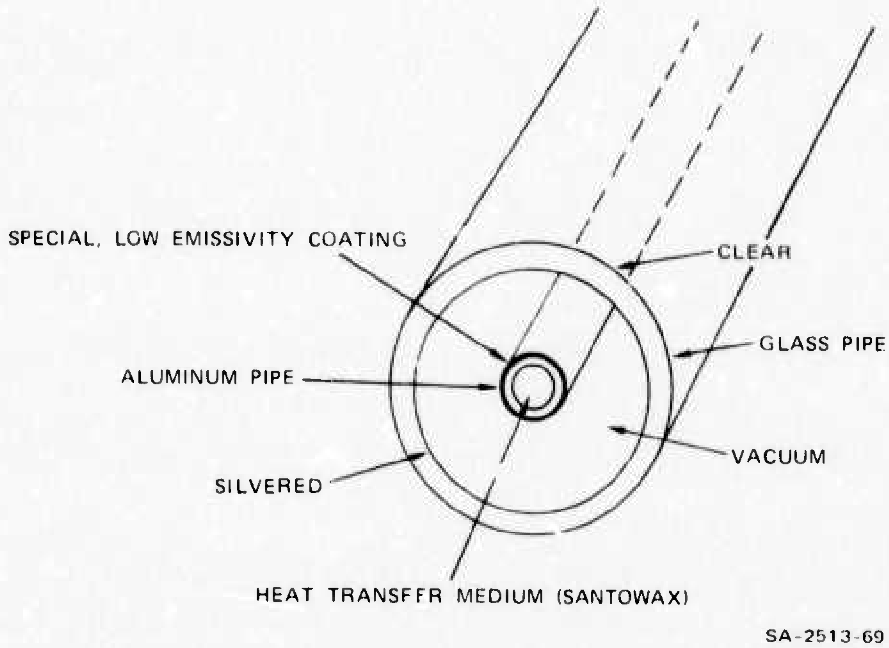


FIGURE E-3 MODERATE TEMPERATURE COLLECTOR SCHEMATIC FOR STEAM PRODUCTION, ~350°F

Rounding to \$6.00 and assuming that the price might vary by one-third either way, collector costs of \$4.00 and \$8.00 per square foot for the moderate temperature system are used in the analysis of Chapter VII of Volume I.

Appendix F

USE OF THE TOTAL ENERGY SYSTEM MODEL

Introduction

This appendix describes how to use the total energy model developed in this study for determining the economic feasibility and fuel savings for a particular total energy system application. The model applies to the fossil fuel total energy systems--diesel electric, gas turbine, and steam turbine--used to generate electricity on site, with use of heat recovered from the electric generation for heat demands. For simplicity, use of the model is described with reference primarily to the diesel electric system. Two levels of detail of analysis are described. The first level, for a preliminary evaluation of economic feasibility, applies if the energy demands for the application are similar to the cases covered in this study, and requires only an estimation of the uniform annual prices of fuel and electricity. The second level of detail requires synthesis of a total energy system to meet a given energy demand pattern. A description and program listing of the fuel consumption program are also given.

Preliminary Evaluation

A preliminary evaluation of the economic feasibility of a total energy system application to a new base or a major new complex on an existing base can be easily made if the energy demand pattern for the application can reasonably be approximated by one of the patterns given for the three climate types--North Central, Southeast, and Southwest--in Tables B-19 to B-21, and the size range of the application is within the 5 MW to 40 MW peak electric demand range considered in the study.

First, the uniform annual costs of the electric energy charge (¢/kWh) over the 25 year system life are estimated, in accordance with the standard DoD discount procedures, using the same 6-1/8 percent discount rate on which the study results are based. The electric energy charge excludes the electric demand charge which is assumed to be constant, and should be expressed in constant 1973 dollars. Similarly, the uniform annual cost of fuel ($ per million Btu) used by the base is estimated.

Next, Figures 19 and 21 to 24 of Volume I are used to determine whether the uniform annual cost of the diesel total energy system is lower or higher than that of a conventional system. These figures give the annual cost of a total energy system as a function of the fuel cost. For a conventional system with electric energy charges of 0.75, 1.5, or 2.5¢/kWh, points are marked on each line of the graphs where the annual cost of the conventional system is equal to that of the total energy system. For example, in Figure 21, for a base with a 5 MW peak electric load, a Southeast climate energy demand pattern, and an electric energy charge of 1.5¢/kWh the annual costs of the TE and conventional systems will be equal ($1.8 million), if the fuel cost is $1.67 per million Btu. If the estimated fuel cost is less than that figure, then the annual cost of the TE system is less than that of the conventional system. If the fuel cost is higher, then the TE system will cost more than the conventional system.

Detailed Evaluation

The figures in this report can also be used to make a more detailed evaluation of the economic feasibility and fuel savings for a particular TE application. The evaluation requires:

- Estimation of the energy demands
- Synthesis of a TE system to meet the energy demands
- Calculation of fuel consumption

- Estimation of costs
- Comparison with conventional system.

Energy Demands

Estimates are needed for the peak electric, thermal, and air conditioning demands, and the diurnal pattern of the demands for at least several representative days of the year (such as shown in Table B-19 to B-21). The electric demands should exclude air conditioning.

System Synthesis

A TE system to meet the estimated energy demands should be synthesized. The peak heat demands in each load center, as well as the heat losses in transmission, determine the transmission line capacity. The heat losses in transmission are estimated from Figure A-18. The total air conditioning capacity is determined by the peak air conditioning load, but must be divided in some proportion between electric and absorption air conditioning. This division depends in part on the availability of excess heat recovered from the electric generation, above the thermal demand, for the absorption air conditioning.

The electric demands for the electric air conditioning (0.83 kWe/ton), and the electric pump power for the hot water transmission lines (Figure A-17) are added to the original electric demands. The new peak electric demand, plus the additional capacity to allow for equipment down time, then determines the required electric generating capacity. For the diesel electric systems, six generating units were assumed in this study, with capacity to meet the peak demand with one unit down. For the multiple unit gas turbine system, seven units were assumed, with capacity to meet the peak demand with one unit down.

The heat recovery from the electric generation by a diesel system as a function of percent of rated load is given in Figure A-13. The heat recovery for a gas turbine system at rated load is given in Figure A-3, and a multiplier to account for part load is given in Figure A-4. The capacity required for the high temperature water generator is equal to the maximum difference (over the year) between the thermal demand (including transmission line heat loss) and the heat recovered from the electric generation. In this study, installed capacity was based on three units sized to meet the demand with one unit on standby.

Fuel Consumption

The TE system uses fuel for both electric generation and auxiliary heating. Although a computer program was used in this study to calculate fuel consumption, hour by hour, a simpler method can be used if the energy demands are simply represented by diurnal patterns for a few representative days of the year. The annual fuel consumption for electric generation is calculated from the annual electric load (including air conditioning and pump power for the hot water transmission lines), using the appropriate heat rate from Figure A-1 for gas turbines and Figure A-12 for diesels, and a heat rate multiplier from Figure A-2 to account for part load conditions.

The annual auxiliary heat load to be met by the high temperature water generator is given by:

> Auxiliary heat load = total heat demand (including transmission line losses) - heat recoverable from the electric generation + recoverable heat in excess of needs.

As previously mentioned, the heat recoverable from the electric generation for a diesel system is obtained from Figure A-13, using an estimate of the effective average part load over the year. The excess recoverable heat can be estimated from a graph of the heat demand and recoverable heat for the hours when the recoverable heat exceeds the heat demand.

The annual fuel consumption for auxiliary heating is obtained by dividing the auxiliary heat load by the efficiency of the high temperature water generator (0.83 for an oil-fired system, from this volume, page 23).

Costs

The uniform annual cost of a TE system is the sum of the annualized capital costs, the annual operating and maintenance costs, and the uniform annual costs of the fuel over the system lifetime. The capital cost is the sum of the capital costs of the four component groups: electric generating plant; high temperature water generator; hot water transmission lines; and air conditioning. The capital costs (including installation) per unit of capacity as a function of installed capacity, for each component group, are given in the figures in Appendix A. An example of the derivation of capital costs is given on pages 74 to 76 of this volume.

The annual operating and maintenance costs for each component group are also derived from data in Appendix A. An example is given on pages 76 and 77.

The fuel costs are obtained by estimating the fuel costs in each of the 25 years of the system life and calculating the uniform annual costs, using the appropriate discount rate.

Comparison with Conventional System

The conventional system includes only two of the four component groups: high temperature water generators and air conditioning. Capital costs for these two equipment groups are given in Figures A-15 and A-21, respectively. Annual maintenance costs for air conditioning are given in Figure A-21.

The conventional system purchases electricity from a utility, and purchases fuel for consumption on base for space and water heating. The annual fuel consumption is equal to the total annual heat demands divided by the fuel efficiency of the heating system (0.83 for an oil-fired system). The charges for electricity include a demand charge that is based on peak electric demand, and an energy charge that is based on the amount used. Estimates must be made of the fuel prices and the electric demand and energy charges over the lifetime of the system. The resulting annual costs for fuel and electricity are converted to uniform annual costs using the discount rate.

Fuel Consumption Program

A computer program was developed to calculate the fuel consumption of a TE system. A summary flow diagram of the program is shown in Figure F-1. A more detailed flow diagram of the subroutines of the program is shown in Figure F-2.

Input Data

The fuel consumption program uses three types of input data: (1) energy loads, (2) equipment capacities, and (3) system parameters (i.e., equipment performance characteristics).

The energy load data consist of the hourly electric, heating, and cooling loads for five representative days of the year. The input data for the energy loads include:

- The number of days of the year which each of the five days represents.
- The peak electric, total heat, and total cooling loads for each of the five days.

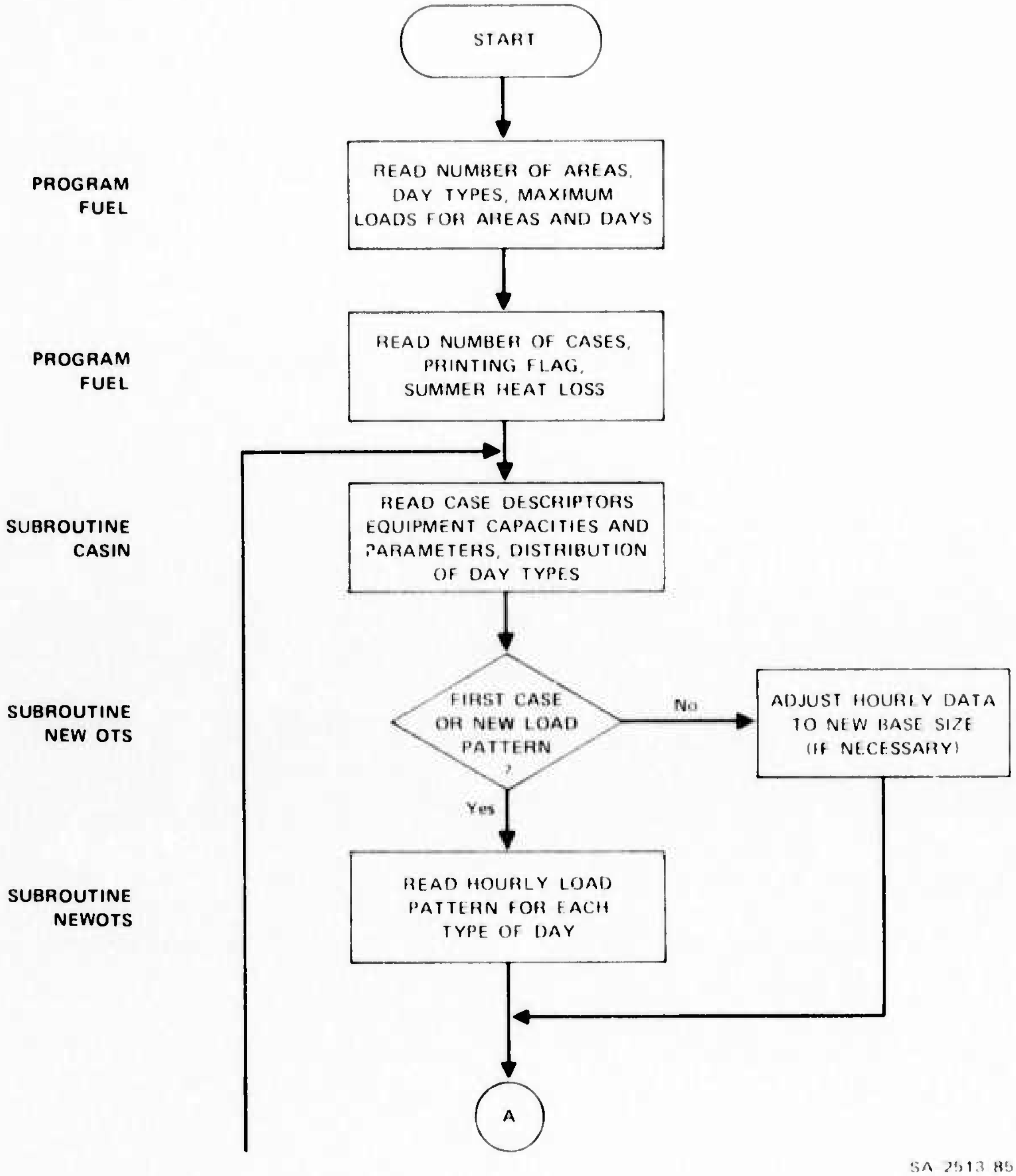


FIGURE F-1 FUEL CONSUMPTION PROGRAM SUMMARY FLOW DIAGRAM

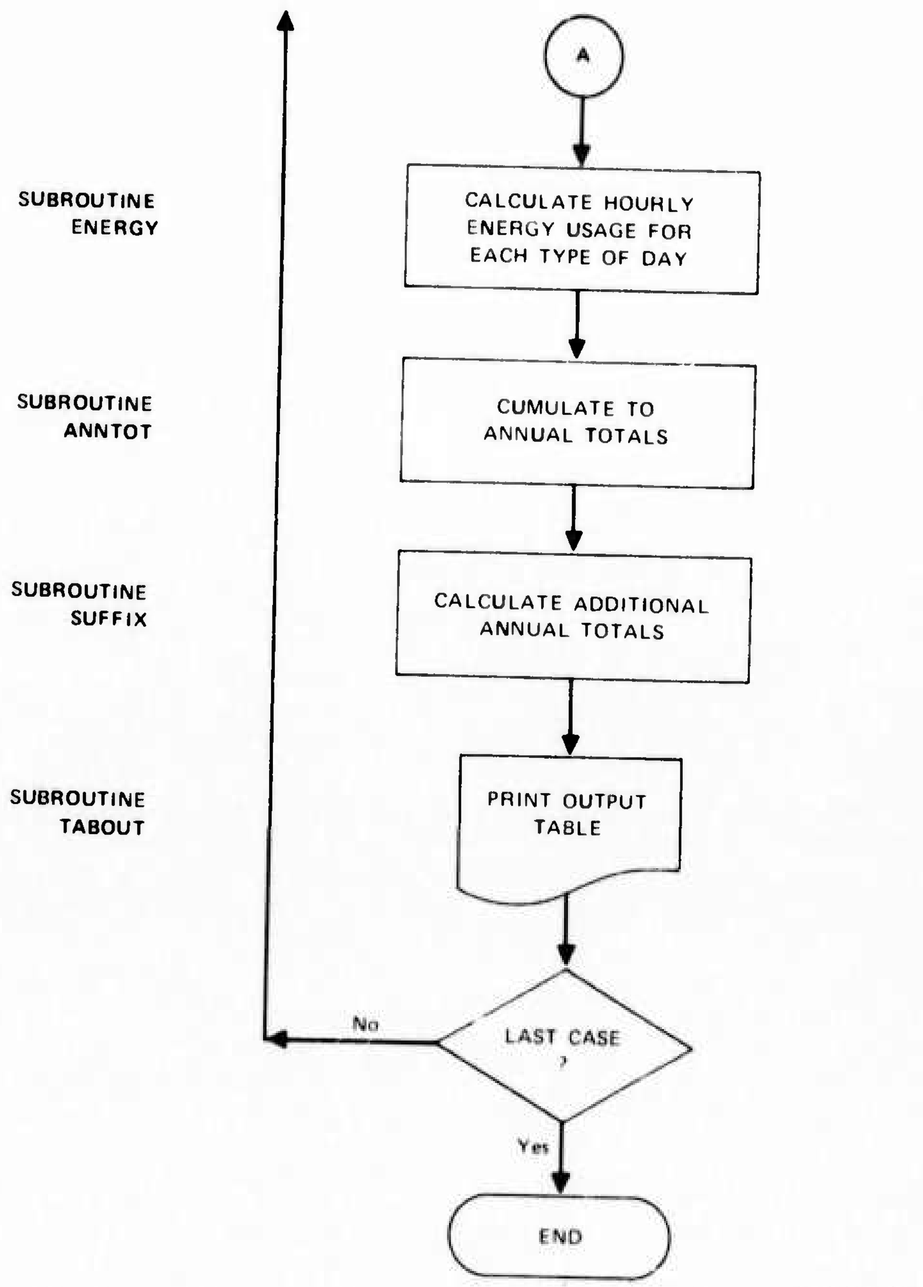
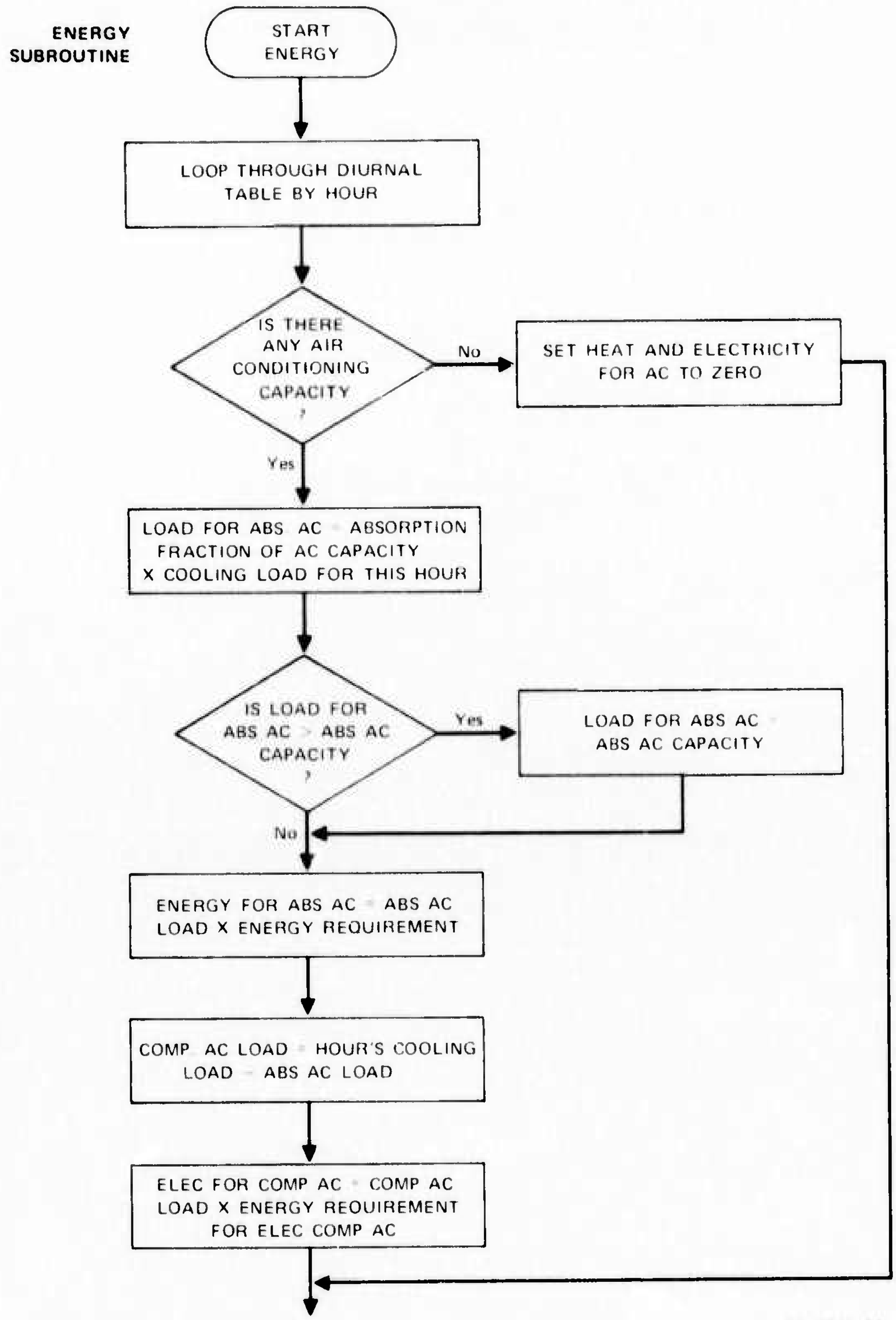


FIGURE F-1 FUEL CONSUMPTION PROGRAM SUMMARY FLOW DIAGRAM (Concluded)



SA 2513 86a

FIGURE F-2 FUEL CONSUMPTION PROGRAM SUBROUTINE FLOW DIAGRAM

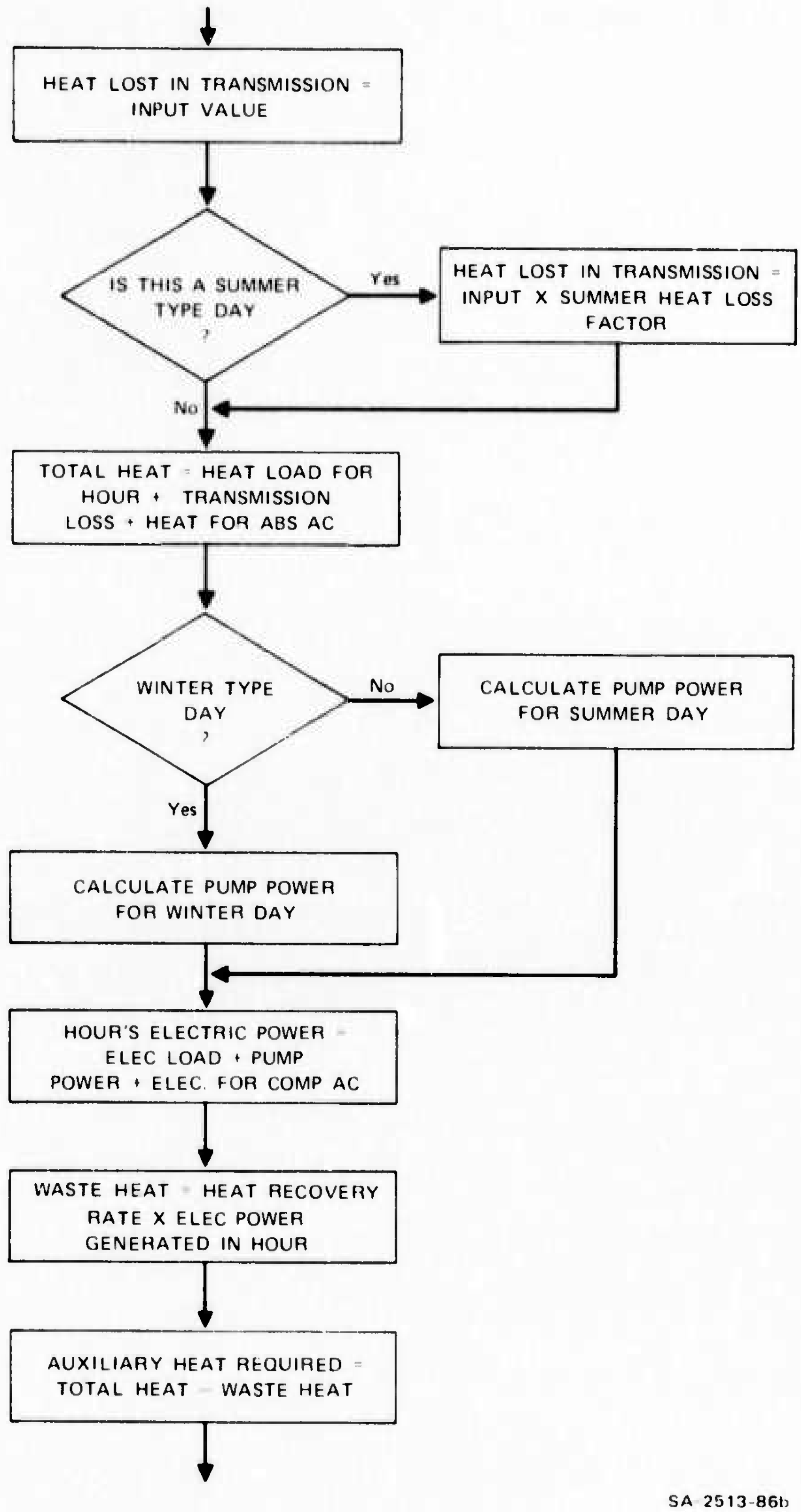


FIGURE F-2 FUEL CONSUMPTION PROGRAM SUBROUTINE FLOW DIAGRAM (Continued)

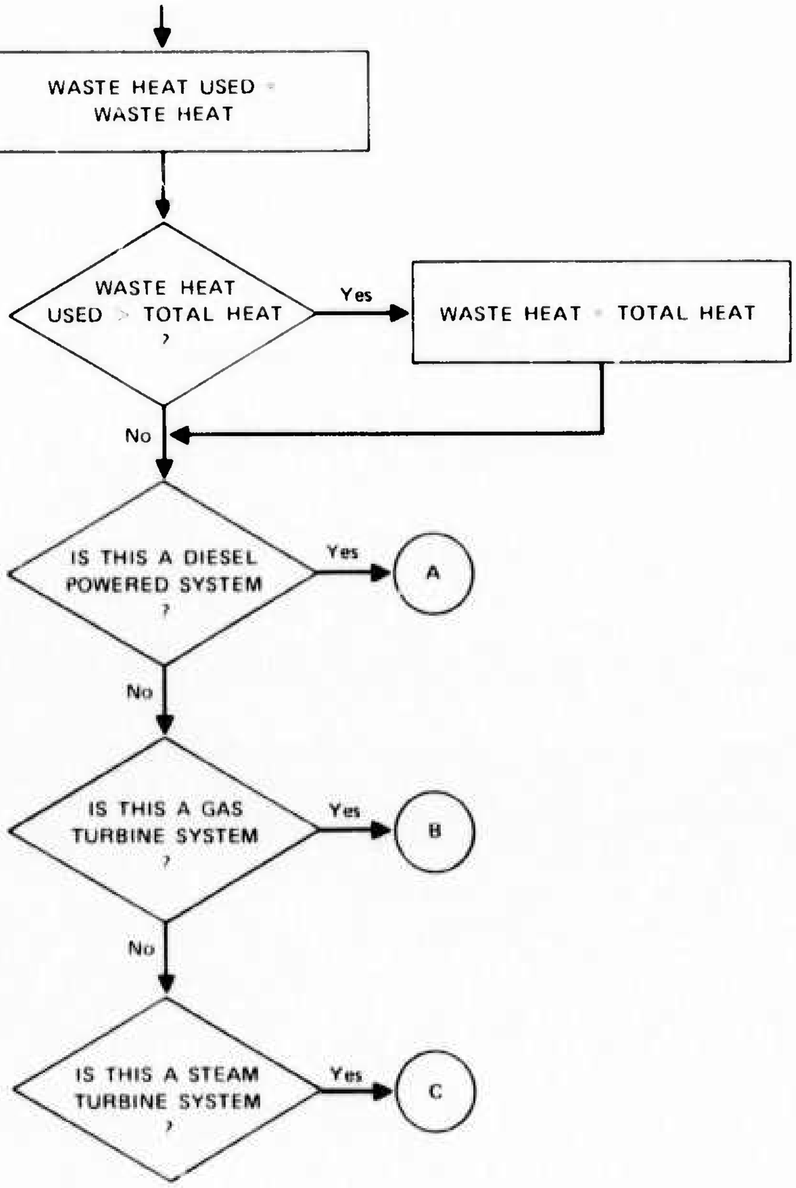


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FIGURE F-2 FUEL CONSUMPTION PROGRAM SUBROUTINE FLOW DIAGRAM (Continued)

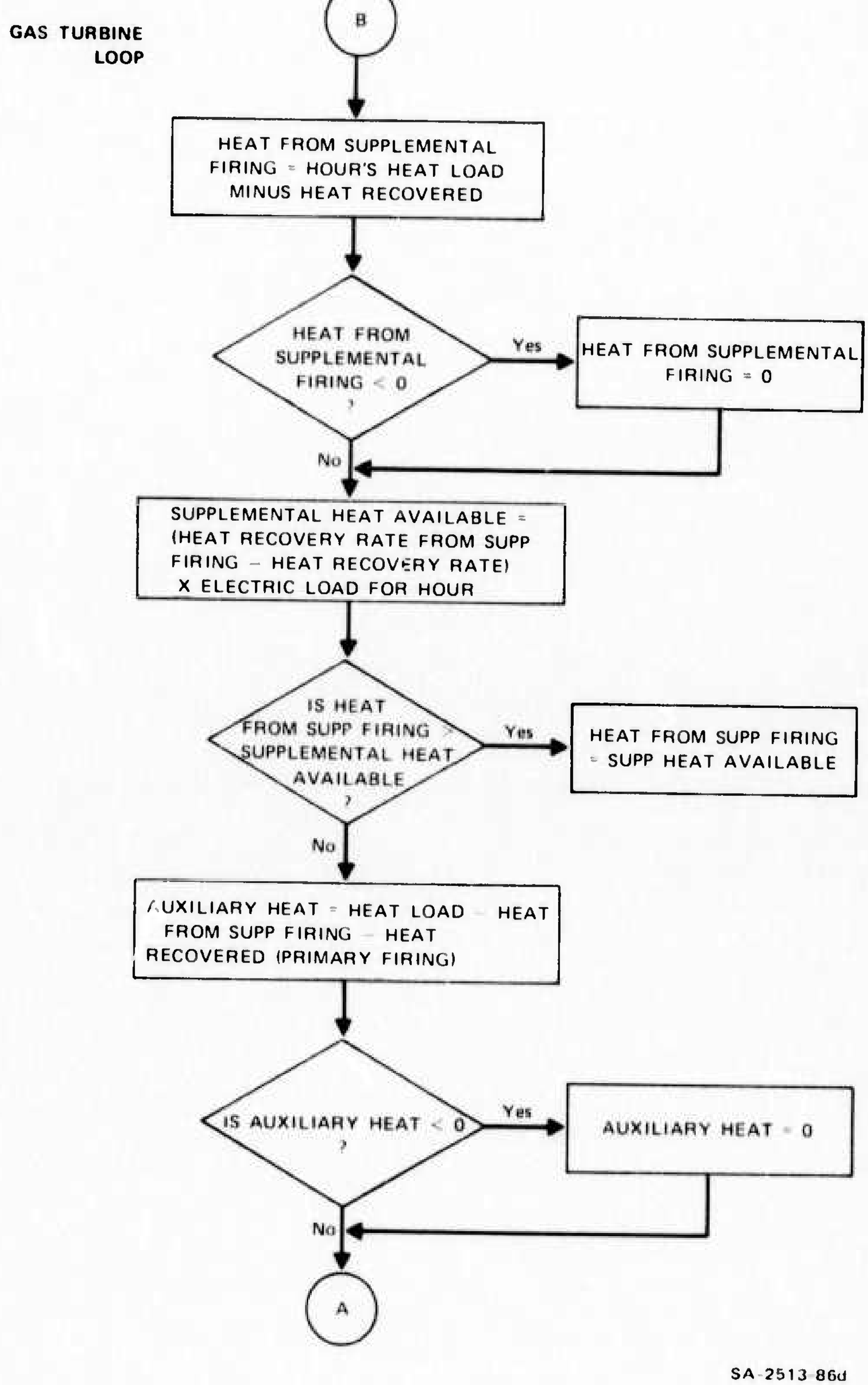

FIGURE F-2 FUEL CONSUMPTION PROGRAM SUBROUTINE FLOW DIAGRAM (Continued)

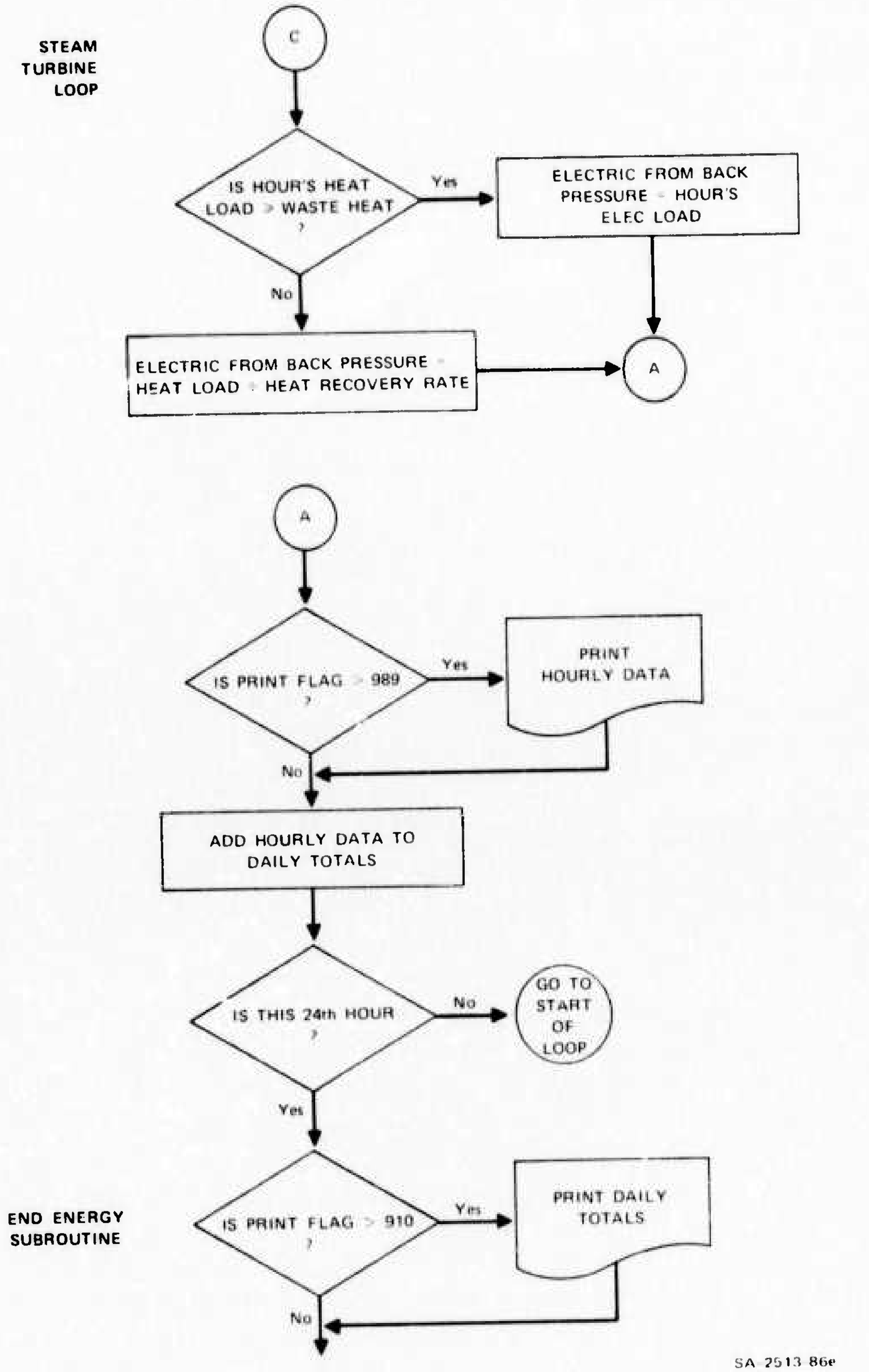

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FIGURE F-2 FUEL CONSUMPTION PROGRAM SUBROUTINE FLOW DIAGRAM (Continued)

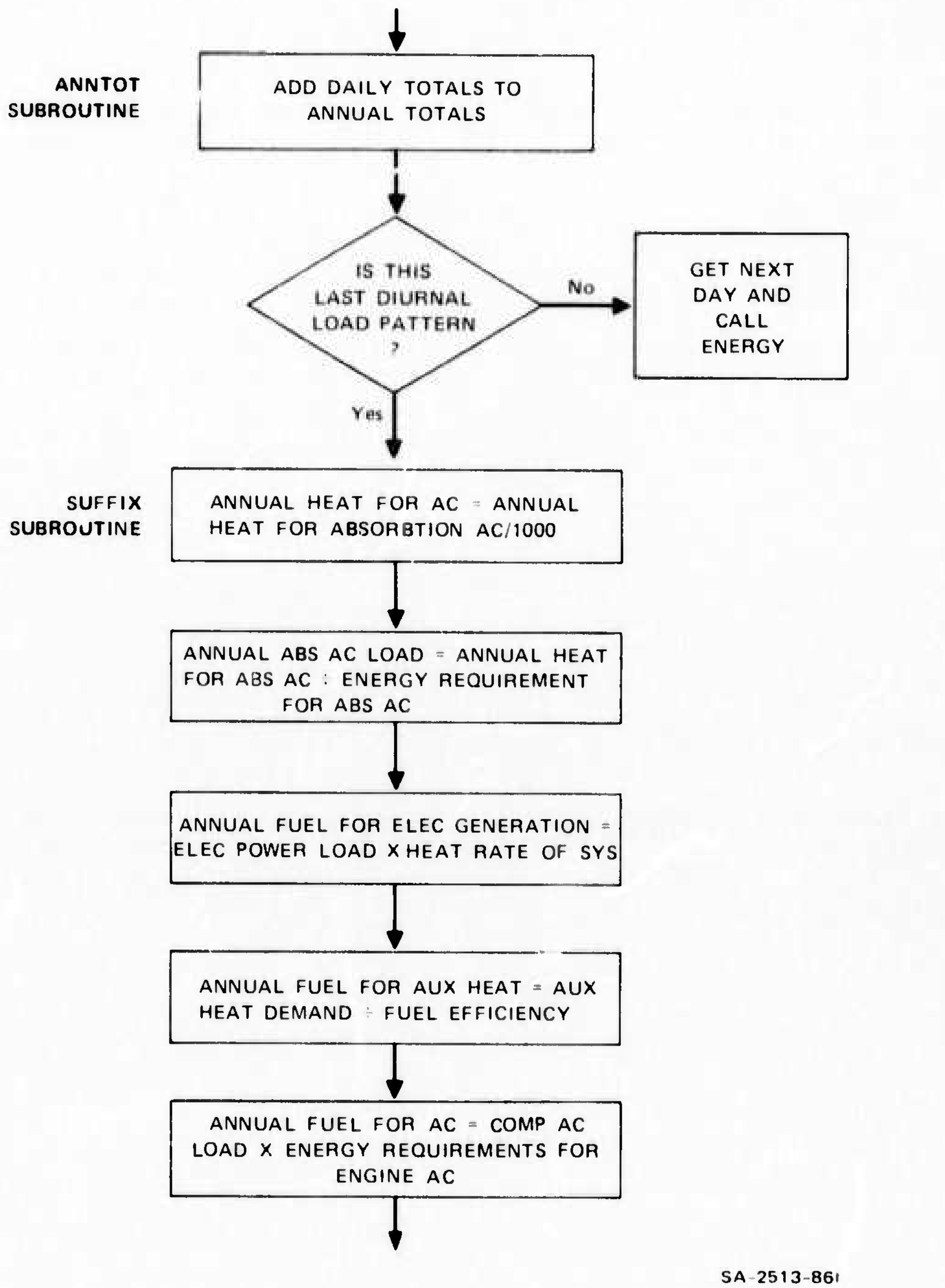

FIGURE F-2 FUEL CONSUMPTION PROGRAM SUBROUTINE FLOW DIAGRAM (Continued)

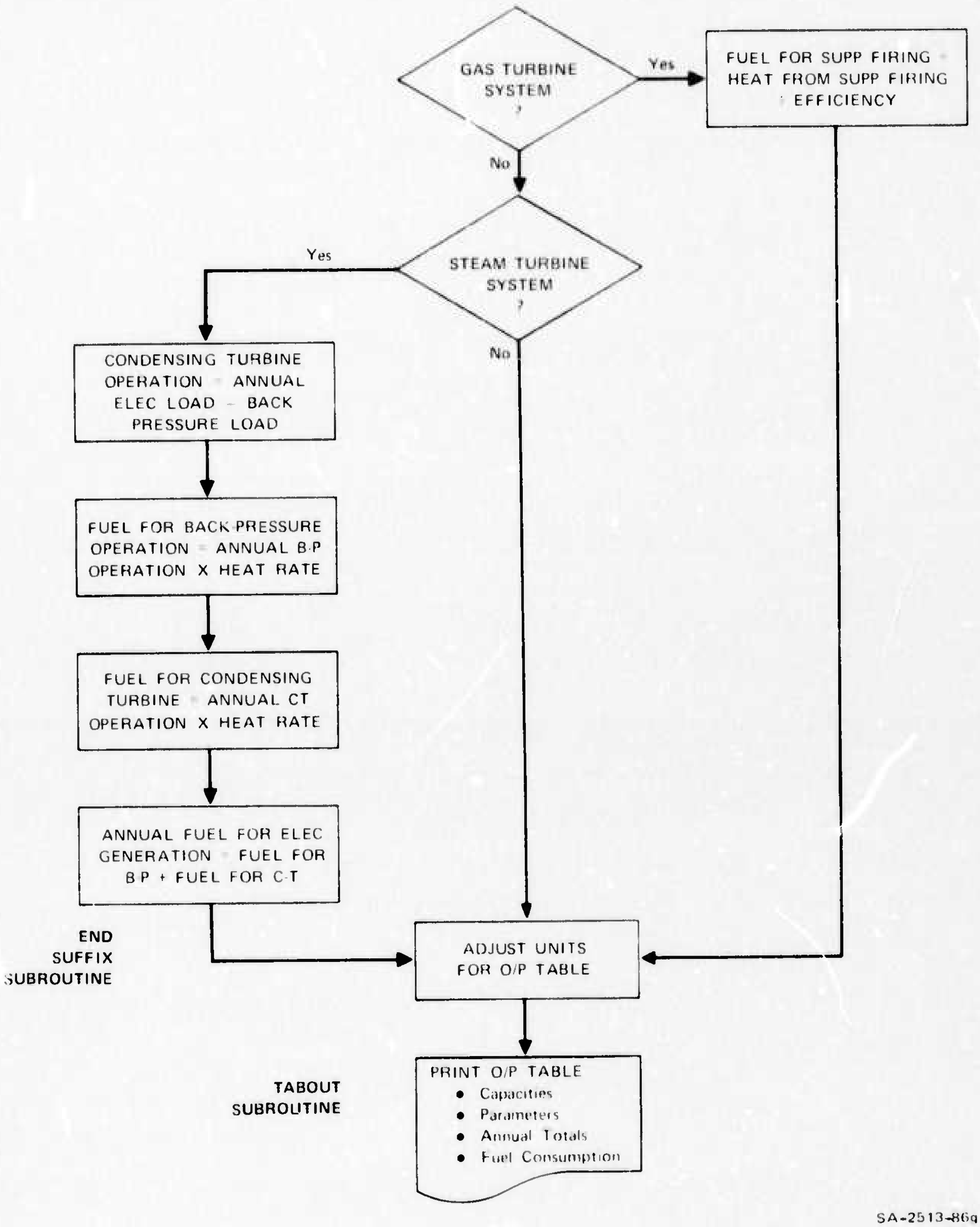

FIGURE F-2 FUEL CONSUMPTION PROGRAM SUBROUTINE FLOW DIAGRAM (Concluded)

- The hourly energy loads:
  - Electric load as a percent of the peak electric for each of the five days.
  - Heat load as a percent of the daily heat load for each of the five days.
  - Cooling load as a percent of the daily cooling load for the two days which have a cooling load.

The input deck is composed of three groups of input cards: (1) program data, (2) case data, and (3) load pattern data. The data deck setup is shown in Figure F-3. A description of the cards in each group is given in Table F-1.

The first card in the program data deck gives the number of geographic areas or type of load patterns to be run, and the number of days used to represent all the days of the year. The next three cards give the peak electric and total daily heating and cooling loads for each of the representative days.

The first card in the case data deck gives a set of index numbers describing the case, and an alphanumeric descriptor label. The second and third cards give the capacities of each equipment element, and the system parameters or equipment performance characteristics. The fourth card gives the number of days of the year which each exemplar day represents.

The load pattern data deck gives the hourly electric, heating, and cooling loads as a percent of the peak electric or total heating or cooling load for the day. Two cards are required for each 24-hour load pattern. The code in the fourth column describes the type of load. The electrical, heating, and cooling loads are grouped by type of day, and must be read in the following order:

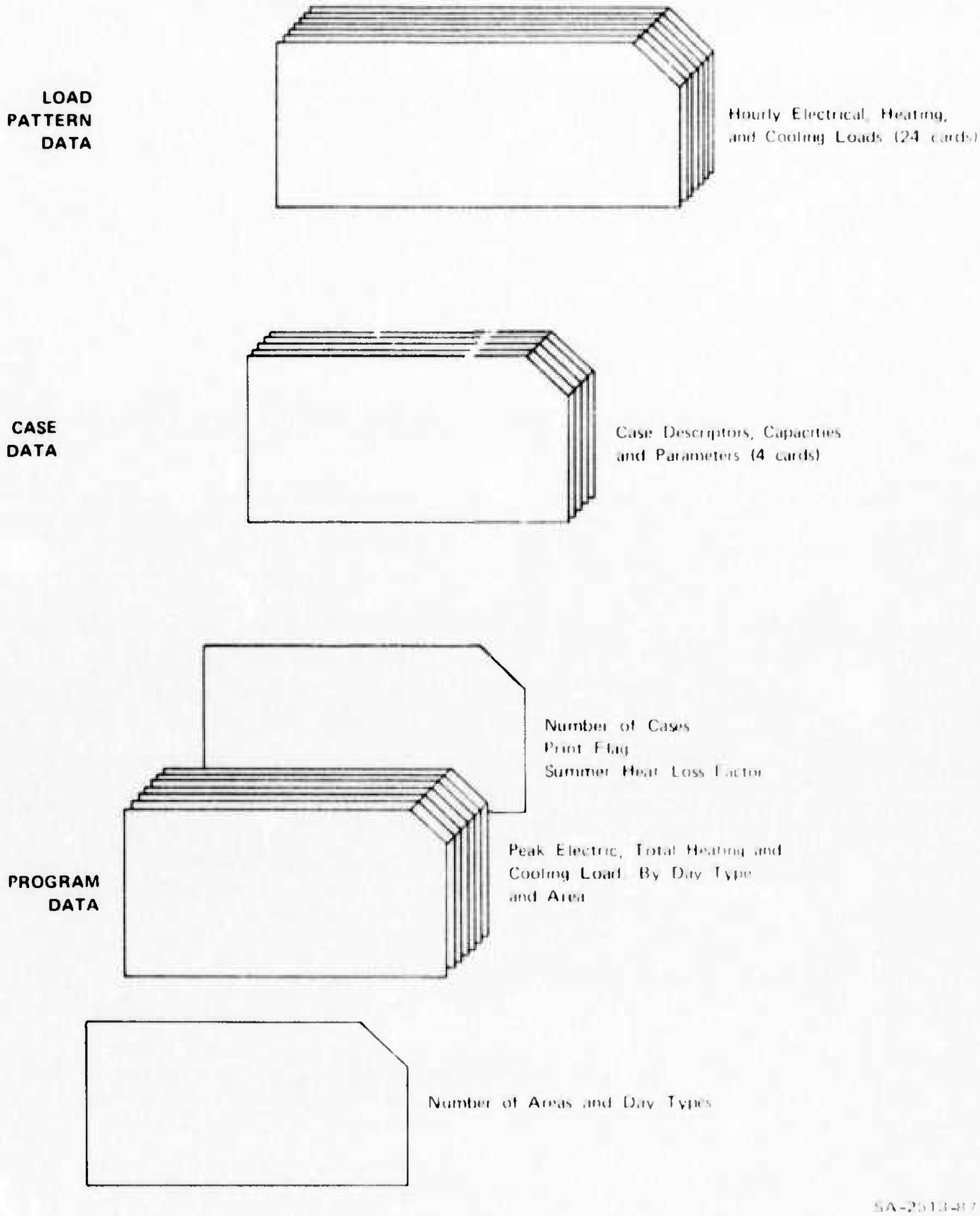

FIGURE F-3 MAKEUP OF DATA DECK FOR FUEL CONSUMPTION PROGRAM

Table F-1

FUEL CONSUMPTION PROGRAM INPUT DATA CARDS

Program Data

Card No.	Card Columns	Program Variable	Description
1	5	NAREA	Number of geographic areas (maximum of 5)
1	10	NDTYPE	Number of day types (maximum of 5)
2	1-80	PKWE	Peak electric loads for each type of day by area
3	1-80	THTG	Total heating load for each type of day by area
4	1-80	TCLG	Total cooling load for each type of day by area
5	1-5	MAXCASE	Number of cases to be read in this run
5	6-10	LPRINT	Printing lag for intermediate outputs (999 for maximum output)
5	11-15	SHLOSS	Summer heat loss in transmission lines as a fraction of winter heat loss

Case Data

Card No.	Card Columns	Program Variable	Description
1	1	ICODE(1)	Index for area load pattern
	2	ICODE(2)	Index for base size
	3	ICODE(3)	Index for heat transmission line length
	4	ICODE(4)	Index for type of electric system
	5	ICODE(5)	Index for type of fuel
1	11-40	NAN(1)-(3)	Alphanumerical descriptor for case (30 characters)
2	1-10	CELEC	Electric generation capacity (MW)
	11-20	CABAC	Absorption air conditioning capacity (tons)
	21-30	CCPAC	Compression air conditioning capacity (tons)

Table F-1 (Continued)

Case Data - Continued

Card No.	Card Columns	Program Variable	Description
2	31-40	CAUXL	Auxiliary heating capacity (millions of Btu/hr)
	41-50	CHTRN	Heat transmission line capacity (thousands of Btu/hr)
	51-60	CPUMP	Pump power capacity for the heat transmission line (kw)
	61-70	HEATL	Heat loss for heat transmission line in winter (thousands of Btu/hr)
3	1-10	HREC	Heat recovery rate from electric generation (Btu/kWh)
	11-20	ABTU	Energy requirement for absorption air conditioning (Btu/ton-hr)
	21-30	BKWH	Energy requirement for electric compression air conditioning (kWh/ton-hr)
	31-40	DENG	Energy requirement for engine compression air conditioning (Btu/ton-hr)
	41-50	FEFF	Heating efficiency of auxiliary heat system (fraction, e.g., .83)
	51-60	HEATRT	Heat rate for electric generation (Btu/kWh)
	61-70	HRCTUR	Heat recovery rate from gas turbine with supplemental firing (Btu/kWh)
	71-80	SEFF	Heating efficiercy for supplemental firing of gas turbine (fraction)
4	1-5	NODT	Number of day types (should equal NDTYPE above)
	6-10	NDAY(1)	Number of calendar days that first diurnal load pattern (high heat) applies
	11-15	NDAY(2)	Same for second load pattern
	16-20	NDAY(3)	Same for third load pattern
	21-25	NDAY(4)	Same for fourth load pattern
	26-50	NDAY(5)	Same for fifth load pattern (high cooling)

Table F-1 (Concluded)

Load Pattern Data

Card No.	Card Columns	Program Variable	Description
1	2	IAR	Area code
	3	IDY	Day type code
	4	IL	Load Type E: Electrical; H: Heat, C: Cool
	5	Not read	First (1) or second (2) card for load
	9-80	TIN(1)-(12)	Hourly loads for morning as percent of daily peak or total
2	1-8	Not read	
	9-80	TIN(13)-(24)	Hourly loads for PM

Type of Day	Type of Load Data
High heating	Electric Heating
Moderate heating	Electric Heating
Minimum heating and no cooling	Electric Heating
Moderate cooling	Electric Heating Cooling
High cooling	Electric Heating Cooling

An example of a card listing of the input data is given in Table F-2. This example is for a run covering two base sizes--10 MW and 20 MW--for a Southeast type load pattern and a diesel electric TE system.

Output

An example of the output of the fuel consumption program is shown in Tables F-3 and F-4. The first part of the output describes the case and repeats part of the input data. The five digits after CASE are the index numbers for load pattern, base size, heat transmission line lengths, electric generating system type, and fuel type. The next line is the alphanumeric descriptor label. The case description block further identifies the case.

Next, the input data for the equipment capacities are listed. These include electric generation plant, absorption air conditioning, compression air conditioning, auxiliary heating, heat transmission line, winter heat loss in the heat transmission line, and pump power for the heat transmission line. (In the units, the M is thousands and MM is millions.)

Table F-2

FUEL CONSUMPTION PROGRAM INPUT DATA CARD LISTING EXAMPLE

```
    3    5
 9.5 8.5 7.5 6.5 9.5 9.5 8.5 7.5 6.5 9.5 9.5 8.5 7.5 8.5 9.5
64803256 833 833 83352882697 750 750 75048312358 500 500 500
   0   0   0  55 102   0   0   0  91 172   0   0   0 103 221
   2  900 0.74
22112     CONV A C 50 PCT ABSORPTION
  17.1        5100.       5100.       216.        241700.     104.5       3700.
  2900.       17987.      0.83        0.0         0.83        10600.
   5   56  116   71   82   40
21E1      80.0   79.0   77.0   76.0   78.0   80.0   83.0   90.0   93.0   94.0   95.0   96.0
21E2      95.0   94.0   93.0   93.0   94.0   97.0  100.0  100.0   99.0   96.0   92.0   86.0
21H1       4.2    4.1    4.0    4.1    4.2    4.2    4.3    4.4    4.5    4.5    4.4    4.3
21H2       4.2    4.0    3.9    3.8    3.9    4.0    4.1    4.1    4.2    4.2    4.2    4.2
22E1      66.0   62.0   60.    59.0   60.0   62.0   70.0   77.0   85.0   90.0   92.0   92.0
22E2      92.0   90.0   88.0   88.0   89.0   92.0   97.0  100.0   99.0   95.0   89.0   77.0
22H1       4.2    4.1    4.0    4.1    4.2    4.2    4.3    4.4    4.5    4.5    4.4    4.3
22H2       4.2    4.0    3.9    3.8    3.9    4.0    4.1    4.1    4.2    4.2    4.2    4.2
23E1      56.0   54.0   51.0   50.0   51.0   52.0   55.0   63.0   78.0   87.0   90.0   90.0
23E2      88.0   87.0   85.0   84.0   82.0   82.0   84.0   90.0  100.0   97.0   86.0   75.0
23H1       2.7    2.6    2.5    2.6    2.7    3.0    3.5    4.0    4.7    5.0    5.3    5.5
23H2       5.3    5.1    5.0    4.9    4.8    4.9    5.1    5.2    4.7    4.2    3.6    3.1
24E1      56.0   54.0   51.0   50.0   51.0   52.0   55.0   63.0   78.0   87.0   90.0   90.0
24E2      88.0   87.0   85.0   84.0   82.0   82.0   84.0   90.0  100.0   97.0   86.0   75.0
24H1       2.7    2.6    2.5    2.6    2.7    3.0    3.5    4.0    4.7    5.0    5.3    5.5
24H2       5.3    5.1    5.0    4.9    4.8    4.9    5.1    5.2    4.7    4.2    3.6    3.1
24C1       3.0    2.6    2.0    1.4    1.0    0.8    0.8    1.0    1.0    2.2    3.4    4.6
24C2       5.8    6.6    7.3    7.7    7.9    7.9    7.7    6.9    6.0    5.0    4.2    3.4
25E1      56.0   54.0   51.0   50.0   51.0   52.0   55.0   63.0   78.0   87.0   90.0   90.0
25E2      88.0   87.0   85.0   84.0   82.0   82.0   84.0   90.0  100.0   97.0   86.0   75.0
25H1       2.7    2.6    2.5    2.6    2.7    3.0    3.5    4.0    4.7    5.0    5.3    5.5
25H2       5.3    5.1    5.0    4.9    4.8    4.9    5.1    5.2    4.7    4.2    3.6    3.1
25C1       3.6    3.3    3.1    2.8    2.6    2.5    2.5    2.5    2.6    3.2    3.6    4.4
25C2       5.0    5.4    5.7    5.9    6.0    6.0    5.9    5.5    5.1    4.6    4.2    3.8
23112     CONV A C 5. PCT ABSORPTION
  34.2        10300.      10300.      432.        590300.     278.8       6900.
  2900.       17987.      0.83        0.0         0.83        10300.      0.0
   5   56  116   71   82   40
```

Table F-3

FUEL CONSUMPTION PROGRAM OUTPUT--10 MW BASE

SUMMARY TABLE - CASE 22112 JUN 07, 1974

10 MW BASE IN SO. EAST CONV A C 50 PCT ABSORPTION

CASE DESCRIPTION

LOAD PATTERN	SO. EAST
BASE SIZE	10 MW
LINE LENGTH	STANDARD
TYPE OF SYSTEM	DIESEL EL.
FUEL USED	LIGHT OIL

EQUIPMENT CAPACITIES

ELECTRIC GENERATION	(MW)	17.
ABSORPTION AIR C.	(TONS)	5100.
COMPRESSION A. C.	(TONS)	5100.
AUX. HEATING	(MM-BTU/HR)	216.
HEAT TRANS CAP.	(M-BTU)	241700.
WINTER HEAT LOSS	(M-BTU/HR)	3700.
PUMP POWER	(KW)	104.

SYSTEM PARAMETERS

ABSORPTION AIR COND.	(BTU/TON-HR)	17987.
ELEC. COMPRESSION A.C.	(KWH/TON-HR)	.830
ENG . COMPRESSION A.C.	(BTU/TON-HR)	0.
HEAT RECOVERY RATE	(BTU/KWE)	2900.
FUEL HEAT RATE (ELEC)	(BTU/KW-HR)	10600.
AUX HEAT FUEL EFFICIENCY	(PCT)	83.

ANNUAL TOTALS - ELECTRIC

ELECTRIC POWER LOAD	(MW-HR)	60170.
ELEC LOAD FOR PUMPS	(MW-HR)	183.
ELEC FOR COMP. A.C.	(MW-HR)	5962.
TOTAL ALL USES	(MW-HR)	66315.

ANNUAL TOTALS - AIR COND

ABSORPTION AIR COND	(M-TON-HR)	7174.
COMPRESSION AIR COND	(M-TON-HR)	7183.

ANNUAL TOTALS - HEAT

HEATING LOAD	(MILLION-BTU)	753730.
HEAT LOSS-TRANS	(MILLION-BTU)	27956.
HEAT TO AIR C	(MILLION-BTU)	129033.
HEAT REQUIRED	(MILLION-BTU)	910719.
WASTE HEAT AVAILABLE	(MM-BTU)	192314.
HEAT RECOVERED	(MILLION-BTU)	192314.
AUXILIARY HEAT	(MILLION-BTU)	718404.

FUEL CONSUMPTION

ELECTRIC GENERATION	(MM-BTU)	702942.
AUXILIARY HEATING	(MM-BTU)	865547.
ENGINE AIR COND.	(MM-BTU)	0.
TOTAL FUEL	(MM-BTU)	1568489.

Table F-4

FUEL CONSUMPTION PROGRAM OUTPUT--20 MW BASE

SUMMARY TABLE - CASE 23112 JUN 07, 1974

20 MW BASE IN SO. EAST CONV A C 50 PCT ABSORPTION

CASE DESCRIPTION

LOAD PATTERN	SO. EAST
BASE SIZE	20 MW
LINE LENGTH	STANDARD
TYPE OF SYSTEM	DIESEL EL.
FUEL USED	LIGHT OIL

EQUIPMENT CAPACITIES

ELECTRIC GENERATION	(MW)	34.
ABSORPTION AIR C.	(TONS)	10300.
COMPRESSION A. C.	(TONS)	10300.
AUX. HEATING	(MM-BTU/HR)	432.
HEAT TRANS CAP.	(M-BTU)	590300.
WINTER HEAT LOSS	(M-BTU/HR)	6900.
PUMP POWER	(KW)	279.

SYSTEM PARAMETERS

ABSORPTION AIR COND.	(BTU/TON-HR)	17987.
ELEC. COMPRESSION A.C.	(KWH/TON-HR)	.830
ENG . COMPRESSION A.C.	(BTU/TON-HR)	0.
HEAT RECOVERY RATE	(BTU/KWE)	2900.
FUEL HEAT RATE (ELEC)	(BTU/KW-HR)	10300.
AUX HEAT FUEL EFFICIENCY	(PCT)	83.

ANNUAL TOTALS - ELECTRIC

ELECTRIC POWER LOAD	(MW-HR)	120340.
ELEC LOAD FOR PUMPS	(MW-HR)	270.
ELEC FOR COMP. A.C.	(MW-HR)	11918.
TOTAL ALL USES	(MW-HR)	132527.

ANNUAL TOTALS - AIR COND

ABSORPTION AIR COND	(M-TON-HR)	14355.
COMPRESSION AIR COND	(M-TON-HR)	14359.

ANNUAL TOTALS - HEAT

HEATING LOAD	(MILLION-BTU)	1507460.
HEAT LOSS-TRANS	(MILLION-BTU)	52134.
HEAT TO AIR C	(MILLION-BTU)	258209.
HEAT REQUIRED	(MILLION-BTU)	1817803.
WASTE HEAT AVAILABLE	(MM-BTU)	384328.
HEAT RECOVERED	(MILLION-BTU)	384328.
AUXILIARY HEAT	(MILLION-BTU)	1433475.

FUEL CONSUMPTION

ELECTRIC GENERATION	(MM-BTU)	1365028.
AUXILIARY HEATING	(MM-BTU)	1727079.
ENGINE AIR COND.	(MM-BTU)	0.
TOTAL FUEL	(MM-BTU)	3092106.

The input data for the system parameters are also listed. These parameters include the energy requirements for three types of air conditioning (absorption, electric compression, and engine compression), the heat recovery rate from the electric generation, the heat rate of the electric generation, and the efficiency of the auxiliary heating system.

The output of the program gives the annual totals for the electric, air conditioning, and heating loads as well as the total for annual fuel consumption. The electric loads include the primary electric demand, the additional demands for the heat transmission line pumps and the air conditioning, and the total. The annual total ton-hrs of air conditioning are listed separately for the absorption air conditioning and the vapor compression air conditioning.

The next block of output gives the annual totals of each type of heat load or heat generation. The heat loads include the primary heat load, the additional heat loss in the heat transmission lines and the heat load for the absorption air conditioning. The sum of these heat loads is identified on the next line as "heat generated." This block also gives the amount of waste heat available from the electric generation, how much of that heat is used, and, finally, the additional heat required from the auxiliary heating system.

The last output block gives the annual fuel consumption for electric generation, auxiliary heating, engine driven vapor compression air conditioning if used, and the total.

Program Listing

The program listing for the fuel consumption program is given in Table F-5. The table begins with the listing for the master program, followed by the listings for six subroutines.

Table F-5

FUEL CONSUMPTION PROGRAM LISTING

```
PROGRAM     FUEL      TRACE

      PROGRAM  FUEL (INPUT,OUTPUT, TAPE9)
      COMMON/ NDATA/ ICODE(10), HREC,ABTU,BKWH,DENG,NODT, NDAY(5)
     2           , HL(24), EL(24),CL(24), HEATRT, FEFF,LPRINT,SHLOSS
     3        , FRAB, CELEC,CABAC,CCPAC,CAUXH,CHTRN,CPUMP,HEATL
      COMMON/PAS/  PKWE(5,5),THTG(5,5),TCLG(5,5),DTEL(5,24),DTHT(5,24)
     2           ,  DTCL(5,24),SIZFAC(4),ISAVLP,ISAVSZ
      DATA NCAS/ /,ISAVLP/0/
      DATA ((DTCL(I,J),I=1,3),J=1,24)/72*0./
C
  903 FORMAT(8I5)
  905 FORMAT (  I5,I5,F5.2)
  906 FORMAT(  20F4.0)
C
C   * * *
C **********    READ PROGRAM DATA  --PEAK LOADS AND PROGRAM PARAMETERS
      READ 903,NAREA,NDTYPE
      READ 906,((PKWE(I,J),J=1,NDTYPE),I=1,NAREA)
      READ 906,((THTG(I,J),J=1,NDTYPE),I=1,NAREA)
      READ 906,((TCLG(I,J),J=1,NDTYPE),I=1,NAREA)
      READ 905, MAXCASE,LPRINT,SHLOSS
C
   50 NCAS=NCAS+1
      CALL CASIN
      IF(NCAS .EQ.1) GO TO 90
C  CHECK DT DATA FCR CHANGE FROM LAST CASE
      IF(ICODE(1).EQ.ISAVLP .AND. ICODE(2).EQ.ISAVSZ)  GO TO 140
C  READ DIURNAL TABLES
   90 CALL NEWDTS(NODT)
  140 CONTINUE
C   LOOP THRU DIURNAL TABLES TO TOTAL ANNUAL ENERGY USAGE
      DO 200  IDY =1, NODT
C  CALCULATE ENERGY USAGE
       CALL ENERGY(IDY)
CUMULATE ANNUAL DATA
      CALL ANNTOT (NDAY(IDY))
  200 CONTINUE
      ISAVLP=ICODE(1)          $         ISAVSZ=ICODE(2)
C  **  **  **  CALCULATE FURTHER ANNUAL DATA
      CALL SUFFIX
C   * * *
C PRINT SUMMARY TABLE
      CALL TAHOUT
C END OFTHIS CASE
      IF(NCAS .LT. MAXCASE) GO TO 50
      CALL EXIT
      END
```

SUBROUTINE CASIN TRACE

```
      SUBROUTINE CASIN
      COMMON/ NDATA/ ICODE(10), HREC,ABTU,BKWH,DENG,NODT, NDAY(5)
     2              , HL(24), EL(24),CL(24), HEATRT, FEFF,LPRINT,SHLOSS
     3        , FRAB, CELEC,CABAC,CCPAC,CAUXH,CHTRN,CPUMP,HEATL
      COMMON/STOUT / YFEG,YFAH,YFAC,YELP,YAUX,YHRE,YABS,YCMP,YHLT,YETP
     2              ,YHET,DHET,     DELP,DAUX,     DABS,DCMP,DHLT,DETP
     +              ,DBPT,YBPT,YCDT,FBPT,FCDT,   HRCTUR,DHRE,DEAC,YEAC
     4              ,DHSF,YHSF,FGTS,SEFF,HRECSF,YHAC
     5              ,DEL,YEL,DHL,YHL,DCL,YCL
      COMMON/NAME/ NAN(3)
  901 FORMAT(5I1,5X,3A10)
  902 FORMAT(8F1 .0)
  903 FORMAT(8I5)
C  ICODE(1) - AREA  - 1=NO.CENTRAL, 2=SO.EAST, 3=SO.WEST
C  ICODE(2) - SIZE  - 1=5MW, 2=10MW, 3=20MW, 4=40MW
C  ICODE(3) - HEAT TRANSMISSION  - 1=STANDARD LINE LENGTH
C  ICODE(4) - ELEC.PRIME MOVER - 1=DIESEL SYSTEM, 2=GAS TURBINE, 3=STEAM TURBINE
C  ICODE(5) - FUEL TYPE - 1=NATURAL GAS, 2=LT.OIL, 3=HEAVY OIL
      READ 901, (ICODE(I),I=1,5),(NAN(I),I=1,3)
      READ 902, CELEC,CABAC,CCPAC, CAUXH,CHTRN,CPUMP,HEATL
      READ 902, HREC,ABTU, BKWH, DENG, FEFF,HEATRT,HRCTUR,SEFF
      IF(ICODE(4).EQ.2)HRECSF=HRCTUR
       FRAB=CABAC/(CABAC+CCPAC)
C     NODT SHOULD EQUAL NDTYPE INPUT ON FIRST CARD IN PROGRAM FUEL
      READ 903, NODT, (NDAY(I),I=1,NODT)
C  ZERO ANNUAL TOTALS
      YFEG=0.      $   YFAH=0.     $   YFAC=0.0    $   YELP=0.
      YAUX=0.      $   YHRE=0.     $   YABS=0.     $   YCMP=0.
      YHLT=0.      $   YETP=0.     $   YHET=0.     $   YEAC=0.
      YBPT=0.      $   YCDT=0.     $   YHSF=0.
      YEL =0.      $   YHL =0.     $   YCL =0.
      PRINT 911,(ICODE(I),I=1,5),NODT,(NDAY(I),I=1,NODT)
  911 FORMAT(*1NEW CASE-CODE= *,5I1, 6I6//)
      RETURN
      END
```

SUBROUTINE NEWDTS TRACE

```
      SUBROUTINE NEWDTS(N)
      COMMON/ NDATA/ ICODE(10), HREC,ABTU,BKWH,DENG,NODT, NDAY(5)
     1            , HL(24), EL(24),CL(24), HEATRT, FEFF,LPRINT,SHIOS
     2
     3       ,  ACA, CELEC,CABAC,CCPAC,CAUXH,CHTRN,CPUMP,HEATL
      COMMON/PAS/  PKWE(5,5),THTG(5,5),TCLG(5,5),DTEL(5,24),DTHT(5,24)
     2       ,  DTCL(5,24),SIZFAC(4),ISAVLP,ISAVSZ
      DIMENSION TIN(24)
      DATA SIZFAC/0.5,1.0,2.0,4.0/
  901 FORMAT(1X,2I1,A1,4X,12( 2PF6.1)/8X,12( 2PF6.1))
  902 FORMAT(//* LOAD DATA OUT OF ORDER          *,I4,*  IHA=  *,A1/
     +       1X,2I4,2X,A1, 24F5.1)
  903 FORMAT(//* PCT DATA DOES NOT MATCH CASE CODE*,I4,*  IHA=  *,A1/
     +       1X,2I4,2X,A1, 24F5.1)
      I2=ICODE(2)
CHECK FOR SIZE CHANGE ONLY - SAME LOAD PATTERN
      IF(ICODE(1).EQ.ISAVLP)30,60
C     LOAD PATTERN CHANGE - NEW AREA
   30 CONTINUE
      SF=SIZFAC(I2) / SIZFAC(ISAVSZ)
C  ADJUST LOADS TO NEW SIZE
       DO 50 J=1,N
       DO 50 I=1,24
      DTEL(J,I)=DTEL(J,I) *SF
      DTHT(J,I)=DTHT(J,I) *SF
      DTCL(J,I)=DTCL(J,I) *SF
   50 CONTINUE
      RETURN
   60 CONTINUE
C  MUST READ NEW DATA FOR HOURLY TABLE - NEW LOAD PATTERN
      DO  200 NT=1,N
C  READ ELEC LOAD
      READ 901, IAR,IDY,IL,(TIN(I),I=1,24)
       IHA=1HE
      IF(IL.NE.IHA) GO TO 300
      IF(IAR.NE.ICODE(1) .OR. IDY.NE.NT)  GO TO 330
      DO 120  I=1,24
  120 DTEL(NT,I)= TIN(I) * PKWE(IAR,IDY)*SIZFAC(I2)
C  READ HEATING REQUIREMENTS
      READ 901, IAR,IDY,IL,(TIN(I),I=1,24)
       IHA=1HH
      IF(IL.NE.IHA) GO TO 300
      IF(IAR.NE.ICODE(1) .OR. IDY.NE.NT)  GO TO 330
      DO 140  I=1,24
  140 DTHT(NT,I) = TIN(I) * THTG(IAR,IDY) * SIZFAC(I2)
C
      IF(NT.LT.4) GO TO 200
CCOOLING REQUIREMENTS ARE READ FOR  DAY TYPES 4 AND 5 ONLY
C  ***********  N.B. POSSIBLE ERROR IF N IS LESS THAN 5
      READ 901, IAR,IDY,IL,(TIN(I),I=1,24)
       IHA=1HC
      IF(IL.NE.IHA) GO TO 300
      IF(IAR.NE.ICODE(1) .OR. IDY.NE.NT)  GO TO 330
      DO 160  I=1,24
  160 DTCL(NT,I) = TIN(I) * TCLG(IAR,IDY) * SIZFAC(I2)
  200 CONTINUE

      RETURN
  300 PRINT 902, NT,IHA,IAR,IDY,IL,(TIN(I),I=1,24)
      CALL EXIT
  330 PRINT 903, NT,IHA,IAR,IDY,IL,(TIN(I),I=1,24)
      CALL EXIT
      END
```

SUBROUTINF ENERGY TRACE

```
      SUBROUTINE ENERGY(ND  )
      COMMON/ NDATA/ ICODE(10), HREC,ABTU,BKWH,DENG,NODT, NDAY(5)
     2              , HL(24), EL(24),CL(24), HEATRT, FEFF,LPRINT,SHLOSS
     3        , FRAB, CELEC,CABAC,CCPAC,CAUXH,CHTRN,CPUMP,HEATL
      COMMON/STOUT / YFEG,YFAH,YFAC,YELP,YAUX,YHRE,YABS,YCMP,YHLT,YETP
     2              ,YHET,DHET,     DELP,DAUX,     DABS,DCMP,DHLT,DETP
     *              ,DBPT,YBPT,YCDT,FBPT,FCDT,   HRCTUR,DHRE,DEAC,YEAC
     4              ,DHSF,YHSF,FGTS,SEFF,HRECSF,YHAC
     5              ,DEL,YEL,DHL,YHL,DCL,YCL
      COMMON/PAS/  PKWE(5,5),THTG(5,5),TCLG(5,5),DTEL(5,24),DTHT(5,24)
     2       ,  DTCL(5,24),SIZFAC(4),ISAVLP,ISAVSZ
C        ZERO DAILY TOTALS
      DELP=0.0     $     DAUX=0.0     $    DCMP=0.0
      DHET=0.0     $     DABS=0.0     $    DHLT=0.0
      DETP=0.0     $     DHRE=0.0     $    DHSF=0.0
      DBPT=0.0     $     EBP=0.       $   HSGT=0.0
      DEL =0.0     $     DHL =0.0     $    DCL =0.0
      DEAC=0.0
C
      DO 10 I=1,24
      EL(I) = DTEL( ND,I) *1000.
      HL(I) = DTHT( ND,I)  * 1000.
      CL(I) = DTCL( ND,I)*1000.
   10 CONTINUE
      I4=ICODE(4)
C   * * *
C        LOOP THRU DIURNAL TABLE BY HOUR
      DO  100  I=1,24
CHECK A.C. CAPACITIES FOR ZERO A.C. CASES
      IF(CABAC+CCPAC.LE.0.) 11,15
   11 CONTINUE
      HABAC=0.   $   HAC=0.   $   COMPAC=0.   $   EAC=0.
      GO TO  20
   15 CONTINUE
      HABAC =FRAB*CL(I)
      IF(HABAC.GT.CABAC) HABAC=CABAC
      HAC= ABTU * HABAC/1000.
      COMPAC = CL(I)- HABAC
      EAC=  BKWH * COMPAC
   20 CONTINUE
C  HEAT LOSS IN TRANSMISSION , HP
      HP= HEATL    $       IF(ND.GT.2) HP=HP*SHLOSS
C  TOTAL HEAT , HT
      HT = HL(I) +HP+HAC
C  POWER FOR HEAT TRANSMISSION PUMPS   , EP
      EP=0.
      IF(CHTRN.LE.0.) GO TO  35
       IF(ND.GT.2) GO TO 30
C  WINTER
      EP=((HT/CHTRN)**2.96)*CPUMP
      GO TO 35
C  ******NO HEATING DAYS
   30 CONTINUE
      EP=((HT*1.33/CHTRN)**2.96)*CPUMP
   35 CONTINUE
```

```
C TOTAL ELEC POWER LOAD FOR HOUR, ET
      ET = EL(I)+ EP + EAC
C
C  AUXILIARY HEAT
      RET=HREC*ET/1000.
      HAUX = HT- RET
      IF(HAUX .LT. 0.0) HAUX=0.0
C  ACTUAL WASTE HEAT USED : AREC
      AREC=RET      $    IF(RET.GT. HT) AREC=HT
      GO TO (60,40,50)  I4
C   ********   GAS TURBINE
   40 HSGT=HT-RET
      IF(HSGT.LT.0.) HSGT=0.
      RECOV=(HRECSF-HREC)*ET /1000.
      IF(HSGT.GT.RECOV)HSGT= RECOV
      HAUX= HT-HSGT-RET
      IF(HAUX.LT.0.)  HAUX=0.0
      GO TO 60
C
   50 CONTINUE
C   STEAM TURBINE OPERATION
      IF(ICODE(4).NE.3) GO TO 60
       IF(HT.GE.RET)52,53
   52 EBP=ET
      GO TO 60
   53 EBP=(HT/HREC )*1000.
   60 CONTINUE
      IF(LPRINT .GT. 989) PRINT 993,I,EL(I),EAC,EP,ET,HL(I),HAC,HP,HT
     2,    RET,AREC,HAUX,CL(I),HABAC,COMPAC
  993 FORMAT(1X,I2,2F9.0,F6.1,2F10.0,F9.0,F7.0,2F10.0,  5F9.0)
C
C DAILY TOTALS
      DELP=DELP + ET
      DAUX=DAUX + HAUX
      DCMP=DCMP + COMPAC
      DEAC=DEAC + EAC
      DHRE=DHRE + AREC
      DHET=DHET + HT
      DABS=DABS + HAC
      DHLT=DHLT + HP
      DETP=DETP + EP
      DBPT=DBPT + EBP
      DHSF=DHSF + HSGT
      DEL =DEL  + EL(I)
      DHL =DHL  + HL(I)
      DCL =DCL  + CL(I)
  100 CONTINUE
C
      IF(LPRINT .LT. 910) RETURN
      PRINT 990, ND, (ICODE(I),I=1,5)
      PRINT 991,   DELP,DAUX,DCMP,DHET,DABS,DHLT,DETP,DBPT,DHSF
  990 FORMAT(//* DAY NO.*,I3,3X,5I1)
  991 FORMAT(/1X, 8F15.2)
      RETURN
      END
```

SUBROUTINE ANNTOT TRACE

```
      SUBROUTINE ANNTOT (ND)
      COMMON/STOUT / YFEG,YFAH,YFAC,YELP,YAUX,YHRE,YABS,YCMP,YHLT,YETP
     2             ,YHET,DHET,     DELP,DAUX,     DABS,DCMP,DHLT,DETP
     +             ,DBPT,YBPT,YCDT,FBPT,FCDT,   HRCTUR,DHRE,DEAC,YEAC
     4             ,DHSF,YHSF,FGTS,SEFF,HPECSF,YHAC
     5             ,DEL,YEL,DHL,YHL,DCL,YCL
C
      YELP=YELP + DELP * ND
      YAUX=YAUX + DAUX * ND
      YCMP=YCMP + DCMP * ND
      YHET=YHET + DHET * ND
      YHRE=YHRE + DHRE * ND
      YEAC=YEAC + DEAC * ND
      YABS=YABS + DABS * ND
      YHLT=YHLT + DHLT * ND
      YETP=YETP + DETP * ND
      YBPT=YBPT + DBPT * ND
      YHSF=YHSF + DHSF * ND
      YEL =YEL  + DEL * ND
      YHL =YHL  + DHL * ND
      YCL =YCL  + DCL * ND
      RETURN
      END
```

SUBROUTINE SUFFIX TRACE

```
      SUBROUTINE SUFFIX
      COMMON/ NDATA/ ICODE(10), HREC,ABTU,BKWH,DENG,NODT, NDAY(5)
     2         , HL(24), EL(24),CL(24), HEATRT, FEFF,LPRINT,SHLOSS
     3      , FRAB, CELEC,CABAC,CCPAC,CAUXH,CHTRN,CPUMP,HEATL
      COMMON/STOUT / YFEG,YFAH,YFAC,YELP,YAUX,YHRE,YABS,YCMP,YHLT,YETP
     2              ,YHET,DHET,     DELP,DAUX,     DABS,DCMP,DHLT,DETP
     +              ,DBPT,YBPT,YCDT,FBPT,FCDT,   HRCTUR,DHRE,DEAC,YEAC
     4              ,DHSF,YHSF,FGTS,SEFF,HRECSF,YHAC
     5              ,DEL,YEL,DHL,YHL,DCL,YCL
C
C  ANNUAL HEAT RECOVERY AND ABSORPTION AC
      YHAC=YABS/1000.
      YABS =(YABS/ABTU )
CALCULATE FUEL USAGE       - MILLIONS OF BTU
      YFEG = YELP * HEATRT /10.**6.
      YFAH = YAUX /FEFF  /1000.
      YFAC = YCMP * DENG /10.**6.
      I4=ICODE(4)
      GO TO (40,20,30) I4
C  *** ****   GAS TURBINE
   20 YHSF=YHSF/1000.
      FGTS= YHSF/SEFF
       GO TO 40
C
C             STEAM TURBINE
   30 YCDT= YELP - YBPT
      FBPT=YBPT*HEATRT /10.**6.
      FCDT=YCDT*HRCTUR /10.**6.
      YFEG=FCDT+FBPT
   40 CONTINUE
C  ADJUST UNITS
      YCMP=YCMP/1000.
      YETP=YETP /1000.
      YEAC=YEAC /1000.
      YEL = YEL /10.**3.
      YHL =YHL /1000.
      YAUX=YAUX/1000.
      YELP = YELP/1000.
      YHET=YHET/1000.
      YHRE=YHRE/1000.
      YHLT=YHLT/1000.
      RETURN
      END
```

SUBROUTINE TABOUT TRACE

```
      SUBROUTINE TABOUT
      COMMON/ NDATA/ ICODE(10), HREC,ABTU,BKWH,DENG,NODT, NDAY(5)
     2          , HL(24), EL(24),CL(24), HEATRT, FEFF,LPRINT,SHLOSS
     3     , ACA, CELEC,CABAC,CCPAC,CAUXH,CHTRN,CPUMP,HEATL
      COMMON/STOUT / YFEG,YFAH,YFAC,YELP,YAUX,YHRE,YABS,YCMP,YHLT,YETP
     2              ,YHET,DHET,     DELP,DAUX,      DABS,DCMP,DHLT,DETP
     +              ,DBPT,YBPT,YCDT,FBPT,FCDT,   HRCTUR,DHRE,DEAC,YEAC
     4              ,DHSF,YHSF,FGTS,SEFF,HRECSF,YHAC
     5              ,DEL,YEL,DHL,YHL,DCL,YCL
      COMMON/PAS/  PKWE(5,5),THTG(5,5),TCLG(5,5),DTEL(5,24),DTHT(5,24)
     2        ,  DTCL(5,24),SIZFAC(4),ISAVLP,ISAVSZ
      COMMON/NAM/NAMLP(5),NAMBS(4),NAMLL(4),NAMST(3),NAMFU(4),NAMDY(5)
      COMMON/NAME/ NAN(3)
      DATA NAMDY/10HHIGH HEAT ,10HMOD. HEAT ,10HMIN  H+C  ,
     2          10HMOD. COOL ,10HHIGH COOL /
      DATA  (NAMLP(I),I=1,3)/10HNO.CENTRAL,10HSO. EAST  ,10HSO. WEST  /
     2   ,  (NAMBS(I),I=1,4)/ 5H 5 MW,5H10 MW,5H20 MW, 5H40 MW/
     3   ,  (NAMLL(I),I=1,3)/8HSTANDARD, 8H .5* STD,  8H2.0* STD /
     4   ,  (NAMST(I),I=1,3)/10HDIESEL EL.,10HGAS TURB. ,10HSTEAM TURB/
     5   ,  (NAMFU(I),I=1,4)/10HNATURAL G.,10HLIGHT OIL ,10HHEAVY OIL ,
     6                       10HCOAL      /
C  ******* * * * * * * * * * * * * * * **** ***
      CALL DATEX (IX,IXA)
      I1=ICODE(1)       $   I2 =ICODE(2)    $  I3=ICODE(3)
      I4 =ICODE(4)      $   I5 =ICODE(5)
C
C     PRINT HOURLY LOADS FOR EACH TYPE OF DAY
      IF(LPPINT .GT. 900)100,200
  100 PRINT 901,(ICODE(I),I=1,5), IX,IXA
      PRINT 908, NAMBS(I2),NAMLP(I1),(NAMDY(I),I=1,NODT)
      PRINT 909
      DO 120  I=1,24
      IF(MOD(I,6).EQ.1) PRINT 910
      IM=I-1
      PRINT 911,  IM,(DTEL(J,I), DTHT(J,I),DTCL(J,I),J=1,NODT)
  120 CONTINUE
      PRINT 913, YEL,YHL,YCL
  200 CONTINUE
C
      TWHA=HREC*YELP/1000.
      TOTF=YFEG+YFAH+YFAC
      IF(I4  .EQ. 2) TOTF = TOTF+ FGTS
C   * * *
      PRINT 901, (ICODE(I),I=1,5), IX,IXA
      PRINT 912, NAMBS(I2),NAMLP(I1) ,NAN
      PRINT 902, NAMLP(I1),NAMBS(I2 ),NAMLL(I3),NAMST(I4),NAMFU(I5)
      PFEFF=100.* FEFF
      PRINT 903, CELEC, CABAC, CCPAC, CAUXH,CHTRN,HEATL,CPUMP
      PRINT 904, ABTU,  BKWH,  DENG,  HREC, HEATRT,PFEFF
      PRINT 905,YEL,YETP,YEAC,YELP
      PRINT 915,YABS,YCMP
      PRINT 907,YHL, YHLT,YHAC,YHET,TWHA,YHRE,YAUX
      IF(I4.EQ.2) PRINT 9071, YHSF
      PRINT 906, YFEG, YFAH, YFAC
      IF(I4.EQ.2) PRINT 9062, FGTS
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      IF(I4.EQ.3) PRINT 9061,  FBPT,FCDT
       RRINT 9063,  TOTF
C  ******* * * * * * * * * * * * *  * * ****     ***
C   * * *
C
  901 FORMAT(1H1, *SUMMARY TABLE  - CASE *,5I1,  20X, 2A10/)
  902 FORMAT(*0CASE DESCRIPTION*/10X,  *LOAD RATTERN    *,2-X,A10/ 10X,
     2   *BASE SIZE*,31X,A10/10X, *LINE LENGTH*,29X,A10/10X,*TYPE OF SYS
     3TEM *,25X,A10/10X,*FUEL USED *,30X,A10 )
  903 FORMAT(*0EQUIPMENT CAPACITIES*/
     1        10X, *ELECTRIC GENERATION        (MW)*,  20X,F10.0/
     2        10X, *ABSORPTION AIR C.        (TONS)*, 20X,F10.0/
     3        10X, *COMPRESSION  A. C.       (TONS)*,  20X,F10.0/
     4        10X, *AUX. HEATING          (MM-BTU/HR)*,  20X,F10.0/
     5        10X, *HEAT TRANS CAP.           (M-BTU)*,  20X,F10.0/
     +        10X, *WINTER HEAT LOSS      (M-BTU/HR)*,  20X,F10.0/
     6        10X, *PUMP POWER                   (KW)*,  20X,F10.0/)
  904 FORMAT(*0SYSTEM PARAMETERS */
     2     10X,*ABSORPTION AIR COND.    (BTU/TON-HR)*, 15X,F10.0/
     3     10X,*ELEC. COMPRESSION A.C. (KWH/TON-HR)*, 15X,F10.3/
     4     10X,*ENG . COMPRESSION A.C. (BTU/TON-HR)*, 15X,F10.0/
     5     10X,*HEAT RECOVERY RATE      (BTU/KWE   )*, 15X,F10.0/
     6     10X,*FUEL HEAT RATE (ELEC)  (BTU/KW-HR )*,  15X,F10.0/
     7     10X,*AUX HEAT FUEL EFFICIENCY      (PCT )*, 15X,F10.0)
  905 FORMAT(//* ANNUAL TOTALS - ELECTRIC*/
     2     10X,      *ELECTRIC POWER LOAD      (MW-HR)*, 20X, F10.0/
     5     10X,      *ELEC LOAD FOR PUMPS      (MW-HR)*, 20X, F10.0/
     4     10X,      *ELEC FOR COMP. A.C.      (MW-HR)*, 20X, F10.0/
     4     10X,      *     TOTAL ALL USES      (MW-HR)*, 20X, F10.0)
  915 FORMAT(//* ANNUAL TOTALS - AIR COND*/
     4     10X,      *ABSORRTION AIR COND (M-TON-HR)*, 20X, F10.0/
     5     10X,      *COMPRESSION AIR COND(M-TON-HR)*, 20X, F10.0)
  906 FORMAT(//* FUEL CONSUMRTION *//
     2     10X,      *ELECTRIC GENERATION     (MM-BTU)*, 15X, F15.0/
     3     10X,      *AUXILIARY HEATING       (MM-BTU)*, 20X, F10.0/
     4     10X,      *ENGINE AIR COND.        (MM-BTU)*, 20X, F10.0)
 9061 FORMAT(10X,  *BACK PRES TURBINE        (MM-BTU)*, 20X, F10.0/
     2        10X,  *CONDENSING TURBINE       (MM-BTU)*, 20X, F10.0)
 9062 FORMAT(10X,  *GAS TURB-SUPP FIRING     (MM-BTU)*, 20X F10.0)
 9063 FORMAT(10X,  *     TOTAL FUEL           (MM-BTU)*, 20X, F10.0)
  907 FORMAT(//* ANNUAL TOTALS - HEAT*/
     2     10X,      *HEATING LOAD        (MILLION-BTU)*, 20X, F10.0/
     3     10X,      *HEAT LOSS-TRANS     (MILLION-BTU)*, 20X, F10.0/
     4     10X,      *HEAT TO AIR C       (MILLION-BTU)*, 20X, F10.0/
     5     10X,      *HEAT REQUIRED       (MILLION-BTU)*, 20X, F10.0/
     6        10X,  *WASTE HEAT AVAILABLE  (MM-BTU)*, 20X, F10.0/
     3     10X,      *HEAT RECOVERED      (MILLION-BTU)*, 20X, F10.0/
     8     10X,      *AUXILIARY HEAT     (MILLION-BTU )*, 20X, F10.0)
 9071 FORMAT(10X,  *HEAT-SUPP FIRE GAS T   (MM-BTU)*, 20X, F10.0)
  908 FORMAT( /5 X,*HOURLY LOADS FOR *,A5,* BASE IN *,A10//
     2          3X,  5(8X,A10,8X) )
  909 FORMAT(1H0,2X, 5(3X,* ELEC  HEATING  AC LOAD*)/
     2          3X, 5(3X,* (MW)    MM-BTU  M-TONS *))
  910 FORMAT(1H0)
  911 FORMAT(1X,I2,  5(F8.3, F9.1,F9.1))
  912 FORMAT( 3X,A5,*  BASE IN *,A10,5X,3A10)
  913 FORMAT(////* ANNUAL LOADS FOR BASE*/10X,*ELECTRIC LOAD  *F20.1/
     2   10X,*HEATING LOAD   *,F20.1/10X,*COOLING LOAD    *,F20.1)
      RETURN
      END
```