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Performance Analysis of the Jersey City Total Energy Site: Interim Report

Center for Building Technology
Institute for Applied Technology
National Bureau of Standards
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Prepared for

Department of Housing and Urban Development
Division of Energy, Building Technology and Standards
Office of Policy Development and Research
Washington, D.C. 20410

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PERFORMANCE ANALYSIS OF THE JERSEY CITY TOTAL ENERGY SITE: INTERIM REPORT

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ABSTRACT

Under the sponsorship of the Department of Housing and Urban Development (HUD), the National Bureau of Standards (NBS) has gathered engineering and economic data from an operating diesel total energy plant which supplies all electrical power, hot water, and chilled water to a 485 unit apartment/commercial building complex in Jersey City, New Jersey.

Engineering data has been continuously collected since April 1975 by a data acquisition system (DAS) which monitors approximately 200 sensors located in the plant and site buildings. In this report, data for a one-year period from November 1975 through October 1976 is presented. Electrical and thermal demands by the site and plant equipment efficiencies have been determined from this data and are reported. Reliability data is also reported.

Relative fuel savings by the total energy plant have been determined from the engineering data. Adjustments were performed to compensate for the malfunctioning absorption chillers. Calculations indicate that an alternative conventional central plant using purchased electrical power, oil-fired boilers, and absorption chillers would have required 17.3% more fuel than required by the JCTE plant as adjusted. These savings correspond to 160,000 gallons (606 m^3) of fuel oil annually. Minor design modifications are suggested in this report which would improve the JCTE plant performance an additional 5.7%. If the JCTE plant chillers were properly adjusted and the suggested minor modifications were performed, the above alternative conventional plant would have consumed 24.5% more fuel oil annually.

Economic data describing the capital, operating, owning, and maintenance costs during the one-year period are also presented. Unit costs of electrical, heating and cooling energy commodities are determined and compared to conventionally - supplied energy unit costs.

Executive Summary

This is an executive summary of the major results contained in the document: Performance Analysis of the Jersey City Total Energy Site: Interim Report, HUD Utilities Demonstration Series Volume 7, NBSIR 77-1243.

The Jersey City total energy plant consists of five diesel engine-generators with jacket and exhaust heat recovery, two hot-water boilers, and two absorption chillers. The plant supplies all electrical power, hot water, and chilled water through an underground distribution system to four medium- and high-rise apartment buildings (485 apartments total), a 46,000 square foot (4300 m^2) commercial building, a school, and an outdoor pool. The installed plant has an electrical capacity of 3000 kW with 9.3 MBtu per hour (2.7 MW) heat recovery capacity, a boiler capacity of 26.8 MBtu per hour (8 MW), and a chilling capacity of 1092 tons (3.8 MW).

During the reported period (November 1975 through October 1976) the plant supplied a total of 6,360,000 kWh of electrical energy, 37,400 MBtu (39400 GJ) of heating, and 7,740 MBtu (8160 GJ) of chilling to the site and distribution system. During this period, the plant consumed a total of 986,000 gallons (3730 m^3) of fuel oil. Heat recovered from the engines was used to meet 39% of the site and chiller heat demands. During this year, peak engine-generator, boiler, and chiller output levels were 1350 kW, 14 MBtu per hour (4.1 MW) and 6 MBtu per hour (1.8 MW); or 45%, 52%, and 46% of installed capacity, respectively. Engine-generator gross electrical efficiency was 32.4%; and gross electrical plus thermal efficiency was 61.4%. Seasonal average boiler efficiency was 81.6% and chiller COP was measured as 0.40. The losses of the site distribution systems were not studied.

*MBtu = million Btu

Analysis of the plant's electrical reliability indicated that the plant supplied power to the site for 99.8% of the reported year. Outages were mostly due to malfunctions in the plant's electrical control systems.

A preliminary comparative energy analysis between the plant and two alternative conventional central plants indicates that a central plant using purchased electrical power, oil-fired boilers, and absorption chillers would have required 17.3% more fuel oil (based on chillers in both plants operating at 0.6 COP). This savings corresponds to 160,000 gallons of fuel oil annually. A central plant using purchased electrical power, oil-fired boilers, and electrical driven compression chilling would have required 9.5% more fuel oil than the JCTE site (assuming JCTE chiller operation at 0.6 COP).

Suggestions for improving the plant's energy effectiveness include minor modifications such as bypassing an idle boiler, bypassing an idle engine, reducing dry cooler losses, and reducing the amount of chilled water used to cool the plant. Implementing these minor modifications will result in an annual fuel savings of at least 5.7% or approximately 55,000 gallons of fuel oil. It is also suggested that extensive servicing be applied to the absorption chillers. Increasing the chiller COP to the manufacturers specifications will result in an additional annual fuel savings of approximately 7% or 65,000 gallons of oil.

During the reported year, the total plant costs included $335,000 for fuel oil, $267,000 for operation and maintenance, and $397,000 for capital costs. Using a preliminary cost separation procedure, the unit costs of energy consumed by the site are 3.9¢/kWh for electrical power, 9.1 $/MBtu for hot water, and 38.87 $/MBtu for chilled water. A preliminary analysis indicates that these unit costs are approximately equal to the cost of equivalent energy services if supplied by conventional means. Significant impacts on these unit costs appears to have been experienced due to partial site occupancy, low chiller performance, use of chilled water for plant cooling and unoptimized heat recovery.

The vast majority of the reported engineering data was collected by a data acquisition system which monitors approximately 200 transducers at the site. The raw data from the site was processed by computer at NBS. For the annual period the accuracy of the electrical, thermal, and fuel data presented in this report is approximately 1% to 3%.

In the main report, for reasons described in the respective sections, some of the monthly values have uncertainties as high as 15%.

Performance Analysis of the Jersey City Total Energy Site: Interim Report

1.0 Introduction

The amount of waste heat normally produced during the generation of electrical power, and the potential conservation of energy which would result from the recovery and use of that heat, is widely recognized. Today, in even the most efficient electrical generation systems, only 40% or less of the energy in the consumed coal, oil, or natural gas is converted to electricity. The remaining 60% of the input energy is usually rejected into the environment as waste heat.

The total energy concept proposes to make use of the waste heat associated with the electrical generation process. This heat can be used to heat buildings and to power absorption chillers for cooling. The use of this waste heat for heating and cooling conserves the additional conventional energy which would otherwise be used to meet these needs. Of course, the total energy concept requires that electrical generation be located sufficiently near the point of use of its waste heat; this encourages the application of on-site electrical generation systems.

The Department of Housing and Urban Development (HUD) has sponsored the Jersey City Total Energy Plant to test the potential effectiveness (energy savings, economics, reliability, etc.) of a total energy system in a building complex. Here, six residential and commercial buildings located in an urban environment are being supplied with all electrical energy, heating, and cooling by a central diesel total energy plant. This plant has five 600 kW diesel engine-generators with waste heat recovery, two 546 ton (1.9 MW) absorption chillers, and two 400 HP (3.9 MW) fire tube boilers. Extensive engineering and economic data is being continually collected by the National Bureau of Standards (NBS) to determine the energy savings, costs, reliability, and environmental impact of this system.

In this interim report, engineering and economic data covering one year from November 1975 through October 1976 is presented. This data includes energy production and consumption by the plant; capital, operation and maintenance costs, and plant reliability. Engineering and economic analysis is performed to determine the plant's energy savings, the unit costs of electrical power, heating, and cooling, and the potential for further improving the plant's energy effectiveness.

1.1 Site Description

The 6.35 acre (2.6 hectare) site has four medium- and high-rise apartment buildings housing thirteen hundred people in 485 apartments, an elementary school, a swimming pool, a 46,000 ft^2 (4300 m^2) commercial building, parking space for tenants, and the total energy plant that supplies all heating, domestic hot water, air conditioning, and electrical energy to the buildings. Figure 1-1 shows an aerial view of the site. Individual buildings are identified by the layout diagram in figure 1-2.

The residential buildings were designed by three companies participating in HUD's Operation Breakthrough: Shelley Systems, Camci Inc., and Descon-Concordia Systems; utilizing the concept of prefabricated modules. Occupancy of the residential buildings started in March of 1974. The residential area was 96% occupied by October, 1974. The first commercial tenant moved into a storefront in October 1975, and the first school session was held in September, 1976.

1.2 Total Energy Plant Description

The main focus of the energy study at Jersey City is the total energy plant which produces all electricity, hot water, and chilled water for the site buildings.

The plant is housed in a three-story central equipment building (figure 1-3). Electrical power is generated by five 600 kW diesel engine-generators (figures 1-4 and 1-5). Thermal energy for space heating and domestic hot water production is recovered from the jackets of the engines and from heat exchangers on their exhausts. Supplementary thermal energy is supplied by two 13.4 MBtu per hour (4.0 MW) hot-water boilers (figure 1-6). During the air-conditioning season, the thermal energy is used in two 546 ton (6.6 MBtu per hour) (1.9 MW) absorption chillers (figure 1-7) to produce chilled water. The engines and boilers both burn number 2 fuel oil which is stored in three 25,000 gallon (95 m^3) underground tanks. The total energy plant is completely automatic, allowing unattended overnight and weekend operation. The plant is operated by Gamze-Korobkin-Caloger, Inc., Chicago, Illinois, under contract to HUD.

Heat is recovered from the engine-generators and utilized by a primary hot water (PHW) loop (see figure 1-8). Primary hot water at a temperature ranging from 180°F to 230°F (82°C to 110°C) is pumped at a rate of 11000 pounds (5000 kg) per minute, transferring heat from the engines and boilers to the chillers and site hot water system. From the engines, the PHW passes through two 25 HP (19 kW) circulation pumps and then through the boilers where additional heat can be added if necessary. During the summer the PHW is routed through two 546 ton (1.9 MW) absorption chillers which provide 45°F (7°C) chilled water for the site. The PHW then passes through two water-to-water heat exchangers transferring heat to the site secondary hot water system. In the rare event that both heating and cooling demands are extremely low, a forced circulation, dry surface heat exchanger (dry coolers) (figure 1-9) releases the excess PHW heat to the atmosphere to control the upper limit of the PHW temperature.

Electricity, hot water, and chilled water are delivered to the site via underground conduits. Two sets of 480 volt, three-phase feeders (normal and essential) are used for electric power distribution. In the event of an electrical plant outage, power is automatically supplied only to the essential feeder from the local utility to preserve operation of emergency lighting, fire protection systems and the elevators. Hot and chilled water are circulated by a four-pipe system (hot water supply and return and chilled water supply and return). Heat exchangers in the buildings transfer heat to and from building loops designed for space heating and cooling and domestic hot water production.

The site is also equipped with a pneumatic trash collection system (PTC) which pulls trash from the site buildings into a single, compactor-type receptacle located in the central equipment building.

1.3 NBS Instrumentation and Data Acquisition System

Evaluation of the performance of the total energy plant and its components and determination of building utility loads is being accomplished by analyzing data from approximately 200 transducers located in the plant and site buildings. These specialized transducers translate physical variables into analog voltages that are sampled and recorded electronically. The Data Acquisition System (DAS) (see figure 1-10) is the engineering tool that accomplishes the task of recording measurements on a 24-hour, year-round basis, at time intervals short enough to reflect changes in plant status and to accurately measure changing physical quantities.

The instrumentation consists of a variety of transducers which measure thermal and electrical variables. Water and fuel flow measurements are made by turbine meters with integrating circuitry or by venturis with differential pressure cells. Temperatures are measured by copper/constantan or iron/constantan thermocouples; temperature differentials are measured more accurately by multijunction thermopiles. Potential and current transformers placed on electrical buses feed signals to watt transducers and voltage transducers. The DC output of the watt transducer can be amplified for use as an instantaneous power signal and integrated over time to obtain kilowatt-hour data. Pressure cells generate a signal proportional to gage pressure. Other signals include 7 weather station signals, plant electrical frequency, main bus power factor, and the utilility system voltage.

Signal lines from plant transducers directly feed DAS scanning equipment. This equipment selects one line at a time to feed the system digital voltmeter. Each of the 8 remote stations in site buildings have relays controlled by the central DAS. These relays select each remote transducer signal to be sampled by the DAS. A system time clock initiates data scans at five minute intervals. In the scan mode, the DAS selects data channels sequentially. The digital voltmeter digitizes the analog voltages which are then written with their respective channel numbers (in EBCDIC code) on an incremental 9-track tape drive. Data scans occur every 5 minutes and include approximately 130 channels in the central equipment building plus 13 sub-channels in each of 8 remote buildings. The entire data scanning process occurs in 30 seconds. A ten inch (25.4 cm) diameter tape reel will hold 2 weeks of raw data.

The DAS began monitoring and recording plant data in April, 1975. The first remote building data was recorded in November 1975 from the Shelley A high-rise building. The remaining buildings have been brought on line according to building construction and equipment calibration schedules.

The DAS functioned continuously during the reported year. With the exception of a one month period in July, all data losses have been less than one week in duration and cumulatively equal to less than 11% of the year. The July data loss resulted from high temperatures in the DAS operating room. To correct this problem an auxiliary air conditioning unit was installed in the DAS room.

The accuracy of the instrumentation system transducers has, for the most part, met design goals. Where instrumentation system inaccuracies have been detected, prompt action has been taken to correct the problem. For example, analysis of engine 1 and engine 2 heat recovery data showed a discrepancy equivalent to a 1.4°F (.8°C) temperature measurement error. Laboratory experiments indicated that this error was caused by inadequate insulation of the thermopile leads. This problem was corrected by insulating the exposed leads and thermocouple wells.

The most serious instrumentation problem has been that of inaccuracies in the fuel measurement system. Fuel for engine and boiler consumption is supplied from day-tanks in continuously circulating, high flow rate, supply/return loops. Turbine meters were used to measure supply and return loops of 2 individual engines, all engines as a group, and the individual boilers. Consumption was calculated by subtracting return from supply. However, because the flow rates in the fuel supply/return loops were 5 to 20 times the fuel consumption rates, the measurement tolerances of the precisely calibrated flow meters ($\pm 1\%$) resulted in unacceptably large uncertainties in the fuel consumption measurements.

As a temporary measure to obtain accurate monthly fuel data, manually-read flow meters were placed in day-tank filler lines in April 1976. To permit electronic fuel consumption logging for the individual units by the DAS, special Pelton-wheel type turbine meters have been purchased and calibrated, and are being placed in supply lines to each engine's fuel injectors and to each boiler's fuel nozzle. A forthcoming report will describe the instrumentation system, problem areas and modifications in more detail.

Reels of magnetic tape containing DAS recorded data are sent from the site to NBS for data processing. The recorded data is converted into engineering quantities, e.g., kilowatt-hours, Btu's, etc., by a unique configuration of computer hardware and software developed and assembled by NBS. The computer system used for data processing consists of a central processing unit with 32k of core memory and two disk memories, 7 and 9 track tape drives, cathode ray tube (CRT) visual read out equipped with hard copy unit, paper tape punch and reader, and a teletype terminal.

Data processing starts by reading a raw data tape from the 9 track DAS tape unit one five minute scan at a time. For each 5-minute scan, the software checks each data channel for parity errors, dropped bits, partial scans and other irregularities that may occur during data logging, then the approximately 200 data channel voltages are converted to engineering quantities. Twelve 5-minute scan values are accumulated to yield a single hourly data point for each channel. All hourly channel values are written on a single monthly disk, along with calculated daily and monthly averages. The last processing step calculates the engineering quantities for each hour of a month, e.g., heat recovered from flow times delta temperature or site kWh from gross kWh minus plant kWh, according to equations describing plant component and gross plant and building status.

Versatile data output routines have been developed which permit easy access to the site data contained on a monthly disk. These routines can present hourly, daily, or monthly averages of any variables in tabular or graphical form. The graphical output routines will plot up to five variables on any time scale from one day to the entire month.

The entire data acquisition and processing system from site transducers to the computer output software has been designed by NBS. Much of the hardware and software involved has been specially developed for this project and, as with any "first-time system", some debugging has been necessary. Because of this necessary debugging, data has not been presented here for the first six months of DAS operation. Instead a complete one year period of reliable data has been presented in this interim report. It is anticipated that a future report will contain data for a longer period of time as well as a more complete description and analysis of site operation.

Figure 1-1 Aerial view of the Jersey City Total Energy Site. See Figure 1-2 to identify the buildings at the Total Energy Site.

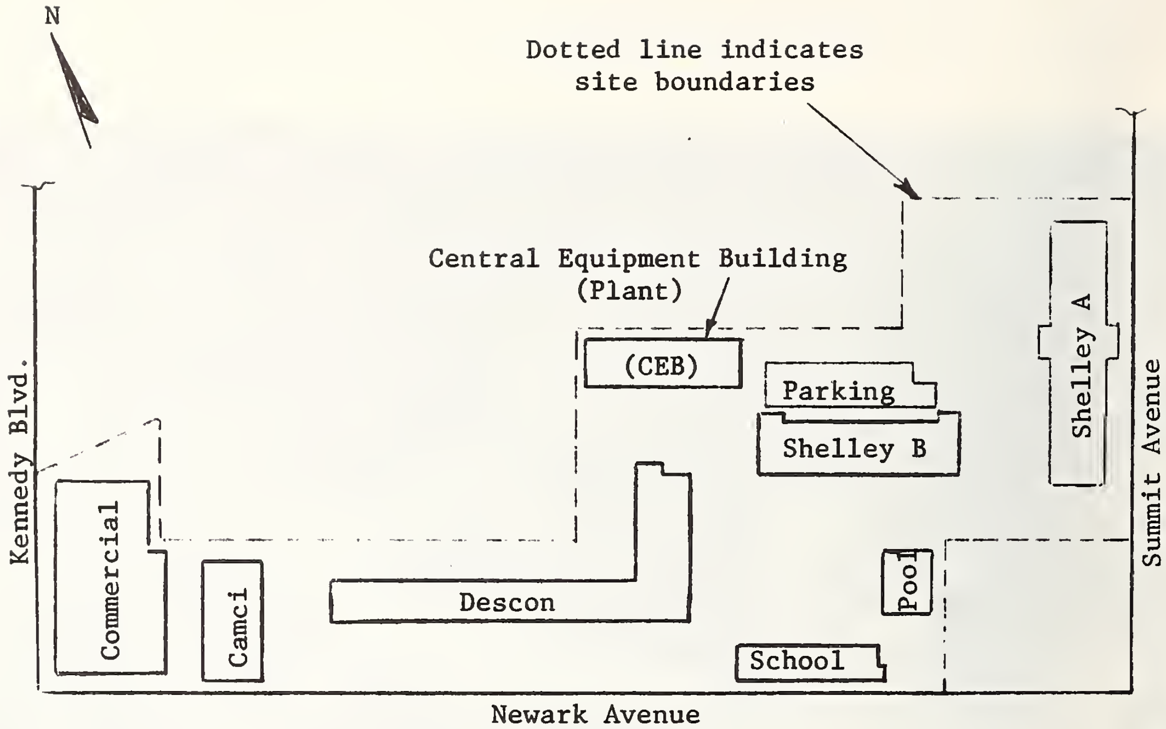

Figure 1-2 Relative location of individual buildings at the Jersey City Total Energy Site.

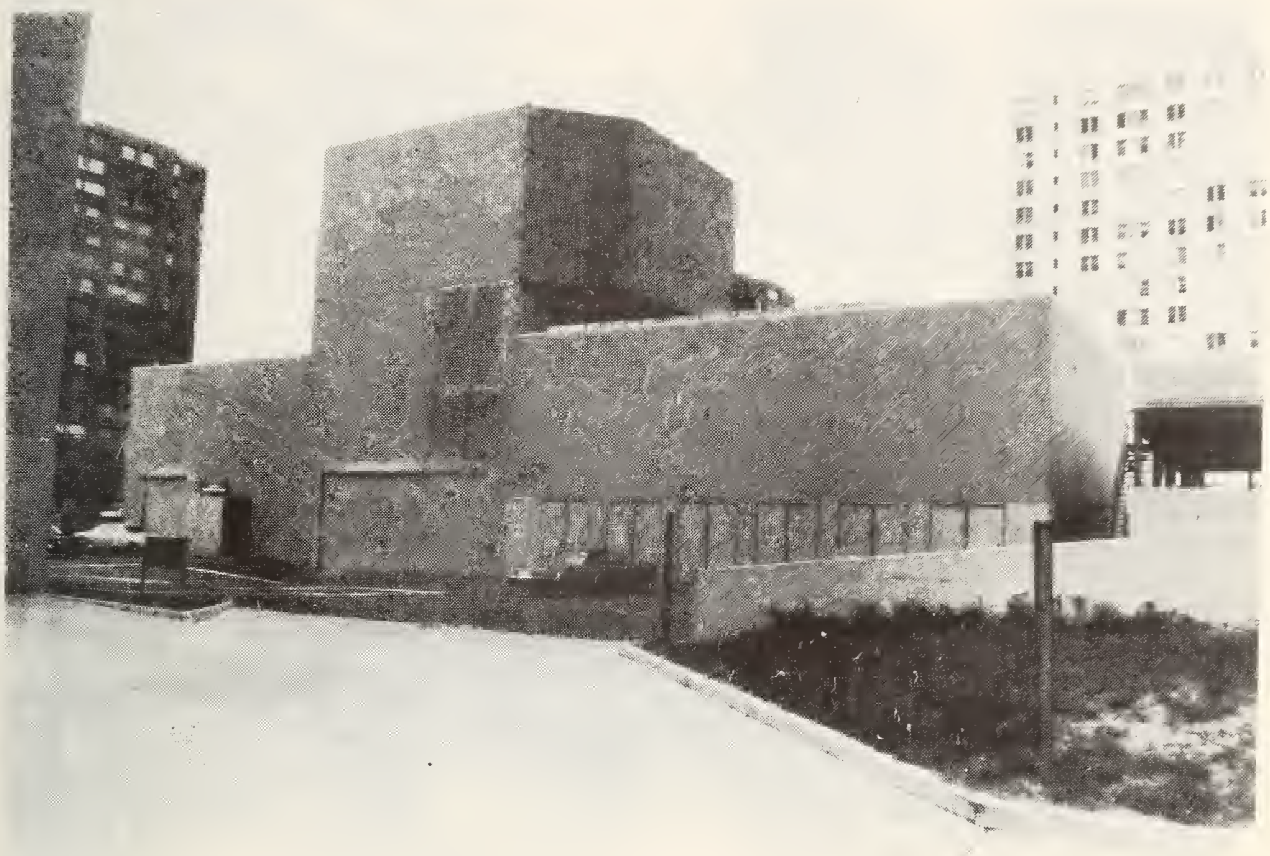

Figure 1-3 Central Equipment Building which houses the Total Energy Plant. The five engine-generators are located just inside the six sets of doors. The central tower houses the cooling towers. Ventilation air for the plant is supplied through the central grill.

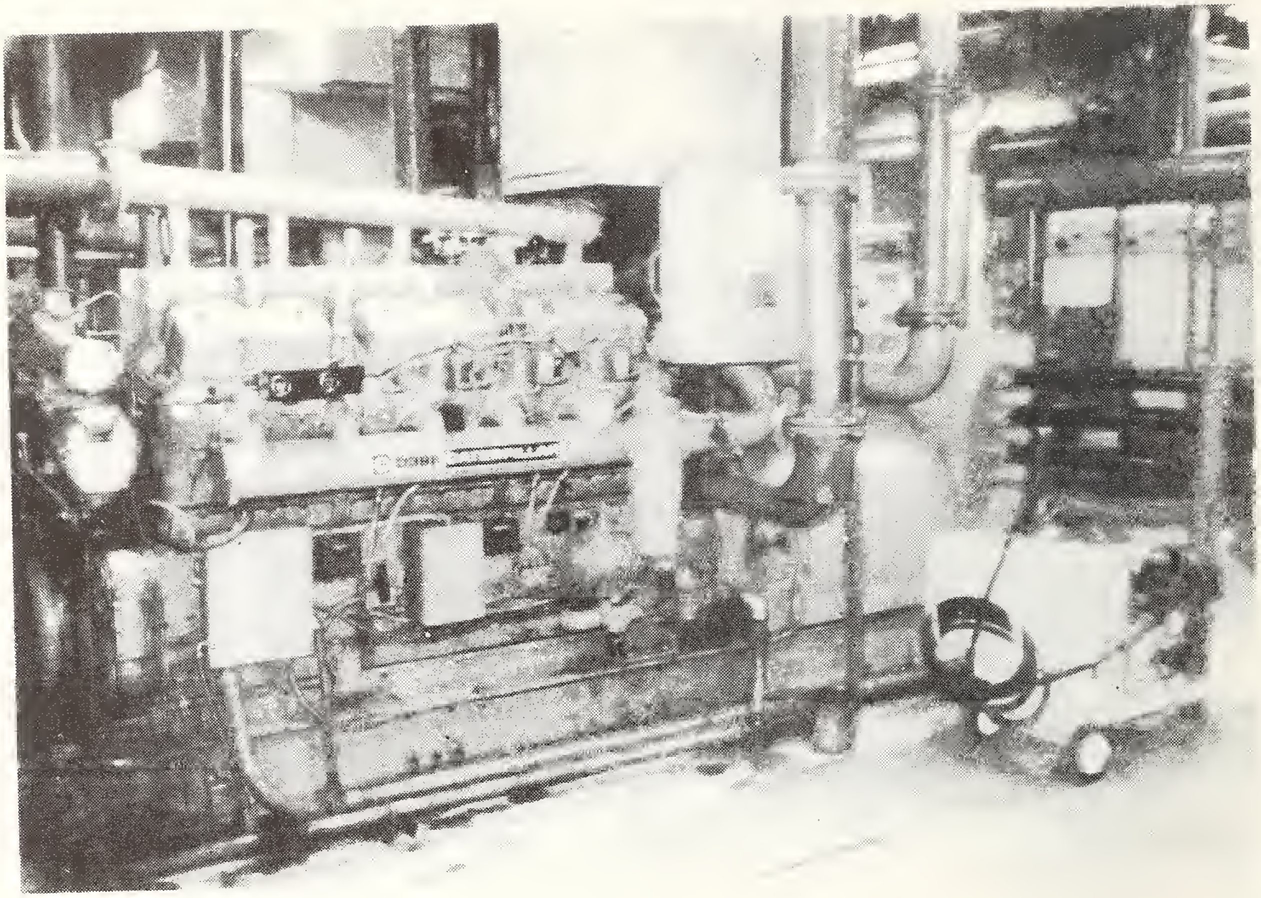

Figure 1-4 One of the five 600 kW diesel engine-generator sets. The inclined pipe above the cylinder heads returns primary hot water from the engine jacket.

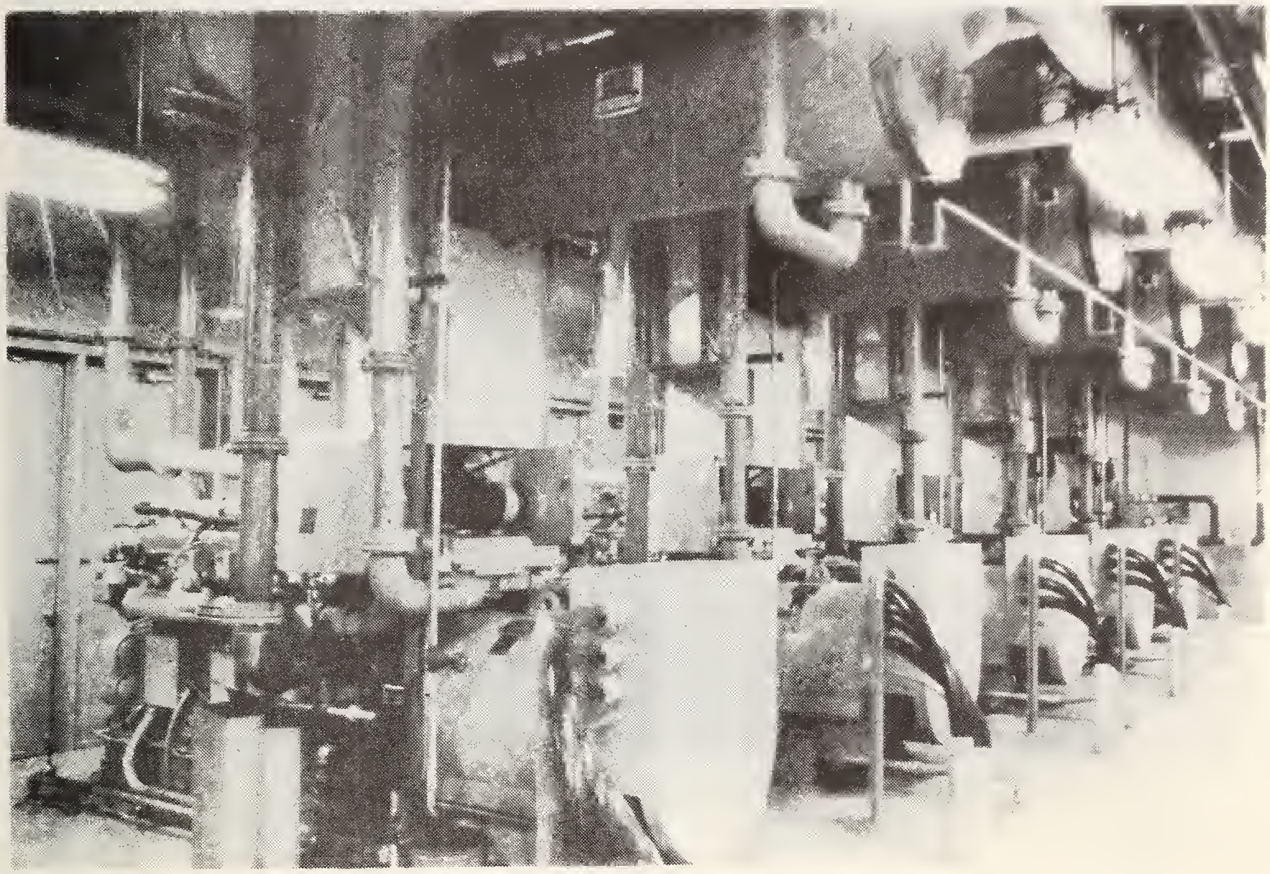

Figure 1-5 The bank of five engine-generators. Flexible conduits carry 3 phase 4 wire feeders from each generator to a common 480 volt bus. The exhaust heat exchangers are visible in the upper portion of the picture.

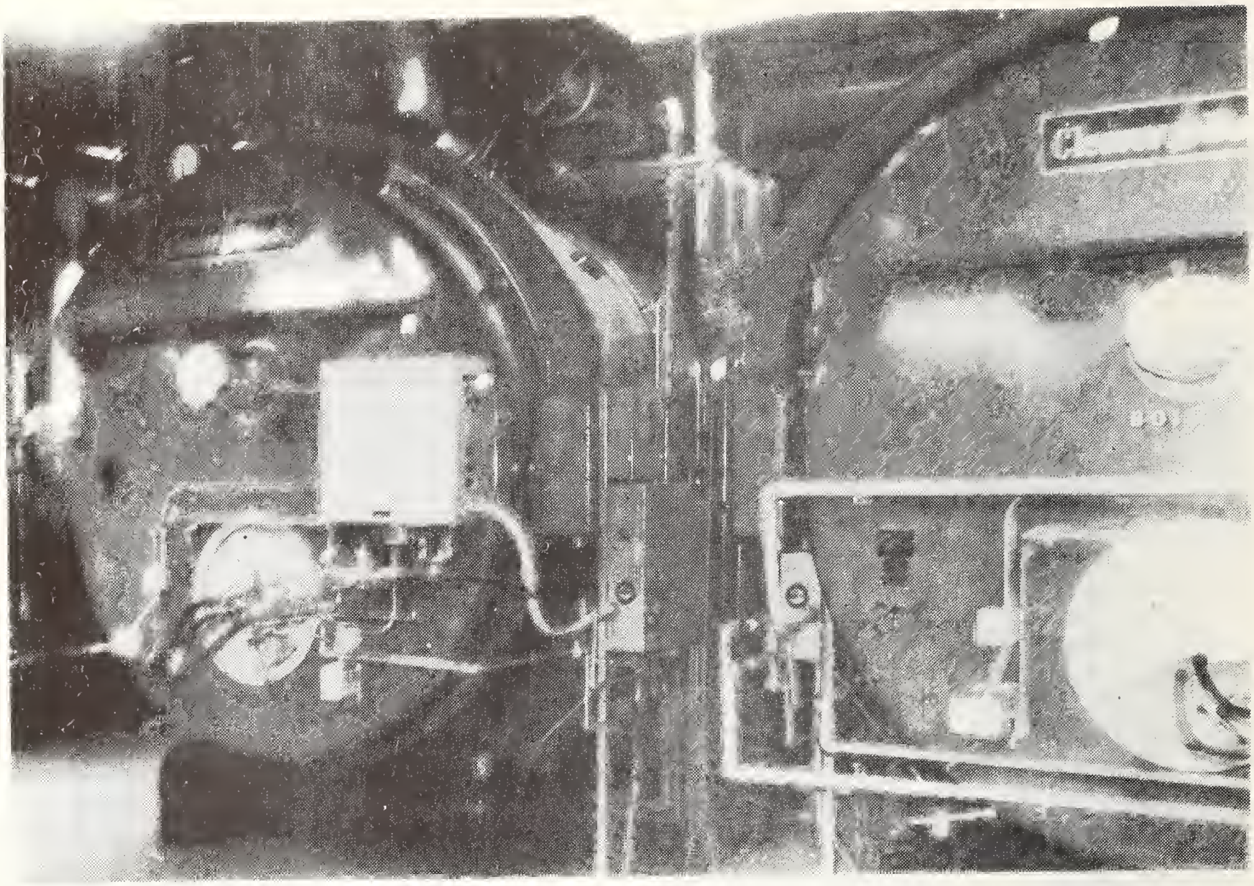

Figure 1-6 The two 13.4 MBTU per hour (3.9 MW) fire tube, hot water boilers. The heat from these boilers supplements the recovered engine heat to meet site hot water and absorption chiller demands.

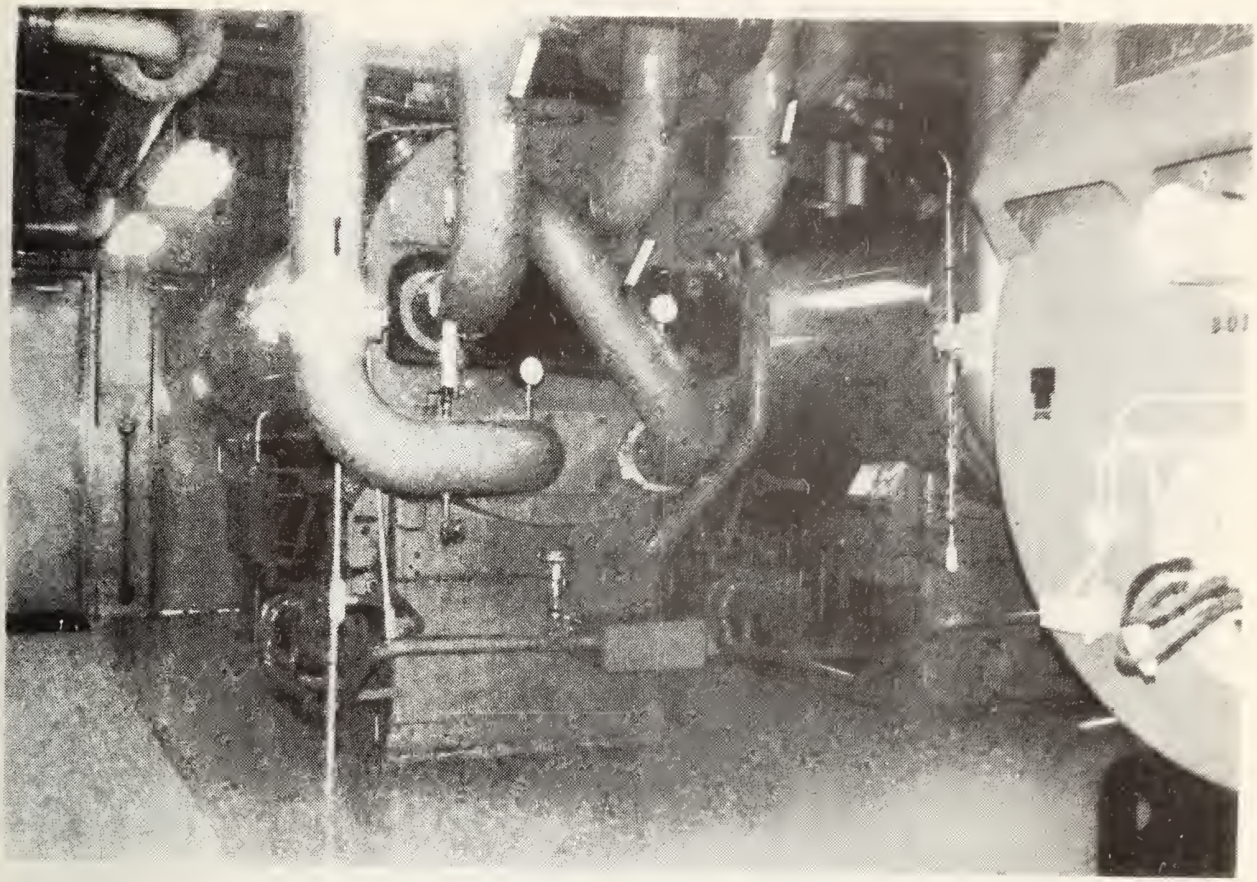

Figure 1-7 The two 546 ton (1.9 MW) absorption chillers which use primary hot water loop heat to produce chilled water for the site and plant air conditioning.

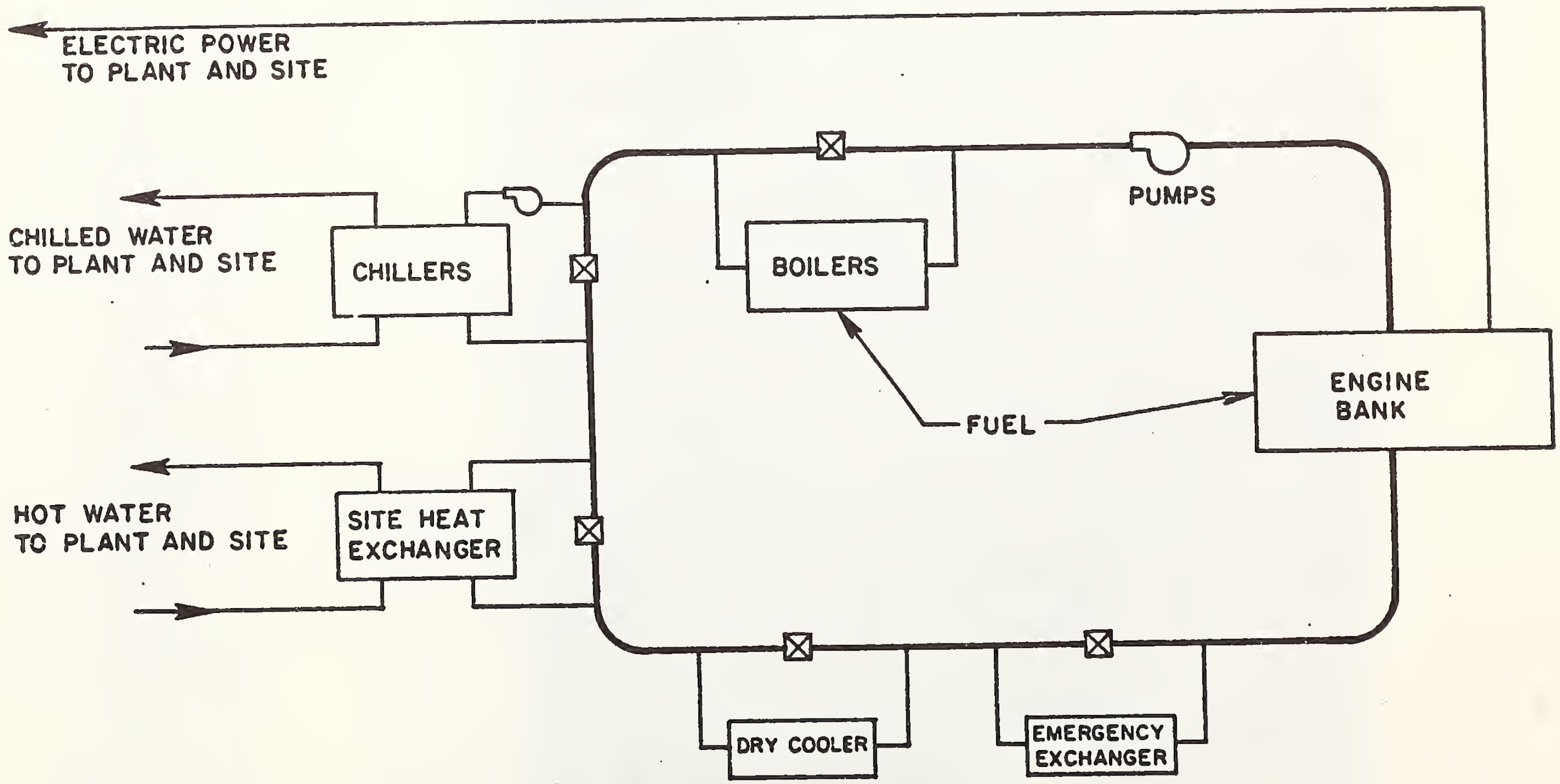

Figure 1-8 Schematic of the primary hot water loop. The PHW loop transfers thermal energy recovered from the engines and boilers to the site secondary hot water system and to the two absorption chillers.

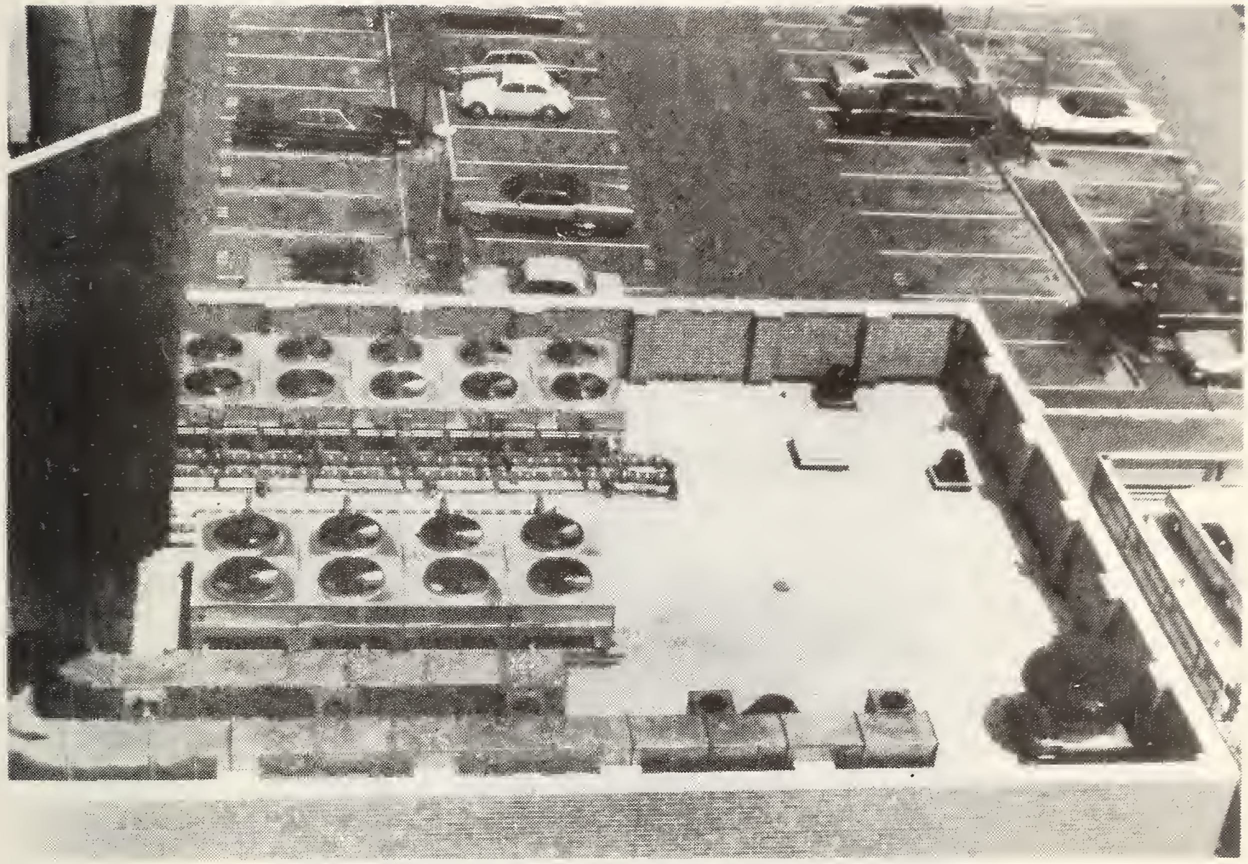

Figure 1-9 The plant roof showing the dry coolers. The eight fan unit can release primary hot water loop heat to the atmosphere. The other dry cooler unit (ten fans) controls the temperature of water used to cool the engine lubrication oil.

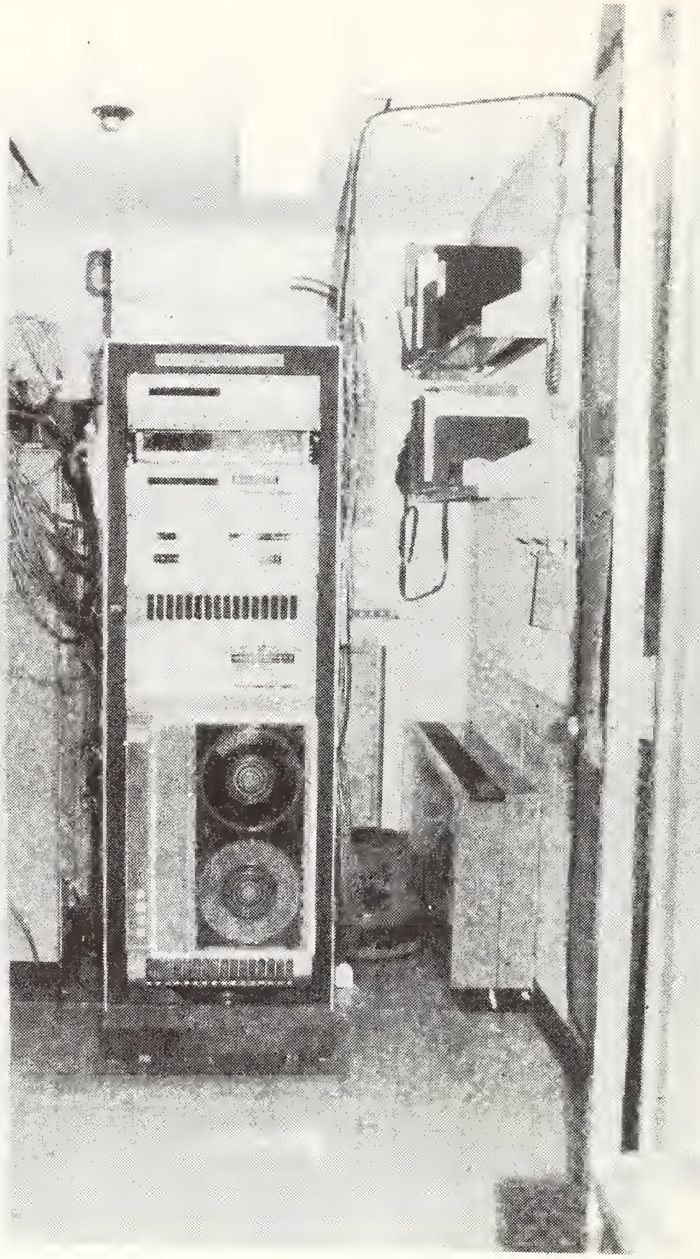

Figure 1-10 The Data Acquisition System (DAS) which records approximately 200 variables in 30 seconds every five minutes.

2.0 Engineering Data

In this section, engineering data recorded at the site is reported. This data describes both the energy production and consumption by the plant and site energy demands. Integrated monthly values and typical load patterns are presented. The integrated data covers one complete year of operation from November 1975 through October 1976. A full year's data is required for a complete seasonal evaluation of the total energy plant. This twelve month period was selected because it represents the first full year of adequate data collection for analysis. Data prior to November 1975 was used primarily to check out the instrumentation system. All data collection is continuing and will be presented in subsequent reports.

2.1 Definition of Engineering Variables

The engineering variables that are reported in this section describe the major flows of electrical, thermal and fuel energies in the plant and to the site. Also these variables are used to determine the efficiencies and coefficient of performance (COP) of major plant components. Figure 2-1 is a schematic of the major energy flows in the plant; the reported variables are marked on the schematic. Each of these variables and its measurement is described in this section.

2.1.1 Electrical Energy Variables

Four electrical energy variables are reported:

- gross electrical energy generated
- electrical energy consumed by site and PTC
- electrical energy consumed by heating, ventilating and cooling (HVAC) equipment in the plant
- net electrical energy required by site, PTC and HVAC processing

The definition and measurement of these terms follows.

Gross Generated is the total electrical energy produced by the generators. This measurement is made by both a DAS transducer and a kilowatt-hour meter connected to the main bus from the generators.

Site consumption including PTC reports the electrical energy distributed to the site buildings (not including the CEB) by the normal and essential feeders plus the energy used by the pneumatic trash collector (PTC) exhauster. The electrical energy consumption by the PTC is relatively constant from month to month, averaging approximately 3500 kilowatt-hours per month. Electrical power data is measured by DAS transducers.

HVAC processing in plant reports the electrical energy required to operate the boilers, the chillers and their auxiliary equipment (including the condenser water cooling towers), the secondary loop hot and chilled water circulation pumps, and the HVAC plant lighting. This data is determined by periodic manual measurements of electrical power consumption of these components and by the hours of operation for each component. The operating hours for each component are determined by computer analysis of DAS data related to each piece of equipment.

Net electrical energy required by the site, PTC and HVAC processing in plant reports the electrical energy which would be purchased if the engine-generators were not used. The net electrical energy is determined by summing the measured site electrical consumption, the measured PTC consumption, and the computed electrical energy required for HVAC processing in plant. The difference between net and gross electrical energy is approximately equal to the electrical energy required by the engine-room exhaust fans, the primary loop pumps, the engine oil-cooler pumps, and the dry cooler fans.

2.1.2 Thermal Energy Variables

Seven thermal energy variables are reported. Five of these, heat recovered from engines, heat added by boilers, PHW heat used by chillers, PHW heat used to produce secondary hot water, PHW losses (input minus output), describe the major energy flows to and from the PHW loop.

The two other variables, total chilled water produced and chilled water used by site, allow determination of the chiller COP and the total site demand. The definition of these terms follow.

Heat Recovered from Engines reports the total amount of thermal energy added by the engine jackets and exhaust heat exchangers to the PHW loop. This variable is calculated using DAS measurement of the total PHW flow rate through all five engines and of the PHW temperature differential across the entire engine bank. This variable includes the heat added to the PHW by engines which are running less the heat lost from the PHW by idle engines.

Heat Recovered from Boilers reports the thermal energy added by the boilers to the PHW loop. This variable is calculated using DAS measurement of the PHW flow rate through the boilers and of the PHW temperature differential across the boilers. This variable includes the heat added to the PHW by the boiler(s) which are firing less the heat lost from the PHW by idle boiler(s).

PHW Heat Used by Chillers reports the amount of thermal energy removed from the PHW loop by the two absorption chillers. These chillers use PHW thermal energy to produce chilled water which is circulated in the plant and from the plant to the site buildings. PHW heat used by the chillers is calculated using DAS measurement of the PHW flow rate and PHW temperature difference across the chillers.

PHW Heat Used to Produce Secondary Hot Water reports the amount of thermal energy removed from the PHW loop by the two site heat exchangers. The site heat exchangers transfer thermal energy from the PHW to the secondary hot-water loops which circulate from the plant building to the site buildings. This quantity is calculated using DAS measurement of the PHW flow rate and the PHW temperature differential across the exchangers.

PHW Dry Cooler and Piping Losses reports the difference between the thermal energy supplied to the PHW loop by the engines and boilers minus the heat removed from the PHW loop by the site hot water heat exchangers and by the absorption chillers. Most of this quantity represents PHW heat removed by the dry coolers via continual convective losses and via heat released during erratic operation of the dry cooler fan controls.

Total Cooling Load reports the total amount of thermal energy absorbed by the chillers from the secondary chilled water system which supplies cooling to the site buildings and to the plant. This quantity is the total chiller output and is calculated using DAS measurements of the secondary chilled water flow rate and temperature differentials across the chillers.

Site Cooling Load reports the thermal energy absorbed from the site by the secondary chilled water. This quantity is computed by subtracting the energy absorbed by the chilled water used in the plant from the total energy absorbed in the chilled water produced. Both these quantities are calculated using DAS measurements of water flow rates and temperature differentials.

2.1.3 Fuel Variables

Four fuel variables are reported: fuel consumed by engines, fuel consumed by boilers, total fuel consumed, and heat content of fuel. The reported fuel data from May 1976 through September 1976 is measured data (see section 1.3). The fuel data from November 1975 through April 1976 and October 1976 was calculated using measured engine and boiler output data along with engine and boiler efficiency models based upon the May through September data. The calculated fuel data has been confirmed by fuel oil delivery records (compensated for storage tank levels). The definition and determination of fuel variables follows.

Fuel Consumed by Engines reports the total amount of fuel oil consumed by the engines. For five months (May '76 - Sept. '76) this quantity was measured by a manually-read meter recording the amount of fuel which was pumped into the engine day-tanks from the underground storage tanks. Because the fuel system maintains the day-tank level within 30 gallons, fuel flow to the day-tank is an accurate ($\pm 1\%$) measurement of monthly engine fuel consumption. Because engine operating conditions were unchanged, monthly engine fuel consumption for the prior six months (Nov.'75 - April '76) and October was determined using the engine-generator electrical efficiency, 32.4%, as determined during periods of measured fuel data and monthly gross electrical energy generated measurements.

Fuel Consumed by Boilers reports the total amount of fuel oil consumed by the boilers. From May 76 to Sept. 76 this quantity was measured from the difference between two manually-read meters: one which recorded the total fuel pumped to both the engine and boiler day-tanks, the other which recorded fuel pumped into the engine day-tank (the location of the boiler day-tank lines prevented installation of direct boiler fuel metering). For the other months, boiler fuel consumption is determined using measurements of boiler output data and a model describing the boiler fuel consumption based upon periods of measured data (see appendix III). During months of mild weather the uncertainty of measured boiler fuel data increases. For these months, boiler fuel consumption may be only 20% of the total fuel consumption, increasing the uncertainty of boiler fuel consumption data from 2% to 7% (see section 2.2.2).

Total Fuel Consumed reports all fuel consumed by engines and boilers.

Fuel Oil Heat Content reports the energy available by complete combustion of one gallon of the plant fuel oil. The fuel oil heat content is determined by averaging values of the fuel's higher heating value (HHV) reported by a testing laboratory. The testing laboratory determines the heat content of samples from chemical and physical properties measured using ASTM test procedures D1552, D874, D95, and D287. Fuel oil samples are taken periodically from the day-tank which supplies the engines. Both the engines and boilers use the same fuel.

2.1.4 Efficiencies

The operating efficiencies address both selected plant components and overall plant performance. Engine electrical efficiency, engine electrical plus thermal efficiency, boiler efficiency, and chiller COP, describe component performances. Electrical production efficiency and plant energy effectiveness, describe overall plant performance.

Engine-Generator Gross Electrical Efficiency is defined as the total electrical energy produced by the generators divided by the energy in the consumed fuel using consistent units.

Engine-Generator Gross Electrical Plus Thermal Efficiency is defined as the total electrical energy produced plus total thermal energy recovered from the jackets and exhaust heat exchangers divided by by the total heat content of the consumed fuel using consistent units. Electrical plus thermal efficiency is based upon heat recovered across the bank of engines; losses from idle engines reduce this efficiency.

Boiler Efficiency is defined as the total thermal energy added to the PHW by the boilers divided by the total heat content of the consumed fuel. Because the total boiler output includes the continual losses from the boiler(s) to their surroundings including periods when they are not fired, the reported boiler efficiency will decrease during low output months. The uncertainty of the boiler efficiency reflects the accuracy of the boiler fuel measurement and may be 5% to 10% during low usage months.

Chiller COP is defined as the total thermal energy taken from the secondary chilled water by the chillers divided by the total thermal energy consumed from the PHW by the chillers. The chiller COP does not include electrical energy used by the chiller pumps, cooling tower, and secondary chilled water loops.

Engine-Generator Net Heat Rate is defined as the engine-generator's efficiency in producing the net electrical energy required by the plant and site. This quantity is computed by dividing the total heat content of engine fuel in Btu by the net electrical energy produced. In computing this efficiency, net electrical energy rather than total generated electrical energy is used because the electrical energy used to operate the electrical plant is not available to the site and HVAC equipment. The Btu per kWh form is used because it can be directly compared with the efficiencies of the local electrical utilities. In 1975, the local utility at Jersey City generated and distributed electrical energy with a point-of-use heat rate of 11,451 Btu per kWh. This value has been calculated as follows: The 1975 published net heat rate for the Public Service Electric and Gas Company[8] was 10,582 Btu per kWh. This value was adjusted for distribution losses, by multiplying by the ratio of "kilowatt hours produced, purchased and interchanged (net)" to "total sales to customers".

Energy Effectiveness in Meeting Site Demands is defined for the purposes of this report as the sum of the energy conveyed by the three plant products; (site electric energy, site hot water, and site chilled water) divided by the energy content of the total fuel consumed by the site. The reported values for energy effectiveness do not include the losses in the distribution systems between the plant and site buildings. It should be noted that a specific definition for the energy effectiveness of a total energy system has not been accepted by any recognized group to date.

2.2 Plant Performance Data

2.2.1 Engineering Data

In this section the plant variables and efficiencies defined in section 2.1 are reported for each month from November 1975 through October 1976 and annual totals are given. Table 2-1 reports monthly and annual electrical data, table 2-2 reports monthly and annual thermal data, table 2-3 reports monthly and annual fuel data, and table 2-4 reports monthly and annual efficiencies. A table of the monthly summaries which were prepared for the reported period is shown in appendix I.

During the reported period (November 1975 through October 1976) the plant supplied a total of 6,363,154 kWh of electrical energy, 37,353 MBtu (39411 GJ) of heating, and 7,735 MBtu (8161 GJ) of chilling to the site and distribution system. During this period, the plant consumed a total of 986,136 gallons (3733 m^3) of fuel oil. Heat recovered from the engines was used to meet 39% of the site and chiller heat demands. Engine-generator gross electrical efficiency was 32.4%; and gross electrical plus thermal efficiency was 61.4%. Average boiler efficiency was 81.6% and chiller COP was measured as 0.40.

2.2.2 Accuracy of Engineering Data

Confirmation of the accuracy of the engineering data presented in section 2.2.1 is important for assessing the accuracy of the Jersey City Total Energy performance evaluations. In this section, the factors which influence the accuracy of this data are examined and an analysis is performed which establishes the accuracy of the engineering data submitted in this report.

2.2.2.1 Sources of Uncertainty

The reported engineering data include electrical energy data, hot- and chilled-water thermal energy data and fuel quantity data. The major factors that affect the uncertainties of the monthly engineering quantities are the accuracies of various transducers used for measurement and the number of hours of acceptable data recorded in a particular month. In the case of electrical energy data, such as total generated or site consumption, measurements are performed by one or more Hall-effect wattmeters with hardware integrators. These individual devices and their associated circuitry have end-to-end uncertainties of less than 1%.

Thermal energy data (such as heat recovered from engines, heat produced by boilers, heat sent to the site, heat consumed by chillers, and chilled water sent to the site) require at least one pair of temperature measurements and one flow measurement for each piece of data. Some data require several flow and temperature measurements. Uncertainty of a pair of thermocouple and thermopile temperature measurements has been less than 0.1°F for pairs in which both measurement locations experienced similar ambient conditions. These extreme accuracies are required because of the low temperature differentials which must be measured. For example, in the primary loop a 0.1°F measurement error across the bank of engines will result in an error in the monthly heat recovery data of 2% (50 MBtu). A typical flow measurement is made by a venturi in conjunction with a differential pressure cell. Despite problems associated with the primary water fouling the pressure cells, frequent cleaning and calibration has maintained the uncertainties below 1.5% based on an assumed accuracy in the venturi and maximum observed drift in the differential pressure cells. Considering that the specific heat of the plant water is also uncertain ($\pm$1%), the cumulative accuracy of individual thermal data involving one pair of temperature measurements and one flow measurement is:

$$\sigma = \sqrt{\sigma^2_{\text{TEMP}} + \sigma^2_{\text{FLOW}} + \sigma^2_{\text{SPECIFIC HEAT}}}$$

$$= \sqrt{(.1/\Delta T)^2 + (.015)^2 + (.01)^2}$$

where ΔT is the mean differential temperature measured. Assuming a typical ΔT of 5° to 10°F, the typical thermal data uncertainty is 2.7% to 2.1%.

Both thermal and electrical monthly data are also affected by DAS malfunctions which results in blank data periods. For the most part these periods have been short, however, one period extended from July 3, 1976 through August 3, 1976. Figure 2-2 charts the hours of available data for the 12-month period. Compensating for data losses is frequently complicated and reduced in accuracy because environmental extremes such as temperature or line voltage variations may trigger a DAS malfunction. Summaries for periods which include DAS malfunctions during plant or environmental extremes may have increased uncertainty. For instance, on August 4, 1976, the plant had voltage control problems making it necessary to shut off the boilers. The line voltage variations also resulted in a DAS malfunction so that for the 24 hour period of unpredictable plant conditions, data was unavailable. As a result the uncertainty of the August data was increased.

Longer DAS outages may result in noticeable discrepancies between DAS corrected data and continuously recorded manual fuel data. For example, because of the long July DAS outage, the monthly thermal data was based on only several days of the month, whereas fuel data was being continuously recorded for the entire month. Because boiler output data was based on only a few days while fuel consumption data covered the entire month the resulting July boiler efficiency was 77% whereas June boiler efficiency was 80%. The reported August boiler efficiency is also somewhat affected by this DAS outage.

Fuel consumption data (including fuel consumed by engines, fuel consumed by boilers, and total fuel consumed) was measured by two manually-read fuel meters for the last six months of the reported period. These meters have uncertainties of approximately 1%. One meter measures total fuel and the other meter measures engine fuel.*

*Regarding the problems involving fuel measurement, several items should be noted. First, the manually read meters were installed as a temporary method of overcoming the problems of the original supply/return measurement system previously described. Second, the method of installation of these temporary meters was dictated by the physical layout of the plumbing in the plant. And third, the new individual component metering system now being designed which will directly measure the fuel consumption of each component via an individual channel to the DAS, will greatly reduce the uncertainties of the fuel consumption measurements.

Boiler fuel consumption is determined from the difference between the total and engine fuel data. The boiler fuel measurement uncertainty varies according to the magnitude of boiler fuel consumption. For periods when boiler consumption equals engine consumption, as in the month of January, the measurement uncertainty is 2%. However, for periods of mild weather, boiler consumption may be one-quarter to one-tenth engine consumption and the boiler measurement uncertainty becomes 6% to 15%.

The accuracy of monthly fuel allocations may be affected by the dates of the manual meter readings. Work schedules frequently cause meter readings to be made several days before and after the ends of the months so that monthly fuel data may have to be manually divided between months. If weather conditions shift near the end of such a month, uncertainties may result. For example, in one extreme case involving sickness, fuel measurements for September were not taken on scheduled dates but were only taken on September 1, 17 and October 8. Also the chillers had major adjustments on September 21, so that the extrapolation of exact boiler and total fuel consumption for the entire month of September is uncertain. For October fuel data is not directly available due to a week of missing fuel data in mid October when the fuel meters were inadvertently bypassed by the plant engineer.

2.2.2.2 Confirmation of Data Accuracy

The accuracy of the most important monthly data can be verified through independent DAS measurements and plant log information.

The accuracy of thermal energy data for the primary loop including engine heat recovery, boiler heat production, chiller heat consumption, site heat consumption and dry cooler heat removal can be assessed by summing the monthly figures for energy supplied to and consumed from the primary loop. Performing the computation for the last six months of data indicates a monthly RMS difference of 4% relative to the mean engine heat recovered. A second method of assessing primary loop accuracy involves comparison of measurements of heat supplied to and extracted from the site heat exchangers. This comparison indicates a monthly RMS difference of 5% which suggests the primary measurement uncertainty was $5\%/\sqrt{2}$ or 3.6%. These two results suggest that uncertainty of the monthly thermal energy data due to instrumentation inaccuracies is approximately 4%.

Uncertainty of monthly electrical data can be determined by comparison of gross electrical energy generated as measured by the DAS with the plant engineer's manual readings of a kilowatt-hour meter. This comparison over the entire 12 month period indicates a RMS difference of 2.7% between the DAS data and the meter data. Recent calibration of the DAS kilowatt-hour transducer indicates that this difference is mostly the result of an incorrect DAS transducer setting. The monthly values of gross generated electrical power reported in section 2.2.1 are based upon the kilowatt-hour meter data.

Uncertainty of monthly fuel data can be evaluated by comparison of the annual total fuel data in section 2.2.1 with the sum of the plant fuel delivery records during the reported period and storage tank levels on November 1, 1975 and November 1, 1976. Delivery records indicate that a total of 958,251 gallons of fuel oil were delivered during the reported period. On November 1, 1975, plant records indicate that 56,700 $\pm$1000 gallons of fuel oil were in the three storage tanks. On November 1, 1976, there were 32,100 $\pm$3000 gallons of fuel oil in the storage tanks. Thus, total fuel consumption for the reported period was 983,000 $\pm$4000 gallons.

The monthly fuel data reported in section 2.2.1 is based upon 5 months of fuel oil data from the manually-read meters and 7 months of fuel oil projections based upon monthly generator output and boiler output data and engine-generator and boiler efficiency models determined from periods during the five months of measured fuel data. Summation of the five months of measured fuel data and seven months of projected fuel data indicate an annual fuel consumption of 986,136 gallons. The difference between the fuel data determined from delivery and storage tank records and the fuel data computed from the monthly data is 0.3% for the year.

The actual engine fuel uncertainty can be evaluated by comparison of the engine-generators electrical efficiency with the electrical efficiencies measured during the factory acceptance tests as reported in a separate document.[1] In that document the electrical efficiency measured at 60% load was 31.1%. For the year reported herein, the electrical load averaged approximately 60% and the electrical efficiency averaged 32.4%. This figure is 1.3 percentage points or 4% above the efficiency observed during the factory tests, however, it is generally accepted that diesel engines tend to increase in efficiency several percent after they have "run-in" for several thousand hours. Thus, the engine fuel uncertainty is probably in the range of 1% to 2%.

The boiler fuel uncertainty can be evaluated from the manufacturer's "typical performance" data describing the boilers or from the uncertainties of the total and engine fuel consumptions as described in the preceeding two paragraphs. As described in appendix III, a model of the boiler's performance based on the measured boiler performance has been produced. This model agrees with the manufacturers "typical performance" within 1% suggesting an uncertainty of approximately 1%. A back-up analysis based upon uncertainties of total and annual fuel can be performed. Total annual fuel data has an uncertainty of approximately 1%, engine fuel uncertainty is less than 4%, and boiler fuel consumption is approximately one-third of the total annual fuel consumption; suggesting a boiler fuel uncertainty less than 8%. As mentioned in section 2.2.2.1, the uncertainty of boiler fuel data for individual months is greater than the uncertainty for longer periods due to the problems involved in manual fuel meter readings. Uncertainty of monthly boiler efficiency data is likewise affected by this factor and by the thermal data uncertainties, so that individual months boiler efficiency data has uncertainties in the range of 10%.

It should be emphasized that the uncertainty of the annual reported boiler efficiency as computed from total annual fuel consumption is less than 8% and more likely in the range of 1% to 2%.

In summary, the accuracy of annual electrical and thermal data is approximately 1% to 3%. Some monthly data are less accurate and as described, the uncertainties range as high as 15%.

2.3 Profiles of Typical Daily Electrical and Thermal Demands

2.3.1 Plant Profiles

The rate of engine heat recovery is proportional to engine-generator electrical load, and because of this, a good match between electrical and thermal demands is important for effective total energy plant operation. The thermal and electrical site demands served by the plant vary during each day. In this section examples of these daily thermal and electrical load profiles are shown. The four, four-day periods used in this section were selected as typical examples for each of the four seasons.

Figure 2-3 illustrates the typical site, HVAC, and total electrical demands for each of the four seasons. Note that the site demand follows a fairly consistent diurnal cycle from a peak near 900 kW in the evening to a low near 500 kW before dawn. The mean daily site electrical demand is approximately constant year round. In contrast, the plant HVAC electrical demand is diurnally unvarying, but varies from approximately 300 kW in summer to 100 kW in fall, winter, and spring. The increased summer demand is due to the absorption chiller pumps, their condenser water cooling towers, and other associated pumps.

Site thermal demands also show large variations (see figure 2-4). Because thermal demands are based more upon the weather than upon the cumulative habits of the site occupants, the site thermal demands have a diurnal profile which is much less regular than the diurnal electrical demand profile. (One thermal demand which exhibits a regular diurnal cycle is the hot water demand. This can be seen in summer when occupant domestic hot water demand is the only site hot water demand.) Section 2.3.2 more fully describes individual building demands.

The site thermal demands are met through the hot-water heat exchangers and the chillers which draw heat from the primary loop according to the site hot and chilled water thermal demands. In figure 2-5, the PHW thermal demands resulting from the site hot and chilled water demands are plotted along with the rate of engine heat recovery. Note that in summer, the chiller PHW demands are similar to the winter site hot water demands; and that in spring and fall, heat recovered from the engines is approximately equal to PHW demands from the site. Examination of all the spring and fall data indicates that rarely do PHW thermal demands fall below the rate of engine heat recovery. Never during the year reported here did the dry coolers have to release PHW heat due to very low site thermal demands.

Inspection of profile data for the entire reported year was used to establish peak engine-generator, boiler, and chiller loads. Peak engine-generator load was 1350 kW or 45% of installed capacity. Peak boiler load was 14 MBtu per hour (4.1 MW) or 52% of installed capacity. Peak chiller load was 6 MBtu per hour (1.8 MW) or 46% of installed capacity.

2.3.2 Site Building Profiles

Extensive data describing the electrical energy used for normal and for essential services, the thermal energy used for space heating and for domestic hot water production, and the thermal energy absorbed for space cooling are monitored by the DAS for all site buildings which utilize these services.

These data are available as hourly profile data or as integrated daily or monthly values. However, because the building instrumentation systems have just recently been brought on line and calibrated, building demand data are not yet available for a complete year. Therefore, building data will be presented in subsequent reports.

Figures 2-6 and 2-7 present examples of individual site buildings electrical demand, space heating demand, space cooling demand, and domestic hot water demand for the winter, spring, and summer seasons.

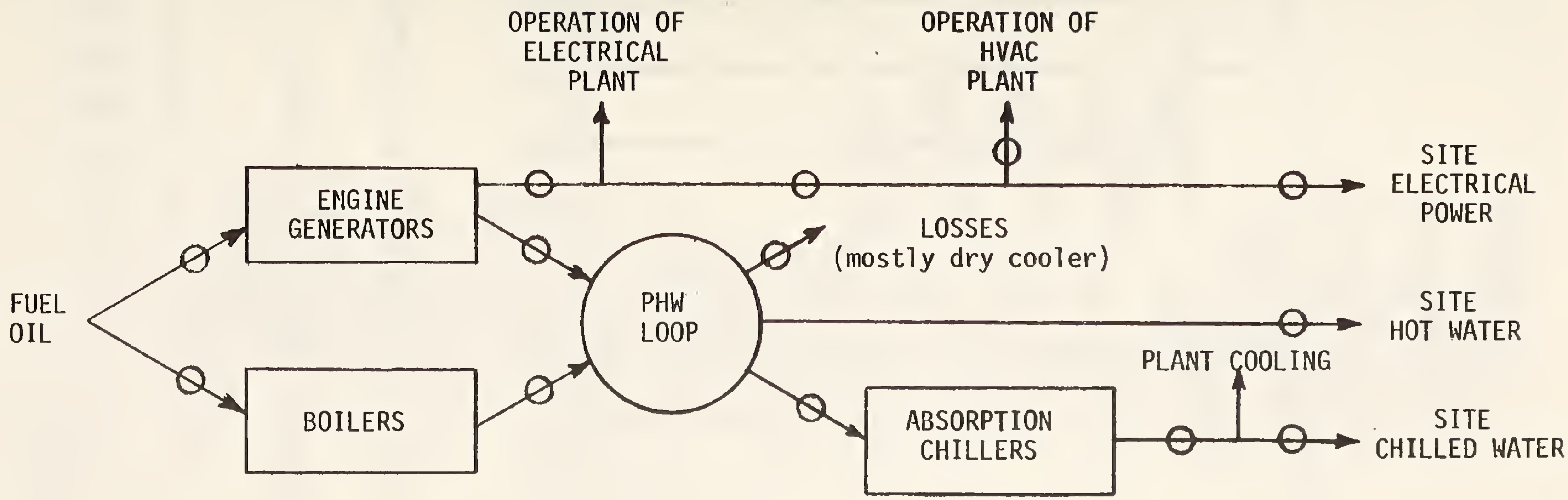

Figure 2-1 Schematic of major energy flows in JCTE plant. Reported integrated variables are marked (0).

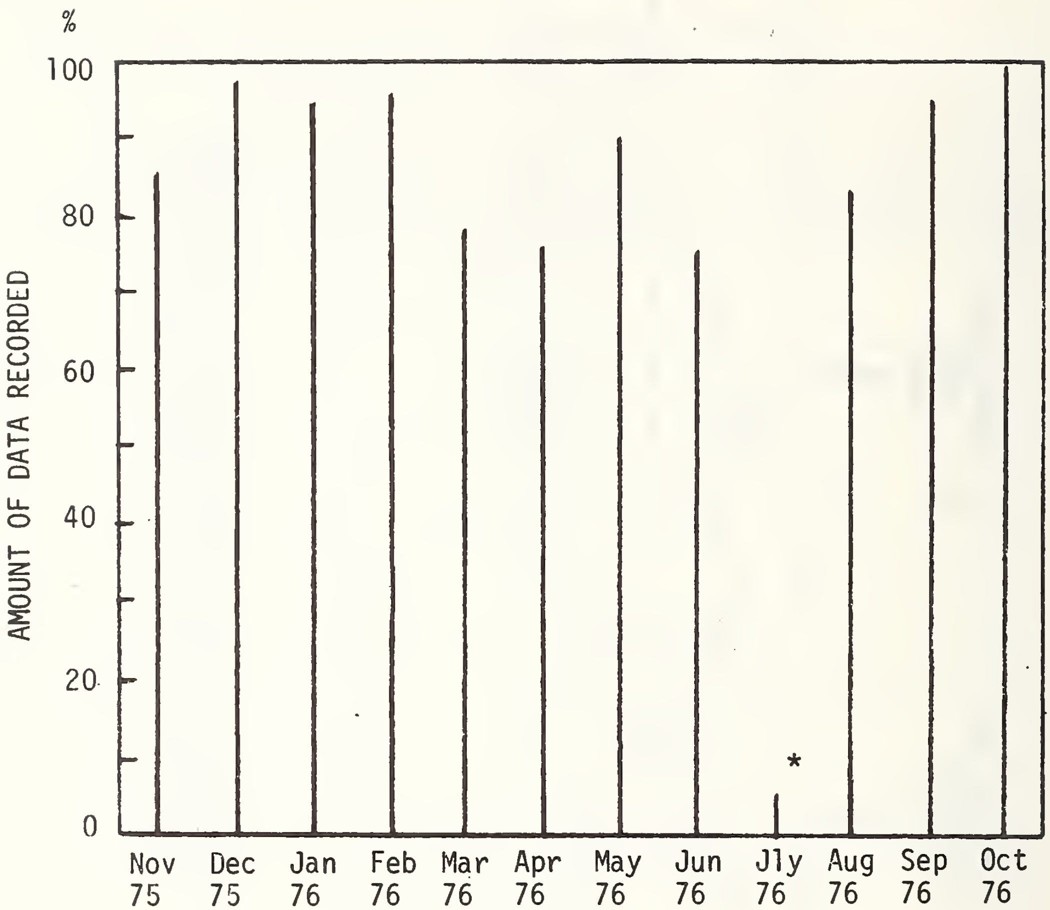

Figure 2-2. Percentage of total monthly data recorded by DAS.

*DAS inoperative because of failure of plant office area cooling system.

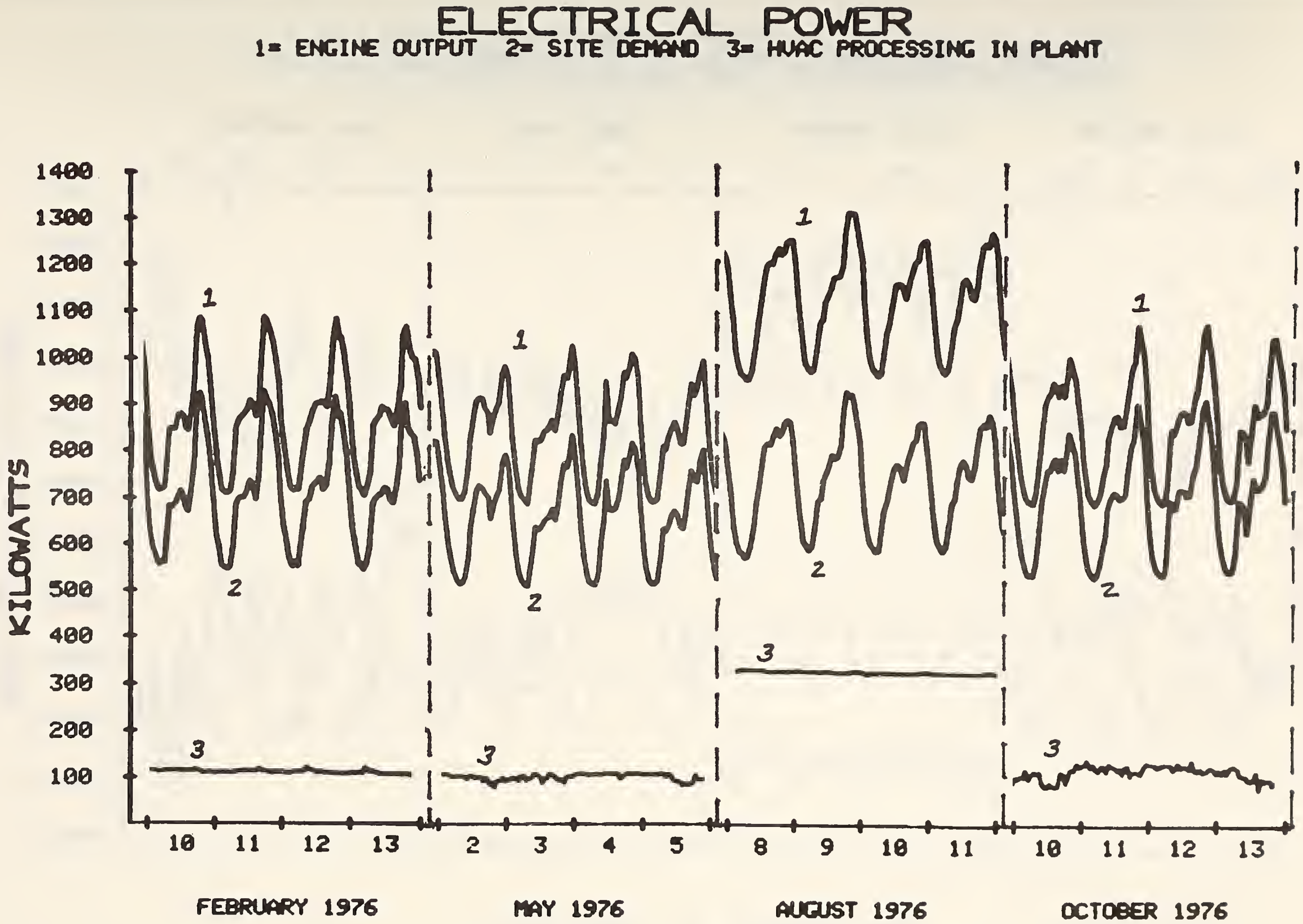

Figure 2-3 Typical profiles of gross electrical power generated (1), site electrical demand (2), and HVAC electrical demand (3) for the four seasons.

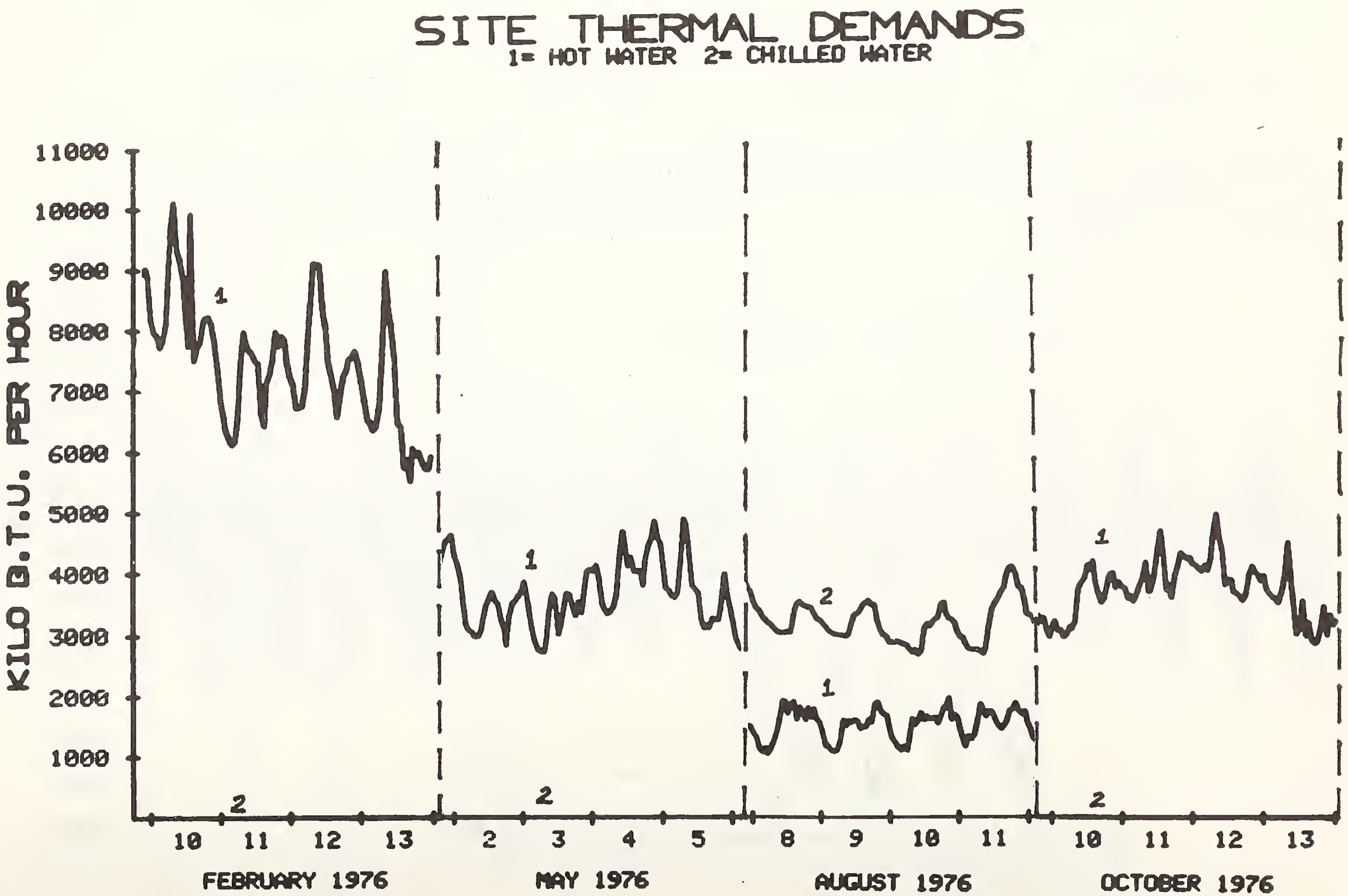

Figure 2-4 Typical profiles of site hot water (1) and chilled water (2) thermal demands for four seasons.

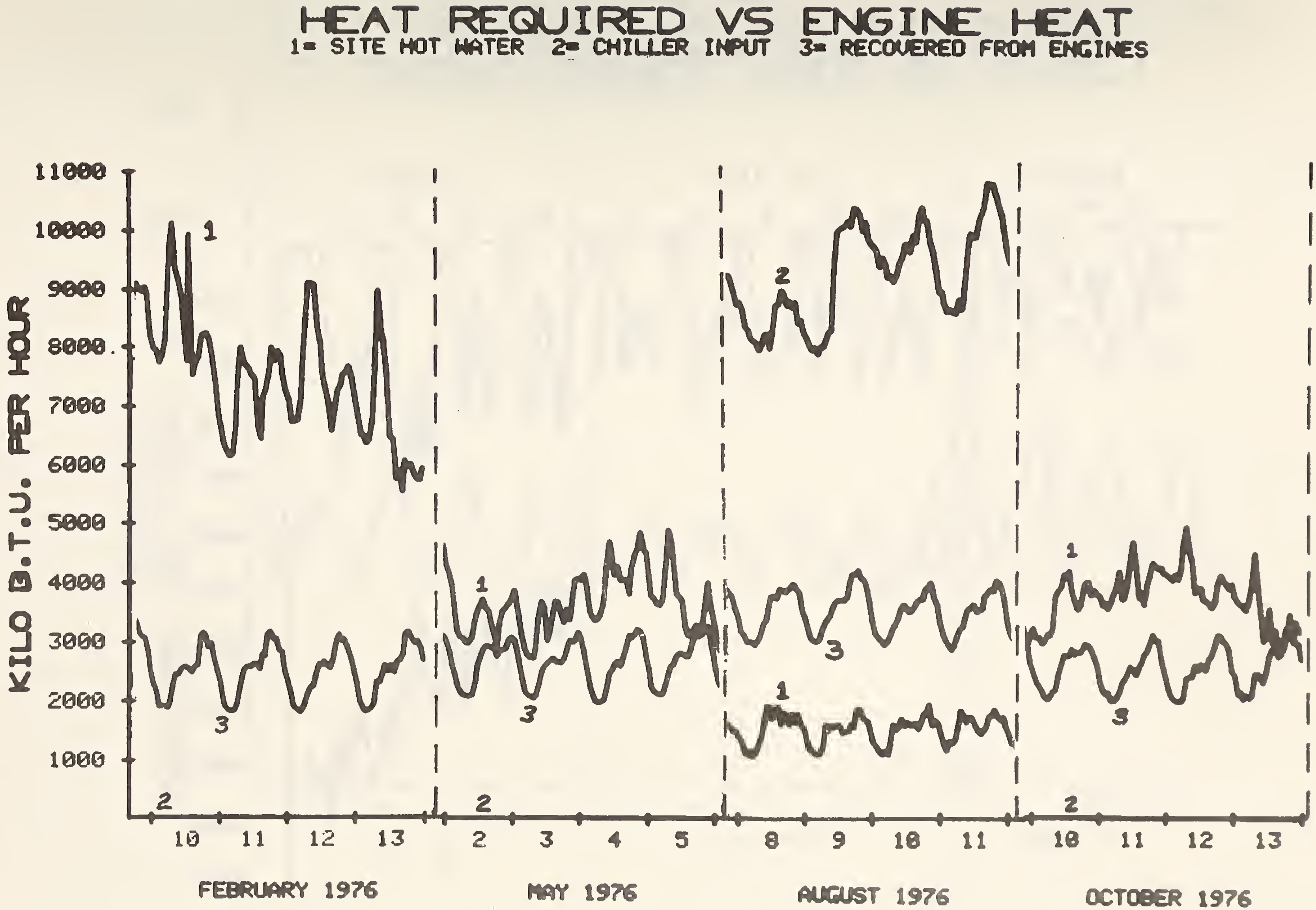

Figure 2-5 Typical profiles of site PHW demands (1), chiller PHW demands (2), and heat added to the PHW by the engines (3).

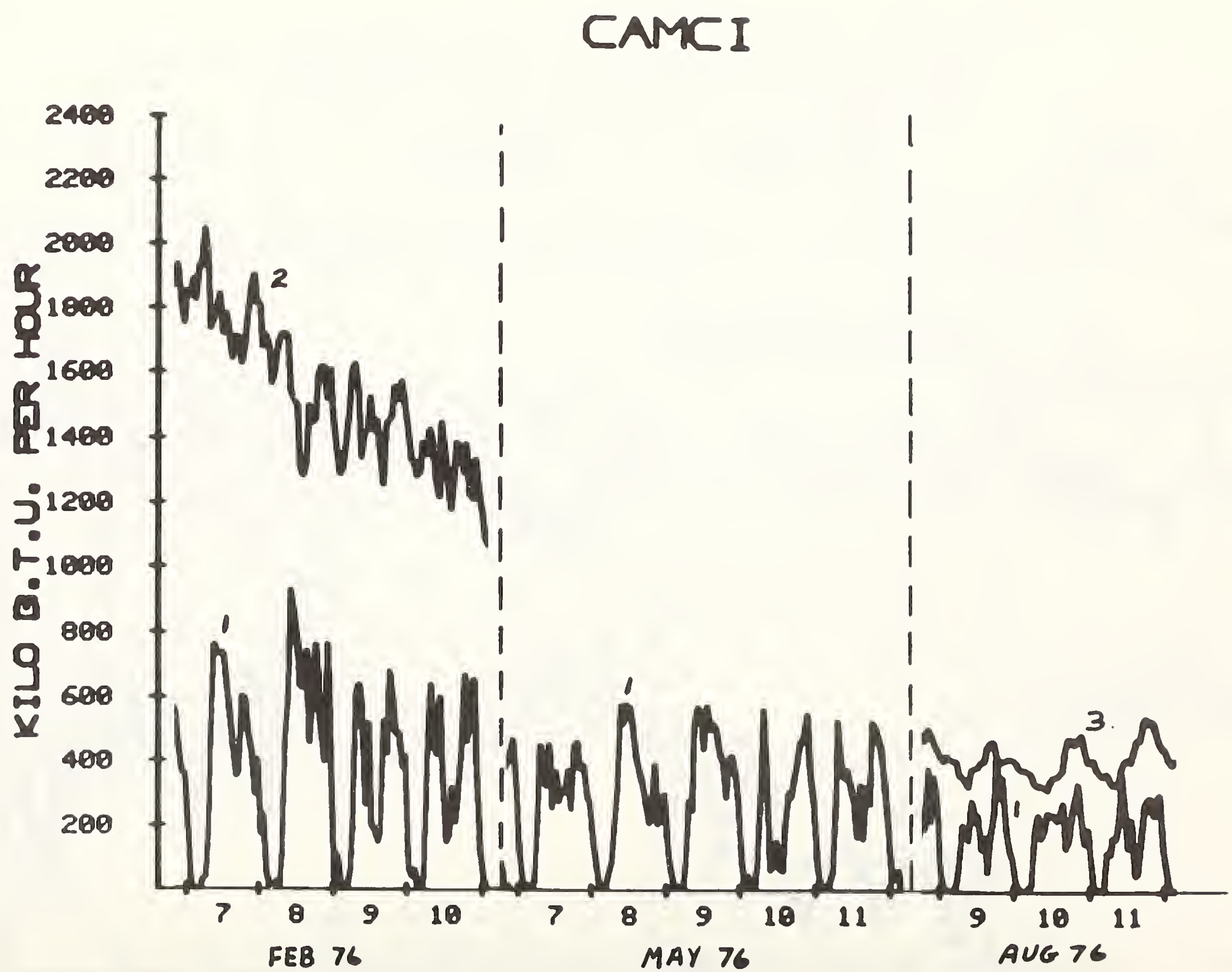

Figure 2-6 Typical domestic hot water (1), space heating (2), and space cooling (3) thermal demands of Camci apartments for winter, spring and summer.

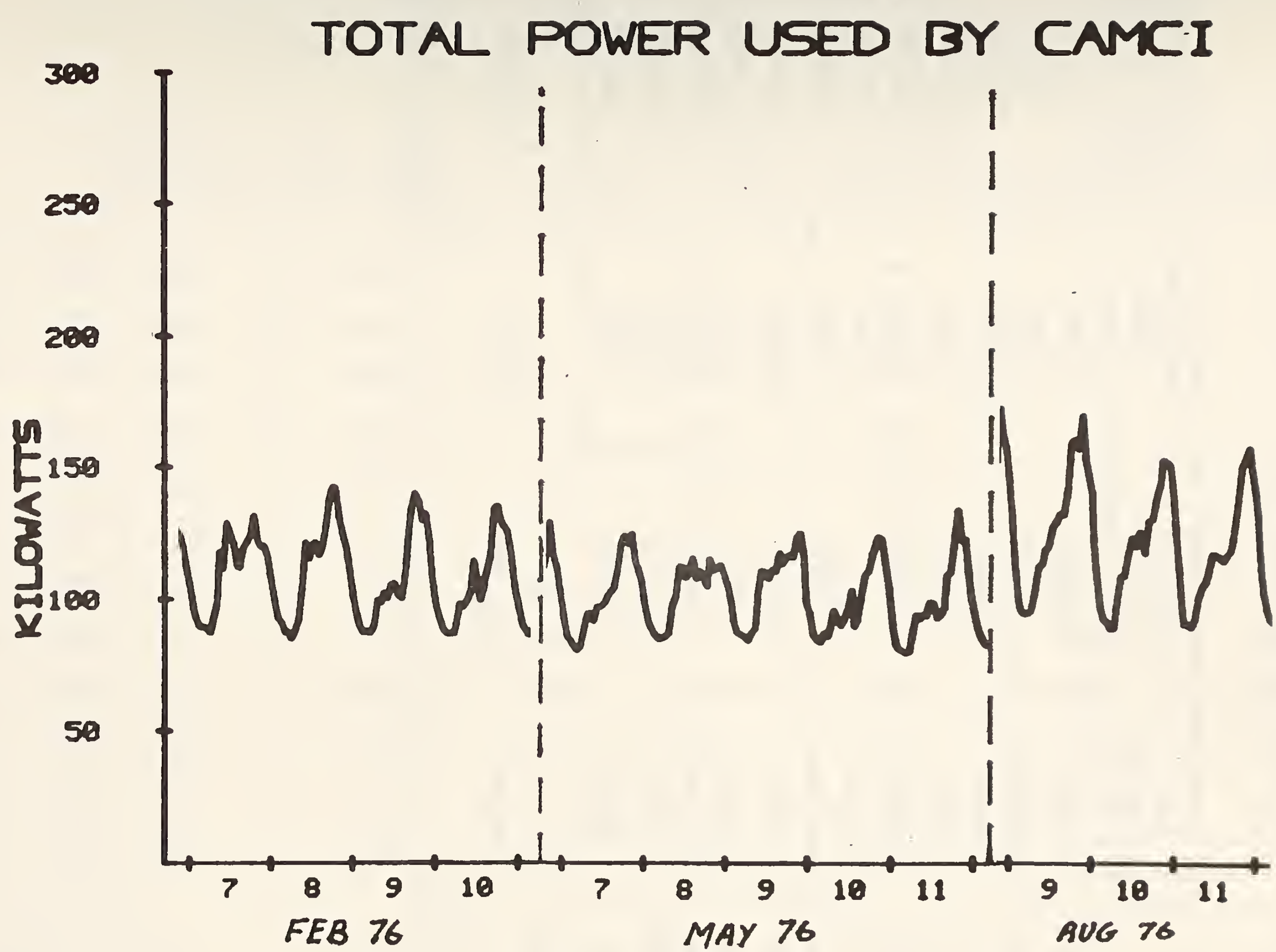

Figure 2-7 Typical electrical demand by Camci apartments for winter, spring, and summer.

Table 2-1

Monthly and annual integrated electrical data
(kilowatt-hours)

	Gross generated	Site and PTC load	HVAC plant load	Net required by site, PTC, and HVAC
November 1975	594800	485906	71269	557175
December 1975	654100	539589	76612	616201
January 1976	674500	536732	79411	616143
February 1976	622400	507440	70594	578034
March 1976	654500	527840	75708	603548
April 1976	607100	484335	63499	547834
May 1976	631600	488367	67094	555461
June 1976	797700	566763	186330	753093
July 1976	821100	577302	209671	786973
August 1976	851900	570811	231836	802647
September 1976	808400	546427	211095	757522
October 1976	661200	531642	77152	608794
November 1975 through October 1976	8,379,300	6,363,154	1,420,271	7,783,425

Table 2-2

Monthly and annual integrated thermal data

(Millions of Btu)

	Recovered from engines	Recovered from boilers	PHW heat to chillers	PHW heat * to secondary hot water	PHW dry cooler and piping losses	Total ** cooling load	Site ** cooling load
Nov. 1975	1863	1985	----	3360	488	----	----
Dec. 1975	2029	4148	----	5546	631	----	----
Jan. 1976	1890	5632	----	6903	619	----	----
Feb. 1976	1780	3820	----	5158	442	----	----
Mar. 1976	1915	2869	----	4376	408	----	----
Apr. 1976	1934	1245	----	2871	308	----	----
May 1976	1993	555	392	1748	408	54	47
June 1976	2432	4598	5209	1144	677	2050	1745
July 1976	2536	3932	5246	1081	141	2713	2296
Aug. 1976	2657	5791	7076	1090	282	2735	2274
Sept. 1976	2614	3575	4762	1124	303	1536	1269
Oct. 1976	2010	1724	309	2952	473	129	104
Nov. 1975 through Oct. 1976	25,653	39,874	22,994	37,353	5,180	9,217	7,735

* Equivalent to Site Heating Load, Including Distribution System Losses

** Cooling Load Including Distribution System Losses

Table 2-3

Monthly and annual integrated fuel data
(gallons)

	Consumed by engines	Consumed by boilers	Total consumed	Heat content (Btu per gallon)
Nov. 1975	45324*	18340*	63664	138200
Dec. 1975	49475*	36699*	86174	139226
Jan. 1976	50955*	49327*	100282	139400
Feb. 1976	46876*	33750*	80626	139824
Mar. 1976	49232*	25621*	74853	140000
Apr. 1976	45666*	11811*	57477	140000
May 1976	48361	5455	53816	138971
June 1976	60267	41505	101772	138364
July 1976	62824	36794	99618	138364
Aug. 1976	64586	47618	112204	138364
Sept. 1976	61906	29450	91356	138200
Oct. 1976	49174*	15120*	64294	141600
Nov. 1975 through Oct. 1976	634,646	351,490	986,136	139,100

*Fuel Data Determined from Models Based Upon May 1976 to Sept. 1976 Fuel, Engine-Generator Output, and Boiler Output data. See Sections 2.1.3, 2.2.2.2., and Appendix III.

Table 2-4

Monthly and annual component and plant performances

	Engine gross electrical efficiency	Engine-generator gross electrical plus thermal fficiency	Boiler efficiency	Chiller COP	Engine-Generator heat rate (Btu per kWh)	Plant energy effectiveness
Nov. 1975	32.4%*	62.1%	78.3%*	---	11242	57.0%
Dec. 1975	32.4%*	61.9%	81.2%*	---	11179	61.6%
Jan. 1976	32.4%*	59.0%	81.9%*	---	11528	62.5%
Feb. 1976	32.4%*	59.6%	80.9%*	---	11339	61.1%
Mar. 1976	32.4%*	60.2%	80.0%*	---	11420	58.9%
Apr. 1976	32.4%*	62.7%	75.3%*	---	11670	56.2%
May 1976	32.1%	61.7%	73.2%	.14	10641	46.3%
June 1976	32.6%	61.8%	80.1%	.39	11073	34.2%
July 1976	32.2%	61.4%**	77.2%**	.52**	11046	38.8%**
Aug. 1976	32.5%	62.3%	87.9%**	.39	11134	34.2%
Sept. 1976	32.2%	62.8%	87.8%**	.32	11294	33.7%
Oct. 1976	32.4%*	61.3%	80.5%*	.42	11437	53.5%
Nov. 1975 through Oct. 1976	32.4%	61.4%	81.6%	.40	11342	48.7%

* Based On Fuel Consumption Model. See sections 2.1.3, 2.2.2, and appendix III.

** Data uncertainties because of DAS outage or fuel measurement problems impact these monthly values. See section 2.2.2.1.

3.0 Economic Data Summary

The purpose of this section is to present and analyze the actual costs as they have occurred during the 12-month period covered by this report. The following types of costs are considered:

1. Operation and Maintenance (O & M) costs for the 12 months.
2. Initial capital costs and capital improvements and their equivalent annualized capital recovery.
3. Owning costs other than capital recovery (i.e. property insurance and taxes).

Indirect revenue from providing utilities to tenants and income tax effects are not considered.

For this interim report, the cost data are presented "as reported" for the JCTE plant, with no modification or normalization to reflect a generic situation. (For example, any additional "overhead" costs due to government sponsorship requirements have not been removed from the data.) Further, no attempt is made to present a typical year or a life-cycle cost picture. With the exception of engine-generator overhaul costs, no attempt is made to project future costs.

This section deals with direct costs only. Direct costs are the costs associated with subsystem inputs (goods, services or capital equipment) for which actual payment is made to a supplier. These direct costs are separated into cost components for the electrical, heating, cooling and PTC subsystems. Indirect costs are the costs associated with transfers of energy between subsystems within the T.E. plant and for which no actual monetary transaction is made. Indirect costs are a means of further allocating direct costs to the subsystems so that unit costs (¢/kWh, $/MBtu) can be calculated. This further allocation of costs is the subject of section 6 of this report.

Actual cost data for the plant have been gathered continuously: capital costs since site construction began in November, 1971, and operation and maintenance costs since plant start-up in January, 1974. Therefore, the reported costs for the 12 months are only a portion of the cost data base which will eventually be available for economic analysis. Collection of cost data is continuing and it is expected that four years of data will be available for a comprehensive economic evaluation, to be presented in future reports.

3.1 Operation and Maintenance Cost Data

3.1.1 Cost Collection Methodology

Cost data are submitted to NBS by the firm operating the plant (Gamze-Korobkin-Caloger, Inc., Chicago, Illinois) (GKC) on a monthly basis in the form of individual disbursements to other companies as well as charges made by themselves for operating the plant. These data are also collated and reported to HUD by GKC in accordance with GKC/HUD accounting procedures.

Only one O & M cost item is not directly reported by GKC. This is the cost of water consumed by the plant. Water is supplied to the entire Summit Plaza site by the City of Jersey City and invoices rendered to the site owner do not separately show the water consumption of the plant. A portion of the water for the plant is separately metered by the plant operator for maintenance reasons, but no monetary transactions are made for the water consumed. The water is mainly for make-up purposes in the cooling tower, the heat transfer circuits within the plant and the site distribution systems. For this report, the total monthly water consumption based on measurements and calculations is used along with the appropriate city water rate to develop monthly O & M cost data for this item. The rate used is for the highest incremental consumption category since plant use can be considered additional to the basic residential use. This rate is \$3.80 per 1000 ft^3 (\$0.134 per m^3) and has been in effect from March 20, 1975 to the present. The annual cost for this item is quite small, 2.4% of total O & M costs other than fuel.

The monthly cost data described above include all expenditures as they occurred during the 12-month period. With the four exceptions treated in the next paragraph, this report uses this data on individual expenditures directly in terms of magnitude of expenditure and the time of its occurrence during the year.

3.1.2 Prorated Expenses

Four large expenditure items occurred during the year in such a way as to substantially distort month-to-month costs if they were used directly in terms of magnitude or time-occurrence. Three of these expenditures (engine overhauls, lube oil and insurance) are prorated so that, for each month, a cost is incurred which is equivalent to one-twelfth of the appropriate cost for the 12-month period. The expenditure for fuel oil is based on actual monthly fuel use, which varies from month to month. By means of these adjustments, the monthly and quarterly cost data in this report more accurately reflect the actual level of plant production and maintenance in each period. The four prorated major expense items are further described below:

1. Engine overhauls. The projected overhaul schedule in use during the 12-month period consisted of three overhauls, two minor and one major, for each engine during a running time of 36,000 hours. This schedule meant that overhauls would occur less than once per year for any given engine. Thus, use of overhaul costs actually experienced during the 12 months (if any) could significantly distort the expected cost picture for overhauls. For this report, the total cost for this overhaul cycle is estimated based on the actual cost of minor overhauls performed to date and the estimated cost of a future major overhaul provided by the overhaul contractor. The individual cost items are not escalated for inflation nor discounted. To

develop monthly engine cost data, this total estimated cost is divided by the average number of months it is expected to take for an engine to reach 36,000 hours. This period is estimated to be 82 months.

The actual cost of overhauls experienced during the 12-month period was $27.976. This resulted from minor overhauls on two engines. This total cost of overhauls for the 12 months is increased by $8,000 to properly reflect the projected costs for the entire overhaul cycle.

In the course of actual operation of the plant , the projected overhaul schedule may be modified and actual overhauls may occur more frequently or less frequently than the 36,000-hour cycle. Based on engine condition of the time of completed minor overhauls, the plant operator is presently increasing the period between overhauls such that only one minor and one major overhaul will be required over a 36,000 to 40,000 hour overhaul cycle. Future economic reports will be based on the actual overhaul schedule as this develops.

2. Lubrication Oil. Several expenditures for lube oil used in the engine-generators were made during the period. These expenditures were for lube oil used prior to, during, and after the 12 months being reported. Examination of all data collected to date indicates that $8,400 is an appropriate yearly expenditure for this item. The data in this report include this item by means of a $700 per month cost.

3. Insurance. Premium for liability insurance (for accidents occurring in the plant) is generally paid once for an entire year. Since this item is significant ($5,400 for the 12-month period), the data in this report include a $450 per month cost for this item. Month-to-month distortions in cost are thereby eliminated.

4. Fuel Oil. Expenditures for fuel are made monthly but fuel deliveries and invoicing can be somewhat irregular. For example, a substantial delivery can be made/billed on the last day of a month for fuel which would be used in the following month. Since fuel cost is a significant single item (56% of total O & M costs), a more accurate representation of monthly fuel costs is desired. Therefore, monthly cost data in this report is developed from the fuel actually consumed by the plant during the month (as measured by NBS) and the average unit cost of fuel for the month.

3.1.3 Subsystem Direct Cost Separation

Each direct cost item is assigned to the subsystem to which it pertains, except when a single item pertains to two or more subsystems. For these items the cost is divided between the subsystems either by estimation or by use of secondary data. In some cases the cost is divided between subsystems according to an estimated fixed percentage. These percentages are estimated by the plant operator and reviewed by NBS. In other cases, secondary data allows accurate division of cost items between subsystems. For example, the direct expenditure for fuel oil is charged to the electrical and heating subsystems according to the actual fuel consumption of each, as registered by the NBS data acquisition system.

3.1.4 Cost Categories

After the individual monthly expenditures are assigned to the subsystems to which they belong, they are condensed into the following categories:

1. Fuel
2. Contract maintenance
3. Direct labor and overhead
4. Plant burden
5. Direct material
6. Miscellaneous

The plant burden category includes those services which are incidental to plant operation and generally not associated with a particular subsystem. Examples are: telephone service, insurance, standby power and GKC operating fee.

Direct material includes non-capital operation and maintenance items not provided by contract maintenance services. Examples are: water treatment chemicals, lubrication oil, tools and spare parts.

The O & M costs for each of the four subsystems (electrical, heating, cooling and PTC) are given in table 3-1 for each of the six cost categories for the 12-month period, November, 1975 through October, 1976. Appendix II presents O & M costs on a monthly basis.

Fuel cost is a significant portion of overall JCTE system costs During the period being reported (November 1, 1975 through October 31, 1976) the price of fuel has averaged 34.1¢ per gallon (\$90.1 per m^3), or \$2.43 per MBtu (\$2.56 per GJ). The actual as-delivered fuel costs since plant start-up in early 1974 are shown in figure 3-1. Costs have remained relatively stable since the initial increase resulting from the "oil crisis" of 1974.

3.2 Capital and Owning Cost Data

Owning costs, usually including a capital recovery component, are often termed "fixed charges". These costs are fixed in that they do not vary with plant production quantities.

3.2.1 Capital Equipment Costs

Capital equipment costs represent the initial investment as well as capital improvements and replacements during the life of the plant.

The initial investment consists of all energy and PTC equipment external to the served buildings and is reported in the following cost categories according to the separate construction contracts:

Engine-generators
Mechanical system
Electrical system
Distribution
Central equipment bldg.
Design fee

These actual initial costs are presented in table 3-2. These costs were incurred during plant construction which took place from November, 1971 through mid-1974. No cost is included for the cost of land occupied by the CEB.

These initial capital costs must be converted to an equivalent annual basis in order to make them comparable with the annual O & M cost data. To accomplish this conversion, the initial capital costs are multiplied by the appropriate uniform capital recovery (UCR) factor. Determination of UCR depends on the interest rate and the life span of the plant. The interest rate depends on the viewpoint of the 12-month analysis. The analysis can be formulated to display a typical year in the life of the plant, thereby giving a picture of the life-cycle cost relationship between O & M and capital recovery expenses. In this case the effective or real interest rate (i.e. excluding inflation) should be used. Alternatively, the analysis can simply present actual expenditures which have occurred during the period. In this case, the nominal (i.e. including inflation) interest rate is appropriate. This latter approach is used in this report. This report therefore provides actual O & M and capital recovery expenditures in approximately the third year of plant operation (1976). O & M costs have been influenced by inflation during the two years since plant start-up while capital recovery costs are constant over the life of the plant.

Capital recovery costs are based on financing the plant with 100% debt at a nominal interest rate which was typical of early 1973 when the present owner purchased the entire Summit Plaza site. Industrial and public utility A-rated bond yields were approximately 7.3% and 7.8%, respectively, during that period.[2] Major insurance company financing of income-producing multi-family and non-residential mortgages in the same time period averaged 8.6%.[3] Housing developers however, when financing a partly subsidized housing project such as Summit Plaza usually obtain Federally-guaranteed loans at an interest rate less than they could obtain under normal circumstances. For this report, an interest rate of 8.0% is used in determining the UCR factor.

Electric utilities generally use a service life of 30 years[4] in estimating capital recovery of conventional large steam generating equipment, which should outlast a diesel Total Energy facility. Also, the minimum useful life of chillers, boilers and engines for depreciation purposes is generally estimated at 20 years.[5] Therefore the life span of the JCTE plant for capital recovery purposes is conservatively assumed to be 20 years. Applying a life of 20 years and the interest rate of 8.0%, UCR is calculated as follows:[6]

$$(\text{UCR}, 8.0\%, 20) = \frac{0.08\ (1.08)^{20}}{(1.08^{20} - 1)} = 0.10185$$

This is equivalent to an annual fixed charge rate of 10.185% of the initial capital costs. Monthly and quarterly cost entries for capital recovery are one-twelfth and one-quarter, respectively, of the annual cost.

Certain equipment replacement and improvement items, which have occurred during the first three years of operation, are considered to be capital expenses and are thus included in the reported capital recovery cost entries. These capital expense items are individually reported by GKC as they occur. Examples of such expenses are: pump replacement, control system modifications, etc. The capital cost entries are determined in the same manner as for initial capital costs. They are based on the year in which the expense is incurred, the remaining life of the plant and the same interest rate as for the initial capital investment. For example, capital improvement items occurring in the second year of plant operation (1975) are annualized by a UCR corresponding to 8.0% and an 18-year life.

This report does not attempt to forecast future replacement or improvement items. Also, in assuming that the prior replacement/improvement items are capitalized in the year in which the expense occurred and have useful life equal to the remaining plant life, the data in this report do not account for the lower level of capital recovery during the years prior to the incurring of such costs. This approach, therefore, presents the actual expenditures for the plant in its third year of operation without including life-cycle cost considerations or a typical year approach in developing the data.

3.2.2 Other Owning Costs

Owning costs other than capital recovery consist of expenditures for property taxes and property insurance by the site owner. Invoices for these items are based on the entire Summit Plaza complex and do not separately include the TE plant. In addition, the magnitude of these cost items is not affected by the existence of the plant. For example, the Summit Plaza complex has real estate tax exemption pursuant to New Jersey statutes, NJSA 55.14 J-1, et. seq., as set forth in an agreement with the City of Jersey City. This agreement provides that the real estate taxes payable for the complex will be 15% of the annual "shelter rent" of the complex. Therefore, the actual expenditures for real estate taxes do not directly depend on the value of equipment used for providing utility services. In presenting the actual costs as experienced for the JCTE plant, this report includes no portion of the total Summit Plaza cost for real estate taxes or property insurance.

Generic studies of TE plant economics may require that part of the costs for these items be allocated to the Total Energy plant. To accomplish this, data on the construction cost of the various elements (residential, commercial, institutional and utility) of the entire Summit Plaza complex and information on the tax and insurance valuation/assessment process should be utilized. This effort is being undertaken so that future generic reports will include any incremental owning cost of the plant.

3.2.3 Subsystem Cost Separation

In table 3-2, the capital costs are assigned to the four subsystems on the basis of the function of each piece of equipment. Costs for equipment shared between two or more subsystems are separated using relevant indices. For example, fuel storage costs are apportioned by annual average boiler and engine fuel consumption, and CEB envelope costs are proportioned by square feet of floor area.

Tables 3-3 through 3-7 present, on a quarterly and yearly basis, the total costs for each of the subsystems including a capital cost component. The term "Other O & M Cost" in these tables is the sum of O & M cost categories 2 through 6 of section 3.1.3.

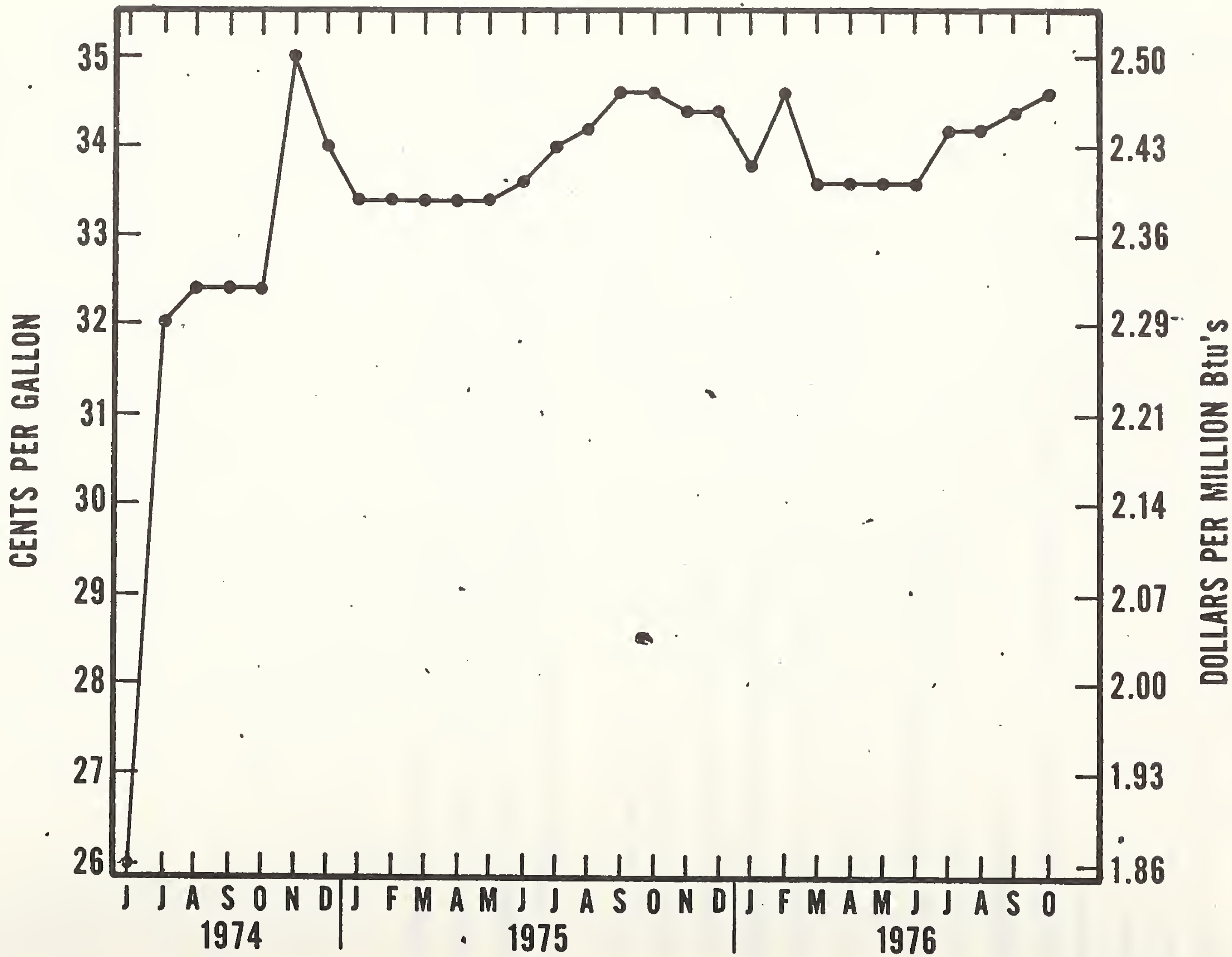

Figure 3-1 Unit cost of fuel oil delivered

Table 3-1. Direct O&M costs - yearly summary

Nov. 1, 1975 through Oct. 31, 1976

Cost category	Subsystem								Plant total	
	Electrical		Heating		Cooling		PTC			
		%		%		%		%		%
1. Fuel	$216,047	56.9	$119,691	68.6	$ 0	.0	$ 0	.0	$ 335,738	55.6
2. Contract maint.	67,044	17.7	5,923	3.4	6,138	21.1	0	.0	79,105	13.1
3. Direct labor +OH	49,931	13.2	28,322	16.2	6,630	22.7	14,979	75.9	99,862	16.6
4. Plant burden	26,915	7.1	11,997	6.9	3,381	11.6	4,529	23.0	46,822	7.8
5. Direct material	18,343	4.8	7,900	4.5	12,846	44.0	0	.0	39,089	6.5
6. Miscellaneous	1,118	0.3	734	0.4	161	0.6	224	1.1	2,237	0.4
Totals	$379,399	100.0	$174,567	100.0	$ 29,156	100.0	$ 19,731	100.0	$ 602,853	100.0

Table 3-2. Capital cost summary

Actual construction costs including overhead & profit

Thousands of dollars

Cost category	Subsystem				Total
	Electrical	Heating	Cooling	PTC	
Engine-Gen.	$ 316	-	-	-	$ 316
Mechanical	132	553	714	85	1,484
Electrical	213	-	-	-	213
Distribution	214	86	110	713	1,123
CEB envelope	208	130	148	109	595
Design fee	52	39	49	Included above	140
Totals	$ 1,135	$ 808	$ 1,021	$ 907	$3,871

Table 3-3. Total direct costs - winter quarter

Dec. 1, 1975 through Feb. 28, 1976

Cost category	Subsystem				Plant total
	Electrical	Heating	Cooling	PTC	
1. Fuel	$ 50,409	$ 40,939	$ 0	$ 0	$ 91,348
2. Other O&M	44,102	16,433	2,344	5,618	68,497
3. Capital recov.	29,157	21,092	26,118	23,095	99,462
Totals	$ 123,668	$ 78,464	$ 28,462	$ 28,713	$ 259,307

Table 3-4. Total direct costs - spring quarter

Mar. 1, 1976 through May 31, 1976

Cost category	Subsystem				Plant total
	Electrical	Heating	Cooling	PTC	
1. Fuel	$ 48,207	$ 14,431	$ 0	$ 0	$ 62,638
2. Other O&M	44,222	19,996	3,520	5,000	72,738
3. Capital recov.	29,156	21,092	26,118	23,095	99,461
Totals	$ 121,585	$ 55,519	$ 29,638	$ 28,095	$ 234,837

Table 3-5. Total direct costs - summer quarter

June 1, 1976 through Aug. 31, 1976

Cost category	Subsystem				Plant total
	Electrical	Heating	Cooling	PTC	
1. Fuel	$ 63,633	$ 42,701	$ 0	$ 0	$ 106,334
2. Other O&M	36,145	6,328	16,061	4,370	62,904
3. Capital recov.	29,157	21,092	26,118	23,095	99,462
Totals	$ 128,935	$ 70,121	$ 42,179	$ 27,465	$ 268,700

Table 3-6. Total direct costs - fall quarter

Sept. & Oct., 1976 & Nov., 1975

Cost category	Subsystem				Plant total
	Electrical	Heating	Cooling	PTC	
1. Fuel	$ 53,798	$ 21,620	$ 0	$ 0	$ 75,418
2. Other O&M	38,823	12,118	7,231	4,744	62,916
3. Capital recov.	29,156	21,092	26,118	23,095	99,461
Totals	$ 121,777	$ 54,830	$ 33,349	$ 27,839	$ 237,795

Table 3-7. Total direct costs - yearly summary

Nov. 1, 1975 through Oct. 31, 1976

Cost category	Subsystem				Plant total
	Electrical	Heating	Cooling	PTC	
1. Fuel	$ 216,047	$ 119,691	$ 0	$ 0	$ 335,738
2. Other O&M	163,352	54,876	29,156	19,731	267,115
3. Capital recov.	116,626	84,367	104,473	92,378	397,844
Totals	$ 496,025	$ 258,934	$ 133,629	$ 112,109	$ 1,000,697

4.0 Engineering Factors Influencing the Plant's Energy Effectiveness

Many factors influence the plant's energy effectiveness. Several of these factors can be changed by corrections in plant operation, relatively minor modifications to the plant configuration and combinations of these two items. This section focuses on five engineering factors which have the potential for significantly improving the JCTE plant's energy effectiveness without requiring extensive modifications or degradation of the plant's operating longevity or safety. Some of these modifications may not be implemented due to considerations other than energy effectiveness such as reliability, while others have already been accomplished. However, each factor warrants discussion due to its applicability to the JCTE plant and to other TE plants. This report only examines the energy effectiveness factors involving the plant and not the site distribution systems or building loads.

The five factors selected are: 1) primary-loop thermal losses from idle boiler(s) connected into the primary loop; 2) primary-loop thermal losses from idle engines; 3) excessive dry cooler primary-loop thermal losses from continuous convective heat transfer and from improper fan control; 4) excessive energy consumption of the chillers due to use of chiller output for air-conditioning the engine room; 5) excessive thermal energy consumption by the absorption chillers. The potential savings and ramifications of modifications will be discussed for each of these five factors.

It should be noted that correction of idle boiler losses was implemented during the year of operation covered by this report (May 1976); correction of idle engine losses and engine room air conditioning involves minor modifications to the plant configuration; correction of dry cooler losses requires a minor modification to one of the components of the plant and an improvement in the plant operation or the installations of more reliable controls; and, improvement of chiller COP involves an improvement in the plant operation by more reliable servicing.

4.1 Idle Boilers

The JCTE plant has two 13.4 MBtu per hour (3.9 MW) oil-fired, hot-water boilers capable of meeting all primary loop thermal demands, even without engine heat recovery. The two boilers are piped and valved so that both, either, or neither can be connected into the primary loop (see figure 4-1). This versatile boiler arrangement was originally conceived to permit both boilers to be connected to the primary loop in series or to allow a boiler to be valved off and cooled for servicing and cleaning. With both boilers in the primary loop, the most extreme heating loads can be met without engine heat recovery.

DAS data indicates that an idle boiler heated by the PHW continually loses an average of 100 kBtu per hour (29 kW) of primary loop thermal energy to the surrounding plant. When both boilers are connected to the primary loop, the losses by the idle boiler must be made up by the operating boiler. At the boiler firing efficiency of 84% (see appendix III), the operating boiler consumes approximately an additional 630 gallons (2.4 m^3) of fuel oil each month to make up the continual losses from the idle boiler.

Because valving a boiler in and out of the primary loop in its present design would require manual operator intervention and could thermally stress the boiler's refractory material, a study was made to determine how often both boilers have been needed to meet boiler heat demands. The November 1975 through October 1976 JCTE data indicated that under normal operating conditions one boiler could always meet the primary loop heat demands not supplied by the thermal output of the engines. Analysis of peak boiler load data for the most severe winter and summer months during this period indicates that the boiler demand rarely approaches 100% rated capacity of a single boiler. For example, figure 4-2 indicates the boiler demand for January 1976, with the capacity of one boiler marked. It is anticipated that during infrequent, severe weather conditions both boilers may be needed.

Based upon the measured idle boiler losses, the fact that one boiler could meet heat demands, and the ease of valving off a boiler, the plant operator made the decision in May 1976 to valve off one boiler. The impact of this decision will be a future annual oil savings of 7500 gallons (28.4 m^3) of fuel oil and an improvement in plant energy effectiveness of approximately 1%.

4.2 Idle Engines

The five engines at the JCTE plant have heat recovered from them by primary hot water (PHW) which flows through their jackets and exhaust heat exchangers. Although the electrical demand can always be met by any three engines, five engines are provided so that at least one engine can back up the running engines while the fifth engine is undergoing required maintenance. Currently PHW circulates through all five engines in parallel whether or not an engine is running.

An analysis of the data from the DAS indicates that an idle engine including its exhaust-exchanger loses approximately 120 kBtu per hour (35 kW) of PHW heat, and that a running engine has an average of 1100 kBtu per hour (320 kW) of heat recovered from it by the PHW.

The PHW thermal energy which is lost by an idle engine is made up by increased boiler firing. On a monthly basis, the PHW heat lost from one idle engine is equivalent to firing 750 gallons (2.8 m^3) of oil in the boilers. By always bypassing one idle engine, approximately 9,000 gallons (34 m^3) of fuel oil can be saved annually.

Aspects other than fuel savings must be considered in the decision to bypass one or more idle engines. Of primary concern is the risk of running an engine without proper coolant flow and causing severe thermal stresses within the engine. To prevent this, a fail-safe interlock must be installed. If two engines are bypassed, equipment must be provided to automatically valve in a back-up engine before it is started. Automatic valving could cause equipment damage if it did not operate properly. For example, with the present engine control system, if an engine was called upon to start and it was receiving insufficient or no cooling water, it would shut down. However, because the site load dictates that another engine generator is required, the start-up and malfunction sequences would be repeated. This could be repeated several times before an operator could respond to an alarm and physically check the engine control system. To install additional controls to protect against this possibility would increase the complexity and possibly reduce the reliability of the engine control system.

No action has been taken to bypass one or more idle engines. Due to the need for additional control circuitry, bypassing more than one engine may not be advisable. As for bypassing one engine, a decision has not been made whether the potential for engine injury and need for additional automatic control or increased requirement for manual operator intervention is justified by the potential fuel savings. If one idle engine were bypassed, the plant's energy effectiveness could be improved about 1%.

4.3 Dry Cooler Losses

The dry cooler functions to release PHW thermal energy whenever the PHW temperature exceeds a preset limit. This limit is set at a value which provides adequate engine cooling. When the PHW exceeds this value, the dry cooler fans turn on and forced-air convection transfers PHW heat to the atmosphere.

The designer of the dry cooler anticipated that its fans would operate only during rare times in the spring or fall when PHW demands dropped below the engine heat recovery rate or during times when site hot or chilled water loops were shut down for maintenance. However, due to both incorrect setting and malfunction of the dry cooler fan controllers, large quantities of PHW heat have been released and had to be replaced by boiler firing. For instance, from June 1 to June 7, 1975, the dry cooler fans continuously operated and dumped approximately

1500 MBtu (1600 GJ) of PHW heat. Simultaneously, one boiler fired at its maximum rate, unnecessarily consuming 13,000 gallons (49.2 m^3) of fuel oil. This problem of simultaneous running of the boilers and dry coolers happened numerous times during the reported year and wasted at least 5,000 gallons (19 m^3) of fuel oil.

The dry cooler also loses PHW heat via continual natural convection. The dry cooler is constructed with open top ducts containing the fan blades (see figure 1-8 in the first chapter). Outside air can freely move from below the dry cooler, through it, and out the top duct. The finned coils, which carry PHW, transfer heat to this freely flowing air, causing it to rise, and carry heat away from the coils. Data from the DAS indicates that 200 to 500 kBtu per hour (59 to 145 kW) of heat is continually lost, depending on ambient wind and temperature conditions. Annually 5,000 MBtu (5300 GJ) are lost from the dry coolers via continuous natural convection.

An experiment was performed at the JCTE site on October 19, 1976, to determine the potential for cutting dry cooler losses by covering the open dry cooler fan ducts. In this experiment the dry cooler ducts were covered with 3.5 inch (9 cm) glass fiber mat to simulate louvers placed over the ducts (see figure 4-3). It is recognized that although both glass fiber mats and louvers could equally stop convection through the duct, louvers may conduct and radiate more heat from inside the dry cooler than would the glass fiber mat. However heat lost from the warmed louvers would be much less than the open duct convective losses. As shown in figure 4-4, data from the DAS indicates that dry cooler losses were more than halved during the test period when the ducts were covered.

Recognizing that louvers on the dry cooler ducts may conduct more heat from inside the dry cooler than the glass fiber mat, a reasonable estimate for the reduction in dry cooler loss by installing louvers is 30 to 40%. A 30% to 40% reduction in the current rate of dry cooler convective loss would save 12,000 to 16,000 gallons (45.4 m^3 to 60.6 m^3) of fuel oil annually.

A second method for reducing dry cooler continual convective losses would involve placing an automatic valve in the PHW line to the dry cooler. This valve would be connected to the dry cooler motor control lines so that it would only open and allow PHW to flow to the dry cooler when the dry cooler fans were energized. This technique would save approximately 30,000 gallons (151 m^3) of fuel oil annually. This alternative would require measures to avoid water freezing in the dry coolers during the winter.

4.4 Air Conditioning the CEB

The ventilation system for the CEB forces outside air into the engine and boiler rooms. This air is filtered and, in summer, is cooled by a large chilled water fan-coil. The ventilation system with cooling utilizes a significant portion of the produced chilled water and affects the overall plant energy effectiveness. It should be pointed out the plant is a public demonstration project; creating a comfortable environment for visitors was a design consideration.

During the summer of 1976, 1482 MBtu (1560 GJ) of heat was added to the chilled water system by the plant ventilation air. This heat represents 16% of the total chilled water thermal load. To provide plant cooling the chillers consumed 3705 MBtu (3910 GJ) of PHW heat corresponding to 31,700 gallons (120 m^3) of additional fuel oil consumption. If the chillers had operated properly (with a COP of 0.6), then approximately 21,000 gallons (80 m^3) of fuel oil would have been required for plant cooling.

The value of cooling plant air is debatable. As mentioned earlier, this plant is cooled partly to make its environment comfortable for visitors. Also, a cooler plant environment may result in better servicing of the engines. However, the energy and resulting cost trade-off must be considered. Possibly increased plant ventilation with cooling only during engine maintenance periods in the hottest months is a realistic alternative to continuous summer cooling. Adequate cleaning of the ventilation system filters and reducing primary loop and engine heat losses (for example covering the engine turbocharger assemblies with removable insulating blankets) will also improve engine room conditions.

No action has been taken to modify the plant to reduce or eliminate the chilled water required to "cool the plant." After other plant modifications such as bypassing an idle engine and boiler are performed, an increased ventilation rate may be sufficient to keep the engine room at tolerable temperatures without the use of chilled water. Restricting cooling of the plant air to maintenance periods during the hottest part of the summer is an alternative. Currently the air is chilled from May to October.

4.5 Malfunctioning of Chillers

The JCTE plant has two single stage absorption chillers which use PHW heat to produce 45°F (7°C) chilled water for plant and site cooling. The COP of these chillers is defined in this report as the total thermal energy removed from the chilled water divided by the PHW thermal energy consumed by the chillers. During the summer, the chiller PHW heat requirements are larger than can be met by recovered engine heat and require large heat outputs from the boiler to meet these demands. Thus, efficient chiller operation is vital for plant energy effectiveness.

During the summer of 1976 the chillers produced a total of 9200 MBtu (9700 GJ) of chilled water and consumed 23,000 MBtu (24300 GJ) of PHW heat. Thus, their overall COP was .40. The ASHRAE handbook[7] states that a COP from .60 to .65 is to be expected from single-stage absorption chillers. Also, representatives of the company which produce the chillers installed at the site have informed the authors they have observed COP's from .60 to .70 for similar chillers in field operation.

Two distinct conditions appear to have caused the observed low overall chiller COP: 1) several periods of extremely low COP operation

(COP's between .2 and .3); and, 2) a generally low COP during "normal" operation (COP of less than .53). At least three periods of extremely low COP operation occured in the summer of 1976. These periods ranged in duration from four to seven days. During these periods the chillers required continuous high-output boiler firing.

An example of a period of extremely low COP operation is shown in figure 4-5 which reports PHW heat input and chilled water produced during September 1976. Note the large amount of PHW heat required between the fourteenth and the twenty-first of September. This chiller heat demand resulted in a high-output boiler operation during that period (see figure 4-6). "Normal" chiller operation was restored on September 21, 1976, by the chiller servicing contractor who reportedly adjusted controls, reducing the concentration of the solution in the concentrator. The periods of extremely low COP operation by the chillers wasted at least 2600 MBtu (2700 GJ) of PHW heat in 1976, requiring that an additional 22,000 gallons (83.3 m^3) of fuel oil be consumed by the boilers.

Periods of "normal" chiller operation during 1976 showed low COP's. During two-to-three day periods of moderate to full-load chiller operation in 1976, the highest average chiller COP measured was .53. This value is significantly below the .6 to .7 reference COP and below the .62 COP determined from DAS measurements for the site chillers during several days in late June 1975. The reason for the low COP during the 1976 season is not known, however, it may relate to a problem detected at the end of the 1975 chilling season. At that time, it was discovered that several large gaskets in the chillers had been improperly installed during routine contractor servicing. Fragments of these shredded gaskets may have blocked flows inside the chillers.

Had the chillers operated with an overall COP of .6 during the 1976 cooling season, the chillers would have required only 15,400 MBtu (16,250 GJ) of PHW heat rather than 22,994 MBtu (24,259 GJ) they actually consumed. The additional PHW heat consumed due to low chiller

COP, 7660 MBtu (8240 GJ), is equivalent to firing 65,000 gallons (246 m^3) of fuel oil in the boilers. If the low chiller COP is corrected, another summer of DAS data will provide opportunity to determine the improved system energy effectiveness.

4.6 Summary

Five factors affecting plant energy effectiveness have been discussed here. Table 4-1 presents the possible improvement in plant effectiveness and fuel savings which could result from implementing these measures. Implementing the four minor modifications would result in a fuel savings of at least 56,500 gallons (214 m^3) of fuel oil annually and an improvement in plant energy effectiveness of 5.5%. The fifth factor, improved servicing of the chillers, would result in a savings of 65,000 gallons (246 m^3) of fuel oil. Together, all five measures would result in an annual fuel savings of 121,500 gallons (460 m^3) of fuel oil or 12.4%.

In section 5, these measures are implemented in an analytic model of the JCTE system. Improvement in seasonal performance is shown in that comparative analysis.

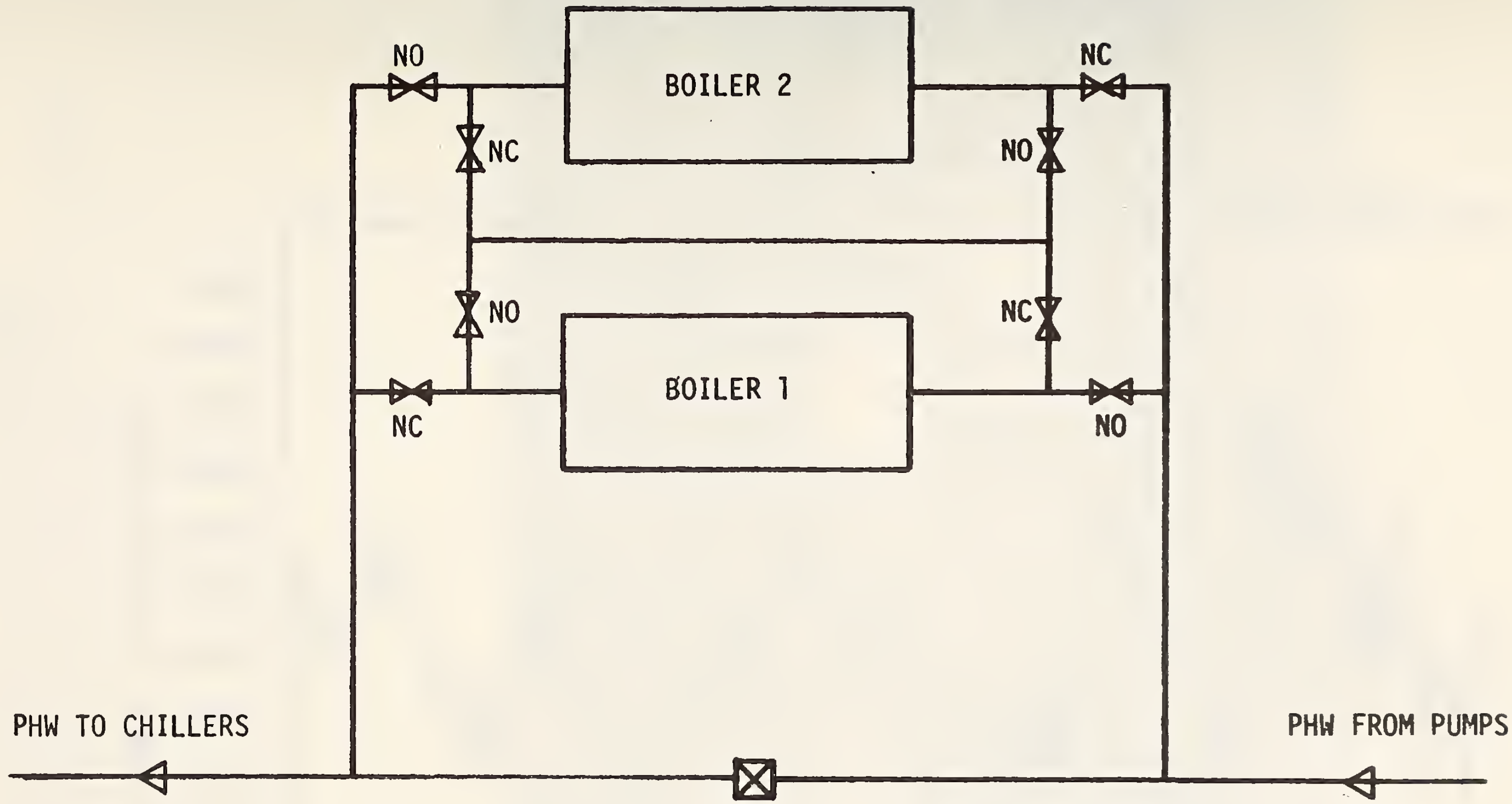

Figure 4-1 Valves and piping of PHW through boilers. Valves are shown as set for series flow through both boilers.

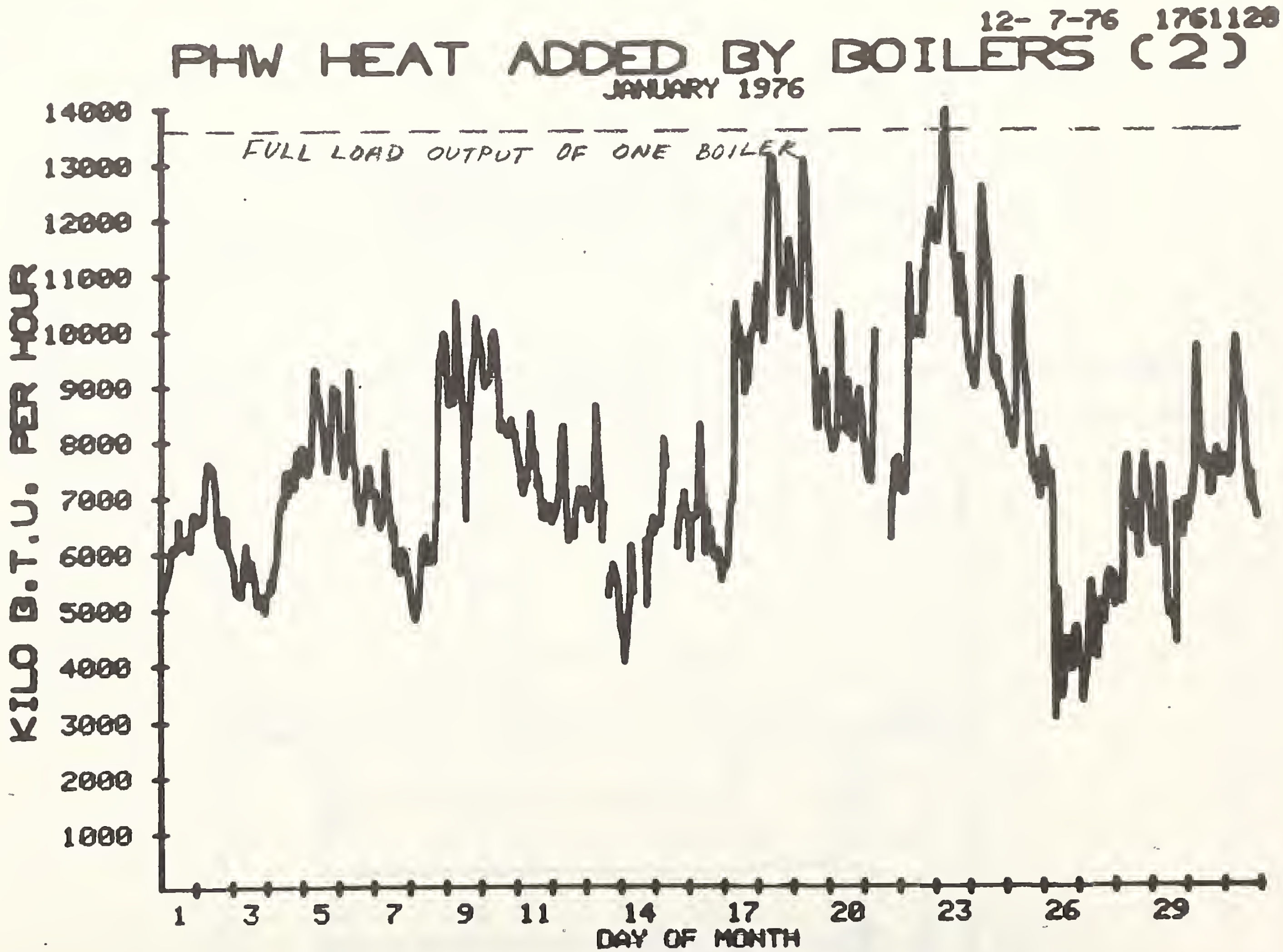

Figure 4-2 Boiler output during most severe winter month of 1976.

Figure 4-3 Dry cooler convective heat loss experiment: in this experiment the natural convective flow through the ducts was restricted using glass fiber mat.

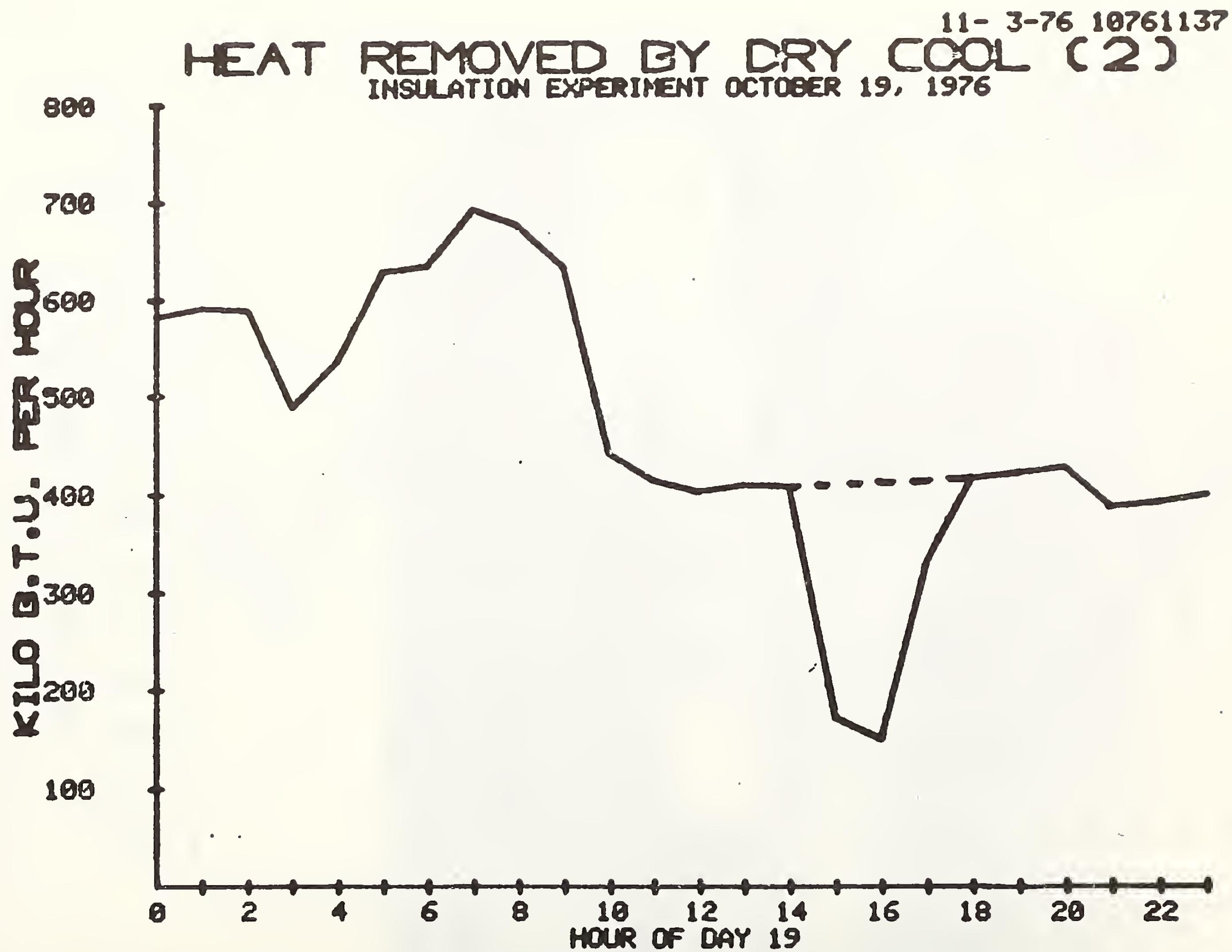

Figure 4-4 Results of dry cooler convective heat loss experiment. Dry cooler ducts were fully covered at 1600 hours. Dotted line indicates loss expected if the dry coolers were uncovered.

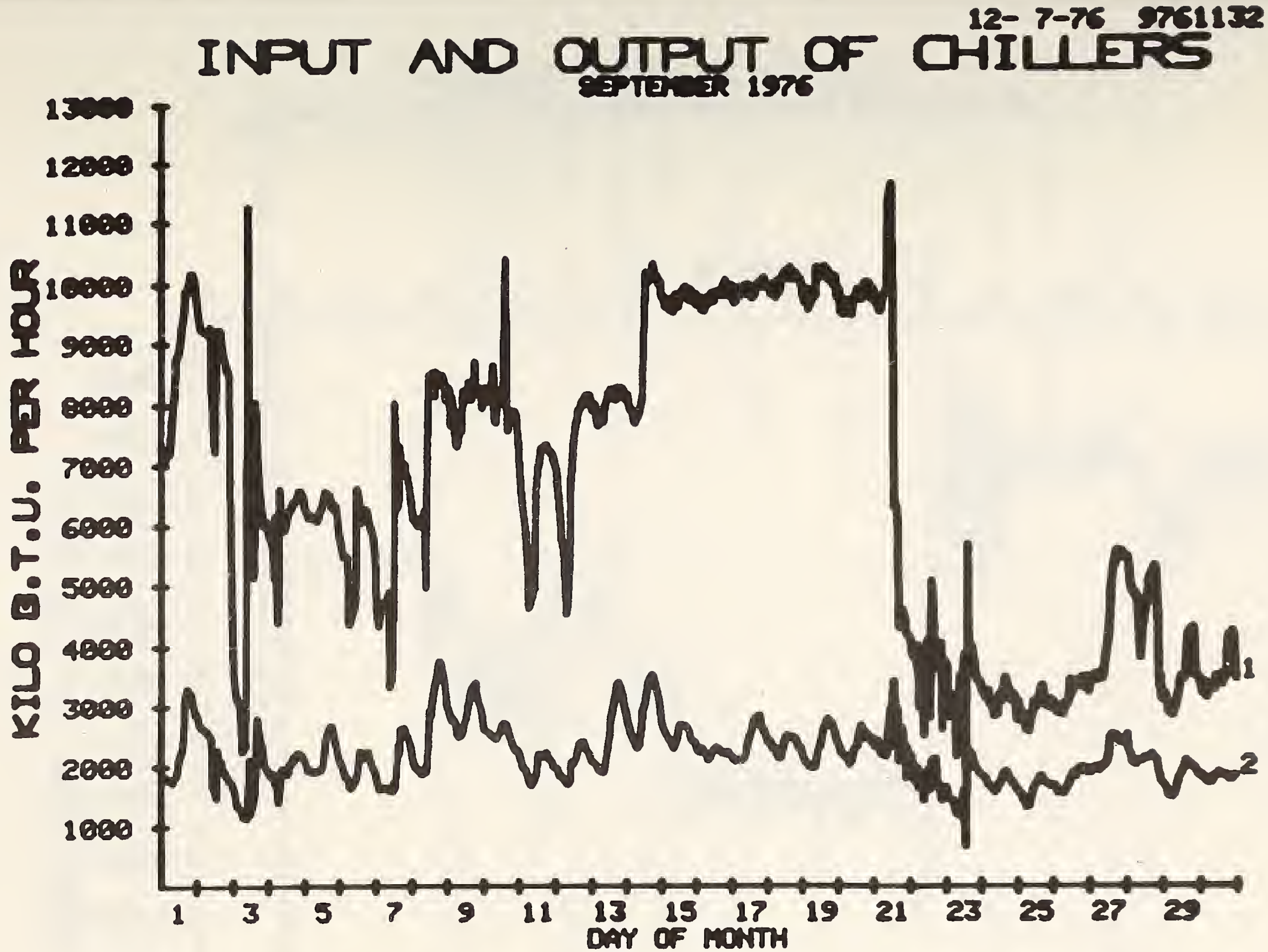

Figure 4-5 Example of chiller malfunction. From September 14 to September 21st large amounts of PHW heat (1) were used by chiller to accomplish moderate chilled water production (2). Chiller adjusted on September 21, 1976. See figure 4-6.

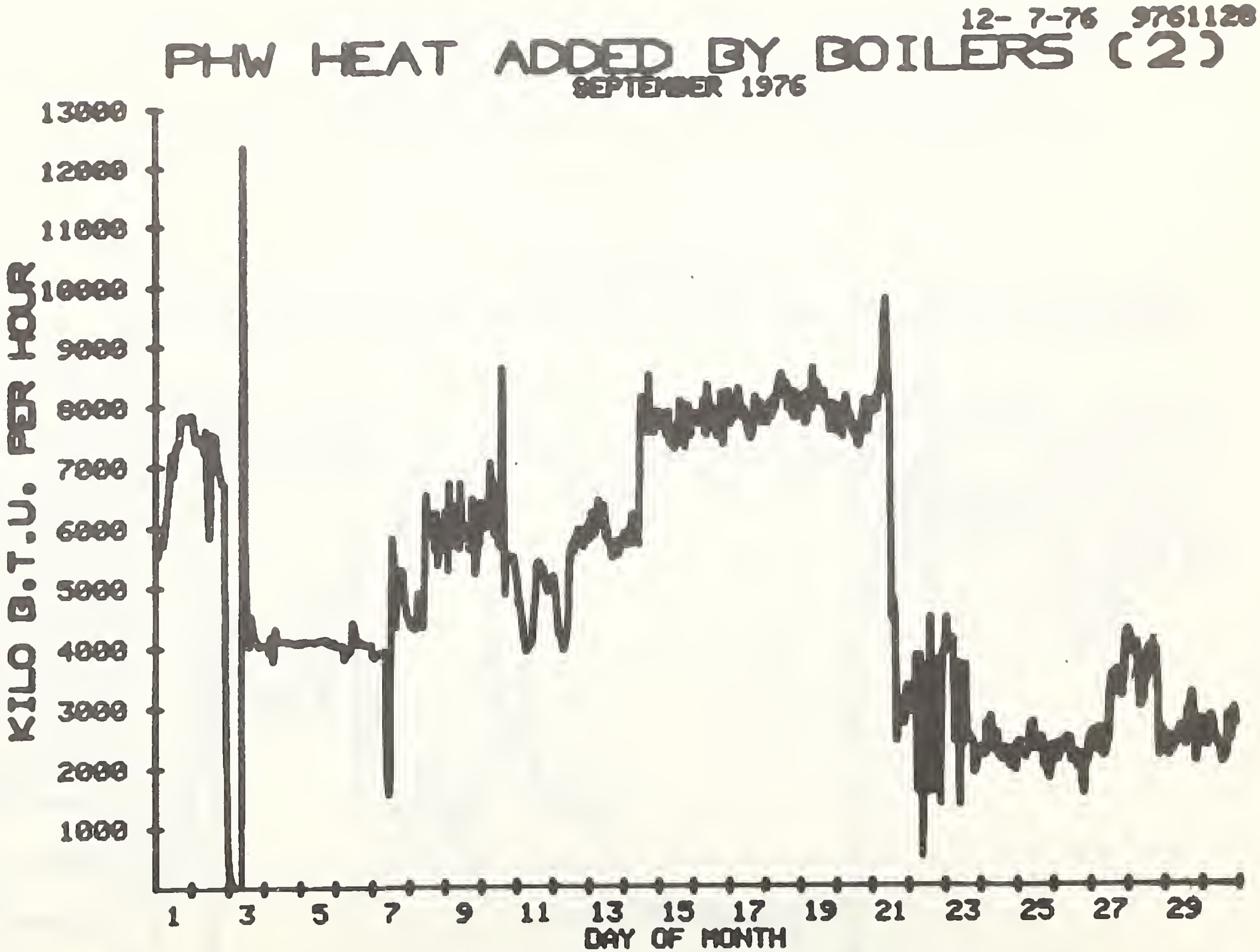

Figure 4-6 Boiler heat demand before and after chiller adjustment on September 21, 1976.

Table 4-1

Summary of annual fuel savings which would result from suggested minor plant modifications and chiller adjustment

Action	Annual Fuel Oil Savings
1. Bypass Idle Boiler	7,500 gallons ($28m^3$)
2. Bypass one idle engine	9,000 gallons ($34m^3$)
3. (a) Improve dry cooler controller	5,000 gallons ($19m^3$)
(b) Louver dry cooler fan ducts	14,000 gallons ($53m^3$)
4. No cooling of plant ventilation air	21,000 gallons* ($80m^3$)
All Minor Modifications	56,500 gallons ($214m^3$)
Chiller Adjustment	65,000 gallons ($246m^3$)
All minor modifications and chiller adjustment	121,500 gallons ($460m^3$)

*Assumes chiller COP is 0.6.

5.0 Preliminary Comparative Energy Analysis

To provide a basis for evaluating the relative fuel performance of the JCTE plant, it is necessary to make at least a preliminary comparison with alternative systems. In this section, engineering models are used to compare the fuel consumption of the JCTE plant (with and without adjustments for the malfunctioning chillers) with the fuel consumptions of two non-TE types of central plants and with the consumption of the JCTE plant incorporating the minor modifications described in section 4. The two non-TE central plants which are modeled represent alternative central plants using conventional technologies which might have been installed at the Jersey City site. Both use electrical power purchased from the local utility; both produce site hot water with oil-fired boilers; and both use site distribution systems like the present JCTE system. However, one non-TE plant produces chilled water via boiler-driven absorption chillers and the other uses electric-motor-driven compression chillers. Actual fuel consumption by the JCTE plant is presented with and without adjustments to compensate for the malfunctioning absorption chillers.

The three comparative systems selected were chosen to place the present JCTE fuel consumption in perspective by determining the fuel consumption of two non-TE types of central plants which would have been applicable to the Jersey City site and by determining the fuel consumption which can be achieved by the JCTE plant with minor modifications. Non-central comparative systems, such as purchased electrical power and individual heat pumps, or combinations of electric resistance baseboard heating and electric room air conditioners are not modeled in this report. A study involving several additional alternate systems is underway as a part of the final reporting on the Jersey City project.

The data from the JCTE plant and site is fundamental to the preliminary energy analysis presented here. This data is used in two ways, first, to establish the combined energy demands of the site and its distribution system, and second, to establish component efficiencies for plant equipment such as the boilers and engines. These two bodies of data, plus published information on electrical utility generation-distribution efficiency and chiller COP's are the basis for the comparative models.

The fuel data for all the comparative models is normalized to the average heat content per gallon of fuel oil delivered to the JCTE site (139,000 Btu per gallon). This is done so that all results are expressed as gallons of fuel oil. The authors recognize that actual systems may consume other fuels, however, the total heat content of the other fuels will be equal to the total heat content expressed as gallons of fuel oil.

It should be noted that for this comparative study the JCTE fuel data is also obtained from a model. This is done to normalize the fuel data to a constant heat content to allow compensation for the chiller malfunctions. The fuel consumption predicted by this model is within .5% of the annual fuel consumption of the site as given in section 2.2.2.2.

The following sections discuss each comparative system, the model, assumptions in the model and the method of computing fuel data. Results are reported in section 5.2.

5.1 Description of Comparative Systems

5.1.1 JCTE System

The JCTE System is fully described in the introductory section of this report. Briefly, the JCTE System uses engine-generators to produce electric power for the site, the HVAC plant, the PTC, and the electric plant operation. Heat is recovered from the engine bank by a primary hot water (PHW) loop. The PHW heat is used to heat secondary hot water distributed to the site and is used by absorption chillers which provide secondary chilled water for the site. A hot water, oil-fired boiler supplements the engine heat to meet PHW demands. A dry cooler, installed to provide the engines with adequate cooling during rare periods of very low PHW heat demands, continually transfers some PHW heat to the atmosphere.

In the JCTE System model, engine-generator fuel consumption is computed from engine efficiency measurements and from month-by-month electrical consumption measurements. The engine-generator electrical efficiency, as determined from JCTE data, averages 32.4%. The combined electrical demand of the site, PTC, HVAC plant, and electrical plant is determined from JCTE kilowatt-hour data taken at the output of the generators. Fuel oil heat content is set at 139,000 Btu per gallon (38.7 GJ per m^3).

In the JCTE System model, primary thermal demands are computed month-by-month from the measured secondary hot water demands, the measured chilled water demands divided by the chiller COP, and the measured dry cooler losses. These demands are met by heat recovered from the engines and produced by the boiler(s). Analysis of monthly data indicates that heat is recovered from the engines at a rate of 3.061kBtu per gross kWh produced (3.230 MJ per kWh) (this number is a 12 month average having a month-by-month standard deviation of 4%). The necessary boiler(s) output is determined from the heat demand minus the recovered engine heat. The boiler(s) fuel consumption is computed from the boiler output using an analytic boiler model (see appendix III). The boiler fuel model has a continual heat loss term of 100 kBtu per hour per boiler (29 kW) (the heat loss rate from a boiler heated to the PHW temperature) and a boiler <u>firing</u> efficiency term of 84% (percentage of combusted fuel's heat content which is transfered to the boiler water). This boiler fuel model is used for all four comparative systems. It is more fully explained in appendix III.

To compute the actual JCTE System consumption the chiller COP is set to the measured value of 0.40. To compute the JCTE System consumption with adjustments for the chiller malfunctions, the chiller COP is set to a conservative reference value of 0.60[7]. All other steps in the two computations are the same for both models.

5.1.2 Modified JCTE System

The modified JCTE System is essentially the same as the JCTE System except that it incorporates the energy saving suggestions of section 4. These suggestions are:

1) having only one boiler in the PHW loop
2) bypassing one of the two idle engines
3) louvering the dry cooler and improving the fan controller
4) eliminating cooling of plant ventilation air.

This model also assumes properly functioning chillers.

Fuel consumption of the modified JCTE System is equal to the boiler fuel computed from the modified JCTE System boiler heat load plus the computed JCTE System engine fuel. Boiler heat load is determined by summing the dry cooler, secondary hot-water, and chiller heat and subtracting heat recovered from the engines. Dry cooler heat losses are assumed to be 300 kBtu/hr (88 kW) in summer, 350 kBtu/hr (103 kW) in the spring and fall, and 400 kBtu/hr (117 kW) in winter based on the installation of louvers and proper controller adjustment. These numbers are based upon a one-third reduction from current convective loss rates. The amount of heat transferred from the PHW to secondary hot-water loops is the same as the measured JCTE value. Chiller primary heat requirements assume a properly adjusted chiller COP of 0.6[7] and assume that no chilled water is used for cooling the engine plant. Chiller primary heat is computed by dividing the measured site chilled water requirements by 0.6. The heat recovered from the engines is equivalent to the JCTE System values plus 120 kBtu per hour (35 kW) due to bypassing one idle engine. Boiler fuel consumption is computed by adding the continual 100 kBtu/hr (29 kW) boiler heat loss to the boiler load and dividing that quantity by the boiler firing efficiency, 84%, and the fuel heat content 139,000 Btu/gallon (38.7 GJ per m^3).

5.1.3 JC System Using Purchased Electric Power and Central Absorption Chillers

The JC System using purchased power and absorption chillers assumes that electrical power for the site, HVAC plant, and PTC is purchased from the local utility; secondary hot-water is produced by central boilers; and secondary chilled water is produced by a central boiler and absorption chiller combination. The secondary hot and chilled water loops are the same as the actual JCTE system and building demands are all the same. The model's fuel oil consumption is based on utility fuel requirements to produce the necessary electrical energy and the fuel consumed by this plant's hot water boilers. The local utility's electrical generation-distribution efficiency is obtained from their published 1975 annual report.[8] Boiler efficiency is set at the measured JCTE value and the absorption chiller COP is set to a conservative reference value of 0.6.[7]

The energy consumed by the local utility in meeting the plant and site electrical demand is computed by multiplying the measured JCTE electrical site demand plus the JCTE HVAC plant demand times the utility electrical generation distribution efficiency, 11,451 Btu per kWh (12.081 MJ per kWh). Boiler thermal loads are determined from chiller heat requirements and from measured site hot water demands. The chiller heat requirement is obtained from the site chilled water demand divided by the chiller COP, 0.6. Boiler fuel consumption equals boiler load plus a continual boiler loss of 100 kBtu per hour (29 kW) per boiler divided by the boiler firing efficiency (84%) and the heat content of fuel oil, 139,000 Btu per gallon (38.7 GJ per m^3).

5.1.4 JC System Using Purchased Electrical Power and Central Electrical Compression Chillers

For this comparative model it is assumed that all site, PTC, and HVAC electrical energy will be purchased from the local utility; secondary hot water will be produced by central boilers; and site chilled water will be produced by an electric-motor-driven compression chiller. The electrical, hot water, and chilled water distribution systems are assumed the same as the actual JCTE site, and site electrical, site hot water, and site chilled water demands equal the measured JCTE values.

The efficiencies and loads used in this model are determined from JCTE data and reference data. The boiler efficiency is equivalent to JCTE boiler measurements. The utility electrical production-distribution efficiency is equivalent to 1975 published local utility reports.[8] The compression chiller COP is set at a handbook value of 3.0.[7] A field study[9] on a large compressor chilling facility reports a 3.5 chiller COP. Additional HVAC electrical requirements for secondary pumps, fans, etc., are the same as JCTE data, except that compression chilling requires half the cooling tower capacity, no hot water pumps, no small internal pumps and the same chilled water pumps; thus auxiliary HVAC processing power is approximately 80 kW less than JCTE measured HVAC power during summer months.

The fuel used by the local utility is computed from the site and plant electrical consumption times the utility generation-distribution efficiency, 11,451 Btu per kWh (12.081 MJ per kWh) divided by the heat content of fuel oil, 139,000 Btu per gallon (38.7 GJ per m^3). The electrical consumption of the plant and site is equal to the measured JCTE site consumption, plus the measured JCTE site chilled water thermal load divided by a COP of 3.0, and plus the measured JCTE HVAC processing electrical consumption minus 80 kW times the hours of chiller operation. The boiler fuel consumption is equal to the measured JCTE secondary hot-water thermal load plus the continual 100 kBtu per hour (29 kW) boiler heat loss, divided by the boiler firing efficiency, 84%, and the heat content of fuel oil, 139,000 Btu per gallon (38.7 GJ per m^3).

5.2 Comparative Results

Figure 5-1 shows the projected annual fuel consumption of the four comparative systems: JCTE System (with and without adjustments for the malfunctioning chillers), Modified JCTE System, JC System using purchased electrical power and absorption chillers, and JC System using purchased electrical power and consumption chillers.

The models indicate the following annual fuel consumptions: JCTE System (without adjustments for the malfunctioning chillers) would require 988,000 gallons of fuel oil, JCTE System (with adjustments for the malfunctioning chillers) would require 923,000 gallons of fuel oil, Modified JCTE System would require 870,000 gallons of fuel oil, JC using purchased electrical power and absorption chilling would require 1,083,000 gallons of fuel oil, and JC using purchased electrical power and compression chilling would require 1,011,000 gallons of fuel oil.

A comparison between the JCTE System (with adjustments to compensate for the malfunctioning chillers) and the two purchased power systems indicate that the system using purchased electrical power with absorption chilling would annually require 17.3% more fuel and the system using purchased electrical power with compression chilling would annually require 9.5% more fuel than required by the JCTE System. If the JCTE System were modified according to the suggestions in section 4, then it would annually consume 5.7% less fuel than is consumed by the JCTE System. The purchased power with absorption chilling system would require 24.5% more fuel and the purchased power with compression chilling system would require 16.2% more fuel than the Modified JCTE System.

These results indicate that an alternative conventional plant using purchased electrical power, oil-fired boilers, and absorption chillers, would annually require 160,000 gallons more fuel oil than the JCTE plant (with adjustments for absorption chiller malfunctions).

The seasonal fuel consumption of the comparative systems is shown in figure 5-2. For this comparison the winter season includes December 1975, January 1976, and February 1976; the spring season includes March, April, and May of 1976; the summer season includes June, July, and August of 1976; and the fall season includes September 1976, October 1976, and November 1975. In general, the non-TE plants cause approximately 14% more fuel to be consumed during the winter months than was consumed by the JCTE System.

During the summer cooling season, a comparison of the JCTE System (adjusted to compensate for the malfunctioning chillers) and the systems using purchased electrical power indicates that the system using purchased power with absorption chilling would require approximately 17% more fuel and the system using purchased power with compression chilling would require approximately 4% less fuel oil than required by the JCTE System. It should be noted that the low JCTE chiller COP has significantly affected the JCTE summer fuel consumption. If the JCTE System were modified according to the suggestions in section 4, then during the summer the system using purchased power with absorption chilling would require approximately 28% more fuel and the system using purchased power with compression chilling would require approximately 6% more fuel than the Modified JCTE System.

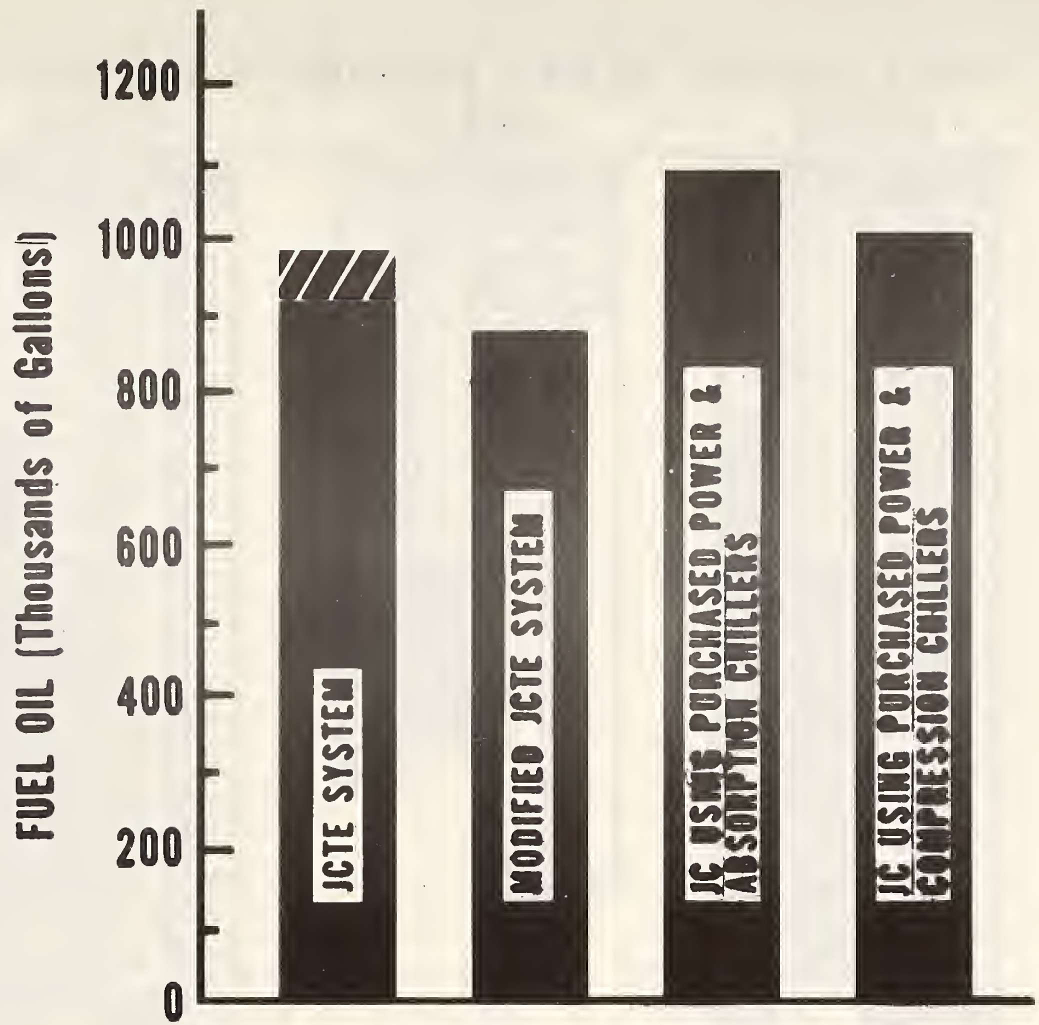

Figure 5-1 Annual fuel consumption projected for the four systems. Hatched area above JCTE system represents additional fuel consumed due to malfunctioning chillers.

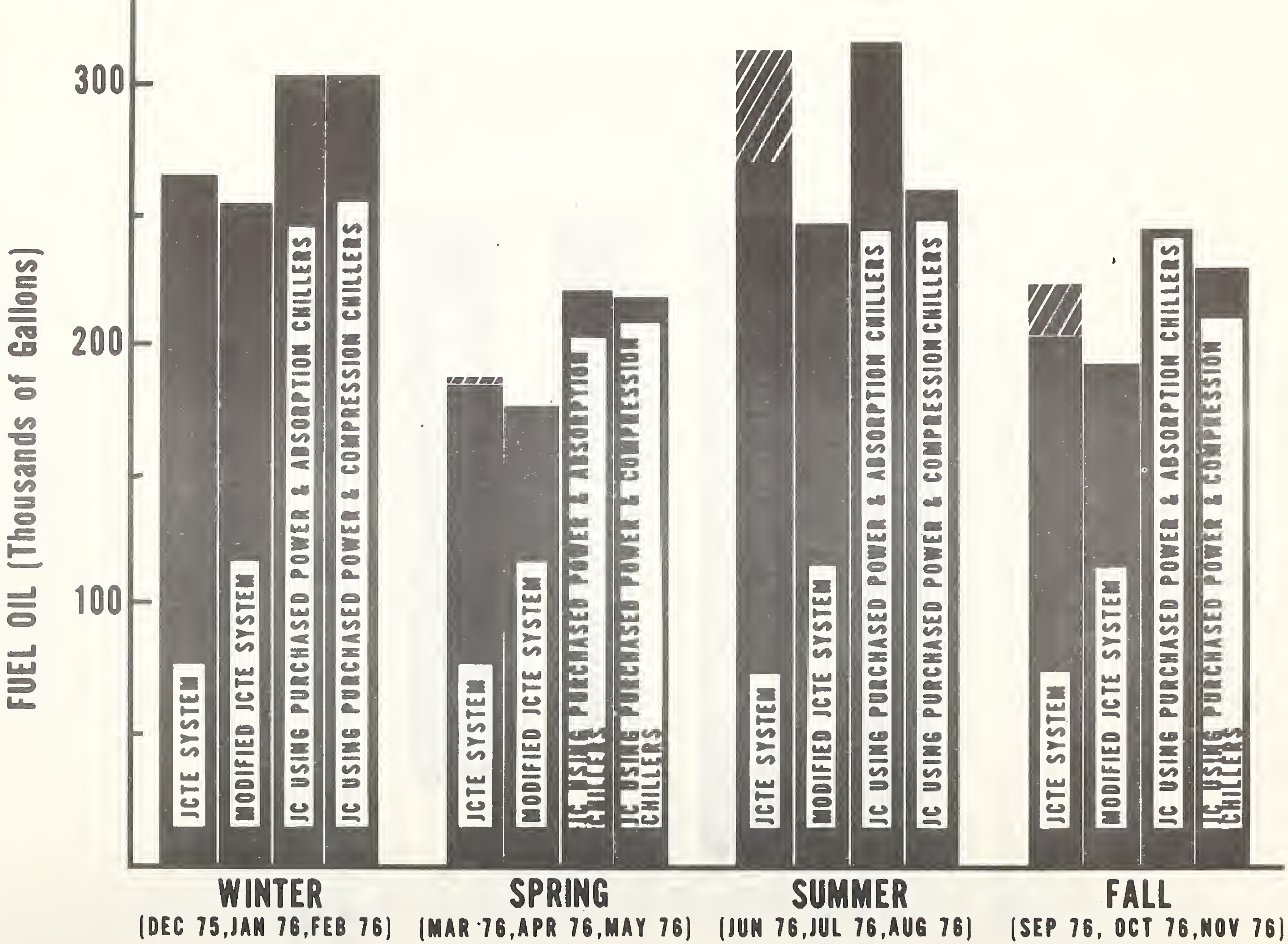

Figure 5-2 Seasonal fuel consumption projected for the four systems. Hatched area above JCTE system represent fuel consumed due to malfunctioning chillers.

6.0 Unit Energy Cost and Preliminary Cost Comparison

Economic evaluation of the JCTE plant should be based on comparative total costs for various Total Energy (TE) and alternative conventional system concepts. Major required steps of such a comparative evaluation are:

1. design and capital cost estimating for the hypothetical alternative systems; and
2. computer simulation of TE and conventional plants to determine energy consumption and O & M costs.

Design and capital costing efforts are currently in progress under contract to NBS. This design data as well as a larger data base of actual plant O & M costs will be available in the future for economic evaluation of the JCTE Project. Therefore, the complete comparative economic evaluation of alternatives based on total cost cannot be completed at this time.

As an interim measure for this report, the actual cost data of section 3 are utilized to develop the unit costs (¢/kWH, $/Btu) of energy commodities delivered to the site buildings. These data can be compared with available data for conventional systems to put the JCTE plant costs into perspective. The comparisons are limited and do not constitute a thorough and complete economic analysis of alternatives.

This section develops a means of accounting for energy transfers between subsystems so that unit costs can be calculated for electricity, hot water and chilled water provided by the JCTE plant. Estimated data are developed for one case on the cost of equivalent conventional services and a preliminary comparison with the plant costs is presented.

6.1 Need for Cost Separation

The purpose of cost separation in this report is to provide an equitable allocation of total plant costs to the various subsystems so that meaningful unit costs can be calculated for each energy product.

These unit costs can be used to compare with other data, but the results are only an approximate indication of comparative economic viability due to the difficulty in obtaining directly comparable data for conventional plant costs.

Cost separation assumptions can influence the cost of the subsystems in a major way. However, since total costs for the plant do not change in any way through cost separation, overall cost comparisons should not be influenced. It should be further noted that whatever methods are used for cost separation, only total costs are relevant. Economic comparisons of alternative energy systems must include costs for all energy services used by site buildings.

As shown in figure 6-1, the quantity of utility services supplied to the site is not the same as that produced by the subsystems due to energy flows internal to the plant between subsystems. In order to calculate unit costs of utility services supplied to the site, cost separation must be used to account for these internal energy flows. Energy flows requiring consideration are as follows:

- thermal energy recovered from engines and used in heating and cooling subsystems.
- electrical energy used for the heating, cooling and PTC subsystems.
- heat used by the chillers for production of chilled water.
- chilled water used to cool plant office and equipment areas.

It should be noted that any supplementary heating required by plant office areas or for cooling tower freeze protection is supplied by the waste heat from the engine-generators' lubrication oil coolers and combustion air aftercoolers, not by hot water from the heating subsystem. This has not been included as a factor in cost separation since the heat actually used is quite small and because it would be quite tenuous to attach costs to a waste heat commodity with limited use.

It appears possible to make an adequate comparison of the economic performance of single-purpose (conventional HVAC) and dual-purpose (Total Energy electricity and HVAC) plants by means of careful cost separation. The method is to derive the cost of thermal energy produced by the dual-purpose plant using actual cost data from a single-purpose plant. All remaining costs for the TE plant can then be allocated to electric power production. If this can be accomplished, a straightforward comparison with published electric utility costs and rate structures (as done later in this section) constitutes an adequate economic analysis of two alternatives.

This incremental approach requires detailed investigation of O & M costs such as operating labor as well as design of a hypothetical conventional plant in enough detail to discern capital cost differences. This process should be followed even if the hypothetical plant is exactly the same basic design as the TE plant but without electrical production. Such analysis will be undertaken after design and costing efforts for hypothetical alternative plant designs are complete.

6.2 Cost Separation Methodology

6.2.1 Heat Recovery from Engines

The electrical subsystem direct costs reported heretofore must be apportioned to the electrical and heat-using subsystems to reflect the thermal energy generated by the diesel engines for use by other subsystems. This must be done because the electrical subsystem primarily exists for the dual purpose of electrical & thermal energy production.

A number of techniques can be devised for electrical/thermal cost separation. However, there appears to be no consensus among engineers and economists regarding cost separation from dual-purpose diesel energy systems. Decisions to be made regarding cost separation for heat recovery involve the following points:

1. Whether recovered heat should be individually allocated to the heating and cooling subsystems in some way.
2. Whether the costs of rejected heat (i.e. recovered heat not actually used) should be charged to recovered heat, electrical production or both.
3. Whether net or gross electric energy should be used as a basis of cost allocation to the electrical subsystem.
4. Whether equivalent energy units of recovered heat and electricity should be equally valuable (equal in cost) or on what basis their costs should be separately developed.
5. Whether different treatment should be accorded to electrical subsystem components related to electricity only, to recovered heat only, and to both products.
6. Whether variable costs (O&M) should be treated differently from fixed costs (capital recovery).

The cost separation technique used in this report to account for recovered heat is quite simple and is adequate for preliminary data presentation purposes. Important assumptions relating to the above decision points are:

1. The heating subsystem is responsible for all heat production/recovery and hence cost separation only involves the electrical and heating subsystem. The chiller receives all its heat from the heating subsystem. This assumption does not affect results, but merely streamlines cost separation accounting. Recovered heat is assumed to be indistinguishable from boiler-produced heat, and therefore the heating and cooling subsystems share the benefits of recovered heat in proportion to their use of heat.
2. Recovery and efficient use of heat from the diesel engine-generators is one function of the heating subsystem in a TE plant. Both design features and operating practices can greatly affect the quantity of heat actually recovered and/or utilized. In the JCTE plant, the heating subsystem can contribute to cost

minimization by (1) proper design & maintenance of diesel engine heat recovery devices to recover the maximum possible heat and (2) proper design & control of excess heat rejection devices to utilize the maximum possible amount of heat recovered. In developing the appropriate level of potential heat recovery as a baseline for cost separation, potential design changes to the existing plant are not considered. Heating subsystem operating and maintenance practices, where the expected effect on heat recovery/utilization is known, are considered in formulating cost separation.

<u>Heat Recovery</u> - Inefficiency in recovery of heat can be reflected in added costs to the heating subsystem. Operating and maintenance practices related to heat recovery include operation of the engines to maximize recoverable heat and maintenance (cleaning) of the heat recovery devices. O & M practices have been formulated by the plant operator and have not been evaluated by NBS for energy or economic effectiveness. Changes in these practices to improve heat recovery may be justified. Since the additional heat recovery is somewhat hypothetical at this time, possible improvements in heat recovery will not be used in establishing a baseline for cost separation.

<u>Heat Utilization</u> - For the 12 months, 8% of the total PHW heat from engines and boilers has been rejected unused (see table 2-2). The bulk of this loss was due to operating conditions within the heating subsystem (see section 4.3). It is clear from section 4.3 that relatively minor changes to the plant could have nearly eliminated such losses. Therefore, this report considers recovered heat (rather than utilized heat) as the basis for cost separation. Had the heat rejection from JCTE been largely due to a time-wise mismatch of thermal/electrical demand periods, the cost separation probably should be based on utilized heat, not on recovered heat. However, periods of mismatch between heat production & demand were quite rare during the period as indicated

by figure 2-5. Hence the use of recovered heat for allocating costs to the heating subsystem is considered valid for this report.

3. Minimization of parasitic losses and auxiliary loads (e.g. PHW pumps) within the electrical subsystem is one function of the electrical subsystem. Therefore, the costs of such electrical energy should be borne by the electrical subsystem. Costs are separated (and allocated to the electrical subsystem) on the basis of gross electrical energy generated rather than net energy generated.
4. Separation of costs is based on the energy equivalence of recovered heat and electricity (i.e., heat and electricity are considered equally valuable on an energy quantity basis).
5. All electrical subsystem components are considered in heat/electricity cost separation with the exception of site distribution costs which are allocated only to site electrical energy. (Electrical switchgear relates only to electrical energy production and could be separately allocated to electrical energy only but it is a rather small part of the total electrical subsystem cost.)
6. Variable costs (O&M) and fixed costs (capital recovery) are treated the same for heat recovery cost separation. This means that a portion of the capital recovery costs as well as O&M costs associated with the electrical subsystem are allocated to the recovered heat. In this sense the heat and electricity are inseparable joint products of the electrical subsystem. Neither can be considered an incremental or optional product which incurs only incremental production costs.

The above assumptions allow the formulation of cost separation for heat recovery as follows:

$$C_{e,h} = C'_e \cdot \frac{E_r}{E_r + E_g}$$

$C_{e,h}$ is that portion of the electrical costs to be allocated to the heating subsystem to account for heat recovery and C'e is the total electrical subsystem direct costs (less site distribution) including fuel, O&M and capital recovery costs. E_r is the thermal energy recovered from the engines by the PHW and E_g is the gross electrical energy generated in the same units as E_r. (Both E_r and E_g are defined more fully in sections 2.1.2 and 2.1.1, respectively.) The quantity $E_r/(E_r+E_g)$ is designated "χ" later in this section. The value of χ is dependent only on the thermal characteristics of the diesel engine-generators and heat recovery devices. Its value is relatively constant throughout the year and averaged 0.47 for the 12-month period.

As stated under item 4 above, the costs transferred to the heating subsystem include a portion of the capital recovery costs of the electrical subsystem. In designing a TE plant, the heating subsystem should consider engine-generator recovered heat as added heat production capacity. Therefore, the installed boiler capacity of a dual-purpose T.E. plant should be less than that of a single-purpose conventional HVAC plant. The resultant reduced capital costs would be offset by the portion of engine-generator capital costs allocated to the heating subsystem in the cost separation technique developed in this report. Details on the design approach and the extent to which boiler size was reduced by recovered heat availability will be covered in a future design report to be prepared by the plant design engineer.

6.2.2 Other Intersubsystem Energy Transfers

In developing an approach for cost separation for other than recovered heat, a basic assumption was that the unit cost of a particular energy product at the producing subsystem is the same regardless of how it is used (by another subsystem or site buildings). This means that all uses of an energy product are considered to share proportionately in O & M and capital recovery expenses of the producing subsystem. (This also conveniently allows use of unit cost in cost separation equations rather than absolute costs.) Allocating capital recovery costs to energy commodities used within the plant also means that these energy outputs are not optional outputs which bear only incremental production costs. This is clearly the case with all intersubsystem energy exchanges with the possible exception of the chilled water used for plant equipment area cooling.

The cost of energy commodities as provided to the site buildings is being developed in this section. In cost separation for the intersubsystem energy transfers in figure 6-1, site distribution costs are not included in plant subsystem direct costs. Site costs are applied only to the energy quantities delivered to the site. This was done because distribution costs are a significant portion (approximately 10%) of the costs of their respective subsystems but only relate to energy products delivered to the site. For this reason, the unit cost of each energy product as delivered to the site will be slightly higher than the plant unit cost used for cost separation between subsystems.

6.2.3 Cost Separation Formulation

In formulating the cost separation, the following basic equation has been used:

Direct cost + indirect cost of energy from other subsystems (1)
= cost of products

The direct cost is that cost already described in section 3, i.e., the reported costs before cost separation. Applying this equation to each subsystem will result in a set of equations which can be solved simultaneously. This should provide a basis for solving the cost separation problem. In applying eq. (1), the following notation is used:

C'_i = total direct cost of subsystem i, less distribution costs. This item is primed to indicate "as reported" costs, before cost separation.

$E_{i,j}$ = quantity of product energy transferred from subsystem i to subsystem j.

$\bar{c}_i$ = unit cost of energy produced at plant by subsystem i.

for i: e = electrical; h = heating; c = cooling;

p = pneumatic trash collection

for j: same as above except s = site and n = net (useful)

For the electrical subsystem, the net cost of energy from other subsystems consists of the added cost of the chilled water energy used for plant cooling and the reduction in cost due to heat recovery. The entire cost of plant cooling is assigned to the electrical subsystem because only a very small portion of the plant cooling is used for space conditioning of the office area, while the cooling of the areas surrounding the engine-generators constitutes the greater portion. The reduction in cost due to recovered thermal energy is the total electrical subsystem cost (including the cost of chilled water energy) multiplied by a heat recovery factor, (denoted by "χ") as described in section 6.1.1. Thus, for the electrical subsystem, eq. (1) becomes:

$$C'_e + E_{c,e} \cdot \overline{c}_c - \chi(C'_e + E_{c,e} \cdot \overline{c}_c) = E_{e,n} \cdot \overline{c}_e$$

or $$(1-\chi)\,(C'_e + E_{c,e} \cdot \overline{c}_c) = E_{e,n} \cdot \overline{c}_e \qquad (2)$$

where: $E_{e,n} = E_{e,s} + E_{e,c} + E_{e,h} + E_{e,p}$

For the heating subsystem, the net cost of energy from other subsystems consists of the added cost of recovered heat plus the added cost due to electric energy consumption by the heating subsystem. Thus for the heating subsystem, eq. (1) becomes:

$$C'_h + \chi\,(C'_e + E_{c,e} \cdot \overline{c}_c) + E_{e,h} \cdot \overline{c}_e = E_{h,n} \cdot \overline{c}_h \qquad (3)$$

where: $E_{h,n} = E_{h,s} + E_{h,c}$

For the cooling subsystem, the cost of energy from other subsystems consists of the added cost due to use of hot water energy in the absorption chillers plus the added cost due to electric energy consumption. Equation (1) for the cooling subsystem becomes:

$$C'_c + E_{h,c} \cdot \bar{c}_h + E_{e,c} \cdot \bar{c}_e = E_{c,n} \cdot \bar{c}_c \qquad (4)$$

where: $E_{c,n} = E_{c,s} + E_{c,e}$

For the pneumatic trash collection system, the cost of electric energy consumed is the only cost element to be considered in addition to the direct costs. Equation (1) becomes:

$$C'_p + E_{e,p} \cdot \bar{c}_e = C_p$$

Equations (2) through (4) represent a system of three equations in three unknowns. The unknowns are the unit costs $\bar{c}_e$, $\bar{c}_h$ and $\bar{c}_c$. Assuming consistency and independence of this set of equations, the solution is a straightforward matter. Moreover, negative unit costs or other anomalous solutions are unlikely because costs are separated in proportion to energy flows which are reasonable and consistent.

Since published data often provide only O & M costs for comparison purposes, it is desirable to provide site unit costs for the JCTE plant showing O & M and capital recovery components separately. The set of equations (1) through (4) is used three times to calculate the three unit cost components: fuel, other O & M, and capital. By this process, each of the direct cost components of a particular subsystem is allocated to other subsystems in proportion to the amount of energy utilized. This procedure also guarantees that the cost structure of a particular energy commodity is the same whether used as a final site product or as an input to another subsystem. Taking the fuel cost component as an example, equation (4) for the cooling subsystem becomes:

$$C'_{c,f} + E_{h,c} \cdot \bar{c}_{h,f} + E_{e,c} \cdot \bar{c}_{e,f} = E_{c,n} \cdot \bar{c}_{c,f}$$

$C'_{c,f}$, which is the direct fuel costs for the cooling subsystem, is zero as shown in table 3-7 since the chillers consume no fuel directly. However, the electric energy and hot water energy used by the cooling subsystem have fuel cost components associated with them and thus the fully allocated unit cost for cooling contains a fuel cost component. This is $\bar{c}_{c,f}$.

The data for these equations are readily available from the cost data base of section 3 and from production quantities reported in section 2. However, the items $E_{e,h}$ and $E_{e,c}$ may require some clarification. Referring to table 2-1, only the sum of $E_{e,h}$ and $E_{e,c}$ is directly available from the column entitled "HVAC plant load." However, $E_{e,h}$ is relatively constant over the year. Thus, by taking the average consumption during the months the chillers were not operating, an approximate average value for the $E_{e,h}$ can be obtained. This value can be subtracted from the values in the column for the months the chillers were operating to obtain an approximate average value for $E_{e,c}$. Data for $E_{e,c}$ has been directly collected, but was not processed and available for this report. Future reports will utilize actual values of $E_{e,c}$.

6.3 Unit Cost of Site Energy - JCTE

By combining the direct costs for site distribution with the unit costs of energy products at the plant, the unit cost for energy products delivered to the site buildings can be calculated.

Conceivably, the site distribution costs could include both capital recovery and O & M components. The reported data of section 3 does not separately show O & M costs for site distribution. The plant operator's responsibility theoretically ends at the TE plant building wall and maintenance of distribution equipment on the site grounds and inside site buildings is the responsibility of the site owner/operator. This division of responsibility has not always been adhered to, resulting in some plant labor being expended on site distribution. During the period under investigation, overall site distribution O & M activities have been minor except for the PTC subsystem and only a small percentage of plant labor has been involved. Thus the assumption of zero O & M costs for site distribution of energy products up to the site building wall is a relatively good one.

Equations are developed for the cost of site energy commodities using the following basic equation:

$$\text{site unit cost} = \text{plant unit cost} + \text{site distribution unit cost} \quad (5)$$

In applying eq. (5), the following notation is used:

$\bar{c}_{i,k,j}$ = the unit cost for subsystem energy product i, of cost component k provided to j.

$C'_{i,k}$ = Direct cost for subsystem i of cost component k (plant cost only)

$C'_{i,k,j}$ = As above except denotes added direct cost for j

for i: subsystems e, h, c are as defined as before

for k: f = fuel cost; o = other O & M; d = capital recovery

for j: s = site; p = plant

and other notation is as before.

Since there are no reported O & M costs for site distribution, both the fuel and O & M site unit costs components are the same as at the plant. Therefore, eq. (5) for fuel and O & M unit costs for each site energy commodity becomes the following:

<u>electrical</u>

$$\bar{c}_{e,f,s} = \bar{c}_{e,f,p} \quad (6)$$

$$\bar{c}_{e,o,s} = \bar{c}_{e,o,p} \quad (7)$$

<u>heating</u>

$$\bar{c}_{h,f,s} = \bar{c}_{h,f,p} \quad (8)$$

$$\bar{c}_{h,o,s} = \bar{c}_{h,o,p} \quad (9)$$

<u>cooling</u>

$$\bar{c}_{c,f,s} = \bar{c}_{c,f,p} \quad (10)$$

$$\bar{c}_{c,o,s} = \bar{c}_{c,o,p} \quad (11)$$

The capital costs for site distribution are separately reported in section 3 of this report. Equation (5) for capital recovery unit cost for each site energy commodity becomes:

electrical

$$\bar{c}_{e,d,s} = \bar{c}_{e,d,p} + C'_{e,d,s}/E_{e,s} \tag{12}$$

heating

$$\bar{c}_{h,d,s} = \bar{c}_{h,d,p} + C'_{h,d,s}/E_{h,s} \tag{13}$$

cooling

$$\bar{c}_{c,d,s} = \bar{c}_{c,d,p} + C'_{c,d,s}/E_{c,s} \tag{14}$$

Site unit energy costs are directly calculated using eq. (1) through (14) and presented quarterly in tables 6-1 and 6-2 for electrical and hot water energy respectively.

Chilled water unit cost data are not presented on a seasonal basis since the spring and fall periods of operation are not meaningful, representing only 6 and 34 days of operation, respectively. However, seasonal direct cost data for the cooling subsystem need to be developed in order to determine (using eqs. (2), (3) and (4)) the costs of plant electrical and hot water energy on a seasonal basis. Since cooling subsystem costs are incurred even in the winter when no cooling takes place, the total 12-month cooling subsystem costs need to be spread over the period the cooling subsystem operated. This is done by allocating total O & M cost by the quantity of chilled water produced each month and allocating total capital recovery expenses by the number of days the chilling subsystem operated in each month. Monthly cooling subsystem costs obtained in this way are used in the cost separation equations to develop the electrical and hot water data of tables 6-1 and 6-2.

A 12-month summary of site unit cost data including chilled water is presented in table 6-3. Site total allocated costs are also presented for the 12-month period in table 6-4. The unit cost of site electrical energy is also calculated monthly and presented in table 6-5.

The unit cost of electrical energy is greatly affected by cost separation for heat recovery and for cooling energy use. Since there are several techniques for calculating the effect of heat recovery and since the cost of cooling has been excessively high over the period being reported, it is important to show the effect on costs of these subsystem interactions as developed in this report. Data are presented in table 6-5 for electrical energy cost with and without cost separation. The following equations are used to calculate the electrical energy unit costs based on total direct costs, without cost separation:

$$\bar{c}'_{e,f,s} = C'_{e,f}/E_{e,n} \tag{15}$$

$$\bar{c}'_{e,o,s} = C'_{e,o}/E_{e,n} \tag{16}$$

$$\bar{c}'_{e,d,s} = C'_{e,d}/E_{e,n} + C'_{e,d,s}/E_{e,s} \tag{17}$$

The first column in table 6-6 shows the cost of site electrical energy calculated by eqs. (15), (16) and (17). The second column shows the cost of site electrical energy after recovered heat costs have been allocated to the heating subsystem. The third column shows the final cost of site electrical energy after the cost of chilled water energy used by the electrical subsystem is included.

Quarterly and monthly unit costs are developed to provide additional insight into the affects of plant operation on costs. It should be noted, however, that it is not possible to reproduce the yearly unit costs by any simple weighted averaging of quarterly or monthly unit costs. Due to the form of the cost separation equations, the allocation of total costs to the site energy commodities does depend on whether the cost separation is done monthly, quarterly, or yearly. The total allocated cost data presented in table 6-4 are based on applying the cost separation equation to the full 12-month period. Legitimate differences of up to 10% in these values can be obtained by summing quarterly costs based on the unit cost data of tables 6-1 and 6-2 which were developed by applying the equations quarterly.

6.4 Comparative Unit Cost of Utility-Supplied Electrical Energy

This section develops estimates of the cost of electricity if purchased from the local electric utility company and delivered to site buildings. Existing rate schedules are used. These data are prepared for the purpose of putting the JCTE plant costs into some perspective. When these conventional electrical energy cost data are combined with heating and cooling costs for conventional systems, an approximate overall cost comparison with the TE plant can be accomplished.

The cost for electrical energy is based on the demand and consumption pattern of the reported JCTE "Net" electrical energy data presented in table 2-1, which includes the site, HVAC and PTC. This electrical energy pattern therefore is equivalent to that of a central conventional HVAC plant utilizing absorption chillers, oil-fired boilers, and other equipment in the same way as the existing JCTE plant but without the electrical generation subsystem. It is felt that for this type of conventional central HVAC system, the costs developed for electrical energy are quite accurate. Other types of conventional HVAC systems will have different electrical demand and consumption patterns and therefore will have different costs. Thus, the electrical unit costs presented represent only one case of a comparative conventional energy system and therefore (when combined with conventional heating and cooling data) do not answer the question of overall comparative economic viability of Total Energy.

6.4.1 Electric Rate Structures

The local electric utility serving the areas adjacent to the Summit Plaza site is the Public Service Electric and Gas Company (PSE&G). In consultation with PSE&G personnel it was determined that the Large Power and Lighting Schedule (LPL) would be applicable to the site if a central conventional energy plant was installed at Summit Plaza. (Standby or "Breakdown" electrical service is currently provided by PSE&G to the

Summit Plaza site under the LPL rate.) Under the present situation of including utilities in the rent, this rate would be the most attractive available rate structure to the site owner/operator. (That is, it affords the lowest cost energy to the site.)

The basic LPL rate has been revised upwards twice during the period covered by this report. On November 7, 1975 the rate was increased approximately 14% for the demand/consumption levels of the site. On October 20, 1976, the rate was increased again approximately 9%. The energy adjustment charge (fuel adjustment charge) portion of the rate is calculated by PSE&G on a monthly basis. In the period under consideration, this has varied over a range of $\pm$ 20%, with no discernable overall trend.

6.4.2 Purchased Electric Energy Cost

Data for net electrical energy demand and consumption required by the site, PTC and HVAC (as defined in section 2.1.1) for each month was used for calculating purchased electricity cost. This amount of electrical energy consumption and electrical power demand is consistent with the use of a conventional single-purpose central HVAC plant with absorption chillers and boilers (i.e. the existing JCTE plant less the engine-generators and their auxiliaries). The monthly demand for billing purposes as stated in the rate schedule is based on the highest 15-minute interval demand.

These demand and consumption data were used along with the appropriate PSE&G rate schedules and energy adjustment charges to determine electricity cost. These data and results are shown in table 6-6. Costs in table 6-6 vary considerably not just due to the site demand and consumption variations but also due to the monthly variations in the energy adjustment charge.

6.4.3 On-Site Costs

The total cost of electric energy to site buildings in the utility-supplied case must include the cost of on-site equipment necessary for distribution of purchased electricity from a conventional HVAC central equipment building (CEB). This on-site equipment includes CEB equipment and site distribution. CEB equipment includes switch-gear, an emergency generator and CEB space; this equipment relates to the total quantity of electrical energy purchased. Site distribution equipment is nearly identical to that for the actual JCTE case and relates to electrical energy delivered to the site. The reported capital cost of JCTE site distribution (from table 3-2), less \$16,000 for equipment for standby service, can thus be used for the utility-supplied case. For the conventional CEB equipment there is no such direct correlation with JCTE plant equipment.

Conceptual design and costing efforts for alternative systems are being conducted under contract to NBS for future comparative studies as noted previously. The preliminary results of this work indicate that the cost of switchgear, an emergency generator and central equipment building space for a conventional utility-supplied central HVAC case is at least equal to the cost of site distribution. (The complete conventional system design and costing data will be the subject of a future report.) Therefore, as a conservative approximation, the added capital cost for conventional CEB equipment is assumed equal to the reported cost of the JCTE site distribution in order to calculate the total cost of site electrical energy in the utility-supplied case.

No additional O & M cost is added for the site electrical distribution or conventional CEB electrical equipment. The actual costs for the JCTE plant presented earlier also did not include any O & M costs for site distribution.

These plant and site distribution costs are added to the cost of purchased electric energy by means of the following equation:

$$\bar{c}_{e,s} = \bar{c}_{e,p} + C'_{e,p}/E_{e,n} + C'_{e,s}/E_{e,s} \qquad (18)$$

where:

$\bar{c}_{e,s}$ = unit cost of electric energy delivered to the site, \$/kWh

$\bar{c}_{e,p}$ = unit cost of electric energy as purchased, \$/kWh

$C'_{e,p}$ = on-site plant equipment direct capital recovery cost, \$ (= \$198,000 x UCR)

$C'_{e,s}$ = site distribution direct capital recovery cost, \$ (= \$198,000 x UCR)

$E_{e,n}$ = Net electrical energy purchased, kWh

$E_{e,s}$ = Electrical energy delivered to the site, kWh

UCR = Uniform capital recovery factor

The added unit cost due to on-site equipment and the resultant total unit cost for electric energy delivered to site buildings are calculated monthly by eq. (18) and results are presented in table 6-7. The 12-month average electric energy cost to the site buildings is 4.15 ¢/kWh.

6.5 Comparative Cost of Conventional Heating & Cooling

In contrast to electrical energy there is no direct supply of hot water, steam or chilled water energy from central utility sources in the Jersey City vicinity. Thus, directly-comparable costs for a conventional option to the JCTE plant are not readily available. As stated previously, heating and cooling costs for conventional single-purpose plants can be estimated based on separation of TE plant costs but this requires that a conventional plant design be executed and analyzed. At this time, reliance must be placed on published actual cost data from existing building complexes. In general, published data are either aggregated data based on national-regional surveys of a particular class of building or detailed case study data based on a particular plant. In either case, these data provide only an approximate indication of the cost of possible conventional systems at Summit Plaza.

Several separate sources of aggregated data exist for the operating cost of office buildings, apartments, campuses, shopping centers and hospital facilities. One of these has been selected as the basis of the initial comparison in this report.

The Building Owners and Managers Association International (BOMA) publishes each year cost data for owning, operating and maintaining office buildings. This data is based on a nationwide survey which, in 1975, included a total of 1,023 individual buildings. Cost data is reported in 16 cost categories. Respondees to the BOMA survey can report HVAC O & M costs either of two ways: in separate categories for heating and air-conditioning-ventilating or in a combined HVAC category. Energy costs are separately reported in a single category and not allocated to HVAC, lighting, etc., nor identified by fuel type or average cost. Alterations (capital improvements) and fixed charges (i.e., capital recovery) are also separately reported and not allocated. The BOMA data provides a good source for HVAC O & M costs, exclusive of energy. Separation of fuel costs is desirable because of the great variability in the cost of the various energy sources used in the surveyed buildings.

BOMA data is aggregated by region, city size and building characteristics: size, age and number of stories. Variations in HVAC costs due to building size, age, stories and city size are much less than the variations due to location. By using data for the Middle Atlantic Region to compare with JCTE, the most significant variations (probably due to climatic and labor cost effects) should be excluded.

The BOMA report for calendar year 1975 provides the data shown in table 6-8 for downtown buildings. Examination of these data in relation to the entire data base indicates that the New York City data provides a good basis for comparison with the JCTE data. The combined HVAC cost for New York City compares well with Middle Atlantic and other locations. The sum of the individual heating and A/C-ventilating costs also nearly matches the combined HVAC value, although the sample size for the separate reporting is small.

6.6 Preliminary Comparison of Unit Costs

A comparison of unit costs is presented here for the purposes of adding perspective to the JCTE unit cost data of section 6.3. This comparison uses the fairly accurate costs for purchased electrical energy developed in section 6.4 and the approximate O & M costs for conventional HVAC energy commodities presented in section 6.5.

It should be emphasized that the level of detail and scope of this preliminary comparative analysis is an approximate indication of comparative economics. Evaluation of economic viability should examine alternative systems in detail and should consider various entrepreneurial and societal measures for economic evaluation. The comparison presented in this section is not intended to be a decisional basis for either a developer or utility or for TE policy decisions by governmental/ regulatory entities.

6.6.1 Electrical Energy Costs

Figure 6-2 compares the purchased electricity cost data from table 6-8 with the electricity cost of the JCTE plant from table 6-1.

As figure 6-2 shows, the electrical power cost of JCTE and the utility supply are essentially equal given the approximations inherent in the JCTE cost separation approach. Unit costs for electricity for the 12 months is 3.93¢/kWh for JCTE and 4.15¢/kWh for one conventional case of a central HVAC plant (with absorption chillers) with utility-supplied electric energy.

6.6.2 Heating & Cooling Energy Costs

The BOMA data presented in section 6.5 are developed on a cents per square foot of building basis. The Summit Plaza site contains a total of 547,400 ft^2 (50,850 m^2), excluding the CEB.

The heating and cooling subsystem O & M cost data for JCTE from table 6-4 along with the BOMA data are used in the following comparison:

O & M COST COMPARISON, ¢/ft^2

	JCTE	BOMA
Heating	17.3	20.2
Cooling	13.5	17.7
Total HVAC	30.8	37.9

The individual BOMA heating and cooling values used above are based on New York City data from table 6-8 proportionately adjusted so that the sum of heating and cooling is equal to the BOMA-reported "Combined HVAC" category for New York City.

The BOMA data is exclusively collected from office buildings. In using this data for a comparison with JCTE, a primarily residential site, some inconsistencies are obviously introduced. For example, office buildings often require some space cooling year-round, thus increasing the cooling costs on a ¢/ft^2 basis. Also, their occupancy and resultant load patterns can be significantly different than apartment buildings. Office buildings are, however, often served by centralized HVAC systems which may have much in common with a hypothetical central conventional system for Summit Plaza.

Within the limitations stated above, the comparison shows that JCTE heating and cooling O & M costs, other than fuel, are about the same as, or somewhat lower than, could be expected from a conventional plant in the same geographical area.

The BOMA data generally include costs for maintenance of end-use items (e.g. ductwork, fan-coil units) which are excluded from the JCTE data base. This tends to shift the cost comparisons to favor JCTE. The BOMA HVAC data excludes two non-allocated items (water supply and plumbing) which are included in the JCTE data. For the Middle Atlantic region, water supply and plumbing costs are 3.1 and 3.3 ¢/ft^2, respectively. A small portion of these items is probably allocable to the HVAC systems in the BOMA data. The absence of these costs tends to shift the comparison against JCTE slightly.

6.7 Some Factors Influencing Unit Costs

Several factors which are known to have a significant influence on the JCTE unit cost data are discussed below. The discussions are to make the reader aware of some of the possible influences on plant economics which will be reflected in future plant operating data and/or in future NBS analytical reports. A thorough and complete evaluation of the factors discussed has not been undertaken. Thus the magnitude of cost changes presented herein are rough estimates only. Not all factors which could affect costs in a major way have been identified and examined at this time. Other factors may be of equal or greater significance than the ones discussed.

6.7.1 Site Occupancy

During the 12 months under examination in this interim report, all apartment buildings were essentially 100% occupied. However, the school was initially occupied in September, 1976 and the commercial building has been only partially occupied (approximately 37% of floor space) during the entire 12-month period. The design electrical demand and consumption for these facilities, obtained from the plant design engineers, is as follows:

Facility	Design demand, kW	Design consumption, kWh
Commercial	191	950,300
School	60	199,000
Totals	251	1,149,300

The magnitude of these design loads indicate they may have a significant beneficial effect on the electrical energy unit cost since this parameter is quite sensitive to net electric energy produced. It is estimated that full occupancy of the commercial building and 9 months' use of the school would add 753,300 kWh, a 12% increase in net electric energy. Fuel costs are directly dependent on output and would increase by approximately this amount. Other O & M and capital recovery costs would remain essentially constant. Since fuel represents 41% of total allocated costs, the 12% increase in fuel cost would result in total cost increasing only 5%. Thus overall electrical energy unit costs could be expected to decrease by approximately 6%. The effect of site occupancy will be examined in detail in future performance reports if full occupancy of the commercial building is not realized.

The anticipated increase in electrical loads from full occupancy would not greatly impact heating and cooling costs. The reduction in boiler fuel due to the availability of additional recovered heat would be offset by additional fuel costs transferred from the electrical subsystem to account for the additional recovered heat.

6.7.2 Chiller Operation

As the data of table 2-4 indicate and as discussed in section 4.5, the performance of the chillers has been quite poor during the 12-month period under analysis. Section 4.5 indicates that a 33% decrease in energy consumption by the chillers can be expected with proper operation and maintenance. This will lead to a significant reduction in site chilled water unit cost because 36% of this cost is due to hot water consumption by the chillers.

The 33% reduction in energy use by the chillers translates to a 26% decrease in energy output by the heating subsystem during the summer. The cost of in-plant hot water energy during the summer quarter is equal to the value shown in table 6-2 less site distribution capital recovery costs, or 7.28 \$/MBtu. This value would increase to approximately 9.10 \$/MBtu due to the reduction in hot water output. Using this value and the reduced energy input for cooling, the total quarterly cost of hot water used for production of chilled water is estimated to decrease by approximately \$23,800 or 19%. Site chilled water unit costs would decrease by 9%. The 33% reduction in energy use by the chillers increases the annual unit cost of site hot water by about 10% due to the reduced hot water output. Also, the cost of electric energy would decrease slightly due to reduced cost of plant cooling.

6.7.3 Heat Recovery from Engine-Generators

Maximum recovery of heat from the diesel engine-generators is vital for economical plant operation. Any heat recovery inefficiency is reflected in high exhaust gas temperatures downstream of the waste heat recovery devices indicating removal of less than the maximum possible heat from the exhaust gases. During the 12-month period the stack exhaust gas temperature averaged 440-475°F (227-246°C), indicating only partial recovery of heat. Exhaust gas temperatures upstream of the heat recovery devices have averaged 570-660°F (300-350°C). It is felt that the heat recovery mufflers could be designed to lower the average exhaust temperature to 350°F (177°C) without danger of low-temperature corrosion. If this were done, calculations show that an increase of about 20% in the total thermal energy recovered from the engines could be obtained.

This additional heat would substantially change the cost separation results. Electrical energy unit costs would decrease approximately 10% due to the allocation of a larger portion of electrical subsystem direct costs to the heating subsystem. Hot water unit costs would increase since the reduction in boiler fuel cost would be more than offset by the added fuel, O & M and capital recovery direct costs allocated to the heating subsystem. This dichotomous situation occurs because the original formulation of heat recovery cost separation (in section 6.2.1) did not include the maximum possible heat recovery as a basis for allocating costs to the heating subsystem. However, overall plant economics would improve since less fuel would be used while providing the same services to the site.

The exhaust gas temperature of a diesel engine decreases as the load is decreased. For this reason, the average level of exhaust gas temperature leaving the heat recovery mufflers is dependent on maintaining a minimum exhaust temperature of about 300°F (150°C) during minimum-load operation. The impact of this requirement is mitigated when engines are operated so as to achieve a high average load, i.e. shutting the third engine down when two engines can carry the load reliably. The combination of optimal engine operating criteria and improved exhaust heat recovery design may possibly achieve an increase in total heat recovery greater than the 20% stated above. Efforts are currently being made by the JCTE plant operator to improve heat recovery within the constraints of the equipment now in place.

6.7.4 Plant Cooling

As discussed in section 4.4, it is desirable to reduce or eliminate, if possible, the use of chilled water to cool plant ventilation air in order to reduce fuel consumption. Sixteen percent of total chilled water production is used within the CEB. The economic effect of complete elimination of plant cooling is shown in table 6-6 to be a decrease in annual average electrical energy unit cost of 0.38 ¢/kWh, or a 10% reduction. During the summer quarter, the decrease is more dramatic, 0.80 ¢/kWh.

The effect of plant cooling on electrical energy unit costs for June through October is not readily apparent in the data of table 6-5. This is because of the opposing effect of increased electrical energy production for the cooling subsystem auxiliaries. (See section 2.3.1 for a discussion of chiller electrical loads.) The dual effect of plant cooling and increased electrical output on the unit cost of electrical energy is shown in figure 6-3. Note that the unit cost during the summer season would be approximately 3.1 ¢/kWh if plant cooling is eliminated entirely.

The unit costs of hot water and chilled water energy would increase slightly if plant cooling were reduced or eliminated since a smaller quantity of output would be produced. Total plant costs would of course decrease and overall plant economics would improve.

6.7.5 Miscellaneous Reductions in Losses

Sections 4.1, 4.2 and 4.3 examine three possible actions to reduce plant thermal losses:

- bypassing the idle boiler,
- bypassing one idle engine and
- improving waste heat management.

Using the approximate fuel oil savings for each of these actions from the referenced sections, the impact on unit cost can be roughly estimated. The fuel oil savings is obtained by reduced firing rates for the boiler for a given net heat output by the heating subsystem. As stated in section 4, the estimated aggregate fuel oil savings for the three actions is 35,500 gal (134 m^3), or $12,105 at an average of 34.1¢/gal. The cost of in-plant hot water energy is equal to the value shown in table 6-3 less site distribution capital recovery costs, or 8.82 $/MBtu. This would decrease to 8.62 and would decrease the unit cost of site chilled water as well as site hot water. The decrease in annual site hot water unit cost is approximately 2% while the decrease in site chilled water unit cost is less than 1%.

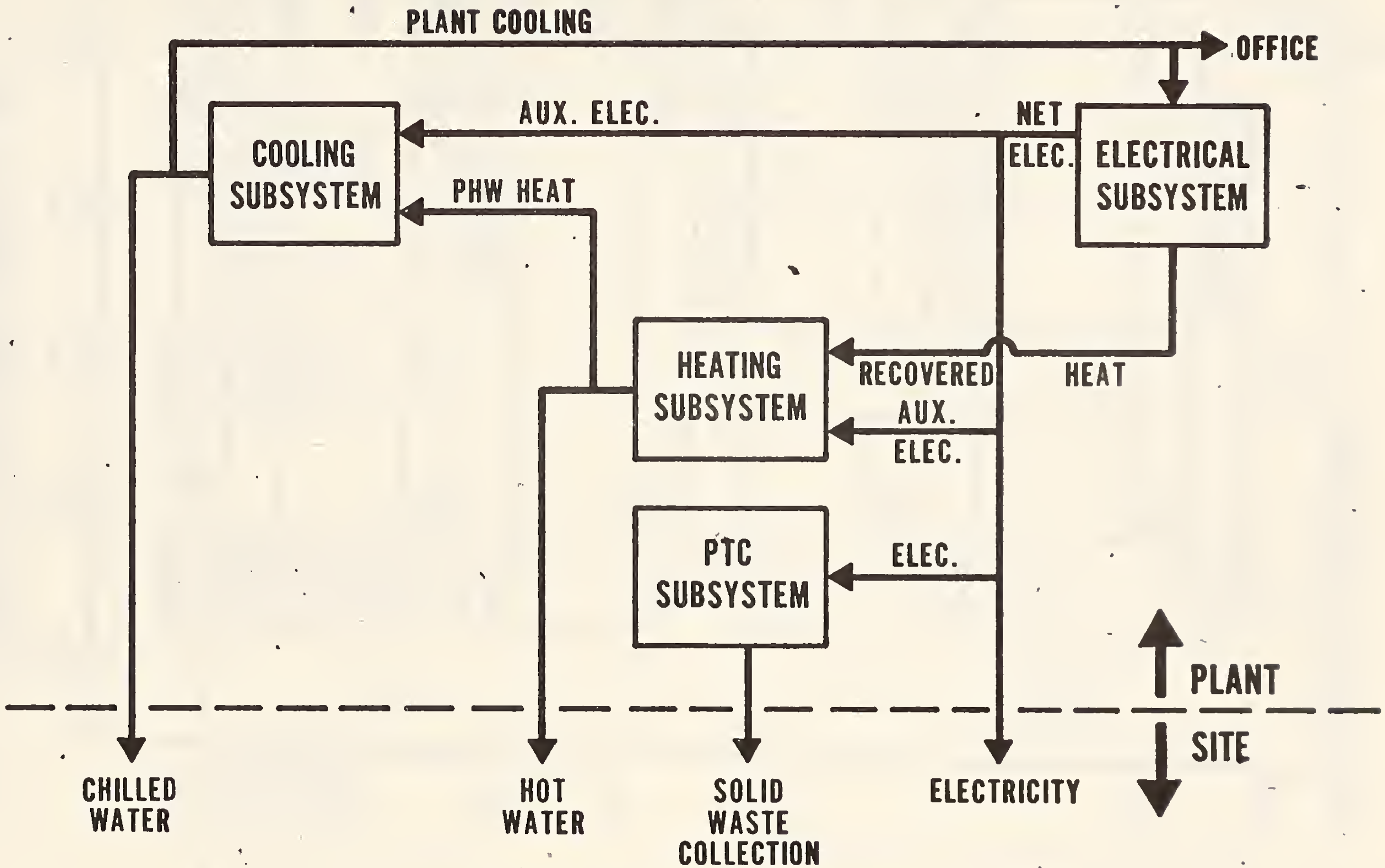

Figure 6-1. Plant and subsystem energy flow

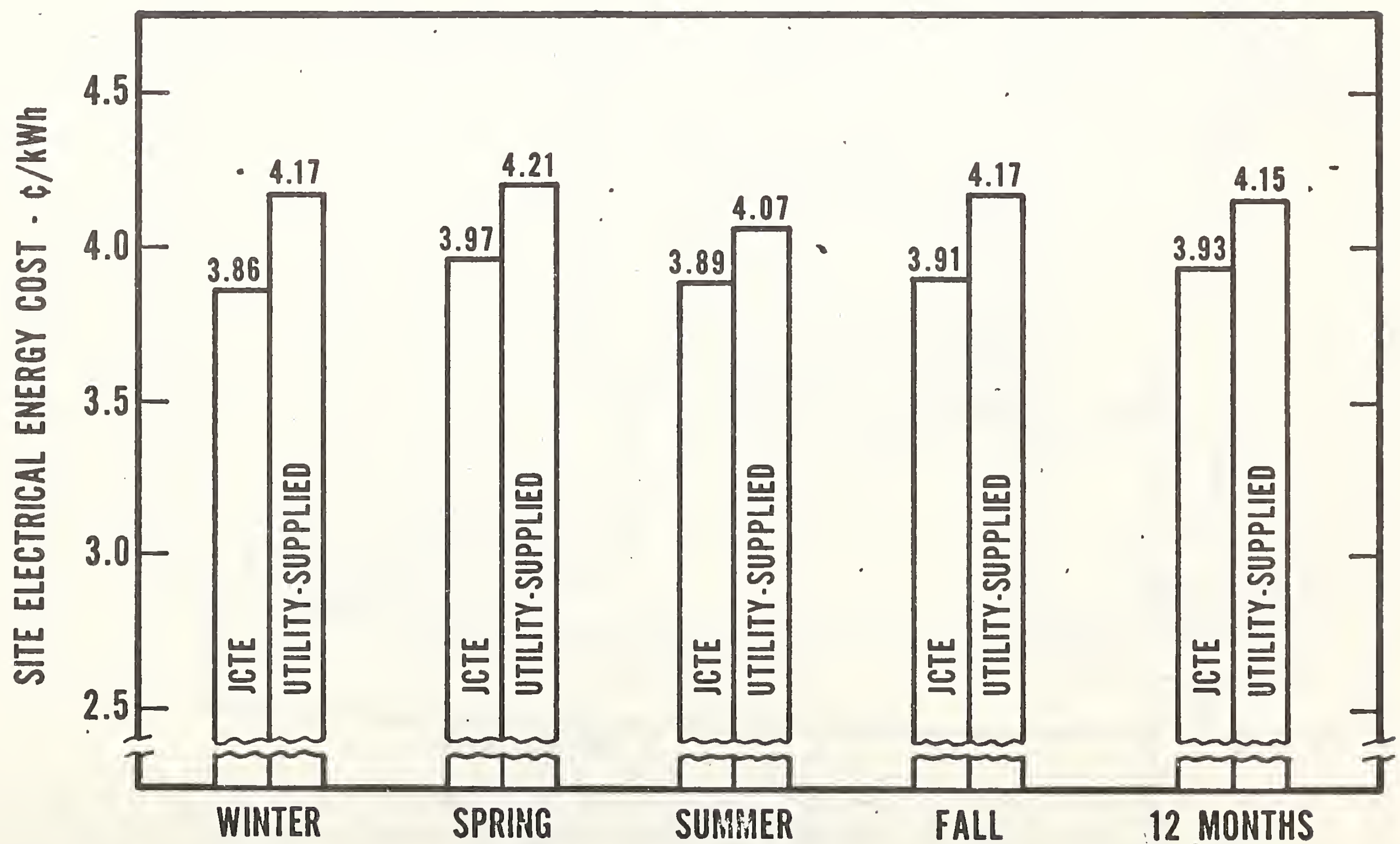

Figure 6-2. Electrical Energy Cost Comparison

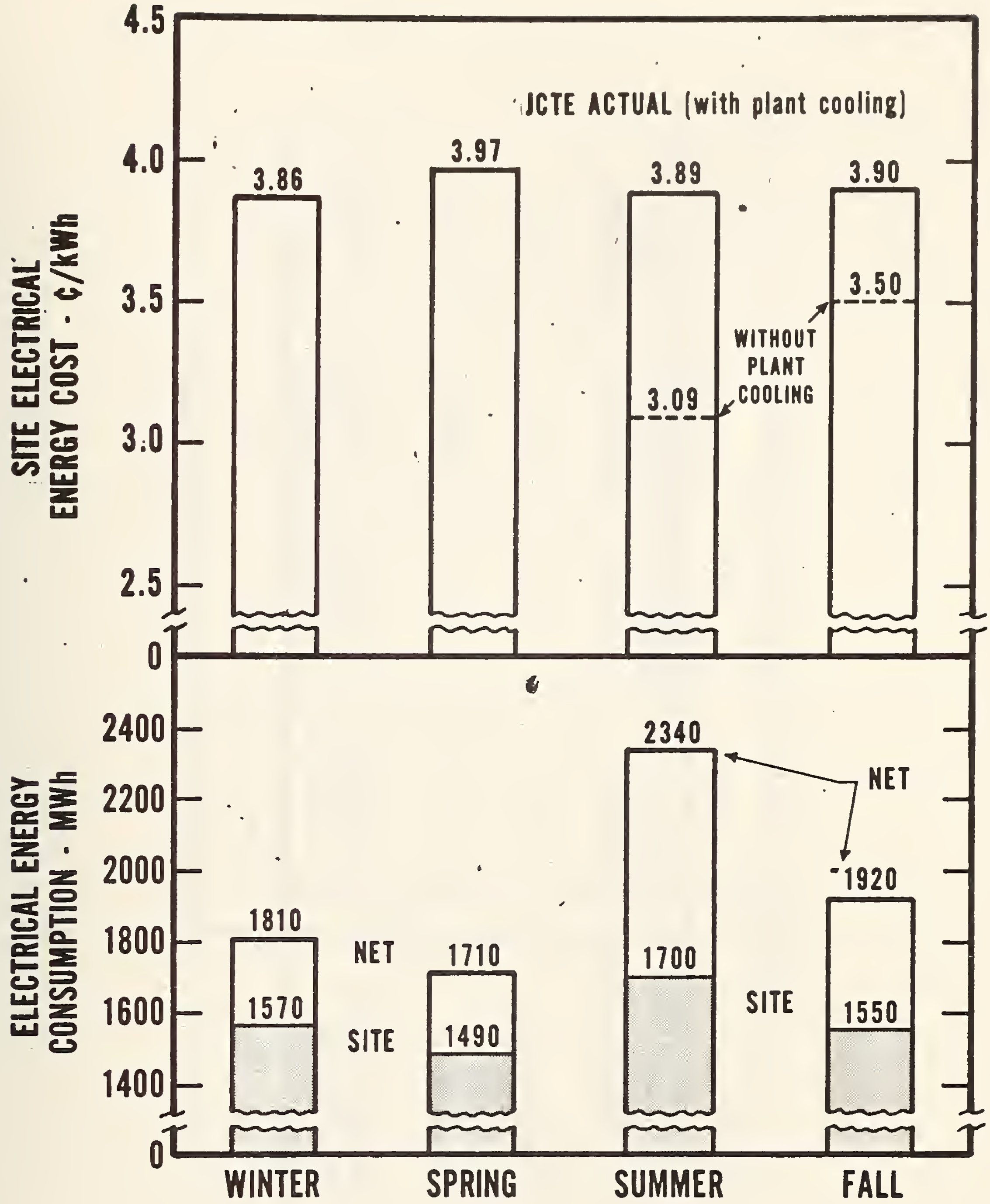

Figure 6-3. Effect of net electrical energy consumption and plant cooling on unit cost

Table 6-1. Cost of site electrical energy

Cost category	Electrical Energy, ¢/kWh			
	Winter quarter	Spring quarter	Summer quarter	Fall quarter
1. Fuel	1.50	1.49	1.70	1.57
2. Other O&M	1.31	1.37	0.98	1.16
3. Capital recov.	1.05	1.11	1.21	1.18
Totals	3.86	3.97	3.89	3.91

Table 6-2. Cost of site hot water energy

Cost category	Hot water, \$/MBtu			
	Winter quarter	Spring quarter	Summer quarter	Fall quarter
1. Fuel	3.84	4.31	3.96	4.22
2. Other O&M	2.26	4.69	1.41	2.82
3. Capital recov.	1.91	3.64	2.57	3.13
Totals	8.01	12.64	7.94	10.17

Table 6-3. Cost of site thermal and electrical energy

Nov. 1, 1975 through Oct. 31, 1976

Cost category	Electricity	Hot water	Chilled water
	¢/kWh	$/MBtu	$/MBtu
1. Fuel	1.57	4.03	10.99
2. Other O & M	1.21	2.48	10.07
3. Capital recov.	1.15	2.54	17.79
Totals	3.93	9.05	38.85
Site energy delivered, MWh or MBtu	6,321	37,353	7,735

Table 6-4. Total allocated site costs

Nov. 1, 1975 through Oct. 31, 1976

Cost category	Subsystem				Plant total
	Electrical	Heating	Cooling	PTC	
1. Fuel	$ 99,452	$ 150,610	$ 85,016	$ 661	$ 335,739
2. Other O&M	76,310	92,685	77,882	20,238	267,115
3. Capital recov.	72,755	94,769	137,604	92,717	397,845
Totals	$ 248,517	$ 338,064	$ 300,502	$ 113,616	$ 1,000,699

Table 6-5. Monthly unit cost of site electrical energy

Month	Site energy*, kWh	Cost, ¢/kWh
Nov. 75	482,400	4.19
Dec.	536,100	3.53
Jan. 76	533,200	4.25
Feb.	503,900	3.81
Mar.	524,300	3.83
Apr.	480,800	3.91
May	484,900	4.21
Jun.	563,300	3.72
Jul.	573,800	3.86
Aug.	567,300	4.08
Sept.	542,900	3.78
Oct.	528,100	3.68
12 months	6,321,000	3.93

* Includes site only, does not include HVAC or PTC energy requirements. Data is from table 2-1, column entitled "Site and PTC Load", less a constant 3500 kWh per month for the PTC consumption (see section 2.1.1) and rounded to nearest 100 kWh.

Table 6-6. Effect of cost separation on cost of site electrical energy

Nov. 1, 1975 through Oct. 31, 1976

Cost category	Direct cost		With heat recovery		With plant cooling	
		¢/kWh		¢/kWh		¢/kWh
1. Fuel	$ 216,047	2.78	$ 113,873	1.46	$ 99,452	1.57
2. Other O & M	163,352	2.10	86,098	1.11	76,310	1.21
3. Capital recov.	116,626	1.56	71,778	.98	72,755	1.15
Totals	$ 496,025	6.44	$ 271,749	3.55	$ 248,517	3.93

Table 6-7. Cost of purchased electrical energy

PSE&G rate schedule "LPL"

Month	Net energy consumption* kWh	Net billing demand kW	Total cost** $	Unit cost ¢/kWh
Nov. 75	557,175	1070	21,935	3.94
Dec.	616,201	1145	21,176	3.44
Jan. 76	616,143	1144	23,130	3.75
Feb.	578,034	1147	20,287	3.51
Mar.	603,548	1118	22,504	3.73
Apr.	547,834	1037	19,445	3.55
May	555,461	1019	19,087	3.44
Jun.	753,093	1326	26,214	3.48
Jul.	786,973	1303	28,880	3.67
Aug.	802,647	1364	28,284	3.52
Sept.	757,522	1354	24,949	3.29
Oct.	608,794	1254	21,525	3.54
12 months	7,783,425	14,281	277,416	3.57

* includes site, PTC and HVAC auxiliaries (from table 2-1)
** includes energy, demand & fuel adjustment components

Table 6-8. Unit cost of site electrical energy when supplied by utility

Month	Site energy* kWh	Unit cost, ¢/kWh		
		Purchased	On-site capital recovery	Total
Nov. 75	482,400	3.94	0.65	4.59
Dec.	536,100	3.44	0.59	4.03
Jan. 76	533,200	3.75	0.59	4.34
Feb.	503,900	3.51	0.63	4.14
Mar.	524,300	3.73	0.60	4.33
Apr.	480,800	3.55	0.66	4.21
May	484,900	3.44	0.65	4.09
Jun.	563,300	3.48	0.52	4.00
Jul.	573,800	3.67	0.51	4.18
Aug.	567,300	3.52	0.51	4.03
Sept.	542,900	3.29	0.53	3.82
Oct.	528,100	3.54	0.59	4.13
12 months	6,321,000	3.57	0.58	4.15
Season				
Winter	1,573,200	3.57	0.60	4.17
Spring	1,490,000	3.58	0.63	4.21
Summer	1,704,400	3.56	0.51	4.07
Fall	1,553,400	3.52	0.65	4.17

* Includes site only, does not include PTC and HVAC energy requirements. Data is from table 2-1, column entitled "Site and PTC Load", less a constant 3500 kWh per month for the PTC consumption (see section 2.1.1) and rounded to nearest 100 kWh.

Table 6-9. Cost of conventional space heating and cooling

Regional aggregation	¢/ft² (# buildings) *		
	Heating	A/C-Vent	Combined HVAC
New York City	20.5 (3)	18.0 (3)	37.9 (39)
Middle Atlantic **	9.9 (57)	16.2 (51)	36.6 (87)
All U.S.	9.1 (245)	13.3 (215)	27.5 (419)

* ¢/ft²: $\frac{\text{O\&M costs only, no fuel or capital recovery}}{\text{total building floor area}}$

\# buildings: number of individual building responses in the regional/cost category aggregations.

** Middle Atlantic Reg.; New England states plus NY., PA., MD., DE., NJ., DC.

*** Data is from calendar year 1975 BOMA data for downtown buildings from reference 7.

7.0 Reliability and Maintenance

7.1 Electric Service Reliability

The Jersey City Total Energy plant is designed to provide highly reliable electrical power for the site buildings. The plant has five diesel engine-generators; any three of these units can meet the plant and site electrical demand. Automatic controls regulate these engines, keeping their voltage and frequency constant. The controls also will start and parallel an additional engine or stop an engine in response to electrical demands. Should an engine malfunction occur, the controls can stop an engine and shed load (cut power to non-vital loads in a predetermined sequence) if the remaining on-line engine-generators are overloaded. Should the plant go down, other controls automatically connect site essential buses to the local utility buses. The essential buses provide back-up power for restoring plant power and for site emergency lights, fire protection, and elevators. Any time a malfunction is encountered by the automatic controls, a signal is sent to a telephone center and the plant engineer is notified via his radio call device (beeper).

The automatic controls, stand-by engine, and operator beeper have resulted in reliable electric power production. From November 1975 through October 1976 the plant supplied the site with power 99.8% of the time.

There were eleven electrical outages in the period from November 1975 through October 1976 (see table 7-1). These outages ranged from 10 minutes to 4.5 hours in duration and had a cumulative duration of approximately twenty hours. Six of the outages were caused by electrical control system malfunctions. These outages had a cumulative duration of approximately seven hours. Two of the outages were caused by fuel control system problems and had a cumulative duration of approximately three hours. The other three outages were related to maintenance and modification of the electrical control system. These outages had a cumulative duration of ten hours. Two of these were planned outages. Descriptions of the outages follow. These descriptions are based on an engineering analysis of data from the plant engineer's logs, kilowatt strip-chart recordings, the plant operator, utility electric bills, the DAS, the daily NBS logs and reports by authorized persons present during the outages.

The first outage of this one year period occured at 2:47 am on February 14, 1976 and lasted several hours. The plant engineer was beeped at home, came to the plant, and quickly restored power. He diagnosed the shut down as resulting from spurious overspeed alarms. To restore engine-generator operation, he temporarily disconnected the faulty overspeed alarm circuits. Later that week an electrical controls consultant found that most of the speed switches were not operating according to specifications.

The second outage occured at 2:29 pm on February 14, 1976 and lasted for 10 to 20 minutes. The plant engineer was in the plant and quickly restored electrical production. This outage was probably caused by the same controls problem as the first outage.

The third outage occured on Sunday morning, February 15, 1976, and lasted for several hours. The outage was not related to the February 14 outages. The plant engineer was beeped while in his car. He drove directly to the plant and diagnosed the problem as a malfunction in the automatic equipment which switches the plant fuel supply from one underground storage tank to another. The plant engineer manually switched the storage tank valves, bled the air from the engine injectors, restarted the engines, and put them on-line.

The fourth outage occured at 4:50 am on February 21, 1976 and lasted three hours. This outage was planned by the plant operator so that the plant engineer and an electrical controls consultant could clean, tighten, and adjust the engine-generator control equipment. Site occupants were notified in advance of this outage.

The fifth outage occured at 2:15 am on March 2, 1976 and lasted approximately one and one-half hours. The plant engineer was notified at home by the site resident manager. Responding to the call, the plant engineer found generator circuit-breaker alarms on four engines and the fifth engine showing an excessive start-time alarm. He restarted three engines and put them back on-line. These events imply a malfunction of the engine-generator control equipment.

The sixth outage occured at 5:05 pm on August 4, 1976 and lasted approximately ten minutes. The plant engineer was in the plant when the outage occured and he restarted the engines and put them back on-line. The exact cause of the outage is not known, however, for several hours preceeding the outage the generator bus voltage had been dropping from 480 volts to 425 volts, implying the outage was caused by the engine-generator control equipment. The problem may have been relieved as the plant engineer readjusted the voltage and frequency of the individual engines while he was putting them back on-line.

The seventh outage occured at 10:27 am on August 5,1976 and lasted for approximately ten minutes. This outage was caused by an engine control circuitry problem.

The eighth outage occured at 9:00 am on August 12, 1976 and lasted several hours. The outage occured when four fuses where jarred lose by an electrical controls consultant during servicing of the electrical control equipment. The consultant restored plant operation.

The ninth outage occured at 9:15 am on August 17, 1976 and lasted four and one-half hours. This was a planned outage, made so that modifications could be made to the electrical control equipment and the plant switchgear. Site occupants were notified in advance of this outage. During this outage it was necessary to cut off utility power from the essential buses to modify several 480 volt circuits.

The tenth outage occured at 8:12 pm on October 4, 1976 and lasted for two or three hours. The plant engineer was beeped in his car. The engines had gone down showing overspeed alarms. During the process of restoring plant operation, the plant engineer found large variations in the output voltages and frequencies of the individual engine-generators, suggesting that they were maladjusted or that the engine control equipment was malfunctioning.

The eleventh outage occured at 8:26 pm on October 15, 1976 and lasted approximately twenty minutes. This outage was caused by an engine-generator fuel shortage from a failure in the engines' back up fuel system.

In summary, the plant supplied electrical power to the site for 99.8% of the reported year. Most outages were due to malfunctions in the plant electrical control systems.

7.2 Equipment Maintenance and Reliability

Plant maintenance is accomplished by the plant engineer, his two assistants, and several outside contractors who perform the maintenance on specalized plant equipment. Because the plant was designed to operate automatically, the plant engineer and his assistants work only a weekday shift. The plant engineer notifies outside contractors when routine engine, boiler, or chiller maintenance is necessary or when one of these devices malfunctions. The routine contracted maintenance operations include: 1,000 hour engine service; minor engine overhauls; muffler cleanings; cleaning, inspection and adjustment of the chillers; and cleaning, inspection, and adjustment of the boilers. The plant engineer also routinely sends samples of the engine lube oil for chemical analysis to detect engine problems. The plant engineer and his assistants service and repair most other plant mechanical equipment.

The plant equipment reliability, as documented by the plant log has, in general, been good. Most maintenance which has been performed has been routine or to repair statistical or expected failures. However, several systems have required a larger than expected share of maintenance. Examples of these types of problems will be discussed in the following paragraphs.

The electrical control equipment has shut down one or more individual engines more than twenty-five times in the last year. The plant log indicates that very few of these shutdowns were due to an actual engine problem. Most shutdowns were related to problems in the engine control equipment. Problems have included out-of-specification sensors, malfunctioning circuitry, overheated circuitry, and blown fuses. The variety and number of problems related to the electrical control equipment seems excessive for properly designed, installed, and adjusted control equipment.

Seven secondary hot water pipes in site buildings have split from freezing. The reasons given for this splits have included low flow rates due to inadequately wired pumps and low flow rates due to accumulation of dirt in the pipes.

Problems have been encountered with the absorbers including difficulty in starting them at the beginning of the cooling season, splits in their air lines, and blown and improperly installed gaskets. As pointed out in section 4.4, the chillers have had periods of very low COP operation.

Although the PTC system is not considered as a part of the total energy plant, previous to the reported year it has occupied a large amount of plant personnel time. At least thirty times during the reported year the PTC has shut down or discharge valves have jammed and required manual intervention to restore operation. However, most of the major initial problems of the PTC have been corrected.

Table 7-1

Summary of electrical outages from
November 1975 through October 1976

Date	Beginning of Outage	Duration	Probable Cause
Feb. 14, 1976	2:47 am	several hours	electrical controls
Feb. 14, 1976	2:28 pm	10 to 20 minutes	electrical controls
Feb. 15, 1976		several hours	fuel supply equipment
Feb. 21, 1976	4:50 am	3 hours	planned outage
Mar. 2, 1976	2:15 am	1.5 hours	electrical controls
Aug. 4, 1976	5:05 am	10 minutes	electrical controls
Aug. 5, 1976	10:27 am	10 minutes	electrical controls
Aug. 12, 1976	9:00 am	several hours	maintenance error
Aug. 17, 1976	9:15 am	4.5 hours	planned outage
Oct. 4, 1976	8:12 pm	several hours	electrical controls
Oct. 15, 1976	8:26 pm	20 minutes	fuel supply equipment

Essential buses used utility power for a total of 18 hours

Acknowledgment

The authors wish to acknowledge the contributions of Charles Bulik and Dan E. Rorrer in the collection and processing of JCTE engineering data. Charles Bulik has directed the debugging, the calibration, the maintenance and the upgrading of the JCTE on-site instrumentation and data acquisition system. Through Mr. Bulik's efforts the instrumentation system was made operational, kept operational, and has been improved in accuracy. Dan E. Rorrer has developed the equations, engineering techniques, and computer software necessary to convert the raw data from the 5-minute site data tapes into engineering data. Furthermore, Mr. Rorrer has developed computer systems which permit rapid and simple accessing of this data in numerical or graphical form. Both Mr. Bulik and Mr. Rorrer are in the Mechanical Systems Section at NBS.

Appendix I

Engineering Monthly Data Summaries

Appendix I

Engineering Monthly Data Summaries

1. Schematic Diagram of System and Related Items Listed in the Monthly Summaries.

2. Definition of Terms Used in Presenting Monthly Engineering Performance Data.

3. Monthly Summaries of Engineering Data for November, 1975 through October, 1976.

4. Monthly Summaries of Engineering Data with Fuel Measurements and Comparative Analysis for May, 1976 through October, 1976.

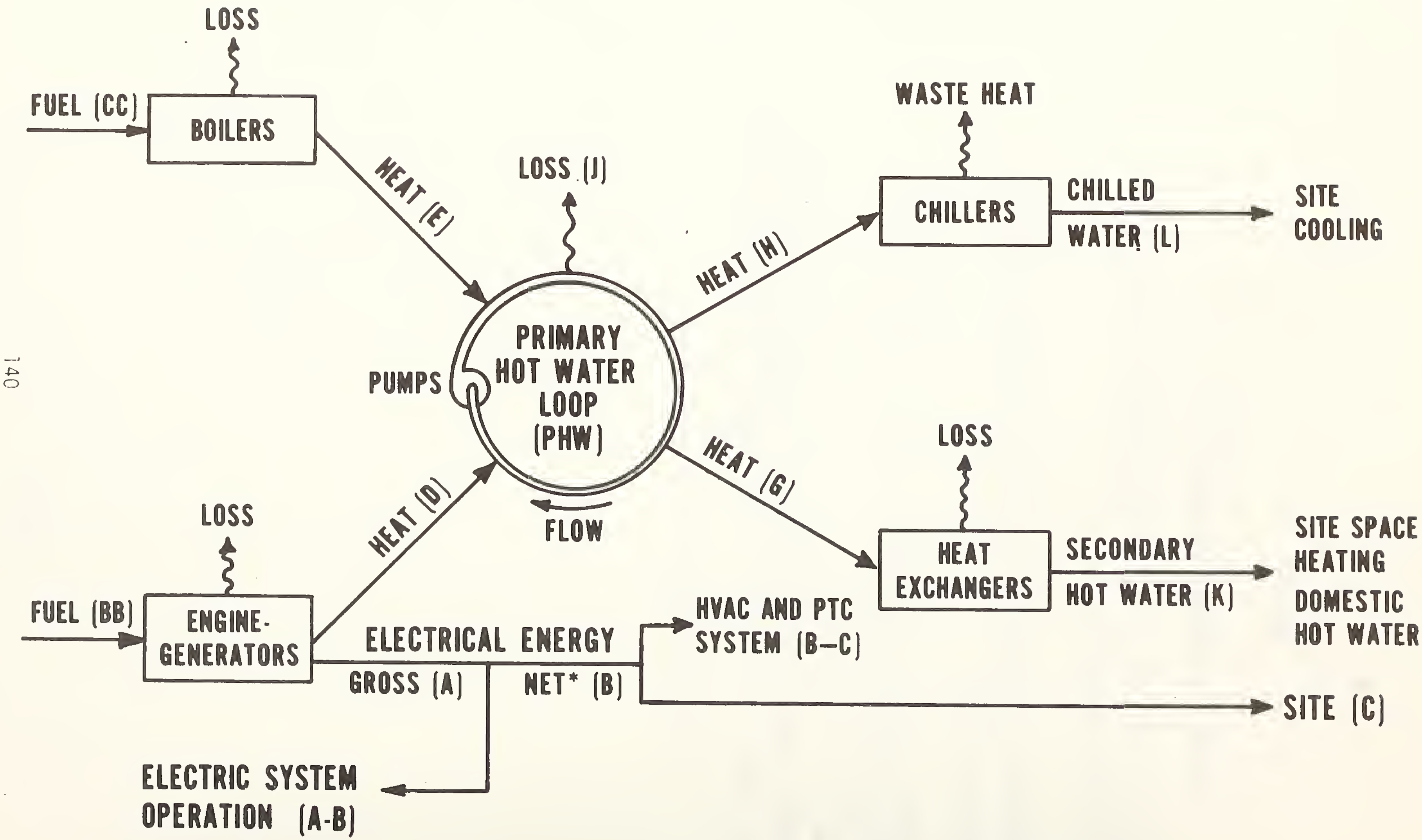

Figure I-1 Energy flow diagram

Bracketed letters refer to items in tables in this appendix

DEFINITION OF TERMS LISTED IN ENGINEERING PERFORMANCE DATA

ELECTRICAL ENERGY

A. Gross Generated is the total electrical energy produced by the generators. This measurement is made by both a DAS transducer and a kilowatt-hour meter connected to the main bus from the generators.

B. Net (Required if purchased from utility) is the amount of electrical energy generated minus the electrical energy used in the electrical production process. The net electrical energy is determined by summing the measured site electrical consumption, the measured PTC consumption, and the computed electrical energy required for boiler and chiller operation. The boiler and chiller electrical energy consumption is extrapolated from boiler and chiller thermal output data. The difference between net and gross electrical energy is approximately equal to the electrical energy required by the engine-room exhaust fan, the primary loop pumps, the engine oil-cooler pumps, and the dry cooler fans.

C. Site consumption including PTC exhauster and compactor is the electrical energy required by the site not including the CEB. Energy for the pneumatic trash collector (PTC) exhauster and compactor is included. The electrical energy required for the air supply for the PTC pneumatic controls is not included. Electrical energy data is measured by DAS transducers.

HVAC processing in plant reports the electrical energy required to operate the boilers, the chillers (including the cooling towers), and the secondary hot and chilled water circulation pumps.

THERMAL ENERGY ADDED TO PHW LOOP

D. Thermal Energy Recovered from Engines reports the total amount of thermal energy added by the engine jackets and exhaust exchangers to the primary hot water (PHW) loop. This quantity is measured by DAS instrumentation for the total PHW flow rate through all five engines and for the PHW temperature differential across the entire engine bank. This quantity includes the heat added to the PHW by running engines minus the heat lost from the PHW by idle engines.

E. Thermal Energy Recovered from Boilers reports the total amount of thermal energy added by the boilers to the primary hot water (PHW) loop. This quantity is measured by DAS instrumentation for the PHW flow rate through the boilers and for the PHW temperature differential across the boilers. This quantity includes the heat added to the PHW by firing boilers minus the heat lost from the PHW by idle boilers.

F. Total Thermal Energy Recovered is the sum of the thermal energy recovered from the engines and the boilers. It represents the total thermal energy added to the PHW by running engines and firing boilers minus the thermal energy lost by idle engines and idle boilers.

THERMAL ENERGY CONSUMED

G. Thermal Energy Extracted from the PHW loop to Produce Hot Water is the amount of thermal energy removed from the primary hot water (PHW) loop by the two site heat exchangers. The site heat exchangers transfer thermal energy from the PHW to the secondary hot water loops which circulate from the central equipment building (CEB) to the site buildings. This quantity is measured by DAS instrumentation for the PHW flow rate and for the PHW temperature differential across the exchangers.

H. Thermal Energy Extracted from the PHW Loop to Produce Chilled Water is the amount of thermal energy removed from the PHW loop by the two absorption chillers. These chillers use PHW thermal energy to produce chilled water which is circulated from the CEB to the site buildings. PHW thermal energy extracted by the chillers is measured by DAS instrumentation for the PHW flow rate and for PHW temperature difference across the chillers.

I. Total Thermal Energy Extracted from PHW is the amount of thermal energy removed from the primary hot water (PHW) loop by the heat exchangers and by the absorption chillers. This quantity reports the thermal energy which was supplied to the secondary hot water loop for heating and domestic hot water production and to the absorption chillers for production of secondary chilled water. Two measurements, PHW heat consumed by the heat exchangers (G) and PHW heat consumed by the chillers (H), are summed to determine this quantity.

J. Thermal Energy PHW Loop Losses: Input MINUS Output is the difference between the thermal energy supplied to the primary hot water loop (PHW) by the engines and boilers (F) and the thermal energy removed from the PHW loop for site use by the site heat exchangers and the absorption chillers (I). This quantity reports thermal energy removed from the primary loop by the dry coolers, by the emergency heat exchanger, and by some of the piping losses. Most of this quantity represents PHW heat removed by the dry coolers via continuous convective losses and via heat dumped during running of the dry cooler fans.

K. Thermal Energy Released in Secondary Hot Water System is the amount of thermal energy supplied to the secondary hot water system by the site heat exchangers. This quantity is measured by DAS instrumentation for secondary hot water flow rate and temperature differential. Within the limits of measurement accuracy, the thermal energy released in the secondary system equals the thermal energy extracted from the PHW to produce site hot water minus heat exchanger losses to the surroundings.

L. Thermal Energy Absorbed by Secondary Chilled Water System reports the total amount of thermal energy absorbed by the chillers from the secondary chilled water system which supplies cooling to the site buildings and to the CEB. This quantity is equivalent to the total chiller output and is measured by DAS instrumentation for the secondary chilled water flow rates and temperature differentials across the chiller.

M. Thermal Energy Absorbed by the Secondary Chilled Water System from Site reports the thermal energy absorbed from the site by the secondary chilled water. This quantity is computed by subtracting the chilled water used in the CEB from the total chilled water produced. Both these quantities are measured by DAS instrumentation for water flow rates and temperature differentials. Most of the chilled water used to cool the CEB was used to cool the engine-generators space.

FUEL CONSUMPTION

AA. Fuel Oil Heat Content reports the energy available by completely combusting one gallon of the plant fuel oil. The fuel oil heat content is determined by averaging weekly values of the fuel's higher heating value (HHV) reported by a testing laboratory. Fuel oil samples are taken from the day tanks which supply the engines. Both the engines and boilers use the same fuel.

BB. Fuel Consumed by Engines reports the total amount of fuel oil consumed by the engines. This quantity is measured by a manually-read meter recording the amount of fuel which is pumped into the engine day-tanks from underground storage tanks. The fuel system maintains the day-tank level within 30 gallons, to provide an accurate measurement of monthly engine fuel consumption.

CC. Fuel Consumed by Boilers reports the total amount of fuel oil consumed by the boilers. This quantity is determined from the difference between two manually-read meters; one which records the total fuel pumped to the engine and boiler day-tanks and the other which records fuel pumped into the engine day-tank . This quantity has good accuracy except during months of mild weather. During these months, boiler fuel consumption may be only 10% of the total fuel consumption causing the accuracy of boiler fuel consumption data to be 6% to 15%.

DD. Total Fuel Consumed at Site reports the total amount of fuel consumed by the engines and boilers. This quantity is measured by a manually-read meter which records the total amount of fuel oil pumped up to the engine and boiler day-tanks.

PLANT PERFORMANCE

The operating efficiencies address both individual plant components and overall plant performance. The first four indices, engine electrical efficiency, engine electrical plus thermal efficiency, boiler efficiency, and chiller COP, describe component performances. The last two indices, electrical production efficiency and plant effectiveness, describe overall plant performance.

EE. Engine Efficiency in Producing Gross Electrical Energy reports the engine-generator electrical efficiency for the total power produced. This efficiency is determined by dividing total electrical energy produced by the generators (A) (using the 3412 Btu per kWh conversion factor) by the energy in the consumed fuel (gallons of fuel consumed (BB) times its heat content per gallon (AA)).

FF. Engine Efficiency in Producing Gross Electrical Plus Thermal Energy reports the efficiency of electrical plus thermal energy production by the engine bank. This efficiency is determined by dividing the total electrical energy produced (A) (normalized to BTU's) plus total thermal energy recovered from the jackets and exhaust exchangers (D) by the total heat content of the consumed fuel (AA · BB). Electrical plus thermal efficiency is based upon heat recovered across the bank of engines; losses from idle engines reduce this efficiency.

GG. Boiler Efficiency reports the total thermal energy added to the PHW by the boilers (E) divided by the energy content of the consumed fuel (gallons of fuel consumed (CC) times its heat content (AA)). In that the heat recovered includes losses during periods when the boiler is idle, the reported boiler efficiency will decrease during low usage months. The accuracy of the boiler efficiency reflects the accuracy of the boiler fuel measurement and may degrade to 5% to 10% during low usage months.

HH. Chiller COP reports the total thermal energy extracted from the chilled water by the chillers (L) divided by the total thermal energy consumed from the PHW by the chillers (H).

AAA. Btu of Fuel per kWh of Net Electrical Energy Production reports the engine-generators' efficiency in producing the electrical energy required by the plant and site (B). This quantity is computed by dividing the total heat content of engine fuel (AA · BB) by the net electrical energy produced (B). The Btu per kWh form can be compared with the efficiencies of the local electrical utilities. In computing this efficiency, net electrical energy rather than total generated electrical energy is used because the electrical energy used to operate the electrical plant is not usable by the site or HVAC equipment. In 1975, the local utility at Jersey City distributed electrical energy with an efficiency of 11,451 Btu per kWh.

BBB. Energy Effectiveness in Meeting Site Demands reports the sum of the energy conveyed by the three plant products; site electric power (C), site hot water (K), and site chilled water (M); divided by the energy content of the total fuel consumed by the site (AA · DD). The energy effectiveness is not a direct measure of thermal efficiency due to the second-law operation of the chillers. It is a relative measure of the effectiveness of plant energy usage.

COMPARATIVE ANALYSIS OF J.C.T.E. PLANT WITH CONVENTIONAL PLANT USING CHILLERS AND PURCHASED UTILITY POWER

The comparative analysis section of the monthly summary compares the total fuel used by the J.C.T.E. plant with the fuel required by an electrical utility and a boiler for a central plant in which electrical power is purchased from the local utility, boilers produce secondary hot water, and absorption chillers produce secondary chilled water. The electrical energy, hot water and chilled water required by the site are determined from reported data on net electrical energy, thermal energy released in secondary hot water, and thermal energy absorbed from site by the secondary chilled water system. In this analysis, the "conventional system" is not required to produce 1) electrical energy used by the T.E. site for electrical energy production, 2) thermal energy to make up primary loop losses, or 3) chilled water to air condition the engine-generator facility. Utility electrical production efficiency is obtained from local utility annual reports. Boiler and chiller efficiencies used in the "conventional system" are obtained from T.E. boiler and chiller data reported in the summary. It should be noted that during the first two summers of operation the COP of the hot-water-driven T.E. absorption chillers is significantly below the COP of other absorption chilling systems and compressor chilling systems.

The total fuel used by a "conventional system", in which electric energy is purchased and hot and chilled water are produced by a central oil-fired boiler, and absorption chiller, respectively, is computed in three parts. The first part is the fuel required by a utility to produce the net electric energy (LL). This quantity (LL) is computed by multiplying the net electrical energy (B) required by the T.E. site (including T.E. HVAC processing and the pneumatic trash collection system) times the local utility's efficiency in distributing electric energy (Btu per kWh) (KK) divided by the heat content per gallon of fuel oil (AA). The second part is the fuel required by boilers to produce secondary hot water (NN). This quantity (NN) is computed by dividing the thermal energy released in the T.E. secondary hot water system (K) by the T.E. boiler efficiency (GG) and the fuel oil heat content per gallon (AA). The third part is the fuel required by a boiler-absorption system to produce chilled water (QQ). This quantity (QQ) is computed by dividing the site thermal energy absorbed by the T.E. secondary chilled water (M) by the combined boiler and absorber COP (PP) and the heat content per gallon of fuel oil (AA). The above technique assumes the COP of the "conventional" plant hot water absorber is similar to the COP observed for the J.C.T.E. plant absorber.

During the first two summers of operation, the COP of the T.E. absorbers was significantly different from commonly referenced COP for absorption chillers. Common reference handbook values for single stage absorption chiller COP range from .6 to .7. Assuming a boiler efficiency of 85%, the combined boiler-absorber COP would be .5 to .6. Common values for the motor-compressor COP of a compressor chiller are 2.5 to 3.0. Assuming an electric generation efficiency equal to the local utilities efficiency of 30% (3412/11451), the compressor chiller has an end-to-end COP of .75 to .9. Thus, the range of COP which might be used to compare a "conventional" plant to the J.C.T.E. plant could range from .5 to .9.

Computation of the total fuel required by the "conventional" system (RR) involves summing the fuel used by the electric utility for electric energy production (LL), plus fuel required by a boiler to produce the site hot water (NN), plus the fuel required to operate the boiler-fired absorption chiller (QQ). Additional fuel required by "conventional" plant (UU) is computed by subtracting the fuel used in the T.E. plant (DD) from the fuel extrapolated for a "conventional" plant (RR).

Engineering Performance Data
Total Energy System, Jersey City, N.J.
NOV 1975 to OCT 1976

	Electrical Energy (kilowatt hours)	NOV 1975	DEC 1975	JAN 1976	FEB 1976	MAR 1976	APR 1976	MAY 1976	JUNE 1976	JULY 1976	AUG 1976	SEPT 1976	OCT 1976	TOTAL
A.	Gross Generated	594800	654100	674500	622400	654500	607100	631600	797700	821100	851900	808400	661200	8379300
B.	Net (Required if Purchased from Utility)	557175	616201	616143	578034	603548	547834	555461	753093	786973	802647	757522	608794	7783425
C.	Site Consumption including PTC Exhauster and Compactor	485906	539589	536732	507440	527840	484335	488367	566763	577302	570811	546427	531642	6363154
	HVAC Processing in Plant (B-C)	71269	76612	79411	70594	75708	63499	67094	186330	209671	231836	211095	77152	1420271
	Thermal Energy Added to PHW Loop (10^6BTU)													
D.	Thermal Energy Recovered from Engines	1863	2029	1890	1780	1915	1934	1993	2432	2536	2657	2614	2010	25653
E.	Thermal Energy Recovered from Boilers	1985	4148	5632	3820	2869	1245	555	4598	3932	5791	3575	1724	39874
F.	Total Thermal Energy Recovered (D+E)	3848	6177	7522	5600	4764	3179	2548	7030	6468	8448	6189	3734	65527
	Thermal Energy Consumed (10^6BTU)													
G.	Thermal Energy Extracted from PHW Loop to Produce Hot Water	3360	5546	6903	5158	4376	2871	1748	1144	1081	1090	1124	2952	37353
H.	Thermal Energy Extracted from PHW Loop to Produce Chilled Water	-	-	-	-	-	-	392	5209	5246	7076	4762	309	22994
I.	Total Thermal Energy Extracted from PHW Loop (G+H)	3360	5546	6903	5158	4376	2871	2140	6353	6327	8166	5886	3261	60347
J.	Thermal Energy PHW Loop Losses: Input Minus Output (F-I)	488	631	619	442	408	308	408	677	141	282	303	473	5180
K.	Thermal Energy Released In Secondary Hot Water System	3276	5482	6783	5282	4541	3051	1875	1177	1206	1113	1209	2950	37945
L.	Thermal Energy Absorbed by Secondary Chilled Water System	-	-	-	-	-	-	54	2050	2713	2735	1536	129	9217
M.	Thermal Energy Absorbed by Secondary Chilled Water System from Site.	-	-	-	-	-	-	47	1745	2296	2274	1269	104	7735

		May 1976	June 1976	July 1976	Aug 1976	Sept 1976
	Fuel Consumption					
AA.	Fuel Oil Heat Content (BTU/gal)	138971	138364	138364	138364	138200
BB.	Fuel Consumed by Engines (gallons)	48361	60267	62824	64586	61906
CC.	Fuel Consumed by Boilers (gallons)	5455	41505	36794	47618	29450
DD.	Total Fuel Consumed at Site (gallons)	53816	101772	99618	112204	91356
	Plant Performance					
EE.	Engine Efficiency in Producing Gross Electric Energy $\frac{3412 \cdot A}{AA \cdot BB} \cdot 100$	32.07%	32.64%	32.23%	32.53%	32.24%
FF.	Engine Efficiency in Producing Gross Electric plus Thermal Energy $\frac{(3412 \cdot A)+D}{AA \cdot BB} \cdot 100$	61.72%	61.80%	61.40%	62.26%	62.79%
GG.	Boiler Efficiency $\frac{E}{AA \cdot CC} \cdot 100$	73.21%	80.07%	77.23%	87.89%	87.84%
HH.	Chiller COP $\frac{L}{H}$	.14	.394	.517	.386	.322
AAA.	Btu of Fuel per kWh of Net Electrical Energy Production $\frac{AA \cdot BB}{B}$	10641	11072	11045	11133	11293
BBB.	Energy Effectiveness in Meeting Site Demands $\frac{(3412 \cdot C)+M+K}{AA \cdot DD} \cdot 100$	46.28%	34.48%	36.70%	34.36%	34.39%

	Comparative Analysis of T.E. Plant with Conventional Plant Using Absorption Chillers and Utility Power	May 1976	June 1976	July 1976	Aug. 1976	Sept. 1976
KK.	BTU per kWh Required by Electric Utility	11451	11451	11451	11451	11451
LL.	Fuel Required by Utility to Produce Net Electric Energy $\frac{B \cdot KK}{AA}$ (gallons)	45769	62326	65130	66427	62767
MM.	Thermal Energy Released in Secondary Hot Water System (K) (10^6 Btu)	1748	1177	1206	1113	1209
NN.	Fuel Required by Boilers to Produce Secondary Hot Water $\frac{MM}{GG \cdot AA}$ (gallons)	17181	10623	11286	9152	9688
OO.	Thermal Energy Absorbed by Chilled Water System from Site (M)*** (10^6 Btu)	47	1745	2296	2274	1269
PP.	Combined Boiler and Absorption Chiller COP** $\frac{GG \cdot HH}{100}$	.102	.315	.399	.340	.291
QQ.	Fuel Required by Boiler Absorption System to Produce Chilled Water $\frac{OO}{AA \cdot PP}$*** (gallons)	3316	40037	41589	48338	31554
RR.	Total Fuel Required by Conventional System LL + NN + QQ (gallons)	66266	112986	118005	123917	104009
SS.	Total Fuel Consumed by T.E. Site (DD)	53816	101772	99618	112204	91356
TT.	Fuel Saved by T.E. Site (RR-SS) (gallons)	12450	11214	18387	11713	12653
UU.	Additional Fuel Required by Conventional Plant $\frac{TT}{SS} \cdot 100$	23.1%	11.0%	18.5%	10.4%	13.9%

* Data produced from models described in sections

** Using a Motor-Driven Compressor Chiller, the Effective COP could be:

$$(3.0 \frac{BTU}{BTU} \cdot 3412 \frac{BTU}{KWH} / 11451 \frac{BTU}{KWH}) = .893$$

*** Does not include chilled water used to cool plant.

Appendix II

Economic Monthly Data Summaries

Table II-1. Direct O&M costs - November, 1975

Cost category	Subsystem				Plant total
	Electrical	Heating	Cooling	PTC	
1. Fuel	$15,569	$ 6,300	$ 0	$ 0	$21,869
2. Contract maint.	9,539	0	0	0	9,539
3. Direct labor +OH	3,620	2,534	0	1,086	7,240
4. Plant burden	1,401	697	0	199	2,297
5. Direct material	2,696	1,996	0	0	4,692
6. Miscellaneous	50	40	0	10	100
Totals	$ 32,875	$ 11,567	$ 0	$1,295	$ 45,737

Table II-2. Direct O&M costs - December 1975

Cost category	Subsystem				Plant total
	Electrical	Heating	Cooling	PTC	
1. Fuel	$ 16,994	$12,606	$ 0	$ 0	$29,600
2. Contract maint.	5,349	0	0	0	5,349
3. Direct labor +OH	3,668	2,568	0	1,101	7,337
4. Plant burden	2,961	1,981	0	670	5,612
5. Direct material	700	0	581	0	1,281
6. Miscellaneous	32	26	0	6	64
Totals	$ 29,704	$17,181	$ 581	$1,777	$49,243

Table II-3. Direct O&M costs - January 1976

Cost category	Subsystem				Plant total
	Electrical	Heating	Cooling	PTC	
1. Fuel	$ 17,233	$16,683	$ 0	$ 0	$33,916
2. Contract maint.	8,660	0	998	0	9,658
3. Direct labor +OH	4,056	2,840	0	1,217	8,113
4. Plant burden	4,218	3,057	0	826	8,101
5. Direct material	1,555	855	765	0	3,175
6. Miscellaneous	286	229	0	57	573
Totals	$ 36,009	$23,664	$ 1,763	$2,100	$63,536

Table II-4. Direct O&M costs - February, 1975

Cost category	Subsystem				Plant total
	Electrical	Heating	Cooling	PTC	
1. Fuel	$ 16,182	$ 11,650	$ 0	$ 0	$ 27,832
2. Contract maint.	4,731	0	0	0	4,731
3. Direct labor +OH	4,532	3,172	0	1,360	9,064
4. Plant burden	2,162	1,215	0	381	3,759
5. Direct material	1,190	490	0	0	1,680
6. Miscellaneous	0	0	0	0	0
Totals	$ 28,797	$ 16,528	$ 0	$ 1,741	$ 47,066

Table II-5. Direct O&M costs - March, 1976

Cost category	Subsystem				Plant total
	Electrical	Heating	Cooling	PTC	
1. Fuel	$ 16,567	$ 8,621	$ 0	$ 0	$ 25,188
2. Contract maint.	6,203	845	0	0	7,048
3. Direct labor +OH	4,261	2,983	0	1,278	8,522
4. Plant burden	1,418	628	0	180	2,226
5. Direct material	2,497	1,797	465	0	4,759
6. Miscellaneous	250	200	0	50	500
Totals	$ 31,196	$15,074	$ 465	$ 1,508	$ 48,243

Table II-6. Direct O&M costs - April, 1976

Cost category	Subsystem				Plant total
	Electrical	Heating	Cooling	PTC	
1. Fuel	$ 15,367	$ 3,974	$ 0	$ 0	$ 19,341
2. Contract maint.	5,761	4,047	1,211	0	11,019
3. Direct labor +OH	4,047	2,833	0	1,214	8,095
4. Plant burden	2,765	1,311	0	428	4,503
5. Direct material	1,568	868	651	0	3,087
6. Miscellaneous	0	0	0	0	0
Totals	$ 29,508	$13,033	$ 1,862	$ 1,642	$ 46,045

Table II-7. Direct O&M costs - May, 1976

Cost category	Subsystem				Plant total
	Electrical	Heating	Cooling	PTC	
1. Fuel	$ 16,273	$ 1,836	$ 0	$ 0	$ 18,109
2. Contract maint.	7,031	114	97	0	7,242
3. Direct labor +OH	5,044	2,896	635	1,513	10,088
4. Plant burden	1,952	855	180	286	3,274
5. Direct material	1,234	454	244	0	1,933
6. Miscellaneous	250	164	36	50	500
Totals	$ 31,784	$ 6,320	$ 1,193	$ 1,849	$ 41,146

Table II-8. Direct O&M costs - June, 1976

Cost category	Subsystem				Plant total
	Electrical	Heating	Cooling	PTC	
1. Fuel	$ 20,280	$ 13,966	$ 0	$ 0	$ 34,246
2. Contract maint.	3,688	0	0	0	3,688
3. Direct labor +OH	3,296	1,162	1,145	989	6,593
4. Plant burden	1,901	317	675	289	3,181
5. Direct material	996	118	1,732	0	2,846
6. Miscellaneous	0	0	0	0	0
Totals	$ 30,161	$ 15,563	$ 3,552	$ 1,278	$ 50,554

Table II-9. Direct O&M costs - July, 1976

Cost category	Subsystem				Plant total
	Electrical	Heating	Cooling	PTC	
1. Fuel	$ 21,297	$ 12,473	$ 0	$ 0	$ 33,770
2. Contract maint.	4,451	0	0	0	4,451
3. Direct labor +OH	4,524	1,611	1,556	1,357	9,048
4. Plant burden	1,958	381	823	340	3,502
5. Direct material	1,301	240	2,333	0	3,874
6. Miscellaneous	250	75	125	50	500
Totals	$ 33,781	$ 14,780	4,837	1,747	$ 55,145

Table II-10. Direct O&M costs - August, 1976

Cost category	Subsystem				Plant total
	Electrical	Heating	Cooling	PTC	
1. Fuel	$ 22,056	$ 16,262	$ 0	$ 0	$ 38,318
2. Contract maint.	5,451	0	998	0	6,449
3. Direct labor +OH	3,511	1,225	1,233	1,053	7,023
4. Plant burden	1,900	313	672	292	3,176
5. Direct material	2,917	887	4,769	0	8,573
6. Miscellaneous	0	0	0	0	0
Totals	$ 35,835	$ 18,687	7,672	1,345	$ 63,539

Table II-11. Direct O&M costs - September, 1976

Cost category	Subsystem				Plant total
	Electrical	Heating	Cooling	PTC	
1. Fuel	$ 21,190	$ 10,081	$ 0	$ 0	$ 31,271
2. Contract maint.	3,060	106	213	0	3,379
3. Direct labor +OH	4,011	1,419	1,389	1,203	8,023
4. Plant burden	1,963	396	844	334	3,538
5. Direct material	839	56	1,195	0	2,090
6. Miscellaneous	0	0	0	0	0
Totals	$ 31,064	$ 12,058	$ 3,641	$ 1,538	$ 48,301

Table II-12. Direct O&M costs - October, 1976

Cost category	Subsystem				Plant total
	Electrical	Heating	Cooling	PTC	
1. Fuel	$ 17,039	$ 5,239	$ 0	$ 0	$ 22,278
2. Contract maint.	3,120	811	2,621	0	6,552
3. Direct labor +OH	5,357	3,079	671	1,607	10,715
4. Plant burden	2,316	846	187	304	3,653
5. Direct material	848	137	111	0	1,097
6. Miscellaneous	0	0	0	0	0
Totals	$ 28,681	$ 10,113	$ 3,590	$ 1,911	$ 44,295

Appendix III

Boiler Fuel Consumption Model

A mathematical boiler model has been devised to determine the boiler fuel consumption for months when fuel data was unavailable. This model predicts the fuel consumed by the boiler(s) from monthly DAS measurements of the total boiler(s) output.

The boilers at the JCTE site are fire-tube, hot-water boilers having a rated full-load of 13.4 MBtu per hour (3.9 MW). Unless a boiler is bypassed, primary hot water continuously flows through it. The construction of a fire-tube boiler is such that the boiler shell inner walls are maintained at the temperature of the boiler water while the endplates are heated by the combustion gases.

The mathematical boiler model is described by two terms. The first term, constant loss, results mostly from heat losses from the boiler's shell. This shell is held at a relatively constant temperature by the primary hot water flowing through the boiler. The second term, constant firing efficiency, results from a fixed percentage of the combusted fuel's heat content being transfered to the boiler water. The firing efficiency is relatively constant due to boiler mechanisms which carefully regulate the fuel/air mixture and due to boiler controls which only allow firing at rates greater than 30% full-load. The boiler model is expressed by the equation:

$$BO = (m_f)(HV)(F) - (L)(T)(N) \qquad (1)$$

where BO is the DAS measurement of boiler output for the time period T.

m_f is the constant boiler firing efficiency

HV is the higher heating value of one gallon of fuel oil

F is the gallons of fuel oil consumed in the time period T

L is the constant boiler loss rate,

and N is the number of boilers connected into the primary loop during time interval T.

Note that the boiler firing efficiency is different from the boiler operating efficiency which includes shell losses.

Numerical values for the two terms of the boiler model were determined from DAS measurements and boiler fuel measurements. From DAS measurements of idle boiler PHW heat, the constant loss term was found to be approximately 100 kBtu per hour. Using a regression analysis based on eq. (1) and specific periods of boiler output and boiler fuel data when uninterrupted DAS and fuel data were available, the average firing efficiency was determined to be 84%. Once the firing efficiency and constant loss terms are known, the boiler fuel consumption and boiler operating efficiency can be determined for any period in which boiler output data is available.

The manufacturer's data sheet which describes boiler part-load operating efficiency is in agreement with this model. The model predicts operating efficiencies of 83.3% at 100% load and 82.0% at 30% steady-state load. These values are within 1% of the typical performance curve given by the manufacturer.

Computation of boiler fuel consumption using the model requires only data for the total boiler output and the duration that the boiler(s) were valved into the primary loop (generally this is all or none of a month). To compute fuel consumption, the boiler(s) loss rate is multiplied by the duration of time that each boiler was "valved in" and added to the measured total boiler(s) output. This quantity is divided by the boiler firing efficiency and the fuel's heat content. This computation is represented by the following rearrangement of equation (1):

$$F = \frac{BO + [L]\,[T]\,[N]}{[HV]\,[m_f]}, \text{ or}$$

$$F(\text{gallons}) = \frac{BO(\text{Btu}) + [100\ \text{kBtu/h}]\,[T(\text{hours})][N]}{[.84]\,[HV(\text{Btu/gallon})]}$$

The <u>operating efficiencies</u> of the boiler(s) are determined by dividing the measured boiler output by the fuel consumption times the fuel heat content. Measured fuel consumption data is used when available, however, when measured data is not available the boiler model is used to determine fuel data. Due to the constant loss term, the monthly <u>operating efficiency</u> of the boiler(s) may drop below 80% during low output months.

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16. ABSTRACT *(A 200-word or less factual summary of most significant information. If document includes a significant bibliography or literature survey, mention it here.)* Under the sponsorship of the Department of Housing and Urban Development (HUD), the National Bureau of Standards (NBS) has gathered engineering and economic data from an operating diesel total energy plant which supplies all electrical power, hot water, and chilled water to a 485-unit apartment/commercial building complex in Jersey City, New Jersey.

Engineering data has been continuously collected since April 1975 by a data acquisition system (DAS) which monitors approximately 200 sensors located in the plant and site buildings. In this report, data for a one-year period from November 1975 through October 1976 is presented. Electrical and thermal demands by the site and plant equipment efficiencies have been determined from this data and are reported. Reliability data is also reported.

Relative fuel savings by the total energy plant have been determined from the engineering data. Adjustments were performed to compensate for the malfunctioning absorption chillers. Calculations indicate that an alternative conventional central plant using purchased electrical power,oil-fired boilers, and absorption chillers would have required 17.3% more fuel than required by the JCTE plant as adjusted. These savings correspond to 160,000 gallons (606 m^3) of fuel oil annually. Minor design modifications are suggested in this report which would improve the JCTE plant performance an additional 5.7%. If the JCTE plant chillers were properly adjusted and the suggested minor modifications were performed, the above alternative conventional plant would have consumed 24.5% more fuel oil annually.

Economic data describing the capital, operating, owning, and maintenance costs during the one-year period are also presented. Unit costs of electrical, heating and cooling energy commodities are determined and compared to conventionally-supplied energy unit costs.

17. KEY WORDS *(six to twelve entries; alphabetical order; capitalize only the first letter of the first key word unless a proper name; separated by semicolons)*

Absorption chillers; boiler performance; central utility plant; diesel engine performance; engine-generator efficiency; heat recovery; total energy systems.

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