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FEASIBILITY STUDY—FUEL CELL COGENERATION IN A
WATER POLLUTION CONTROL FACILITY

Volume 1: Final Report

February 1980

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Gilbert/Commonwealth
Engineers/Consultants
Reading, Pennsylvania

U. S. DEPARTMENT OF ENERGY

Division of Industrial Energy Conservation

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FEASIBILITY STUDY FUEL CELL COGENERATION IN A WATER POLLUTION CONTROL FACILITY

VOLUME 1

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ABSTRACT

Gilbert/Commonwealth, in association with Public Service Electric and Gas Company, the Bergen County Utilities Authority and United Technologies Corporation, conducted a conceptual design study for the U.S. Department of Energy to investigate the technical and economic feasibility of a cogeneration fuel cell power plant operating in a large water pollution control facility. In this particular application, the fuel cell power plant would use methane-rich digester gas from the water pollution control facility as a fuel feedstock to provide electrical and thermal energy.

Several design configurations were evaluated. These configurations were comprised of combinations of options for locating the fuel cell power plant at the site, electrically connecting it with the water pollution control facility, using the rejected power plant heat, supplying fuel to the power plant, and for ownership and operation.

A configuration was selected which met institutional/regulatory constraints and provided a net cost savings to the industry and the electric utility. The displacement of oil and coal resulting from the Bergen County Utilities Authority application was determined.

A demonstration program based on the selected configuration was prepared to describe the scope of work, organization, schedules, and costs from preliminary design through actual tests and operation.

The potential market for nationwide application of the concept was projected, along with the equivalent oil displacement resulting from estimated commercial application.

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EXECUTIVE SUMMARY

The U.S. Department of Energy (DOE) has undertaken several conceptual design studies to determine the technical and economic feasibility of utilizing fuel cell power plants for industrial cogeneration applications. The objective of this effort was to establish the practicality of pursuing a phased engineering program, similar to that already in progress for an electric utility application, culminating in a fuel cell power plant cogeneration demonstration.

One of these studies addressed the integration of fuel cell power generation with a large water pollution control facility and electrical grid system. The study, under the direction of Gilbert/Commonwealth (G/C), is specifically focused on application of the United Technologies Corporation (UTC) 4.5 MWe Utility (fuel cell) Demonstrator Power Plant to the Bergen County Utilities Authority (BCUA) water pollution control facility located in Little Ferry, New Jersey. Methane-rich gas from the anaerobic digestion of raw sewage provides a fuel feedstock for the power plant. In turn, heat rejected from the fuel cell power plant is used to sustain high levels of bacterial action in the digesters (which have an optimum operating temperature of 95°F) and satisfy other facility heat requirements. The electrical output of the fuel cell power plant is fed to the Public Service Electric and Gas Company (PSE&G) power grid serving the BCUA facility.

This report presents the methodology and conclusions from which a decision can be made to proceed with the next phase of the fuel cell cogeneration demonstration program. Specific study results show that the UTC 4.5 MWe Utility Demonstration Power Plant is operationally compatible with the BCUA water pollution control facility. No institutional, environmental or regulatory constraints were found which would prohibit the installation or operation of the power plant. Further, the fuel cell power plant could deliver electric energy (30×10^6 kWhr/yr) equivalent to about half the annual needs of the water pollution control facility and provide over ninety per cent (approximately 70×10^9 Btu) of its annual thermal energy requirements while

using all of the facility's digester gas. Sixty-five percent of the energy in the digester gas is used to produce this electrical and thermal energy. This is accomplished with essentially no changes to the 4.5 MWe Utility Demonstrator Power Plant's present design or operating characteristics.

A detailed economic comparison was conducted which indicated the cost savings to be realized if the cogeneration fuel cell power plant was used in place of the conventional means of supplying electrical and thermal energy to the facility. For example, if the cost of the UTC supplied fuel cell power plant equipment were \$650/kW (uninstalled, in 1982 dollars, \$535/kW in 1979 dollars), a total levelized savings of \$589,000 per year (1982 dollars) could be realized. Uninstalled break-even capital costs for the fuel cell power plant equipment are \$1258/kW (1979 dollars) or \$1488/kW (1979 dollars), depending on whether, respectively, PSE&G or BCUA owns the power plant.

In addition to these economic considerations, this specific cogenerating fuel cell power plant would displace 26,000 barrels of No. 6 fuel oil (on-peak) and 5,900 tons of coal (off-peak) each year.

Based on the favorable results of this conceptual design analysis, continuation of this project to the next phase, a Preliminary Engineering Design Study, under the management of PSE&G is recommended.

SECTION 1.0
FUEL CELL POWER PLANT COGENERATION IN A
WATER POLLUTION CONTROL FACILITY

1.1 BACKGROUND

First generation phosphoric acid fuel cell power plants offer industrial and institutional users of electricity three distinct advantages. First, they are particularly attractive for decentralized, on-site power generation applications. This feature is due to their modularity (fuel cell power plants can be fabricated in a range of sizes without penalties to plant economics or performance) and to their high conversion efficiency over a power output range of 25% to 100%. In addition, the fuel cell has demonstrated emissions characteristics which are approximately one-tenth (1/10) the present federal standards and, therefore, is a "good neighbor" in applications at or near load centers.

Second, the fuel cell power plant is a prime candidate for cogeneration. Effective use of the rejected heat from the fuel cell power plant can increase overall energy conversion efficiency to over 80% in some applications (Ref. 1.1).

Third, the phosphoric acid fuel cell power plant is being developed to operate with a range of liquid and gaseous fuels (including gasified coal). Fuel processing of methane (as well as liquid hydrocarbons) to produce hydrogen for the fuel cell reaction has already been demonstrated. As a result, the possibility exists to use industrial by-product fuels, which otherwise might be flared or used at less than desired efficiencies.

Many studies have been performed on generic commercial applications of fuel cell power plants. Most of these studies have focused on identifying major operating characteristics of fuel cells and on establishing the basic technical feasibility of fuel cell electric power generation. The next step in the commercialization of fuel cell technology is the demonstration of engineering-scale fuel cell power plants in various specific commercial environments. In the electric utility sector, this requirement will initially be met by the

4.5 MWe Utility Demonstrator Power Plant scheduled for operation in 1980. In the industrial market, where many potential applications have been identified, demonstration programs for specific uses of fuel cell power plants must now be undertaken. To initiate this effort, the U.S. Department of Energy (DOE) has sponsored four engineering studies to determine the technical and economic feasibility of fuel cells in industrial cogeneration.

One of these studies addresses the integration of fuel cell power generation with a large water pollution control facility and an electrical grid. Water pollution control facilities, using anaerobic digestion of sewage solids, represent a potentially ideal application of fuel cell cogeneration. Pollution control facilities yield significant quantities of by-product methane gas while requiring both electricity and low grade heat for process operation. The study, performed by a contractor team under the direction of Gilbert/Commonwealth (G/C)*, is specifically focused on application of the United Technologies Corporation (UTC) 4.5 MWe Utility (fuel cell) Demonstrator Power Plant (FCPP) to the Bergen County Utilities Authority (BCUA) water pollution control facility (WPCF) located in Little Ferry, New Jersey (Figure 1.1). Methane-rich gases from the anaerobic digestion of raw sewage would provide a fuel feedstock for the FCPP. In turn, heat rejected from the FCPP would be used to sustain high levels of bacterial action in the digesters, which have an optimum operating temperature of 95°F. The electrical output of the FCPP would be connected to the Public Service Electric and Gas Company (PSE&G) power grid serving the BCUA facility.

1.2 PROGRAM OBJECTIVE, SCOPE, AND STUDY CONSTRAINTS

The overall objective of the study described in this report is to determine the technical and economic feasibility of commercial fuel cell cogeneration in a WPCF with anaerobic digesters. This specific study, therefore, constitutes the first phase in a demonstration program aimed at proving the viability of combining fuel cell power plant cogeneration with utilization of by-product fuels.

*Appendix A is provided for the definition of terms, abbreviations and symbols.

FIGURE 1.1
FUEL CELL POWER PLANT COGENERATION
IN A WATER POLLUTION CONTROL FACILITY

Achievement of this first phase objective was accomplished through completion of four major activities constituting the scope of work:

- a. Evaluation of Installation Options - Identification and analysis of various power plant locations, electrical connections, fuel supplies, rejected heat utilization, operation, and ownership.
- b. Power Plant Configuration - Selection of a preferred conceptual design based on analysis of the above options. (Includes modification to the fuel cell power plant and the industrial facility to achieve the best performance and economics.)
- c. Potential Benefits - Assessment of the operational and economic benefits of a fuel cell power plant cogeneration application at a water pollution control facility.
- d. Demonstration Program Plan - Development of a comprehensive program plan (scope of work, schedules, costs, and organizational responsibilities) for implementation of the design, construction, installation, and operation of a cogenerating fuel cell power plant in the water pollution control facility.

To obtain results consistent with other parallel studies of industrial cogeneration applications, the Department of Energy stipulated the following uniform set of FCPP study constraints:

- a. "Fuel cell power plant physical characteristics should be based on the existing definition of the 4.5 MWe Utility Demonstrator Power Plant established under DOE Contract EX-76-C-03-2102." As a result of this constraint, the Demonstrator Model Specification, FCS-0493, prepared for Contract EX-76-C-01-2102 by Power Systems Division of United Technologies Corporation, dated 15 March 1978, was used as the primary source of information for the definition of the FCPP.

Additional detailed information was obtained from United Technologies through discussions with their personnel and through the use of UTC prepared Demonstrator Component Design Requirements Documents (CDRs) and drawings.

- b. "Thermal characteristics should be based on the 4.5 MWe Utility Demonstrator Power Plant with those modifications needed to recover heat for the particular installations." This constraint allows for alteration of the water/glycol loop of the power plant for adaptation to specific cogeneration use.
- c. According to DOE, all FCPP costs should be based on those shown in the description of the fuel cell power plant, Section 1.3.2. However, the results of the study should not be constrained by these costs. Rather, the UTC supplied equipment cost was 'backed out' and then compared with the given cost to determine whether it is feasible to consider a fuel cell power plant for the specific application.

In addition to the above Department of Energy study constraints, the project team imposed a fourth constraint related to facility operation - that the cogeneration installation could not interfere with the present WPCF operating modes. The facility has to continue operation even during planned and unplanned shutdowns of the FCPP due to the critical function of the industry within the community and the environmental damage which can result when the WPCF operation is interrupted. Allowances were made to permit switching from operation with cogeneration to operation without. Supporting the reasoning for this constraint is that this feasibility study is merely one step of a program leading to an actual demonstration. As a result, all modifications considered that the FCPP would be removed from the industry after the conclusion of the program. The placement of the FCPP within the industry must, therefore, be accomplished with minimum impact.

Finally, no WPCF processes were altered to make the study generic or to improve the potential benefits of the cogeneration installation. Therefore, results of the study show conservative estimates of potential benefits of the cogeneration installation.

1.3 DESCRIPTION OF THE 4.5 MWe DEMONSTRATOR (FUEL CELL) POWER PLANT

Background: A fuel cell is an electrochemical device in which the energy stored in the chemical bonds of a conventional (hydrocarbon) fuel is converted directly and efficiently into low voltage, direct current electrical energy. Fuel cell power generation thus bypasses the normal combustion energy conversion methods and the associated mechanical-to-electrical processes with their inherent mechanical complexity and energy losses (Ref. 1.2). Fuel cell power plants can accept a wide range of fuel feedstocks while cleanly and efficiently producing electric power. This fuel use versatility combined with inherent sizing flexibility, minimal environmental impact (when compared to conventional combustion systems) and the potential for cogeneration (rejected heat utilization) make fuel cells a promising option for a wide range of commercial applications.

History and Status: Although development of fuel cells for commercial use is relatively recent, the basic concept dates to 1801 when Humphrey Davies first experimented with the use of electrochemical reactions. In 1839, William Grove began work which resulted in his acknowledgement as originator of the fuel cell (Ref. 1.2). Between the 1800's and the present, there was little incentive to develop commercial fuel cell technology. Cheap, relatively plentiful fuel was available so that the savings due to high efficiency did not offset development and capital cost requirements. It was during the space program that fuel cells were developed to furnish convenient, on-board electric power for manned space missions. United Technologies Corporation (UTC), continued its efforts beyond the space program with the goal of bringing about development of the technology for large scale commercial application.

In 1967, UTC in cooperation with several gas utilities (including PSE&G) initiated the "TARGET" program focused on demonstrating fuel cell technology in commercial applications. During 1976-1977, UTC successfully operated an electric utility sponsored 1 MWe pilot plant version of a planned multi-MWe fuel cell power plant. This pilot plant, located at the manufacturer's facility in South Windsor, Conn. used naphtha or methane fuel to produce AC electrical power which was fed into the local electric grid. The next step in this effort is to demonstrate a larger FCPP in a commercial electric utility environment. The U.S. Department of Energy and the Electric Power Research

Institute (EPRI) are jointly funding the design, fabrication and testing, in New York City, of a 4.5 MWe Utility Demonstrator Power Plant module of the multi-MWe power plant. Operation is scheduled for 1980 (Ref. 1.3). Besides DOE and EPRI, the "host" utility, Consolidated Edison of New York, Inc. and UTC are supporting the project.

As stated in Section 1.2, the FCPP used in this study is based on the 4.5 MWe Utility Demonstrator Power Plant, but adapted for cogeneration. Appendix B describes the relevant characteristics of the 4.5 MWe Utility Demonstrator Power Plant. Further information can be obtained from the UTC prepared Demonstrator Power Plant Specification (Ref. 1.4).

The use of the 4.5 MWe Utility Demonstrator Power Plant imposes some compromises on portions of a study such as this stemming from the fact that the power plant was designed for dispersed electric utility operation and, therefore, was not optimized thermally, electrically, or operationally for industrial cogeneration applications. In addition, the Demonstrator represents early and, therefore, immature technology which imposed design compromises that development and operating experience will alter.

Adaptability for Cogeneration: A significant characteristic of the 4.5 MWe Utility Demonstrator Power Plant is its ability to be located at or near major load centers. This is due to:

- a. Emissions and particulate release less than existing or projected federal standards. The fuel cell process itself is noiseless, with the power plant noise level set by ancillary equipment (air and fuel processing; cooling fan, if a dry cooling tower is used).
- b. Modular construction to match load requirements.
- c. High conversion efficiency at all load conditions above 25% design capacity.

- d. Factory-produced, palletized (modular) assemblies which are truck-transportable, providing increased siting flexibility, ready availability, and short construction lead-times.
- e. Adaptability to using various fuel feedstocks.

The characteristic of being able to locate at or near major load centers permits the possible integration of electric power production with both cogeneration and industrial by-product utilization, if fuels of adequate quantity and quality are available. Several operating characteristics of the 4.5 MWe Utility Demonstrator Power Plant must be defined for its consideration in a cogeneration application. These characteristics are fuel requirements, net electrical power output, and thermodynamic operating conditions.

Fuel Requirements and Net Electrical Power Output: Fuel requirements can be related to electrical power output through the power plant heat rate curve:

$$\text{Fuel Flow} = \frac{(\text{Electrical Power Output})(\text{Heat Rate of FCPP})}{\text{Fuel Heating Value}}$$

Figure 1.2 is the heat rate curve of the 4.5 MWe Utility Demonstrator Power Plant, fueled by methane, based on methane's lower heating value. An important characteristic of the heat rate curve is a step improvement (decrease) in heat rate when the electric output power is reduced to 30% of design capacity. This change is attributable to the method of supplying process air to the Demonstrator Power Plant. A large turbocompressor, sized for 100% design flow, provides air at the higher power settings. As the electric load is reduced, the turbocompressor uses proportionately more energy causing the heat rate to increase at power levels below 60-70% design. A small turbocompressor replaces the larger unit to provide process air at 30% power, reducing the auxiliary fuel demand and, thus, reducing the heat rate.

The heat rate curve, Figure 1.2, is based on a methane heating value since the FCPP in this study will use the methane-rich WPCF anaerobic digester produced gas for fuel. UTC has estimated that the performance of fuel cells using the

FIGURE 1.2
4.5 MWe FUEL CELL POWER PLANT
HEAT RATE (LHV)-METHANE FUEL

digester gas (65% CH₄, 35% CO₂ by volume) would be the same as performance using pure methane. In a fuel cell power plant operating on natural gas (pure CH₄), the overall reformer and shift converter reaction at 100% efficiency is:

Four moles of H₂ are produced for each mole of CO₂ or the relative partial pressure of H₂ in the products is 0.8.

With 65% CH₄ digester gas:

There are 2.6 moles of H₂ for each mole of CO₂ or the relative partial pressure of H₂ in the products is 0.72.

Based on UTC test data, the difference in relative partial pressures of hydrogen between the pure CH₄ case and the 65% CH₄ digester case will have a negligible effect on fuel cell performance, i.e., heat rate.

It should be noted that the electrical power output of the 4.5 MWe Utility Demonstrator Power Plant is dependent upon being connected to the grid. The 4.5 MWe Utility Demonstrator Power Plant, by design, is not self-regulating, but depends on grid conditions to control its phasing of electric power since the unit is designed for utility use. Isolated operation (self-regulating) capability would be desirable since industries being served by a FCPP cogeneration installation would prefer to have power and heat even when the grid fails.

Thermodynamic Operating Conditions: Table 1.1 lists the thermodynamic characteristics from which the 4.5 MWe Demonstrator Power Plant cogeneration potential can be determined. This table defines the FCPP heat sources, their quantities, and their temperature limitations at design power. The heat available from the Water Treatment System Heat Exchanger, No. 609, is intermittent and so cannot be considered for cogeneration. However, equipment

must be sized to reject this water treatment heat. Also, there is no heat exchanger to reclaim the turbine exhaust heat in the present design. The available pressure drop in the exhaust is approximately 1 in. H₂O, which dictates a very large heat exchanger. This would not be practical without a redesign of the entire air supply system. As a result, a maximum total of 18.8×10^6 Btu/hr is available for cogeneration at design power. Figure 1.3 depicts the characteristics of the Demonstrator Power Plant heat exchangers at capacity levels less than design. The arrangement of the heat exchangers for the Demonstrator Power Plant is shown in Figure 1.4.

TABLE 1.1
FUEL CELL POWER PLANT DESIGN POWER
REJECTED HEAT SOURCES

	<u>UTC Hex No.</u>	<u>Heat Rejected 10⁶ Btu/hr</u>	<u>T_{°F}In</u>	<u>T_{°F}Out</u>
1. Water/Glycol Cooling Stream				
Source Heat Exchanger				
Anode Exhaust Steam Condenser	406	2.43	≤ 120	-
Cathode Exhaust Steam Condenser	407	6.82	≤ 120	-
Anode Process Fuel	318	2.4	≤ 120	-
Cell Stack Cooling	405	7.14	-	≤ 240
Water Treatment System	609	<u>1.65</u>	-	-
Total Water/Glycol Cooling Stream		20.44		
2. Turbine Exhaust Stream	No Existing			
46,080 lb/hr, T _{Hot} = 370°F, T _{Cold} = 220°F	Hex.	1.76	-	-
Total Fuel Cell Power Plant		<u>22.20</u>

FIGURE 1.3
FUEL CELL POWER PLANT HEAT REJECTION CHARACTERISTICS

FIGURE 1.4
4.5 MWe UTILITY DEMONSTRATOR
HEAT EXCHANGERS ARRANGEMENT

Industry Selection: The industry selected for a study of the technical and economic feasibility of a cogenerating FCPP is a large secondary treatment WPCF operating with anaerobic digesters. This application was selected because of its requirements for electricity and low grade thermal energy, as well as the capability of the WPCF to produce a methane-rich by-product fuel (from anaerobic digestion of sewage solids) which can be used in the FCPP without revision to the FCPP's fuel processing unit.

Selection of the particular WPCF was based on matching the WPCF by-product fuel production with the design requirements for methane fuel of the FCPP. The selected WPCF, operated by the BCUA, is located in Little Ferry, New Jersey, and serves a heavily urbanized area of northeastern New Jersey adjacent to New York City. At present, the facility, which services 43 municipalities is designed to treat 50×10^6 gpd of municipal sewage by a process of screening, grit removal, solids separation, aeration, and chlorination.

Site Description: The facility site, which is located at the foot of Mehrhof Road on the west bank of the Hackensack River, consists of 150 acres of low land having a mean elevation of 7 feet in the New Jersey Meadowlands area. The site is across the river from PSE&G's Bergen Generating Station. Figure 1.5 shows the general location in New Jersey and Figure 1.6 shows the exact location within the Greater New York metropolitan area. The WPCF itself occupies approximately 17 acres of the site, Figure 1.7, and is serviced by road access from the communities of Little Ferry and Moonachie, New Jersey. Electrical power to the site is presently supplied with a 4 kV primary service from the PSE&G Little Ferry 13 kV circuit that utilizes six 500 kVa 13/4 stepdown transformers. This service is soon to be replaced with a 26 kV dual line service. Fuel oil storage for emergency power generation and auxiliary heating is in the form of underground storage tanks of 140,000 gallon capacity. Fuel oil is received by truck deliveries.

FIGURE 1.5
GENERAL LOCATION MAP

GENERAL PLAN
0 80 160 240 FT.

LEGEND
 — EXISTING FACILITIES
 — EXPANSION UNDER CONTRACT 87
 P-9 BORING LOCATION AND NUMBER
 PN PLANT NORTH

NOTE:
FOR BORING LOGS SEE SPECIFICATIONS

FIGURE 1.7
BCUA WATER POLLUTION
CONTROL FACILITY

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Industrial Process Description (Figure 1.8): Raw sewage enters the facility by gravity flow through 8 ft. diameter trunk sewer lines about 30 feet underground. The raw sewage entering is more than 99% water and less than 1% of residential and industrial solids. After screening, blending, and grit removal, the raw sewage is pumped to primary settling tanks, which are sized for a raw sewage retention time of approximately one hour at design flow. Sludge, which settles to the bottom of the primary settling tanks, is conveyed by drag chain collectors to sludge hoppers at the head of each tank. The primary sludge is then pumped to sludge thickening tanks. Grease and scum are skimmed from the surface of the sewage waters in the primary settling tanks and stored in skum tanks for use in the anaerobic digestion process. The effluent from the primary settling tanks then flows by gravity to the aeration tanks. Here the sewage is mixed with activated sludge (which is comprised of living organisms) returned from the settled material in the final settling tanks. Air is bubbled through this mixture to provide oxygen for the organisms to degrade the organic matter in the sewage. Effluent from the aeration tanks is fed by gravity to the secondary settling tanks where the suspended particles are removed, leaving the clarified effluent low in suspended solids and dissolved organic materials. This effluent is then disinfected by chlorination and discharged to the Hackensack River.

Solids collected in the secondary settling tank eventually are routed to the sludge thickening tanks to be mixed with the primary sludge. The resulting sludge, now 94% water, is pumped to the anaerobic digesters where digester gas is produced by a bacterial decomposition process. Retention time of the sludge in the digester tanks is approximately 15 days. The digested sludge is then pumped to holding tanks where it is finally removed offsite for disposal. Figure 1.9 depicts an approximate mass balance of the process for 50×10^6 gpd of raw sewage. Through this process, sludge from the thickening tanks is digested by anaerobic bacteria under carefully controlled conditions of time (15 day retention) and temperature (95°F). This anaerobic process yields a digester gas of approximately 65% methane and 35% carbon dioxide. Other components i.e. nitrogen, moisture etc. are also present in small amounts.

FIGURE 1.8
BERGEN COUNTY UTILITIES AUTHORITY
WATER POLLUTION CONTROL PLANT PROCESS

FIGURE 1.9
PROCESS MASS BALANCE

Digester Gas Production: The digester gas has a 550-650 Btu/scf heat content and is produced at an average rate of approximately 1.1×10^6 acfd. As shown in Figure 1.10, actual daily gas production was metered by BCUA during the first nine months of 1978. The monthly and cumulative average digester gas production for this period is shown in Table 1.2 (September's abnormally low gas production was due to a process upset which caused two of the digesters to go out of service. This is a rare occurrence, and happens only once or twice every five years).

TABLE 1.2
AVERAGE DAILY DIGESTER GAS PRODUCTION
JAN. 1978 - SEPT. 1978

<u>Month</u>	<u>Daily Flow (10^6 cfd)</u>	<u>Cumulative Average Daily Flow (10^6 cfd)</u>
January	1.050	1.050
February	1.179	1.115
March	1.191	1.138
April	1.219	1.158
May	1.134	1.154
June	1.058	1.138
July	.989	1.116
August	.935	1.093
September	.440	1.021

Discounting September, the cumulative average gas production was 1,093,000 acfd. BCUA estimated that by the projected cogeneration demonstration date (October 1982) an additional 300,000 cfd of sewer gas would be available. This increase would result from eliminating gas leakage through the present digester covers.

The fuel supply rate assumed for this study, shown in Figure 1.11, is therefore 300,000 cfd over the present production, resulting in a nominal gas supply of 1,400,000 cfd. The digester gas is available at 90 - 95°F and a pressure of several inches of water.

1-23/24

FIGURE 1.11
PROJECTED BCUA DIGESTER GAS PRODUCTION
JANUARY 1, 1982 - DECEMBER 31, 1982

1-25/26

FIGURE 1.10
BCUA DIGESTER GAS PRODUCTION
JANUARY 1, 1978 - SEPTEMBER 30, 1978

Digester Gas Quality: During the same nine month period, BCUA intermittently sampled and analyzed the digester gas for methane, carbon dioxide, and air content. The results for 60 different samples taken over the nine month period showed an average methane content of 64.4% (five samples were deleted because they fell outside the range of acceptable data scatter). An analysis of a single sample was also performed by United Technologies Corporation, East Hartford, Ct. and two samples by Gollub Analytical Service of Berkley Heights, N.J. These results showed a slightly lower methane content than BCUA (60%, 57%, and 63% methane respectively). A nominal methane concentration of 65% was selected as being most representative based on the high number of samples (60) at that percentage methane. The remaining portion of the digester gas is primarily carbon dioxide. Figure 1.12 shows a sulfur analysis of the digester gas. Total sulfur was low (≤ 3 ppm) and no H_2S was detected.

Present Gas Usage: At the present time the digester gas is being used with diesel fuel (90% digester gas, 10% diesel oil) to fire diesel engines which mechanically drive blowers that provide the air for water aeration. The heat recovered from the engines is used to provide heat for the anaerobic digesters and grease transport, supplemented by two boilers also fired by digester gas. The existing diesel engines can also drive emergency generators instead of the blowers in case there is an electric feeder failure.

Expansion of the Water Pollution Control Facility: The WPCF is now being expanded to treat up to 75 mgd of municipal sewage. During this expansion the digester roofs are being repaired to eliminate leakages of digester gas. As a result, the digester gas production capacity is expected to increase to approximately 1.4×10^6 cfd when the facility is completed in 1981.

Under the expansion plans the diesel engines will be replaced by electric motors and the digester gas diverted to supply two additional boilers and the two existing boilers whose rating is shown in Table 1.2. The replacing of the digester gas fueled diesel engines with electric motors seems questionable considering the present energy situation. However, when the expansion plan was formulated and design commenced approximately ten years ago, energy conservation considerations were not as critical as at the present time. Then, the diesel engines which drive the air compressors had been in operation for

FIGURE 1.12
BCUA MASS SPECTROMETRY/GAS CHROMATOGRAPHY ANALYSIS
Gollob Analytical Service

MOLININI-GOLLOB, INC.

47 INDUSTRIAL ROAD, BERKELEY HEIGHTS, NEW JERSEY 07922 • TEL. (201) 464-3331

TO: J.I. Padula
Public Service Electric
& Gas Company
200 Boyden Avenue
Maplewood, N.J. 07040

G.A.S. REPORT No. 40467A

Date Reported: 5/5/78
Date Requested: 3/31/78
P. O. No. 639755

MATERIAL SUBMITTED: 1 -125ml glass gas sample of sewer gas

INFORMATION REQUESTED: Mass Spectrometry/Gas Chromatography Analysis

NOTEBOOK REFERENCE: NB PS 488 page 71

RESULT OF INVESTIGATION

<u>Constituents</u>	<u>Concentration ppm Volume/Volume</u>
Carbonyl Sulfide	1.7
Methyl Mercaptan	0.1
Methyl Disulfide	0.2
Unidentified*	0.1

No other sulfur compounds were detected.

*Possibly methyl sulfide or ethyl mercaptan.

Mass Spectrometry results were reported 4/27/78.

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By

GOLLOB ANALYTICAL SERVICE

twenty-five years. The number of maintenance actions was increasing to the extent that it was decided to install low maintenance electric motors in place of the diesel engines. Even though electric power would have to be purchased, the digester gas could be fired in boilers to raise steam so that the WPCF heat requirements could still be satisfied internally.

TABLE 1.3
BOILER CAPACITY

<u>Boiler</u>	<u>Boiler Hp Rating</u>	<u>Equivalent Btu/hr (10⁶)</u>
Existing	150	5.02
Existing	200	6.70
New	500	16.74
New	500	16.74

Facilities Heat Requirement: The boilers in Table 1.3 will produce heat for three major uses in the expanded WPCF. These are:

- To maintain a 95°F temperature in the anaerobic digesters at which the bacterial gas production process is sustained.
- To melt grease so that it can be easily transported to the digesters from the scum tanks. The grease is used as feed for the bacteria to increase gas production.
- To provide space heat to the buildings and facility.

All of these requirements will be satisfied in the expanded WPCF by the boilers except for some remote space heat requirements which will be satisfied by electric unit heaters. Table 1.4 lists the quantities of hot water heat requirements which can be satisfied by either the boilers or a water cooled cogenerating power plant. Figure 1.13 depicts the profiles resulting from these requirements. Excess digester gas which is not burned in the boilers for heating will be flared to the atmosphere.

MONTHLY
AVERAGE
HEAT
REQUIRED
 10^6 BTU/
HOUR

FIGURE 1.13
BERGEN COUNTY UTILITIES AUTHORITY
TOTAL HEAT REQUIREMENTS

TABLE 1.4
BERGEN COUNTY UTILITIES AUTHORITY
PROJECT HEAT REQUIREMENTS

Heat Required - 10^6 Btu/hr

<u>Month</u>	<u>Space Heat</u>	<u>Digester</u>	<u>Grease Melt</u>	<u>Total Required</u>
January	7.99	3.96	1.98	13.93
February	7.48	3.86	1.98	13.32
March	6.10	3.43	1.98	11.51
April	4.38	2.84	1.80	9.02
May	2.47	2.25	1.80	6.52
June	--	1.81	1.80	3.61
July	--	1.60	1.80	3.40
August	--	1.74	1.80	3.54
September	1.43	2.15	1.80	5.38
October	3.43	2.69	1.80	7.92
November	5.24	3.35	1.80	10.39
December	7.16	3.84	1.98	12.98

These requirements are based on information contained in the BCUA Sludge Management Facility Plan which was prepared as part of the contract for the expansion of the facility. The related information appeared as Table 17 in the Sludge Management Facility Plan and is reproduced here as Table 1.5. Some revisions were made to the quantities shown in Table 1.5 and are described in the next three paragraphs.

TABLE 1.5
BCUA SPACE AND DIGESTER HEATING REQUIREMENTS

<u>Month</u>	<u>Space Heat Required (10^6 Btu/hr)</u>	<u>Digester Heat Required (10^6 Btu/hr)</u>	<u>Total Required (10^6 Btu/hr)</u>	<u>Total Required (10^9 Btu/Mo)</u>
January	9.63	3.96	13.59	10.1
February	9.01	3.86	12.87	8.65
March	7.35	3.43	10.78	8.02
April	5.28	2.84	8.12	5.85
May	2.97	2.25	5.22	3.88
June	--	1.81	1.81	1.30
July	--	1.60	1.60	1.19
August	--	1.74	1.74	1.29
September	1.72	2.15	3.87	2.79
October	4.13	2.69	6.82	4.91
November	6.31	3.35	9.66	6.95
December	8.63	3.84	12.47	9.28

The digesters require varying amounts of heat throughout the year. The quantity of heat required at the present time and for the next several years is that shown in Table 1.5. The quantity of heat required in January was checked against existing data. The existing data show that the digesters receive heat in January from a 600 gpm water loop which drops an average of 9°F when passed through the digester heat exchangers. This yields 2.6×10^6 Btu/hr for the digesters. However, with this amount of heat the digesters cannot be maintained at 95°F but fall to the mid-eighties. It is estimated that the digesters must be furnished with an additional 1.4×10^6 Btu/hr to sustain them at 95°F. Improvements are now underway to accomplish this. With these improvements, the total heat requirement of the digesters is approximately 4.0×10^6 Btu/hr which agrees with Table 1.5.

Grease used for feeding the anaerobic bacteria is melted at 180°F, but is additionally heated to 200°F to account for heat losses in transporting it from the grease melting pots to the digesters. A test was conducted to quantify the amount of heat required to melt the grease and transport it. Data taken at one hour intervals from 4 p.m. to 11 a.m. Nov. 19, 1978 showed that the hot water heat source flowing at a rate of 130 gpm dropped an average of approximately 25°F in the grease pit heating loop. This amounts to 1.6×10^6 Btu/hr. The grease temperature, when added to the pits in solid form, was 50°F. The grease pits are presently being enlarged as part of the WPCF expansion program. As a result, there will be an increased heat loss to the atmosphere through the larger covers. It is anticipated that this heat loss will be an additional $.2 \times 10^6$ Btu/hr, bringing the total heat required for the next several years to 1.8×10^6 Btu/hr. It should be noted that this is the heat requirement expected for eight months of the year when the raw sewage temperature, which is the grease source, is 50°F. From December to March the raw sewage temperature drops to 35°F. During this time period 10% additional heat is needed to allow for the grease entering the scum tanks at 35°F which is the approximate temperature in winter of raw sewage in the primary settling tanks bringing the heat requirement to 1.98×10^6 Btu/hr.

The building and other facility space heat requirements, specified for the expanded facility, were also obtained from the BCUA Sludge Management Facilities Plan, Table 17. As expected these requirements vary with ambient temperature. The amounts, as shown in Table 1.5, include heat supplied by the hot water loop and by electric unit heaters which are used in remote parts of the facility where it is uneconomical to route the hot water loop. It is estimated that the electric heating amounts to 17% of the space heat requirements for each month shown. The space heat requirements satisfied by hot water heat, Table 1.4, are thus 17% less than that shown in Table 1.5.

Facility Electric Demand: The electric power requirements of the WPCF are projected to range from a high of 10 MWe during the winter to a low of 6 MWe for the summer period as shown in Table 1.6. This estimate which considers load diversity is based on an analysis of electric requirements of the facility expansion currently underway as well as the existing electric load.

The additional load to be installed under this expansion includes:

- a. 4-2500 hp electric motors in the blower building.
- b. 1490 kW for pumps in pump buildings 1 and 2.
- c. 900 kW for a new control building.
- d. 300 kW for lighting and transformer losses in the new 26 kV substation.

The existing load consists primarily of pumps, electric heating, and lighting. The blowers which are presently driven by dual-fuel diesel engines (digester gas/oil) will be replaced by electrically driven blowers.

TABLE 1.6
WPCF LOAD ESTIMATES

	<u>Installed kW</u>	<u>kW @ Peak Time</u>	<u>kW @ Low Demand Time</u>
26kV Sub. (Losses & Lights)		300	240
Control Building	918	510	400
Blower Building	7500	5625	3875
Pump Building #1	390	390	200
Pump Building #2	1100	1100	550
Existing Load Transfer	<u>2500</u>	<u>2300</u>	<u>800</u>
TOTAL	12408	10225	6065

Historical electric load data collected at the WPCF indicate:

- a. The peak electric demand consistently occurs between September and May and the off-peak occurs in the summer period.
- b. The electric load is dependent on the need for heat and the flow of sewage into the facility which is directly related to adverse weather conditions (i.e. rain and snow storms).

Figure 1.14 shows the estimated monthly peak load variation of the WPCF for an entire year. This curve is based on an analysis of the historical billing data of the facility which takes into account the additional equipment being installed under the expansion. The projected maximum and minimum loads of 10 MWe and 6 MWe respectively are not shown on Figure 1.14 because the analyzed billing data is based on an average of three highest monthly peak loads, giving a slightly lower estimate than the maximum of 10 MWe. The 6 MWe value represents the lowest possible load, which too, is not depicted on Figure 1.14. The annual electric energy requirement of the BCUA facility is estimated to be approximately 61×10^6 kWhr.

FIGURE 1.14
ESTIMATED BCUA LOAD DEMAND CURVE

FIGURE 1.15
26KV SERVICE
BERGEN COUNTY UTILITIES AUTHORITY
WATER POLLUTION CONTROL FACILITY

Figure 1.15 shows a simple one-line diagram of the 26 kV subtransmission circuits which will supply the new WPCF substation. The 26 kV supply is stepped down to 4 kV at the BCUA owned substation. The reliability of this service is extremely high. A momentary interruption of less than 30 seconds can occur if either one of the two circuits fails. Longer interruptions are most unlikely and can only happen if both circuits or substations fail at the same time.

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SECTION 2.0

EVALUATION OF INSTALLATION OPTIONS

In this section, the possible design configurations integrating the FCPP into the WPCF are described. These configurations differed by various options of installation: location of the FCPP, output voltage and electric connection of the FCPP, fuel supply, FCPP cooling/rejected heat utilization, ownership, and operation. Once all of the possible conceptual design configurations had been identified, they were screened by consideration of operating conditions, institutional factors, and capital cost aspects to develop several candidate conceptual designs for economic analysis.

2.1 POWER PLANT LOCATION

Options for locating the FCPP were based on the 4.5 MWe Utility Demonstrator Power Plant, Section 1.3, the interface and layout requirements of the WPCF and the electric grid, Section 1.4, as well as the overall study constraints, Section 1.2. Additionally, any potential location of the FCPP had to assure that there was no interference with existing underground piping and plans for WPCF expansion.

Two potential FCPP locations satisfied the above physical constraints and also were within the proximity of the facility's electrical, fuel supply and heat utilization interfaces. These locations are shown in Figures 2.1 and 2.2.

The layout shown in Figure 2.1 represents the most favorable location from the viewpoints of minimum heat loss, piping runs and auxiliary power requirements. This is due to the proximity of the FCPP to the Anaerobic Digester Building and Pump Building No. 1. Digester gas will be piped from the anaerobic digesters to the FCPP. Also, it is important that the FCPP be close to the Pump Building No. 1 because this is the site for heat exchange between the FCPP and the WPCF. Possible problems could develop for this site if additional equipment needs are identified or land needs for equipment laydown during construction are inadequate due to the proximity of the Hackensack Valley Trunk Sewer Line and the Hackensack River.

FIGURE 2.1
PLOT PLAN, LOCATION #1

FIGURE 2.2
PLOT PLAN, LOCATION #2

The location shown in Figure 2.2 has more than adequate area for the FCPP itself and for construction activities. Although the heating and digester gas pipe runs would be longer, the electric line run is shorter between the FCPP and the WPCF substation. The location also features gas storage away from other FCPP or WPCF equipment.

BCUA expressed a preference for the Figure 2.2 location after a review of the layouts. An enlarged view of this location is shown in Figure 2.3. This preference is based on BCUA's desire to keep the land, which would be occupied by the FCPP in Figure 2.1, open for aesthetic reasons (it is contiguous to that portion of the Administration Building which now has a river vista) and because of the possible need for expansion of the WPCF emergency electrical system.

2.2 ELECTRICAL INTEGRATION

There are two options for electrical integration of the FCPP with the WPCF. In the first option, the FCPP output is boosted to 26 kV and fed directly to the PSE&G electric grid serving the WPCF. In the second option, the FCPP output is rated at 4160V and fed into the WPCF 4160V bus. There would be an increase in power output due to better electrical efficiency in this approach since there is no electric loss through the main substation's 26 kV to 4 kV transformers.

In both options, the maximum power output of the FCPP, which is dependent on fuel availability, would be utilized since 1) the minimum power requirements of the WPCF (6 MWe) is more than the maximum power output of the FCPP (4.5 MWe), and 2) all major WPCF loads operate from a single electrical distribution system.

2.3 FUEL SUPPLY

From the FCPP Heat Rate Curve, Figure 1.2, and the fuel flow equation, both in Section 1.3, it is found that the 4.5 MWe Utility Demonstrator Power Plant

FIGURE 2.3
COGENERATION PROJECT
LOCATION NO. 2

LEGEND

1. AIR COMPRESSORS
2. NEW ROAD
3. DIESEL GENERATOR
4. SWITCHGEAR BLDG.
5. POWER CONDITIONING SUBSYSTEM BLDG.
6. CONTROL AND DATA ACQUISITION BLDG.
7. N₂ STORAGE
8. UNDERGROUND NAPHTHA STORAGE
9. H₂ STORAGE
10. GAS SUPPLY COMPRESSORS
11. DC MODULE
12. COOLING TOWERS (OPTIONAL)
13. UNDERGROUND H₂O STORAGE
14. WATER TREATING BLDG.

requires 1817 lb/hr, or 978,000 scfd of methane to operate at design load. This is equivalent to 1,505,300 scfd of digester gas (65% methane by volume) or 1,697,000 cfd at 95°F and 1 in. of water, which are the digester gas exit conditions.

Cleanup: Table 2.1 shows the gaseous fuel specification for the FCPP from Ref. 1.4. Note that there is no specific limitation on carbon dioxide. UTC has determined that the FCPP can physically handle the larger volume of digester gas resulting from the carbon dioxide/methane mixture. From test data, UTC has also determined that no performance penalty will result from the presence of the 35% (by volume) carbon dioxide. During fuel processing within the FCPP, carbon dioxide is formed from any hydrocarbon fuel. The additional carbon dioxide brought in with the digester gas will dilute the gas somewhat, but as shown in Section 1.3, the relative partial pressure of the reformed hydrogen is reduced from 80% with natural gas to 72%. Since the carbon dioxide content of the digester gas has a negligible effect on the FCPP, treating the digester gas to remove carbon dioxide is unnecessary.

The digester gas easily meets the sulfur, nitrogen and olefins limits. The oxygen content, due to air leakage during gas collection in the digesters, has exceeded specification limits. UTC has indicated that this level of oxygen can be handled in the present demonstrator configuration by adding a small amount of catalyst immediately preceding the hydrodesulfurizer (HDS-201-D).

TABLE 2.1
GAS FUEL SUPPLY CRITERIA

Function	Fuel for the DC Module (run only, not for start)
Max. Flow	1817 lb/hr (at 4.5 MWe net power output)
Delivery Pressure	95 psig $\pm$ 5 psi
Filtering	10 micron

<u>Impurity</u>	<u>LIMIT</u>
Sulfur	100.0 (PPM Vol)
Nitrogen	10.0 (Vol. %)
Oxygen	0.1 (Vol. %)
Olefins	0.2 (Vol. %)

The delivery pressure required is 95 ± 5 psig. The digester gas is available at 1 or 2 in. of water and will have to be compressed to delivery pressure. The filtering requirement of 10 microns will be met by the facility water sprays.

Supply Options: The projected digester gas supply from the WPCF of a nominal 1.4×10^6 cfd is less than the FCPP demand of 1.7×10^6 cfd. As a result, there are two possible options for fuel supply.

The first option is to provide digester gas to the FCPP and to allow the power output and available cogeneration heat to vary according to the digester gas supply. Table 2.2 shows the projected digester gas supply and the percent of full load methane available based on daily gas production, Figure 1.11. The average amount of methane available to the FCPP would be 84% of methane needed at design power. This corresponds to an average FCPP electric power output of 87% (due to higher power plant efficiency at off-design power level).

TABLE 2.2
DIGESTER GAS FUEL SUPPLY

<u>1982 Digester Gas Supply 90-95°F, 1-2 in. H₂O (10⁶ cfd)</u>	<u>% of Time</u>	<u>Methane Available to Fuel Cell (% of Design)</u>
< 1.0	0.8	< 59
1.0-1.1	2.1	59-65
1.1-1.2	4.9	65-71
1.2-1.3	19.8	71-77
1.3-1.4	18.9	77-82
1.4-1.5	28.0	82-88
1.5-1.6	20.2	88-94
1.6-1.7	4.9	94-100
> 1.7	0.4	100
Average Amount of Methane to Fuel Cell		83.9

The second fuel supply option is to augment the digester gas with enough natural gas so that the FCPP can operate at constant design power and maximum available cogeneration heat. Table 2.3 shows the projected digester gas supply and the amount of natural gas supplement required. Based on daily flows, an average of 174,000 scfd of supplemental natural gas is needed.

TABLE 2.3
DIGESTER GAS/NATURAL GAS FUEL SUPPLY

1982 Digester Gas Supply 90-95°F, 1-2 in. H ₂ O (10 ⁶ cfd)	% of Time	Natural Gas Supplement 32°F, 1 atm (10 ⁶ cfd)	Methane Available to FCPP (% of Design)
< 1.0	0.8	.400	100.0
1.0-1.1	2.1	.344 - .400	100.0
1.1-1.2	4.9	.287 - .344	100.0
1.2-1.3	19.8	.229 - .287	100.0
1.3-1.4	18.9	.171 - .229	100.0
1.4-1.5	28.0	.114 - .171	100.0
1.5-1.6	20.2	.056 - .114	100.0
1.6-1.7	4.9	0.0 - .056	100.0
> 1.7	0.4	0.0	100.0
Average Natural Gas Supplement Needed		.174	

Three possible natural gas supply schemes were evaluated by PSE&G. The selected scheme requires that 4000 feet of 6 inch pipe be installed to connect the FCPP to the PSE&G distribution system. PSE&G estimates that this would cost \$140,000. Pressure delivered to the area would be about 10-12 psig in winter and nearly 15 psig at times in the summer. Pressure at the meter would normally be reduced to six inches water column (approximately 1/4 psig), but the customer could probably receive higher than normal pressure if so requested. The upper limit might be three to five psig. For evaluation purposes, the delivered pressure was considered to be three psig.

For purposes of considering various conceptual design approaches, the two fuel supply options were evaluated based on averaged monthly flow rates. Figure 2.4 shows both options for supplying fuel. The lower trace is the first fuel supply option with the available methane from the digester gas and the expected range of power output. The difference between the upper and lower trace is the amount of natural gas required to augment the digester gas to furnish the FCPP with design load methane flow, Option 2.

FIGURE 2.4
FUEL SUPPLY/FCPP
NET ELECTRIC POWER

As shown in Figure 2.4, the minimum power production of the FCPP, 3.46 MWe, is 77% of design. This is well above the 30% power level where the FCPP low-flow turbocompressor takes over to provide process air from the high-flow turbocompressor, (see Section 1.3). As a result, the low-flow turbocompressor and its associated equipment can be eliminated from the FCPP in both fuel supply options, thus saving 2% of the FCPP cost.

Storage: During the investigation of fuel supply options, the need for storage was evaluated with the following results. When operating on digester gas, Option 1, there is not enough digester gas produced to operate the FCPP at design load. Thus, there is never excess gas to store. For Option 2, where supplemental natural gas is used, the gas supplier provides varying amounts of natural gas necessary to operate the FCPP at design load. The natural gas pipeline system itself provides the necessary storage. For these reasons, on-site gas storage was not considered.

In summary, there are two fuel supply options, digester gas alone and digester gas augmented with natural gas. The FCPP can utilize the digester gas with no additional processing. The FCPP low-flow turbocompressor and associated equipment can be eliminated with a 2% cost savings. The evaluation and costing of gas storage tanks is unnecessary in the determination of a conceptual design approach.

2.4 REJECTED HEAT UTILIZATION

It is possible to use the rejected heat from the FCPP by placing heat exchangers which satisfy WPCF heat requirements in the water/glycol cooling loop upstream of the the UTC dry cooling tower. Figure 2.5 shows the constraints of selecting a cogeneration loop resulting from the FCPP and the WPCF, and an approach to satisfying these constraints. Thermodynamic parameters shown in Figure 2.5 are for the most demanding heat rejection and utilization conditions, i.e. 1) the FCPP is rejecting the maximum amount of heat, 18.8×10^6 Btu/hr, which coincides with design power output, 2) the WPCF heat requirements are for the highest heat demand month, January and 3) the FCPP is situated at Location 2. Additional assumptions contributing to the analysis are:

NOTE: Q IN 10^6 BTU/HR

FIGURE 2.5
COGENERATION HEAT UTILIZATION

- a. A minimum ambient temperature of 0°F, which is that recommended for the coastal N.J. area according to the Heating, Ventilating, Air Conditioning Guide, 1952, published by the American Society of Heating and Ventilating Engineers. (ASHRAE is consistent).
- b. A minimum pinch temperature of 10°F across any heat exchanger.
- c. A 35% by weight solution of glycol/water to be consistent with 0°F ambient temperature design.
- d. A maximum glycol/water temperature of 120°F at the FCPP inlet and a maximum of 240°F at the exit. A maximum of 195°F at the inlet to HEX 405, which is allowable with the 35% glycol/65% water mixture.
- e. There will be no direct heating from the glycol/water loop, except for digester heating. Intermediate heat exchangers will be used to satisfy other WPCF heat requirements to insure that there will be a minimum chance of contaminating the glycol/water loop since an FCPP shutdown may result.

Cogenerating Characteristics: The cogeneration loop shown in Figure 2.5 results from the following considerations. As noted above, the inlet temperature of the glycol/water into the FCPP must be $\leq 120^{\circ}\text{F}$. The exit temperature with full coolant flow should be no more than 240°F . It is sensible for cogeneration purposes to keep these two temperatures at their highest values, respectively, 120°F and 240°F . At the 4.5 MWe design power level, 18.8×10^6 Btu/hr are released from the FCPP by the glycol/water loop. It takes 171,800 lb/hr of the glycol/water to provide the 120°F temperature rise within the FCPP at the design heat rejection rate. This sets the temperatures and the maximum flow rate of the glycol/water mixture into and out of the FCPP.

The highest temperature required by the WPCF is the temperature of the water used to melt grease in the skum tanks. The grease is melted so that it can be pumped to the digester tanks. Therefore, the highest temperature heat exchanger is the grease melt heat exchanger. As noted in Figure 2.5, this heat exchanger

must transfer 1.98×10^6 Btu/hr. The second highest temperature demand of the WPCF is for space heat requirements. In January, 7.99×10^6 Btu/hr are needed for heating the facility buildings. If this amount of heat is summed with that required for grease melting, the glycol/water temperature will drop from 240°F to 177°F. The 177°F temperature, when considered with the 10°F pinch temperature, would yield only 167°F in the return of the WPCF space heat water line. This temperature is too low to maintain comfort within the existing space heating system. For proper comfort, this return temperature must be $\geq 170^\circ\text{F}$. Therefore, only 7.49×10^6 Btu/hr can be used from the glycol/water loop which yields the required 180°F glycol/water temperature out of the space heat exchanger. The extra half million Btu/hr must be provided to the space heat water loop by using one of the existing facility dual-fired boilers. Oil would be used to fire the boiler to prevent taking available digester methane away from the FCPP with the resulting reduction in power output and available cogeneration heat.

An additional 3.96×10^6 Btu/hr is taken from the glycol/water mixture to provide heat to the four anaerobic digesters, which must be maintained at 95°F. The cold side fluid in the digester heat exchangers, which transfers the heat to the digesters, is sludge. This amount of heat, summed with the other two utilizations, results in a total of 13.43×10^6 Btu/hr being transferred to the WPCF by the glycol/water stream in January.

Temperature Control Heat Exchanger: The difference between the heat used in the cogeneration heat exchangers and the amount produced by the FCPP ($18.8 \times 10^6 - 13.43 \times 10^6 = 5.37 \times 10^6$ Btu/hr) must be rejected by other means. Part of this heat is lost in the piping runs. However, 5.3×10^6 Btu/hr must be rejected by a temperature control heat exchanger. Actually, this heat exchanger must be sized to reject the entire amount of heat produced by the FCPP including the intermittent load of the Water Treatment System, 1.65×10^6 Btu/hr, and its additional flow rate of 19,000 lb/hr. The dry cooling tower designed for the utility 4.5 MWe demonstrator power plant is sized to accept this heat load. It is also possible to replace the dry cooling tower with a shell and tube heat exchanger whose heat sink is clean effluent water piped from the rear of the WPCF.

Selected Approach: The option shown by Figure 2.5 is the only cogeneration loop which will satisfy FCPP and WPCF constraints. Not even a revision of the internal plumbing between the FCPP heat exchangers will result in eliminating the need to oil fire a boiler to provide makeup heat for space heating. Actually, this additional heat ($.5 \times 10^6$ Btu/hr) is needed only during the coldest month, January. With this approach, approximately 71% of the rejected FCPP heat is used for the maximum heat utilization case shown.

The same conclusions and cogeneration loop result if the FCPP is not operating at design power and not providing as much heat to the cogeneration loop. This situation occurs if only the digester gas is furnished to the FCPP and there is no supplemental natural gas. In January, there is enough methane in the digester gas to achieve a FCPP power output of 3.76 MWe. At the 3.76 MWe net power output condition, the FCPP produces 13.65×10^6 Btu/hr of rejected heat. Unfortunately, the FCPP does not produce enough high temperature thermal energy. An additional 3.08×10^6 Btu/hr must be added to the space heating loop by an existing oil-fired boiler to satisfy the high temperature thermal energy requirement. As a result, 2.73×10^6 Btu/hr of low temperature heat, not usable by the facility, must then be rejected from the cogeneration cooling loop.

Similar analyses show that thermal energy must be furnished by the oil-fired furnace for three additional months when the FCPP is operating on digester gas only. December requires 2.24×10^6 Btu/hr., February requires 1.59×10^6 Btu/hr and March requires 0.16×10^6 Btu/hr.

In summary, there is only one cogeneration loop which satisfies the constraints of both the FCPP and the WPCF. The high temperature glycol/water mixture flowing from the FCPP is routed to four in-line heat exchangers. The heat exchangers in order of high to low temperature are grease melting, space heating, digester heating and temperature control. The temperature control heat exchanger could be either the dry cooling tower designed for the 4.5 MWe Utility Demonstrator Power Plant or a shell and tube heat exchanger cooled with WPCF effluent. During the winter months, some additional heat is added to the water/glycol loop for space heating using one of the existing WPCF oil-fired boilers.

2.5 OWNERSHIP AND OPERATION

The following two ownership and operation options of the FCPP were considered in this feasibility study:

1. Ownership and operation of the FCPP by Public Service Electric and Gas Company, the utility serving the WPCF (Figure 2.6).
2. Ownership and operation of the FCPP by the Bergen County Utilities Authority, operators of the WPCF (Figure 2.7).

These two were selected as the most logical options, for ease of analysis and to minimize the institutional problems which would have to be addressed.

PSE&G OWNERSHIP AND OPERATION: In the PSE&G ownership and operation option, the FCPP would be considered part of the PSE&G's electric generating capacity in which the electric output of the FCPP would be fed into the PSE&G grid. The FCPP would be connected to the PSE&G grid at the WPCF substation. BCUA would purchase all of their electric load requirements from PSE&G at the appropriate rate, as at present. The rate, their terms, and conditions for exchange of heat and digester gas between PSE&G and BCUA would have to be negotiated and a long term contract developed agreeable to both parties. The rates would be determined based on a detailed rate analysis study using the overall conceptual economic feasibility analysis as a guide and taking into consideration cost allocations, anticipated revenues, and risks.

In general, there does not appear to be any major legal or regulatory constraints that would hinder PSE&G from owning and operating a cogeneration FCPP on a long term basis. PSE&G's charter describes the company as an energy company, not restricted to just electric and gas sales.

Assuming that a project of this type is found to be sufficiently economically viable to pursue in light of the risk involved in dealing with an emerging technology, then this project would receive the same consideration as any other project for the purpose of electric power production. The source of

FIGURE 2.6
PSE&G OWNERSHIP/OPERATION

FIGURE 2.7
BCUA OWNERSHIP/OPERATION

funds for all PSE&G construction projects is the overall pool of capital consisting of long term debt, preferred stock and common equity. The required capital investment would represent only a small portion of the company's projected overall capital requirements over the expected life of the FCPP. There would be no anticipated financial and regulatory constraints imposed on the implementation of this project if it is judged to be economically viable.

For a project to be bondable under PSE&G's ownership, PSE&G must either own or lease on a long term basis the land on which the power plant facilities would be located. There does not appear to be any legal or regulatory problems with the sale or lease of land by BCUA to PSE&G.

BCUA OWNERSHIP AND OPERATION: In the BCUA ownership and operation option, the electric output of the FCPP, which is less than the minimum electric load of the WPCF, would be used by BCUA to provide a base portion of their electric load requirements. BCUA would purchase from PSE&G supplemental electricity and standby capacity at the appropriate rates. For those conceptual design configurations that use supplemental natural gas, BCUA would purchase the supplemental natural gas from PSE&G at the appropriate rate. However, it should be noted that PSE&G's ability to supply natural gas to BCUA would certainly depend on the future natural gas supply situation and federal and state regulations at the time when the FCPP would go into operation.

There does not appear to be any major legal or regulatory constraints that would prohibit the BCUA from owning and operating a FCPP fueled by digester gas for the purpose of providing a part of the heat and electric requirements of the WPCF.

The FCPP like any facility expansion or purchase of major equipment, if shown to be economically feasible, would be financed through BCUA bonds, the usual source of capital for a utility of this nature.

Regardless of ownership option, the following license and permits must be obtained prior to installing the FCPP:

Operating License Requirements: Guide Rule #3 of the New Jersey Department of Labor and Industry - Mechanical Inspection Bureau Rules and Regulations states that: "Any steam boiler, steam generator, hot water boiler for service over 250°F, or similar equipment potentially capable of generating steam having safety valve or valves set higher than fifteen pounds per square inch gauge and rates over six horsepower, require the attention of licensed operators."

The FCPP has the following components to which Guide Rule #3 appears to apply:

1. A startup burner which generates steam at 375°F and 185 psig. The rating of this burner is approximately 107 hp.
2. A reformer/burner which is a fired pressure vessel with air and fuel relief valves set at 37 and 77 psig, respectively.
3. A power section which also is a pressure vessel (unfired) generating steam at 375°F and 195 psig.

For the purposes of this study, Guide Rule #3 was interpreted conservatively and, based on this, a full-time qualified operator with a Fireman's License was considered as an operational requirement. Associated O&M costs were included in the economic analysis.

A more liberal interpretation of Guide Rule #3 may be applied to the FCPP based on further study which would include discussions with the Mechanical Inspection Bureau.

Construction Permit Requirements: In accordance with the New Jersey State Uniform Construction Code, a construction permit for the installation of the cogeneration FCPP must be obtained. The application for this construction

permit must be made to the Hackensack Meadowlands Development Commission (HMDC), the designated plan review agent for the Bureau of Housing Inspection of the New Jersey Department of Community Affairs.

Before such an application can be made, the following prior approvals must be obtained:

- a. Borough of Little Ferry - The WPCF is located in an M-2 zone of this municipality which is designated for general industrial uses. Section 7.1 of the Little Ferry Zoning Ordinance neither lists a device such as WPCF nor a public utility as a permitted or a prohibited use. Since the WPCF is already there, it would be logical to assume that the FCPP would be approved. This approval will consist of the completion of a local clearance form which is the first step in obtaining a construction permit.
- b. Northeast Soil Conservation District - An application must be made to the Northeast Soil Conservation district located in Hackensack. This body is a part of the State Soil Conservation committee of the New Jersey Department of Agriculture. This requirement is necessary when an area of land 5000 square feet or more is disturbed.
- c. New Jersey Department of Environmental Protection - A stream encroachment permit must be obtained from the Bureau of Flood Plain Management, Division of Water Resources, D.E.P. In general, a permit is required for construction along a stream within the high water mark of the 100 year flood as determined by the Division.

In addition to the construction permit, a zoning certificate must also be obtained from the HMDC. The WPCF is located in a public utility zone of the Hackensack Meadowlands District. An electric power generating station, which certainly includes an FCPP, is a permitted use here.

Finally, upon receipt of the above HMDC approvals, application must then be made to the Borough of Little Ferry for a building permit. This step is merely a formality since technical review is conducted by the HMDC.

In general, the above requirements deal primarily with the structural support of the proposed installation and will not be concerned with the operation and design of the FCPP. No major problems are anticipated in obtaining the permit to allow the construction of the cogeneration FCPP at the WPCF.

2.6 POSSIBLE CONCEPTUAL DESIGN CONFIGURATIONS

There are thirty-two possible conceptual design configurations resulting from the installation options described in this Section. This is due to the combinations which can be formed from the following installation options whose technical feasibility was agreed upon by BCUA, PSE&G, AND G/C:

- a. Two power plant locations.
- b. FCPP electric connection to either the 26 kV or the 4 kV side of WPCF substation.
- c. Two fuel supply options.
- d. Only one heat rejection scheme, but two approaches to rejecting excess FCPP heat.
- e. Two ownership and operation options.

By separately evaluating the effect of each option and combining the various effects, it is possible to analyze the operating conditions and equipment needs of the thirty-two possible configurations while performing only eight sets of calculations (ownership and operation does not have an effect on operating conditions and equipment needs).

SECTION 3.0 SELECTION OF CANDIDATE CONCEPTUAL DESIGNS

3.1 OPERATING CONDITIONS

Prior to the economic analysis, it was necessary to screen the thirty-two possible conceptual design configurations (Section 2.6) to a prudent number of candidate designs. This was done to avoid the time consuming process of economically evaluating thirty-two possible configurations. The screening was achieved by means of a design analysis from which the overall operating conditions and equipment requirements of the thirty-two configurations were defined. From this design analysis, specific operating conditions and capital costs could be estimated. With the resulting information, it was possible to identify and eliminate those installation options which had negligible impact on operating conditions, equipment needs, and costs.

The design analysis of the thirty-two possible configurations was based on the study constraints and general characterization of the WPCF, the electric grid and the FCPP, Section 1. As noted in Section 2, it was unnecessary to prepare detail analyses of all thirty-two configurations. Instead, the following options could be evaluated separately:

- a. Two locations.
- b. Connecting the FCPP output to either the 4 kV bus or the 26 kV bus of the WPCF substation.
- c. Fueling the FCPP with digester gas only, or augmenting the fuel supply with natural gas.
- d. Rejecting excess FCPP heat using a dry cooling tower or a shell and tube heat exchanger using WPCF effluent for cooling.

By properly combining the mass flows, heat balances and electrical operating conditions, all thirty-two configurations can be evaluated with minimum effort. Note that the installation option, ownership and operation, does not affect operating conditions or equipment needs.

3.1.1 Mass Flow and Heat Balance Operating Conditions

Figure 2.4 showed the average hourly methane flow for each month available from the digesters. Also shown is the amount of natural gas required to allow the FCPP to operate at its design capacity. By using these methane flows in conjunction with the heat rate curve, Figure 1.2, and the fuel flow/heat rate equation, Section 1.3, the per cent of FCPP design capacity was determined, Figure 3.1. Once the capacity was fixed, it was possible using the FCPP Heat Exchanger Characteristics, Figure 1.3, to quantify the heat available from individual FCPP heat exchangers and the total cogeneration heat available. From this, a heat balance of the cogeneration water/glycol loop was prepared.

Table 3.1 is a compilation of the methane flows, the percent of FCPP power output, the heat contributed by individual FCPP heat exchangers, and the total cogeneration heat available. For convenience, the values of the WPCF heat requirements are also listed.

By adapting the information in Table 3.1 to the approach shown for heat utilization in Figure 2.5 a heat balance of the water/glycol loop could be generated for each month of the year, provided that a method of control is assumed. The method of control chosen for this specific application is based on maintaining the highest possible temperature (240°F) of the water/glycol mixture exiting the FCPP Heat Exchanger, No. 405, Figure 2.5. To maintain 240°F, the water/glycol flow rate is varied by adjusting the bypass of the primary circulating pump, Figure 3.2. At lower FCPP capacities, a lower quantity of heat is available for cogeneration, Figure 1.3. To meet the requirement that the water/glycol mixture temperature into the FCPP can not exceed 120°F, it is necessary to reduce the water/glycol flow rate through the FCPP so that the exit temperature can be maintained at 240°F. This reduction of flow through the FCPP is achieved by increasing the water/glycol flow from the high pressure pump exit to the low pressure pump entrance, thus bypassing flow through the rest of the water/glycol loop. The rate of bypass is controlled by sensing and maintaining the 240°F water/glycol temperature at

FIGURE 3.1
FUEL CELL POWER PLANT NET ELECTRIC POWER

TABLE 3.1
FCPP HEAT AVAILABLE/WPCF HEAT REQUIREMENTS

Month	Digester Gas Flow (10 ⁶ cfd)	Digester Methane (lb/hr)	% FCPP Design Capacity	Heat Contributed by FCPP (10 ⁶ Btu/hr)					Heat Required by BCUA (10 ⁶ Btu/hr)			
				Hex 406	Hex 407	Hex 318	Hex 405	Total	Grease Melt	Space Heat	Digester	Total
I. Digester Gas Fuel Supply Only												
January	1.350	1408	82.6	1.70	5.40	1.70	4.85	13.65	1.98	7.99	3.96	13.93
February	1.479	1548	89.4	1.94	5.95	2.00	5.68	15.57	1.98	7.48	3.86	13.32
March	1.491	1561	90.0	1.95	6.00	2.00	5.75	15.70	1.98	6.10	3.43	11.51
April	1.519	1591	91.4	2.03	6.10	2.08	5.93	16.14	1.80	4.38	2.84	9.02
May	1.434	1499	87.1	1.85	5.76	1.89	5.37	14.87	1.80	2.47	2.25	6.52
June	1.358	1417	83.1	1.70	5.44	1.71	4.90	13.75	1.80	0.0	1.81	3.61
July	1.289	1342	79.1	1.56	5.12	1.55	4.46	12.69	1.80	0.0	1.60	3.40
August	1.235	1284	76.0	1.50	4.90	1.50	4.15	12.05	1.80	0.0	1.74	3.54
September	1.519	1591	91.4	2.03	6.10	2.08	5.93	16.14	1.80	1.43	2.15	5.38
October	1.491	1561	90.0	1.95	6.00	2.00	5.75	15.70	1.80	3.43	2.69	7.92
November	1.479	1548	89.4	1.94	5.95	2.00	5.68	15.57	1.80	5.24	3.35	10.39
December	1.350	1408	82.6	1.70	5.40	1.70	4.85	13.65	1.98	7.16	3.84	12.98

II. Digester Gas and Natural Gas Fuel Supply

		Digester And Natural Gas Methane (lb/hr)								
January - December	Same as above	1817	100	2.43	6.82	2.40	7.14	18.79	-----	Same As Above -----

FIGURE 3.2
REJECTED HEAT UTILIZATION

the exit of the FCPP Heat Exchanger No. 405. A pressure control valve is required to match the pressure drop of the circulating pump with the pressure drop of the loop, which decreases as the water/glycol flow through the loop is reduced. Other control features of the water/glycol loop are addressed in the description of the selected configuration contained in Section 4.2.

With the control scheme and boundary conditions established, the mass flows and heat balances of the water/glycol loop could be determined for all operating conditions. Figure 3.3 is an example of a heat balance, this being for the January WPCF heat requirements, for the FCPP operating at design capacity and based on FCPP Location No. 2. The FCPP location affects the temperature losses in the water/glycol piping and the requirements for pumping power which must be considered in determining net installation output. Figures 3.4 and 3.5 show the pipe routes used to determine the temperature drop and requirements for pumping power for all heat balances.

Appendix C is a compilation of the 48 heat balances used to determine the monthly operating conditions and equipment needs for:

<u>Fuel Supply</u>	<u>Location</u>
Digester Gas Only	1 and 2
Digester Gas Augmented with Natural Gas	1 and 2

Note that the amount of make-up oil to completely satisfy the WPCF heat requirements could be determined from the change in enthalpy between Stations 12 and 13 of each heat balance. As stated in Section 2.4, with the FCPP fueled only by digester gas, make-up heat is required from the oil-fired burners in January (3.08×10^6 Btu/hr), February (1.59×10^6 Btu/hr), March (0.16×10^6 Btu/hr), and December (2.24×10^6 Btu/hr). With digester gas and natural gas, heat is required only in January (0.50×10^6 Btu/hr). Also note that the temperature

FIGURE 3.3
REJECTED HEAT UTILIZATION
OPERATION CONDITIONS

control heat exchanger, which rejects FCPP low temperature excess heat, can be either the UTC supplied dry cooling tower or a shell and tube heat exchanger cooled by WPCF effluent.

3.1.2 Electrical Operating Conditions

The net electrical output of the cogeneration installation is the FCPP net output reduced by the auxiliary power requirements of the cogeneration installation equipment.

FCPP Net Electric Power: The primary impact on the amount of FCPP net power produced is due to the fuel supply option. With digester gas alone, the FCPP net output varies from 3.46 MWe to 4.16 MWe according to the amount of methane available from the digester gas, Table 3.2. The FCPP operates at a yearly average capacity of 86% (not considering maintenance and forced outages). When the digester gas is augmented with natural gas, the FCPP output can be brought to its design capacity, Table 3.3, and kept continuously at that level, since the power requirements of the WPCF are always greater than the FCPP output. According to UTC, the FCPP electric output is available at either 26 kV or 4 kV, Section 1.3.

Table 3.3 shows the FCPP net output as 4.55 MWe. This differs with the advertised Utility Demonstrator Power Plant with a net output of 4.5 MWe (4.8 MWe gross power). This 4.5 MWe output includes an auxiliary power debit for the dry cooling tower fans and the coolant loop circulating pump. In this study, these auxiliary power requirements, totaling approximately .05 MWe at design power, were eliminated from the FCPP net electric output. Auxiliary power for cooling, depending on whether a dry cooling tower or a shell and tube heat exchanger is used, was deducted along with other auxiliary loads from the FCPP net electric output to determine the cogeneration installation net output.

Auxiliary Power Requirements: Sources of auxiliary power for the cogeneration installation are: the gas compressors (both digester gas and natural gas), the primary water/glycol recirculating pump, the dry cooling tower fans, the

FIGURE 3.4
GENERAL PLAN
LOCATION #1

3-9/10

3-11/12

FIGURE 3.5
GENERAL PLAN
LOCATION #2

TABLE 3.2
ELECTRIC OPERATING CONDITIONS
Fuel Supply - Digester Gas Only
Electric Connection - 26 kV

Month	Digester Methane (lb/hr)	FCPP Net Electric Power Output (MW)	Cogeneration Installation Net Electric Power			
			Dry Cooling Tower		Effluent Cooling	
			Location No. 2 (MW)	Location No. 1 (MW)	Location No. 2 (MW)	Location No. 1 (MW)
January	1408	3.76	3.56	3.57	3.59	3.60
February	1548	4.07	3.88	3.88	3.90	3.91
March	1561	4.10	3.90	3.91	3.93	3.94
April	1591	4.16	3.96	3.97	3.99	4.00
May	1499	3.97	3.77	3.78	3.80	3.81
June	1417	3.78	3.58	3.59	3.61	3.62
July	1342	3.60	3.40	3.41	3.43	3.44
August	1284	3.46	3.26	3.27	3.29	3.30
September	1591	4.16	3.96	3.97	3.99	4.00
October	1561	4.10	3.90	3.91	3.93	3.94
November	1548	4.07	3.88	3.88	3.90	3.91
December	1408	3.76	3.56	3.57	3.59	3.60

TABLE 3.3
ELECTRIC OPERATION CONDITIONS
Fuel Supply - Digester Gas Augmented With Natural Gas
Electric Connection - 26 kV

Month	Digester & Natural Gas Methane (lb/hr)	FCPP Net Electric Power Output (MW)	Cogeneration Installation Net Electric Power			
			Dry Cooling Tower		Effluent Cooling	
			Location No. 2 (MW)	Location No. 1 (MW)	Location No. 2 (MW)	Location No. 1 (MW)
January	1817	4.55	4.33	4.34	4.36	4.37
February	1817	4.55	4.33	4.34	4.36	4.37
March	1817	4.55	4.33	4.34	4.36	4.37
April	1817	4.55	4.33	4.34	4.36	4.37
May	1817	4.55	4.33	4.34	4.36	4.36
June	1817	4.55	4.33	4.34	4.36	4.36
July	1817	4.55	4.31	4.31	4.34	4.34
August	1817	4.55	4.31	4.31	4.34	4.34
September	1817	4.55	4.33	4.34	4.36	4.36
October	1817	4.55	4.33	4.34	4.36	4.37
November	1817	4.55	4.33	4.34	4.36	4.37
December	1817	4.55	4.33	4.34	4.36	4.37

effluent water pump (for temperature control heat exchanger cooling) and cable resistance losses. The magnitudes of these losses depend on location, fuel supply, and the method of excess heat rejection. In addition, the electrical connection (to 26 kV or 4 kV busses) influences the cogeneration installation net electric output. An electric power credit must be applied to the 4 kV connection option since there are no losses resulting from the FCPP electric output being routed through the WPCF 26 kV to 4 kV transformers.

Tables 3.4 - 3.7 list the auxiliary power requirements according to the influencing options. In Table 3.4, the auxiliary power requirements are shown for these options: digester gas only fuel supply, 26 kV electric connection and FCPP Location No. 2. Two total columns are presented, one for operation with a dry cooling tower, the other with WPCF effluent cooling.

Table 3.5 lists similar auxiliary power requirements, but for FCPP Location No. 1.

Tables 3.6 and 3.7 are similar, respectively, to Tables 3.4 and 3.5, but consider auxiliary power requirements with the FCPP fueled by digester gas augmented with natural gas.

Table 3.8 shows the credit which is added to the cogeneration installation net output for the 4 kV connection option.

TABLE 3.4
AUXILIARY POWER REQUIREMENTS
(In Kilowatts)

Fuel Supply - Digester Gas Only
Electric Connection - 26 kV
Location - No. 2

Month	Digester Gas Compressor	Recirculating Pump	Cable Loss	Dry Cooling Tower	Effluent Cooling Pump	Total With Dry Cooling Tower	Total With Effluent Cooling
January	155	9.5	.6	30	1.5	195	167
February	155	9.5	.7	30	1.5	195	167
March	155	9.5	.7	30	1.5	195	167
April	155	9.5	.7	30	1.5	195	167
May	157	9.5	.7	30	1.5	197	169
June	157	9.5	.6	30	1.5	197	169
July	157	9.5	.5	30	1.5	197	169
August	157	9.5	.5	30	1.5	197	169
September	157	9.5	.7	30	1.5	197	169
October	155	9.5	.7	30	1.5	195	167
November	155	9.5	.7	30	1.5	195	167
December	155	9.5	.6	30	1.5	195	167

TABLE 3.5
AUXILIARY POWER REQUIREMENTS
(In Kilowatts)

Fuel Supply - Digester Gas Only
Electric Connection - 26 kV
Location - No. 1

<u>Month</u>	<u>Digester Gas Compressor</u>	<u>Recirculating Pump</u>	<u>Cable Loss</u>	<u>Dry Cooling Tower</u>	<u>Effluent Cooling Pump</u>	<u>Total With Dry Cooling Tower</u>	<u>Total With Effluent Cooling</u>
January	150	8.5	1.8	30	1.5	190	162
February	150	8.5	2.1	30	1.5	191	162
March	150	8.5	2.1	30	1.5	191	162
April	150	8.5	2.2	30	1.5	191	162
May	151	8.5	2.0	30	1.5	192	163
June	151	8.5	1.8	30	1.5	191	163
July	151	8.5	1.6	30	1.5	191	163
August	151	8.5	1.5	30	1.5	191	162
September	151	8.5	2.2	30	1.5	192	163
October	150	8.5	2.1	30	1.5	191	162
November	150	8.5	2.1	30	1.5	191	162
December	150	8.5	1.8	30	1.5	190	162

TABLE 3.6
AUXILIARY POWER REQUIREMENTS
(In Kilowatts)

Fuel Supply - Digester Gas Augmented with Natural Gas
Electric Connection - 26 kV
Location - No. 2

<u>Month</u>	<u>Digester Gas Compressor</u>	<u>Natural Gas Compressor</u>	<u>Recirculating Pump</u>	<u>Cable Loss</u>	<u>Dry Cooling Tower</u>	<u>Effluent Cooling Pump</u>	<u>Total With Dry Cooling Tower</u>	<u>Total With Effluent Cooling</u>
January	155	22	9.5	.6	30	1.5	217	189
February	155	22	9.5	.7	30	1.5	217	189
March	155	22	9.5	.7	30	1.5	217	189
April	155	22	9.5	.7	30	1.5	217	189
May	157	22	9.5	.7	30	1.5	219	191
June	157	22	9.5	.6	30	1.5	219	191
July	157	45*	9.5	.5	30	1.5	242	214
August	157	45*	9.5	.5	30	1.5	242	214
September	157	22	9.5	.7	30	1.5	219	191
October	155	22	9.5	.7	30	1.5	217	189
November	155	22	9.5	.7	30	1.5	217	189
December	155	22	9.5	.6	30	1.5	217	189

*Additional Compressor Required

TABLE 3.7
AUXILIARY POWER REQUIREMENTS
(In Kilowatts)

Fuel Supply - Digester Gas Augmented with Natural Gas
Electric Connection - 26 kV
Location - No. 1

Month	Digester Gas Compressor	Natural Gas Compressor	Recirculating Pump	Cable Loss	Dry Cooling Tower	Effluent Cooling Pump	Total With Dry Cooling Tower	Total With Effluent Cooling
January	150	22	8.5	1.8	30	1.5	212	184
February	150	22	8.5	2.1	30	1.5	213	184
March	150	22	8.5	2.1	30	1.5	213	184
April	150	22	8.5	2.2	30	1.5	213	184
May	151	22	8.5	2.0	30	1.5	214	185
June	151	22	8.5	1.8	30	1.5	213	185
July	151	45*	8.5	1.6	30	1.5	236	208
August	151	45*	8.5	1.5	30	1.5	236	208
September	151	22	8.5	2.2	30	1.5	214	185
October	150	22	8.5	2.1	30	1.5	213	184
November	150	22	8.5	2.1	30	1.5	213	184
December	150	22	8.5	1.8	30	1.5	212	184

*Additional Compressor Required

TABLE 3.8
4 KV ELECTRICAL CONNECTION CREDIT

<u>FPCC Net Electric Output (MW)</u>	<u>26.4 kV - 4.16 kV Transformer Loss Credit (kW)</u>
3.4	7.4
3.6	8.3
3.7	8.8
3.9	9.8
4.0	10.3
4.1	10.8
4.5	13.0

Cogeneration Installation Net Electric Power: The total auxiliary power requirements of Tables 3.4 through 3.7 were combined with the FCPP net electric power level to determine the cogeneration installation net electric power, Columns 5-8 in Table 3.2 and Table 3.3. Note that the net electric outputs in Tables 3.2 and 3.3 do not include the 4 kV connection credit. This credit is applied from Table 3.8 in the design analysis performance summary.

3.1.3 Operating Conditions Performance Summary

The thirty-two possible configurations resulting from the options of installation are identified in Table 3.9.

TABLE 3.9
INSTALLATION OPTIONS OF CASES

Ownership & Operation:	Case No.																																
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	
PSE&G																																	
BCUA																																	
Location:																																	
1																																	
2																																	
Electric Connection:																																	
4 kV																																	
26 kV																																	
Fuel Supply:																																	
Digester Gas																																	
Digester and Natural Gas																																	
Excess Heat Rejection:																																	
Dry Cooling Tower																																	
Shell & Tube HEX																																	

Tables 3.10 through 3.17 summarize the performance for Cases 1 through 8. The tables were compiled using the information derived in the previous Sections 3.1.1 and 3.1.2. For example, for Table 3.10 (Case 1), the fuel supply and rejected heat used are directly from Table 3.1 (Digester Gas Fuel Supply Only). The make-up oil was based on the amount of make-up heat required, which is shown in the appropriate heat balances, Appendix C. The total energy input was determined from the total heat contributed by the FCPP, Column 9 of Table 3.1, summed with the heat value of the digester methane and make-up oil. The net electric power was obtained from Tables 3.2, 3.3, and 3.8.

Performance data for Cases 9 through 16 are the same as Cases 1 through 8 with the exception of the following. First, the net electric power of the cogeneration installation in Cases 9 through 16 must be adjusted to the values shown for effluent cooling in Tables 3.2 and 3.3. Second, the amount of effluent cooling water must also be included in the performance summary. The effluent cooling water, after passing through the temperature control heat exchanger, Figure 3.2, is dumped into the front end of the WPCF. As a result, a normal sewage charge is applied to the amount of effluent cooling water for use of the WPCF. Table 3.18 is the amount of effluent required, based on the heat balances in Appendix C.

Performance data for Cases 17 - 32 are identical, respectively, with Cases 1 - 16. The change in ownership has no effect on operation of the cogeneration installation.

3.1.4 Availability

Tables 3.10 through 3.18 define the mass flows and electrical power of the cogeneration installation during operation. Along with unit costs for electricity, fuels, and labor, this information can be used to determine operating costs, Section 4. Before these operating costs can be incorporated as part of the overall economics, it is necessary to also define the time of service or "availability" of the cogeneration installation. Since the installation is out of service for scheduled maintenance and forced outages, its availability is less than 100%.

TABLE 3.10
PERFORMANCE SUMMARY
CASE NO. 1

Options:
Location - No. 2
Electric Connection - 4 kV
Fuel Supply - Digester Gas

Excess Heat Rejection - Dry Cooling Tower

Ownership and Operations - PSE&G

Month	Digester Gas Flow 10 ⁶ cfd	Natural Gas Flow 10 ⁶ cfd (lb/hr)	Boiler Makeup Oil Flow cpd (lb/hr)	Total Energy Input 10 ⁶ Btu/hr	Heat Used 10 ⁶ Btu/hr	Net Electric Power 10 ⁶ Btu/hr (MWe)	Total Net Energy Output 10 ⁶ Btu/hr	Overall Energy Conversion Efficiency %
January	1.35	0	728 (233)	34.18	13.93	12.18 (3.57)	26.11	76.4
February	1.48	0	376 (120)	34.90	13.32	13.28 (3.89)	26.60	76.2
March	1.49	0	38 (12)	33.13	11.51	13.34 (3.91)	24.85	75.0
April	1.52	0	0	33.51	9.02	13.55 (3.97)	22.57	67.4
May	1.43	0	0	31.64	6.52	12.90 (3.78)	19.42	61.4
June	1.36	0	0	29.96	3.61	12.25 (3.59)	15.86	52.9
July	1.29	0	0	28.44	3.40	11.64 (3.41)	15.04	52.9
August	1.24	0	0	27.25	3.54	11.16 (3.27)	14.70	53.9
September	1.52	0	0	33.51	5.38	13.55 (3.97)	18.93	56.5
October	1.49	0	0	32.90	7.92	13.34 (3.91)	21.26	64.6
November	1.48	0	0	32.63	10.39	13.28 (3.89)	23.67	72.5
December	1.35	0	530 (169)	32.98	12.98	12.18 (3.57)	25.16	76.3

TABLE 3.11
PERFORMANCE SUMMARY
CASE NO. 2

Options:

Location - No. 2

Electric Connection - 4 kV

Fuel Supply - Digester Gas Augmented with Natural Gas

Excess Heat Rejection - Dry Cooling Tower

Ownership and Operations - PSE&G

Month	Digester Gas Flow 10 ⁶ cfd	Natural Gas Flow 10 ⁶ cfd (lb/hr)	Boiler Makeup Oil Flow gpd (lb/hr)	Total Energy Input 10 ⁶ Btu/hr	Heat Used 10 ⁶ Btu/hr	Net Electric Power 10 ⁶ Btu/hr (MWe)	Total Net Energy Output 10 ⁶ Btu/hr	Overall Energy Conversion Efficiency %
January	1.35	0.200 (409)	119 (38)	39.29	13.93	14.81 (4.34)	28.74	73.1
February	1.48	0.126 (269)	0	38.41	13.32	14.81 (4.34)	28.13	73.2
March	1.49	0.119 (256)	0	38.40	11.51	14.81 (4.34)	26.32	68.5
April	1.52	0.103 (226)	0	38.38	9.02	14.81 (4.34)	23.83	62.1
May	1.43	0.151 (318)	0	38.48	6.52	14.81 (4.34)	21.33	55.4
June	1.36	0.195 (400)	0	38.56	3.61	14.81 (4.34)	18.42	47.8
July	1.29	0.235 (475)	0	38.65	3.40	14.81 (4.31)	18.21	47.1
August	1.24	0.267 (533)	0	38.71	3.54	14.81 (4.31)	18.35	47.4
September	1.52	0.103 (226)	0	38.37	5.38	14.81 (4.34)	20.19	52.6
October	1.49	0.119 (256)	0	38.40	7.92	14.81 (4.34)	22.73	59.2
November	1.43	0.126 (269)	0	38.41	10.39	14.81 (4.34)	25.20	65.6
December	1.35	0.200 (409)	0	39.21	12.98	14.81 (4.34)	27.79	70.9

TABLE 3.12
PERFORMANCE SUMMARY
CASE NO. 3

Options:
Location - No. 1
Electric Connection - 4 kV
Fuel Supply - Digester Gas

Excess Heat Rejection - Dry Cooling Tower

Ownership and Operations - PSE&G

Month	Digester Gas Flow 10 ⁶ cfd	Natural Gas Flow 10 ⁶ cfd (lb/hr)	Boiler Makeup Oil Flow gpd (lb/hr)	Total Energy Input 10 ⁶ Btu/hr	Heat Used 10 ⁶ Btu/hr	Net Electric Power 10 ⁶ Btu/hr (MWe)	Total Net Energy Output 10 ⁶ Btu/hr	Overall Energy Conversion Efficiency %
January	1.35	0	723 (231)	34.15	13.93	12.22 (3.58)	26.15	76.6
February	1.48	0	371 (119)	34.87	13.32	13.28 (3.89)	26.60	76.3
March	1.49	0	31 (10)	33.09	11.51	13.28 (3.92)	24.89	75.2
April	1.52	0	0	33.51	9.02	13.58 (3.98)	22.60	67.4
May	1.43	0	0	31.64	6.52	12.94 (3.79)	19.46	61.5
June	1.36	0	0	29.96	3.61	12.29 (3.60)	15.90	53.1
July	1.29	0	0	28.44	3.40	11.67 (3.42)	15.07	53.0
August	1.24	0	0	27.25	3.54	11.19 (3.28)	14.73	54.1
September	1.52	0	0	33.51	5.38	13.58 (3.98)	18.96	56.6
October	1.49	0	0	32.90	7.92	13.38 (3.92)	21.30	64.7
November	1.48	0	0	32.63	10.39	13.28 (3.89)	23.59	72.3
December	1.35	0	525 (168)	32.95	12.98	12.22 (3.58)	25.20	76.5

TABLE 3.13
PERFORMANCE SUMMARY
CASE NO. 4

Options:

Location - No. 1

Electric Connection - 4 kV

Fuel Supply - Digester Gas Augmented with Natural Gas

Excess Heat Rejection - Dry Cooling Tower

Ownership and Operations - PSE&G

Month	Digester Gas Flow 10 ⁶ cfd	Natural Gas Flow 10 ⁶ cfd (lb/hr)	Boiler Makeup Oil Flow gpd (lb/hr)	Total Energy Input 10 ⁶ Btu/hr	Heat Used 10 ⁶ Btu/hr	Net Electric Power 10 ⁶ Btu/hr (MWe)	Total Net Energy Output 10 ⁶ Btu/hr	Overall Energy Conversion Efficiency %
January	1.35	0.200 (409)	106 (34)	39.21	13.93	14.85 (4.35)	28.78	73.4
February	1.48	0.126 (269)	0	38.41	13.32	14.85 (4.35)	28.17	73.3
March	1.49	0.119 (256)	0	38.40	11.51	14.85 (4.35)	26.36	68.6
April	1.52	0.103 (226)	0	38.38	9.02	14.85 (4.35)	23.87	62.2
May	1.43	0.151 (318)	0	38.48	6.52	14.85 (4.35)	21.37	55.5
June	1.36	0.195 (400)	0	38.56	3.61	14.85 (4.35)	18.46	47.9
July	1.29	0.235 (475)	0	38.65	3.40	14.74 (4.32)	18.14	46.9
August	1.24	0.267 (533)	0	38.71	3.54	14.74 (4.32)	18.28	47.2
September	1.52	0.103 (226)	0	38.37	5.38	14.85 (4.35)	20.23	52.7
October	1.49	0.119 (256)	0	38.40	7.92	14.85 (4.35)	22.77	59.3
November	1.48	0.126 (269)	0	38.41	10.39	14.85 (4.35)	25.24	65.7
December	1.35	0.200 (409)	0	39.21	12.98	14.85 (4.35)	27.83	71.0

TABLE 3.14
PERFORMANCE SUMMARY
CASE NO. 5

Options:
Location - No. 2
Electric Connection - 26 kV
Fuel Supply - Digester Gas

Excess Heat Rejection - Dry Cooling Tower

Ownership and Operations - PSE&G

Month	Digester Gas Flow 10 ⁶ cfd	Natural Gas Flow 10 ⁶ cfd (lb/hr)	Boiler Makeup Oil Flow gpd (lb/hr)	Total Energy Input 10 ⁶ Btu/hr	Heat Used 10 ⁶ Btu/hr	Net Electric Power 10 ⁶ Btu/hr (MWe)	Total Net Energy Output 10 ⁶ Btu/hr	Overall Energy Conversion Efficiency %
January	1.35	0	728 (233)	34.18	13.93	12.15 (3.56)	26.08	76.3
February	1.48	0	376 (120)	34.90	13.32	13.24 (3.88)	26.56	76.1
March	1.49	0	38 (12)	33.13	11.51	13.31 (3.90)	24.82	74.9
April	1.52	0	0	33.51	9.01	13.52 (3.96)	22.54	67.3
May	1.43	0	0	31.64	6.52	12.87 (3.77)	19.39	61.3
June	1.36	0	0	29.96	3.61	12.22 (3.58)	15.83	52.8
July	1.29	0	0	28.44	3.40	11.60 (3.40)	15.00	52.7
August	1.24	0	0	27.25	3.54	11.13 (3.26)	14.67	53.8
September	1.52	0	0	33.51	5.38	13.52 (3.96)	18.90	56.4
October	1.49	0	0	32.90	7.92	13.31 (3.90)	21.23	64.5
November	1.48	0	0	32.63	10.39	13.24 (3.88)	23.63	72.4
December	1.35	0	530 (169)	32.98	12.98	12.15 (3.56)	25.13	76.2

TABLE 3.15
PERFORMANCE SUMMARY
CASE NO. 6

Options:

Location - No. 2

Electric Connection - 26 kV

Fuel Supply - Digester Gas Augmented with Natural Gas

Excess Heat Rejection - Dry Cooling Tower

Ownership and Operations - PSE&G

Month	Digester Gas Flow 10 ⁶ cfd	Natural Gas Flow 10 ⁶ cfd (lb/hr)	Boiler Makeup Oil Flow gpd (lb/hr)	Total Energy Input 10 ⁶ Btu/hr	Heat Used 10 ⁶ Btu/hr	Net Electric Power 10 ⁶ Btu/hr (MWe)	Total Net Energy Output 10 ⁶ Btu/hr	Overall Energy Conversion Efficiency %
January	1.35	0.200 (409)	119 (38)	39.29	13.93	14.78 (4.33)	28.71	73.1
February	1.48	0.126 (269)	0	38.41	13.32	14.78 (4.33)	28.10	73.2
March	1.49	0.119 (256)	0	38.40	11.51	14.78 (4.33)	26.29	68.5
April	1.52	0.103 (226)	0	38.38	9.02	14.78 (4.33)	23.80	62.0
May	1.43	0.151 (318)	0	38.48	6.52	14.78 (4.33)	21.30	55.4
June	1.36	0.195 (400)	0	38.56	3.61	14.78 (4.33)	18.39	47.7
July	1.29	0.235 (475)	0	38.65	3.40	14.71 (4.31)	18.11	46.9
August	1.24	0.267 (533)	0	38.71	3.54	14.71 (4.31)	18.25	47.1
September	1.52	0.103 (226)	0	38.37	5.38	14.78 (4.33)	20.16	52.5
October	1.49	0.119 (256)	0	38.40	7.92	14.78 (4.33)	22.70	59.1
November	1.48	0.126 (269)	0	38.41	10.39	14.78 (4.33)	25.17	65.5
December	1.35	0.200 (409)	0	39.21	12.98	14.78 (4.33)	27.76	70.8

TABLE 3.16
PERFORMANCE SUMMARY
CASE NO. 7

Options:

Location - No. 1
Electric Connection - 26 kV
Fuel Supply - Digester Gas

Excess Heat Rejection - Dry Cooling Tower

Ownership and Operations - PSE&G

Month	Digester Gas Flow 10 ⁶ cfd	Natural Gas Flow 10 ⁶ cfd (lb/hr)	Boiler Makeup Oil Flow gpd (lb/hr)	Total Energy Input 10 ⁶ Btu/hr	Heat Used 10 ⁶ Btu/hr	Net Electric Power 10 ⁶ Btu/hr (MWe)	Total Net Energy Output 10 ⁶ Btu/hr	Overall Energy Conversion Efficiency %
January	1.35	0	723 (231)	34.15	13.93	12.18 (3.57)	26.11	76.5
February	1.48	0	371 (119)	34.87	13.32	13.24 (3.88)	26.56	76.2
March	1.49	0	31 (10)	33.09	11.51	13.34 (3.91)	24.85	75.1
April	1.52	0	0	33.51	9.02	13.55 (3.97)	22.57	67.4
May	1.43	0	0	31.64	6.52	12.90 (3.78)	19.42	61.4
June	1.36	0	0	29.96	3.61	12.25 (3.59)	15.86	52.9
July	1.29	0	0	28.44	3.40	11.64 (3.41)	15.04	52.9
August	1.24	0	0	27.25	3.54	11.16 (3.27)	14.70	53.9
September	1.52	0	0	33.51	5.38	13.55 (3.97)	18.93	56.5
October	1.49	0	0	32.90	7.92	13.34 (3.91)	21.26	64.6
November	1.48	0	0	32.63	10.39	13.24 (3.88)	23.63	72.4
December	1.35	0	525 (168)	32.95	12.98	12.18 (3.57)	25.16	76.4

TABLE 3.17
PERFORMANCE SUMMARY
CASE NO. 8

Options:

Location - No. 1

Electric Connection - 26 kV

Fuel Supply - Digester Gas Augmented With Natural Gas

Excess Heat Rejection - Dry Cooling Tower

Ownership and Operations - PSE&G

Month	Digester Gas Flow 10 ⁶ cfd	Natural Gas Flow 10 ⁶ cfd (lb/hr)	Boiler Makeup Oil Flow gpd (lb/hr)	Total Energy Input 10 ⁶ Btu/hr	Heat Used 10 ⁶ Btu/hr	Net Electric Power 10 ⁶ Btu/hr (MWe)	Total Net Energy Output 10 ⁶ Btu/hr	Overall Energy Conversion Efficiency %
January	1.35	0.200 (409)	106 (34)	39.21	13.93	14.81 (4.34)	28.74	73.3
February	1.48	0.126 (269)	0	38.41	13.32	14.81 (4.34)	28.13	73.2
March	1.49	0.119 (256)	0	38.40	11.51	14.81 (4.34)	26.32	68.5
April	1.52	0.103 (226)	0	38.38	9.02	14.81 (4.34)	23.83	62.1
May	1.43	0.151 (318)	0	38.48	6.52	14.81 (4.34)	21.33	55.4
June	1.36	0.195 (400)	0	38.56	3.61	14.81 (4.34)	18.42	47.8
July	1.29	0.235 (475)	0	38.65	3.40	14.71 (4.31)	18.11	46.9
August	1.24	0.267 (533)	0	38.71	3.54	14.71 (4.31)	18.25	47.1
September	1.52	0.103 (226)	0	38.37	5.38	14.81 (4.34)	20.19	52.6
October	1.49	0.119 (256)	0	38.40	7.92	14.81 (4.34)	22.73	59.2
November	1.48	0.126 (269)	0	38.41	10.39	14.81 (4.34)	25.20	65.6
December	1.35	0.200 (409)	0	39.21	12.98	14.81 (4.34)	27.79	70.9

TABLE 3.18
EFFLUENT COOLING WATER REQUIREMENTS
(1000 lb/hr)

<u>Fuel Supply</u>	<u>Jan</u>	<u>Feb</u>	<u>Mar</u>	<u>Apr</u>	<u>May</u>	<u>June</u>	<u>July</u>	<u>Aug</u>	<u>Sept</u>	<u>Oct</u>	<u>Nov</u>	<u>Dec</u>
Digester Gas	35.0	47.4	53.4	88.25	97.55	112.0	94.95	84.5	152.9	96.4	60.25	38.0
Digester Gas Augmented With Natural Gas	62.35	64.15	80.25	107.8	135.7	189.0	189.0	189.9	157.1	120.2	92.7	67.65

The economic comparisons among candidate configurations in Section 4 were based on an availability of 92%. This availability, predicated on normal utility operation of an FCPP, was assumed adequate for relative economic analysis. In parallel with the economic analysis, a study was made to consider not only the assumptions resulting in the 92% availability, but other effects, primarily the digester outage rate (two weeks in five years) and a more complicated FCPP cooling loop (additional heat exchangers in series with the normally supplied dry cooling tower). This study resulted in an availability of 87.2%. As will be shown in Section 4.1, this lower availability decreased the annual levelized savings of the selected configuration by 20%. Appendix D describes in detail the basis for the 87.2% availability.

3.2 EQUIPMENT REQUIREMENTS

Conceptual design specifications are required so that capital costs can be estimated and compiled for the possible conceptual design configurations resulting from the installation options, Section 3.1. The initial step in this process is to prepare specifications for the equipment lists resulting from each installation option. Then by consulting equipment vendors, vendor catalogs, and in-house design and cost estimating information, the capital costs can be prepared for each specific configuration.

Overall, the specifications were produced using the major sources of information shown in Table 3.19.

TABLE 3.19
MAJOR SOURCES OF SPECIFICATION CONTENT

UTC Supplied Equipment (Table B.1) - UTC 4.5 MWe Demonstrator
Power Plant Specification (Ref. 1.4)

Balance of Plant Equipment:

Mechanical - Design Analysis (Section 3.1)

Electrical - UTC 4.5 MWe Demonstrator Power Plant
Specification (Ref. 1.4)

Civil - Layouts (Figures 3.4 and 3.5), Equipment Foundation and
Building Foundation Requirements

For convenience in compiling the conceptual design specifications, the two major equipment classifications, UTC Supplied and Balance of Plant, were further divided into the categories shown in Table 3.20. Appendix E contains the actual conceptual design specifications used for cost estimating purposes.

TABLE 3.20
EQUIPMENT CATEGORIES

- a. UTC Supplied Equipment:
 - DC Module (Gas Clean-up, Fuel Processing, Power Section, Thermal Management)
 - Power Conditioner
 - Control Center
 - Water Treatment
 - Cooling

- b. Balance of Plant Equipment:
 - Fuel Supply
 - Coeneration Loop
 - Auxiliary Power Supply
 - Auxiliary Power Distribution
 - Emergency Power Supply
 - Uninterruptable Power Supply
 - Stored Gas Supply (Includes compressed air system)
 - Water Storage
 - Site Yard Piping
 - Site Vents and Drains
 - Fire Protection

- c. Miscellaneous
 - Lighting
 - Communications
 - Grounding
 - Roadways
 - Consumables

3.3 CAPITAL COSTS

In Table 3.21 the components of the total capital cost are shown.

TABLE 3.21
TOTAL CAPITAL COST COMPONENTS

UTC Supplied Equipment Cost	\$ xxx
UTC Supplied Equipment Installation Cost*	xxx
Balance of Plant Equipment Cost*	xxx
Balance of Plant Equipment Installation Cost*	<u>xxx</u>
Total Capital Cost (TCC)	\$ xxx

The UTC supplied equipment installation cost and the balance of plant equipment and installation costs must be known to quantify the relation between total capital cost and the UTC supplied equipment cost.

Costs for the UTC supplied equipment installation and the balance of plant equipment and installation can be obtained by engineering cost estimates using the information contained in Section 3.2, Equipment Requirements, and Appendix E, Conceptual Design Specifications. For convenience, these costs, *in Table 3.21, can be referred to collectively as the Installation and Balance of Plant Equipment Capital Costs.

Table 3.22 lists the material and labor costs which comprise the installation and balance of plant equipment costs for Cases 1-16, defined in Section 3.1.3, according to the equipment categories defined in Table 3.20. Costs for Cases 17-32 are respectively the same since only ownership changes.

Table 3.23 is a similar listing, but differs from Table 3.22 in that the costs are listed by engineering construction disciplines. Note that in both tables, contingency and engineering design costs have been separately listed, whereas in Table 3.21 the contingency and engineering design costs are included in the major categories of UTC supplied equipment installation cost, balance of plant equipment cost, and balance of plant equipment installation cost.

The bulk of the line item costs in Table 3.22 do not change from case to case. However, it is interesting to note the major reasons for cost changes. All are due to the effect of installation options.

For example, there is a change in both material and labor costs between Cases 1-8 and 9-16 for the equipment category "Cooling" under UTC supplied equipment installation. The material cost increases from \$51,000 to \$62,000 due primarily to the addition of a temperature control heat exchanger and piping for WPCF effluent cooling water. However, the labor cost decreases from \$98,00 to \$54,000 because the dry cooling tower installation and its associated civil effort are eliminated.

The increase in both material and labor costs for the even numbered cases compared to the odd numbered cases in the category "Fuel Supply" is due to the need for natural gas compressors. The effect of location on the amount of digester gas piping is evident in the decrease in material and labor costs from Cases 1 to 3, Cases 2 to 4, etc.. Cases 1 and 2 are for Location No. 2 and Cases 3 and 4 are for Location No. 1. The same location effect on cogeneration piping is evident in the equipment category "Cogeneration Loop."

What appears to be an inconsistent increase in material cost occurs in Cases 7, 8, 15 and 16 of the category "Auxiliary Power Supply." This increase is due to a longer run of electrical cable in the cases where the FCPP is situated in Location No. 1 and the electric connection from the FCPP is to the 26 kV side of the WPCF substation (see Figure 2.1). This is the longest run of electric cable, approximately double that of all other cases. Changes of cable runs in the rest of the cases have a negligible impact on material costs.

Other cost changes, some not evident, require backup information too detailed for reporting. However, the assumptions shown next lend some insight into the depth used to prepare the costs shown in Tables 3.22 and 3.23.

TABLE 3.22

WPCF COGENERATION PROJECT
INSTALLATION AND BALANCE OF PLANT EQUIPMENT CAPITAL COSTS

(IN \$1000's - 1979)

ITEM	CASE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
A. UTC Supplied Equipment Installation¹																	
<u>DC MODULE</u>																	
Material		79	79	79	79	79	79	79	79	79	79	79	79	79	79	79	79
Labor		135	135	135	135	135	135	135	135	135	135	135	135	135	135	135	135
Subtotal		214	214	214	214	214	214	214	214	214	214	214	214	214	214	214	214
<u>POWER CONDITIONER</u>																	
Material		66	66	66	66	66	66	66	66	66	66	66	66	66	66	66	66
Labor		127	127	127	127	127	127	127	127	127	127	127	127	127	127	127	127
Subtotal		193	193	193	193	193	193	193	193	193	193	193	193	193	193	193	193
<u>CONTROL CENTER</u>																	
Material		50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50
Labor		95	95	95	95	95	95	95	95	95	95	95	95	95	95	95	95
Subtotal		145	145	145	145	145	145	145	145	145	145	145	145	145	145	145	145
<u>WATER TREATMENT</u>																	
Material		21	21	21	21	21	21	21	21	21	21	21	21	21	21	21	21
Labor		47	47	47	47	47	47	47	47	47	47	47	47	47	47	47	47
Subtotal		68	68	68	68	68	68	68	68	68	68	68	68	68	68	68	68
<u>COOLING</u>																	
Material		51	51	51	51	51	51	51	51	62	62	62	62	62	62	62	62
Labor		98	98	98	98	98	98	98	98	54	54	54	54	54	54	54	54
Subtotal		149	149	149	149	149	149	149	149	116	116	116	116	116	116	116	116
SUBTOTAL		769	769	769	769	769	769	769	769	736	736	736	736	736	736	736	736
B. Balance of Plant Equipment and Installation																	
<u>FUEL SUPPLY</u>																	
Material		287	340	282	335	287	340	282	335	287	340	282	335	287	340	282	335
Labor		155	167	130	142	155	167	130	142	155	167	130	142	155	167	130	142
Subtotal		442	507	412	477	442	507	412	477	442	507	412	477	442	507	412	477
<u>COGENERATION LOOP</u>																	
Material		109	109	92	92	109	109	92	92	105	105	88	88	105	105	88	88
Labor		86	86	51	51	86	86	51	51	86	86	54	54	86	86	54	54
Subtotal		195	195	143	143	195	195	143	143	191	191	142	142	191	191	142	142

¹Excludes UTC Supplied Equipment.

TABLE 3.22 (Cont'd.)

WPCF COGENERATION PROJECT
 INSTALLATION AND BALANCE OF PLANT EQUIPMENT CAPITAL COSTS
 (IN \$1000's - 1979)

ITEM	CASE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
B. Balance of Plant Equipment and Installation (Cont'd.)																	
<u>AUXILIARY POWER SUPPLY</u>																	
Material		51	51	51	51	51	51	67	67	51	51	51	51	51	51	67	67
Labor		17	17	19	19	23	23	32	32	17	17	19	19	23	23	32	32
Subtotal		68	68	70	70	74	74	99	99	68	68	70	70	74	74	99	99
<u>AUXILIARY POWER DISTRIBUTION</u>																	
Material		153	153	153	153	153	153	153	153	153	153	153	153	153	153	153	153
Labor		149	149	149	149	149	149	149	149	149	149	149	149	149	149	149	149
Subtotal		302	302	302	302	302	302	302	302	302	302	302	302	302	302	302	302
<u>EMERGENCY POWER SUPPLY</u>																	
Material		39	39	39	39	39	39	39	39	39	39	39	39	39	39	39	39
Labor		3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Subtotal		42	42	42	42	42	42	42	42	42	42	42	42	42	42	42	42
<u>UNINTERRUPTABLE POWER SUPPLY</u>																	
Material		18	18	18	18	18	16	18	18	18	18	18	18	18	18	18	18
Labor		14	14	14	14	14	14	14	14	14	14	14	14	14	14	14	14
Subtotal		32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32
<u>STORED GAS SUPPLY</u>																	
Material		55	55	55	55	55	55	55	55	55	55	55	55	55	55	55	55
Labor		84	84	84	84	84	84	84	84	84	84	84	84	84	84	84	84
Subtotal		139	139	139	139	139	139	139	139	139	139	139	139	139	139	139	139
<u>WATER STORAGE</u>																	
Material		46	46	46	46	46	46	46	46	46	46	46	46	46	46	46	46
Labor		62	62	62	62	62	62	62	62	62	62	62	62	62	62	62	62
Subtotal		108	108	108	108	108	108	108	108	108	108	108	108	108	108	108	108
<u>SITE YARD PIPING</u>																	
Material		25	25	25	25	25	25	25	25	25	25	25	25	25	25	25	25
Labor		45	45	45	45	45	45	45	45	45	45	45	45	45	45	45	45
Subtotal		70	70	70	70	70	70	70	70	70	70	70	70	70	70	70	70
<u>SITE VENTS & DRAINS</u>																	
Material		27	27	27	27	27	27	27	27	27	27	27	27	27	27	27	27
Labor		23	23	23	23	23	23	23	23	23	23	23	23	23	23	23	23
Subtotal		50	50	50	50	50	50	50	50	50	50	50	50	50	50	50	50

TABLE 3.22 (Cont'd.)

WPCF COGENERATION PROJECT
INSTALLATION AND BALANCE OF PLANT EQUIPMENT CAPITAL COSTS

(IN \$1000's - 1979)

ITEM	CASE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
B. Balance of Plant Equipment and Installation (Cont'd)																	
<u>FIRE PROTECTION SYSTEM</u>																	
Material		40	40	40	40	40	40	40	40	40	40	40	40	40	40	40	40
Labor		32	32	32	32	32	32	32	32	32	32	32	32	32	32	32	32
Subtotal		72	72	72	72	72	72	72	72	72	72	72	72	72	72	72	72
SUBTOTAL		1,520	1,585	1,440	1,505	1,526	1,533	1,469	1,534	1,516	1,581	1,349	1,504	1,522	1,587	1,468	1,533
C. Miscellaneous																	
<u>LIGHTING</u>																	
Material		4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Labor		3	3	3	3	3	3	3	3	3	3	3	3	3	3	3	3
Subtotal		7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
<u>COMMUNICATIONS</u>																	
Material		1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Labor		1	1	1	1	1	1	1	1	1	1	1	1	1	1	1	1
Subtotal		2	2	2	2	2	2	2	2	2	2	2	2	2	2	2	2
<u>GROUNDING</u>																	
Material		4	4	4	4	4	4	4	4	4	4	4	4	4	4	4	4
Labor		10	10	10	10	10	10	10	10	9	9	9	9	9	9	9	9
Subtotal		14	14	14	14	14	14	14	14	13	13	13	13	13	13	13	13
<u>ROADWAYS</u>																	
Material		5	5	5	5	5	5	5	5	5	5	5	5	5	5	5	5
Labor		7	7	7	7	7	7	7	7	7	7	7	7	7	7	7	7
Subtotal		12	12	12	12	12	12	12	12	12	12	12	12	12	12	12	12
<u>CONSUMABLES</u>																	
Subtotal		3	3	2	2	3	3	2	2	3	3	2	2	3	3	2	2
SUBTOTAL		38	38	37	37	38	38	37	37	37	37	36	36	37	37	36	36
INSTALLATION AND BALANCE OF PLANT EQUIPMENT CONSTRUCTION COST (CC)		2,327	2,392	2,246	2,311	2,333	2,398	2,275	2,340	2,289	2,354	2,211	2,276	2,295	2,360	2,240	2,305
CONTINGENCY (15% OF CC)		349	358	337	346	350	359	341	351	343	353	331	341	344	354	336	345
ENGINEERING DESIGN (8% OF CC)		186	191	180	184	187	192	182	187	183	188	177	182	184	189	179	184
INSTALLATION AND BALANCE OF PLANT EQUIPMENT CAPITAL COST		2,862	2,941	2,763	2,841	2,870	2,949	2,798	2,878	2,815	2,895	2,719	2,779	2,823	2,903	2,755	2,834

TABLE 3.23

WPCF COGENERATION PROJECT
INSTALLATION AND BALANCE OF PLANT EQUIPMENT CAPITAL COSTS

(IN \$1000's - 1979)

DISCIPLINE	CASE	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16
<u>CIVIL</u>																	
Material		380	380	380	380	380	380	380	380	337	337	337	337	337	337	337	337
Labor		751	751	751	751	751	751	751	751	670	670	670	670	670	670	670	670
Subtotal Civil		1,131	1,131	1,131	1,131	1,131	1,131	1,131	1,131	1,007	1,007	1,007	1,007	1,007	1,007	1,007	1,007
<u>ELECTRICAL</u>																	
Material		248	248	248	248	248	248	263	263	247	247	247	247	247	247	263	263
Labor		140	140	142	142	146	146	156	156	139	139	142	142	145	145	155	155
Subtotal Electrical		388	388	390	390	394	394	419	419	386	386	389	389	392	392	418	418
<u>MECHANICAL</u>																	
Material		506	559	484	537	506	559	484	537	555	608	532	585	555	608	532	585
Labor		302	314	241	253	302	314	241	253	341	353	283	295	341	353	283	295
Subtotal Mechanical		808	873	725	790	808	873	725	790	896	961	815	880	896	961	815	880
INSTALLATION AND BALANCE OF PLANT EQUIPMENT CONSTRUCTION COSTS (CC)		2,327	2,392	2,246	2,311	2,333	2,398	2,275	2,340	2,289	2,354	2,211	2,276	2,295	2,360	2,240	2,305
CONTINGENCY (15% OF CC)		349	358	337	346	350	359	341	351	343	353	331	341	344	354	336	345
ENGINEERING DESIGN (8% OF CC)		186	191	180	184	187	192	182	187	183	188	177	182	184	189	179	184
INSTALLATION AND BALANCE OF PLANT EQUIPMENT CAPITAL COST		2,862	2,941	2,763	2,841	2,870	2,949	2,798	2,878	2,815	2,895	2,719	2,799	2,823	2,903	2,755	2,834

ASSUMPTIONS FOR COST ESTIMATES

- a. All equipment was costed individually (except some instrumentation and valving which was bulk costed) and then compiled to prepare the line items shown in Tables 3.22 and 3.23. The costs are more detailed than typically prepared for a conceptual cost analysis. For example, complete routing and entrenchment of all piping, including the fire hydrant system, was considered (Figures 3.6, 3.7, and 3.8). Some diameters of FCPP interconnecting yard piping and electrical cable were averaged to reduce the cost estimating effort. However, all electrical and pipe connections were costed including the effects of welding according to UTC drawing requirements, Appendix B. All foundations were sized. Due to unfavorable soil conditions, costs were included in the civil detail for shoring, dewatering, and piling. These costs were based on prior in-house civil experience and practice at the WPCF.
- b. Plant equipment and bulk material pricing were applied using current market prices from manufacturers and suppliers (Figure 3.9).
- c. Labor rates for the New York - New Jersey region were used.
- d. Interface design yard process piping ranged from .5 to 6 inch carbon steel. All yard piping was estimated an average 3 inch carbon steel, Schedule 40, coated and wrapped.
- e. HVAC provisions were included in the Control and Data Acquisition Building and the Switchgear Building.

COMMON ENTRENCHMENT TO ACCOMMODATE 7 PROCESSES

$$\begin{aligned}\text{CROSS SECTION AREA} &= .5(5) (3.25 + 13.25) \\ &= .5(5) (16.5) \\ &= 41.25 \text{ FT.}^2\end{aligned}$$

$$\begin{aligned}\text{VOLUME OF FILL} &= 41.25 \times 50' \\ &= 2063 \text{ FT.}^3 \\ &= 76 \text{ YD.}^3\end{aligned}$$

$$\begin{aligned}\text{SAND FILL} &= 16 \text{ YD.}^3 \\ \text{BACKFILL} &= 60 \text{ YD.}^3\end{aligned}$$

FIGURE 3.6
EXAMPLE OF COSTING DETAIL

FIGURE 3.7
EXAMPLE OF COSTING DETAIL

CLIENT **DOE**
 PROJECT **FUEL CELL COGENERATION PLANT**
 JOB DESCRIPTION **PROCESS YARD PIPING**
 WORK ORDER NO. **088249-002**

ESTIMATED **HDM** DATE **3/15/79**

CHECKED _____ DATE _____

APPROVED _____ DATE _____

☐ SUMMARY ☒ DETAIL

SHEET **2** OF **2**

☐ C/S/A ☒ MECH ☐ PIPE ☐ ELEC ☐ INST

ITEM AND DESCRIPTION	QUANTITY	UNIT	UNIT MAT'L COST \$	MANHOURS			PLANT EQUIPMENT	BULK MATERIAL	LABOR	TOTAL
				UNIT	TOTAL	\$/MH				
PROCESS YARD PIPING (CON'T.) (BASED ON LOCATION 2)										
PIPING										
3"C.S. SCHEDULE 40 A53 B31.1 (COAT AND WRAP)	2530	LF	4.31	.31	784	28.		10,900	20,380	31,280
FITTINGS										
3" 90°LR ELBOWS C.S. STD B31.1	102	EA	10.50	2.1	214	28.		1,070	5,560	6,630
3" TEES C.S. STD B31.1	2	EA	28.18	2.1	4.2	28.		60	110	170
FIELD WELDS (ASSUME 20' LENGTHS)										
3" C.S. SCH 40 B31.1 (COAT AND WRAP)	127	EA	-	2.1	267	28.			6,940	6,940
INSULATION										
3" RIGID CALCIUM SILICATE WITH ALUMINUM JACKET AND SEALER	380	LF	5.12	.28	98.8	28.		1,950	2,570	4,520
VALVES										
3" GATES OPEN/CLOSE C.S.	17	EA	594.00	3.8	64.6	28.	10,100		1,680	11,780
TOTAL THIS PAGE				1185.80			10,100	13,980	37,240	61,320
							10,100	14,820	44,870	69,790

FIGURE 3.8
 EXAMPLE OF COSTING DETAIL

CLIENT **DOE**
 PROJECT _____
 JOB DESCRIPTION **FUEL SUPPLY**
 WORK ORDER NO. **088249-002**

ESTIMATED **HDM** DATE **4/17/79**
 CHECKED _____ DATE _____
 APPROVED _____ DATE _____
☐ SUMMARY ☐ DETAIL

SHEET **2** OF **5**
☐ C/S/A ☒ MECH ☐ PIPE ☐ ELEC ☐ INST

ITEM AND DESCRIPTION	QUANTITY	UNIT	UNIT MATL COST \$	MANHOURS			PLANT EQUIPMENT	BULK MATERIAL	LABOR	TOTAL
				UNIT	TOTAL	\$/MH				
EQUIPMENT										
DIGESTER GAS GAS COMPRESSOR - DIGESTER GAS - 1323 ACFM INLET CAPACITY AT 90°F 12.91 PSIA, 2 STAGE PRESSURE RATIO PER STAGE 2.92, OVERALL PRESSURE RATIO 8.5, T-INTERCOOLER 85°F, MINIMUM GAS-T-OUT OF INTER- COOLER 105°F, 150 HP MOTOR TEPC I.R. MOD - 14-3/4 AND 9-1/2 X 11 ESH 2 WITH INTERCOOLER	2	EA	98,000	500	1000	26.	196,000		26,000	222,000
AFTERCOOLER	2	EA	5,000	35	70	26.	5,000		1,800	6,800
TOTAL THIS PAGE					1070		201,000		27,800	228,800

FIGURE 3.9
 EXAMPLE OF COSTING DETAIL

- f. Fire protection and vent and drain systems were analyzed as a requirement of the installation.
- g. Existing power sources were assumed to be available at the existing Pumphouse and Digester Control Buildings for additional equipment required in these facilities due to design modifications. Also, direct burial cable was entrenched at the site facilities in lieu of ductbank for all power and control networks.
- h. Domestic service water was assumed to be available at the site locations. Augmented natural gas piping is not included in Tables 3.22 and 3.23. However, equipment requirements (compressor and aftercooler) with associated piping and instrumentation are included. The natural gas piping costs will be included as a line item in the economic analysis.

3.4 CANDIDATE CONCEPTUAL DESIGNS

It would be both time consuming and wasteful to subject all 32 possible configurations to an economic analysis. Thus, as stated in Section 3.1, it was necessary to screen the 32 possible configurations to a reduced number of candidate conceptual designs. Possible configurations were eliminated whose installation options had negligible impact on operating conditions and capital costs, or which did not exhibit any factors of institutional importance, such as the option of ownership and operation.

Table 3.24 lists the candidates screened and approved by BCUA, PSE&G, and G/C for economic analysis. The logic of their screening is best understood by systematically evaluating each installation option (location, electric connection, fuel supply, heat utilization, and ownership) affecting the 32 possible configurations.

TABLE 3.24
CANDIDATE CONCEPTUAL DESIGNS

<u>Cases</u>	<u>Fuel Supply</u>	<u>Ownership</u>	<u>Location No.</u>	<u>Cooling</u>
5	Digester Gas	PSE&G	2	Dry Cooling Tower
21	Digester Gas	BCUA	2	Dry Cooling Tower
6	Digester & Natural Gas	PSE&G	2	Dry Cooling Tower
22	Digester & Natural Gas	BCUA	2	Dry Cooling Tower
13	Digester Gas	PSE&G	2	Effluent
29	Digester Gas	BCUA	2	Effluent
14	Digester & Natural Gas	PSE&G	2	Effluent
30	Digester & Natural Gas	BCUA	2	Effluent
3	Digester Gas	PSE&G	1	Dry Cooling Tower

Location: There were two location options as shown in Figures 2.1 and 2.2.

Table 3.25 identifies similar cases in all options except location. By referring to the performance summary tables, shown in parenthesis, it can be seen that the fuel supplies, electrical power output, and efficiency differences between Location No. 1 and Location No. 2 cases are negligible. For example, consider the first line of Table 3.25. The Performance Summary Table, 3.10, shows that, for Location No. 2 in January, the digester gas available is 1.35×10^6 cfd, the make-up oil required is 728 gpd, the heat used is 13.93×10^6 Btu/hr, and the net electric power is 3.57 MWe for an overall energy efficiency of 76.4%. For Location No. 1 in January, Table 3.12 has a digester gas supply of 1.35×10^6 cfd, a make-up oil requirement of 723 gpd, a heat used of 13.93×10^6 Btu/hr and a net electric power of 3.58 MWe for an overall efficiency of 76.6%. The difference in the respective operating conditions between the two locations are negligible, indicating that an economic analysis is unwarranted.

TABLE 3.25
CASE COMPARISON FOR LOCATION OPTION

<u>Electric Connection</u>	<u>Heat Utilization</u>	<u>Fuel Supply</u>	<u>Case Location 2</u>	<u>Case Location 1</u>
4 kV	Dry Cooling Tower	Digester Gas	Case 1 (3.10)	Case 3 (3.12)
4 kV	Dry Cooling Tower	Digester Plus Natural Gas	Case 2 (3.11)	Case 4 (3.13)
26 kV	Dry Cooling Tower	Digester Gas	Case 5 (3.14)	Case 7 (3.16)
26 kV	Dry Cooling Tower	Digester Plus Natural Gas	Case 6 (3.15)	Case 8 (3.17)

Similar results occur for Cases 9-16 with effluent cooling.

Capital cost differences (Table 3.22) between the cases shown in Table 3.25 vary from 2.5 percent to 4 percent for the installation and balance of plant equipment capital cost. Thus, there is some basis for economically evaluating the location option due to differences in capital cost.

Two factors, other than operating conditions and capital cost, had a bearing on whether to include the location options in the economic analysis. First, Location No. 1 is area limited for equipment placement. Problems would arise if additional equipment were required. Similarly, there may not be enough area for laydown of equipment at Location No. 1 during construction. Second, the Bergen County Utilities Authority expressed a strong preference for Location No. 2, stating that a) "Location No. 1 is directly across from the Administration Building and aesthetically unacceptable," b) "the storage of naphtha and hydrogen near their fuel oil storage tanks appears a hazard," and c) "the Authority may wish to expand (WPCF electrical) generating facilities requiring the use of land near Location No. 1."

The overriding factor in the decision to consider the location option in the economic analysis was BCUA's expressed preference. It was decided on that basis not to pursue the location option further, except to economically evaluate a single Location No. 1 case (Case 3) so that this option's impact would be known.

Electric Connection: As stated in Section 1.3, a range of FCPP electric voltage outputs is available including 4 kV and 26kV. Therefore, the FCPP could be connected to either the 4 kV switchgear - Bus 1 in the Switchgear Building or to the 26 kV grid side bus in the WPCF substation.

An inspection of the Performance Tables, 3.10 through 3.17, shows an approximate .3% difference in net electric power between similar cases where only the electric connection option is changed from 4 kV to 26 kV. This change in performance was considered as being insignificant in a feasibility study. Similarly, equipment capital costs did not change between the 4 kV and the 26 kV electric connection cases. This is apparent in Table 3.22 where no capital costs changes appear in the Auxiliary Power Distribution Equipment between Cases 1 through 4 with the 4 kV connection, and Cases 5 through 8 with the 26 kV connection.

Since the electrical connection installation option has an insignificant effect on operating conditions and no effect on capital costs, this option was disregarded during the economic analysis.

Fuel Supply: The FCPP could be fueled either by digester gas only or digester gas augmented with natural gas.

The results of the design analysis show that the method of fuel supply has a major effect on operating conditions and an approximate 3% capital cost difference between similar cases. For these reasons, the fuel supply option was considered in the economic analysis.

Heat Utilization: As described in Section 2.4, there is only one approach to heat utilization; however, two methods were identified for rejecting excess FCPP heat. These are rejection by a dry cooling tower or effluent cooling.

There appears to be a negligible affect (approximately a 30 kW increase in auxiliary power for the dry cooling tower) on operating conditions between the two methods of rejecting excess heat. However, there is a normal sewage

charge for the effluent water used for cooling in the shell and tube heat exchanger since this coolant is dumped into the WPCF at the beginning of the treatment process.

It was difficult to evaluate the effect of each heat rejection method on capital cost before the economic analysis. The installation cost is reduced in the effluent coolant cases. This is because the cost of the dry cooling tower foundations, piping, and pipe entrenchment is less than the increased capital cost of the shell and tube heat exchanger and its installation. Also, the cost of the UTC supplied dry cooling tower must be considered in the economic analysis.

In summary, it was difficult to assess the impact of the method of heat rejection prior to the economic analysis. For this reason this option was retained for economic analysis.

Ownership and Operation: There are two options of ownership and operation: by PSE&G or by BCUA. The investigation of the other installation options and the design analysis showed no effects due to this option. The effect of ownership and operation can only be determined by the economic analysis.

SECTION 4.0 POTENTIAL BENEFITS

4.1 ECONOMIC EVALUATION OF SPECIFIC APPLICATION

This section contains a description of the economic analysis of the candidate conceptual designs shown in Table 3.24. Also shown is the selected design configuration along with a discussion of the rationale for selection. The environmental regulations that apply to the FCPP and the environmental benefits that can be attained with the FCPP are discussed, along with the nationwide application of FCPP in water pollution control facilities that use the anaerobic digestive process.

At present, BCUA is planning to install two new boilers to increase the heat production capacity of the WPCF. In the economic evaluations, it was assumed that the FCPP would be installed in addition to the new boiler capacity. The planned boiler additions would provide back-up thermal supply capacity to the WPCF during maintenance or forced outages of the FCPP.

This economic evaluation was based on a total system approach in which the levelized annual revenue requirements associated with the ownership and operation of the cogenerating FCPP were compared to the alternative levelized annual revenue requirements of operating the conventional boiler plant to satisfy the WPCF heat requirements. Annual revenue requirements include (1) fixed costs, such as return on investment, depreciation and appropriate taxes which result from a capital expenditure for a plant, (2) operating costs such as fuel, operation and maintenance, and (3) other charges associated with the operation of the plant. The alternative plan (i.e. FCPP or conventional boiler plant) with the least annual revenue requirements was considered the proper economic choice.

The economic evaluation methodology used for this study was based on life cycle costing, recognizing all appropriate escalation rates. All cost components were treated on an annual levelized basis. Annual levelized revenue requirements were determined by finding the present worth of each cost

component for 1982 (i.e. service date of the FCPP). The uniform series of costs, over the life of the plant, that is equivalent to the present worth value is the levelized annual revenue requirements. A 20 year life of the FCPP was assumed for this study.

UTC supplied a breakdown of their estimate of the FCPP selling price. From this estimate, a breakdown of only UTC supplied equipment, defined in Appendix B, Table B.1, was determined as follows:

	Selling Price Breakdown	
	FCPP	UTC Supplied Equipment
UTC Supplied Equipment		
DC Module Including Water Treatment Subsystem	73%	81%
Dry Cooling Tower	7%	8%
Power Conditioning System	10%	11%
Utility Supplied Subsystems	<u>10%</u>	<u>-</u>
	100%	100%

For those economic evaluations which involve effluent cooling of the FCPP, the capital cost of UTC supplied equipment was assumed to be 8% less than the capital cost of UTC supplied fuel cell equipment with a dry cooling system. The breakeven capital cost of UTC supplied equipment will be presented both with and without dry cooling tower equipment.

The results of the economic evaluation are shown in Tables 4.1, 4.2, 4.3, and 4.4. The UTC supplied equipment capital cost in those cases which utilize dry cooling was assumed to be \$535/kW (1979 dollars). In those cases which utilize effluent cooling, the UTC supplied equipment capital cost was assumed to be \$490/kW to reflect the exclusion of the dry cooling tower. The availability, of the FCPP in Tables 4.1, 4.2 and 4.3 was assumed to be 92%. This availability was taken from the EPRI Report EM-336 "Economic Assessment of the

Utilization of Fuel Cells in Electric Utility Systems". In Table 4.4, the availability of the FCPP was assumed to be 87.2%, based on the analysis described in Section 3.1.4. All cases in Tables 4.1, 4.2 and 4.4 were based on the FCPP being installed at Location No. 2.

In Table 4.1, Item I shows the levelized annual revenue requirements for each candidate design with PSE&G ownership and operation of the FCPP. Item II shows the levelized annual revenue requirements for ownership and operation of the conventional boiler plant. An inspection of the FCPP revenue requirements and the conventional boiler plant revenue requirements shows that in all cases the FCPP is the proper economic choice, with a levelized savings each year (i.e., difference in levelized revenue requirements) ranging from \$546,400 to \$589,700 (in 1982 dollars). These annual savings result because the energy and capacity credits that can be realized with the FCPP more than offset the additional capital investment for the FCPP and the charges to provide back-up boiler capacity. Cases 5 and 6, in which the FCPP was fueled with digester gas only, show potentially greater savings than Cases 13 and 14 in which the digester gas was supplemented with natural gas.

Table 4.2 shows the economic results based on BCUA ownership/operation of the FCPP for Cases 21, 22, 29 and 30. Again, in all four cases, the FCPP is the economic choice based on a revenue requirement comparison with the conventional boiler plant. The levelized annual savings ranged from \$296,900 to \$570,100. As with the PSE&G ownership options, those cases with digester gas only (i.e. Cases 21 and 22) show greater potential savings than those cases with digester gas supplemented with natural gas (Cases 29 and 30).

Table 4.3 shows one case with PSE&G ownership of the FCPP, digester gas only, dry cooling and Location No. 1. Since BCUA has a strong preference for Location No. 2 as described in Section 2.0, Location No. 2 was the predominant location for all cases studied. Table 4.3 shows that the potential annual savings for the FCPP installed at Location No. 1 are approximately the same as Location No. 2: \$602,500, Case 7, compared to \$589,700, Case 5.

TABLE 4.1
SUMMARY OF LEVELIZED ANNUAL REVENUE REQUIREMENTS
PSE&G Ownership/Operation
Location No. 2
(In \$1,000 - 1982)

	Digester Gas Only Dry Cooling CASE 5	Digester Gas Natural Gas Dry Cooling CASE 6	Digester Gas Effluent Cooling CASE 13	Digester Gas Natural Gas Effluent Cooling CASE 14
I. Fuel Cell Power Plant				
A. Capital Carrying Charges				
UTC Supplied Equipment	390.0	390.0	358.8	358.8
Balance of Plant	465.7	478.5	458.0	471.0
Gas Mains	-	23.6	-	23.6
Boilers (1)	0	0	0	0
Working Capital	11.5	11.7	11.4	11.6
B. Auxiliary Fuel				
No. 2 Fuel Oil	46.4	3.4	46.4	3.4
Natural Gas	-	299.8	-	299.8
C. Fuel Cell Operation and Maintenance Expenses				
Variable	291.5	338.4	293.3	340.4
Fixed (Operator)	286.0	286.0	286.0	286.0
D. Standby Boiler Charge	147.2	147.2	147.2	147.2
E. Effluent Cooling Charge	-	-	52.5	79.1
F. Credits				
Replacement Energy	(1,905.0)	(2,216.0)	(1,919.0)	(2,228.9)
Replacement Capacity	(67.5)	(67.5)	(67.5)	(67.5)
Decrease in Transmission & Distribution Losses	(89.5)	(104.1)	(90.2)	(104.9)
Subtotal	(423.7)	(409.2)	(423.1)	(380.4)
II. Conventional Boiler Plant				
A. Capital Carrying Charges				
Boilers	0	0	0	0
B. Auxiliary Fuel	0	0	0	0
C. Operation and Maintenance Expenses				
Parts and Materials				
Standby Boilers	9.4	9.4	9.4	9.4
Operating Boilers	18.8	18.8	18.8	18.8
Operators	137.8	137.8	137.8	137.8
Subtotal	166.0	166.0	166.0	166.0
III. Fuel Cell Power Plant				
Penalty or (Savings)	(589.7)	(575.2)	(589.1)	(546.4)

(1) The boilers to be used as backup for the FCPP are existing equipment at the WPCF.

TABLE 4.2
SUMMARY OF LEVELIZED ANNUAL REVENUE REQUIREMENTS
BCUA Ownership/Operation
Location No. 2
(In \$1,000 - 1982)

	Digester Gas Only Dry Cooling CASE 21	Digester Gas Natural Gas Dry Cooling CASE 22	Digester Gas Effluent Cooling CASE 29	Digester Gas Natural Gas Effluent Cooling CASE 30
I. Fuel Cell Power Plant				
A. Capital Carrying Charges				
UTC Supplied Equipment	288.8	288.8	268.6	268.6
Balance of Plant	345.0	354.5	339.4	349.6
Boilers (1)	0	0	0	0
Working Capital	4.9	5.0	4.9	5.0
B. Auxiliary Fuel				
No. 2 Fuel Oil	54.9	4.0	54.9	4.0
Natural Gas	-	494.6	-	494.6
C. Fuel Cell Operation and Maintenance Expenses				
Variable	307.2	357.2	307.2	357.2
Fixed (Operator)	137.8	137.8	137.8	137.8
D. Standby Boiler Charge	147.2	147.2	147.2	147.2
E. Effluent Cooling Charge	-	-	52.5	79.1
F. Electrical Requirements				
Supplemental Electricity and Standby Capacity	<u>2,648.8</u>	<u>2,365.3</u>	<u>2,648.8</u>	<u>2,365.3</u>
Subtotal	3,934.6	4,154.4	3,961.3	4,207.8
II. Conventional Boiler Plant				
A. Capital Carrying Charges				
Boilers	0	0	0	0
B. Auxiliary Fuel	0	0	0	0
C. Operation and Maintenance Expenses				
Parts and Materials				
Standby Boilers	9.4	9.4	9.4	9.4
Operating Boilers	18.8	18.8	18.8	18.8
Operators	137.8	137.8	137.8	137.8
D. Electrical Energy	<u>4,338.7</u>	<u>4,338.7</u>	<u>4,338.7</u>	<u>4,338.7</u>
Subtotal	4,504.7	4,504.7	4,504.7	4,504.7
III. Fuel Cell Power Plant Penalty or (Savings)	(570.1)	(350.3)	(543.4)	(296.9)

(1) The boilers to be used as backup for the FCPP are existing equipment at the WPCF.

TABLE 4.3
SUMMARY OF LEVELIZED ANNUAL REVENUE REQUIREMENTS
PSE&G Ownership/Operation
Location No. 1
(In \$1,000 - 1982)

	Digester Gas Only Dry Cooling <u>Case 7</u>
I. Fuel Cell Power Plant	
A. Capital Carrying Charges	
UTC Supplied Equipment	390.0
Balance of Plant	454.0
Boilers (1)	0
Working Capital	11.4
B. Auxiliary Fuel	
No. 2 Fuel Oil	45.7
C. Fuel Cell Operation and Maintenance Expenses	
Variable	291.2
Fixed (Operators)	286.0
D. Standby Boiler Charge	147.2
E. Credits	
Replacement Energy	(1,905.0)
Replacement Capacity	(67.5)
Decrease in Transmission & Distribution Losses	(89.5)
Subtotal	<u>(436.5)</u>
II. Conventional Boiler Plant	
A. Capital Carrying Charges	
Boilers	0
B. Auxiliary Fuel	0
C. Operating and Maintenance Expenses	
Parts and Materials	
Standby Boilers	9.4
Operating Boilers	18.8
Operators	137.8
Subtotal	<u>166.0</u>
III. Fuel Cell Power Plant Penalty or (Savings)	(602.5)

(1) The boilers to be used as backup for the FCPP are existing equipment at the WPCF.

TABLE 4.4
SUMMARY OF LEVELIZED ANNUAL REVENUE REQUIREMENTS
PSE&G Ownership/Operation
Location No. 2
Fuel Cell Plant Availability - 87.2%
(In \$1,000 - 1982)

	Digester Gas Only Dry Cooling Case 5
I. Fuel Cell Power Plant	
A. Capital Carrying Charges	
UTC Supplied Equipment	390.0
Balance of Plant	454.0
Boilers (1)	0
Working Capital	11.5
B. Auxiliary Fuel	
No. 2 Fuel Oil	46.4
C. Fuel Cell Operation and Maintenance Expenses	
Variable	276.0
Fixed (Operators)	286.0
D. Standby Boiler Charge	147.2
E. Credits	
Replacement Energy	(1,800.0)
Replacement Capacity	(67.5)
Decrease in Transmission & Distribution Losses	(84.8)
Subtotal	(329.5)
II. Conventional Boiler Plant	
A. Capital Carrying Charges	
Boilers	0
B. Auxiliary Fuel	0
C. Operating and Maintenance Expenses	
Parts and Materials	
Standby Boilers	9.4
Operating Boilers	18.8
Operators	137.8
Subtotal	166.0
III. Fuel Cell Power Plant Penalty or (Savings)	(495.5)

- (1) The boilers to be used as backup for the FCPP are existing equipment at the WPCF.

All of the above economic evaluation cases were based on FCPP availability of 92%. This availability results from a two week per year maintenance outage and a 4% forced outage of the FCPP. In parallel with the economic evaluation, a reliability evaluation of the total FCPP including the cogeneration thermal system was conducted. This evaluation, which is described in Section 3.1.4, resulted in a FCPP availability of 87.2%. In Table 4.4, the economic evaluation of Case 5 with a FCPP availability of 87.2% shows that the total annual levelized savings is \$495,000 or approximately 20% less than the same evaluation of Case 5 with a FCPP availability of 92% shown in Table 4.1.

The relationship of break-even capital cost of the UTC supplied equipment for either PSE&G or BCUA ownership and operation versus total annual savings is shown in Figure 4.1 for UTC supplied equipment with a dry cooling tower and in Figure 4.2 for UTC supplied equipment without a dry cooling tower. In Figure 4.1, the break-even capital with dry cooling was based on Case 5 for PSE&G ownership/operation and Case 21 for BCUA ownership/operation since these two cases are the best economic choices (i.e. greatest savings) of the conceptual design alternates with dry cooling. In Figure 4.2, the break-even capital without dry cooling was based on Case 13 for PSE&G ownership and operation and on Case 29 for BCUA ownership and operation. These two figures show that if the revenue requirements for the FCPP were the same as the revenue requirements for the conventional boiler plant (i.e. no total savings) then the breakeven capital cost of the UTC supplied equipment with dry cooling could be as high as \$1258/kW (1979) for the PSE&G ownership option and \$1488/kW (1979) for the BCUA ownership option. Also, the uninstalled, break-even capital cost of the UTC supplied equipment without dry cooling could be as high as \$1217/kW (1979) for PSE&G ownership and as high as \$1407/kW (1979) for BCUA ownership. However, for any organization to be willing to invest in a new technology such as fuel cells, there has to be potential savings over conventional alternative energy supplies. It should be noted that the breakeven capital cost for BCUA ownership and operation is greater than the breakeven capital cost of PSE&G ownership and operation due to the lower cost of money for BCUA financing.

Appendix F contains a description of each of the revenue requirements, economic back-up data, and a detailed economic calculation for Case 5: PSE&G

FIGURE 4.1
FCPP COGENERATION PROJECT
BREAKEVEN CAPITAL COST OF
UTC SUPPLIED EQUIPMENT
INCLUDING DRY COOLING TOWER

FIGURE 4.2
FCPP COGENERATION PROJECT
BREAKEVEN CAPITAL COST OF
UTC SUPPLIED EQUIPMENT
EXCLUDING DRY COOLING TOWER

ownership/ operation of the FCPP, digester gas only, 26 kV electric connection and dry cooling. All other cases were analyzed in exactly the same manner using the appropriate economic parameters.

4.2 SELECTED CONFIGURATION

4.2.1 Basis of Selection

The preceeding evaluation describes the overall economics of each candidate conceptual design in Table 3.24. Along with institutional factors, described in Section 2.0, this information formed the basis of selection for continuing one of the candidates into the preliminary engineering design phase.

4.2.2 Selection Result

Due to the favorable economics and the technical feasibility of the application, a recommendation will be made in Section 5.0 to continue this application into a preliminary engineering phase. The candidate selected for continuation is Case 5, Table 3.24. A review of its associated installation options is shown in Table 4.5.

TABLE 4.5
INSTALLATION OPTIONS OF THE SELECTED CONFIGURATION

Location - No. 2

Electrical Connection - To WPCF 26 kV bus

Fuel Supply - Digester gas only

Heat Utilization - Four in-line heat exchangers; grease melting, space heating, digesters (actually subdivided into 4 parallel heat exchangers) and temperature control (excess heat rejection). The method of excess heat rejection is through the use of a UTC supplied dry cooling tower.

Operation and Ownership - PSE&G

4.2.3 Rationale for Selection

The following is a summary of the rationale for selection of Case 5. The items addressed appear in the order of their relative importance in the selection process.

Ownership and Operation: PSE&G is the preferred owner and operator of the cogeneration FCPP based on their normal business function of providing electric power. This conclusion is based on PSE&G experience and knowledge in operating conventional, cogeneration, and fuel cell power plants. The BCUA does not have the experience nor the desire to own and operate an FCPP. Therefore, the BCUA O&M costs could be higher than estimated in this study. Furthermore, BCUA would prefer PSE&G ownership and operation of the FCPP while sharing in the resulting savings.

It should also be noted that the economic results show higher savings with PSE&G ownership and operation when the UTC supplied equipment capital cost is \$600/kW (1979 dollars) or less. This cost estimate is within the range of projected commercial cost for the UTC supplied equipment. With this cost, the project would meet the investment criteria of PSE&G, hence, the recommendation is made in Section 5.0 to proceed with the preliminary engineering phase.

Fuel Supply: The option for fuel supply by digester gas only was selected on the basis of higher savings. Each case with only digester gas showed a higher savings than the similar case where the digester gas was augmented with natural gas. This result simplifies control, operation, and maintenance of the installation. In addition, the supply situation for natural gas is uncertain in the future, although natural gas is presently available.

Location: In all candidate conceptual designs, except Case 9; the FCPP was sited at Location No. 2 due to BCUA preference (see Section 3.4). The evaluation of Case 9 indicated that the impact on the operating conditions and economic analysis of changing to Location No. 1 was minimal.

Heat Rejection: The choice of heat rejection using the UTC supplied dry cooling tower was based solely on economics. Cases with the dry cooling tower showed larger savings than respective cases with effluent cooling.

Electrical Connection: As previously stated, the electrical connection from the FCPP to either the WPCF 26 kV or the 4 kV buses had negligible impact on the study results. The 26 kV connection was selected so that all power input to the WPCF would be at the 26 kV level. (The PSE&G circuits to the WPCF are rated at 26 kV.)

4.2.4 Description of the Selected Configuration

The selected configuration offers a number of important features. On a yearly basis, it provides 30×10^6 kW/hr of electricity and fulfills the heating requirements of the WPCF with only 50,000 gallons of No. 2 heating fuel oil required for make-up heat. This results in a 65% annual utilization of the energy available from the digester gas, whereas with the conventional boiler plant only 27% of the energy in the digester gas is used. Installation of the FCPP also results in an annual levelized savings of \$589,700 (in 1982 dollars) over the 20 year lifetime compared to the conventional method of supplying heat, provided that the UTC supplied equipment (defined by Table B.1) cost \$535/kW (in 1979 dollars). Capital cost required for the configuration equipment (exclusive of UTC supplied equipment) and its installation (including UTC supplied equipment) is \$2,870,000 in 1979 dollars. The selected configuration uses all digester gas produced (monthly average basis) resulting in an equivalent savings of 26,000 barrels of No. 6 oil each year (on peak) and savings of 5,900 tons of coal each year (off peak).

Appendix G is a detailed description of the selected configuration according to the equipment categories, Table 3.20.

4.3 ENVIRONMENTAL REGULATIONS AND BENEFITS

One of the factors which makes fuel cell power generation technology attractive is its favorable environmental impact when contrasted to other systems for producing electricity from fossil or synthetic fuels. Although there are no federal water or air regulations which specifically apply to FCPP's, Section 8-101 of the Hackensack Meadowlands Development Commission (HMDC) Master Plan specifies air, water, noise, vibration, fire and explosion,

glare, radioactive, and wetlands buffer strip regulations which apply to the site. Of these many regulations those that apply to the FCPP are discussed below and listed in Table 4.6.

TABLE 4.6
ENVIRONMENTAL REGULATIONS
HACKENSACK MEADOWLANDS DEVELOPMENT COMMISSION (HMDC)

	<u>Standards</u>	<u>FCPP Characteristics</u>
Noise	55 dB @ property line or neighboring use	55 dB @ 30 meters
Particulates	.1 lb/10 ⁶ Btu heat	.000003 lb/10 ⁶ Btu
Sulfur Oxides	.3 lb/10 ⁶ Btu input	.00003 lb/10 ⁶ Btu
Nitrogen Oxides	No standard	.02 lb/10 ⁶ Btu
Water Temperature	85°F maximum discharge temperature	<1°F rise in effluent water

- a. Noise - The 4.5 MWe Utility Demonstrator Power Plant to be installed in New York City by Consolidated Edison has an acoustic emission design criterion not exceeding 55 dB(A) measured 30 meters from the module. The Hackensack Meadowlands Development Commission noise level restriction at the WPCF site is "55 dB(A) at neighboring uses or property lines, whichever is more restrictive". Considering the size of the BCUA property and assuming that the proposed FCPP is similar to that being installed by Consolidated Edison, the noise level regulation can be met.
- b. Airborne emissions - Assuming that the FCPP is similar to the 4.5 MWe Utility Demonstrator Power Plant, there will be no problem meeting airborne emission requirements. The 4.5 MWe Utility Demonstrator Power Plant is expected to be well below EPA requirements for the emission of NO_x, SO₂, particulates, and for opacity.

- c. Water quality - For the proposed FCPP, an alternate heat rejection scheme is to utilize the WPCF effluent. The temperature rise of the effluent should not be greater than 0.5°F.
- d. Wetlands buffer strip - The 50 ft. wide buffer strip requirement between any construction and the Hackensack River is satisfied by the two proposed locations as shown in Figures 2.1 and 2.2.

In addition to complying with the above HMDC Master Plan regulations the FCPP has the following favorable environmental attributes:

- a. The FCPP will use 65% of the energy content of the methane-rich digester gas to produce electric power and thermal energy for the WPCF. With conventional boilers only 27% of the energy content in the sewage gas is utilized to produce heat.
- b. The use of the digester gas in an FCPP to produce electric energy will displace on the PSE&G grid 26,000 barrels of oil (on-peak) and 5,900 tons of coal (off-peak) per year.

4.4 EVALUATION OF NATIONWIDE APPLICATION

As an addendum to the original scope of work, a brief analysis was prepared of potential national benefits associated with significant market penetration of the WPCF fuel cell cogeneration approach. This study (Appendix H) indicates that the application potential of the suggested approach is modest for the size and scale considered; significant additional benefits could arise from utilizing a smaller size FCPP (2.25 MWe) in lower capacity water pollution control facilities.

For the purposes of this study, a minimum water pollution control facility size of 50 million gallons per day (BCUA facility size) was assumed for the 4.5 MWe FCPP application. Operating personnel of several large municipal water pollution control facilities were contacted to determine digester gas

production per gallon of waste treated, and also the percentage of gas typically available for cogeneration fuel use. Based on these figures and on a compilation of large water pollution control facilities, calculations were made of the total amount of oil (fuel oil and crude) which would be displaced with the use of the methane-rich digester gas. Based on scenarios of 100%, 50% and 33% of the screened facilities being available for installation of fuel cell power plants, the below listed oil displacement figures were determined:

Displacement of Fuel, 4.5 MWe Power Plant

<u>Fuel Displaced</u>	% Possible Installations		
	100%	50%	33%
Barrels/Day #6 Fuel Oil	3,171	1,586	1,056
Barrels/Day Crude Oil	3,438	1,719	1,145

A similar analysis was prepared assuming a smaller (2.25 MWe) FCPP size, which would increase the number of potential water pollution control facilities available for application:

Displacement of Fuel, 2.25 MWe Power Plant

<u>Fuel Displaced</u>	% Possible Installations		
	100%	50%	33%
Barrels/Day #6 Fuel Oil	5,137	2,568	1,712
Barrels/Day Crude Oil	5,568	2,784	1,856

SECTION 5.0
CONCLUSIONS AND RECOMMENDATIONS

5.1 PRINCIPAL FINDINGS AND CONCLUSIONS

The UTC 4.5 MWe Utility Demonstrator (fuel cell) Power Plant could be used to provide a major portion of the electrical and thermal energy required by the BCUA water pollution control facility. Additionally, the water pollution control facility digester gas could be used as a fuel feedstock for the fuel cell power plant. Thirty-two configurations were identified with various options of installation which showed technically feasible.

Of the thirty-two configurations, nine were identified which described the complete range of savings possible while satisfying all environmental, regulatory, and institutional factors. All of the nine configurations showed a net savings in total annual revenue requirements compared to the conventional method of supplying heat to the water pollution control facility.

A configuration, approved by both BCUA, the industry, and PSE&G, the electric utility, was selected in which the FCPP would provide the following benefits:

- a. Production of 30×10^6 kWhr of electric power which is half the water pollution control facility annual needs.
- b. Production of over 90% (approximately 70×10^9 Btu) of the water pollution control facility annual thermal energy needs.
- c. Annual levelized savings of \$589,000 (1982 dollars), can be realized based on a UTC supplied equipment (defined in Table B.1) cost of \$535/kW (in 1979 dollars).
- d. Displacement of 26,000 barrels of No. 6 oil (on-peak) and 5,900 tons of coal (off-peak) each year.

It was concluded by the project team members that PSE&G, the electric utility, is the preferred owner and operator of the cogenerating fuel cell power plant.

The displacement of fuel from nationwide applications in similar water pollution control facilities would range from over 3,400 barrels per day of crude oil with 100% market penetration to over 1,100 barrels per day with 33% penetration.

5.2 RECOMMENDATION FOR PROJECT CONTINUATION

On the basis of both the technical and the economic feasibilities performed in this Phase I study and also because there appears to be no major institutional constraints, it can be concluded that there is sound justification for a recommendation to proceed toward completion of a Cogeneration Fuel Cell Power Plant Demonstration Program. Specifically, it is recommended by PSE&G and BCUA, as well as G/C, that the program should enter Phase II, Preliminary Engineering with government and industry sponsorship. This recommendation is consistent with the PSE&G and BCUA objective that resource recovery is in the local and national interest. The Preliminary Engineering Phase has as its objective the obtaining of the additional design, engineering, and cost data on the selected configuration. As indicated in Figure 5.1, this information is required to make a final "go/no go" decision for implementation of Phase III, Detailed Design, Procurement, and Demonstration. The major deliverables or end items required for the go/no go decision are an FCPP preliminary design report including engineering/cost tradeoff studies, a preliminary design, construction cost estimates, equipment bid specifications, equipment bid estimates, verification of the conceptual economics, and tentative agreements addressing the exchange rates for fuel, thermal and electric energy.

5.3 RECOMMENDATIONS FOR FUEL CELL POWER PLANT

Although there were no internal cooling piping or fuel processing changes to the 4.5 MWe Utility Demonstrator Power Plant and there was an excellent balance of heat rejection/heat utilization and electrical output/ usage, several recommendations are in order to improve the match between the fuel cell power plant and the water pollution control facility:

FIGURE 5.1
RECOMMENDATION

- a. The present 4.5 MWe Utility Demonstrator Power Plant will not operate in isolation from the electric grid. The demonstrator as presently designed for an electric utility peaking station, is not self regulating, but depends on the grid for its regulation. Industry would prefer a power plant capable of operation during an electric grid blackout. It is recommended that self regulation be investigated.
- b. The fuel cell power plant fuel processing section was designed primarily for liquid fuel. Gas is a secondary fuel and, as a result, has to be compressed to 95 ± 5 psig with attendant high auxiliary power required. Many industries would prefer to operate on natural gas due to its cleanliness, convenience and cost. It is recommended that UTC investigate the possibility of lower gas pressures in the fuel processing section.
- c. There were changes to the 4.5 MWe Utility Demonstrator Power Plant resulting from this study other than those required for cogeneration adaptation. There is no requirement for the low flow turbocompressor, only a single fuel will be used for normal operation, and 26 kV was selected for the voltage level. An assessment of the effect of these changes on the 4.5 MWe Utility Demonstrator Power Plant should be made. UTC should also investigate whether other changes might better match the 4.5 MWe Utility Demonstrator Power Plant to the specific application.

SECTION 6.0
DEMONSTRATOR PROGRAM PLAN

6.1 SUMMARY

This study has shown the technical and economic feasibility of cogeneration with a commercially available FCPP. The next step toward commercialization is to verify the study results by demonstration prior to a commitment to start commercial production and application.

It is envisioned that a twelve month demonstration program is required to:

- a. Demonstrate and provide operating experience and data for a cogenerating FCPP fully integrated with an industry.
- b. Verify the electrical/thermal capability of the FCPP.
- c. Verify the favorable economics and energy savings.
- d. Provide information on the impact of institutional factors.
- e. Demonstrate the availability and environmental impact of a cogenerating FCPP in an industrial application.

The cogeneration demonstrator could be installed and operating by October, 1982. Results could be evaluated approximately one year later. Achievement of this goal would require a phased engineering/construction program, with preliminary engineering requiring nine months, a detailed design of nine and a half months, which would be within the twenty-three months required to fabricate and install the cogenerating FCPP (this is based on an eighteen month FCPP fabrication and delivery).

Costs for the entire effort, preliminary engineering through evaluation of operating results (except for the UTC supplied equipment procurement) are estimated at \$4,710,000 based on the cost estimates of the conceptual design feasibility study.

These cost and schedule estimates are not based on a detailed breakdown of activities, and so would have to be updated at the end of the Preliminary Engineering Phase to the accuracy required for the major go/no go decision. This decision would be made prior to funding detailed design, equipment procurement and construction.

6.2 PROGRAM APPROACH

Implementation of the FCPP Cogeneration Demonstration Program will be through the completion of three consecutive program phases:

- 1) Conceptual Design
- 2) Preliminary Design
- 3) Detailed Design, Construction, and Demonstration

The conceptual design activities, now completed, are described in this report. The objective and deliverables for the Phase II Preliminary Engineering are discussed in Section 5.2. The next phase, Detailed Design, Construction, and Demonstration, represents the culmination of the entire program.

Major activities include:

- a. Prepare a detailed design for the construction of the cogeneration installation.
- b. Issue procurement for long lead time equipment (UTC supplied equipment through a separate contract).

- c. Procure the services of equipment manufacturers and major constructors.
- d. Fabricate, erect, and install balance of plant equipment. Install the FCPP.
- e. Provide all operating and maintenance manuals and train personnel.
- f. Checkout and startup the cogenerating FCPP.
- g. Operate and test the cogenerating FCPP.
- h. Accumulate and evaluate the data.
- i. Deliver the data, its evaluation, and recommendations for commercialization of cogenerating fuel cell power plants.

An overall summary schedule with milestones is shown in Figure 6.1 based on initiating operation by October 1982.

Since joint sponsorship by government and industry is assumed, the Demonstration Phase would be subject to the procedures, documentation and reviews appropriate for the size project as described in the DOE Uniform Contractor Reporting System Guidelines, DOE/CR-0001/1 dated February 1978.

6.3 PROGRAM ORGANIZATION

6.3.1 Program Control

A proposed organization for conduct of the Cogeneration FCPP Demonstration Program is shown in Figure 6.2.

It is assumed that DOE would, under separate contract, procure the UTC supplied equipment directly from UTC. This allows the balance of the program cost to be estimated independently of UTC supplied equipment costs.

FIGURE 6.1
SUMMARY SCHEDULE

FIGURE 6.2
PROGRAM ORGANIZATION

6.3.2 Functions/Responsibilities

The following defines the responsibilities for first level activities (functions) of the two remaining phases.

a. Preliminary Design Phase

Program Control - DOE

Project Management, Institutional Evaluations, Economics, Engineering Review - PSE&G

Engineering Design, Program Planning - G/C

Installation Requirements, Engineering Review - BCUA

Fuel Cell Power Plant Interface, Engineering Review - UTC

b. Demonstration Phase

Program Control - DOE/PSE&G

Long Lead Time Equipment Procurement - DOE/GAI Acting as PSE&G Agent

Project Management, Documentation and Reporting - PSE&G

Detailed Design - G/C

Equipment and Construction Specification Preparation, Bid Lists, Requests -

G/C with PSE&G approval

Bid Evaluation - G/C with PSE&G review

Selection and Award - PSE&G with DOE approval

Manuals Preparation - G/C

Construction Management - G/C

Equipment procurement (G/C acting as PSE&G agent)

Subcontractors accounting (G/C acting as PSE&G agent)

Supervision & coordination of subcontracts

Field liaison

Fabrication - Equipment Manufactures

Construction - Construction Contractors

Equipment and Construction Acceptance - PSE&G with assistance from G/C for Evaluation and Recommendation

Training - G/C-UTC

System and Installation Checkout - PSE&G assisted by G/C-UTC

Startup - PSE&G with Assistance from UTC

Operations and Tests - PSE&G with Assistance from BCUA

Evaluation of Results - PSE&G with Assistance of All Team Members

Recommendations for Commercial Application - PSE&G

6.4 PROGRAM STRUCTURE AND SCHEDULING

6.4.1 Work Breakdown Structure

By far the largest effort within the Demonstration Program is that expended for the construction and preparation for operation of the cogeneration installation. The description of the effort and control required for the Preliminary Engineering Phase is identical to that used during the Conceptual Design (Feasibility Study) Phase. The effort required for operation of the fuel cell demonstration unit will be formulated along with the test program.

An approach to organizing the construction and preparation for operation of the demonstration unit into discrete work elements is summarized in Figure 6.3, the Work Breakdown Structure (WBS). This WBS describes the organization of work elements to the third level of detail. In keeping with the idea of a separate contract for procurement of the UTC supplied equipment, a separate section is provided for the FCPP. Provisions have been made in the WBS so that elements relating directly to a demonstration unit can be isolated from elements required for a normal commercial power plant installation so that commercial application costs can be better defined.

Table 6.1 further divides the third level of detail to the degree necessary for relating the activities and results of the conceptual design study described in this report to the WBS.

FIGURE 6.3
 WORK BREAKDOWN STRUCTURE
 FUEL CELL COGENERATION DEMONSTRATION PROGRAM PLAN

TABLE 6.1
WORK BREAKDOWN STRUCTURE
FUEL CELL COGENERATION DEMONSTRATION PROGRAM PLAN

- i. PROGRAM
 - 10. BALANCE OF PLANT
 - 101. Auxiliary Power Supply
 - 102. Auxiliary Power Distribution
 - 103. Uninterruptable Power Supply
 - 104. Emergency Power Supply
 - 105. Cogeneration Loop
 - 105.1 Heat Exchangers
 - 105.2 Circulating H₂O Pump
 - 105.3 Piping
 - 106. Fuel Supply
 - 106.1 Compressors
 - 106.2 Piping
 - 106.3 Flame Traps and Flares
 - 106.4 Condensate Pump and Piping
 - 107. Liquid and Gas Supplies
 - 107.1 Piping
 - 107.2 Tanks
 - 108. Controls and Instrumentation
 - 20. DOCUMENTATION (no further subdivision than Figure 6.3)
 - 30. SITE AND STRUCTURES
 - 301 Property
 - 301.1 Acquisition
 - 301.2 Environmental Assessment
 - 301.3 Licensing
 - 301.4 Security
 - 301.5 Fire Protection

TABLE 6.1 (Cont'd.)
WORK BREAKDOWN STRUCTURE
FUEL CELL COGENERATION DEMONSTRATION PROGRAM PLAN

302. Site Preparation

- 302.1 Excavation
- 302.2 Shoring & Dewatering
- 302.3 Piling
- 302.4 Trenches
- 302.5 Fill & Grade
- 302.6 Piping/Valves
- 302.7 Vents/Drains
- 302.8 Conduit/Cable
- 302.9 Foundations
- 302.10 Lighting
- 302.11 Roadways
- 302.12 Grounding
- 302.13 Communications
- 302.14 Landscaping

303. Structures

- 303.1 Switchgear
- 303.2 Control and Data Acquisition
- 303.3 Power Conditioner
- 303.4 Water Treatment

304. Utilities

- 304.1 Electric
- 304.2 Water
- 304.3 Communications

TABLE 6.1 (Cont'd.)
WORK BREAKDOWN STRUCTURE
FUEL CELL COGENERATION DEMONSTRATION PROGRAM PLAN

40. FUEL CELL POWER PLANT

401. DC Module

- 401.1 Air Processing
- 401.2 Hydrodesulfurization
- 401.3 Fuel Processing
- 401.4 Thermal Management
- 401.5 Power Section

402. Power Conditioning

- 402.1 Electrical Protection
- 402.2 Inverter Bridge
- 402.3 Series Reactor
- 402.4 Harmonic Transformer
- 402.5 Output Transformer

403. Control Center

404. Water Treatment

405. Cooling

6.4.2 Scheduling

The overall program schedule, Figure 6.1, summarizes detailed activities including those occurring during the design, fabrication, construction and checkout of the cogeneration installation as shown in Figure 6.4. This detailed schedule has been compiled assuming a "Construction Management" approach. In this approach, PSE&G, acting through its agent, G/C, will manage and contract construction of the cogeneration installation directly. This approach contrasts with the more familiar "General Contractor" approach where a disinterested contractor controls the construction, by offering two benefits:

FIGURE 6.4
DETAILED DESIGN, CONSTRUCTION & PREPARATION OF THE DEMONSTRATOR

- a. Project Management has more direct control, an important consideration in a Demonstrator Program due to the development status of the FCPP.
- b. It is possible to phase major design packages with individual contractor bid awards. With general contracting all design packages must be finished prior to a general contractor award.

6.5 ESTIMATED COSTS

The estimated cost for the remainder of the program, quoted in Section 6.1, was developed using the cost estimates of the selected configuration, Case 5, Table 3.22, but altered according to Table 6.2. The cost consists of a \$295,000 Preliminary Engineering Phase, \$3,858,000 for detailed design and construction and \$557,000 for operations and evaluation. UTC supplied equipment listed in Table 6.3, spares for this equipment, delivery and rigging are not included in the estimate since it is assumed that these items would be funded under a separate contract.

The detailed design, construction and operation phase costs shown in this section are preliminary and would be subject to revision at the end of the Preliminary Engineering Phase. For example, the design costs in Table 6.2 are based on a fixed percentage of the balance of plant construction costs and the UTC supplied equipment cost. The highest UTC supplied equipment cost was used to provide a more conservative design cost. The costs can be better defined based on an estimate of the number of drawings required for detailed design.

The revised costs would be to the accuracy required to allow a major go/no go decision prior to detailed design and equipment ordering.

TABLE 6.2
REMAINING DEMONSTRATION PROGRAM COSTS*

	<u>Cost</u> (In \$1,000-1979)
Program Management	370
Engineering Design (Preliminary & Detailed)	685
Construction Management	140
Checkout/Startup	20
Operations and Test	355
Evaluation of Tests, Commercial Recommendations	20
Installation and Balance of Plant Equipment Construction Costs, Selected Configuration	<u>2,333</u>
Subtotal	\$3,923
Contingency (20%)	<u>785</u>
Total	\$4,708

* UTC supplied equipment not included.

TABLE 6.3

UTC SUPPLIED EQUIPMENT

(Changes from 4.5 MWe Utility Demonstrator Power Plant noted)

DC Module: Unchanged except provision required to plumb in cogeneration cooling loop using 35% glycol/65% water (by volume) and elimination of the low flow turbocompressor and associated equipment.

Power Conditioner: Unchanged

Control Center: Minor changes in instrumentation and data acquisition equipment

Water Treatment: Unchanged

Cooling: Unchanged