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COGENERATION

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

Volume 2: Final Report

MASTER

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 2

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THE UNITED STATES DEPARTMENT OF ENERGY
DIVISIONS OF POWER SYSTEMS AND
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APPENDIX A
ABBREVIATIONS AND DEFINITIONS

This Appendix consists of two parts: (1) a list of abbreviations commonly used in the text, tables and illustrations and (2) a glossary of terms. The glossary is included to provide basic definitions for the important terminology used in the report.

A.1 LIST OF ABBREVIATIONS

A	Availability of a system, plant, or component
AC, ac	Alternating current
acfd	Actual cubic feet per day
acfm	Actual cubic feet per minute
ADAR	Automatic data acquisition and recording
AF	Amp frame rating
AH	Ampere hour
APS	Auxiliary power supply
APDS	Auxiliary power distribution system
AS	Ammeter switch
AT	Amp trip
AWG	American Wire Gage
bbl	Barrels
BCUA	Bergen County (N.J.) Utilities Authority
bbl/d	Barrels per day
bbl/yr	Barrels per year
BIL	Basic insulation level
BKR	Breaker
BOP	Balance of plant
Btu	British thermal unit
d	Depth
dB(a)	Decibel (actual)
CC	Construction cost
CCIF	Compound construction interest factor
CDR	Component design requirement
cf	Cubic foot (or feet)

cf _d	Cubic feet per day
CLG	Cooling
C.S.	Carbon Steel
CT	Current transformer
D.E.P.	Department of Environmental Protection (New Jersey)
DC, dc	Direct current
DCT	Dry cooling tower
DOE	U.S. Department of Energy
EPRI	The Electric Power Research Institute
EPS	Emergency power supply
EPU	Emergency power unit
°F	Degrees Fahrenheit
FCPP	Fuel cell power plant
FM	Frequency meter
ft	feet
G	Ground
G/C	Gilbert/Commonwealth Companies (also Gilbert Associates, GAI)
gpd	Gallons per day
gpm	Gallons per minute
h	Height
Δh	Enthalpy
HEX, HX	Heat exchanger
hhv	Higher heating value
HMDC	Hackensack Meadowlands Development Commission
hp	Horsepower
hr	Hour
HT	High temperature
HTR	Heater
HV	High voltage
HVAC	Heating, ventilating, air conditioning
Hz	Hertz, or cycles per second (frequency)
i/o	Input/output
kV	Kilovolt
kVA	Kilovolt-ampere
kW	Kilowatt
kWhr	Kilowatt-hour

kWyr	Kilowatt-year
lb	Pound
lhv	Lower heating value
LI	Long time
LMTD	Log mean temperature difference
LS	Long time - short time
LT	Low temperature
LTG	Lighting
LV	Low voltage
MCC	Motor control center
MCM	One thousand circular mills
mgd	Million gallons per day
MH	Manhour
M.H.	Manhole
ml	Milliliter
Mo.	Month
MVA	Megavolt ampere
MWe	Megawatt (electrical)
MWt	Megawatt (thermal)
N	Neutral
N ₂	Nitrogen
NC	Normally closed
NEMA	National Electrical Manufacturers Association
NT	BCUA breaker identification
OA/OA/FA	Transformer rating
OCB	Oil circuit breaker
O&M	Operation and maintenance
P	Pole
PCS	Power conditioner system
PDC	Pressure differential controller
PDT	Pressure differential transmitter
PJM	Pennsylvania, New Jersey, Maryland Power Interchange Pool
PNL	Panel
PPM, ppm	Parts per million
PSD	Power Systems Division (of United Technologies Corporation)
PSE&G	Public Service Electric and Gas Company
psia	Pounds per square inch (absolute)

psig	Pounds per square inch (gauge)
PT	Potential transformer
PWR	Power
Q	Heat quantity (Btu/hr)
R	Recording meter, resistor
REF	Reference
RFP	Request for Proposal
scf	Standard cubic foot (or feet)
scfd	Standard cubic foot (feet) per day
SW	Switch
SWGR	Switchgear
TARGET	Team to Advance Research in Gas Energy Transformation
TC	Temperature controller
TCC	Total capital cost
TEFC	Totally enclosed, fan cooled
T _{in}	Temperature in
TMS	Thermal management system
T _{out}	Temperature out
TT	Temperature transmitter
UA	Product of overall heat transfer coefficient and the area of transfer
UPS	Uninterruptible power supply
UTC	United Technologies Corporation
V	Volt
VAR	Volt amp reactance
VS	Voltmeter switch
Vol	Volume
w	width
W	Water, Watt
WACF	Weighted average conversion factor
WBS	Work Breakdown Structure
WPCF	Water pollution control facility
WTS	Water treatment system
YD	Yard
XFMR	Transformer

A.2 GLOSSARY

Annual Levelized Revenue Requirements - Annual levelized revenue requirements were determined by finding the present worth of power plant cost components for 1982. The uniform series of costs, over the life of the plant, that is equivalent to the present worth value is the levelized annual revenue requirement.

Balance of Plant - Those elements of a cogeneration installation comprising the plant envelope around the power generation system. In this case, the plant subsystems (cooling system, electric switchgear, instrumentation and control, interface piping, valves, foundations, buildings, etc.) not intended to be supplied by United Technologies Corporation.

Candidate Designs - Conceptual design configurations which were screened for economic analysis. Configurations were eliminated from consideration as a candidate design whose installation options had negligible impact on operating conditions and capital costs, or which did not exhibit any factors of institutional importance.

Capacity Payment Rate Schedule - Negotiated rate within PJM interchange pool to buy or sell excess capacity.

Cogeneration - The simultaneous generation of two, or more, energy forms from a single energy source, e.g., electricity and steam from a fuel cell power plant.

Cogeneration Installation - A specific, complete power generation system installed in a larger host facility for the purposes of producing two (or more) forms of energy.

Conceptual Design Configurations - Power plant configurations resulting from all possible combinations of various options of installation.

Installation Options - The total number of design choices (e.g. location within host plant, cogeneration mode, plant interfaces, ownership and operation) available which can be combined into possible conceptual design configurations.

Load Diversity - The combined peak electric loads considering time difference of individual load components.

Pinch Temperature - The minimum allowable temperature difference between matching terminal flows of a heat exchanger.

Present Worthing - Determination of the value today of a given amount of money in the future.

Selected Configuration - The selected or preferred conceptual design based on optimum cost and technical feasibility consideration. Also, the conceptual design to serve as the basis for subsequent program phases (preliminary design, detailed design, etc.).

UTC Supplied Equipment - Fuel cell power plant components and subsystems assumed to be supplied to the project from United Technologies Corporation (listed in Appendix B).

APPENDIX B

4.5 MWe UTILITY DEMONSTRATOR POWER PLANT - STUDY INFORMATION

B.1 POWER PLANT DESCRIPTION

The 4.5 MWe Utility Demonstrator Power Plant (Figure B.1) is a modularly constructed, truck transportable, energy conversion device consisting of a fuel processor, a power section, a power conditioner, and ancillary equipment to maintain the appropriate process balance. It is fully described by the Demonstrator Power Plant Specification, Ref. 1.4, and UTC documents listed at the end of this appendix. The power plant is shipped in sections to the site: two power section pallets consisting of 10 cell stacks each, a thermal management pallet, two fuel processor pallets, a control center, three power conditioner pallets, a water treatment pallet, two cooling tower sections, and a transformer. Other equipment, such as storage tanks, piping, electrical, communication, a control building, and fencing are furnished by the "host" utility (Ref. 1.4).

The 4.5 MWe Utility Demonstrator Power Plant consists of three basic segments: a fuel processor, the power section, and a power conditioner. The overall power plant heat rate, 9300 Btu/kWhr (hhv), includes the efficiencies of all three segments which, when combined, convert the low sulfur distillate fuel, naphtha or methane, to AC power. This conversion is achieved with emissions which are acceptable under the most stringent of present and proposed environmental control standards (Ref. 1.4).

The fuel cells themselves require a hydrogen-rich gas as a fuel and, therefore, the function of the fuel processor is to convert the naphtha or methane, by steam reforming and shifting, to a mixture of hydrogen and carbon dioxide. Water to produce the steam is recycled from condensate obtained in the fuel cell air and fuel exhaust streams. Heat for the reforming process is produced by burning the excess hydrogen not utilized in the fuel cell reaction (Refs. 1.4 and B.1).

FIGURE B.1
UTILITY 4.5 MWe DEMONSTRATOR POWER PLANT

The power section converts the processed hydrogen-rich gas and oxygen contained in the process air into electricity and water vapor through electrochemical reactions occurring in the fuel cells at the anode and cathode, Figure B.2.

The reactions occur at 325-400°F as a result of the presence of a platinum catalyst on the electrode surfaces. At the cathode, oxygen (from air) combines with hydrogen ions in the phosphoric acid electrolyte and an electron returning from the external load to form product water. This water is removed from the cell as a vapor by the depleted air and fuel exhaust. At the anode, hydrogen forms the hydrogen ion giving up an electron to the load in the process. The function of the electrolyte is to act as an electron and gas crossover barrier and to effect the transport of hydrogen ions from the anode to the cathode. Voltage and current output of the power section are dependent upon cell performance, the number of cells, the area of each cell, and whether they are connected in series, parallel, or a combination of the two. Design cell performance of the 4.5 MWe Utility Demonstrator Power Plant is approximately 550 watts DC for each cell. The two power sections of the module have a total of 20 fuel cell stacks each with 456 cells for a total of nearly 10,000 cells (Ref. 1.4).

The DC power from the fuel cell stacks must be converted to AC power in an efficient manner. This is accomplished by the third segment of the fuel cell module; the power conditioner (inverter). A 9.2 MWe inverter operating at 96% conversion efficiency is used in the power plant. It has been designed to accept DC input from two of the 4.5 MWe stack systems and, hence, is oversized in the utility project. Circuitry has been modified in the 4.5 MWe Utility Demonstrator Power Plant to exclude penalties of the oversized unit. The inverter consists of a number of parallel solid state switching and filtering circuits which finally produce an AC product with characteristics meeting utility grid specifications (Ref. 1.5).

Other equipment is required to satisfy the operation and requirements of the three FCPP basic segments. These are included in the Major Equipment and Subsystem Classification.

Major Equipment and Subsystem Classification: Table B.1 is a listing of the

FIGURE B.2
FUEL CELL REACTIONS
PHOSPHORIC ACID ELECTROLYTE

TABLE B.1

POWER PLANT AND AUXILIARY EQUIPMENT

<u>Item</u>	<u>Function</u>	<u>Supplied By</u>
<u>Power Plant</u>		
One (1) DC Module	Generates up to 4.8 MWe of DC power operating on liquid fuel and ambient air	UTC
One (1) DC/AC Power Conditioner	Converts 4.8 MWe of DC to 4.6 MWe AC (60 Hz) at 13.8 kV utility line voltage	UTC
Control Center	Controls equipment for on-site or remote operation	UTC
Water Treatment Subsystem	Purifies recovered DC module process water for re-use	UTC
Cooling Tower Subsystem	Rejects power plant waste heat to air	UTC
<u>Auxiliary Equipment</u>		
Fuel Supply Subsystem	Storage and supply of fuel for the power plant	Utility
Fuel Dump Subsystem	Management of fuel vented from power plant on shutdown	Utility
Pressurized Air Subsystem	Operation of pneumatic controls and start of turbocompressor in DC module	Utility
Gas Supply Subsystem	Provides nitrogen and hydrogen to the DC module for startup and shutdown, pressurization, purge, and passivation	Utility
Water Storage Subsystem	Provides capability for continued operating during intervals above 95°F ambient	Utility
Water Flush Subsystem	Manages effluent from water treatment system regeneration	Utility

TABLE B.1 (Cont'd)

POWER PLANT AND AUXILIARY EQUIPMENT

<u>Item</u>	<u>Function</u>	<u>Supplied By</u>
<u>Auxiliary Equipment (Cont'd)</u>		
Auxiliary Power Supply	Provides 480/277 volt and 208/120 volt, three-phase power from the utility line to the power plant	Utility
Auxiliary Power Distribution System	Distributes 480/277 volt and 208/120 volt three-phase power to the power plant and ancillary equipment for pumps, fans, and controls	Utility
Emergency Power Supply	Provides auxiliary power for controlled shutdown sequencing in the event of loss of utility line power	Utility
Uninterruptible Power Supply	Provides for uninterrupted power to critical controls during transition to the emergency power supply	Utility
Site Instrumentation and Safety Subsystem	Provides automatic detection and safing from combustibles	Utility

major pieces of equipment and subsystems of which the 4.5 MWe Utility Demonstrator Power Plant is comprised (Ref. 1.4). The table also lists responsibility for design and fabrication of each item. This division of responsibility represents that chosen for the utility demonstration, but was also used for this study.

Costs of a Fuel Cell Power Plant for Utility Application: Because of the developmental status of fuel cell technology, it is difficult to estimate capital, operating, and maintenance costs of a FCPP. First, there is no history of similar power plants on which to base cost estimates. Second, at this stage it is premature to accurately determine the cost of manufacturing processes and facilities, training of personnel, number of units to be manufactured each year, ancillary equipment availability, market impacts, and other aspects of commercialization which affect both cost and price. For these reasons, present projections of cost estimates for an FCPP appear as a range of values.

Capital Selling Price (Ref. 5): So that the results of all the cogeneration studies (Section 1.1) would be based on the same FCPP costs, DOE stipulated that the selling price of an FCPP for a utility application would be \$350/kW to \$750/kW (in 1978 dollars). This includes the fabrication and installation of all the equipment shown in Table B.1. For the 4.5 MWe Utility Demonstrator Power Plant, Table B.2 is UTC's estimated breakdown of the entire, installed power plant selling price.

TABLE B.2
BREAKDOWN OF MAJOR COMPONENT PRICE

DC Module (including Water Treatment System)	73%
Cooling System	7%
Power Conditioning Equipment	10%
Utility Supplied Subsystems	10%
	<u>100%</u>

These prices are subject to revision depending on whether the function of the FCPP is changed from the utility application for which the prices were

estimated. For example, equipment changes would alter the above selling price for a cogeneration installation. Similarly, there is a possibility in some installations that the FCPP may have to operate only at powers above 30% design. The discontinuity in the heat rate curve, Figure 1.2, shows the effect of a second, smaller turbocompressor which takes over providing process air from a larger turbocompressor and reduces the auxiliary fuel power requirements at power levels of 30% design and less. If the FCPP were always operated above 30% design power, the small turbocompressor and associated equipment could be eliminated from the FCPP with an estimated 2% cost savings.

Overhaul and Maintenance Cost (Ref. B.2): Figure B.3 quantifies the estimated overhaul and maintenance costs for the range of selling prices which corresponds to capital costs described in the previous section. These costs are based on the labor, parts, and materials necessary for routine maintenance, failure maintenance, and scheduled overhaul and replacement of parts for the UTC supplied equipment. These costs do not include the value of site consumables, such as fuel, nitrogen, or hydrogen. The estimated O&M costs are presented in mills per kilowatt hour and are given as a function of load factor - the average power output when the power plant is operating.

Tables B.3 and B.4 are, respectively, estimates of the routine field maintenance tasks and the scheduled overhaul and replacement tasks for the major components from which the operating and maintenance costs were compiled. These costs should be considered as the "best available" since it is obvious that there is, as yet, no actual operating experience for demonstrator-scale or larger FCPP's. Routine maintenance and most failure maintenance, Table B.3, would be performed by normal mechanical and electrical maintenance personnel. Major items such as the fuel cell stacks and reformer units would probably be removed and returned to the factory for overhaul.

Time requirements for these maintenance items have been estimated, Table B.5. The downtimes are based on one shift maintenance for each calendar day.

FIGURE B.3
ESTIMATED 4.5 MWe DEMONSTRATOR POWER PLANT
OVERHAUL AND MAINTENANCE COST

TABLE B.3
SCHEDULE OF ROUTINE MAINTENANCE

<u>Monthly</u>	<u>Quarterly</u>	<u>Semi-Annually</u>	<u>Yearly</u>
General visual inspection	Replace cell stack assembly exhaust scrubber elements	Inspect separator level controls	Service and recalibrate control sensors
Check lube oil levels		Clean coolant magnetic filters	
Check pressure drop DC module process air filter	Replace mechanical filters and replenish regenerant in water treatment system	Change lube oil recycle blowers	Inspect Reformer start burners Aux. burner TMS burner Turbocompressors
Check zinc oxide unit utilization (replacement interval is 6 mos. for average fuel sulfur level)	Lubricate rotating machinery		Replace fuel filter element
Check anode and cathode exhaust scrubber pressure drop	Inspect air filters, clean or replace as required		Service charcoal filter in water treatment system
	Exercise relief valves		Inspect anode and cathode exhaust heat exchanges
	Check calibration on control and instrumentation sensors		Inspect and clean inverter heat sinks
			Inspect thermal insulation
			Inspect wiring
			Inspect and service dry cooling tower coolant filters

TABLE B.4
SCHEDULE OF OVERHAUL AND REPLACEMENT

Operating Hours	<u>4,000*</u>	<u>16,000*</u>	<u>20,000*</u>	<u>40,000</u>
	Replace ZnO Bed (Typical)	Replace units (for catalyst change)	Overhaul recycle blowers and motors	Overhaul coolant pump
		Reactor LT shift converter HT shift converter	Replace demineralizer resin in water treatment system	Overhaul cooling tower fans
		Replace seals in anode and cathode recycle blowers		Overhaul burners
		Replace continuously - powered solenoid coils		Overhaul water treatment system
				Overhaul controls
				Replace hydrodesulfur- izer unit for catalyst change
				Overhaul turbocom- pressors
				Remove and replace cell stack assemblies

* At Full Power

TABLE B.5
MAINTENANCE TIME REQUIREMENTS
(One shift each day)

<u>Year</u>	<u>Downtime</u>	<u>Year</u>	<u>Downtime</u>
1	2-3 days	6	2-3 days
2	2-3 weeks	7	2-3 weeks
3	2-3 days	8	2-3 days
4	2-3 weeks	9	2-3 weeks
5	2-3 weeks	10	3-4 weeks

Availability: A numerical availability/reliability analysis (Ref. B.3) has been prepared as part of the Utility Demonstrator Program for the 4.5 MWe Utility Demonstrator Power Plant. This analysis indicates that the demonstrator design with fully developed components is predicted to experience forced outages 5.6% of the time, hence its availability based on forced outages is 94.4%. A simple block diagram was chosen to define the availability, Figure B.4. Despite its simplicity, it is believed that the method adequately approximates the true physical situation.

FIGURE B.4
4.5 MWe DEMONSTRATOR POWER PLANT
AVAILABILITY BLOCK DIAGRAM

B.2 LIST OF UTC DRAWINGS, ANCILLARY SUBSYSTEM DESIGN REQUIREMENTS AND FLUID SPECIFICATIONS

B.2.1 List of Drawings

The following drawings, design requirements and specifications are contained in the Demonstrator Power Plant Specification, Ref. 1.4 and were used in the preparation of the study.

FCL-481 Arrangement - Power Plant site

This drawing shows the layout of the power plant on the Con Edison site in New York City.

FCL-283 Diagram - Site P&I, Fluid

This drawing defines site piping between the DC module and the various site ancillaries, and identifies the auxiliary, environmental, and site interfaces. The flows in the pipes and at the interfaces are shown in Figure 7-3 and Tables 2-4 thru 2-6 of the Demonstrator Powerplant Model Specification (FCS-0493). The fuel dump subsystem is not required for operation on gaseous fuel.

FCL-462 Site Electrical Schematic

This drawing defines the control cabling between various pallets and subsystems. All ADAR (automatic data acquisition and recording) equipment shown is for demonstrator testing only. Some equipment was eliminated in the cogenerating FCPP.

FCL-501 Interface Control Drawing - DC Module Internal Large Piping

This drawing defines the interconnections that must be made at the site by the customer between the pallets of the DC module.

FCL-495 Interface Control Drawing - DC Module to Site Piping

This drawing defines the size and location of the auxiliary interfaces on the DC module.

FCL-502 Interface Control Drawing - DC Module External Electrical

This drawing defines the type and location of electrical connections on the DC module.

FCL-485 Foundation - DC Module

This drawing describes the DC module foundation (pallets A, B, C, D, and E) and tabulates the pallet weights.

FCL-491 Dry Cooling Tower Foundation Plan

This drawing defines the dry cooling tower (DCT) foundation and includes the DCT weight. External electrical and piping interfaces are located between the two sections of the DCT.

FCL-489 Foundation - Power Conditioning System

This drawing defines the foundation for the output transformer, the two inverter pallets, the electrical protection unit, and the DC breaker. System weights are also indicated.

FCL-496 Interface Control Drawing - Power Conditioning System, External Electrical

This drawing defines the type and location of electrical connections to the power conditioning system.

FCL-650 Arrangement - Control Room

This drawing shows the control room plan. The cabinets with red X's are for utility demonstrator testing only (contractor copy only).

FCL-651 Arrangement - Data Acquisition Room

This drawing shows the arrangement of the data acquisition room. Equipment with red X's is for utility demonstrator testing only (contractor copy only).

FCL-560 Diagram - Electrical Installation Connection, Control Building

This drawing describes control cabling in the control building. Cables connected to equipment marked with red X's is for utility demonstrator testing only (contractor copy only).

B.2.2 List of Ancillary Subsystem Design Requirements

CDR SE-1 Fuel Supply Subsystem

CDR SE-2 Dry Cooling Tower Subsystem

CDR SE-4 Pressurized Air Subsystem

CDR SE-5 Gas Supply Subsystem

CDR SE-6 Water Supply Subsystem

CDR SE-7 Emergency Power Supply

CDR SE-8 Uninterruptible Power Supply

CDR SE-9 Auxiliary Power Supply (Transformer and Circuit Breaker)

CDR SE-10 Auxiliary Power Distribution System

CDR SE-12 Control Building

CDR SE-14 General Requirements

CDR SE-16 Site Installation Interface Definition

CDR SE-18 Water Flush Subsystem

CDR SE-20 Site Instrumentation and Safety Subsystem

B.2.3 Fluid Specifications

SE-01 Nitrogen

SE-02 Hydrogen

SE-03 DCT Coolant

REFERENCES

- B.1 ERDA (DOE) in Cooperation with EPRI, "Implementation of the 4.8 MWe Fuel Cell Module Demonstrator in an Electric Utility System", RFP EC-77-R-01-5018, February 11, 1977.
- B.2 L. G. Eklund, Program Manager, UTC; (Letter to Terry Vaeth, USD OE), 2 March 1979.
- B.3 L. M. Handley, Program Manager, UTC; FCG-1 Module Demonstrator Program (Letter to Mr. Greg Kawalkin, Division of Procurement, USD OE). "FCG-1 Module Demonstrator Data Submittal", 5 December 1977.

APPENDIX C

REJECTED HEAT UTILIZATION

Appendix C contains summary sheets listing results of thermodynamic calculations and analysis of operating conditions for four cases:

- Figures C.1-C.12 - Digester Gas Only, Location No. 2
- Figures C.13-C.24 - Digester Gas Only, Location No. 1
- Figures C.25-C.36 - Digester and Natural Gas, Location No. 2
- Figures C.37-C.48 - Digester and Natural Gas, Location No. 1

Each of the four cases is then analyzed for twelve months to derive complete envelopes of plant design and operating parameters pertaining to rejected heat (cogeneration) utilization.

FIGURE C.1
REJECTED HEAT UTILIZATION
DIGESTER GAS

FIGURE C.2
REJECTED HEAT UTILIZATION
DIGESTER GAS

FIGURE C.3
REJECTED HEAT UTILIZATION
DIGESTER GAS

FIGURE C.4
REJECTED HEAT UTILIZATION
DIGESTER GAS

FIGURE C.5
REJECTED HEAT UTILIZATION
DIGESTER GAS

FIGURE C.6
REJECTED HEAT UTILIZATION
DIGESTER GAS

FIGURE C.7
REJECTED HEAT UTILIZATION
DIGESTER GAS

FIGURE C.8
REJECTED HEAT UTILIZATION
DIGESTER GAS

FIGURE C.9
REJECTED HEAT UTILIZATION
DIGESTER GAS

FIGURE C.10
REJECTED HEAT UTILIZATION
DIGESTER GAS

FIGURE C.11
REJECTED HEAT UTILIZATION
DIGESTER GAS

FIGURE C.12
REJECTED HEAT UTILIZATION
DIGESTER GAS

FIGURE C.14
REJECTED HEAT UTILIZATION
DIGESTER GAS

FIGURE C.15
REJECTED HEAT UTILIZATION
DIGESTER GAS

FIGURE C.16
REJECTED HEAT UTILIZATION
DIGESTER GAS

FIGURE C.17
REJECTED HEAT UTILIZATION
DIGESTER GAS

FIGURE C.18
REJECTED HEAT UTILIZATION
DIGESTER GAS

FIGURE C.19
REJECTED HEAT UTILIZATION
DIGESTER GAS

FIGURE C.20
REJECTED HEAT UTILIZATION
DIGESTER GAS

FIGURE C.21
REJECTED HEAT UTILIZATION
DIGESTER GAS

FIGURE C.22
REJECTED HEAT UTILIZATION
DIGESTER GAS

FIGURE C.23
REJECTED HEAT UTILIZATION
DIGESTER GAS

FIGURE C.24
REJECTED HEAT UTILIZATION
DIGESTER GAS

FIGURE C.25
REJECTED HEAT UTILIZATION
DIGESTER & PIPELINE GAS

FIGURE C.26
REJECTED HEAT UTILIZATION
DIGESTER & PIPELINE GAS

FIGURE C.27
REJECTED HEAT UTILIZATION
DIGESTER & PIPELINE GAS

FIGURE C.28
REJECTED HEAT UTILIZATION
DIGESTER & PIPELINE GAS

FIGURE C.29
REJECTED HEAT UTILIZATION
DIGESTER & PIPELINE GAS

FIGURE C.30
REJECTED HEAT UTILIZATION
DIGESTER & PIPELINE GAS

FIGURE C.31
REJECTED HEAT UTILIZATION
DIGESTER & PIPELINE GAS

FIGURE C.32
REJECTED HEAT UTILIZATION
DIGESTER & PIPELINE GAS

FIGURE C.33
REJECTED HEAT UTILIZATION
DIGESTER & PIPELINE GAS

FIGURE C.34
REJECTED HEAT UTILIZATION
DIGESTER & PIPELINE GAS

FIGURE C.35
REJECTED HEAT UTILIZATION
DIGESTER & PIPELINE GAS

FIGURE C.36
REJECTED HEAT UTILIZATION
DIGESTER & PIPELINE GAS

FIGURE C.37
REJECTED HEAT UTILIZATION
DIGESTER & PIPELINE GAS

FIGURE C.38
REJECTED HEAT UTILIZATION
DIGESTER & PIPELINE GAS

FIGURE C.39
REJECTED HEAT UTILIZATION
DIGESTER & PIPELINE GAS

FIGURE C.40
REJECTED HEAT UTILIZATION
DIGESTER & PIPELINE GAS

FIGURE C.41
REJECTED HEAT UTILIZATION
DIGESTER & PIPELINE GAS

FIGURE C.42
REJECTED HEAT UTILIZATION
DIGESTER & PIPELINE GAS

FIGURE C.43
REJECTED HEAT UTILIZATION
DIGESTER & PIPELINE GAS

FIGURE C.44
REJECTED HEAT UTILIZATION
DIGESTER & PIPELINE GAS

FIGURE C.45
REJECTED HEAT UTILIZATION
DIGESTER & PIPELINE GAS

FIGURE C.46
REJECTED HEAT UTILIZATION
DIGESTER & PIPELINE GAS

**FIGURE C.47
REJECTED HEAT UTILIZATION
DIGESTER & PIPELINE GAS**

FIGURE C.48
REJECTED HEAT UTILIZATION
DIGESTER & PIPELINE GAS

APPENDIX D

AVAILABILITY

Reliability and availability are two of the parameters normally used to describe the anticipated performance of a power generation plant. The term reliability is concerned with the probability that a component or system will function within specified limits for a minimum period of time under specified operating conditions. This implies that reliability calculations are associated only with the operating life span of a component or system up to the point of a failure. If it is assumed that the components and systems have constant failure rates, then the reliability can be expressed by the equation:

$$R = e^{-\lambda t}$$

where $\lambda = 1/\text{Mean Time Between Failure (MTBF)}$ and $t = \text{Service Life}$

It should be noted that in this equation there is no reference to maintenance. This is a result of the definition of reliability which is not concerned with the fact that many operating components can be repaired after a failure occurs.

Availability can be either a statement of a plant's past performance or an estimate of its expected performance. In either case, it indicates the percentage of time that a plant, subsystem, or component is serviceable regardless of the extent of time that it has been or may be operated. Typically, when evaluating existing plants, availability is calculated as $1 - \text{unavailability}$, where the unavailability is composed of the full forced outage rate, maintenance outage rate, scheduled outage rate, and depending upon calculation procedure, an equivalent forced outage rate determined from the partial outage rate.

Calculated on the basis of a year, availability is:

$$A = \frac{8760 - \text{Outage Hours}}{8760}$$

where 8760 is the number of hours in a year and the outage hours are the average number of hours per year that a component, subsystem, or system is out of service. Normally, conceptual design availability predictions are based on only full forced outage rates or the sum of the forced outage rate and maintenance outage rate. This is done because scheduled outages are usually a characteristic of operating procedures. However, in this study availability includes all outages.

To determine the availability of power to the WPCF the cogeneration installation was organized into a number of subsystems for which individual availabilities were known or calculated. These availabilities were then combined to produce an overall availability. Assumptions and steps taken are described more fully in Sections D.1 through D.4.

In summary, it was calculated that the availability of power to the WPCF (Figure D.1) based on total outage hours is .99999 while availability of the cogeneration installation (Figure D.2) is .87225.

D.1 SYSTEM DESCRIPTION

Figure D.1 is a schematic indicating the idealized power connections for the cogeneration installation with the WPCF and the electric grid. As shown, electrical power is used by the WPCF directly from the electrical substation. A link from the substation is also required by the FCPP to control inverter phasing. Although the FCPP is intended to use digester gas generated by the WPCF as fuel, both electrical standby and control power or supplemental natural gas (even numbered cases), can be provided by PSE&G (Figure D.2). Standby or backup electrical power is provided by a set of existing gas turbine generators consisting of four units, three large units and one smaller unit. Plant power requirements can be met by two of the large units.

Figure D.2 shows a simplified schematic of the fuel, electrical power, coolant, and miscellaneous services provided to and by the FCPP. In a simplified sequence, the service hookups consist of fuel, air, water, and electrical power. The primary fuel is digester gas produced by the WPCF and

FIGURE D.1
WATER POLLUTION CONTROL FACILITY
POWER CONNECTIONS

FIGURE D.2
FUEL CELL POWER PLANT SUBSYSTEM

supplied to the FCPP through a compressor. Supplemental natural gas is supplied by PSE&G through a compressor (even numbered cases). The pressurized air system is essentially an air compressor with inlet filters. City water is supplied at line pressure. Heat produced by the FCPP is removed in a heat exchanger loop for use in the digesters and for space heating as needed. This loop is shown in more detail Figure D.3.

D.2 DATA SOURCES

Data defining average maintenance and forced outage hours were obtained from several sources. The unit year average for forced outage hours associated with the subsystems was obtained from the Edison Electric Institute (EEI) Report on Equipment Availability for the ten-year period, 1966-1975. This is a report of the Equipment Availability Task Force of the Prime Movers Committee of EEI (Publication No. 76-85). Availability data on individual components making up some of the subsystems were obtained from the EEI "Equipment Availability Component Cause Code Summary Report" for 1975.

Data concerning the FCPP was obtained from UTC (see Section 1.3). Digester availability was calculated based on historical operation data supplied by BCUA.

D.3 AVAILABILITY CALCULATION

To show how the availability of each major portion of the cogeneration facility was calculated, it will be helpful first to define several terms and demonstrate the typical approach to the calculation.

A series system is defined as one in which each component is required for operation of the facility. The availability of a system of this type is the product of individual component availabilities within the subsystem. A parallel system is one in which the component/system has a backup component/subsystem, only one of which must be in operation at a given time. In this case, availability

FIGURE D.3
REJECTED HEAT UTILIZATION

is calculated by subtracting the product of the component/subsystem unavailabilities (1 - availability) from one. As can be seen, system availability increases with the number of parallel subsystems and decreases with the number of series subsystems.

Calculation of the availability of power to the WPCF was simplified by first determining the availability of the major subsystems shown below:

D.3.1 Fuel Cell Power Plant

Fuel cell power plant availability values (shown in Table D.1) were used as received from UTC in all subsystems except the dry cooling tower subsystem. Because the cooling tower is not used in the availability evaluation but the rest of the subsystem is used, the UTC availability value was adjusted to account for its removal.

TABLE D.1
COMPONENT/SUBSYSTEM AVAILABILITIES

Component or Subsystem	Availability Based on	
	Forced Outage Hours	Total Outage Hours
Gas Turbines	.93064	.87417
Natural Gas Supply	.99997	.99997
Digester Gas Supply	.99178	.99178
Boilers	.99668	.95879
Heat Exchangers	.99991	.99909
Air Compressors	.99990	.99983
Heat Utilization Subsystem (Figure D.3)	.99972	.95776
Overall Cogeneration Installation Subsystem (Figure D.2)	.94397	.87225
Power to Overall WPCF	1.0	.99999

D.3.2 WPCF Digesters

Availability of the WPCF digesters was calculated from operational data supplied by the BCUA. The digesters are down (not operational) at a rate of three times in ten years (0.3 upsets/year). Upsets last an average of 10 days. Availability for this section is then calculated as:

$$\begin{aligned} A &= \frac{\text{Total hours} - \text{Outage Hours}}{\text{Total Hours}} \\ &= \frac{365 \frac{\text{days}}{\text{year}} - 0.3 \frac{\text{upsets}}{\text{year}} \times 10 \frac{\text{days}}{\text{upset}}}{365 \frac{\text{days}}{\text{year}}} \\ &= .99178 \end{aligned}$$

D.3.3 Heat Utilization Subsystem

As shown in Figure D.3, this subsystem consists of four in-line heat exchangers, three backup boilers, a circulating pump and required valving. Availabilities of individual components were taken from the EEI "Equipment Availability Component Cause Code Summary Report" for 1975. Availability of the subsystems was calculated by making the following assumptions:

- a. The grease melt heat exchanger is in series with the existing boiler, in the same loop. The same is true of the space heat exchanger boiler loop.
- b. Because of bypass valving the space, digester and grease melt heat exchanger subsystems were assumed to be in parallel.
- c. The main boiler was assumed to form one leg of a parallel system with the space and grease melt heat exchangers.
- d. The temperature control heat exchanger is in series with the remainder of the subsystem.

D.3.4 Fuel Supply Subsystem

Fuel supply availability was calculated as a pair of redundant series systems. For both natural and digester gas supplies, the gas supply and its compressor were calculated as a series system. Overall fuel supply subsystem availability, then, is just the parallel combination of the natural and digester gas supply subsystem availabilities.

D.3.5 Cogeneration Installation Subsystem

Availability of FCPP power output was calculated assuming that all subsystems supplying input or takeoff services to it (Figure D.2) are in series.

D.4 RESULTS

By first calculating availabilities of the subsystems shown above, determination of power availability to the WPCF is made easier. The overall system is shown in Figure D.1. Electrical substation power availability was based on an average yearly outage rate of 0.5 hours. Turbogenerator gas turbine system availability was calculated by assuming that the three turbogenerators operate in parallel to provide needed power with one of the three acting as a spare. The cogeneration installation subsystem power availability was calculated as shown in Subsection D.3.5.

Results of these availability calculations, for both the subsystems and the overall WPCF, are shown in Table D.1. Availabilities based both on forced outage hours and total outage hours, including maintenance, are shown.

APPENDIX E
CONCEPTUAL DESIGN SPECIFICATIONS

E.1 UTC SUPPLIED EQUIPMENT

E.1.1 PROCUREMENT (Equipment described in 4.5 MWe Demonstrator Specification - Ref. 1.4).

One (1) DC Module - fabricated, delivered, and rigged (pilings, foundations, mechanical hookups, and electrical hookups by others).

One (1) DC/AC Power Conditioner - fabricated, delivered, and rigged (pilings, foundations, electrical hookup, and brick veneer by others).

Control Center - fabricated, delivered, and rigged (pilings, foundations, mechanical hookups, electrical hookups, brick building, and building services by others).

Water Treatment System - fabricated, delivered, and rigged (pilings, foundations, mechanical hookups, electrical hookups, and brick veneer by others).

Cooling System - Cases 1-8: one (1) dry cooling tower with fans and motors; Cases 1-16: one (1) circulation pump, one (1) bypass control, one (1) accumulator, one (1) heater, one (1) filter, one (1) controller. All fabricated, delivered, and rigged (pilings, appropriate foundations, mechanical hookups, and electrical hookups by others).

E.1.2 INSTALLATION (Ref. list of UTC drawings, ancillary subsystem design requirements, and fluid specifications, Appendix B).

DC Module - dewatering, shoring, pilings, foundations, mechanical hookups, and electrical hookups.

Power Conditioner - dewatering, shoring, pilings, foundations, mechanical hookups, electrical hookups, and brick veneer.

Control Center, (Figure E.1) - mechanical and electrical hookups of equipment. Dewatering, shoring, pilings, foundations, brick building, flat, built-up roof, and all building services (HVAC, plumbing).

Water Treatment System - dewatering, shoring, pilings, foundations, mechanical hookups, electrical hookups, and brick veneer.

Cooling System - Cases 1-8: dewatering, shoring, pilings, and foundation for dry cooling tower heat exchanger cores, and ancillary equipment (circulating pump, bypass control, accumulator, heater, filter, controller), mechanical and electrical hookups. Cases 9-16: dewatering, shoring, pilings, and foundations for ancillary equipment only.

E.2 BALANCE OF PLANT EQUIPMENT PROCUREMENT AND INSTALLATION

E.2.1 FUEL SUPPLY, Figure E.2 (Cases 1-16)

Digester Gas Compressors - pilings and foundations, installed:

Total Inlet Capacity	1326 acfm @ 90°F, 12.91 psia
Number of Stages	2
Pressure Ratio per Stage	2.92
Overall Pressure Ratio	8.5

EQUIPMENT LIST

1. POWER PLANT MONITOR WITH KEYBOARD	6. GAS ANALYSIS CABINET
2. MANUAL CONTROL PANEL	7. D.C. MODULE CONTROLLER
3. CONTROL ANALYSIS PANEL WITH KEYBOARD	8. POWER PLANT I/O
4. SITE CONTROLLER	9. POWER PLANT I/O
5. LOCAL OPERATOR PANEL	* CHAIR

FIGURE E.1
FUEL CELL POWER PLANT
CONTROL AND DATA ACQUISITION BUILDING

FIGURE E.2
DIGESTER GAS COMPRESSOR ARRANGEMENT

Temperature of Intercooler Water 85°F
Gas Temperature Out of Intercooler 105°F
Total Power Required 220 hp

Assume Standby Compressor of equal capacity required

Intercooler for each Gas Compressor:

Water Flow Rate to Each	8970 lb/hr
Temp. Water In	85°F
Temp. Water Out	110°F
Temp. Gas In	270°F
Temp. Gas Out	105°F
Q each	230,520 Btu/hr

Aftercooler for Compressed Gas:

Water Flow Rate	8,970 lb/hr
Temp. Water In	110°F
Temp. Water Out	127°F
Temp. Gas In	285°F
Temp. Gas Out	150°F
Q	153,800 Btu/hr

Digester Gas Transport from Digester Building to FCPP (Figures 3.4, 3.5, Section 3.1.1 and Figure E.3):

6" nominal diameter plastic gasline pipe, entrenched and supported by existing pilings.

Maximum Temp. 95°F

Pressure: Maximum, 1 atm.

Minimum, 12.5 psi

Manifold to split flow from 6" pipe to 2 compressors with 6" nominal diameter pipe to each compressor inlet.
Open/Shut valves before and after each compressor.

Manifold to combine flow after compression (100 psia, 150°F)

One compressor bypass line with pressure control throttle valve.

One safety check valve.

Digester Gas Accessories:

Two flame trap assemblies each with total capacity of 1.7×10^6 cfd @ 95°F, 14.7 psia.

One waste gas burner assembly with capacity of 1.7×10^6 cfd @ 95°F, 14.7 psia.

Condensate Accumulator with drip trap - total capacity 150 gpd.

Digester Gas Pipe Condensate Line:

From Pump Building No. 1 to Digester
Gas Compressors - 2" nominal diameter
Schedule 40 pipe, entrenched (Figure E.3).

E.2.2 FUEL SUPPLY (Cases 2, 4, 6, 8, 10, 12, 14, and 16)

Natural Gas Compressors - pilings and foundations, installed.
Two (2) Compressors each rated for:

FIGURE E.3
ENTRENCHMENT OF PROCESS LINES
FROM GALLERY "A" TO POWER PLANT SITE

Overall Pressure Ratio	9.0
Inlet Capacity	126 acfm
Number of Stages	3
Pressure Ratio per Stage	2.08

Intercoolers:

After 1st Stage (1 per compressor):

Water Flow Rate	1000 lb/hr	
Temp. Gas In	200°F	
Temp. Gas Out	105°F	
Temp. Water In	85°F	each intercooler
Temp. Water Out	105°F	
Q	19,762 Btu/hr	

After 2nd Stage (1 per compressor):

Water Flow Rate	1000 lb/hr	
Temp. Gas In	230°F	
Temp. Gas Out	105°F	
Temp. Water In	105°F	each intercooler
Temp. Water Out	130°F	
Q	26,000 Btu/hr	

Aftercooler (1):

Water Flow Rate	2000 lb/hr
Temp. Gas In	230°F
Temp. Gas Out	150°F
Temp. Water In	130°F
Temp. Water Out	147°F
Q	33,250 Btu/hr
Gas Flow	820 lb/hr

Mains - 4,000 feet of 6" diameter main, operating pressure to 15 psig.

E.2.3 COGENERATION LOOP (Cases 1, 3, 5, and 7)

Grease Melt Heat Exchanger - installed in Pump Building No. 1:

Space Heat Exchanger - but installed in Pump Building No. 1:

Digester Heat Exchangers - installed in Digester Building, four (4) loops required each having these characteristics:

All heat exchangers must be sized for a maximum (intermittent) water/glycol flow rate of 190,800 lb/hr (47,400 lb/hr for each digester heat exchanger).

Water/Glycol Transport:

Piping from FCPP location to Pump Building No. 1, (Cases 1 and 5 to FCPP Location No. 2 shown in Figure 3.5, Section 3.1.1; Cases 3 and 7 to FCPP Location No. 1 shown in Figure 3.4, Section 3.1.1) - installed according to Figure E.3:

6" Schedule 40 pipe with 2.7" polyurethane insulation and 12" PVC jacket underground from FCPP to Pipe Gallery "A" (240°F).

6" Schedule 40 pipe with 2.5" fiberglass insulation (240°F) inside Pipe Gallery "A" to Pump Building #1.

Piping from Pump Building No. 1 to Dry Cooling Tower - installation same as previous piping:

6" Schedule 40 pipe with 2.5" fiberglass insulation
(120°F) inside Pipe Gallery "A".

6" Schedule 40 pipe with 0.7" polyurethane insulation and
8" PVC jacket underground from Pipe Gallery "A" to FCPP.

Piping inside Pump Building No. 1 - installed (all cases):

6" Schedule 40 pipe with 2.5" insulation interconnecting
heat exchangers, and for heat exchanger bypasses. Open/Shut
valves before and after each heat exchanger. An open/shut
valve in each bypass and one at the entrance and exit pipe
for Pump Building No. 1.

Water/Glycol Circulating Pumps - installed in Pump Building No. 1:

Primary Circulation Pump:

Flow	171,800 lb/hr (~350 gpm)
Pressure Drop	50 psi
Power	~13 hp

Standby Circulation Pump:

Flow	200,000 lb/hr (~400 gpm)
Pressure Drop	20 psi
Power	~6 hp

Valves-installed:

Open/Shut valves (2) on water/glycol piping into and
exiting FCPP.

Flow control valve (1) and bypass piping around water/glycol circulating pump (Figure 3.2, Section 3.1.1).

Pressure drop control valve after water/glycol circulating pump (Figure 3.2, Section 3.1.1).

E.2.4 COGENERATION LOOP (Cases 9, 11, 13, and 15)

Grease Melt Heat Exchanger, Space Heat Exchanger, Digester Heat Exchangers, Circulating Pumps and Valves same as Cases 1, 3, 5 and 7.

Temperature Control Heat Exchanger - installed in Pump Building No. 1:

This heat exchanger must be sized for a maximum (intermittent) water/glycol flow rate of 190,800 lb/hr.

Water/Glycol Transport Piping - same as Cases 1, 3, 5 and 7 with one exception: the water/glycol pipe from Pump Building No. 1 is routed to the FCPP DC Module.

Effluent Water Transport (cooling for Temperature Control Heat Exchanger):

Piping from WPCF Secondary Settling Tanks to Pump Building No. 1 via pipe galleries - installed:

8" nominal diameter Schedule 40 pipe with 2 open/shut valves (500 gpm Water Flow).

Effluent Water Pump - installed in Pump Building No. 1:

Flow	500 gpm
Pressure Drop	negligible

E.2.5 COGENERATION LOOP (Cases 2, 4, 6, 8, 10, 12, 14 and 16)

Cases 2, 4, 6 and 8 are the same as Cases 1, 3, 5 and 7 except for the specifications of the following two heat exchangers. Cases 10, 12, 14 and 16 are the same as Cases 9, 11, 13 and 15 with the same exceptions.

Space Heat Exchanger - installed in Pump Building No. 1:

Q	7.47×10^6 Btu/hr
UA	353,900 Btu/hr/°F
LMTD	21°F
Temp. Water/Glycol In	227°F
Temp. Water/Glycol Out	180°F
Temp. Water In	170°F
Temp. Water Out	189°F
Nominal Water/Glycol Flow	171,800 lb/hr
Maximum Water/Glycol Flow	190,800 lb/hr

Digester Heat Exchanger, Four (4) Required - installed in
Digester Building:

Q	0.99×10^6 Btu/hr
UA	13,920 Btu/hr/°F
LMTD	71°F
Temp. Water/Glycol In	180°F
Temp. Water/Glycol Out	155°F
Temp. Sludge In	95°F
Temp. Sludge Out	96°F
Nominal Water/Glycol Flow	42,950 lb/hr
Maximum Water/Glycol Flow	47,400 lb/hr

E.2.6 AUXILIARY POWER SUPPLY - installed (Cases 1-4 and 9-12)

One Line Diagram Figure E.4 shows the interface of the FCPP's output with the Cogeneration Installation 4.16 kV Bus 3 and the connection from the Cogeneration Installation 4.16 kV Bus 3 to the auxiliary power distribution system (to XFMR #4).

Medium Voltage Metal-clad Switchgear (4.16 kV):

Two, 1200 amp, 250 MVA breaker units.

Auxiliary cable termination unit.

One, instrument transformer and metering unit.

Approximate dimensions: 90" h x 104" w x 74" d.

E.2.7 AUXILIARY POWER SUPPLY - installed (Cases 5-8 and 13-16)

One Line Diagram Figure E.5 shows the interface of the FCPP's output with the WPCF 26.4 kV bus. One Line Diagram Figure E.6 shows the connection from the WPCF 4.16 kV Bus 1 to the auxiliary power distribution system (to XFRM #4).

FIGURE E.4
ELECTRICAL ONE LINE DIAGRAM
BUS 1 - 4.16 kV SWITCHGEAR

LEGEND:

R - RECORDING METER
FM - FREQUENCY METER

FIGURE E.5
ELECTRICAL ONE LINE DIAGRAM
26.4 kV SUBSTATION

FIGURE E.6
ELECTRICAL ONE LINE DIAGRAM
4160V SWITCHGEAR

Oil Circuit Breaker:

Outdoor frame, 3-pole, single tank, 1200 amp, 34.5 kV, 1500 MVA interrupting rating with two weatherproof cabinets (one for operating mechanism, one for relays).

Approximate dimensions: 128" h x 71" w x 47" d.

Bushing Current Transformers for the Oil Circuit Breaker:

Three 200-5A, relay accuracy, multi-ratio and on the "line-side" for differential relaying.

Metering Transformer Unit:

Consisting of potential and current transformers and to be used specifically for PSE&G's three-phase metering.

Oil Circuit Breaker Line Isolating Switches:

Three, horizontally mounted, 34.5 kV, 200 kV BIL, 600 amp, 40,000 amp momentary, single pole, hook switch operated and provided with post type insulators.

Switchgear Building (Cases 1-16):

Mechanical and electrical, dewatering, shoring, pilings, foundations, brick building, flat built-up roof, building services (HVAC, plumbing). Layout shown in Figure E.7.

E.2.8 AUXILIARY POWER DISTRIBUTIONS - installed (All cases)

One Line Diagrams Figures E.8, E.9, and E.10.

EQUIPMENT LIST

1. MEDIUM VOLTAGE SWITCHGEAR	6. BATTERY RACK
2. LOW VOLTAGE SWITCHGEAR	7. INVERTER
3. 480V MOTOR CONTROL CENTER	8. 120/208V MOTOR CONTROL CENTER
4. BATTERY CHARGER	9. 480-120/280V TRANSFORMER
5. D.C. PANEL	10. 120/280V BREAKER PANEL

FIGURE E.7
FUEL CELL POWER PLANT
SWITCHGEAR BUILDING

Low Voltage Unit Substation:

Transformer - 4160-480/277V, 750/1000KVA, dry type, fan-cooled, standard impedance.

Approximate dimensions: 77" h x 31" w x 55" d.

Air-filled terminal compartment for the 4.16 kV connection to transformer above.

Approximate dimensions: 77" h x 22" w x 39" d.

Low Voltage Switchgear Units:

One main breaker unit stack consisting of one 1600 amp frame breaker; one 600 amp frame breaker; and one instrument panel section.

One auxiliary unit stack consisting of the potential transformers.

One feeder breaker unit stack consisting of four, 600 amp frame breakers.

Approximate dimensions: 92" h x 38" w x 60" d.

480 Volt Motor Control Center - four vertical stacks consisting of the following totals:

Two, NEMA size 4 combination starters
One, NEMA size 3 combination starter
Three, NEMA size 2 combination starters
Five, NEMA size 1 combination starters
One, NEMA size 4 contactor

FIGURE E.8
ELECTRICAL ONE LINE DIAGRAM
480V SWITCHGEAR

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FIGURE E.9
ELECTRICAL ONE LINE DIAGRAM
480V MOTOR CONTROL CENTER

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FIGURE E.10
ELECTRICAL ONE LINE DIAGRAM
120/208V DISTRIBUTION PANELBOARDS

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Two, NEMA size 1 contactors
One, 225 amp frame breaker
One, 150 amp frame breaker
Two, 100 amp frame breakers

Approximate dimensions (total): 90" h x 80" w x 20" d.

Transformer:

480-120/208 Volt, 225 kVA, dry-type standard impedance, with six 2-1/2% taps, floor-mounted.

Approximate dimensions: 48" h x 39" w x 25" d.

Circuit Breaker Distribution Panelboard:

120/208V, 3-phase, 4 wire, with a 600 amp frame main breaker. Branch breakers shall consist of five, 100 amp frame 3 pole breakers; three, 100 amp frame 1-pole breakers; and two, 22 amp frame 3-pole breakers.

Approximate dimensions: 46" h x 35" w x 11" d.

Fusible Switch Distribution Panelboard:

120/208V, 3-phase, 4 wire, with a 200 amp main switch. Branch switches shall consist of three, NEMA size 0 motor starters with fusible disconnect switches; six, two-pole, 30 amp fusible switches; and four, 3-pole, 30 amp fusible switches.

Approximate dimensions: 66" h x 35" w x 12" d.

E.2.9 EMERGENCY POWER SUPPLY (EPS) - installed (All cases). No diagram.

Diesel Generator:

275 kW standby, 287.5 kVA continuous rating, 480/277 Volt output, with a starting time of 10 seconds or less.

Approximate dimensions: 63" h x 124" w x 38" d.

E.2.10 UNINTERRUPTIBLE POWER SUPPLY (UPS), installed (All cases). One Line Diagram Figure E.11.

Inverter System:

120/208V, three-phase output rated 25 kVA from .8 lagging to 1.0 power factor. The system shall include the following:

Inverter

Static transfer switch

Maintenance bypass switch

120/208V - 120/208V regulating transformer

Approximate dimensions: 78" h x 96" w x 36" d.

Battery Bank:

Comprised of 60 lead-calcium cells, with an 8 hour capacity to 1.75 volts per cell average of approximately 380 ampere-hours.

Battery Racks:

One, two-step type rack, suitable for holding 60 lead-calcium batteries (previous item).

Approximate dimensions: 22" h x 14'-0" w x 25" d.

Battery Charger:

One, 200 amp, 480V, three-phase input and 125V DC output.

Approximate dimensions: 70" h x 38" w x 40" d.

125V DC Distribution Panelboard:

Two wire, rated 250V DC with a 400 amp frame main breaker.
Branch breakers shall consist of one, 225 amp frame, 2-pole
breaker and two, 100 amp frame, 2-pole breakers.

Approximate dimensions: 45" h x 22" w x 6" d.

120/208 Volt Motor Control Center - Two vertical stacks
consisting of the following totals:

- Two, three-phase, NEMA size 1 contactors
- Three, 100 amp frame, 3-pole, circuit breakers
- Seven, 100 amp frame, 1-pole, circuit breakers
- Two, three-phase, NEMA size 1 combination starters

Approximate dimensions: 90" h x 40" w x 20" d.

E.2.11 CABLES AND CONDUIT FOR ALL ELECTRICAL

Cable

35 kV Power (Cases 5-8 and 13-16):

500 MCM stranded copper, single conductor for the connection
of the FCPP output to the electric grid system and the

connection of the 34.5 kV oil circuit breaker to the grid system.

5 kV Power:

500 MCM, stranded copper 195°F, three conductor, shielded, insulated, for the connections from the 4.16 kV switchgear to the fuel cell power plant output transformer (Cases 1-4 and 9-12), to the WPCF 4.16 kV switchgear Bus 1 (Cases 1-4 and 9-12), and to the 750/1000 kVA XFMR #4.

4/0 AWG, stranded copper 195°F, three conductor, shielded, insulated, for the connection from the 4.16 kV switchgear to the 750/1000 kVA XFMR #4 (all cases).

600V Power:

#10 AWG through 350 MCM, stranded copper, 195°F, insulated, three conductor cables for miscellaneous power connections.

600V Control:

#18 AWG through #14 AWG, stranded copper, 195°F insulated, multi-conductor cable for miscellaneous control connections.

Conduit System:

The conduit system shall consist of heavy wall rigid steel conduit, coated with plastic inside and outside or galvanized, to be used underground and through exterior building walls. Rigid steel galvanized conduit shall be used in reinforced concrete poured wall, floors and foundations. All exposed conduit shall be standard aluminum.

Other:

Assume existing power sources are available at the existing pumphouse and digester control buildings for additional equipment required in these facilities due to design modifications. Also, direct burial cable should be entrenched at the site facilities in lieu of ductbank for all power and control networks.

E.2.12 STORED GAS SUPPLY

Pressurized Air System - installed per UTC CDR SE-4, Appendix B.

N₂ and H₂ System - installed per UTC CDR SE-5, Appendix B.

E.2.13 MISCELLANEOUS

Water Storage - installed per UTC CDR SE-6.

Site Yard Piping - installed per UTC documents, Appendix B.

Interface design yard process piping ranges from .5 to 6 inch carbon steel. All yard piping was estimated at an average 3 inch carbon steel, Schedule 40, coated and wrapped.

Site Vents & Drains, Fire Protection - base on layouts and experience from similar type and size installations. The yard fire protection system is to be composed of piping, a pump and hydrants spaced at 150 feet. Assume domestic service water is available at the site location. Place automatic CO₂ extinguishing systems in the Switchgear Building and the Control and Data Acquisition Building.

Lighting, Communications, and Roadways - base on layouts and experience from similar type and size limitations.

Grounding - the equipment grounding system shall include all necessary grounding electrodes, ground buses and grounding conductors necessary to ground all non-current carrying metal parts of the wiring system and associated apparatus.

Consumables - nitrogen, hydrogen and cooling system coolant according to UTC Fluid Specifications SE-01, SE-02 and SE-03. Naphtha according to fuel specification in the 4.5 MWe Demonstrator Power Plant Model Specification, Ref. 1.4.

APPENDIX F
DETAILS OF THE ECONOMIC ANALYSIS

This appendix presents details of the economics developed in Section 4.0. Section F.1 and F.2 clarify the revenue requirement components for ownership and operation, respectively, by PSE&G and by BCUA and Section F.3 describes the detailed economic evaluation of the selected configuration.

F.1 PSE&G OWNERSHIP AND OPERATION OF THE FUEL CELL POWER PLANT

The following discussion is intended to clarify each of the revenue requirement components shown in Tables 4.1, 4.2, 4.3 and 4.4. Table F.1 contains all the pertinent economic backup data. The annual revenue requirement components for the FCPP and the conventional boiler plant are listed below and are shown pictorially within the dotted boundary of Figure F.1.

<u>Fuel Cell Power Plant</u>	<u>Conventional Boiler Plant</u>
Capital Carrying Charge	Capital Carrying Charge
Auxiliary Fuel Charge (Oil and/or Natural Gas)	Auxiliary Fuel Oil Charge
Operating and Maintenance Expenses	Operation and Maintenance Expenses
Standby Boiler Charge	
Effluent Cooling Charge	
Energy and Capacity Credits	

In the evaluation of the PSE&G ownership/operation option, the exchange rate for the digester gas and heat is within the boundary of the total economic evaluation. For this reason, the rates for digester gas and thermal energy were not included in the economic analysis. However, if this project were to continue beyond the conceptual design phase, additional analyses would be necessary prior to formulation of a contract which would be agreeable to both BCUA and PSE&G. The cost components of PSE&G ownership and operation are described following Table F.1.

TABLE F.1

I. Fuel Cell Power Plant and Conventional Boiler Plant Data

(A) Capital Costs (1979 \$)

(1) UTC Supplied Equipment	\$535/kW (with dry cooling towers)
	\$490/kW (without dry cooling towers)

(2) Balance of Plant Equipment

<u>Case #</u>	<u>Capital Cost</u>
5, 21	\$2,870,000
6, 22	\$2,949,000
13, 19	\$2,823,000
14, 30	\$2,903,000
7	\$2,798,000

- (3) Extension of natural gas pipe to the FCPP location-\$120,000

(4) Working Capital

1% of total plant investment

(5) FCPP Capital Related Carrying Charge Rates

	<u>PSE&G</u> %	<u>BCUA</u> %
Return	10.4	7.0
Depreciation	1.7	2.44
Federal Income Tax	<u>.4</u>	<u>-</u>
	12.5	9.44

- (6) Compound Construction Interest Factor - 1.067

TABLE F.1
(Cont'd)

(B) Fuel Costs (\$/10⁶Btu)

<u>Representative Years</u>	<u>PSE&G Costs Ownership/Operation</u>		<u>BCUA Costs Ownership/Operation</u>	
	<u>No. 2 Oil</u>	<u>Natural Gas</u>	<u>No. 2 Oil</u>	<u>Natural Gas</u>
1982	4.04	2.72	4.86	4.96
1985	5.00	3.85	5.98	6.16
1990	7.17	5.53	8.46	8.85
1995	9.39	8.36	11.11	12.70
2000	12.36	12.03	14.62	18.23
Levelized Annual Cost (1982-2001)	6.62	5.33	7.84	9.16

(C) Fuel Cell Power Plant Operating and Maintenance Costs (O&M)

- (1) Fuel Cell Power Plant

<u>Representative Years</u>	<u>Variable O&M Mills/kWhr</u>
1982	5.96
1985	7.10
1990	9.50
1995	12.71
2000	17.01
Levelized Annual Cost (1982-2001)	9.65

(2) Fuel Cell Power Plant Startup Costs

\$400/start (1979\$)
\$648/start (levelized)

(3) Fuel Cell Power Plant Annual Fixed Costs

	<u>1979</u>	<u>Levelized</u>
F CPP Operators		
PSE&G Ownership/Operation	\$148,400	\$286,000
BCUA Ownership/Operation	\$ 67,500	\$137,800

TABLE F.1
(Cont'd)

(D) Conventional Boiler Plant O&M Expenses

	<u>1979 Costs</u>	<u>Levelized</u>
Operators	\$ 67,500	\$137,800
Parts and Materials		
Standby Boilers	\$ 4,600	\$ 9,400
Standby Boilers	\$ 9,200	\$ 18,800

II. PSE&G Utility Data - Energy and Capacity

<u>Representative Years</u>	<u>Capacity Payment Rate Schedule (\$/kW/yr)</u>	<u>Avg. Incremental Energy Cost (Mills/kWhr)</u>
1982	32	36.9
1985	40	46.3
1990	54	73.5
1995	72	104.3
2000	96	129.4
Levelized Annual Cost (1982-2001)	57*	63.5

*It is assumed that PSE&G has a 25% chance of making capacity payments in the long term. Therefore the capacity payment rate for this study purpose was assumed to be \$15/kW/yr.

III. BCUA Utility Data

	<u>1979 Cost</u>	<u>Levelized</u>
Effluent Cooling Charge (\$/10 ⁶ gal)	345	622

IV. Annual Escalation Rates (%)

Capital	6.75
Fuel	
No. 2 Oil	6.50
Natural Gas	8.50
Operating & Matinenance Costs	6.00
Customer Utility Bills	
Gas	7.50
Electric	5.00
Effluent Cooling Charge	5.00

a. Fuel Cell Power Plant

Capital Related Carrying Charges: The FCPP capital costs consists of two components; UTC supplied equipment and balance of plant equipment with installation of all equipment. The capital cost for UTC supplied equipment in the economic analyses was \$535/kW. According to UTC, the dry cooling towers are approximately 8% of the cost of UTC supplied equipment. For those conceptual design alternates which use effluent cooling (i.e. Cases 7, 13 and 14), the cost of the dry cooling towers have been removed from the UTC supplied equipment cost. The capital costs for balance of plant equipment and installation of all equipment are shown in Tables 3.22 and F.1.

For those conceptual design configurations which involve the supplementation of digester gas with natural gas, the capital cost of extending a gas pipe to the FCPP location was estimated based on previous PSE&G natural gas pipe construction experience.

The boilers to be used as back-up for the FCPP are existing equipment at the WPCF. Since this component of revenue requirements does not affect the overall economic evaluation, it was set equal to zero.

The working capital components consist of 1% of the total capital cost.

The annual revenue requirement was determined by multiplying the installed capital by the appropriate carrying charge rate and compound construction interest factor.

Auxiliary Fuel Charge: In Conceptual Design Cases 5, 6 and 7, the FCPP utilizes only digester gas with the output varying according to the production of methane. Supplemental heating requirements are provided by an auxiliary boiler which burns No. 2 oil. Cases 13 and 14 utilize natural gas to supplement the digester gas, enabling the FCPP to operate at design capacity. The costs to PSE&G of No. 2 oil and natural gas were based on the PSE&G Second Quarter 1979 Fuel Price Forecast. Both oil and natural gas prices were treated on a levelized basis, using present worth calculations.

Fuel Cell Operating and Maintenance Costs: The variable operation and maintenance costs of the FCPP and the cogeneration loop were assumed to be 5 mills per kWhr (1979 dollars). It was also assumed that the FCPP would be started from a cold shut down condition three times per year. The total variable O&M expenses were determined based on the electric output of the FCPP and the startup costs.

In determining the electric output of the FCPP, an availability of 92% was assumed for the FCPP. This figure consists of 4% maintenance outage (two weeks per year) and a 4% forced outage rate for the FCPP.

The levelized fixed O&M expenses were based on one operator per shift, three shifts per day which resulted in a need for a total of four men.

Standby Boiler Charge: To provide backup thermal capacity for the FCPP, it is necessary to have some standby boiler capacity. This capacity can be provided by existing WPCF boilers. The additional O&M expenses associated with operating the boilers in a standby mode were separated into personnel costs and parts and materials costs.

Effluent Cooling Charge: The excess FCPP heat over and above the WPCF thermal requirements can either be rejected to the atmosphere in a dry cooling tower as in Cases 5, 6 and 7 or rejected to the WPCF effluent water flow via a shell and tube heat exchanger as in Cases 13 and 14.

In Cases 13 or 14 the source of the water was taken from the process end of the WPCF, passed through the shell and tube heat exchangers and then returned to the WPCF at the beginning of the treatment process. All customers serviced by this facility are charged based on the total flow through the WPCF. The FCPP was considered a customer and charged at the levelized rate of \$622/10⁶ gallons of flow.

Energy and Capacity Credit: This component of revenue requirements consists of expected Pennsylvania-New Jersey-Maryland (PJM) Interconnection energy and capacity credits that PSE&G would realize from the installation of this FCPP. The capacity payment has been based on an analysis of the PJM Supplemental Agreement. Electric energy produced by the FCPP was credited at the average PJM incremental running rate. Both of these costs were levelized using present worth economics over the life of the FCPP.

The decrease in electrical losses on the transmission and distribution grid associated with the displacement of grid supplied energy by electric energy from the FCPP was estimated to be 4.7% of the FCPP output. The decrease in transmission and distribution losses was credited at the levelized PJM running rate.

b. Conventional Boiler Plant

Capital Carrying Charges: The conventional boilers presently being installed at the WPCF were considered as sunk costs with regard to this economic evaluation. Therefore, this component of revenue requirements did not affect the overall economic evaluation and was set equal to zero.

Auxiliary Fuel: For the conventional boiler plant operation, digester gas is used in the boilers to provide heat. No supplemental fuel oil is estimated to be required, therefore this cost component is zero.

Operating and Maintenance Expenses: These are the typical O&M costs associated with WPCF operation to burn digester gas in the boilers to produce heat. The costs are based on a total of four operators plus parts and materials.

F.2 BCUA OWNERSHIP AND OPERATION OF THE FUEL CELL POWER PLANT

The economic evaluation of BCUA's ownership and operation of the FCPP was based on the same methodology as the PSE&G evaluation (i.e. annual revenue requirements). The charges to BCUA for electric energy with the conventional boiler alternative and the charges for supplemental electric energy and standby

capacity with the FCPP alternative were included in the BCUA ownership/operation economic evaluation. The revenue requirement component for BCUA electric energy charges was not included in the PSE&G ownership/operation evaluation because these revenue requirements were the same with the FCPP or the conventional boiler alternatives. The components of the revenue requirements for the FCPP and the conventional boiler plant consist of the following items as indicated within the dotted boundary Figure F.2.

<u>Fuel Cell Power Plant</u>	<u>Conventional Boilers</u>
Capital Carrying Charge	Boiler Plant Capital Carrying Charge
Auxiliary Fuel Charges (Oil and/or Natural Gas)	Auxiliary Fuel Oil Charge
Fuel Cell Operation & Maintenance Expenses	Operation and Maintenance Expenses
Standby Boiler Charge	Electric Energy Charge
Effluent Cooling Charge	
Supplemental Electric Energy and Standby Electric Capacity Charges	

The discussions of all the above components, except for the supplemental electric energy and standby electric charges for the FCPP and the electric energy charge for the conventional boiler plant, are the same as in the PSE&G ownership and operation option. The carrying charge rate for BCUA ownership was based on the cost of money and depreciation accounting methods for BCUA. The cost of natural gas in this option was based on the appropriate retail rate for natural gas, not the cost to PSE&G, as in the PSE&G ownership/ operation economic evaluation. The cost of fuel oil purchased by BCUA was higher than the cost to PSE&G because of difference in quantity buying between PSE&G and BCUA.

Fuel Cell Power Plant Supplemental and Standby Electric Charges: The electric output of the FCPP will be used by BCUA to provide a portion of the WPCF load. It is expected that the BCUA will purchase the remainder of the WPCF electric energy and standby capacity for the FCPP load from PSE&G at the appropriate rates.

Conventional Boiler Plant Electric Energy: BCUA will purchase all of their electric energy from PSE&G at the appropriate rate.

F.3 DETAILED ECONOMIC ANALYSIS FOR THE SELECTED CONFIGURATION

The purpose of this section is to show a detailed economic evaluation calculation for one of the conceptual design alternatives. The details of Case 5, PSE&G Ownership and Operation of the FCPP, Digester Gas Only, Dry Cooling, Location No. 2, are shown below. All other conceptual design cases are similar.

I. Fuel Cell Power Plant

(A) Capital

	<u>Direct Capital</u>	<u>Working Capital</u>
Carrying Charge Rate	12.5%	16.3%
Compound Construction Interest Factor (CCIF)	1.067%	-
Escalation	6.75%	6.75%

UTC Supplied Equipment - \$535/kW
 4500 kW x \$535/kW = \$2,407,500 (1979\$)

Balance of Plant - \$2,870,000 (1979\$)

Working Capital -

N₂, H₂, Naphtha Storage - \$5,400 (1979\$)

1% of Total Plant Investment - \$52,700 (1979\$)

Carrying Charges

<u>Item</u>	<u>Capital</u>	<u>Escalation</u>	<u>CCIF</u>	<u>Carrying Charge Rate</u>	<u>Carrying Charges</u>
UTC Supplied Equipment	\$2,407,500 x	(1.0675) ³ x	1.067 x	.125 =	\$390,000
Balance of Plant	\$2,870,000 x	(1.0675) ³ x	1.067 x	.125 =	\$465,700
Working Capital N ₂ , H ₂ , Naphtha	\$5,400 x	(1.0675) ³ x	1.000 x	.163 =	\$ 1,070
1% of Total Plant Investment	\$5,270,000 x	(1.0675) ³ x	.01 x	.163 =	\$ 10,449

(B) Auxiliary Fuel

Annual Levelized Cost No. 2 oil (1982-2001) $\$6.62/10^6\text{Btu}$

Heating Value $5.8 \times 10^6\text{Btu/bbl}$

Oil needed to supplement FCPP heat 50,704 gal

$$50,704 \text{ gals.} \times \frac{1 \text{ bbl}}{42 \text{ gal.}} \times \frac{5.8 \times 10^6 \text{ Btu}}{\text{bbl.}} \times \frac{\$6.62}{10^6 \text{ Btu}} = \$46,400$$

(C) Operating & Maintenance Costs (O&M)

Electric Production

Average fuel cell electric output (digester gas only) - 3.72 MWe
92% availability for fuel cell

$$3720 \text{ kW} \times 8760 \text{ hrs.} \times .92 = 30 \times 10^6 \text{ kWhr}$$

Variable O&M - 9.65 mills/kWhr levelized

$$30 \times 10^6 \text{ kWhr} \times 9.65 \text{ mills/kWhr} = \$289,500$$

Start up (3 starts/yr.)

$$\begin{aligned} \$648/\text{start} \times 3 \text{ starts} &= \underline{2,000} \\ & \$291,500 \end{aligned}$$

Fixed O&M (Operator)

Salary per PSE&G operator (includes overheads) - \$ 37,100 (1979\$)

\$ 71,500 (levelized)

4 Operators x \$71,500/operator =

\$286,000

(D) Standby Boiler Charge

Salary per BCUA operator (includes overhead) - \$ 16,900 (1979\$)

\$ 34,450 (levelized)

4 operators x \$34,500/operator =

\$137,800

Parts and materials standby boiler =

9,400

\$147,200

(E) Cooling

No Charge

(F) PJM Energy and Capacity Credits

Annual Levelized PJM Capacity Payments \$ 15.00/kW/yr
(1982-2001)

Annual Levelized PJM Purchase Power \$.0635/kWhr
(1982-2001)

Replacement Energy
 $30 \times 10^6 \text{ kWhr} \times \$.0635/\text{kWhr} = \$1,905,000$

Replace Capacity
 $4500 \text{ kW} \times \$15.00/\text{kWyr} = \$67,500$

Decrease in Transmission & Distribution Losses
= 4.7% of electric energy produced by the FCPP

FCPP Generation $30 \times 10^6 \text{ kWhr}$

$30 \times 10^6 \text{ kWhr.} \times \frac{\$.0635}{\text{kWhr}} \times .047 = \$89,500$

(II) Conventional Boiler Plant

(A) Boiler O&M Charges

Salary per BCUA operator (includes overheads) - \$16,900 (1979\$)
- \$34,450 (levelized)

4 Operators x \$34,450/Operator = \$137,800

Parts and Materials Standby Boilers = 9,400

Parts and Materials Operating Boilers = 18,800

\$166,000

APPENDIX G

DETAILED DESCRIPTION OF THE SELECTED CONFIGURATION

G.1 UTC SUPPLIED EQUIPMENT (Erected in Location No. 2, Figures 2.2 & 2.3).

DC Module: The module is the same as that described by the 4.5 MWe Model Specification (Ref. 1.4) with two major and several minor changes. The first major change is that the cogeneration loop will be plumbed directly into the FCPP's secondary cooling system prior to the dry cooling tower, to form a single, in-series loop. A mixture of 35% glycol/65% water (by volume) would be the actual coolant (rather than the 50%/50% used in the 4.5 MWe Utility Demonstrator Power Plant). The presently designed piping scheme of the FCPP is unchanged. Specifically, interconnections among heat exchangers No. 318, 406, 407 and 405 remained the same as in the specification. No additional FCPP heat exchangers were added.

The second major change is that the low flow turbocompressor would be eliminated from the DC module, with a resulting cost savings of 2% based on the 4.5 MWe Utility Demonstrator Power Plant cost, Appendix B. Minor, associated equipment and instrumentation will also be eliminated.

All plumbing and electric will be entrenched between the DC Module, other FCPP pallets and the balance of plant equipment.

Power Conditioner: The power conditioner envelope and the UTC supplied equipment within that envelope were unchanged except for rewindings within the output transformer to provide 26 kV. In keeping with the general architectural style of the facility, a brick veneer over a concrete block wall was added to the UTC supplied prefabricated weather enclosure.

Control Center: Some of the Utility Demonstrator data acquisition equipment and instrumentation was eliminated, but the control equipment remains,

primarily that described by the specification. Some additional instrumentation and control would be added for the cogeneration application. The building, Fig. E.1, to house this equipment is brick over load bearing concrete block wall and has a flat, built-up roof. Comfort facilities, heating, ventilating, and air condition are included.

Water Treatment System: The water treatment system is the same as that shown by the 4.5 MWe Utility Demonstrator Power Plant specification. As with the power conditioner, a brick veneer over a concrete block wall was added to the UTC supplied weather enclosure.

Cooling: The dry cooling tower and associated equipment (pump, heater, accumulator, filter, etc.) are unchanged from the specification.

G.2 BALANCE OF PLANT EQUIPMENT

Fuel Supply: The fuel supply system consist of digester gas compressors, gas piping and a condensate line.

The design requirement for digester gas compression is presented in the Conceptual Design Specifications, Appendix E. Figure E.2 shows the arrangement of compressors to satisfy the design requirements. Two compressors are required, one for regular operation, the other for standby. Their design performance characteristics are listed in Figure 3.9. The piping for digester gas is 6" PVC Schedule 80 plain, routed from the anaerobic digesters to Location No. 2 by attaching it to an existing pile supported electrical duct bank Figure E.3. Several new piles are required to bring the pipe from the duct bank to the FCPP fuel processor. A flame trap assembly and waste gas burner are required prior to the compressors in the event of excess digester gas supply.

The digester gas is water laden. Thus, as the digester gas flows to Location No. 2 water condenses in the bottom of the gas pipe. The pipe must be held in place to insure its pitch so that water will not accumulate, hence the need for piling support. The condensed water is trapped at intervals in the

digester piping and drained to a condensate line below. The condensate is pumped to Location No. 2 and drained into a vent system.

Cogeneration Loop: A glycol/water solution (35% glycol by volume) is the medium for removing rejected heat from the FCPP (Station 6a to 1 and 6a to 18, Figure 3.2) for utilization in the WPCF processes. The flow rate of glycol/water is controlled by a bypass on the primary circulation pump to maintain a constant FCPP exit temperature (Station 1) of 240°F, the maximum allowed by the manufacturer (UTC).

The primary glycol/water circulation pump operates at a constant design flow rate of about 390 gpm (190,800 lb/hr) and pressure differential of 50 psi. The conditions are set by the maximum flow rate required, based on the monthly average gas data and the FCPP characteristics, to maintain the FCPP exit temperature at 240°F and the maximum estimated pressure loss through the system piping and heat exchangers. The flow bypass around the pump regulates the flow rate through the system and the pressure differential control valve just downstream of the pump maintains the balance between system loss and pump head.

The WPCF processes utilizing rejected FCPP heat are grease melt, space heat, and digester sludge heat. An intermediate fluid is used to transfer heat from the water/glycol to the final process fluid in the grease melt and space heat systems. In the grease melt process, heat is transferred from the glycol/water to water in a tube and shell type heat exchanger. Heat is then transferred from the water to the grease in the existing WPCF heat exchangers. An existing WPCF boiler in the water loop will be used to provide heat to the grease when the FCPP is not operating.

Water is also used as the intermediate fluid in the space heat process. A tube and shell type heat exchanger is used to transfer heat from the glycol/water to the water. The water temperature into the heat exchanger is 170°F. The minimum practical terminal temperature difference (glycol/water exit to water inlet temperature difference) is considered to be 10°F. Therefore, the minimum glycol/water exit temperature is 180°F. The desired

water temperature out of the heat exchanger to the space heat process is 190°F. However, there are times when this cannot be achieved and meet the 180°F glycol/water minimum exit temperature specification. Therefore, the existing boilers at the WPCF will be used to provide the necessary make-up heat.

Heat will be transferred from the glycol/water to the digester sludge in shell and tube type heat exchangers. It was determined that, when the FCPP is operating, the quantity of heat available to the digesters from the glycol/water will meet the process needs. An auxiliary boiler will be required, however, to provide heat when the FCPP is not operating. This feasibility study assumed that the boiler currently being used for this process at the WPCF can be used as the auxiliary boiler with glycol/water as the heat transfer fluid.

The temperature of the glycol/water exiting the digester heat exchanger will range from 145°F to 220°F. The temperature at the FCPP inlet (Station 6a) must be 120°F according to the UTC specification. Therefore, a temperature control heat exchanger is included in the system. The temperature control heat exchanger for the selected configuration is the UTC supplied dry cooling tower.

A flow bypass circuit is included around each heat exchanger for removal of the unit from service without shutting down the entire system. In addition, a flow bypass around the entire heat utilization loop (Station 2 to 5) is designed for operation of the FCPP separate from the WPCF processes.

Determination of the actual number of heat exchanger units for each process was beyond the scope of this feasibility study. Functional characteristics for the total process only were considered except in the case of the temperature control heat exchanger. The design points for heat exchangers were chosen as maximum "UA" conditions based on monthly averages. The grease melt and digester sludge heat exchanger design months were January. The space heat heat exchanger design month was March.

Auxiliary Power: The Auxiliary Power System provides the FCPP auxiliary power requirements at 480/277 volts from the WPCF 4,160 volt bus (Figure E.6). This system also interfaces the FCPP output with the Bergen County Utilities Authority's 26.4kV substation (Figure E.5). The components for this system are described in Appendix E., Conceptual Design Specifications (for Cases 5-8 and 13-16).

Auxiliary Power Distribution System: The Auxiliary Power Distribution Subsystem, Figures E.8, E.9, and E.10, distributes AC power from the Auxiliary Power Supply (APS) or the Emergency Power Supply (EPS) to the electrical components in the FCPP. The APDS also provides power to the Uninterruptible Power Supply (UPS) which supplies uninterruptible power to selected critical FCPP components. Components for this system are described in Appendix E, Conceptual Design Specifications.

Emergency Power Supply: This supply provides the necessary output power to effect an orderly FCPP shutdown and to provide freeze protection of the DC Module and ancillary equipment, in the event of an auxiliary power loss. A description of the diesel generator, which is the source of emergency power, is described in Appendix E.

Uninterruptible Power Supply: The Uninterruptible Power Supply, Figure E.11, supplies power to all controllers, control valves, ventilation fans, power conditioner subsystem logic, switchgear and preload during the period between loss of auxiliary power and the start of the EPS. If the EPS does not start, the UPS will supply power sufficiently long into the ensuing shutdown to insure operating safety. Components are described in Appendix E.

Most of the components of the Auxiliary Power Supply, the Auxiliary Power Distribution System, the Emergency Power Supply and the Uninterruptible Power Supply are housed in the FCPP Switchgear Building, Figure E.7. The building is constructed of brick veneer over a concrete block load-bearing wall with a flat built-up roof. Heating, ventilating and air conditioning is furnished due to equipment requirements.

The remaining equipment categories of the selected configuration are described in Appendix E.

G.3 CAPITAL COST COMPARISON WITH UTILITY DEMONSTRATOR

There is a large apparent discrepancy in the Installation and Balance of Plant Equipment Capital Cost of the cogeneration installation, Table 3.22, and the estimate given for a utility FCPP installation, Appendix B. This cost discrepancy is attributable to the manner in which the FCPP is used (utility with electric power output only compared with industrial with both electric power output and heat utilization), size of the FCPP and specifics of the site. To investigate this cost discrepancy, Case 2 of Table 3.22 was recosted to eliminate the equipment needed for cogeneration and for specifics of the WPCF site. Specifically, the following were removed: dewatering, shoring, pilings, fuel gas compression equipment, cogeneration loop piping and heat exchangers, and aesthetics specific to BCUA building requirements. The revised estimate which reflects a utility type FCPP installation is shown in Table G.2. It is the cost estimated in Table G.2 rather than that shown in Table 3.22 which, based on this study, should be compared to the DOE estimated cost. Two additional items must be considered for an accurate comparison: 1) escalation, and 2) FCPP development status.

Escalation: Table G.1 shows the unit investment costs in 1979 dollars for the utility FCPP as estimated by DOE and for the WPCF cogeneration installation revised to reflect a utility FCPP installation.

TABLE G.1
COMPARISON OF INSTALLATION COSTS

	DOE Estimated Cost \$/kW	Revised Cogeneration Installation Cost \$/kW
UTC Supplied Equipment Installation	53 (1978)	272 (1979)
Balance of Plant Equipment & Installation	29-69 (1978) 82-122	272
Similar Year Dollars (1979)	87-130	272

TABLE G.2

CAPITAL COST ESTIMATE SUMMARY OF CANDIDATE #2
EXCLUDING SIGHT SENSITIVE CRITERIA
(In \$1000's - 1979)

<u>ITEM</u>	<u>CANDIDATE #2</u>
A. UTC Supplied Equipment Installation ¹	
<u>D.C. Module</u>	
Material	46
Labor	87
Subtotal	<u>133</u>
<u>Power Conditioner</u>	
Material	37
Labor	73
Subtotal	<u>110</u>
<u>Control Center</u>	
Material	30
Labor	58
Subtotal	<u>88</u>
<u>Water Treatment</u>	
Material	11
Labor	26
Subtotal	<u>37</u>
<u>Cooling</u>	
Material	30
Labor	62
Subtotal	<u>92</u>
Subtotal	460
B. Balance of Plant Equipment and Installation	
<u>Fuel Supply</u>	
Material	-
Labor	-
Subtotal	<u>-</u>
<u>Cogeneration Loop</u>	
Material	-
Labor	-
Subtotal	<u>-</u>

¹Excluding UTC supplied equipment.

TABLE G.2 (Cont'd)

<u>ITEM</u>	<u>CANDIDATE #2</u>
<u>Auxiliary Power Supply</u>	
Material	46
Labor	12
Subtotal	<u>61</u>
<u>Auxiliary Power Distribution</u>	
Material	124
Labor	103
Subtotal	<u>227</u>
<u>Emergency Power Supply</u>	
Material	39
Labor	3
Subtotal	<u>42</u>
<u>Uninterruptible Power Supply</u>	
Material	18
Labor	14
Subtotal	<u>32</u>
<u>Stored Gas Supply</u>	
Material	31
Labor	36
Subtotal	<u>67</u>
<u>Water Storage</u>	
Material	29
Labor	28
Subtotal	<u>57</u>
<u>Site Yard Piping</u>	
Material	25
Labor	45
Subtotal	<u>70</u>
<u>Site Vents & Drains</u>	
Material	27
Labor	23
Subtotal	<u>50</u>
<u>Fire Protection System</u>	
Material	40
Labor	32
Subtotal	<u>72</u>
Subtotal	678

TABLE G.2 (Cont'd)

<u>ITEM</u>	<u>CANDIDATE #2</u>
C. Miscellaneous	
<u>Lighting</u>	
Material	4
Labor	3
Subtotal	<u>7</u>
<u>Communications</u>	
Material	1
Labor	<u>1</u>
Subtotal	2
<u>Grounding</u>	
Material	4
Labor	<u>10</u>
Subtotal	14
<u>Roadways</u>	
Material	5
Labor	<u>7</u>
Subtotal	12
Subtotal	35
Installation and Balance of Plant Equipment Construction Cost (CC)	1,173
Contingency (5% of CC)	59
Engineering (2% of CC)	<u>23</u>
Installation and Balance of Plant Equipment Capital Costs	1,225

Even after considering the effects of similar year dollars, a disparity in cost still remains.

A major factor in the remaining cost difference is associated with power level. The DOE estimated cost is based on a larger 26 MWe power plant while this study assumes a 4.5 MWe size FCPP. Installation costs do not scale linearly and therefore costs per kilowatt do not remain constant for varying power sizes. UTC has estimated installation costs (\$/kW) would be two to three times greater for a 4.5 MWe FCPP than a 26 MWe FCPP. In addition, the DOE figures were based on a commercialized FCPP where the experience with previous installations has resulted in reduced cost requirements. This contrasts with the smaller (4.5 MWe), one-of-a-kind, demonstrator used for the cogeneration application. For example, the commercialized FCPP operates at a higher power density and its foundation requirements are minimized (including the placement of the dry cooling towers on top of the DC Module). Another cost factor favoring the larger power plant is that the 4.5 MWe Demonstrator uses an inverter sized for 9.2 MWe or two 4.5 MWe modules. Although the specific identification of cost differences due to development status was beyond the scope of this study, it is assumed that any remaining disparity in cost could be explained by development status differences between the two power plants.

APPENDIX H
FUEL CELL POWER PLANT PENETRATION ANALYSIS

H.1 SUMMARY

The FCPP has the potential for a variety of applications in the cogeneration mode. While these applications are site specific, they can be planned and developed for integration into both existing and new facilities. To utilize the FCPP in an industrially viable context, there must be onsite needs for both electric power and low temperature thermal energy in the 250°F range.

The application of FCPP's for use in water pollution control facilities has been examined here. While the direct application appears to be moderate, it serves as an example of how one application requiring electricity and low temperature heat could utilize this technology. Also, new, large municipal WPCFs would represent high priority candidate applications for FCPPs since the economics of integrating the FCPP into the original design of a WPCF is more attractive than retrofitting. Activities such as very large agricultural livestock feedlots and biomass processes would be examples of other applications with large quantities of anaerobic digester gas.

If other similar applications were found for a large number of facilities, the fuel cell/cogeneration concept could make a significant contribution toward meeting the energy requirements of many industrial activities. This could free fluid fuels presently being used in these industries for other purposes.

Since identification of other market applications was beyond the scope of this project, it was not examined here. It is suggested that market analysis be done with additional consideration for a market based on a 2.25 MWe FCPP. Our study shows a deeper and wider market for a unit of this size.

H.2 OBJECTIVES

The market penetration analysis was conducted to develop the data base for analyzing the applicability of integrating FCPPs with existing WPCFs.

Specifically, the following two questions were formulated and addressed:

- a. How many 4.5 MWe FCPPs can be integrated with existing WPCFs? The integration was based on the FCPP using methane gas produced in WPCF anaerobic digesters as the source of fuel.
- b. How much oil would be displaced on a national basis using the above FCPP/WPCF application? The results are calculated for equivalent barrels of #6 fuel oil and barrels of crude oil. The results of the data base development and analysis are presented in the sections that follow.

H.3 APPROACH

This subsection presents an overview of the procedures used in developing and analyzing the data. The discussions in Subsection H.4, Data Base, covers data acquisition guidelines, actual data gathered, inconsistencies found in the data, and communications between G/C and outside experts in resolving the inconsistencies in the data. In Subsection H.5, Methodology, the data are analyzed in order to:

- a. Calculate a weighted average conversion factor for estimating average gas production for the WPCFs included in the study that were not contacted for data. Table H.2 is the data base for the plants contacted for data. These data were used in generating the estimates for the WPCFs not contacted. The weighted average conversion was the method used in generating the estimated gas production.

- b. Apply the weighted average conversion factor to the other plants to estimate the potential quantity of anaerobic digester gas available for operating FCPPs and determining the number of FCPPs that the quantity of gas can sustain (Table H.3).
- c. Calculate the number of barrels of petroleum-based fuels displaced by using methane from WPCF anaerobic digesters to operate onsite FCPPs. These petroleum displacement levels have been calculated for three methane consumption cases.

The last Subsection, H.6, Conclusions, develops results of the market penetration analysis and a recommendation which could be of use in the future development of FCPPs for use at WPCFs.

H.4 DATA BASE

The design fuel requirements for a 4.5 MWe FCPP are approximately 1.0×10^6 scfd of methane. The Bergen County Utilities Authority WPCF, which is designed for a wastewater flow of 50×10^6 gpd and which currently processes an average of 68×10^6 gpd, produces 0.91×10^6 scfd of methane. This figure is sufficiently close to the FCPP design requirement of 1.0×10^6 scfd to warrant specifying a wastewater throughput of approximately 50×10^6 gpd through the plant as the minimum size for the ensuing market penetration analysis.

In accordance with this basis, a search was initiated for data covering WPCFs with a minimum actual daily throughput of 50×10^6 gpd and where the primary and secondary treatment sludge is processed in anaerobic digesters.

Two current data sources were found. The first, a report dated December 1978 and entitled "Operational Characteristics of Anaerobic Digesters at Selected Municipal Wastewater Treatment Facilities in the United States" was produced by Battelle-Pacific Northwest Laboratories (Reference H.1). The second data source is information obtained from a 12 July 1978 computer printout from the

Environmental Protection Agency (EPA) of the USA Municipal Waste Facilities Inventory and entitled "Municipal Wastewater Treatment Plants with Design Flows Over 50 MGD That Have Digesters". The Battelle report is based on 1968 data (Reference H.2). The EPA computer printout was compiled from questionnaires (Reference H.3).

A number of problems arose while using the data. Current wastewater flow rates were in some instances substantially different than those listed in the EPA tabulation. For example, the EPA number of 41×10^6 gpd for the actual wastewater flow in Bergen County deviates considerably from the actual 68×10^6 gpd. Another problem concerned the distribution of the primary and secondary sludge. If some of this sludge is processed in facilities other than anaerobic digesters, an accurate determination of the quantity of gas produced from the digesters per given input of wastewater to the facility may be impossible. An example of such a situation exists in the Washington, D.C., Blue Plains plant and in the Chicago WSW plant. Another problem involved the exclusion of many plants from the EPA tabulation. For example, exclusions together with their wastewater flow rates include:

<u>Facility</u>	<u>Wastewater Flow (10^6 gpd)</u>
Miami, FL	67
Elizabeth, NJ	80
Milwaukee, WI	80
Atlanta, GA	82.5
Calumet, IL	220
Boston (Deer I.), MA	312
Los Angeles, CA	350
Chicago, (WSW), IL	850 (Percent of the total sludge charged to the anaerobic digesters is unknown.)

It was necessary to make a number of telephone contacts with appropriate WPCF personnel to complete and verify the data base. In most cases, data needed were obtained. One exception involved the Chicago WSW plant where information

pertaining to the allocation of sludge between a vacuum filter process and the anaerobic digesters was unavailable. The most important conversations, which support data presented in Subsection H.5, Methodology, are referenced.

H.5 METHODOLOGY

A review of data collected and telephone conversations and personal discussions with the operating personnel at the Bergen County Utilities Authority (BCUA) (Reference H.4) revealed there are 45 water pollution control facilities with actual throughputs greater than approximately 50×10^6 gpd that have anaerobic digesters. These facilities are documented in Table H.1 together with applicable footnotes.

It should be noted that the composition of the wastewater flows found in Table 1 is not constant. This arises from the fact that the cities have various means of disposing of sanitary and storm sewage flows. In some cases, the two flows, which consist of a mixture have a lower percent of solids content and, consequently, a lower gas content per unit of inflow than an inflow derived primarily from sanitary sewers. The scope of this current market penetration analysis does not include the development of data for two types of systems.

A sampling was used to estimate the anaerobic gas flows produced from the anaerobic digesters at the 45 plants. Also, the gas data presented in Table H.4 of the Battelle report were not directly used for two reasons:

- a. Their survey covered only 30 of the 45 plants, and
- b. Their data were not as current as that obtained and used in conducting the sample.

The sampling involved personally telephoning the appropriate technical personnel at selected facilities to obtain current wastewater flow, gas production and methane content, and other useful information. The nine facilities selected

represent a 20% sample of the 45 facilities. These nine facilities represent 34% of the total wastewater inflows (excluding Chicago WSW). Geographically, the East Coast, Midwest, and West Coast are represented. In short, the characteristics of the facilities selected are representative of a cross section of large facilities on a national basis.

The data for the nine facilities are tabulated in Table H.2. The weighted percent column was derived by summing the wastewater flow rate for the nine facilities and determining the percent for each facility. To calculate the weighted average conversion factor (WACF), which was used to calculate the gas production at the remaining 35 facilities (excluding Chicago WSW since the gas production at that facility is known), the equation specified in Table H.2 is used. It involves a calculation to determine the weighted methane gas flow for each of the nine facilities and summing the results. Solving the equation with the specified data results in a WACF of $.51 \times 10^6$ scf methane per 100×10^6 gal. of wastewater throughput.

Column 3 of Table H.3 (average methane production) was then calculated by applying the WACF to each of the wastewater flow rates for the facilities (excluding Chicago WSW) not used in the calculation of the WACF. Actual rates were used for the remaining nine facilities and Chicago WSW. The sum of the data tabulated in Column 3 is an estimate of all of the methane produced from the 45 plants, 27.45×10^6 scfd. This is the British thermal unit (Btu) equivalent of 5,341 barrels per day (bbl/d) of No. 6 fuel oil (Footnote n) (Reference H.13). In Column 4, single 4.5 MWe FCPPs capable of operating with a methane flow of $0.5-1.0 \times 10^6$ scfd are applied to the methane production levels of Column 3. For example, the Bergen County WPCF, with a methane production of 0.91×10^6 scfd falls within the required $0.5-1.0 \times 10^6$ scfd range for one FCPP. Another example is the Los Angeles facility with a methane production of 2.1×10^6 scfd. Two FCPPs can use only 2.0×10^6 scfd thereby leaving 0.1×10^6 scfd unused. Since fractional portions of FCPPs are not available, the 0.1×10^6 scfd must be used or disposed of elsewhere. A third FCPP could be added if the flow increased to 2.5×10^6 scfd. In Column 5, actual methane consumption by the FCPPs is tabulated.

The data for displacement of petroleum based fuels is presented in Table H.4. Three scenarios are presented. The 100% scenario represents potential methane consumption and is the bottom line figure from Column 5 of Table H.3. The 50% and 33% scenarios in Table H.4 are approximations of the percent methane consumption levels to be achieved with FCPPs located at WPCFs. These percentages were selected after discussions with experienced WPCF operations management and field personnel because they represent a range of possible number of installations. The underlying reason for this is that substantial capital investments have been made by the 45 cities for equipment presently fueled by the WPCF anaerobic digester methane. This equipment includes gas engine/pump and gas engine/generator combinations, and boilers for sludge combustion, water heating, and steam rising. It is highly unlikely that all the cities will divert total methane production to FCPPs and write off previous capital investments and contractual commitments.

Referring to the 100% consumption Column of Table H.4, twenty 4.5 MWe FCPPs could consume a total of 16.3×10^6 scfd of methane. This quantity is the Btu equivalent of 3,171 bbl/d of No. 6 fuel oil (Footnote n) or 3,438 bbl/d of crude oil (Footnote o). On an annual basis, these figures are 1,157,000 and 1,255,000 barrels of No. 6 fuel oil and crude oil, respectively.

The fuel oil displacement and methane consumption figures drop significantly at the more realistic 50% and 33% scenarios:

<u>Displaced Oil</u> (bbl/d)	4.5 MWe Power Plant Methane Consumption Scenarios, %		
	<u>100</u>	<u>50</u>	<u>33</u>
No. 6 fuel oil	3,171	1,586	1,056
Crude oil	3,438	1,719	1,145

This analysis suggests the desirability of a FCPP smaller than 4.5 MWe to maximize consumption of the gas flows in the 50% and 33% scenarios. If, for example, a 2.25 MWe FCPP were developed with a utilization range of 0.25 - 0.50×10^6 scfd methane, and the calculations of Tables H.3 and H.4 were repeated, the previous table would appear as follows:

<u>Displaced Oil</u> (bbl/d)	2.25 MWe Power Plant <u>Methane Consumption Scenarios, %</u>		
	<u>100</u>	<u>50</u>	<u>33</u>
No.6 fuel oil	5,137	2,658	1,712
Crude oil	5,568	2,784	1,856

Refer to Table H.5 and H.6 for more detailed information. An analysis of these data shows that use of an FCPP half the size of a 4.5 MWe unit would increase the displacement (bbl/d equivalent) of petroleum based fuels by 62%.

H.6 CONCLUSIONS

A number of conclusions can be drawn from this penetration analysis:

- a. In general, 100% of the methane production from the anaerobic digesters is not realistically available for use in FCPPs. More practical average figures would be 50% or 33%. Each plant must be considered separately for an accurate analysis.
- b. At the 50% and 33% consumption levels, the Btu equivalent of 1,586 and 1,056 bbl/d of No. 6 fuel oil, respectively, can be saved by the use of 4.5 MWe FCPPs on a national basis.
- c. If a 2.25 MWe power plant were developed and made available, the preceding Btu equivalent figures would increase significantly to 2,568 and 1,712 bbl/d of No. 6 fuel oil, respectively.

TABLE H.1
THE FORTY FIVE LARGEST WATER POLLUTION CONTROL
FACILITIES UTILIZING ANAEROBIC DIGESTERS (U.S.)

Flow ^{a)} Rate (10 ⁶ gpd)	<u>City</u>	<u>State</u>	<u>Facility Name</u>
49.2	Sacramento	CA	Main Plant
49.5	Columbus	OH	Southerly Plant
53	Richmond	VA	-
53.3	Gary	IN	Sanitary District
58	Queens	NY	Tallmans Island Plant
58	Dayton	OH	-
58.8	Phoenix	AZ	91st. St. Plant
59	Syracuse	NY	Metro Plant
65.4	Yonkers	NY	Westchester Plant
67	Miami	FL	-
68	Bergen County	NJ	Utilities Authority
71.7	Rochester	NY	Main
73	Wilmington	DE	Project #1
73.9	San Antonio	TX	Rilling Road
76	Akron	OH	Project #1
80	Elizabeth	NJ	-
80	Milwaukee	WI	-
82.5	Atlanta	GA	-
85	Brooklyn	NY	26th Ward Plant
85	Oakland/S.F.	CA	East Bay MUD Project #1
86	Seattle	WA	West Point Plant
90	San Jose	CA	Project #1
91.9	Brooklyn	NY	Coney Island Plant

TABLE H.1 (Cont'd)

Flow ^{a)} Rate <u>10⁶ gpd</u>	<u>City</u>	<u>State</u>	<u>Facility Name</u>
92.8	Queens	NY	Jamaica Plant
94.2	Toledo	OH	Bay View Water Reclm.
96	Columbus	OH	Jackson Pike
96.3	Brooklyn	NY	Owl's Head Plant
100	San Diego	CA	Metro Plant Project #1
101.1	Louisville	KY	Morris Foreman
103.9	Queens	NY	Bowery Bay Plant
121	Cincinnati	OH	Mill Creek
128	Boston	MA	South Nut Island
135.9	Philadelphia	PA	SW Plant
145.4	Bronx	NY	Hunts Point
155	Orange Cnty. S.D.	CA	Plant #1 & 2 Project #1
166	Buffalo	NY	-
169	Brooklyn	NY	Newton Creek Plant
180.9	Baltimore	MD	Black River Plant
182.4	Philadelphia	PA	NE Plant
220	Calumet	IL	-
292 ^{b)}	Washington	D.C.	Blue Plains S.T.P.
312	Boston	MA	Deer Island
320	Los Angeles	CA	Hyperion
350	Los Angeles Cnty.	CA	-
850 ^{c)}	Chicago	IL	WSW Plant

TABLE H.2
DERIVATION OF ANAEROBIC DIGESTER
WEIGHTED AVERAGE CONVERSION FACTOR
(Estimation of Average Methane Production)

Flow ^{a)} Rate 10 ⁶ gpd	City	Plant Name	Weighted %	Gas Production 10 ⁶ cfd	% Methane in Gas	Reference
68	Bergen Cnty.	Utilities Authority	3.92	1.4 ^{e)}	65	4)
80	Milwaukee	-	4.61	.75 ^{f)}	65	5)
82.5	Atlanta	-	4.76	.53	70	6)
85	Brooklyn	26th Ward Plant	4.90	.3	64.5	7)
217.5 ^{b)}	Washington, D.C.	Blue Plains	12.54	.75	60	8)
220	Calumet	-	12.68	.45	65	9)
312	Boston	Deer Island	17.98	.45 ^{g)}	60	10)
320	Los Angeles	Hyperion	18.44	3.5 ^{h)}	60	11)
350	L.A. County	-	20.17	5.9	64	12)
1,735 ^{d)}			100.00		62.6 ⁱ⁾	

Weighted Average Conversion Factor (WACF)

$$WACF = \frac{\sum_{i=1}^9 (\text{Weighted } \%) (\text{Gas Production}) (\% \text{ CH}_4)}{\text{Flow Rate}}$$

Solving,

$$WACF = .51 \times 10^6 \text{ scf Methane} / 100 \times 10^6 \text{ gal. Wastewater Throughput.}$$

TABLE H.3
WPCF METHANE PRODUCTION AND
PROJECTED FCPP BASED CONSUMPTION - 4.5 MWe CASE

Flow ^{a)} Rate 10 ⁶ gpd	City	Average ^{j)} Methane Production 10 ⁶ scfd	Number of 4.5 MWe ^{k)} FCPPs Processing the Methane Production	Potential Methane Consumption by the 10 ⁶ scfd
49.2	Sacramento	.25	0	0
49.5	Columbus	.25	0	0
53	Richmond	.27	0	0
53.3	Gary	.27	0	0
58	Queens	.30	0	0
58	Dayton	.30	0	0
58.8	Phoenix	.30	0	0
59	Syracuse	.30	0	0
65.4	Yonkers	.33	0	0
67	Miami	.34	0	0
68	Bergen County	.91 ¹⁾	1	.91
71.7	Rochester	.37	0	0
73	Wilmington	.37	0	0
73.9	San Antonio	.38	0	0
76	Akron	.39	0	0
80	Elizabeth	.41	0	0
80	Milwaukee	.49 ¹⁾	0	0
82.5	Atlanta	.37 ¹⁾	0	0
85	Brooklyn (26th)	.19 ¹⁾	0	0
85	Oakland/S.F.	.43	0	0

TABLE H 3 (Cont'd)

Flow ^{a)} Rate <u>10⁶ gpd</u>	City	Average ^{j)} Methane Production <u>10⁶ scfd</u>	Number of 4.5 MWe ^{k)} FCPPs Processing the Methane Production	Potential Methane Consumption by the <u>10⁶ scfd</u>
86	Seattle	.44	0	0
90	San Jose	.46	0	0
92.8	Queens (Jam)	.47	0	0
94.2	Toledo	.48	0	0
96	Columbus	.49	0	0
96.3	Brooklyn (Owls)	.49	0	0
100	San Diego	.51	1	.51
101.1	Louisville	.52	1	.52
103.9	Queens (Bowery)	.53	1	.53
121	Cincinnati	.62	1	.62
128	Boston (Nut I.)	.65	1	.65
135.9	Philadelphia (SW)	.69	1	.69
145.4	Bronx	.74	1	.74
155	Orange City, S.D.	.79	1	.79
166	Buffalo	.85	1	.85
169	Brooklyn (Newton)	.86	1	.85
180.9	Baltimore	.92	1	.92
182.4	Philadelphia (NE)	.93	1	.93
220	Calumet	.29 ¹⁾	0	0
292	Washington	.45 ¹⁾	0	0
312	Boston (Deer I.)	.27 ¹⁾	0	0
320	Los Angeles	2.10 ¹⁾	2	2.00
350	Los Angeles Cnty	3.78 ¹⁾	4	3.78
850	Chicago	<u>1.43¹⁾</u>	<u>1</u>	<u>1.00</u>
	TOTAL	27.45	20	16.30

TABLE H.4
EQUIVALENT DAILY AND ANNUAL SAVINGS OF PETROLEUM BASED FUELS
AT VARYING LEVELS OF METHANE CONSUMPTION BY 4.5 MWe FCPPs

	Percent of Actual Methane Consumption by FCPPs		
	<u>100</u>	<u>50</u>	<u>33</u>
FCPP Methane Consumption, 10 ⁶ scfd	16.30 ^{m)}	8.15	5.43
Bbl/d Equivalent of No. 6 Fuel Oil ⁿ⁾	3,171	1,586	1,056
Bbl/d Equivalent of Crude Oil ^{o)}	3,438	1,719	1,145
Bbl/Yr Equivalent of No. 6 Fuel Oil	1,157,000	578,900	385,400
Bbl/Yr Equivalent of Crude Oil	1,255,000	627,400	417,900

TABLE H.5
WPCF METHANE PRODUCTION AND
PROJECTED FCPP BASED CONSUMPTION - 2.25 MWe CASE

Flow ^{a)} Rate <u>10⁶ gpd</u>	City	Average ^{j)} Methane Production <u>10⁶ scfd</u>	Number of 2.25 MWe ^{k)} FCPPs Processing the Methane Production	Potential Methane Consumption by the <u>10⁶ scfd</u>
49.2	Sacramento	.25	1	.25
49.5	Columbus	.25	1	.25
53	Richmond	.27	1	.27
53.3	Gary	.27	1	.27
58	Queens	.30	1	.30
58	Dayton	.30	1	.30
58.8	Phoenix	.30	1	.30
59	Syracuse	.30	1	.30
65.4	Yonkers	.33	1	.33
67	Miami	.34	1	.34
68	Bergen County	.91 ¹⁾	2	.91
71.7	Rochester	.37	1	.37
73	Wilmington	.37	1	.37
73.9	San Antonio	.38	1	.38
76	Akron	.39	1	.39
80	Elizabeth	.41	1	.41
80	Milwaukee	.49	1	.49
82.5	Atlanta	.37 ¹⁾	1	.37
85	Brooklyn (26th)	.19 ¹⁾	0	0
85	Oakland/S.F.	.43	1	.43
86	Seattle	.44	1	.44
90	San Jose	.46	1	.46
91.9	Brooklyn (Coney)	.47	1	.47

TABLE H.5 (Cont'd)

Flow ^{a)} Rate <u>10⁶ gpd</u>	City	Average ^{j)} Methane Production <u>10⁶ scfd</u>	Number of 2.25 MWe ^{k)} FCPPs Processing the Methane <u>Production</u>	Potential Methane Consumption by the <u>10⁶ scfd</u>
92.8	Queens (Jam.)	.47	1	.47
94.2	Toledo	.48	1	.48
96	Columbus	.49	1	.49
96.3	Brooklyn (Owls)	.49	1	.49
100	San Diego	.51	1	.50
101.1	Louisville	.52	1	.50
103.9	Queens (Bowery)	.53	1	.50
121	Cincinnati	.62	1	.50
128	Boston (Nut I.)	.65	1	.50
135.9	Philadelphia(SW)	.69	1	.50
145.4	Bronx	.74	1	.50
155	Orange City, S.D.	.79	2	.79
166	Buffalo	.85	2	.85
169	Brooklyn (Newton)	.86	2	.86
180.9	Baltimore	.92	2	.92
182.4	Philadelphia(NE)	.93	2	.93
220	Calumet	.29 ¹⁾	1	.29
292	Washington	.45 ¹⁾	1	.45
312	Boston (Deer I.)	.27 ¹⁾	1	.27
320	Los Angeles	2.10 ¹⁾	4	2.00
350	Los Angeles City	3.78 ¹⁾	8	3.78
850	Chicago	<u>1.43¹⁾</u>	<u>3</u>	<u>1.43</u>
TOTAL		27.45	62	26.40

TABLE H.6
EQUIVALENT DAILY AND ANNUAL SAVINGS OF PETROLEUM-BASED FUELS
AT VARYING LEVELS OF METHANE CONSUMPTION BY 2.25 MWe FCPPs

	Percent of Actual Methane Consumption by FCPPs		
	<u>100</u>	<u>50</u>	<u>33</u>
FCPP Methane Consumption, 10^6 scfd	26.40 ^{p)}	13.20	8.80
Bbl/d Equivalent of No. 6 Fuel Oil ⁿ⁾	5,137	2,568	1,712
Bbl/d Equivalent of Crude Oil ^{o)}	5,568	2,784	1,856
Bbl/Yr Equivalent of No. 6 Fuel Oil	875,000	937,000	624,900
Bbl/Yr Equivalent of Crude Oil	2,032,000	1,016,000	677,400

FOOTNOTES FOR TABLES

- a) Actual millions of gallons per day to the water pollution control facility.
- b) Sludge equivalent of 217.5×10^6 gpd is charged to the anaerobic digesters although total plant feed is 292×10^6 gpd.
- c) Indeterminate sludge equivalent quantity is charged to a vacuum filter instead of the anaerobic digesters.
- d) Chicago, with its 2.2×10^6 scfd of anaerobic digester gas and a methane content of 64%, is excluded since an indeterminate amount of sludge is charged to a vacuum filter instead of the digesters.
- e) Approximately 1.4×10^6 scfd from current 1.1×10^6 scfd after repairing digester roof gas leaks.
- f) Range $.5-1.0 \times 10^6$ scfd.
- g) Range $.4-.5 \times 10^6$ scfd.
- h) Range $4-5 \times 10^6$ scfd.
- i) Weighted % methane in gas; arithmetic average = 63.7%.
- j) Utilizing weighted average conversion factor derived in Table H.2.
- k) 100% design capacity requires 1.0×10^6 scfd methane. Assume FCPP is capable of sustained operation at greater than 50% capacity.
- l) Actual - not derived from weighted average conversion factor.
- m) Bottom line number from Column 5, Figure H.3.
- n) 6.287×10^6 Btu per barrel of No. 6 fuel oil and overall thermal efficiencies of 40% and 32.7%, respectively, for the FCPPs and fossil fueled power plants.
- o) 5.8×10^6 Btu/bbl crude oil. Some efficiencies as in footnote n.
- p) Bottom line number from Column 5, Figure H.5.

REFERENCES

- H.1 Spencer, R.R., A.L. Wong, J.A. Coates, S.B. Ahlstrom. Operational Characteristics of Anaerobic Digesters at Selected Municipal Wastewater Facilities in the United States. Battelle-Pacific Northwest Laboratories, December 1978.
- H.2 Personal communication (April 24, 1979) with D. C. Christensen, Research Engineer, Battelle-Pacific Northwest Laboratories.
- H.3 Letter dated April 16, 1979, by Dr. R. L. Bunch, Chief, U.S. Environmental Protection Agency.
- H.4 Discussion on May 1, 1979, at the Bergen County facility with H. R. Zablatzky, Plant Superintendent, and R. J. Pittbladdo, Assistant Plant Superintendent.
- H.5 Personal communication (May 2, 1979) with S. Graef of the Milwaukee facility.
- H.6 Personal communication (May 2, 3, 1979) with H. Reheis, Chief Engineer, and W. Burbett of the Atlanta facility.
- H.7 Personal communication (May 2, 3, 1979) with B. Lee of the New York Bureau of Water Pollution Control.
- H.8 Personal communication (May 7, 1979) with K. Laden, Urban Planner, and A. Cassell, Chief - Planning & Research, of the D. C. Department of Environmental Services.
- H.9 Communication (April 27, 1979) from R. Barbolini, Chief Process Engineer, Metropolitan Sanitary District of Chicago.

- H.10 Personal conversation (May 7, 1979) with Paul Sullivan of the Boston (Deer Island) plant.
- H.11 Personal conversations (April 25, 26, 1979) with Don Herman, Nichols Engineering Co.; Mr. Callahan, L.A. City Department of Public Works, Bureau of Sanitation; and R. Michle, Chief - Technical Services Department, L.A. County Sanitation Districts.
- H.12 Personal conversations (April 25, 26, 1979) with R. Michle, Chief - Technical Services Department; R. Beeken, Chief - Sewage Treatment Plant Operations; and G. Adams, Project Engineer, all of the L.A. County Sanitation Districts.
- H.13 Statistical Yearbook of the Electrical Industry for 1977, Table 415, Issue #451, October 1978, Edison Electrical Institute.