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Industrial Cogeneration Optimization Program

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Volume II

Appendix A: Conceptual Designs and Preliminary
Equipment Specifications

Appendix B: Characterization of Cogeneration Systems
(Near-Term Technology)

Appendix C: Optimized Cogeneration Systems

January 1980

Prepared for:

U.S. Department of Energy

Office of Industrial Programs

Conservation and Solar Energy

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Prepared by:

Westinghouse Electric Corporation
Gibbs & Hill, Inc.
Contract No. EM-78-C-01-5310
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APPENDIX A: CONCEPTUAL DESIGNS AND PRELIMINARY EQUIPMENT SPECIFICATIONS

In Volume I, Section 7.2.1, we presented, for the soybean oil plant, a conceptual design of a cogeneration facility consisting of a site plan, plot plan, block flow diagram and heat balance, one-line electrical diagram, brief specifications of major components, capital cost estimates, and project milestone schedule. For the other plants, only conceptual cost estimates were presented in Section 7 as follows:

<u>Plant</u>	<u>SIC Code</u>	<u>DOE Region</u>	<u>Location</u>	<u>Report Sub-Section (Vol. I)</u>
1. Soybean Oil	20	V	Indiana	7.2.1
2. Agri-Chem	28	III	Maryland	7.2.2
3. Brewery	20	III	Pennsylvania	7.2.3
4. Air Separation	28	VI	Texas	7.2.4
5. Refinery "B"	29	IX	California	7.2.5
6. Writing Paper	26	III	Pennsylvania	7.2.6
7. Integrated Textile	22	IV	Alabama	7.2.7
8. Kraft Paper	26	I	New Hampshire	7.2.8
9. Finishing Textile	22	IV	So. Carolina	7.2.9

The remaining information for these plants is found in this appendix with table numbers and figure numbers corresponding to the report subsections listed above (e.g., Figures A2-M-1, A3-M-1 found in this appendix correspond to the agri-chem plant and the brewery plant found, respectively, in Sections 7.2.2 and 7.2.3 of Volume I).

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Figure A2-M-1

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INFORMATION

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INDUSTRIAL COGENERATION OPTIMIZATION
PROGRAM
SIC 28 DOE REGION III MARYLAND

PLOT PLAN
COGENERATION FACILITY
AGRI-CHEM PLANT

Scale of 1"=80'
DO NOT SCALE DIMENSIONS, USE DIMENSIONS
FROM PLANS

JUB NO. 11-2775-001

SCALE: 1"=80'

Figure A2-M-2

CADRE / P10 / H13C

INDUSTRIAL COGENERATION
OPTIMIZATION PROGRAM
SIC 28 DOE REGION 111 MARYLAND
BLOCK FLOW DIAGRAM AND
HEAT BALANCE
COGENERATION FACILITY
AGRI-CHEM PLANT

Chao & Hill, Inc.
ENGINEERS, DESIGNERS, CONSTRUCTORS
NEW YORK

SCALE: NONE

INFORMATION

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JOB NO. 11-2775-001

Figure A2-M-3

TABLE A2-1

AGRI-CHEM PLANT COGENERATION FACILITY
PRELIMINARY SPECIFICATIONS OF MAJOR COMPONENTS

Steam Turbine

Type	Single shaft, noncondensing
Steam throttle conditions	1215 psia
Steam exhaust conditions	175 psia/370 F
Speed	3600 rpm

Generator

Rating	10,500 kW
Voltage	13.8 kV
Power factor	0.9
Short circuit ratio	0.64
Cooling	Forced air

Boiler

Type	Non-reheat, balanced draft, water wall
Firing	Crushed coal, stoker fired
Steam flow	215,064 lb/hr
Steam conditions	1215 psia at 9 45 F
Flue Gas flow	102,900 cfm

Fly Ash Removal

Type	Baghouse
Construction	Fiberglass cloth
Net surface	25,000 ft ²

Flue Gas Desulfurization

Type	Tray tower, caustic feed
Capacity	102,900 cfm for coal with 4.3 percent sulfur

Deaerator

Type	Tray
Design pressure	50 psig
Steam flow	20,052 lb/hr
Condensate flow	191,000 lb/hr
Effluent oxygen content	Less than 0.5 ppm
Storage capacity	10 minutes

2-SIZE 4 COMB. STARTERS
1-SIZE 3 COMB. STARTERS
6-SIZE 2 COMB. STARTERS
12-SIZE 1 COMB. STARTERS
4-100A CIRC. BKRS.

INDUSTRIAL COGENERATION OPTIMIZATION PROGRAM SIC 28 DOE REGION 111 MARYLAND	
AGRI-CHEM PLANT ONE LINE ELECTRICAL DIAGRAM	
SCALE: NONE	Figure A2-E-1
JOB NO. 11-2775-001	

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INDUSTRIAL COGENERATION OPTIMIZATION
PROGRAM
SIC 20 DOE REGION III PENNSYLVANIA

SITE PLAN BREWERY

Gibbs & Hill, Inc.
DESIGNS, LEADINGS, CONSTRUCTION
New York

SCALE. 1"=200'

.. JOB NO. 11-2175-001

Figure A3-M-1

TABLE A3-1

BREWERY PLANT COGENERATION FACILITY
PRELIMINARY SPECIFICATIONS OF MAJOR COMPONENTS

Steam Boiler

Type	Stoker fired
Rating	90,000 lb/hr
Steam conditions	at 915 psig/875 F
Flue gas flow	45,130 cfm

Steam Turbine

Type	Single shaft, noncondensing
Steam throttle conditions	900 psig/875 F
Steam exhaust conditions	120 psig/500 F

Generator

Rating	4000 kW
Voltage	13.8 kV, 60 Hz
Power factor	0.9
Short circuit ratio	0.64
Cooling mechanism	Forced air

Electrostatic Precipitator

Volumetric capacity	45,131, acfm at 303 F
Dust loading, inlet	5 grains acf
Dust loading, out	0.064 grains/acf

Flue Gas Desulfurization

Type	Venturi scrubber using soluble caustic for SO ₂ removal
Efficiency	90 percent
Removal	880 lb/hr of SO ₂ based on 5.5 tons/hr coal with 4 percent sulfur
Filter discharge	2800 lb/hr (60 percent solid)

TABLE A3-1 (Continued)

Steam Accumulator

Type	Skid mounted, including pumps, piping, valves, and instru- mentation
Delivery rate	115,000 lb/hr
Duration of delivery	3.5 minutes

Deaerator Feedwater Heater

Type	Spray tray deaerator
Design pressure	50 psig
Feedwater flow	89,460 lb/hr
Effluent oxygen content	Less than 0.5 ppm
Storage capacity	10 minutes

69KV (ASSUMED)

COGENERATION
POWER UNIT
(MOTORS 100-250HP)
1-400A CIRCUIT BKR.
3-800A CIRCUIT BKRS.

COGENERATION
POWER UNIT
(MOTORS 1/4/-75HP)
2-SIZE 4 STARTERS
4-SIZE 3 STARTERS
2-SIZE 2 STARTERS
25-SIZE 1 STARTERS

MISC.
ELEC.
LOADS

INDUSTRIAL COGENERATION
OPTIMIZATION PROGRAM
SIC 20, DOE REGION III PENNSYLVANIA

BREWERY PLANT
ONE LINE
ELECTRICAL DIAGRAM

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Figure A3-E-1

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CADRE/FBP/HISC

INDUSTRIAL COGENERATION OPTIMIZATION PROGRAM SIC 28 DOE REGION VI TEXAS	
BLOCK FLOW DIAGRAM AND HEAT BALANCE COGENERATION FACILITY AIR SEPARATION PLANT
SCALE: NONE
JOB NO. 11-2775-001	Figure A4-M-3

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TABLE A4-1

AIR SEPARATION PLANT COGENERATION FACILITY
PRELIMINARY SPECIFICATIONS OF MAJOR COMPONENTS

GAS TURBINE/GENERATOR

Type:	Open Cycle
Rating:	64 MW
Voltage:	13.8 kV
Power Factor:	0.9
Short Circuit Ratio:	0.64
Cooling:	Hydrogen
Fuel:	2,167,000 lb/hr Nat. Gas

STEAM GENERATOR

Type:	Waste Heat Boiler
Firing:	Flue Gas Only
Steam Flow:	363,000 lb/hr
Steam Conditions:	214 psia @ 388°F
Flue Gas Flow:	2,166,200 lb/hr @ 975°F

DEAERATOR

Type:	Tray
Design Pressure:	50 psig
Steam Flow:	35,500 lb/hr
Feedwater Flow:	282,000 lb/hr
Effluent Oxygen:	Less Than 0.5 ppm
Storage Capacity:	5 min

A-20

10/8/79

CADAE/PRG/HISC

Figure A4-M-4

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SITE PLAN
LARGE REFINERY "B"

SCALE: 1" = 600'

Figure A5-M-1

JOB NO. 11-2775-001

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INDUSTRIAL COGENERATION OPTIMIZATION
 PROGRAM
 SIC 29 DOE REGION III CA.

PLOT PLAN
 COGENERATION FACILITY
 LARGE REFINERY B

Site & Hill, Inc.
 10 CHERRY STREET, NEW YORK, N.Y. 10013

SCALE: 1"=50'

JOB NO. 11-2775-001

Figure A5-M-2

CODE/PRP-1017C

TABLE A5-1
LARGE REFINERY "B" COGENERATION FACILITY
PRELIMINARY SPECIFICATIONS OF MAJOR COMPONENTS

GAS TURBINE/GENERATOR

Type:	Open Cycle
Rating:	95 MW
Voltage:	13.2 kV
Power Factor:	0.9
Short Circuit Ratio:	0.64
Cooling:	Hydrogen
Fuel:	113,750 lb/hr Naphtha

STEAM GENERATOR

Type:	Waste Heat Boiler w/Supp. Firing
Firing:	Flue Gas & Low S. Residual
Steam Flow:	875,000 lb/hr
Steam Conditions:	929 psia @ 739°F
Flue Gas Flow:	2,901,400 lb/hr @ 996°F

STEAM TURBINE

Type:	Extraction, non-condensing
Steam Throttle Conditions:	929 psia, 740°F
Steam Exhaust Conditions:	165 psia, 403°F
Extraction PT:	565 psia, 635°F

GENERATOR

Rating:	45 MW
Voltage:	13.2 kV
Power Factor:	0.9
Short Circuit Ratio:	0.64
Cooling:	Hydrogen

TABLE A5-1 (Continued)

DEAERATOR

Type:	Tray
Design Pressure	50 psig
Steam Flow	149,100 lb/hr
Feedwater Flow	1,600,000 lb/hr
Effluent Oxygen	Less Than 0.5 ppm
Storage Capacity	5 min

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10/8/79

CAD/AF/BDP/MISC

TABLE A6-1
WRITING PAPER MILL COGENERATION FACILITY
PRELIMINARY SPECIFICATIONS OF MAJOR COMPONENTS

STEAM GENERATOR

Type:	Non-Reheat, Balanced Draft
Firing:	Pulverized coal
Steam Flow:	446,904 lb/hr
Steam Conditions:	1215 psia, 946°F
Flue Gas Flow:	719,316 lb/hr

STEAM TURBINE

Type:	Back Pressure
Steam Throttle Conditions:	1215 psia, 946°F
Steam Exhaust Conditions:	180 psia, 541°F

GENERATOR

Rating:	22 MW
Voltage:	13.2 kV
Power Factor:	0.9
Cooling:	

ELECTROSTATIC PRECIPITATOR

Volumetric Capacity:	158,000 ACFM @ 350°F
Dust Loading, Inlet:	8 grains/ACF
Dust Loading, Out:	0.075 grains/ACF

FLUE GAS DESULFURIZATION

Type:	Venturi Scrubber Using Soluble Caustic For SO ₂ Removal
Efficiency:	90%
Removal:	4240 lb/hr of SO ₂ Based on 26.5 T/hr coal with 4% Sulfur
Filter Discharge:	13,500 lb/hr (60% solid)

TABLE A6-1 (Continued)

DEAERATOR

Type:	Tray
Design Pressure:	50 psig
Steam Flow:	54,900 lb/hr
Feedwater Flow:	385,000 lb/hr
Effluent Oxygen:	Less Than 0.5 ppm
Storage Capacity:	5 min

INDUSTRIAL COGENERATION OPTIMIZATION PROGRAM SIC 20 DOE REGION III PENNSYLVANIA	
WRITING PAPER MILL ONE LINE ELECTRICAL DIAGRAM	
<u>Gate & Hill, Inc.</u> ENGINEERING, DESIGN, CONSTRUCTION AND TOOL	SCALE: NONE
JOB NO. 11-2775-001	Figure A6-E-1

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CGOAL/PP/115C

INDUSTRIAL COGENERATION
OPTIMIZATION PROGRAM
SIC 22 DOE REGION IV ALABAMA

**BLOCK FLOW DIAGRAM AND
HEAT BALANCE
COGENERATION FACILITY
INTEGRATED TEXTILE MILL**

CHAS. E. HILL, Inc.
ENGINEERS, DESIGNERS, CONSTRUCTORS
NEW YORK

SCALE: NONE

JOB NO. 11-2775-001

Figure A7-M-3

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TABLE A7-1
INTEGRATED TEXTILE MILL COGENERATION FACILITY
PRELIMINARY SPECIFICATIONS OF MAJOR COMPONENTS

Steam Generator

Type	Balanced draft, water wall, non-reheat
Firing	Wood chip stoker fired
Steam Flow	216,108 lb/hr
Steam Conditions	1215 psia, 946°F
Flue gas flow	110,000 ACFM

Steam Turbine

Type	Single shaft, non-condensing
Steam throttle conditions	1215 psia, 946°F
Steam exhaust conditions	265 psia, 617°F
Speed	3600 rpm

Generator

Rating	9,000 kW
Voltage	13.8 kV
Power Factor	0.9
Short circuit ratio	0.64
Cooling	Forced air

Scrubber

Type	Venturi
Outlet Loading	.05 grains/ACF
Pressure Drop	20" H ₂ O

Deaerator

Type	Tray
Design pressure	50 psig
Steam flow	25,350 lb/hr
Feedwater flow	190,800 lb/hr
Effluent oxygen content	Less than 0.5 ppm
Storage capacity	5 minutes

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INDUSTRIAL COGENERATION
OPTIMIZATION PROGRAM
SIC 26 DOE REGION 1 NEW HAMPSHIRE

BLOCK FLOW DIAGRAM AND
HEAT BALANCE
COGENERATION FACILITY
KRAFT PAPER MILL

CH2M HILL Inc.
ENGINEERS, DESIGNERS, CONSTRUCTORS
NEW YORK

SCALE: NONE

JOB NO. 11-2775-001

Figure A8-M-3

10/22/79

CADAE/PAP/MISC

TABLE A8-1
KRAFT PAPER MILL COGENERATION FACILITY
PRELIMINARY SPECIFICATIONS OF MAJOR COMPONENTS

Steam Generator

Type	Balanced draft water wall, non-reheat
Firing	Crushed coal, stoker fired
Steam Flow	205,452 lb/hr
Steam Conditions	915 psia, 875 ^o F
Flue gas flow	103,000 ACFM

Steam Turbine

Type	Single shaft, non condensing
Steam throttle conditions	915 psia, 875 ^o F
Steam exhaust conditions	55 psia, 155 psia
Speed	3600 rpm

Generator

Rating	10,000 kW
Voltage	13.8 kV
Power Factor	0.9
Short Circuit ratio	0.64
Cooling	Forced air

Electrostatic Precipitator

Volumetric capacity	100,000 ACFM
Dust loading inlet	1 gr/ACF
Dust loading, outlet	90% removal efficiency

Flue Gas Desulfurization

Type	Spray tower, caustic feed
Capacity	103,000 ACFM for coal with 4.3 percent sulfur

TABLE A8-1 (Continued)

Deaerator

Type	Tray
Design pressure	50 psig
Feedwater flow	185,000 lb/hr
Effluent oxygen content	Less than .5 ppm
Storage capacity	5 minutes

A-46

CADAE/PRP/MISC

TABLE A9-1

TEXTILE FINISHING MILL COGENERATION FACILITY
PRELIMINARY SPECIFICATIONS OF MAJOR COMPONENTS

Steam Generator

Type	Balanced draft, waterwall, non-reheat
Firing	Crushed coal, stoker fired
Steam Flow	403,452 lb/hr
Steam Conditions	1215 psia, 949°F
Flue Gas Flow	175,000 ACFM

Steam Turbine

Type	Single shaft, non-condensing
Steam throttle Conditions	1215 psia, 949°F
Steam Exhaust Condition	165 psia, 515°F
Extraction Point	335 psia, 662°F
Speed	360 rpm

Generator

Rating	20,000 kW
Voltage	13.8 kV
Power Factor	0.9
Short Circuit Ratio	0.64
Cooling	Forced Air

Electrostatic Precipitator

Volumetric Capacity	175,000 ACFM
Dust Loading, inlet	1.5 gr/ACF
Dust Loading, outlet	90% removal efficiency

Flue Gas Desulfurization

Type	Spray tower, caustic feed
Capacity	175,000 ACFM for coal with 1.77% sulfur

TABLE A9-1 (Continued)

Deaerator

Type	Tray
Design Pressure	50 psig
Feedwater Flow	301,140 lb/hr
Effluent Oxygen Content	Less than 0.5 ppm
Storage Capacity	5 min

COGENERATION POWER UNIT			
3-SIZE	3	STARTERS	MISC
15-SIZE	2	STARTERS	ELEC.
20-SIZE	1	STARTERS	LOADS

COGENERATION POWER UNIT	
2-SIZE 4 STARTERS	MISC
5-SIZE 3 STARTERS	ELEC.
8-SIZE 2 STARTERS	LOADS
9-SIZE 2 STARTERS	

INDUSTRIAL COGENERATION
OPTIMIZATION PROGRAM
SIC 22; DOE REGION II; SO. CAR.

TEXTILE FINISHING MILL ONE LINE ELECTRICAL DIAGRAM

Case & Hill Inc.
ENGINEERS, DESIGNERS, CONSTRUCTORS
New York

SCALE: NONE

JOB NO. 11-2775-001

Figure A9-E-1

[illegible]

A-53
R

APPENDIX B: CHARACTERIZATION OF COGENERATION SYSTEMS (NEAR-TERM TECHNOLOGY)

APPENDIX B1: LIMITATIONS ON FUEL UTILIZATION IN ENERGY CONVERSION SUBSYSTEMS FOR COGENERATION APPLICATIONS

The primary factor limiting energy utilization by a fossil-fuel-fired cogeneration energy conversion system is the thermal losses through the stack gases and ash. These losses are in the following forms:

- Sensible heat of dry combustion products
- Sensible heat of water vapor in products
- Sensible heat of ash in products
- Latent heat of water vapor in products.

Water vapor is derived from the moisture in the combustion air and the water and hydrogen in the fuel.

Since both the water content and the hydrogen content vary substantially with fuel type, these losses are a rather strong function of fuel type. If, however, the lower heating value of the fuel is used as the basis for loss analysis rather than the higher heating value, the latent heat factor is eliminated from consideration and a rational analysis of the sensible heat losses is possible.

The thermal losses in the combustion products in relation to the lower heating value of the fuel are given by the following expression:

$$\frac{q_{\text{loss}}}{W_f \times \text{LHV}_f} = \left(\left(\frac{W_a}{W_f} \right)_{\text{ST}} + 1 \right) \times \phi_{\text{AIR}} \times (\text{Cp})_{\text{gas}} \times (t_{\text{stack}} - t_{\text{amb}}) \\ + A \times (\text{Cp})_{\text{solid}} \times (t_{\text{solid}} - t_{\text{amb}}) / \text{LHV}_f,$$

where

- q_{loss} = thermal losses - Btu/hr
- W_f = fuel flow rate - lb/hr
- LHV_f = lower heating value of fuel - Btu/lb
- W_a = combustion airflow rate - lb/hr
- $(W_a/W_f)_{\text{ST}}$ = stoichiometric air/fuel ratio
- ϕ_{AIR} = air equivalence ratio
- $(\text{Cp})_{\text{gas}}$ = specific heat of gaseous products - Btu/lb/°F
- t_{stack} = temperature of gaseous products, °F
- t_{amb} = ambient or reference temperature, °F
- A = fraction of ash in as-fired coal

t_{solid} = temperature of solid wastes.

The specific heat for gaseous products is approximately 0.25 and for ash about 0.20.

The expressions for thermal losses for various conversion systems and fuel combinations are given in Table B.1-1.

The minimum allowable stack temperature is a function of the fuel type, the air equivalence ratio, the fuel sulfur content, and the heat exchange configuration. The fuel type and the air equivalence ratio determine the moisture content of the flue gases, and the fuel sulfur content and the air equivalence ratio determine the SO_3 concentration. These two factors determine the acid dewpoint, which controls cold end corrosion. A major boiler manufacturer has published recommended minimum metal temperatures in the heat recovery train as a function of fuel type and sulfur content (see Figure B.1-1).

Table B.1-1 shows that, for a given stack-gas temperature, the sensible heat losses from an open-cycle gas turbine exhaust are, at a minimum, about 2-1/2 times as much as those from boiler flue gases. This difference will be partially offset by the lower dewpoint of the gas turbine exhaust.

TABLE B.1-1
THERMAL LOSSES FROM PRODUCTS OF COMBUSTION

Conversion System	Fuel	$\left(\frac{W_a}{W_f}\right)_{ST}$	ϕ_{AIR}	LHV _f	HHV _f	Ash Content, %	$q_{loss} / (W_f \times LHV_f)$
Boiler	Natural Gas	17	1.05 - 1.10	21,500	23,900	NIL	$2.17 \times 10^{-4} \times t_{stack} - 0.0167$
	Distillate	14	1.10 - 1.15	18,500	19,600	NIL	$2.21 \times 10^{-4} \times t_{stack} - 0.0170$
	Residual Oil	13	1.15 - 1.20	17,300	18,200	0.5	$2.17 \times 10^{-4} \times t_{stack} - 0.0167$
	Bituminous Coal	10	1.15 - 1.20	12,500	13,000	10	$2.42 \times 10^{-4} \times t_{stack} - 0.0186$
Gas Turbine	Natural Gas	17	3.0^a	21,500	23,900	NL	$5.93 \times 10^{-4} \times t_{stack} - 0.0457$
	Distillate	14	3.0^a	18,500	19,600	NL	$5.77 \times 10^{-4} \times t_{stack} - 0.0444$
	Residual Oil	13	3.0^a	17,300	18,200	0.5	$5.42 \times 10^{-4} \times t_{stack} - 0.0417$
	Bituminous Coal	10	3.0^a	12,500	13,000	10	$6.02 \times 10^{-4} \times t_{stack} - 0.0463$

a. For Distillate Fuel And Current Expander Inlet Temperatures (1,900 To 2,100°F), ϕ_{AIR} Ranges From 3.60 To 3.05. The ϕ_{AIR} Values For The Other Fuels Over This Temperature Range Would Be Approximately The Same

Fig. B.1-1 – Limiting tube-metal temperatures to avoid external corrosion in economizers or air heaters when burning fuels containing sulphur

APPENDIX B2: ANALYSIS OF BOILER BLOWDOWN REQUIREMENTS AND THERMODYNAMIC LOSSES DUE TO BLOWDOWN

Figure B.2-1 shows a generalized model of an industrial boiler for cogeneration application, with options for process steam and power steam production. The blowdown requirements (W_{BD}/WS) for this boiler model with either option are given in Figure B.2-2 as a function of the following:

- C_{MU} - concentration of dissolved solids in makeup water
- C_{BD} - concentration of dissolved solids in blowdown from boiler drum
- E - ratio of concentration of suspended solids in steam leaving drum to concentration of dissolved solids in drum which is equal to C_{BD}
- R - ratio of condensate recycled from process to redundant steam supplied to process

Table B.2-1 gives the allowable concentrations of total dissolved solids for boiler water as specified by the American Boiler Manufacturers Association (Combustion Engineering, 1966). A realistic value for E is 1×10^{-4} (Sokolowski and Schwartz, 1972)

TABLE B.2-1

ABMA ALLOWABLE BOILER WATER CONCENTRATIONS

Pressure at Outlet of Steam Generating Unit, psig	Total Solids, ppm
0-300	3500
301-450	3000
451-600	2500
601-750	2000
751-900	1500
901-1000	1250
1001-1500	1000
1501-2000	750
2001 and higher	500

Fig. B.2-1 – Generalized model of conventional steam cogeneration system

Distillation will yield makeup water with dissolved solids concentrations of 5 ppm or less (Handbook, 1973). Demineralization will give even lower concentrations.

The recycled condensate ratio is a function of the steam consumed and the steam and/or condensate lost in the process.

The blowdown requirements shown in Figure B.2-2 are minimum values. The condensate recycled from an industrial process may be contaminated by corrosion products or by in-leakage of raw water or materials used in the process. The use of chemicals for pH control and oxygen scavenging that contribute to the dissolved solids content of the boiler feedwater would increase the boiler blowdown requirements. This analysis indicates that blowdown rates often used in an industrial boiler ($\sim 10\%$) are excessive.

Figure B.2-3 gives the thermodynamic loss due to blowdown from a power boiler as a function of recuperator effectiveness, superheated steam temperature, condensate temperature, and superheated steam pressure.

Figure B.2-4 gives the thermodynamic loss due to blowdown from a process steam boiler as a function of recuperator effectiveness, condensate temperature, and process steam temperature (saturated temperature at process steam supply pressure).

Figures B.2-2, 3, and 4 are applicable to waste heat boilers for process steam and heat recovery steam generators for power steam, as well as to conventionally fired steam boilers for process or power steam, as shown in Figure B.2-1.

Figures B.2-2 and 3 show that the use of recuperators on boiler blowdown will reduce the thermodynamic losses due to blowdown to nearly negligible levels.

REFERENCES TO APPENDIX B2

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Handbook of Environmental Control, Volume III, CRC Press, 1973, p. 508.

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Fig. B.2- 2— Blowdown requirements for steam boilers used for cogeneration applications

Fig. B.2-3 — Thermodynamic loss due to blowdown from a power boiler as a function of operating parameters

Fig. B.2-4 — Thermodynamic losses due to blowdown from a process steam boiler as a function of operating parameters

APPENDIX B3: RELATIONSHIP AMONG PERFORMANCE CRITERIA FOR COGENERATION SYSTEMS

The ideal energy utilization factor and the ratio of gross process heat to electrical energy have been identified as variables for characterization of energy conversion systems for cogeneration applications. This appendix develops the relation of these two parameters to the electricity generating efficiency of the cogeneration system and the energy saved by cogeneration rather than separate generation.

The definition of electricity generation efficiency is well known. An expression for overall energy savings for cogeneration as compared to separate generation has been derived as follows:

$$\text{Energy savings} = \text{energy consumed in separate generation} - \text{energy consumed in cogeneration}$$

$$\text{Energy consumed in cogeneration} = \text{power generation} + \text{gross process heat generation} + \text{losses from energy conversion subsystem}$$

$$\text{Energy consumed in separate generation} = \text{gross process heat generation} / \text{process boiler efficiency} + \text{power generation} \times \text{utility plant heat rate}^{(*)}$$

$$\text{Energy savings} = \text{gross process heat generation} / \text{process boiler efficiency} + \text{power generation} \times \text{utility plant heat rate} - \text{power generation} - \text{gross process heat generation} - \text{losses from energy conversion subsystem}$$

$$\text{Losses from energy conversion subsystem} = (\text{losses from energy conversion subsystem} + \text{energy consumed in cogeneration}) \times \text{energy consumed in cogeneration}$$

$$\text{Energy consumed in cogeneration} = \text{power generation} + \text{energy conversion subsystem power generation efficiency}$$

$$\text{Losses from energy conversion subsystem} = (\text{losses from energy conversion subsystem} / \text{energy consumed in cogeneration}) \times (\text{power generation} / \text{energy conversion subsystem power generation efficiency})$$

* Power transmission losses were assumed to be zero

$$\text{Energy savings} = \text{gross process heat generation} / \text{process boiler efficiency} + \text{power generation} \times \text{utility plant heat rate} - \text{power generation} - \text{gross process heat generation} - (\text{losses from energy conversion subsystem} / \text{energy consumed in cogeneration}) \times (\text{power generation} / \text{energy conversion subsystem power generation efficiency})$$

Since cogeneration systems will normally be sized to match the process heat requirements, it is logical to reference the energy savings to the process heat generation.

$$\begin{aligned} \text{Energy savings} / \text{gross process heat generation} &= 1 / \text{process boiler efficiency} + (\text{power generation} / \text{gross process heat generation}) \times \text{utility plant heat rate} - \text{power generation} / \text{gross process heat generation} - 1 - (\text{losses from energy conversion subsystem} / \text{energy consumed in cogeneration}) \times (\text{power generation} / \text{gross process heat generation}) \times 1 / \text{energy conversion subsystem power generation efficiency} \\ &= 1 / \text{process boiler efficiency} + (\text{power generation} / \text{gross process heat generation}) \times (\text{utility plant heat rate} - 1 - (\text{losses from energy conversion subsystem} / \text{energy consumed in cogeneration}) \times 1 / \text{energy conversion subsystem power generation efficiency}) - 1 \end{aligned}$$

$$\text{Energy savings} / \text{gross process heat generation} = 1 / \text{PBE} - 1 + (\text{EE} / \text{GPH}) \times (1.0549 \times \text{UHR} - 1 - \text{ECLF} / \text{ECPGE})$$

where

PBE - process boiler efficiency for separate generation

EE/GPH - ratio of electrical energy to gross process heat (kWs/Btu)

UHR - utility heat rate for separate generation (Btu/kWs)

ECLF - energy conversion subsystem loss fraction

ECPGE - energy conversion subsystem power generation efficiency

The ideal energy utilization factor is:

$$\text{IEUF} = 1 - \text{ECLF}$$

Figure B.3-1 is a correlation of the IEUF for cogeneration systems with the ratio of gross process heat to electrical energy, the electricity generation efficiency of the energy conversion subsystem, and the ratio of energy savings to gross process heat for a utility central station with FGD lower heating value efficiency of 36% (equivalent to a lower heating value heat rate of 9500 Btu/kWh) and an industry process steam boiler with FGD lower heating value efficiency of 85%. The line for 0 energy savings is, of course, the line for separate generation.

Fig. B.3-1 — Energy utilization characteristics of cogeneration technology

APPENDIX B4: CHARACTERIZATION OF COAL-FIRED STEAM ENERGY CONVERSION
SUBSYSTEM WITH FGD

A generalized model of a conventional coal-fired steam energy conversion subsystem for cogeneration applications is shown in Figure B.4-1. The furnace, superheater, evaporator, economizer, and air preheater are treated as a package. Fuel, combustion air, recycled condensate, and makeup feedwater enter the package; and superheated steam, ash, products of combustion, and boiler blowdown leave. Energy losses from the package consist of incomplete combustion, heat losses to the atmosphere, and sensible heat in the ash and boiler blowdown.

A forced draft fan supplies the combustion air to the air preheater. The products of combustion exhaust to an electrostatic precipitator, a flue gas desulfurization process, a stack-gas reheater, and an induced draft fan in series. A recuperator is used to minimize the thermodynamic losses in the boiler blowdown.

The superheated steam goes to an extraction/back-pressure steam turbine. The extraction steam is used for reheating the treated flue gas. A minor fraction of the exhaust steam is used for deaerating feedwater heating; the balance goes to the process. In some applications the steam conditions required for flue gas reheating and processing would be essentially the same, and extraction from the steam turbine would not be required.

The interface of the energy conversion subsystem and the process heat utilization subsystem is the process steam supply line and the condensate recycle line. In an ideal case the recycled condensate would be at the saturation temperature of the process steam supply pressure. In practice the recycled condensate will be at a temperature below the saturation value.

The losses associated with the combustion products are as follows:

- Loss in dry products of combustion (sensible)
- Loss due to moisture in air (sensible and latent)
- Loss due to moisture in fuel (sensible and latent)
- Loss due to hydrogen in fuel (sensible and latent).

Other losses that occur in the system are:

- Mechanical losses in the steam turbine
- Mechanical and electrical losses in the generator
- Mechanical and electrical losses in the boiler feed pump drive motor.

Fig. B.4-1 — Conventional coal-fired steam energy conversion subsystem

The net system electrical power output is equal to the generator output minus the power to the boiler feed pump drive motor and the other auxiliaries. These other auxiliaries include:

- Fuel handling and preparation
- Ash handling
- Combustion air handling
- Condensate pumps
- Water treatment.

A coal-burning steam-energy conversion subsystem with a back-pressure turbine has been characterized for cogeneration applications on the basis of the following assumptions:

Coal-Ohio Pittsburgh No. 8 seam

Ambient air conditions - 70°F/60 percent RH

Air preheat temperature - 600°F

Fuel temperature - 70°F

Carbon losses in furnace - 1.5 percent

Ash sensible heat loss - 0.11 percent

Radiation losses from boiler - 0.15%

Steam turbine mechanical efficiency - 0.995

Generator efficiency (mechanical and electrical) - 0.975

Boiler feed pump drive motor efficiency - 95%

Boiler feed pump efficiency - 75%

Temperature of combustion products out of air preheater - 275°F

Stack-gas temperature - 175°F

Plant auxiliary power requirements - 2.5%
(in addition to boiler feed pump)

FGD process - limestone slurry

FGD energy requirements - see Rubin and Nguyen, 1978

Boiler pressure drop - 100 psi

Excess air - 20%

Steam turbine characteristics - Westinghouse Type M

Boiler blowdown - thermodynamic effect negligible with recuperator.

The stack gas losses were calculated to be:

Dry gas loss	3.88%
Loss due to moisture in air	0.08
Loss due to hydrogen and moisture in coal	<u>4.14</u>
TOTAL	8.10%

The results of the characterization analysis for the coal-fired steam energy conversion subsystem model are given in Figure B.4-2. This characterization is independent of the process heat utilization subsystem model that connects with the energy conversion subsystem model. Since the air preheater determines the stack-gas temperature and, therefore, the thermal losses from the combustion products and the pinch temperature differences in the boiler are far from limiting values, then varying the recycled condensate temperature has no effect on the energy utilization characteristics of this energy conversion subsystem. It would, however, affect the boiler surface requirements and, thereby, the capital costs.

The ideal energy utilization factor is shown as a function of the ratio of gross process heat to electrical energy with variables of steam conditions (600, 900, 1200, and 1500 psig) and process steam supply pressure (14.7, 29.8, 67.0, 134.6, 247.3, and 422.6 psia).

The ideal energy utilization factor for this energy conversion subsystem model is a weak function of the power steam conditions and a rather weak function of the process steam supply pressure. The spread in the energy utilization factor over the pertinent steam supply pressure range is less than 1 percent, which is hardly significant.

The ratio of gross process heat to electrical energy is also a weak function of steam conditions, but it is a strong function of process steam supply pressure.

Constraints on the operation of this system were assumed to be a back pressure of 0 psig and a turbine inlet to outlet pressure ratio of 3.

The values assumed for certain losses from the steam boiler are typical of utility-type boilers and the larger pulverized coal-fired industrial boilers. The smaller industrial boiler would have significantly greater losses than those used here.

REFERENCES TO APPENDIX B-4

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Fig. B.4.- 2 - Characterization of conventional coal-fired energy conversion subsystem with FGD

APPENDIX B 5: CHARACTERIZATION OF OIL-FIRED GAS TURBINE CONVERSION WITH WASTE HEAT BOILER ENERGY SUBSYSTEM

A model of an oil-fired gas turbine with waste heat boiler energy conversion subsystem for cogeneration application is shown in Figure B.5-1. The waste heat boiler (WHB), which is not fired, has a low pressure evaporator to avoid cold-end corrosion problems.

The characteristics of this energy conversion subsystem when fired on No. 2 distillate fuel are given in Figures B.5-2 through 6. The ideal energy utilization factor and the ratio of gross process heat to electrical energy are shown as functions of gas turbine compressor pressure ratio, gas turbine expander inlet temperature, and process steam supply pressure (ideal process heat temperature). The temperature of the boiler feedwater is assumed to be 100°F less than the saturation temperature for the process steam supply pressure.

In Figures B.5-2 through 5 the ideal energy utilization factor and the ratio of gross process heat to electrical energy are shown to be rather weak functions of gas turbine expander inlet temperature but moderately strong functions of process steam supply pressure (ideal process heat temperature). Figure B.5-6 shows that these quantities are rather strong functions of the gas turbine compressor pressure ratio.

The polytropic compressor and expander efficiencies used in this characterization (0.89 and 0.90) are values which are thought to realistically represent the composite performance of commercially available gas turbines over a size range of 5 to 50 MW.

Fig. B.5-1 — Oil-fired gas turbine energy conversion subsystem with waste heat boiler

Fig. B.5-2 — Characterization of oil-fired gas turbine energy conversion subsystem with waste heat boiler

Fig. B.5-3 - Characterization of oil-fired gas turbine energy conversion subsystem with waste heat boiler

Fig. B.5-4 — Characterization of oil-fired gas turbine energy conversion subsystem with waste heat boiler

Fig. B.5-5 — Characterization of oil-fired gas turbine energy conversion subsystem with waste heat boiler

Fig. B.5-6—Characterization of oil-fired gas turbine energy conversion subsystem with waste heat boiler

APPENDIX B6: CHARACTERIZATION OF OIL-FIRED COMBINED -CYCLE ENERGY CONVERSION SUBSYSTEM

Figure B.6-1 shows a generalized diagram of the oil-fired combined-cycle energy conversion subsystem with provision for firing the heat recovery steam generator (HRSG). The HRSG model shown in Figure B.6-1 is a modification of the configuration commonly used for utility applications, with three pressure levels rather than two. As in the utility configuration, a low-pressure evaporator is used to avoid cold-end corrosion problems. The intermediate pressure evaporator is added to provide an independent source of process steam at conditions either the same as or different from those for the process steam supply from the steam turbine. This significantly increases the quantity of process steam which can be supplied by a combined-cycle system.

There are several possible steam turbine configurations for cogeneration applications: back pressure only, back pressure and extraction, and condensing and extraction. The choice of the steam turbine configuration will depend on the requirements of the process heat utilization subsystem.

The characteristics of the oil-fired combined-cycle energy conversion subsystem with an unfired HRSG and a back-pressure steam turbine are shown in Figures B.6-2 through 6. The ideal energy utilization factor and the ratio of gross process heat to electrical energy are shown as functions of gas turbine compressor pressure ratio, gas turbine expander inlet temperature, and process steam supply pressure (ideal process heat temperature). The gas turbine combustor pressure loss is assumed to be 4-1/2 percent, and the temperature of the boiler feedwater is assumed to 100°F less than the saturation temperature for the process steam supply pressure.

Figure B.6-7 shows the effect of firing the heat recovery steam generator on the characteristics of the combined-cycle energy conversion system. Increasing the temperature at the inlet of the heat recovery steam generator increases both the ratio of process heat to electrical energy and the ideal energy utilization factor.

The polytropic compressor and expander efficiencies used in this characterization (0.89 and 0.90) are values which are thought to realistically represent the composite performance of commercially available gas turbines over the size range of 5 to 50 MW.

Fig. B.6-1 — Oil-fired combined-cycle energy conversion subsystem with modified heat recovery steam generator

Fig. B.6- 2-Characterization of oil-fired combined-cycle energy conversion subsystem with modified/unfired HRSG

Fig. B.6 - 3—Characterization of oil-fired combined-cycle energy conversion subsystem with modified/ unfired heat recovery steam generator

Fig. B.6-4 —Characterization of oil-fired combined-cycle energy conversion subsystem with modified/ unfired HRSG

Fig. B.6-5 — Characterization of oil-fired combined-cycle energy conversion subsystem with modified/ unfired HRSG

Fig. B.6-6—Characterization of oil-fired combined-cycle energy conversion subsystem with modified/ unfired HRSG

Fig. B.6-7 — Characterization of oil-fired combined-cycle energy conversion subsystem with modified/ fired HRSG

APPENDIX B 7: CHARACTERIZATION OF DIESEL ENGINE WITH WASTE HEAT BOILER
ENERGY CONVERSION SUBSYSTEM

Two types of diesel engines with waste heat boilers have been characterized for cogeneration applications. These are:

- Slow-speed two-stroke-cycle marine diesels
- High-speed four-stroke-cycle industrial diesels.

Slow-speed two-stroke-cycle marine diesel engines have demonstrated performance superior to that of other types of diesel engines, and they are available in size ranges applicable to industrial cogeneration systems (Mac Morran and Comerford, 1977). The world leader in the manufacture of two-stroke-cycle marine diesels is Sulzer Brothers, Ltd. of Winterthur, Switzerland. The Westinghouse Marine Division in Sunnyvale, California has a license to manufacture the 76- and 90-cm Sulzer diesels, which cover a power range from 12,000 to 40,000 metric brake horsepower (equivalent to 8605 to 28,685 kW, if one assumes a generator combined efficiency of 0.975).

The slow-speed two-stroke-cycle diesel engine has a shaft power efficiency of about 41 percent. Thirty-four percent of the energy input is rejected in the exhaust gases and 23 percent is rejected to engine cooling water. Mechanical losses amount to about 2 percent.

Typical performance data for the Sulzer Model RND 90 slow-speed, two-stroke-cycle marine diesel engine are as follows:

- Specific fuel consumption (gravity - 25° API) - 0.338 lb/SHPh
- Speed - 115.5 rpm
- Load - 85 percent maximum continuous rating
- Turbosupercharger exit temperature - 300°C (572°F)
- Exhaust flow rate - 16.1 lb/SHPh
- Cooling-water conditions

	Quantity - lb/SHPh	t _h - °F	t _c - °F
Piston	7.3	143	113
Jacket	30.0	154	130
Fuel valves	nil	-	-

Sulzer gives the following design data for waste heat boilers to be used for recovery of heat from their diesel engine exhaust:

- Temperature drop between turboexpander exit and boiler inlet - 18°F
- Radiation losses from waste heat boiler - 3 percent
- Minimum stack-gas temperature
 - Diesel fuels - 338°F
 - Residual oils with high sulfur content - 356°F.

Characterization calculations were made for a low-speed, two-stroke-cycle marine diesel with waste heat boiler energy conversion subsystem based on the following assumptions:

- Engine performance - Sulzer Model RND 90
- Fuel - diesel fuel with gravity = 25° API
 - HHV = 19,150 Btu/lb
 - LHV = 18,000 Btu/lb
 - specific gravity - 0.975
- Generator efficiency - 0.975
- Waste heat boiler inlet temperature - 554°F
- Radiation losses from waste heat boiler - 2 percent
- Minimum metal temperature in waste heat boiler - 220°F
- Pinch value for WHB - 40°F
- Offset value for WHB - 5°F
- Blowdown from waste heat boiler - 0 percent
- Recycled condensate temperature $\leq t_{sat}$.

A model of this energy conversion subsystem is shown in Figure B.7-1. The low-pressure evaporator shown in the waste heat boiler is used to heat the boiler feedwater to a temperature equal to the minimum recommended metal temperature when the recycled condensate temperature is below that temperature. In cases where sufficient heat is not recoverable from the engine exhaust, supplemental heat may be recovered from the engine cooling water.

The results of the characterization calculations for this energy conversion subsystem operating on diesel fuel are shown plotted in Figure B.7-2. The ideal energy utilization factor is given as a function of the ratio of gross process heat to electrical energy, with variables of process steam supply pressure (ideal process steam temperature) and degree of subcooling of recycled condensate. This shows the effect of process steam supply

Fig. B.7-1 — Diesel engine with waste heat boiler energy conversion subsystem

Fig. B.7-2 — Characterization of low speed two-cycle diesel plus waste heat boiler energy conversion subsystem

pressure on the ratio of gross process heat to electrical energy to be substantial and on ideal energy utilization factor to be significant. Both the ideal energy utilization factor and the ratio of gross process heat to electrical energy are weak functions of recycled condensate subcooling.

With distillate fuels the recommended minimum metal temperature in the boiler is 220°F. This value, coupled with the assumed minimum pinch temperature differential of 40°F, gives a minimum stack temperature of 260°F, the condition for the maximum heat recovery from the engine exhaust. This stack temperature requirement can be extended by the use of engine cooling water to preheat the recycled condensate.

The ideal process steam temperature cannot be less than the minimum metal temperature no matter what the degree of subcooling of the recycled condensate.

The Sulzer slow-speed diesels are capable of burning residual oils with sulfur contents up to 5 percent. The use of residual oils with sulfur contents greater than 1 percent is considered to be unlikely, since refining processes are available to desulfurize residual oil to values well below 1 percent, and flue gas desulfurization would be required if fuels containing more than 1 percent sulfur were used. The recommended minimum metal temperatures for waste heat boilers operating on products of combustion of residual oil with a sulfur content of 1 percent or less is 240°F (Babcock & Wilcox, 1972), increasing the constraints on heat recovery from the engine exhaust for the lower values of ideal process steam temperature and limiting the ideal process heat temperature to 240°F. Here, again, the constraint on maximum heat recovery from the engine exhaust can be extended by the use of engine cooling water to preheat the recycled condensate.

Natural gas can also be used in the Sulzer slow-speed diesel engines with a minimum of about 5 percent liquid fuel (Sulzer Brothers Ltd., no date). With 5 percent pilot fuel the continuous rating is about 25 percent lower than with 100 percent liquid fuel because of knocking limitations. Full rating can be attained by the use of about 30 percent pilot fuel. The minimum recommended metal temperature for a waste heat boiler operating on products of combustion from natural gas for sulfur contents less than 1 percent is $135 + \% S \ 0.85$ (Babcock and Wilcox, 1972).

Four-stroke-cycle diesels with waste heat boilers are commercially available from several U.S. manufacturers (Caterpillar Tractor Co., 1969; and Alexander, 1978). A number of four-stroke-cycle diesel generator sets that are currently being manufactured were examined for use with a waste heat boiler for cogeneration applications (Cummins Engine Co., 1976; and Caterpillar Tractor Co., 1974). The data evaluated are typical of a four-stroke-cycle diesel engine in the 500 to 1000 HP range and not necessarily obtained from one manufacturer. A nominal four-cycle diesel generator set is about 30 percent efficient. Approximately 31 percent of the energy goes into water jacket heat, 5 percent is released as ambient loss, and 34 percent escapes up the stack.

The following data were used in the characterization:

- Size - 12 cylinder, 825 HP, turbocharged
- Speed - 1800 rpm
- Fuel consumption - 44 GPH, No. 2 diesel fuel
- Cooling water - 411 GPM, 175-195°F
- Exhaust gas - 5065 CFM at 1000°F
- Fuel - No. 2 diesel fuel, HHV = 19,150 Btu/lb
LHV = 18,000 Btu/lb
Specific gravity = 0.904
- Generator efficiency - 93%
- Waste heat boiler inlet temperature - 980°F
- Radiation losses from waste heat boiler - 2%
- Minimum metal temperature in WHB - 220°F⁽²⁾
- Pinch value for WHB - 40°F
- Offset value for WHB - 5°F

For a four-stroke-cycle diesel engine only No. 2 diesel fuel and natural gas were considered to be satisfactory fuels. Four-stroke-cycle engines operate at higher rpm than do two-stroke-cycle engines, and, therefore, they have a higher piston speed. Heavier fuels tend to burn more slowly and would still be in the process of combustion as the downward stroke of the piston occurred. This delay would cause the lubricating oil film on the cylinder wall to be burned off, causing more cylinder wear. Heavy fuel oil contains higher amounts of vanadium and sodium than does No. 2 diesel fuel. The presence of these metals would cause a cracking-type corrosion on the valves of a four-stroke-cycle engine.

Figure B.7-1 can be applied to the supercharged four-stroke-cycle diesel as well as to the supercharged two-stroke-cycle diesel, except that a radiator rather than a cooling tower would probably be used for heat rejection.

Figure B.7-3 is a characterization of the four-stroke-cycle diesel with waste heat boiler energy conversion subsystem operating on No. 2 distillate fuel oil. The ideal energy utilization factor is plotted as a function of gross process heat to electrical energy with variables of process steam supply pressure (ideal process steam temperature) and recycle condensate subcooling. For the four-stroke-cycle diesel, the effects of process steam supply pressure on both the ratio of gross process heat to electrical energy and the ideal energy utilization factor are significant but not substantial. Both the ideal energy utilization factor and the ratio of gross process heat to electrical energy are weak functions of recycled condensate subcooling.

Fig. B.7-3 - Characterization of four-stroke cycle diesel with a waste heat boiler energy conversion subsystem

The range of ratios of gross process heat to electrical energy is significantly higher for the four-stroke-cycle diesel than it is for the two-stroke-cycle diesel, as shown in Figure B.7-2.

Because of the higher exhaust temperature from the four-stroke-cycle engine, the constraints on heat recovery from the engine exhaust due to the minimum metal temperature are more severe than for the two-stroke cycle engine.

Substantial quantities of low-grade heat are rejected by both the two-stroke-cycle diesel (143-154°F) and the four-stroke-cycle diesel (175-195°F). Some manufacturers utilize ebullient engine cooling, which will generate limited quantities of steam at 250°F.⁴ Present-day technology heat pumps, which have maximum discharge temperatures of about 220°F, could be used to recover heat from the engine cooling water when there is a need for 220°F process heat.

Currently, Federal emission control standards for diesel engines have not been established. Various state and local governments do limit exhaust gas releases to the atmosphere. They also may impose restrictions on the noise levels produced by such an engine. One obvious advantage to the waste heat boiler system is that the engine is muffled by the heat exchanger.

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APPENDIX B8: CHARACTERIZATION OF COAL-FIRED CLOSED-CYCLE GAS TURBINE
ENERGY CONVERSION SUBSYSTEM WITH FLUE GAS DESULFURIZATION

A model of a coal-fired closed-cycle energy conversion subsystem with flue gas desulfurization (FGD) is shown in Figure B.8-1. The closed-cycle working fluid is indirectly heated by a pulverized coal-fired heater that has both radiant and convective heat transfer surfaces. A recuperative air heater is used to preheat the combustion air. The combustion products from the air preheater go to an electrostatic precipitator and a flue gas desulfurization process. The treated flue gas is then reheated with steam. Both forced and induced draft fans are used.

The exhaust from the gas turbine expander goes to a recuperator, a waste heat boiler (WHB), and a cooler in sequence before returning to the gas turbine compressor inlet. The WHB provides process steam in addition to the steam for reheating the treated flue gas. The condensate recycled from the process and the condensate from the flue gas reheater are heated in a deaerating feedwater heater before going to the WHB.

The characterization of this energy conversion subsystem is shown in Figure B.8-2. The design values of the gas turbine compressor pressure ratio and the expander inlet temperature are those that have been used in coal-fired closed-cycle gas turbine installations in Europe (Baummert and Groschup, 1976; and Harman, et.al., 1979). Both the ideal energy utilization factor and the ratio of gross process heat to electrical energy are shown to be rather strong functions of recuperator effectiveness. These parameters are moderately strong functions of process steam supply conditions.

The characterization shown in Figure B.8-2 includes only the process steam from the waste heat boiler. Additional low level waste heat could be recovered in the cooler following the waste heat boiler.

REFERENCES TO APPENDIX B 8

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Harman, Robert A., Kinney, Carey A., and Crim, Winfred M., Jr., "Cogeneration in Europe and the Closed Cycle Gas Turbine", Turbomachinery International, March, 1979, pp. 29-34.

Fig. B.8-1—Closed-cycle gas turbine energy conversion subsystem

Fig. B.8-2 — Characterization of coal-fired closed cycle gas turbine energy conversion subsystem with FGD

APPENDIX B9: CHARACTERIZATION OF COAL-FIRED INDIRECTLY HEATED OPEN-CYCLE GAS TURBINE WITH FLUE GAS DESULFURIZATION

Figure B.9-1 is a flow diagram of the coal-fired indirectly heated open-cycle gas turbine energy conversion subsystem with flue gas desulfurization. The working fluid (air) is heated by a pulverized coal-fired heater. The exhaust from the gas turbine expander goes to a WHB and/or to a process. The unique feature of this energy conversion subsystem is that it can supply pure air to a process at a temperature in the range of 800 to 900°F.

The waste heat boiler generates steam for process use and for flue gas reheating after desulfurization.

The combustion air circuit for the pulverized coal-fired heater is completely independent of the gas turbine working fluid. The air is preheated against the products of combustion. After being cooled in the air preheater, the combustion products are cleaned and desulfurized. The desulfurized combustion products are reheated by steam. Both forced and induced draft fans are used.

The characteristics of this energy conversion subsystem are shown plotted in Figure B.9-2 for a compressor pressure ratio of 4 and an expander inlet temperature of 1325°F. The state-of-the-art pulverized-coal-fired-heater technology used in Europe for closed-cycle gas turbines is assumed to be applicable to the indirectly heated gas turbine, although this specific configuration has never been used commercially. The only design variable investigated was the process steam supply pressure which is shown to have a significant effect on both the ratio of gross heat to electrical energy and the ideal energy utilization factor.

Fig. B.9-1 — Coal-fired indirectly-heated open-cycle gas turbine energy conversion subsystem

Fig. B.9 -2 — Characterization of coal-fired indirectly-heated open-cycle gas turbine energy conversion subsystem

1. INTRODUCTION

We have investigated the possibility of using thermal energy storage to efficiently reconcile time-varying energy supplies and process heat requirements. An initial survey of proposed storage techniques, including storage modes and heat exchange options, was made. Then several representative near-term systems were characterized relative to one another with regard to storage material, mass, and volume, heat exchange requirements, and thermal effectiveness. Finally, a specific analysis of a process-steam load leveling scheme was performed. A bibliography was developed.

Thermal energy may be stored in packed beds of inexpensive solids such as rocks, sand, or firebrick. It may also be stored in pressurized water or in oils or other fluids at low pressures. Heat exchange between source, storage, and process load streams may be achieved by conventional techniques such as tube-side fluid to solid, liquid, or gas; or directly by fluids in contact with solids, be they packed, fluidized, or in dilute flow. These storage and exchange modes all utilize existing technology and are considered near term. Other much touted and promising techniques such as using phase change materials and reversible chemical reactions will require significant further development work and so are not considered here.

2. PACKED BED STORAGE

Thermal energy may be stored in stationary solid material. Typical proposed systems include geological rock or soil formations, brick checkerworks, or sand or pebble beds. All such systems have two major disadvantages: that they are poorly suited to heat transfer to tube-or channel-enclosed fluids because the primary heat transfer mode is conductive and that oversize must be provided to permit the maintenance of a steady input or output of heat because of variation in heat transfer driving force with time. The major advantage is the system simplicity, primarily due to the avoidance of solids transport. The advantages of this system may be overwhelming if heat is transferred both to and from the storage medium by direct contact with fluids, thus precluding the need for expensive heat exchange tubes. However, in such a case the simultaneous charging and discharging of heat in a single storage vessel is impossible.

Figure B.10-1 shows a system whereby waste heat in, say, a flue gas is transferred to a packed bed of granular material in the contactive mode. Steam is generated in tubes buried in the material. Thus the flexibility of simultaneous addition and removal of heat is permitted. By controlling

Fig. B.10-1 — Packed bed integral storage and exchanger

vessel dimensions and supplying hot gas to the top of the vessel, the bed may be made to have two thermal zones. The upper and lower zones are essentially at the temperatures of the incoming gas and the outlet gas, respectively. The two zones are separated by a relatively sharp gradient, the thermocline, maintained by natural convection.

The system is characterized for constant saturated steam supply at 250 to 450°F with available supply of hot gas at 500 to 1500°F. During discharge, the temperature of the superheated steam leaving storage will gradually fall as the temperature driving force in the storage/exchanger is reduced. An energy balance on the desuperheater gives the ratio of superheated steam withdrawn from storage to saturated steam generated (Table B.10-1). The balance is recycled condensate (~100°F). Thus two flows must be feedback-controlled to maintain constant conditions as seen by the process. Note that withdrawal of superheated steam accelerates between charging cycles.

The heat transfer performance can be modeled by assuming:

- No intra-particle gradients within bed
- The upper portion of the bed is at T_h
- The lower portion is at T_c
- Heat transfer area is proportional to the fraction of the bed still at T_h at any time.

In the above

T_h = hot gas temperature (°F)

T_c = condensate recycle temperature (°F).

The rate of energy withdrawal from storage at any time is constant at

$$\Delta h_s m_s = UA \frac{Q_m - Q(t)}{Q_m} \overline{\Delta T} \quad (1)$$

where

Δh_s = difference between the enthalpies of saturated steam and condensate (Btu/lb)

m_s = saturated steam rate (lb/hr)

U = overall heat transfer coefficient in storage/exchanger (Btu/hr - ft² - °F)

A = total heat transfer area in storage container (ft²)

Q_m = energy storage capacity between T_h and T_c (Btu)

$Q(t)$ = total heat withdrawn up to time t (Btu)

TABLE B.10-1

STORAGE COASTDOWN
(lb. superheated steam required per
lb. saturated steam)

Saturated Steam Temp, Superheated Steam Temp	→ 250°F	350	450
↓			
1500°F	0.63	0.65	0.65
1200	0.69	0.71	0.72
900	0.78	0.80	0.81
600	0.87	0.89	0.92
300	0.98	--	--

$$\overline{\Delta T} = \frac{m_s \Delta h_s}{[(T_h - T_{ss}) - (T_h - T_c)] / \ln [(T_h - T_{ss}) / (T_h - T_c)]} t$$

The boundary conditions are

$$T_{ss} = T_h - T' \quad @ \quad t = 0 \quad (2)$$

$$T_{ss} = T_s \quad @ \quad t = t_D \quad (3)$$

where:

T_{ss} = superheated steam temperature (°F)

T' = (parameter) temperature driving force (°F)

T_s = saturated steam temperature (°F)

t_D = discharge cycle length (hr)

Then

$$\frac{m}{m_s t_D} = \frac{\Delta h_s R}{\int_{T_c}^{T_h} C_p dT} \quad (4)$$

where

m = storage mass required (lb)

C_p = solid specific heat (Btu/lb)

and

$$\frac{1}{R} = 1 - \left(\frac{T' - (T_h - T_c)}{T_c - T_s} \right) \frac{\ln \left(\frac{T_h - T_s}{T_h - T_c} \right)}{\ln \left(\frac{T'}{T_h - T_c} \right)} \quad (5)$$

Note that the factor R is the ratio of storage mass required to that which would be required if no dilution of the superheated steam were needed.

The heat transfer area required is that required to generate superheated steam at its initial temperature:

$$\frac{UA_o}{\Delta h_s m_s} = \frac{\ln \left(\frac{T'}{T_h - T_c} \right)}{T' - (T_h - T_c)} \quad (6)$$

The results are summarized in Table B.10-2 for several combinations of parameters, assuming sand for a storage medium.

3. FLUID BED HEAT EXCHANGER WITH PACKED BED STORAGE

The poor heat transfer performance in the stationary packed bed storage mode can be overcome if the storage and heat exchange functions are separated, an example of which is shown in Figure B.10-2. Here, separate storage bins are provided for hot and cold storage. Cold material is lifted as needed to a raining bed heat exchanger in which the hot gas sensible heat is contactively transferred to the solids. This exchange can be virtually complete. From hot storage, material is delivered to a fluidized bed heat exchanger wherein the enthalpy is released to in-bed heat exchange tubes containing the process steam. Fluid bed-to-immersed surface heat transfer rates are very much higher than surface-to-settled bed rates. Therefore, much less heat transfer area is required.

The fluid bed exchanger shown in Figure B.10-2 is shown as a countercurrent staged cascade device. This is because the solids in a single stage are essentially completely mixed and the solids' temperature leaving a stage cannot be reduced to a value below that of the leaving water/steam. Where the available waste heat temperature is much larger than the needed steam temperature, as in the current example, one or two stages may be economically feasible. When the temperatures are less divergent, however, more stages may be desirable for more complete use of the solids' thermal capacity. If multiple stages are used, the quantity of solids needed will be minimized (an R-factor of near unity as described in the previous section). However two bins, each capable of holding all the material must be provided. Also note that heat exchange temperature driving forces may be maintained constant simply by controlling solids flow rates.

A disadvantage of the depicted scheme is the power requirement for fluidizing and transporting solids. The fluid bed exchanger can be quite small, however, and power consumption can be further minimized by using small particles.

The fluid bed exchanger is characterized for one- and two-stage applications. Designating the temperature of the solids leaving the lower stage as T_o then the effectiveness of heat exchanger in extracting heat from the waste heat stream is

$$\epsilon = \frac{T_h - T_o}{T_h - T_c} \quad (7)$$

Defining the parameter T' as the temperature difference between the upper solids bed and steam, then for a single-stage bed

$$T_o = T_s + T' \quad (8)$$

TABLE B.10-2

PACKED BED STORAGE CHARACTERIZATION

T' °F	T_h °F	T_s °F	R	$\left(\frac{m}{\dot{m}_s t_D}\right)$	$\left(\frac{UA_o}{\Delta h_s \dot{m}_s}\right), \text{ } ^\circ\text{F}^{-1}$
50	1500	250	1.44	3.7	.0025
		350	1.47	4.0	"
		450	1.50	4.0	"
	1000	250	1.56	7.1	.0034
		350	1.62	7.7	"
		450	1.72	8.1	"
	500	250	2.12	23.7	.0059
		350	2.94	34.1	"
	100	1500	250	1.59	4.1
350			1.63	4.3	"
450			1.68	4.5	"
1000		250	1.79	8.2	.0028
		350	1.90	8.9	"
		450	2.05	9.8	"
500		250	3.11	34.8	.0046
		350	6.62	76.0	"
500		1500	250	2.94	7.6
	350		3.20	8.5	.0011
	450		3.55	9.6	"
	1000	250	5.79	26.6	"
		350	8.76	41.2	.0015
		450	23.55	112.1	"

Fig. B.10-2 — Fluid bed/packed bed exchanger combination with packed bed storage

and for a two-stage bed

$$T_o = 2 (T_s + T') - T_h$$

or, if larger,

$$T_o = T_c + T' \quad (9)$$

For either case, the mass of storage material required will be

$$\frac{m}{m_s t_D} = \frac{\Delta h_s}{T_o \int_{T_h}^{T'} c_p dT} \quad (10)$$

and the heat exchange requirement will be approximated by the reciprocal of the log-mean temperature difference. The results are shown in Table B.10-3.

4. MOVING BED EXCHANGER/STORAGE

Another way to circumvent the poor bed-to-tube heat transfer rates of the stationary packed bed system is to use an intermediate gas loop to extract heat from solids and deliver them to an evaporator. This arrangement is shown in Figure B.10-3. The Babcock and Wilcox Company has used a similar design (Glenn, 1976), with a moving bed exchanger substituted for the raining bed exchanger shown at the top of Figure B.10-3. We have made the change to prevent the passing of significant amounts of cold solids into hot storage when hot gas is not available. The intermediate air loop shown results in some loss of energy availability, but this is very low because of the very efficient nature of solids-to-gas heat transfer. Again, of course, there is the energy requirement for circulation of the gas stream and elevation of cold solids.

Again designating the cold solids temperature as T_o , the overall heat transfer effectiveness is given by equation 7, the storage mass by equation 10, and the evaporator surface requirement, $UA/\Delta h_s m_s$, by the reciprocal of the log-mean temperature difference. Designating the temperature difference at the cold end of the evaporator as T' and the average temperature difference in the moving bed exchanger as T_E , then

$$T_o = T_c + T_E + T' \quad (11)$$

The results are given in Table B.10-4 for $T_E = 10^\circ\text{F}$.

TABLE B.10-3

FLUIDIZED HEAT EXCHANGER/PACKED BED STORAGE CHARACTERIZATION

T'	T _h	T _s	Single Stage			Double Stage		
			E	$\left(\frac{m}{\dot{m}_s t_D}\right)$	$\left(\frac{UA}{\dot{m}_s \Delta h_s}\right)$	E	$\left(\frac{m}{\dot{m}_s t_D}\right)$	$\left(\frac{UA}{\dot{m}_s \Delta h_s}\right)$
50	1500	250	.86	3.0	.0092	.96	2.8	.020
		350	.79	3.2	.0072	.96	2.8	"
		450	.71	3.5	.0059	.96	2.9	"
	1000	250	.78	5.9	.0092	.94	5.1	"
		350	.67	6.8	.0072	.94	5.2	"
		450	.56	8.1	.0059	.94	5.3	"
	500	250	.50	24.6	.0092	.88	14.9	"
		350	.25	48.6	.0072	.50	25.2	.0092
		450	.13	95.3	.0050	.25	49.1	.0055
100	1500	250	.82	3.1	.0061	.93	2.8	.010
		350	.75	3.3	.0050	.93	2.9	"
		450	.68	3.6	.0043	.93	2.9	"
	1000	250	.72	6.3	.0061	.89	5.3	"
		350	.61	7.3	.0050	.89	5.5	"
		450	.50	8.8	.0043	.89	5.5	"
	500	250	.38	32.2	.0061	.75	17.1	"
		350	.13	95.3	.0050	.25	49.1	.0055
		450	.06	70.9	.0015	.11	36.0	.0016
500	1500	250	.54	4.2	.0017	.64	3.7	.0020
		350	.46	4.9	.0016	.64	3.7	"
		450	.39	5.7	.0015	.64	3.8	"
	1000	250	.28	15.0	.0017	.44	9.4	"
		350	.17	24.0	.0016	.33	12.5	.0018
		450	.06	70.9	.0015	.11	36.0	.0016
	500	250	.38	32.2	.0061	.75	17.1	"
		350	.13	95.3	.0050	.25	49.1	.0055
		450	.06	70.9	.0015	.11	36.0	.0016

Fig. B.10-3 — Moving bed exchanger/storage

TABLE B.10-4

MOVING BED EXCHANGER/PACKED BED STORAGE CHARACTERIZATION

T_c °F	T_h °F	T_s °F	E	$\left(\frac{m}{m_s t_D} \right)$	$\left(\frac{UA}{\Delta h_s m_s} \right)$
50	1500	250	.96	2.8	.0027
		350	"	2.8	.0029
		450	"	2.9	.0031
	1000	250	.93	5.1	.0039
		350	"	5.3	.0043
		450	"	5.3	.0049
	500	250	.85	15.3	.0083
		350	"	15.7	.0114
		450	"	15.7	.0114
	1500	250	.92	2.8	.0022
		350	"	2.9	.0023
		450	"	2.9	.0025
100	1000	250	.88	5.4	.0031
		350	"	5.5	.0034
		450	"	5.6	.0038
	500	250	.72	17.5	.0063
		350	"	18.0	.0084
		450	"	18.0	.0084
	1500	250	.64	3.7	.0012
		350	"	3.8	.0013
		450	"	3.8	.0014
	1000	250	.43	9.6	.0016
		350	"	9.9	.0018
		450	"	10.0	.0019

5. COMBINED FLUID AND ROCK THERMAL STORAGE

McDonnell Douglas Astronautics Company (MDAC) has developed a system whereby the packed bed thermocline concept is used without the need for either immersed heat exchange surfaces or the transport of solids (Hallet and Gervais, 1977). This system is shown in Figure B.10-4. During charging, a commercial heat transfer fluid (Exxon's Caloria HT43), withdrawn from the bottom of a vessel containing a packed bed of one-inch rocks, is heated by the waste gas stream and restored to the top of the storage vessel. A separate steam generator is powered by hot fluid circulating from the top to the bottom of the vessel. Thus independent operation of the source and load are possible. The inventory of fluid in storage is constant and divided into hot and cold zones by natural convection. The rock bed (75% of storage volume) exchanges heat with the circulating oil and minimizes the amount of fluid needed. The disadvantage of this system is, of course, the cost of the heat transfer fluid.

Designating the hot and cold fluid temperatures as T_1 and T_2 we will define the parameter T' by

$$T_2 + T' = T_o \quad (12)$$

and

$$T_2 - T' = T_c \quad (13)$$

where T_o and T_c are the cooled gas and condensate temperatures, respectively. We will also assume that T_1 is the minimum of $T_h - T'$ and 600°F , the maximum working temperature of the fluid. Then the specific storage volume ($V/m_s t_D$) and masses of fluid and rock ($m_L/m_s t_D$ and $m_R/m_s t_D$) can be calculated from densities, heat capacities, Δh_s , and T_1 and T_2 . The results are in Table B.10-5.

6. STEAM ACCUMULATORS

The storage of steam as pressurized water is a well developed technology. It allows the storage of energy in a compact form due to the high heat of vaporization of water. The disadvantage is, of course, the requirement for large pressure vessels.

The two conventional accumulator types are illustrated in Figs. B.10-5 and 6. These are the variable and constant pressure accumulators, respectively. Variable pressure storage (Fig. B.10-5) is suited to independent operation of the steam generation and steam use plants. As heat is available steam is generated at temperatures well above the eventual use temperatures and introduced into the saturated storage vessel. When steam is needed saturated steam is withdrawn directly from storage. The saturated steam pressure and temperature constantly drop during discharge. The minimum storage pressure is, therefore, the steam delivery pressure.

Fig. B.10-4 — Hot liquid/pebble bed storage with thermocline

TABLE B.10-5

MDAC COMBINED FLUID/ROCK STORAGE SYSTEM CHARACTERIZATION

T' °F	T_h °F	T_s °F	$\left(\frac{V}{\dot{m}_s t_D}\right), \frac{ft^3}{lb_{steam}}$	$\left(\frac{\dot{m}_L}{\dot{m}_s t_D}\right)$	$\left(\frac{\dot{m}_R}{\dot{m}_s t_D}\right)$	Steam Generator $\left(\frac{UA}{\Delta h_s \dot{m}_s}\right)$	Fluid Heater $\left(\frac{UA}{\Delta h_s \dot{m}_s}\right)$	E
50	1500	250	.073	0.83	9.1	.0065	.0068	.93
		350	.075	0.85	9.3	.0080	.0068	.93
		450	.076	0.86	9.5	.0110	.0068	.93
	1000	250	.073	0.83	9.1	.0065	.012	.89
		350	.075	0.85	9.3	.0080	.012	.89
		450	.076	0.86	9.5	.0110	.012	.89
	500	250	.111	1.25	13.8	.0092	.040	.75
		350	.114	1.28	14.1	.0139	.040	.75
		450	.114	1.28	14.1	.0139	.040	.75
100	1500	250	.083	0.93	10.3	.0050	.0055	.86
		350	.085	0.95	10.5	.0061	.0055	.86
		450	.086	0.96	10.7	.0081	.0055	.86
	1000	250	.083	0.93	10.3	.0050	.0092	.78
		350	.085	0.95	10.5	.0061	.0092	.78
		450	.086	0.96	10.7	.0081	.0092	.78
	500	250	.166	1.87	20.5	.0081	.020	.50
		350	.170	1.91	21.0	.0139	.020	.50
		450	.170	1.91	21.0	.0139	.020	.50

Fig. B.10-5 — Variable pressure saturated steam accumulator

Fig. B.10-6 — Constant delivery pressure saturated steam accumulator

Carr, et.al. (1978) define the storage volume requirement (ft^3 of storage per lb steam generated during discharge) as:

$$\frac{V}{m_s t_D} = 2/[10 \log_{10} \frac{P_1}{P_2} + P_1 - P_2]$$

where P_1 and P_2 are the maximum and minimum storage pressures, respectively. Table B.10-6 gives the storage volume requirement at various pressure combinations. Note that if fine control of steam quality is required, a small amount of condensate will have to be added or subtracted from the expander. Table B.10-6 gives the ratio of steam being extracted from storage to steam generated (m_1/m_s) at any pressure.

The constant pressure accumulator is shown in Figure B.10-6. It is suitable to situations where steam generation is constant but demand varies. As such it is simply an added capacity in the boiler feedwater system. The boiler must always generate steam at the rate of maximum demand. At lower demands excess steam is mixed with cool feedwater in a constant ratio, yielding a constant enthalpy mixture which is stored. Preheated feedwater is removed from storage at a constant rate. The advantages of the constant pressure accumulator are that steam need not be generated at a pressure in excess of that needed by the process and the boiler can be designed for a lower maximum heat rate.

The ratio of steam to cold feedwater being delivered to storage is constant and has the value

$$z = \frac{h_h - h_c}{h_s - h_h} \quad (15)$$

The ratio of maximum (design) boiler heat rate in a no-storage system to the steady heat rate in the constant-pressure storage system is

$$\frac{h_s - h_c}{h_s - h_h} = 1 + z$$

equation 15, the specific enthalpies are

h_h = saturated water at storage pressure

h_c = cold feedwater

h_s = delivered steam

The storage volume required is

$$\frac{V}{m_s t_D} = \frac{h_s - h_c}{h_h - h_c} \frac{1}{\rho_h} \quad (16)$$

TABLE B.10-6

VARIABLE PRESSURE STEAM ACCUMULATOR REQUIREMENTS

T_s °F	Storage Pressure, psia	$\left(\frac{m_l}{m_s}\right)$	$\left(\frac{v}{m_s t_D}\right),$ ft ³ /lb
250	200	.97	.118
	500	.96	.069
	1000	.97	.048
	1600	1.00	.039
350	200	.99	.473
	500	.99	.123
	1000	1.00	.070
	1600	1.03	.051
450	500	1.00	.762
	1000	1.02	.134
	1600	1.06	.079

where ρ_h is the stored water density. Typical requirements are listed in Table B.10-7.

7. COMPARISON OF THE THERMAL ENERGY STORAGE TECHNIQUES

Using the above relationships the storage requirements for the various systems were estimated for the specific case defined by:

Steam Rate	1000 lb _m /hr
Discharge Time	10 hr
Steam Temperature	350°F
Waste Heat Gas Temperature	1000°F
Temperature Driving Force Parameter, T'	100°F

Gas-particle heat transfer coefficients were evaluated according to the methods presented by Kunii and Levenspiel (1969). The packed bed to tube coefficient is after Holt (1962). The fluid bed coefficient for immersed surfaces follows Zabrodsky et.al (1976). Other coefficients are engineering estimates.

The results of the comparison, including storage volume (total of hot and cold), storage material mass, exchanger sizes, and tube heat transfer areas are listed in Table B.10-8. Variable pressure steam accumulator volumes are given at two pressures.

TABLE B.10-7

CONSTANT PRESSURE ACCUMULATOR CHARACTERIZATION

T_s °F	Storage Pressure, psia	Z	$\left(\frac{V}{m_s t_D} \right), \frac{ft^3}{lb}$
250	20	.11	.165
350	20	.11	.169
	50	.17	.116
	100	.24	.092
450	20	.11	.171
	50	.17	.118
	100	.24	.093
	200	.32	.076
	400	.43	.064

TABLE B.10-8

COMPARISON OF DESIGN REQUIREMENTS FOR THERMAL ENERGY STORAGE SYSTEMS

($\sim 10^7$ Btu Capacity)

System	Stationary Bed	Fluidized Bed		Moving Bed	Oil/Rock Thermocline	Variable Pressure Steam Accumulator	
		one-stage	two-stage				
Particle Size	any	500 μm	500 μm	2000 μm	1 inch	--	--
Storage Pressure, psia	--	--	--	--	--	1000	1600
Heat Transfer Coefficients, - overall (Btu/hr-ft ² -°F)							
Solids To Tube	0.9	60	60	--	--	--	--
Gas to Raining Solids	--	75	75	48	--	--	--
Gas to Packed Solids	--	--	--	46	--	--	--
Gas to Tube	--	--	--	10	15	--	--
Liquid to Tube	--	--	--	--	200	--	--
Stored Solids Mass, lb	89000	73000	55000	55000	105000	--	--
Stored h.t. Fluid Mass, lb	--	--	--	--	9500	--	--
Storage volume, ft ³	960	1460	1100	1100	850	700	510
Fluid Bed Vessel Volume, ft ³	--	90	110	--	--	--	--
Particle Heater Volume, ft ³	--	150	150	35	--	--	--
Moving Bed Exchanger Volume, ft ³	--	--	--	50	--	--	--
Steam Exchanger Tube Area, ft ²	3400	90	190	380	35	--	--
Source Exchanger Tube Area, ft ²	--	--	--	--	700	--	--
Fluidizing Air Power, % of Load	--	1.4	2.0	--	--	--	--

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APPENDIX B11: CHARACTERIZATION OF BOTTOMING CYCLES FOR COGENERATION APPLICATIONS

The application of Rankine bottoming cycles for cogeneration was investigated. The thermodynamic operating performance was determined for selected power generation subsystems in the temperature range 75 to 300°C and the capacity range from 3 to 30 MW.

The working fluids selected for top temperatures of 300°C, 200°C, and 100°C were Fluorinol - 85*, methanol, and ammonia, respectively. These working cycle fluids were selected for application in bottoming cycles in an earlier study (Grimble and Somers, 1977). For the selected working fluids, the T-S diagrams are given in Figures B.11-1, 2, and 3 and the tables of thermodynamic properties are given in Tables B.11-1, 2, and 3. The cycles using Fluorinol - 85 were superheated and the cycles using methanol or ammonia were saturated. Schematic diagrams of the superheated and saturated cycles are shown in Figures B.11-4 and 5.

The program TURB (Grimble and Somers, 1977), which calculates the turbine size, number of stages, and stage efficiency, was modified to incorporate a tabulation of the thermodynamic properties for each working fluid analyzed (Grimble and Somers, 1977; Din, 1956). The program treats the flow as one-dimensional with all parameters being referred to the mean blade radius. Two blading types are considered impulse for the high pressure stages, and 50% reaction for the low pressure stages. Turbine efficiency is estimated from Balje's correlation (Balje and Binsley, 1968), and is included as an iterated input to the turbine performance calculation.

The ratio of plant power to thermal input for the working fluid was correlated as a function of the inlet throttle conditions. This ratio increases with increasing throttle pressure (see Figures B.11-6, 7, and 8). For the superheated cycles, this ratio increases as the extent of superheating increases (see Figure B.11-6). The plant capacity does not influence the ratio of plant power to thermal input for the working fluids (see Table B.11-4).

* 85 mole percent trifluorethanol and 15 mole percent water

Fig. B.11-1 - T-S diagram for fluorinol 85

Fig. B.11-2— T-S diagram for ammonia

Fig. B.11-3—T-S diagram for methanol

TABLE B.11-1

FLUORINOL-85 SATURATED LIQUID AND SATURATED VAPOR PROPERTIES

TEMP, R	PRESS. PSIA	ENTHALPY, BTU/LB		ENTROPY, BTU/LB-R		VOLUME, FT**3/LB	
		LIQUID	VAPOR	LIQUID	VAPOR	LIQUID	VAPOR
519.04	1.00	12.17	237.64	.0241	.4005	.0115	62.78
569.05	4.00	34.55	221.64	.0652	.3938	.0120	16.93
591.74	7.00	44.75	227.94	.0828	.3922	.0122	9.96
607.76	10.00	51.96	232.34	.0948	.3914	.0124	7.09
625.65	14.70	60.07	237.24	.1079	.3910	.0126	4.91
641.04	20.00	67.08	241.39	.1190	.3903	.0127	3.65
661.36	30.00	76.43	246.81	.1333	.3904	.0130	2.46
677.28	40.00	83.84	251.00	.1444	.3911	.0132	1.86
690.39	50.00	90.02	254.40	.1535	.3915	.0134	1.49
701.61	60.00	95.46	257.26	.1612	.3918	.0136	1.25
711.43	70.00	100.18	259.71	.1679	.3921	.0138	1.07
720.18	80.00	104.50	261.83	.1740	.3923	.0139	.93
728.10	90.00	108.46	263.71	.1794	.3926	.0141	.83
735.37	100.00	112.15	265.41	.1845	.3928	.0142	.74
747.90	120.00	118.68	268.19	.1933	.3931	.0145	.61
749.97	140.00	124.59	270.57	.2011	.3934	.0145	.53
768.88	160.00	130.01	272.62	.2082	.3936	.0149	.45
777.90	180.00	135.07	274.43	.2147	.3938	.0152	.40
786.20	200.00	139.84	276.06	.2208	.3940	.0154	.36
803.75	250.00	150.40	279.13	.2341	.3942	.0159	.28
818.89	300.00	159.93	281.37	.2459	.3941	.0164	.23
832.32	350.00	168.78	282.91	.2566	.3937	.0170	.18
844.44	400.00	177.11	283.68	.2665	.3927	.0175	.16
855.51	450.00	185.05	283.83	.2759	.3913	.0182	.14
865.73	500.00	192.76	283.14	.2848	.3892	.0189	.12
875.20	550.00	200.38	281.44	.2936	.3861	.0197	.10
884.01	600.00	207.98	278.00	.3022	.3814	.0206	.08
892.32	650.00	215.72	271.81	.3109	.3737	.0219	.07
900.14	700.00	223.61	260.71	.3197	.3609	.0237	.05
907.55	750.00	234.72	242.29	.3367	.3450	.0289	.04
908.19	778.00	239.35	239.35	.3418	.3418	.0340	.03

TABLE B.11-2

AMMONIA SATURATED LIQUID AND SATURATED VAPOR PROPERTIES

TEMP, R	PRESS. PSIA	ENTHALPY, BTU/LB		ENTROPY, BTU/LB-R		VOLUME, FT**3/LB	
		LIQUID	VAPOR	LIQUID	VAPOR	LIQUID	VAPOR
360.00	1.27	272.00	904.08	1.0300	2.7800	.0220	178.45
378.00	2.61	290.70	913.11	1.0800	2.7300	.0223	91.10
396.00	4.98	309.53	921.71	1.1300	2.6700	.0227	49.91
414.00	8.91	328.53	929.44	1.1700	2.6300	.0231	29.06
432.00	15.08	347.79	935.89	1.2200	2.5800	.0235	17.78
450.00	24.30	367.13	942.34	1.2600	2.5400	.0239	11.37
468.00	37.61	386.70	948.79	1.3100	2.5100	.0244	7.35
486.00	56.12	406.56	953.95	1.3500	2.4700	.0249	5.18
504.00	81.09	426.50	958.68	1.3900	2.4400	.0255	3.65
522.00	113.94	446.92	962.93	1.4300	2.4100	.0260	2.64
540.00	156.13	467.43	965.56	1.4600	2.3900	.0267	1.94
558.00	209.40	488.24	967.70	1.5000	2.3600	.0274	1.45
576.00	274.23	509.47	969.42	1.5400	2.3300	.0282	1.10
594.00	355.94	531.23	969.42	1.5700	2.3100	.0291	.85
612.00	452.93	553.75	967.28	1.6100	2.2900	.0301	.65
630.00	568.74	576.88	963.41	1.6500	2.2600	.0313	.51
648.00	705.85	601.09	956.53	1.6800	2.2300	.0327	.39
666.00	865.74	626.58	946.64	1.7200	2.2000	.0344	.30
684.00	1051.40	652.46	929.44	1.7600	2.1600	.0367	.23
702.00	1264.70	684.14	902.36	1.8000	2.1100	.0401	.17
720.00	1510.70	720.21	852.06	1.8200	2.0400	.0465	.12
730.08	1660.60	784.65	784.57	1.9400	1.9400	.0682	.07

TABLE B.11-3

METHANOL SATURATED LIQUID AND SATURATED VAPOR PROPERTIES

TEMP, R	PRESS. PSIA	ENTHALPY, BTU/LB		ENTROPY, BTU/LB-R		VOLUME, FT**3/LB	
		LIQUID	VAPOR	LIQUID	VAPOR	LIQUID	VAPOR
500.00	.87	23.29	532.24	.0485	1.0665	.0199	192.96
525.00	1.85	38.11	538.76	.0775	1.0311	.0202	94.76
550.00	3.68	53.23	545.57	.1056	1.0007	.0205	49.70
575.00	6.91	68.65	552.68	.1330	.9748	.0209	27.58
600.00	12.31	84.36	560.08	.1597	.9526	.0213	16.07
625.00	20.93	100.38	563.12	.1858	.9262	.0217	9.77
650.00	34.17	116.71	564.23	.2113	.8998	.0221	6.16
675.00	53.74	133.35	565.02	.2363	.8758	.0225	4.01
700.00	81.40	150.33	562.09	.2608	.8491	.0230	2.70
725.00	119.44	167.65	559.50	.2849	.8254	.0234	1.87
750.00	170.42	185.32	557.26	.3085	.8045	.0240	1.32
775.00	236.98	203.36	555.40	.3318	.7860	.0245	.95
800.00	322.82	221.80	547.05	.3547	.7612	.0251	.70
825.00	431.60	240.66	537.54	.3772	.7370	.0256	.52
850.00	567.25	259.97	528.48	.3994	.7153	.0263	.39
875.00	733.98	279.76	501.78	.4213	.6750	.0270	.29
900.00	936.23	300.07	430.12	.4429	.5874	.0277	.22
923.76	1165.55	319.89	319.40	.4632	.4626	.0284	.17

Fig. B.11-4 — Schematic diagram for superheated cycles

Fig. B.11- 5 – Schematic diagram for saturated cycles

Fig. B.11-6— Ratio of plant power to thermal input for the working fluid as a function of throttle pressure for the working fluid fluorinol-85

Fig. B.11-7 — Ratio of plant power to thermal input for the working fluid as a function of throttle pressure for the working fluid methanol

Fig. B.11-8— Ratio of plant power to thermal input for the working fluid as a function of throttle pressure for the working fluid ammonia

TABLE B.11-4

EFFECT OF PLANT CAPACITY ON THE RATIO OF PLANT POWER TO
THERMAL INPUT FOR THE WORKING FLUIDS

WORKING FLUID	SUPERHEATING OF	THROTTLE PRESSURE PSIA	KW /BTU/SEC.	
			PLANT POWER 3 MW	PLANT POWER 30 MW
FLUORINOL - 85	200	347.6	0.3403	0.3413
	200	25.2	0.1573	0.1584
	50	646.2	0.2991	0.2997
	50	244.1	0.2590	0.2600
METHANOL	0	577.5	0.2171	0.2171
	0	50.7	0.1291	0.1296
AMMONIA	0	924.4	0.0974	0.0974
	0	547.4	0.0721	0.0721

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APPENDIX B 12: BASIS FOR CAPITAL EQUIPMENT COSTS

Costing algorithms were developed for the energy conversion equipment to be used in the various cogeneration configurations under consideration.* The algorithms covered the following types of equipment.

- Fired power steam generators (coal & oil)
- Heat recovery steam generators (HRSG's)
- Waste heat boilers (generating saturated steam)
- Steam turbine/generators
- Gas turbine/generators
- Flue gas desulfurization systems
- Organic cycles
- Fired process steam boilers

1. FIRED POWER STEAM GENERATORS

The basic algorithms for coal-fired steam generators, based upon correlations provided by Gibbs & Hill, computed cost as a function of steam capacity for two discrete pressure levels. The boiler generating steam at 615 psia and 750°F was limited to a capacity range 100,000 - 400,000 lb/hr. The 915 psia/825°F boiler covered a range from 500,000 - 1,800,000 lb/hr of superheated steam. To generalize the algorithms for in-place coal-fired boilers, a pressure correction factor was added. The resulting expressions are as follows:

- $W_s < 300,000$ lb/hr $\text{COST (SG)} = (1,072,600 + 16 W_s) \left(\frac{P}{600} \right)^{0.3}$
- $300,000 < W_s < 500,000$ lb/hr $\text{COST (SG)} = (1,072,600 + 16 W_s) \left(\frac{P}{600} \right)^{0.2}$
- $500,000 < W_s$ $\text{COST (SG)} = (6,214,500 + 12 W_s) \left(\frac{P}{900} \right)^{0.125}$

The following equipment is included

- Economizer (stoker spreader units)
- Air heater (pulverized coal units)
- Mechanical collector

*The basic cost estimates were based upon prices at December, 1978 levels

- F. D. fans, air and gas ducts
- Burner and combustion controls
- F. W. regulators and control valves
- Pulverizers (200,000 lbs and over)
- Soot blowers
- Stoker spreader (200,000 lbs and under)
- Ball mills (stoker spreader units)
- Overfire air nozzles
- Std boiler trim
- Foundations, supporting steel

The balance of plant costs was assumed to be 125% of the capital equipment cost.

The oil-fired steam generator correlations were based upon information supplied by Gibbs & Hill. The algorithms are as follows:

- $W_s < 300,000 \text{ lb/hr}$ $\text{COST (SG)} = 718,000 \times \left(\frac{P}{600}\right)^{0.3} \left(\frac{W_s}{100,000}\right)^{0.763}$
- $300,000 < W_s < 500,000 \text{ lb/hr}$ $\text{COST (SG)} = 1,000,000 \times \left(\frac{P}{600}\right)^{0.2} \left(\frac{W_s}{300,000}\right)^{0.8}$
- $500,000 < W_s$ $\text{COST (SG)} = 1,500,000 \times \left(\frac{P}{900}\right)^{0.125} \left(\frac{W_s}{600,000}\right)^{1.0}$

The following equipment is included:

- Burner and combustion controls
- F. D. fans, air and gas ducts
- Air preheater (shop assembled units)
- Air heater
- F. W. regulator and control valves
- Soot blowers
- Std boiler trim
- Foundation, supporting steel

The balance of plant factor for the clean fuel-fired boilers was 3.0.

2. HRSG'S AND WASTE HEAT BOILERS

A heat recovery steam generator is defined as a boiler which produces superheated steam for a mechanical drive or power generation turbine. A waste heat boiler, by contrast, generates saturated steam for use directly in a process. The HRSG costs for this study were derived from specific correlations for cost as a function of heat transfer units, i.e., the product of the overall heat transfer coefficient and the surface area required (in Btu/hr °F). Included in the summation are the superheating, high pressure evaporating, economizing & low pressure evaporating surfaces. The correlations are of the form:

$$\text{COST}(\text{HRSG}) = a (UA/10^6)^b$$

where a and b are assigned according to the following tabulation:

Component	a	b
Superheater	9.6×10^5	0.8499
High pressure evaporator	2.7×10^5	1.3445
Economizer	3.7×10^5	0.6887
Low pressure evaporator	2.87×10^5	1.2146

The balance of the HRSG price is determined by using the following expression:

$$B O (\text{HRSG}) = [500 + 12.214 (W_s)] \times 10^3$$

The balance of plant cost for the HRSG was assumed to be 100% of the capital equipment cost.

The waste heat boiler cost was based upon an algorithm supplied by Gibbs & Hill and was indicated to be valid for a wide range of steam generating capacity (60,000 - 360,000 lb/hr). The correlation is as follows:

$$\text{COST} (\text{WHB}) = 13 W_s + 1,450,500$$

The balance of plant cost for a waste heat boiler was assumed to be 100% of the capital equipment cost.

3. STEAM TURBINE/GENERATORS

The costing procedure for the non-condensing steam turbine generator sets was based upon the "rule of thumb" costing correlation supplied by Gibbs & Hill. The original data described two ranges of generating capacity for two different throttle pressures. Thus, a back pressure turbine generating from 5 to 15 MW and having throttle condition of 650 psig/750°F, with back pressures between 50 - 150 psig had the following algorithm:

$$\text{COST (STG)} = 617,900 + 111,770 (\text{Pwr})$$

where Pwr is in MWe. A second algorithm described a back pressure turbine producing from 5 to 75 MW, with throttle conditions of 850 psig and 825°F, again with a back pressure between 50 and 150 psig. The second expression is as follows:

$$\text{COST (STG)} = 944,800 + 91,130 (\text{Pwr})$$

Since it is necessary, in the optimization procedure, to examine a range of throttle pressures and temperatures for a variety of capacitors and back pressures, cost was judged to be most sensitive to power and throttle pressure. Thus, a simple linear interpolation was used. First the cost at a given power level was computed for pressures of 600 psig and 850 psig, using the above expressions. Subsequently, the cost at the specified throttle pressure was calculated according to:

$$\text{COST (SG)}_p = \text{COST (SG)}_{600} + \left(\text{COST (SG)}_{850} - \text{COST (SG)}_{600} \right) \frac{P-600}{250}$$

No attempt was made to account for the presumably small effect of back pressure on turbine costs. For steam turbines having double or single extraction points, information based on Westinghouse Canada small steam turbine costs showed that a multiplier of 1.17 for each extraction point were applied to the basic turbine cost. The balance of plant cost for a steam turbine/generator set was assumed to be 100% of the capital equipment cost.

4. GAS TURBINE/GENERATORS

The preliminary gas turbine/generator costs were based on Amos and Grube (1976) for existing, proven gas turbine systems. The components of the gas turbine/generator were grouped into five classifications to enable an estimate of cost which would be sensitive to a number of different operating parameters including air flow, pressure ratio and expander inlet temperature.

The Group 1 components are presented as a function of compressor air flow (Wa). The group is comprised of the following components:

- Inlet manifold
- Inlet casing
- Expander diffuser
- Turbine exhaust manifold
- Turbine supports
- Longitudinal assembly

The cost algorithms for Group 1 are as follows:

$$\begin{aligned} \text{Wa} < 200 \text{ lb/s} & \quad \text{COST (1)} = 192,850 \times \frac{\text{Wa}}{100}^{0.50} \\ 200 \text{ lb/s} < \text{Wa} < 500 \text{ lb/s} & \quad \text{COST (1)} = 272,650 \times \frac{\text{Wa}}{100}^{0.6878} \\ 500 \text{ lb/s} < \text{Wa} & \quad \text{COST (1)} = 512,050 \times \frac{\text{Wa}}{100}^{1.0908} \end{aligned}$$

The Group 2 components include the compressor/combustor shell, as well as the compressor spindle and diaphragm. The costs of these components are functions of pressure ratio and the compressor flow factor (CFF) which is defined as follows:

$$\text{CFF} = \text{Wa} \times \text{PR}^* 3600^2 / N^2$$

where $N = 56022 \times (\text{Wa})^{-0.46}$

For pressure ratios of 4, 8, 12 and 16, the cost is related to CFF according to the following expression:

$$\text{COST (2)} = a(\text{CFF})^b$$

and a and b are specific to pressure ratio as:

PR	a	b
4	445,550	0.16765
8	704,900	0.24262
12	877,800	0.29562
16	1,064,000	0.32049

Costs for intermediate pressure levels are attained by using a three-point interpolation method.

Group 3 is composed of the expander cylinder, vanes, and spindle, as well as the spindle assembly. The Group 3 cost is a function of the turbine power factor (TPF) which is equivalent to the product of the air flow (Wa) and the enthalpy change across the expander. The costing is performed by interpolating in a table which represents the data contained in Figure B.12-1.

Group 4 contains engine accessories, and a variety of auxiliary items including the generator/exciter. The cost is expressible in terms of the net power of the gas turbine (Pwr) as:

$$\text{COST (4)} = e^{(0.0115 \times \text{Pwr} + 14.35)}$$

Fig. B.12-1 - Gas Turbine Costs (Group 3) Expander Assembly

The combustor assembly is identified as Group 5. The Group 5 is defined in terms of the pressure ratio, (PR) and the sum of the peak cycle temperature (EIT) and the air temperature at the compressor outlet (COT)

$$\frac{\text{COST (5)}}{W_a(\text{EIT}+\text{COT})} = \phi \text{ (PR)}$$

where the value of ϕ (PR) is determined by interpolating on the data contained in Figure B.12-2.

The total gas turbine/generator cost is simply the sum of the subassembly costs. The balance of plant cost was assumed to be 35% of the capital equipment cost.

5. FLUE GAS DESULFURIZATION

The flue gas desulfurization system costs were based upon an estimate of costs performed by Coffin (1979) for industrial applications. The relationship which was derived is expressed as a function of the quantity of fuel consumed. The correlation is as follows:

$$\text{COST (FGD)} = e^{(0.6 \ln (0.85 Q \text{ in}/1000) + 7.18)}$$

This correlation included balance of plant.

6. ORGANIC CYCLES

Little information is available on the costs for organic bottoming cycle components. The turbine/generator cost for the methanol cycle was based on Grimble and Somers (1977) and was a function of the rated power and the exhaust end area. The following expression was used:

$$\text{COST (MTG)} = (a(\text{Pwr})^{0.75} + bA) \times 1.33$$

where $a = 170$ and $b = 140,000$ for methanol and Fluorinol - 85.

The condenser/circulating water system was also based on correlations contained in Grimble and Somers (1977). For both organic fluids the cost correlation is of the form:

$$\text{COST (CW)} = 133,000 + 1.33 \zeta \left[\frac{Q_R}{\delta \Delta T_r} \ln \left\{ \frac{\text{TTD} + \Delta T_r}{\text{TTD}} \right\} \right]$$

where Q_R is the heat rejected, TTD is the terminal temperature difference and ΔT_r is the temperature change in the cooling water. The constants δ and ζ are 1.64 and 137.7 respectively for methanol, and 0.87 and 101.6 for Fluorinol - 85.

The organic boiler costs were not available and the correlation for a conventional unfired HRSG was used.

Fig. B.12-2 - Gas Turbine Costs (Group 5) Combustor Assembly

7. PROCESS STEAM BOILERS

The reference case for most cogeneration studies is a single purpose process boiler generating steam at saturation conditions. In order to calculate the incremental cost of a cogeneration system, the cost of a process steam boiler generating an equivalent quantity of steam was required.

The following algorithms were used for oil or gas-fired boilers:

$$W_s < 100,000 \text{ lb/s}$$

$$\text{COST(PB)} = e^{(0.8 \ln W_s + 4.907)}$$

(Source: Coffin, 1979; Gibbs & Hill)

$$W_s > 100,000 \text{ lb/s}$$

$$\text{COST(PB)} = e^{(0.8 \ln W_s + 5.593)}$$

(Source: Coffin, 1979; Gibbs & Hill; and Miller, 1968)

For coal-fired process boilers, the following correlation was employed.

$$\text{COST(PB)} = e^{(0.8 \ln W_s + 6.258)}$$

(Source: Coffin, 1979; Gibbs & Hill)

Other Capital Cost Factors

Indirect Costs

For all equipment except gas turbines, the indirect costs were assumed to be 15% of the direct costs. For gas turbines, 7-1/2% was used.

Engineering Costs

Engineering costs were assumed to be 10% of direct capital costs.

Contingency

The allowance for contingency was 20% of the direct capital costs.

Interest During Construction

The interest rate on funds expended during the construction period was assumed to be 10%.

Escalation During Construction

The general inflation rate of 7-1/2% per year was used in calculating the escalation during construction.

REFERENCES TO APPENDIX B 12

Amos, D. J. and J. E. Grube, Energy Conversion Alternatives Study (ECAS), Westinghouse Phase I Final Report Volume IV - Open Recuperated and Bottomed Gas Turbine Cycles, NASA Contract NAS 3-19407, February 12, 1976.

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Grimble R. E., and E. V. Somers, Solar Thermal-Electric Ranking Power Organic Working Fluids, Final Report, Westinghouse Research Report, 77-1E0-SOLEP-R1, April 1977.

Miller, Ryle, "Process Energy Systems", Chemical Engineering, May 20, 1968, pp. 130-148.

APPENDIX C: OPTIMIZED COGENERATION SYSTEMS

C.1 INTRODUCTION

In this Appendix the procedures for determining the optimum cogeneration system for nine of the ten plants examined are described (the agricultural chemicals plant is covered in Volume I, Section 6.2). Discounted cash flow return on the equity portion of the incremental capital investments is calculated for the optimum system for industry and utility ownership. Discounted cash flow return on the equity portion of the total capital investment is calculated for the optimum system with the third party ownership.

The energy requirements for separate generation and cogeneration are tabulated according to fuel source and both the total energy savings and the energy savings for each fuel are determined for the optimum cogeneration system.

C.2 BACKGROUND

Assumptions used in determining the rates of return can be found in Subsection 6.1.2. This includes:

- Financial data found in Subsection 6.1.2 in hurdle rates, debt/equity ratios etc.
- Federal, state, and local tax rates, depreciation schedules and investment tax credits found in Subsection 6.1.2.3
- Energy cost data found in Subsection 6.1.2.4
- Inflation rates found in Subsection 6.1.3
- Maintenance requirements found in Subsection 6.1.4
- Standby power requirements found in Subsection 6.1.5
- Candidate energy conversion systems found in Subsection 6.1.6
- Assumption in the utility central station model found in Subsection 6.1.7
- Process steam boiler costs for separation generation (as opposed to cogeneration) found in Subsection 6.1.8
- Fuels for cogeneration found in Subsection 6.1.9

C.3 AIR SEPARATION PLANT/ CLUSTER CHEMICAL COMPLEX

The air separation plant is located in an industrial park in Texas (DOE Region VI). At this plant, as opposed to the others investigated, the owners intend to provide their own installation with sufficient power to supply in-house needs and to sell process steam to a number of petrochemical plants located within the industrial park.

The electric energy consumption of the plant is 530.4×10^6 kWh/yr which is equivalent to an average power demand of 60,500 kW. The rated power demand is 67,275 kW. The peak power demand, which results when the largest electric motor is started while all of other motors are running at rated load, is estimated to be 80,000 kW.

The potential market for process steam to satisfy incremental steam requirements due to expansion of the petrochemical plants is estimated to be 500,000 lb/hr at 200 psig. There may also be a market for an additional 500,000 per hour of "backout" steam which would replace part of the 700,000 lb/hr of process steam being produced by existing boilers. Because the primary concern of this company is to satisfy its own electrical requirements, optimization was carried out on the basis of a power match rather than a process heat match.

Three optional configurations were explored for application in this environment: the conventional coal-fired steam with back-pressure steam turbine, a gas-fired gas turbine with waste heat boiler, and a gas-fired combined cycle. In DOE Region VI, natural gas prices were below those for coal, so a gas-fired system might be expected to be competitive with coal. Indeed, the conventional coal-fired steam with BPT failed to demonstrate acceptable economics and was discarded as a viable alternative. The combined cycle, while slightly more attractive than the coal-fired system, also resulted in extremely poor (negative) ROE's. On the other hand, the gas-fired GT with WHB did prove to be economically attractive, offering positive return on equity for all ownership options. Figure C.3-1 shows the model of the energy utilization subsystem for the process steam customers as a whole. The conditions at each of the indicated state points are given in Table C.3-1.

Figure C.3-2 displays the configuration of the energy conversion subsystem model. The optimization plots for the system use the gas turbine compressor pressure ratio and base load expander inlet temperature as parameters (see Figures C.3-3a and C.3-3b for industrial and third party ownership). The optimum design parameters for this plant are compressor pressure ratios of 8 or less and expander inlet temperatures of 2100°F or greater, a combination which gives near maximum thermodynamic efficiency in recuperative open cycle gas turbines (Amos and Grube, 1976). A survey of commercially available gas turbines shows, however, that the optimum design is not practically attainable. The typical commercially available industrial gas turbine with a power output of approximately 80,000 kW has a compressor pressure ratio of 10 to 12 and a base load expander inlet temperature of 1900 to 2100°F. It should be noted that units in this capacity range which most recently have reached commercial status have compressor and expander polytropic efficiencies of approximately 91

Fig. C. 3-1 — Model of process heat utilization subsystem for air separation plant with gas-fired gas turbine with waste heat boiler energy conversion subsystem

TABLE C.3-1

STATEPOINTS FOR ENERGY UTILIZATION SUBSYSTEM IN AIR SEPARATION PLANT

STATION	PRESSURE (psia)	TEMPERATURE (°F)	ENTHALPY (Btu/lb)	FLOW RATE (lb/s)
1	215	387.9	1199.3	100.7
2	>15	250	218	75.5
3	15	100	68	25.2
4	>15	212.2	181.5	100.7
5	67.4	212.2	181.5	100.7

AIR SEPARATION PLANT:

GAS-FIRED COMBUSTION TURBINE
WITH WASTE HEAT BOILER

Fig. C.3-2 - Model of energy conversion subsystem for air separation plant

Fig. C.3-3a - Annual energy savings vs return on equity, industrial ownership

Fig. C.3-3b - Annual energy savings vs return on equity, third party ownership

and 92%, respectively (Stanford Research Institute, 1974). These are significantly higher than the composite values used in the characterization procedure (see Appendix B-5). The optimum practical gas turbine for this cogeneration application was assumed to have a compressor pressure ratio of 12 and an expander inlet temperature of 2070°F at the design point. Polytropic efficiencies of 91% for the compressor and 92% for the expander were assumed. The peak (maximum allowable for short periods) expander inlet temperature would be about 2180°F. The compressor air flow rate required to provide the peak power output of 80,000 kW with an expander inlet temperature of 2180°F is approximately 538 lb/s.

It should be noted that the ROE's in Figure C.3-3a are below the industry-wide hurdle rate of 21%. We judged that for the likely third party ownership a hurdle rate of 12% was appropriate for this plant. Note that for utility ownership, essentially all operating points yield a negative incremental cost and very high ROE's.

For the air separation plant only, an analysis of the effect of component redundancy was made. A point was computed assuming three half-sized gas turbine sets and no stand-by power charges. The results showed that such redundancy is extremely costly and is fatal to the cycle's expected ROE.

Under normal electrical load which is about 84% of the design output, the gas turbine provides exhaust gas to the waste heat boiler at 880°F, sufficient to generate 280,000 lb/hr of saturated steam at 215 psia for sale to the surrounding industries (see Table 6.1-6). Deaeration is accomplished through the use of steam generated in a low-pressure evaporator. In Table C.3-2, the state point conditions are given for the system design point. The energy distribution of the facility is summarized in Table C.3-3. The ideal energy utilization factor for this system is 0.735 and the ratio of process heat to electricity is 1.3635.

The preliminary capital costs of the system, on the basis of which the economic analysis was performed, are given in Table C.3-4. Using these costs and the financial assumptions detailed in Table C.3-5, the cash flow vectors were established and the discounted cash flow rate of return on equity was computed. Tables C.3-6a, C.3-6b, and C.3-6c give the results of the analysis. All three ownership options show positive ROE's. However, only the utility ownership and the third party ownership options provide very attractive returns.

The potential energy savings to be realized as a result of this installation are shown in Table C.3-7. Based on the assumption that the central station capacity to be replaced by cogenerating capacity would be coal-fired, we expect an increase in natural gas consumption, which is balanced by a 30% decrease in the overall quantity of fuel consumed annually.

TABLE C.3-2
STATEPOINTS FOR CONVERSION SUBSYSTEM IN
AIR SEPARATION PLANT/GT WITH WHB

Station	Pressure (psia)	Temperature (°F)	Enthalpy (Btu/lb)	Flow (lb/s)
1	14.7	77	0	537.6
2	175.1	657.7	147.4	482.2
3	167.2	450.0	95.2	55.4
4	167.2	2070.0	559.4	492.9
5	15.2	1027.6	254.5	492.9
6	15.2	975.0	238.6	548.2
7	15.0	427.9	93.4	548.2
8	14.8	377.3	80.7	548.2
9	14.7	318.7	65.9	548.2
20	67.4	212.2	181.5	91.8
21	57.4	300.4	270.1	100.8
22	57.4	300.4	270.1	44.9
23	57.4	300.4	452.1	44.9
24	57.4	300.4	1179.9	8.98
25	57.4	300.5	270.3	91.8
26	215.0	372.9	346.0	91.8
27	215.0	387.9	362.1	467.9
28	215.0	387.9	529.5	467.9
29	215.0	387.9	1199.3	91.8

TABLE C.3-3

POWER SUMMARY - AIR SEPARATION PLANT

LPC POWER=	.0000 KW
HPC POWER=	83515.7373 KW
HPT POWER=	158961.2637 KW
GT POWER=	72827.5645 KW

STEAM FRACTION =	.0000 KW
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TOTAL POWER=	72827.5654 KW
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GT AUX=	537.5673 KW
ST AUX=	.0000 KW

NET POWER=	72289.9990 KW
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NET POWER CORRECTED FOR FGD =	72289.9990
-------------------------------	------------

NET STEAM GENERATED	91.82 LB/SEC AT 215.00 PSIA AND 387.91 F
---------------------	--

TOTAL PROCESS HEAT =	3364+009 BTU/HR
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F1=	10.6524 LB/SEC
F2=	.0000 LB/SEC
F3=	.0000 LB/SEC

TOTAL FUEL=	10.6524 LB/SEC
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HEAT RATE	11611.7213 BTU/KWHR
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HEAT REJECT=	.0000 BTU/KWHR
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KW/LB=	72.2900
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GROSS PROCESS HEAT =	336419284.0000 BTU/HR
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RPHEE =	1.3635
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IEUP =	.7351
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TABLE C.3-4

AIR SEPARATION PLANT
SUMMARY OF CAPITAL COSTS: DEC. 1978\$

GAS TURBINE COST	= \$	10265421.8
GAS TURBINE BOP	= \$	3592897.6
WHB COST	= \$	5755637.4
WHB BOP	= \$	5755637.4
TOTAL DIRECT CAPITAL COST	= \$	25369594.0
INDIRECT COSTS	= \$	1633252.3
ENGINEERING	= \$	2536959.4
CONTINGENCY (20%)	= \$	5073918.8
SUBTOTAL	= \$	34613724.5
INTEREST DURING CONSTR.	= \$	4139413.1
ESCALATION DURING CONSTR.	= \$	3058276.8
TOTAL CAPITAL COST	= \$	41811413.5
SPECIFIC CAPITAL COST(\$/KWT)	=	188.892

TABLE C.3-5

RATE OF RETURN ON EQUITY SUMMARY
FOR INDUSTRIAL COGENERATION

ENERGY UTILIZATION SYSTEM CHARACTERIZATION
AIR SEPARATION PLANT

REQUIRED RATIO OF PROCESS HEAT/ELECTRICITY	=	2.4700
REQUIRED PROCESS HEAT	=	723590272.0 (KWH/YR)
REQUIRED ELECTRIC ENERGY	=	530672196.0 (KWH/YR)
SUPPLEMENTAL ELECTRIC ENERGY PURCHASED	=	.0 (KWH/YR)
ASSUMED CAPACITY FACTOR	=	.8380
ASSUMED STANDBY POWER FRACTION	=	1.0000

ENERGY CONVERSION SYSTEM CHARACTERIZATION
GAS-FIRED COMBUSTION TURBINE WITH WHB

ACTUAL RATIO OF PROCESS HEAT/ELECTRICITY	=	1.3635
IDEAL ENERGY UTILIZATION FACTOR	=	.7351
SPECIFIC CAPITAL COST OF CONVERSION SYSTEM	=	188.8921 (\$/KWT)
INCR. LABOR COST (INDUSTRY) (1ST YEAR)	=	405376.2109 (\$)
INCR. LABOR COST (UTILITY) (1ST YEAR)	=	101196.9639 (\$)
INCR. LABOR COST (3RD PARTY) (1ST YEAR)	=	405376.2109 (\$)

TABLE C.3-5 (cont'd.)

AIR SEPARATION PLANT
ECONOMIC AND FINANCIAL ASSUMPTIONS

DEBT / EQUITY RATIO (INDUSTRY)	=	.6000
DEBT / EQUITY RATIO (UTILITY)	=	1.1000
DEBT / EQUITY RATIO (3RD PARTY)	=	5.0000
LIFE OF PROJECT	=	28 (YEARS)
LIFE OF INVESTMENT FOR TAX PURPOSES	=	28 (YEARS)
INCOME TAX RATES (FEDERAL + STATE)	=	.4600 (%/100)
INTEREST RATE ON DEBT	=	.1000 (%/YR/100)
INVESTMENT TAX CREDIT RATE	=	.0000 (%/100)
ITCR UNDER SEPARATE GENERATION (INDUSTRY)	=	.0000 (%/100)
ITCR UNDER SEPARATE GENERATION (UTILITY)	=	.1000 (%/100)
PROPERTY TAX RATE (1ST YEAR)	=	.0150 (%/100)
INSURANCE RATE (1ST YEAR)	=	.0150 (%/100)
CHARGE FOR STANDBY POWER	=	67.1203 (\$/KW)
MAINTENANCE & SUPPLIES COST FACTOR (1ST YR)	=	.0375 (%/100)
BOILER HEAT RATE (SEPARATE GENERATION)	=	3750.0000 (BTU/KWH)
CENTRAL STATION BUS BAR HEAT RATE	=	9500.0000 (BTU/KWH)
TRANSMISSION LOSSES OF PURCHASED POWER	=	.1000 (%/100)
SPECIFIC CAPITAL COST OF NEW UTILITY STATION	=	1000.0000 (\$/KW)
PRICE OF PROCESS STEAM (1ST YR)	=	3.1649 (\$/10 ⁶ BTU)
PRICE OF POWER AT CENTRAL STATION BUS BAR	=	.0164 (\$/KWH)
PRICE OF POWER BOUGHT FROM UTILITY (1ST YR)	=	.0273 (\$/KWH)
PRICE OF POWER SOLD TO UTILITY (1ST YR)	=	.0164 (\$/KWH)
PRICE OF FUEL (COGENERATION)	=	2.3226 (\$/10 ⁶ BTU)
PRICE OF FUEL, (SEP.GEN.: INDUSTRY)	=	2.3226 (\$/10 ⁶ BTU)
PRICE OF FUEL (SEP.GEN.: UTILITY)	=	2.3353 (\$/10 ⁶ BTU)
GENERAL INFLATION RATE	=	.0750 (%/100/YR)
FUEL PRICE RELATIVE ESC.(COGENERATION FUEL)	=	.0444 (%/100/YR)
FUEL PRICE REL. ESC.(SEP.GEN.: INDUSTRY)	=	.0444 (%/100/YR)
FUEL PRICE REL. ESC.(SEP.GEN.: UTILITY)	=	-.0100 (%/100/YR)
RELATIVE ESC. OF ELECTRICAL ENERGY COSTS	=	.0603 (%/100/YR)
RELATIVE ESC. OF PROCESS STEAM COSTS	=	.0222 (%/100/YR)

TABLE C.3-6a

AIR SEPARATION PLANT
FOR INDUSTRIAL OWNERSHIP

CAPITAL INVESTMENT = 41811412 (\$)
NET EQUITY CAPITAL INVESTMENT = 26132132 (\$)

YEAR	STEAM REVENUE	NET SAVINGS IN ELECT.	DELTA FUEL COSTS	DELTA O AND M	DELTA PROP. TAX & INSUR.	TAXES
1	7820745.	9623382.	13532613.	1973304.	1254342.	-1733099.
2	8593943.	10968947.	15193470.	2121302.	1348418.	-1586443.
3	9443583.	12502652.	17058164.	2280400.	1449549.	-1420197.
4	10377222.	14250804.	19151712.	2451429.	1558266.	-1230915.
5	11403166.	16243387.	21502201.	2635287.	1675135.	-1014580.
6	12530540.	18514578.	24141166.	2832933.	1800771.	-766501.
7	13769371.	21103332.	27104011.	3045403.	1935828.	-481211.
8	15130680.	24054052.	30430485.	3273808.	2081015.	-152336.
9	16626574.	27417349.	34165218.	3519344.	2237092.	227546.
10	18270360.	31250911.	38358314.	3783295.	2404873.	667077.
11	20076659.	35620491.	43066030.	4067042.	2585239.	1176313.
12	22061537.	40601035.	48351522.	4372070.	2779132.	1766950.
13	24242650.	46277973.	54285704.	4699975.	2987567.	2452587.
14	26639399.	52748675.	60948187.	5052473.	3211634.	3249024.
15	29273103.	60124125.	68428357.	5431408.	3452507.	4174618.
16	32167187.	68530829.	76826568.	5838764.	3711445.	5250680.
17	35347396.	78112980.	86255491.	6276671.	3989803.	6501952.
18	38842015.	89034930.	96841624.	6747421.	4289038.	7957132.
19	42682130.	101484014.	108726997.	7253478.	4610716.	9649507.
20	46901897.	115673762.	122071058.	7797489.	4956519.	11617673.
21	51538853.	131847554.	137052836.	8382300.	5328258.	13906359.
22	56634240.	150282804.	153873328.	9010973.	5727878.	16567384.
23	62233382.	171295720.	172758198.	9686796.	6157468.	19660772.
24	68386084.	195246712.	193960806.	10413305.	6619279.	23256018.
25	75147073.	222546594.	217765614.	11194303.	7115724.	27433555.
26	82576487.	253663610.	244491986.	12033876.	7649404.	32286460.
27	90740409.	289131484.	274498476.	12936416.	8223109.	37922399.
28	99711458.	329558560.	308187668.	13906647.	8839842.	44465877.

YEAR	BASIC CASH FLOW	DISCOUNTED ADJUSTED CASH FLOW
1	849038	745424
2	918215	707778
3	1010390	683782
4	1129606	671169
5	1280581	668018
6	1468821	672708
7	1700743	683869
8	1983830	700349
9	2326795	721182
10	2739782	745553
11	3234597	772786
12	3824970	802312
13	4526863	833660
14	5358828	866438
15	6342410	900323
16	7502631	935048
17	8868531	970395
18	10473802	1006184
19	12357519	1042271
20	14564991	1078539
21	17148725	1114894
22	20169554	1151262
23	23697939	1187585
24	27815461	1223818
25	32616542	1259925
26	38210447	1295881
27	44723565	1331668
28	52302055	1367270

DISCOUNTED CASH FLOW RATE OF RETURN ON EQUITY(ROE)= 13.90 %

ANNUAL ENERGY SAVED UNDER COGENERATION = 2488484.3125 MBTU/YR

TABLE C.3-6b

AIR SEPARATION PLANT
FOR UTILITY OWNERSHIP

INCREMENTAL CAPITAL INVESTMENT = -38510806 (\$)
NET INCREMENTAL EQUITY CAPITAL INVESTMENT = -14513611 (\$)

YEAR	STEAM REVENUE	DELTA ELECT. REVENUE	DELTA FUEL COSTS	DELTA O AND M	DELTA PROP. TAX & INSUR.	TAXES
1	7820745.	5791627.	451289.	-1342958.	-1155324.	9352957.
2	8593943.	6601427.	1271671.	-1443680.	-1241973.	9746318.
3	9443583.	7524455.	2241890.	-1551956.	-1335121.	10164466.
4	10377222.	8576543.	3383492.	-1668353.	-1435256.	10608735.
5	11403166.	9775736.	4720873.	-1793479.	-1542900.	11080545.
6	12530540.	11142604.	6281638.	-1927990.	-1658617.	11581416.
7	13769371.	12700590.	8097008.	-2072589.	-1783013.	12112987.
8	15130680.	14476418.	10202283.	-2228034.	-1916739.	12677029.
9	16626574.	16500547.	12637353.	-2395136.	-2060495.	13275469.
10	18270360.	18807694.	15447284.	-2574771.	-2215032.	13910416.
11	20076659.	21437433.	18682967.	-2767879.	-2381159.	14584195.
12	22061537.	24434868.	22401847.	-2975470.	-2559746.	15299382.
13	24242650.	27851412.	26668762.	-3198630.	-2751727.	16058856.
14	26639399.	31745665.	31556858.	-3438527.	-2958107.	16865847.
15	29273103.	36184423.	37148633.	-3696417.	-3179965.	17724014.
16	32167187.	41243818.	43537123.	-3973648.	-3418462.	18637511.
17	35347396.	47010632.	50827199.	-4271672.	-3674847.	19611101.
18	38842015.	53583774.	59137064.	-4592047.	-3950460.	20650256.
19	42682130.	61075991.	68599919.	-4936450.	-4246744.	21761298.
20	46901897.	69615788.	79365817.	-5306684.	-4565250.	22951572.
21	51538853.	79349640.	91603782.	-5704685.	-4907644.	24229629.
22	56634240.	90444503.	105504172.	-6132537.	-5275717.	25605456.
23	62233382.	103090678.	121281326.	-6592477.	-5671396.	27090763.
24	68386084.	117505072.	139176544.	-7086913.	-6096750.	28699298.
25	75147073.	133934923.	159461462.	-7618431.	-6554007.	30447225.
26	82576487.	152662036.	182441792.	-8189813.	-7045557.	32353592.
27	90740409.	174007618.	208461564.	-8804049.	-7573974.	34440855.
28	99711458.	198337796.	237907880.	-9464353.	-8142022.	36735522.

YEAR	BASIC CASH FLOW	DISCOUNTED ADJUSTED CASH FLOW
1	7168317	651665
2	7638293	63126
3	8130869	6109
4	8647122	591
5	9188195	57
6	9755312	6
7	10349788	1
8	10973052	0
9	11626667	0
10	12312357	0
11	13032041	0
12	13787877	0
13	14582306	0
14	15418119	0
15	16298528	0
16	17227252	0
17	18208631	0
18	19247749	0
19	20350586	0
20	21524212	0
21	22777000	0
22	24118883	0
23	25561680	0
24	27119459	0
25	28808972	0
26	30650184	0
27	32666888	0
28	34887434	0

DISCOUNTED CASH FLOW RATE OF RETURN ON EQUITY(ROE)= 1000.00 %

ANNUAL ENERGY SAVED UNDER COGENERATION = 2488484.3125 MBTU/YR

TABLE C.3-6c

AIR SEPARATION PLANT
FOR THIRD PARTY OWNERSHIP

CAPITAL INVESTMENT = 41811412 (\$)
NET EQUITY CAPITAL INVESTMENT = 6968568 (\$)

YEAR	STEAM REVENUE	ELECT. REVENUE	FUEL COSTS	O AND M	PROP. TAX & INSUR.	TAXES
1	7820745.	9623382.	13532613.	1973304.	1254342.	-2614622.
2	8593943.	10968947.	15193470.	2121302.	1348418.	-2467967.
3	9443583.	12502652.	17058164.	2280400.	1449549.	-2301721.
4	10377222.	14250804.	19151712.	2451429.	1558266.	-2112439.
5	11403166.	16243387.	21502201.	2635287.	1675135.	-1896104.
6	12530540.	18514578.	24141166.	2832933.	1800771.	-1648025.
7	13769371.	21103332.	27104011.	3045403.	1935828.	-1362734.
8	15130680.	24054052.	30430485.	3273808.	2081015.	-1033860.
9	16626574.	27417349.	34165218.	3519344.	2237092.	-653977.
10	18270360.	31250911.	38358314.	3783295.	2404873.	-214447.
11	20076659.	35620491.	43066030.	4067042.	2585239.	294790.
12	22061537.	40601035.	48351522.	4372070.	2779132.	885426.
13	24242650.	46277973.	54285704.	4699975.	2987567.	1571063.
14	26639399.	52748675.	60948187.	5052473.	3211634.	2367500.
15	29273103.	60124125.	68428357.	5431408.	3452507.	3293094.
16	32167187.	68530829.	76826568.	5838764.	3711445.	4369156.
17	35347396.	78112980.	86255491.	6276671.	3989803.	5620428.
18	38842015.	89034930.	96841624.	6747421.	4289038.	7075608.
19	42682130.	101484014.	108726997.	7253478.	4610716.	8767983.
20	46901897.	115673762.	122071058.	7797489.	4956519.	10736149.
21	51538853.	131847554.	137052836.	8382300.	5328258.	13024835.
22	56634240.	150282804.	153873328.	9010973.	5727878.	15685860.
23	62233382.	171295720.	172758198.	9686796.	6157468.	18779248.
24	68386084.	195246712.	193960806.	10413305.	6619279.	22374494.
25	75147073.	222546594.	217765614.	11194303.	7115724.	26552031.
26	82576487.	253663610.	244491986.	12033876.	7649404.	31404935.
27	90740409.	289131484.	274498476.	12936416.	8223109.	37040874.
28	99711458.	329558560.	308187668.	13906647.	8839842.	43584352.

YEAR	BASIC CASH FLOW	DISCOUNTED ADJUSTED CASH FLOW
1	-185793	-154776
2	-116617	-80930
3	-24441	-14130
4	94774	45644
5	245749	98597
6	433988	145051
7	665911	185410
8	948997	220119
9	1291962	249641
10	1704950	274443
11	2199765	294979
12	2790137	311683
13	3492031	324968
14	4323995	335213
15	5307578	342773
16	6467798	347969
17	7833699	351095
18	9438969	352417
19	11322687	352173
20	13530159	350577
21	16113893	347820
22	19134721	344073
23	22663107	339486
24	26780628	334193
25	31581710	328311
26	37175615	321946
27	43688734	315187
28	51267224	308114

DISCOUNTED CASH FLOW RATE OF RETURN ON EQUITY(ROE)= 20.04 %

ANNUAL ENERGY SAVED UNDER COGENERATION = 2488484.3125 MBTU/YR

TABLE C.3-7

FUEL UTILIZATION, AIR SEPARATION PLANT

	Separate Generation (MBtu/yr)	Cogeneration (MBtu/yr)	Savings (MBtu/yr)
Gas	2713464	5826899	-3113435
Oil	-	-	-
Coal	5601919	-	5601919
Overall	8315383	5826899	2488484

Percent Energy Savings = 29.9%

Note: M designates one million

When power requirements are matched for the gas turbine with waste heat boiler, the amount of process steam generated is significantly less than the 500,000 lb/hr potential market for process steam at premium prices. A gas turbine compressor air flow rate of 953 lb/hr would be required to match the 500,000 lb/hr process steam market under normal operating conditions. The amount of electric power generated would be proportionally larger and 47,500 kW of power would be available for sale to the local utility. A financial analysis of this option was not made.

C.4 BREWERY

The brewery is located in Pennsylvania (DOE Region III) and requires a relatively small amount of energy compared with other industries. The energy requirements of the plant include the use of saturated steam and the use of electricity. The energy use pattern is complicated by short periods of large steam demands during three-hour brewing cycles. Any cogeneration facility chosen should be able to provide some form of energy storage in order to satisfy these peak demands. The overall required ratio of process heat to electricity is 4.42. The annual energy requirements of the brewery are as follows:

- Process heat (sat'd steam) 172.1 million kWh/yr
- Electricity 38.93 million kWh/yr

The candidate energy conversion subsystems considered for application to the brewery were a conventional coal-fired steam plant and an oil-fired combined cycle. Both options contained steam accumulators to provide peaking capacity. The combined cycle option proved to be economically unfeasible and was dismissed from the optimization process. A detailed look at the conventional coal-fired boiler/BPT did, on the other hand, provide a near-acceptable return on equity for all ownership options.

Figure C.4-1 contains the energy utilization subsystem model for the brewery. The appropriate state points are given in Table C.4-1. In Figure C.4-2, the energy conversion subsystem configuration is shown for the coal/steam model chosen for optimization. The steam accumulator subsystem appears in a more detailed manner in Figure C.4-3. The boiler is designed to generate the 'base-load' steam demand as well as a small quantity of steam which is stored as hot water during the periods between peak steam demands.

The highest throttle pressure practical in the capacity range under consideration for the brewery is 915 psia. The optimization procedure revealed that, at that pressure, good return on equity may be expected for a utility owner, while a marginal ROE is predicted for the industrial and a negative ROE is predicted for the third-party owners. Figures C.4-4a and C.4-4b show the trend of energy saved vs. ROE for the industry and utility ownership options. The highest pressure was taken to be the limiting factor in the optimization, assuming that ownership would be arranged to guarantee the maximum possible energy savings. Table C.4-2 contains the state point data corresponding to the indicated points in Figure C.4-3.

The steam generator is a stoker-fired boiler using Ohio Pittsburgh No. 8 seam coal with the composition and physical properties shown in Table C.4-3. The steam generated is expanded to 135 psia through the back pressure turbine and, after extraction streams are taken off to supply energy for flue gas reheat and for deaeration of the recycled condensate, is piped to the process. A small fraction of the high pressure steam is used to store energy in the hot water contained in the high pressure accumulator. The gross power rating of the BPT is 3.4 MWe. In Table C.4-4, the energy distribution of the cogeneration facility is summarized. The ideal energy utilization factor (IEUF) is 0.8723 and the generated ratio of process heat to electricity is 13.0. The preliminary capital costs are listed in Table C.4-5.

Fig. C. 4-1 — Flowsheet of process heat utilization subsystem for brewery with conventional coal-fired steam energy conversion subsystem

TABLE C.4-1

STATEPOINTS FOR ENERGY UTILIZATION SUBSYSTEM IN BREWERY

Station	Pressure (psia)	Temperature (°F)	Enthalpy (Btu/lb)	Flow Rate (lb/s)
1	135	551.5	1302.5	23.07
2	>15	225	193	16.15
3	15	100	68	6.92
4	>15	187.5	155.6	23.07
5	39.8	187.5	155.6	23.07

Fig. C.4-2 - Model of energy conversion subsystem chosen for optimization for brewery

Brewery

Fig. C.4-3 - Model of steam accumulator subsystem for brewery

Fig. C.4-4a - Annual energy savings vs return on equity, industrial ownership

Fig. C.4-4b - Annual energy savings vs return on equity, utility ownership

TABLE C.4-2

STATEPOINTS FOR ENERGY CONVERSION SUBSYSTEM IN BREWERY

Station	Pressure (psia)	Temperature (°F)	Enthalpy (Btu/lb)	Flow (lb/s)
1	14.7	77.0	0.0	36.51
2	16.0	85.0	2.0	36.51
3	16.0	85.0	2.0	36.51
4	15.8	2898.7	824.9	39.34
5	15.6	1800.0	477.7	39.34
6	15.3	1287.3	324.8	39.34
7	15.0	1002.5	243.4	39.34
8	14.7	302.7	56.8	39.34
9	14.7	302.7	56.8	39.34
20	39.8	187.5	155.6	23.07
21	29.8	250.0	218.6	24.85
22	1040.0	252.7	223.4	24.85
23	1015.0	525.3	518.3	24.85
24	965.0	540.3	537.1	24.31
25	965.0	540.3	668.8	24.31
26	965.0	540.3	537.1	103.71
27	965.0	540.3	668.8	103.71
28	965.0	540.3	1195.6	24.85
29	915.0	875.9	1437.1	24.85
30	915.0	875.9	1437.1	24.58
31	135.0	551.5	1302.5	24.58
32	135.0	551.5	1302.5	0.42
33	135.0	551.5	1302.5	24.16
34	135.0	551.5	1302.5	1.36
35	135.0	551.5	1302.5	22.80
36	915.0	875.9	1437.1	0.27

TABLE C.4-3
FUEL SPECIFICATIONS
OHIO PITTSBURGH NO. 8 SEAM COAL

(Source of data: USBM, Pittsburgh, PA)

SAMPLE: Run of mine		As received ⁽¹⁾	As fired ⁽²⁾
PROXIMATE ANALYSIS (wt %):	Volatile matter	42.8	46.8
	Fixed carbon	48.7	45.3
	Ash	8.5	7.9
		<u>100.0</u>	<u>100.0</u>
ULTIMATE ANALYSIS (wt %): (includes moisture)	C	71.2	66.3
	H	5.4	5.8
	O	9.3	14.6
	N	1.3	1.2
	S(3)	4.3	4.0
	Ash	8.5	7.9
		<u>100.0</u>	<u>100.0</u>
GROSS HEATING VALUE:	(Btu/lb)	13000	12099
NET HEATING VALUE:	(Btu/lb)	12500	11634
ASH ANALYSIS (wt %):	SiO ₂	45.3	
	Al ₂ O ₃	21.2	
	Fe ₂ O ₃	27.3	
	TiO ₂	1.0	
	P ₂ O ₅	0.11	
	CaO	1.9	
	MgO	0.6	
	Na ₂ O	0.2	
	K ₂ O	1.8	
	SO ₃	0.7	
		<u>100.1</u>	
	FUSIBILITY OF ASH:	Initial deformation temperature	--
Softening temperature		--	2230°F
Fluid temperature		--	2420°F
PARTICLE DENSITY:	Coal	--	~1.4 gm/cc
	Ash	--	~2.8 gm/cc
GRINDABILITY (Hardgrove):	50-60		
FREE SWELLING INDEX:	5-5.5		
(1) 3.3% moisture			
(2) 10% moisture assumed			
(3) ~60% organic & 40 pyritic			

TABLE C.4-4

POWER SUMMARY - BREWERY

HP STEAM PWR=	2099.0032 KW
LP STEAM PWR=	1287.2206 KW
ST POWER=	3386.2238 KW
GROSS POWER	= 3386.2238 KW
FGD AUXILIARIES	= 694.1351 KW
AUXILIARY POWER	= 260.6983 KW
BOILER FEED PUMP POWER	= 119.0533 KW
NET POWER GENERATED	= 2312.3371 KW

TOTAL FUEL= 2.8326 LB/SEC
THERMAL RATING = 118635087.0000 BTU/HR

HEAT RATE 51305.2725 BTU/KWHR
TOTAL PROCESS HEAT = .9523+008 BTU/HR
PROCESS HEAT AT 135.0 PSIA = .9523209+008 BTU/HR

RPHEE = 13.0323 KWT/KWE

IEUF = .8723

TABLE C.4-5

BREWERY
SUMMARY OF CAPITAL COSTS: DEC. 1978\$

STEAM GENERATOR COST (INSTALLED)	= \$ 2950791.4
STEAM GENERATOR O&M COSTS	= \$ 3688489.3
TURBINE GENERATOR COSTS (INSTALLED)	= \$ 1284854.6
TURB-GEN BOP COSTS	= \$ 1284854.6
FLUE GAS DESULF COSTS (INST+BOP)	= \$ 1328557.4
ENERGY STORAGE SUBSYSTEM COST	= \$ 200000.0
TOTAL DIRECT COSTS	= \$10737547.1
INDIRECT COSTS	= \$ 1610643.1
ENGINEERING	= \$ 1073743.7
CONTINGENCY (20%)	= \$ 2147509.4
SUBTOTAL	= \$15569443.3
INTEREST DURING CONSTRUCTION (36 mo.)	= \$ 2576742.9
ESCALATION DURING CONSTR.	= \$ 1886163.7
TOTAL CAPITAL COST	= \$20032349.9
SPECIFIC CAPITAL COST (\$/kWt)	= 569.785

The results of the cash flow analysis are based on financial and economic assumptions given in Table C.4-6. The cash flow vectors themselves are presented in Tables C.4-7a, C.4-7b, and C.4-7c for the three ownership options.

The potential energy savings to be realized as a result of this cogeneration installation as compared to the conventional energy system are broken down in Table C.4-8. The current fuel, No. 6 fuel oil, is replaced completely by coal and an overall savings in fuel is made possible.

TABLE C.4-6

RATE OF RETURN ON EQUITY SUMMARY
FOR INDUSTRIAL COGENERATION

ENERGY UTILIZATION SYSTEM CHARACTERIZATION
BREWERY

REQUIRED RATIO OF PROCESS HEAT/ELECTRICITY	=	4.4700
REQUIRED PROCESS HEAT	=	172077380.0 (KWH/YR)
REQUIRED ELECTRIC ENERGY	=	38496057.5 (KWH/YR)
SUPPLEMENTAL ELECTRIC ENERGY PURCHASED	=	25292143.0 (KWH/YR)
ASSUMED CAPACITY FACTOR	=	.7040
ASSUMED STANDBY POWER FRACTION	=	1.0000

ENERGY CONVERSION SYSTEM CHARACTERIZATION
COAL-FIRED STEAM WITH BPT / ACCUMULATOR

ACTUAL RATIO OF PROCESS HEAT/ELECTRICITY	=	13.0323
IDEAL ENERGY UTILIZATION FACTOR	=	.8723
SPECIFIC CAPITAL COST OF CONVERSION SYSTEM	=	569.7850 (\$/KWT)
INCR. LABOR COST (INDUSTRY) (1ST YEAR)	=	165846.6250 (\$)
INCR. LABOR COST (UTILITY) (1ST YEAR)	=	330450.9531 (\$)
INCR. LABOR COST (3RD PARTY) (1ST YEAR)	=	330450.9531 (\$)

TABLE C.4-6 (cont'd.)

BREWERY

ECONOMIC AND FINANCIAL ASSUMPTIONS

DEBT / EQUITY RATIO (INDUSTRY)	=	.3000
DEBT / EQUITY RATIO (UTILITY)	=	.9000
DEBT / EQUITY RATIO (3RD PARTY)	=	5.0000
LIFE OF PROJECT	=	28 (YEARS)
LIFE OF INVESTMENT FOR TAX PURPOSES	=	28 (YEARS)
INCOME TAX RATES (FEDERAL + STATE)	=	.5650 (%/100)
INTEREST RATE ON DEBT	=	.1000 (%/YR/100)
INVESTMENT TAX CREDIT RATE	=	.2000 (%/100)
ITCR UNDER SEPARATE GENERATION (INDUSTRIAL)	=	.0000 (%/100)
ITCR UNDER SEPARATE GENERATION (UTILITY)	=	.1000 (%/100)
PROPERTY TAX RATE (1ST YEAR)	=	.0150 (%/100)
INSURANCE RATE (1ST YEAR)	=	.0150 (%/100)
CHARGE FOR STANDBY POWER	=	66.1108 (\$/KW)
MAINTENANCE & SUPPLIES COST FACTOR (1ST YR)	=	.0375 (%/100)
BOILER HEAT RATE (SEPARATE GENERATION)	=	3750.0000 (BTU/KWH)
CENTRAL STATION BUS BAR HEAT RATE	=	9500.0000 (BTU/KWH)
TRANSMISSION LOSSES OF PURCHASED POWER	=	.1000 (%/100)
SPECIFIC CAPITAL COST OF NEW UTILITY STATION	=	1000.0000 (\$/KW)
PRICE OF PROCESS STEAM (1ST YR)	=	4.0725 (\$/10 ⁶ BTU)
PRICE OF POWER AT CENTRAL STATION BUS BAR	=	.0194 (\$/KWH)
PRICE OF POWER BOUGHT FROM UTILITY (1ST YR)	=	.0324 (\$/KWH)
PRICE OF POWER SOLD TO UTILITY (1ST YR)	=	.0194 (\$/KWH)
PRICE OF FUEL (COGENERATION)	=	1.5653 (\$/10 ⁶ BTU)
PRICE OF FUEL, (SEP.GEN.: INDUSTRY)	=	2.8090 (\$/10 ⁶ BTU)
PRICE OF FUEL (SEP.GEN.: UTILITY)	=	1.5653 (\$/10 ⁶ BTU)
GENERAL INFLATION RATE	=	.0750 (%/100/YR)
FUEL PRICE RELATIVE ESC.(COGENERATION FUEL)	=	.0560 (%/100/YR)
FUEL PRICE REL. ESC.(SEP.GEN.: INDUSTRY)	=	.0770 (%/100/YR)
FUEL PRICE REL. ESC.(SEP.GEN.: UTILITY)	=	.0560 (%/100/YR)
RELATIVE ESC. OF ELECTRICAL ENERGY COSTS	=	.0210 (%/100/YR)
RELATIVE ESC. OF PROCESS STEAM COSTS	=	.0300 (%/100/YR)

TABLE C.4-7a

BREWERY
FOR INDUSTRIAL OWNERSHIP

INCREMENTAL CAPITAL INVESTMENT = 19805594 (\$)
NET INCREMENTAL EQUITY CAPITAL INVESTMENT = 12188058 (\$)

YEAR	NET SAVINGS IN ELECT	DELTA FUEL COSTS	DELTA O AND M	DELTA PROP. TAX & INSUR	INCOME TAXES ON SAVINGS
1	286185.	-677195.	908556.	594168.	-1334699.
2	314110.	-809672.	976698.	638730.	-1280188.
3	344759.	-966515.	1049950.	686635.	-1215147.
4	378399.	-1152039.	1128697.	738133.	-1137345.
5	415321.	-1371299.	1213349.	793493.	-1044147.
6	455846.	-1630223.	1304350.	853005.	-932436.
7	500325.	-1935754.	1402176.	916980.	-798536.
8	549145.	-2296023.	1507340.	985754.	-638114.
9	602727.	-2720550.	1620390.	1059685.	-446065.
10	661539.	-3220475.	1741919.	1139161.	-216385.
11	726088.	-3808834.	1872563.	1224598.	57985.
12	796936.	-4500871.	2013005.	1316443.	385334.
13	874697.	-5314410.	2163981.	1415177.	775396.
14	960046.	-6270287.	2326279.	1521315.	1239583.
15	1053722.	-7392849.	2500750.	1635413.	1791278.
16	1156539.	-8710542.	2688306.	1758069.	2446158.
17	1269389.	-10256587.	2889929.	1889925.	3222580.
18	1393249.	-12069778.	3106674.	2031669.	4142030.
19	1529195.	-14195405.	3339675.	2184044.	5229644.
20	1678407.	-16686324.	3590150.	2347847.	6514812.
21	1842177.	-19604215.	3859411.	2523936.	8031890.
22	2021928.	-23021037.	4148867.	2713231.	9821021.
23	2219217.	-27020721.	4460032.	2916723.	11929092.
24	2435757.	-31701146.	4794535.	3135477.	14410849.
25	2673426.	-37176435.	5154125.	3370638.	17330198.
26	2934286.	-43579624.	5540684.	3623436.	20761711.
27	3220599.	-51065769.	5956235.	3895194.	24792382.
28	3534848.	-59815565.	6402953.	4187333.	29523675.

YEAR	BASIC CASH FLOW	DISCOUNTED ADJUSTED CASH FLOW
1	338302	301571
2	331489	263414
3	332783	235730
4	343901	217156
5	366873	206509
6	404098	202766
7	458407	205042
8	533136	212576
9	632214	224711
10	760265	240885
11	922723	260616
12	1125971	283493
13	1377501	309166
14	1686103	337340
15	2062077	367767
16	2517494	400241
17	3066488	434589
18	3725601	470672
19	4514185	508377
20	5454869	547615
21	6574103	588318
22	7902793	630436
23	9477038	673934
24	11338989	718793
25	13537848	765004
26	16131026	812570
27	19185505	861502
28	22779400	911822

DISCOUNTED CASH FLOW RATE OF RETURN ON EQUITY(ROE)= 12.18 %
ANNUAL ENERGY SAVED UNDER COGENERATION = 85997.4141 MBTU/YR

TABLE C.4-7b

BREWERYFOR UTILITY OWNERSHIP

INCREMENTAL CAPITAL INVESTMENT = 16970968 (\$)
 NET INCREMENTAL EQUITY CAPITAL INVESTMENT = 8038879 (\$)

YEAR	STEAM REVENUE	DELTA ELECT. REVENUE	DELTA FUEL COSTS	DELTA O AND M	DELTA PROP. TAX & INSUR.	TAXES
1	2393166.	498821.	917257.	966862.	509129.	-833692.
2	2649833.	547494.	1041270.	1039377.	547314.	-770171.
3	2934027.	600915.	1182050.	1117330.	588362.	-702577.
4	3248701.	659550.	1341863.	1201130.	632489.	-630613.
5	3597125.	723905.	1523283.	1291215.	679926.	-553978.
6	3982916.	794540.	1729231.	1388056.	730921.	-472367.
7	4410084.	872068.	1963023.	1492160.	785740.	-385481.
8	4883065.	957160.	2228423.	1604072.	844670.	-293030.
9	5406774.	1050554.	2529706.	1724377.	908020.	-194740.
10	5986650.	1153062.	2871723.	1853706.	976122.	-90362.
11	6628718.	1265572.	3259979.	1992733.	1049331.	20312.
12	7339648.	1389060.	3700729.	2142188.	1128031.	137445.
13	8126825.	1524598.	4201067.	2302852.	1212633.	261129.
14	8998427.	1673361.	4769051.	2475566.	1303580.	391373.
15	9963508.	1836639.	5413827.	2661234.	1401349.	528073.
16	11032094.	2015849.	6145776.	2860826.	1506450.	670992.
17	12215285.	2212545.	6976685.	3075388.	1619434.	819719.
18	13525374.	2428434.	7919933.	3306042.	1740891.	973636.
19	14975970.	2665389.	8990707.	3553996.	1871458.	1131868.
20	16582143.	2925464.	10206251.	3820545.	2011818.	1293229.
21	18360577.	3210916.	11586136.	4107086.	2162704.	1456161.
22	20329748.	3524221.	13152581.	4415117.	2324907.	1618654.
23	22510113.	3868097.	14930809.	4746251.	2499275.	1778159.
24	24924322.	4245526.	16949455.	5102220.	2686720.	1931488.
25	27597456.	4659783.	19241021.	5484886.	2888224.	2074690.
26	30557282.	5114462.	21842406.	5896253.	3104841.	2202910.
27	33834549.	5613505.	24795499.	6338472.	3337704.	2310223.
28	37463303.	6161243.	28147850.	6813857.	3588032.	2389453.

YEAR	BASIC CASH FLOW	DISCOUNTED ADJUSTED CASH FLOW
1	1037671	877969
2	1082961	775267
3	1134251	687016
4	1191983	610868
5	1256622	544880
6	1328649	487445
7	1408562	437231
8	1496871	393132
9	1594096	354232
10	1700758	319768
11	1817377	289106
12	1944458	261716
13	2082486	237155
14	2231909	215053
15	2393124	195099
16	2566460	177028
17	2752150	160620
18	2950309	145685
19	3160900	132062
20	3383693	119612
21	3618222	108218
22	3863729	97776
23	4119102	88195
24	4382797	79399
25	4652753	71317
26	4926287	63888
27	5199972	57059
28	5469499	50779

DISCOUNTED CASH FLOW RATE OF RETURN ON EQUITY(ROE)= 18.19 %

ANNUAL ENERGY SAVED UNDER COGENERATION = 85997.4141 MBTU/YR

TABLE C.4-7c

BREWERYFOR THIRD PARTY OWNERSHIP

CAPITAL INVESTMENT = 19805594 (\$)
 NET EQUITY CAPITAL INVESTMENT = 2640745 (\$)

YEAR	STEAM REVENUE	DELTA ELECT. REVENUE	DELTA FUEL COSTS	DELTA O AND M	DELTA PROP. TAX & INSUR.	TAXES
1	2393166.	286185.	1135422.	1073161.	594168.	-1773969.
2	2649833.	314110.	1288931.	1153648.	638730.	-1742999.
3	2934027.	344759.	1463194.	1240171.	686635.	-1711961.
4	3248701.	378399.	1661018.	1333184.	738133.	-1681020.
5	3597125.	415321.	1885588.	1433173.	793493.	-1650392.
6	3982916.	455846.	2140519.	1540661.	853005.	-1620352.
7	4410084.	500325.	2429918.	1656210.	916980.	-1591252.
8	4883065.	549145.	2758442.	1780426.	985754.	-1563528.
9	5406774.	602727.	3131384.	1913958.	1059685.	-1537725.
10	5986650.	661539.	3554747.	2057505.	1139161.	-1514513.
11	6628718.	726088.	4035348.	2211818.	1224598.	-1494710.
12	7339648.	796936.	4580927.	2377704.	1316443.	-1479314.
13	8126825.	874697.	5200269.	2556032.	1415177.	-1469530.
14	8998427.	960046.	5903345.	2747734.	1521315.	-1466809.
15	9963508.	1053722.	6701477.	2953814.	1635413.	-1472894.
16	11032094.	1156539.	7607517.	3175350.	1758069.	-1489871.
17	12215285.	1269389.	8636053.	3413502.	1889925.	-1520222.
18	13525374.	1393249.	9803647.	3669514.	2031669.	-1566902.
19	14975970.	1529195.	11129100.	3944728.	2184044.	-1633412.
20	16582143.	1678407.	12633754.	4240582.	2347847.	-1723894.
21	18360577.	1842177.	14341837.	4558626.	2523936.	-1843238.
22	20329748.	2021928.	16280853.	4900523.	2713231.	-1997203.
23	22510113.	2219217.	18482024.	5268062.	2916723.	-2192561.
24	24924332.	2435757.	20980793.	5663167.	3135477.	-2437261.
25	27597456.	2673426.	23817396.	6087904.	3370638.	-2740618.
26	30557282.	2934286.	27037508.	6544497.	3623436.	-3113538.
27	33834549.	3220599.	30692979.	7035334.	3895194.	-3568760.
28	37463303.	3534848.	34842669.	7562984.	4187333.	-4121157.

YEAR	BASIC CASH FLOW
1	103
2	-24834
3	-49719
4	-74680
5	-99881
6	-125536
7	-151913
8	-179350
9	-208267
10	-239177
11	-272714
12	-309642
13	-350891
14	-397579
15	-451046
16	-512899
17	-585049
18	-669771
19	-769760
20	-888205
21	-1028872
22	-1196194
23	-1395384
24	-1632563
25	-1914904
26	-2250801
27	-2650064
28	-3124143

DISCOUNTED CASH FLOW RATE OF RETURN ON EQUITY (ROE) = 10 %
 ANNUAL ENERGY SAVED UNDER COGENERATION = 85997.4141 MBTU/YR

TABLE C.4-8
FUEL UTILIZATION
BREWERY

	Separate Generation	Cogeneration	Savings
Natural Gas	-	-	-
No. 6 Oil	645290	-	645290
Coal	166072	725365	-559293
Overall	811362	725365	85997

Percent Energy Savings = 10.6%

C.5 SOYBEAN OIL PLANT

The soybean oil plant, located in Indiana (Region V), is the smallest of the industrial installations to be examined in this study. The energy requirements of the plant are in the form of process heat (saturated steam at 150 psig), electricity, and direct heating supplied to dryers. The following table summarizes the annual energy requirements:

- Process heat (saturated steam) 128.2×10^6 kWh/yr
- Direct process heat 18.5×10^6 kWh/yr
- Electricity 14.22×10^6 kWh/yr

The candidate energy conversion subsystems considered for the soybean oil plant were:

- Coal-fired steam with back pressure turbine (indirect heating of drying air) and flue gas desulfurization.
- Gas-fired gas turbine with WHB with exhaust products used for drying.

The gas turbine/WHB was quickly eliminated on the basis of very poor (negative) rates of return on equity for all ownership options in spite of large energy savings. The concept identified for detailed consideration is the coal-fired steam boiler driving a back pressure turbine. Figure C.5-1 shows the energy utilization system model reflecting the presence of the steam air heaters used for providing drying air. The conditions at each of the indicated state points are given in Table C.5-1.

The ratio of process heat to electricity required for this case is $10.32 \text{ kW}_t/\text{kW}_e$, a further indication that a system, such as the coal-fired steam system selected, with an inherently high ratio of heat to electricity will provide a good match. Figure C.5-2 displays the system configuration for the soybean oil plant's cogeneration facility. Figure C.5-3 represents the optimization curves for industrial and utility ownership. The operating parameter for the steam system is the turbine throttle pressure. High throttle pressures improve overall energy savings and for industry ownership, provide slightly lower ROE's. Utility ownership demonstrates little effect of pressure on ROE. The optimum plant was chosen to be the plant generating steam at 915 psia, the maximum practical pressure for boiler/turbines of this size. State point data are available in Table C.5-2. Third-party ownership is not a viable option.

The cogeneration facility is a stoker-fed boiler, firing Chinook Indiana #3 seam coal (see Table C.5-3). Steam generated at 915 psia and 876°F is expanded through a back pressure steam turbine, producing a gross power output of 2102 kW. The exhaust steam, at 165 psia, is used to deaerate the condensate return flow, to reheat the flue gas treated in the flue gas desulfurization system, and to supply the soybean plant with 57,100 lb/hr of usable steam. In Table C.5-4, the energy distribution

Fig. C.5-1 – Flowsheet of process heat utilization subsystem for soybean oil mill with coal-fired steam energy conversion subsystem

TABLE C.5-1

STATEPOINTS FOR ENERGY UTILIZATION SUBSYSTEM IN SOYBEAN OIL PLANT

STATION	PRESSURE (psia)	TEMPERATURE (°F)	ENTHALPY (Btu/lb)	FLOW RATE (lb/s)
1	165	505	1275.1	15.87
2	165	505	1275.1	13.57
3	165	505	1275.1	2.30
4	>15	150	118.0	4.75
5	15	100	68.0	8.82
6	>15	118	86.0	13.57
7	39.8	118	86.0	13.57
8	165	366	1195.6	2.30
9	39.8	154	122.0	15.87

Fig. C.5-2 - Model of conventional coal-fired steam energy conversion subsystem.

Fig. C.5-3 - Annual energy savings vs return on equity, industry and utility ownership

TABLE C.5-2
STATEPOINTS FOR CONVERSION SUBSYSTEM IN
SOYBEAN OIL PLANT

Station	Pressure (psia)	Temperature (°F)	Enthalpy (Btu/lb)	Flow (lb/s)
1	14.7	77	0	21.59
2	15.9	85	2	21.59
3	15.9	85	2	21.59
4	15.7	3274	953.5	23.73
5	15.5	1800.0	478.9	23.73
6	15.3	1200.8	300.3	23.73
7	15.0	1110.0	274.3	23.73
8	14.7	302.4	56.4	23.73
9	14.7	302.4	56.4	23.73
20	39.8	157.0	125.1	15.87
21	29.8	250.0	218.6	17.51
22	1040.0	252.7	223.4	17.51
23	1015.0	525.3	518.3	17.51
24	965.0	540.3	537.1	4.71
25	965.0	540.3	668.1	4.71
26	965.0	540.3	537.1	85.97
27	965.0	540.3	668.1	85.97
28	965.0	540.3	1195.6	17.51
29	915.0	875.9	1437.1	17.51
30	165.0	504.9	1275.1	17.51
31	165.0	504.9	1275.1	0.27
32	165.0	504.9	1275.1	17.24
33	165.0	504.9	1275.1	1.37
34	165.0	504.9	1275.1	15.87

TABLE C.5-3
FUEL SPECIFICATIONS
CHINOOK MINE - INDIANA #3 SEAM COAL

(Source of data: Monthly Progress Report 10
May 1973; OCR Contract No. 14-32-0001-1514)

SAMPLE: Run of mine		Dry Basis	As fired ⁽¹⁾
PROXIMATE ANALYSIS (wt %):	Volatile matter	41.72	47.55
	Fixed carbon	47.90	43.11
	Ash	10.38	9.34
		100.0	100.0
ULTIMATE ANALYSIS (wt %): (includes moisture)	C	71.14	64.03
	H	5.20	5.79
	O	8.41	16.45
	N	0.98	0.89
	S (2)	3.89	3.50
	Ash	10.38	9.34
		100.00	100.00
GROSS HEATING VALUE:	(Btu/lb)	12524	11272
NET HEATING VALUE:	(Btu/lb)	-	10730
ASH ANALYSIS (wt %):	SiO ₂	45.9	
	Al ₂ O ₃	23.8	
	Fe ₂ O ₃	23.5	
	TiO ₂	1.4	
	P ₂ O ₅	-	
	CaO	1.5	
	MgO	0.7	
	Na ₂ O	0.5	
	K ₂ O	1.9	
	SO ₃	-	
FUSIBILITY OF ASH:	Initial deformation temperature	--	2560°F
	Softening temperature	--	2600°F
	Fluid temperature	--	2685°F
GRINDABILITY (Hardgrove):	-		
FREE SWELLING INDEX:	2		
(1) 10% moisture assumed			
(2) Sulfur forms (%): Pyritic - 46			
Sulfate - 53			
Organic - 1			

TABLE C.5-4

POWER SUMMARY - SOYBEAN OIL PLANT

HP STEAM PWR= 1495.0553 KW
LP STEAM PWR= 606.6958 KW
ST POWER= 2101.7511 KW

GROSS POWER = 2101.7511 KW
FGD AUXILIARIES = 457.6026 KW
AUXILIARY POWER = 181.5201 KW
BOILER FEED PUMP POWER = 83.8754 KW
NET POWER GENERATED = 1378.7530 KW

TOTAL FUEL= 2.1384 LB/SEC
THERMAL RATING = 82603749.0000 BTU/HR

HEAT RATE 59911.9277 BTU/KWHR
TOTAL PROCESS HEAT = .6825+008 BTU/HR
PROCESS HEAT AT 165.0 PSIA = .6825001+008 BTU/HR

RPHEE = 14.9389 KWT/KWE

IEUF = .8831

is summarized. The ideal energy utilization factor (IEUF) for this case is 0.8831 and the ratio of process heat to electricity is 14.94.

The preliminary capital costs of the cogeneration components are detailed in Table C.5-5. Using these costs and the economic and financial data appropriate to the company and the region involved, the cash flow analysis was performed and a discounted cash flow rate of return (DCFROE) on equity was computed for all ownership options. The assumptions used in this analysis are given in Table C.5-6. The results of the DCFROE computation, along with the specific contributors to the cash flow vector, are given in Tables C.5-7a, C.5-7b, and C.5-7c. The ROE for industry ownership has a marginal value of 12.2%, while the ROE for utility ownership (13.7%) is greater than the 1978 ROE for utilities in this DOE region. The third party option, for this case, was not acceptable.

The potential energy savings to be realized as a result of this installation are broken down in Table C.5-8. The net result is a shift from natural gas to coal, as well as a modest improvement in the overall quantity of fuel burned.

TABLE C.5-5
SOYBEAN OIL MILL
SUMMARY OF CAPITAL COSTS: DEC. 1978 \$

STEAM GENERATOR COST (INSTALLED)	= \$ 2447182.4
STEAM GENERATOR BOP COSTS	= \$ 3058978.0
TURBINE GENERATOR COST (INSTALLED)	= \$ 1154149.2
TURB-GEN BOP COSTS	= \$ 1154149.2
FLUE GAS DESULF COSTS (INST+BOP)	= \$ 1067688.4
TOTAL DIRECT COSTS	= \$ 8882147.0
INDIRECT COSTS	= \$ 1332322.0
ENGINEERING	= \$ 888214.7
CONTINGENCY (20%)	= \$ 1776429.4
SUBTOTAL	= \$12879113.1
INTEREST DURING CONSTRUCTION (36 mo.)	= \$ 2131493.2
ESCALATION DURING CONSTRUCTION	= \$ 1560284.4
TOTAL CAPITAL COST	= \$16570890.7
SPECIFIC CAPITAL COST (\$/kWt)	= 678.502

TABLE C.5-6

RATE OF RETURN ON EQUITY SUMMARY
FOR INDUSTRIAL COGENERATION

ENERGY UTILIZATION SYSTEM CHARACTERIZATION
SOYBEAN OIL PLANT

REQUIRED RATIO OF PROCESS HEAT/ELECTRICITY	=	10.8000
REQUIRED PROCESS HEAT	=	146796088.0 (KWH/YR)
REQUIRED ELECTRIC ENERGY	=	13592230.4 (KWH/YR)
SUPPLEMENTAL ELECTRIC ENERGY PURCHASED	=	3765798.2 (KWH/YR)
ASSUMED CAPACITY FACTOR	=	.8380
ASSUMED STANDBY POWER FRACTION	=	1.0000

ENERGY CONVERSION SYSTEM CHARACTERIZATION
COAL-FIRED STEAM WITH BPT

ACTUAL RATIO OF PROCESS HEAT/ELECTRICITY	=	14.9389
IDEAL ENERGY UTILIZATION FACTOR	=	.8831
SPECIFIC CAPITAL COST OF CONVERSION SYSTEM	=	678.5020 (\$/KWT)
INCR. LABOR COST (INDUSTRY) (1ST YEAR)	=	228582.6152 (\$)
INCR. LABOR COST (UTILITY) (1ST YEAR)	=	454680.6367 (\$)
INCR. LABOR COST (3RD PARTY) (1ST YEAR)	=	454680.6367 (\$)

TABLE C.5-6 (cont'd)

SOYBEAN OIL PLANT
ECONOMIC AND FINANCIAL ASSUMPTIONS

DEBT / EQUITY RATIO (INDUSTRY)	=	.5000
DEBT / EQUITY RATIO (UTILITY)	=	1.0000
DEBT / EQUITY RATIO (3RD PARTY)	=	5.0000
LIFE OF PROJECT	=	28 (YEARS)
LIFE OF INVESTMENT FOR TAX PURPOSES	=	28 (YEARS)
INCOME TAX RATES (FEDERAL + STATE)	=	.5000 (%/100)
INTEREST RATE ON DEBT	=	.1000 (%/YR/100)
INVESTMENT TAX CREDIT RATE	=	.2000 (%/100)
ITCR UNDER SEPARATE GENERATION (INDUSTRY)	=	.0000 (%/100)
ITCR UNDER SEPARATE GENERATION (UTILITY)	=	.1000 (%/100)
PROPERTY TAX RATE (1ST YEAR)	=	.0150 (%/100)
INSURANCE RATE (1ST YEAR)	=	.0150 (%/100)
CHARGE FOR STANDBY POWER	=	67.8746 (\$/KW)
MAINTENANCE & SUPPLIES COST FACTOR (1ST YR)	=	.0375 (%/100)
BOILER HEAT RATE (SEPARATE GENERATION)	=	3750.0000 (BTU/KWH)
CENTRAL STATION BUS BAR HEAT RATE	=	9500.0000 (BTU/KWH)
TRANSMISSION LOSSES OF PURCHASED POWER	=	.1000 (%/100)
SPECIFIC CAPITAL COST OF NEW UTILITY STATION	=	1000.0000 (\$/KW)
PRICE OF PROCESS STEAM (1ST YR)	=	3.8960 (\$/10 ⁶ BTU)
PRICE OF POWER AT CENTRAL STATION BUS BAR	=	.0212 (\$/KWH)
PRICE OF POWER BOUGHT FROM UTILITY (1ST YR)	=	.0353 (\$/KWH)
PRICE OF POWER SOLD TO UTILITY (1ST YR)	=	.0212 (\$/KWH)
PRICE OF FUEL (COGENERATION)	=	1.5532 (\$/10 ⁶ BTU)
PRICE OF FUEL, (SEP.GEN.: INDUSTRY)	=	2.2215 (\$/10 ⁶ BTU)
PRICE OF FUEL (SEP.GEN.: UTILITY)	=	1.5532 (\$/10 ⁶ BTU)
GENERAL INFLATION RATE	=	.0750 (%/100/YR)
FUEL PRICE RELATIVE ESC. (COGENERATION FUEL)	=	.0500 (%/100/YR)
FUEL PRICE REL. ESC. (SEP.GEN.: INDUSTRY)	=	.0850 (%/100/YR)
FUEL PRICE REL. ESC. (SEP.GEN.: UTILITY)	=	.0500 (%/100/YR)
RELATIVE ESC. OF ELECTRICAL ENERGY COSTS	=	.0300 (%/100/YR)
RELATIVE ESC. OF PROCESS STEAM COSTS	=	.0300 (%/100/YR)

TABLE C.5-7a

SOYBEAN OIL PLANT
FOR INDUSTRIAL OWNERSHIP

INCREMENTAL CAPITAL INVESTMENT = 15424445 (\$)
NET INCREMENTAL EQUITY CAPITAL INVESTMENT = 8093421 (\$)

YEAR	NET SAVINGS IN ELECT.	DELTA FUEL COSTS	DELTA O AND M	DELTA PROP. TAX & INSUR.	INCOME TAXES ON SAVINGS
1	255965.	-268361.	844391.	462733.	-1180351.
2	283418.	-348404.	907721.	497438.	-1156625.
3	313814.	-446320.	975800.	534746.	-1126166.
4	347471.	-565671.	1048985.	574852.	-1087312.
5	384737.	-710685.	1127659.	617966.	-1038070.
6	426000.	-886379.	1212233.	664314.	-976057.
7	471689.	-1098702.	1303150.	714137.	-898426.
8	522277.	-1354699.	1400887.	767697.	-801786.
9	578291.	-1662712.	1505953.	825275.	-682099.
10	640313.	-2032609.	1618900.	887170.	-534565.
11	708987.	-2476056.	1740317.	953708.	-353487.
12	785026.	-3006834.	1870841.	1025236.	-132108.
13	869219.	-3641219.	2011154.	1102129.	137574.
14	962443.	-4398418.	2161990.	1184788.	465033.
15	1065665.	-5301088.	2324140.	1273647.	861470.
16	1179958.	-6375941.	2498450.	1369171.	1340122.
17	1306508.	-7654456.	2685834.	1471859.	1916614.
18	1446631.	-9173715.	2887271.	1582248.	2609388.
19	1601782.	-10977382.	3103817.	1700917.	3440185.
20	1773574.	-13116847.	3336603.	1828486.	4434631.
21	1963789.	-15652578.	3586848.	1965622.	5622910.
22	2174406.	-18655693.	3855862.	2113044.	7040554.
23	2407611.	-22209812.	4145051.	2271522.	8729377.
24	2665827.	-26413222.	4455930.	2441886.	10738565.
25	2951737.	-31381411.	4790125.	2625027.	13125942.
26	3268310.	-37250044.	5149384.	2821904.	15959473.
27	3618836.	-44178444.	5535588.	3033547.	19319008.
28	4006957.	-52353663.	5950757.	3261343.	23790498.

YEAR	BASIC CASH FLOW	DISCOUNTED ADJUSTED CASH FLOW
1	-116595	-103926
2	-130861	-103969
3	-138393	-98006
4	-137530	-86812
5	-126280	-71050
6	-102258	-51283
7	-62618	-27991
8	-3969	-1581
9	77726	27604
10	187269	59282
11	330355	93215
12	513742	129210
13	745433	167111
14	1034901	206795
15	1393347	248169
16	1834007	291162
17	2372509	335728
18	3027291	381838
19	3820097	429483
20	4776552	478665
21	5926839	529402
22	7306492	581725
23	8957324	635672
24	10928520	691292
25	13277906	748645
26	16073446	807795
27	19394990	868815
28	23336321	931786

DISCOUNTED CASH FLOW RATE OF RETURN ON EQUITY(ROE)= 12.19 %

ANNUAL ENERGY SAVED UNDER COGENERATION = 46289.8359 MBTU/YR

TABLE C..5-7b

SOYBEAN OIL PLANT
FOR UTILITY OWNERSHIP

INCREMENTAL CAPITAL INVESTMENT = 14877245 (\$)
NET INCREMENTAL EQUITY CAPITAL INVESTMENT = 6694760 (\$)

YEAR	STEAM REVENUE	DELTA ELECT. REVENUE	DELTA FUEL COSTS	DELTA O AND M	DELTA PROP. TAX & INSUR.	TAXES
1	1953098.	191894.	779603.	1012577.	446317.	-931692.
2	2162568.	212474.	879976.	1088521.	479791.	-903241.
3	2394503.	235262.	993273.	1170160.	515775.	-873017.
4	2651314.	260494.	1121157.	1257922.	554459.	-840839.
5	2935667.	288432.	1265506.	1352266.	596043.	-806510.
6	3250517.	319367.	1428440.	1453686.	640746.	-769825.
7	3599135.	353619.	1612352.	1562712.	688802.	-730565.
8	3985142.	391544.	1819942.	1679915.	740462.	-688504.
9	4412549.	433537.	2054259.	1805909.	795997.	-643405.
10	4885795.	480034.	2318745.	1941352.	855697.	-595027.
11	5409796.	531518.	2617284.	2086954.	919874.	-543121.
12	5989996.	588523.	2954259.	2243475.	988865.	-487440.
13	6632423.	651642.	3334620.	2411736.	1063029.	-427738.
14	7343751.	721531.	3763952.	2592616.	1142757.	-363778.
15	8131368.	798915.	4248561.	2787062.	1228463.	-295337.
16	9003457.	884599.	4795563.	2996092.	1320598.	-222212.
17	9969077.	979472.	5412992.	3220798.	1419643.	-144234.
18	11038260.	1084520.	6109914.	3462358.	1526116.	-61274.
19	12222114.	1200835.	6896565.	3722035.	1640575.	26738.
20	13532935.	1329624.	7784498.	4001188.	1763618.	119801.
21	14984342.	1472227.	8786752.	4301277.	1895889.	217820.
22	16591412.	1630123.	9918046.	4623872.	2038081.	320584.
23	18370841.	1804953.	11194995.	4970663.	2190937.	427738.
24	20341113.	1998535.	12636350.	5343462.	2355257.	538749.
25	22522696.	2212877.	14263280.	5744222.	2531901.	652867.
26	24938255.	2450208.	16099677.	6175039.	2721794.	769081.
27	27612882.	2712993.	18172510.	6638166.	2925929.	886061.
28	30574363.	3003962.	20512220.	7136029.	3145373.	1002098.

YEAR	BASIC CASH FLOW	DISCOUNTED ADJUSTED CASH FLOW
1	540642	475373
2	565923	437529
3	595488	404807
4	629706	376390
5	668975	351589
6	713720	329820
7	764393	310593
8	821471	293489
9	885460	278159
10	956895	264310
11	1036335	251695
12	1124363	240108
13	1221586	229376
14	1328630	219358
15	1446134	209934
16	1574750	201007
17	1715130	192496
18	1867920	184335
19	2033747	176470
20	2213210	168858
21	2406857	161463
22	2615169	154258
23	2838536	147221
24	3077223	140332
25	3331342	133581
26	3600805	126955
27	3885276	120447
28	4184115	114052

DISCOUNTED CASH FLOW RATE OF RETURN ON EQUITY(ROE)= 13.73 %

ANNUAL ENERGY SAVED UNDER COGENERATION = 46289.8359 MBTU/YR

TABLE C.5-7c

SOYBEAN OIL PLANT
FOR THIRD PARTY OWNERSHIP

CAPITAL INVESTMENT	=	16421567 (\$)
NET EQUITY CAPITAL INVESTMENT	=	2189542 (\$)

YEAR	STEAM REVENUE	DELTA ELECT. REVENUE	DELTA FUEL COSTS	DELTA O AND M	DELTA PROP. TAX & INSUR.	TAXES
1	1953098.	255965.	940702.	1070489.	492647.	-1397880.
2	2162568.	283418.	1061817.	1150776.	529596.	-1378371.
3	2394503.	313814.	1198526.	1237084.	569315.	-1358350.
4	2651314.	347471.	1352836.	1329866.	612014.	-1337788.
5	2935667.	384737.	1527014.	1429605.	657915.	-1316664.
6	3250517.	426000.	1723617.	1536826.	707258.	-1294967.
7	3599135.	471689.	1945533.	1652088.	760303.	-1272701.
8	3985142.	522277.	2196020.	1775994.	817326.	-1249888.
9	4412549.	578291.	2478758.	1909194.	878625.	-1226572.
10	4885795.	640313.	2797898.	2052383.	944522.	-1202828.
11	5409796.	708987.	3158127.	2206312.	1015361.	-1178766.
12	5989996.	785026.	3564736.	2371786.	1091513.	-1154539.
13	6632423.	869219.	4023696.	2549669.	1173376.	-1130359.
14	7343751.	962443.	4541746.	2740895.	1261380.	-1106499.
15	8131368.	1065665.	5126496.	2946462.	1355983.	-1083316.
16	9003457.	1179958.	5786532.	3167446.	1457682.	-1061262.
17	9969077.	1306508.	6531548.	3405005.	1567008.	-1040903.
18	11038260.	1446631.	7372485.	3660380.	1684534.	-1022945.
19	12222114.	1601782.	8321692.	3934908.	1810874.	-1008257.
20	13532935.	1773574.	9393110.	4230027.	1946689.	-997903.
21	14984342.	1963789.	10602473.	4547278.	2092691.	-993176.
22	16591412.	2174406.	11967541.	4888324.	2249642.	-995642.
23	18370841.	2407611.	13508362.	5254949.	2418366.	-1007186.
24	20341113.	2665827.	15247563.	5649070.	2599743.	-1030068.
25	22522696.	2951737.	17210687.	6072750.	2794724.	-1066990.
26	24938255.	3268310.	19426562.	6528206.	3004328.	-1121168.
27	27612882.	3618836.	21927732.	7017821.	3229652.	-1196423.
28	30574363.	4006957.	24750927.	7544158.	3471876.	-1297276.

YEAR	BASIC CASH FLOW
1	-265358
2	-286296
3	-306722
4	-326607
5	-345930
6	-364681
7	-382862
8	-400496
9	-417628
10	-434331
11	-450715
12	-466936
13	-483203
14	-499791
15	-517055
16	-535448
17	-555536
18	-578025
19	-603785
20	-633878
21	-669598
22	-712511
23	-764502
24	-827832
25	-905201
26	-999826
27	-1115528
28	-1256829

DISCOUNTED CASH FLOW RATE OF RETURN ON EQUITY(ROE)= <0 %
ANNUAL ENERGY SAVED UNDER COGENERATION = 46289.8359 MBTU/YR

TABLE C.5-8
FUEL UTILIZATION
SOYBEAN OIL PLANT

	Separate Generation (MBtu/yr)	Cogeneration (MBtu/yr)	Overall Savings (MBtu/yr)
Gas	544,270	-	544,270
Oil	-	-	-
Coal	143,474	641,444	-497,970
Wood	-	-	-
Total	687,744	641,444	46,300

Percent Energy Savings = 6.7%

C.6 LARGE CAPACITY PETROLEUM REFINERY

The large petroleum refinery is located in California (DOE Region IX). The energy use pattern is the most complex to be considered in this study. Steam is required at three separate pressure levels for mechanical drives as well as for process heat. The steam requirements are as follows:

- Mechanical drive steam (895 psia) 300,000 lb/hr
- Mechanical drive steam (565 psia) 580,000 lb/hr
- Process steam (165 psia) 720,000 lb/hr

In addition, a peak electrical demand of 120 MW is expected.

Figure C.6-1 shows the energy utilization subsystem for the large refinery. The corresponding statepoints are given in Table C.6-1. A number of steam turbine configurations were considered (shown in Figure C.6-2), all of which were required to provide the specified quantities of steam at the needed pressure levels. In the first configuration, the steam turbine throttle pressure would be in excess of 895 psia, up to 1500 psia, and a double-extraction/back pressure turbine would be used. However, inquiries to steam turbine manufacturers revealed that the maximum extraction pressure allowable under those conditions was 700 psig. A second configuration used a high-pressure element exhausting to a single-extraction/back pressure turbine at 895 psia, with a side-stream providing the 300,000 lb/hr of mechanical drive steam. This system was also rejected as impractical on the same basis as the first; that is, that a high pressure steam turbine must have a pressure ratio well in excess of 2:1. The only configuration which is technically feasible is a single extraction steam turbine, with a throttle pressure of 895 psia, exhausting to the process at 165 psia. The high pressure mechanical drive steam is generated in parallel with the steam sent to the power turbine.

Two steam generating options were considered for the large refinery. The first is a conventional power steam boiler fired by petroleum coke. The economic analysis of this system showed that all ownership options may expect a positive return on equity. However, the energy savings realizable under this system are quite modest. The other cycle examined was a combined cycle fired by refinery fuels such as light naphtha and a low-sulfur residual. This configuration will provide a positive ROE for all owners, but the results of the utility ownership ROE calculation were particularly favorable. In addition, the energy savings were substantially higher than the conventional coke-fired system. The optimization curve for the industrial ownership case is given in Figure C.6-3.

The configuration of the energy conversion subsystem is presented in Figure C.6-4. Since the temperature out of the gas turbine expander is less than 1000°F, it is necessary to provide an afterburner to boost the enthalpy of the combustion products. The afterburner temperature

Fig.C.6-1 — Model of process heat utilization subsystem for large petroleum refinery with refinery fuel-fired combined cycle energy conversion subsystem

TABLE C.6-1
STATEPOINTS FOR ENERGY UTILIZATION SUBSYSTEM IN
LARGE PETROLEUM REFINERY

Station	Pressure (psia)	Temperature (°F)	Enthalpy (Btu/lb)	Flow Rate (lb/s)
1	895	739.2	1357.9	83.3
2	565	635.0	1315.0	161.1
3	165	403.0	1219.8	200.0
4	-	-	-	444.4
5	>15	225	193.0	222.2
6	15	100	68	222.2
7	>15	163.0	131.4	444.4
8	39.8	163.0	131.4	444.4

Double Automatic Extraction
Back Pressure Steam Turbine

HPT Back Pressure
LPT Single Extraction/Back
Pressure Steam Turbine

Single Extraction/Back Pressure
Steam Turbine

Fig. C.6-2 - Possible steam turbine configurations

Fig. C.6-3 - Annual energy savings vs return on equity, industrial ownership

was used to provide a match between the steam flows required for on-site use and the capacity of the gas turbines, making it possible to design the system to use available gas turbine technology. Two alternatives were examined: firing the afterburner with naphtha as in the turbine proper, and firing the afterburner with a low-sulfur residual. The latter option gave superior results, and is shown schematically in Figure C.6-2. The properties of the two fuels are given in Tables C.6-2 and C.6-3.

The analysis of the combined cycle cogeneration system indicated that optimum gas turbine configuration for this application was approximately as follows:

- Pressure ratio - 12:1
- Expander inlet temperature - maximum state-of-the-art ($\sim 2100^{\circ}\text{F}$)
- Compressor air flow rate (total) - 1595 lb/s

The most advanced commercially available gas turbines with the above pressure ratio and expander inlet temperature and air flow rates which are integrally proportional to the above air flow rate have polytropic compressor and turbine efficiencies of approximately 91 and 92%, respectively. These values are significantly higher than the composite values which were used in the characterization calculations (see Appendix B-5).

Performance calculations were made for the optimum gas turbine configuration as described above. A model of this energy conversion subsystem is shown in Figure C.6-3. The conditions at the statepoints shown in Figure C.6-3 are listed in Table C.6-4. Two gas turbine modules, each with an inlet air flow of 745.6 lb/s, were assumed, with a pressure ratio of 12:1 and an expander inlet temperature of 2100°F . In Table C.6-5, the energy distribution for the cogeneration facility is given in detail. The net power generated in the gas turbine and the steam expander is 247.8 MW, making it possible for the facility owner not only to provide full electrical service to the refinery, but also to export over 125 MW for sale to other customers. The ideal energy utilization factor (IEUF) for the combined cycle is 0.8453 and the ratio of process heat to electricity is 2.2507.

The preliminary capital cost of the cogeneration facility is given in Table C.6-6. Using these costs as well as the economic and financial assumptions listed in Table C.6-7, the cash flow analysis was performed and a discounted cash flow rate of return on equity was derived for the ownership options. The ownership cash flows are broken down in Tables C.6-8a, C.6-8b, and C.6-8c.

The fuel utilization shift to be expected as a result of this installation is given in Table C.6-9. The use of oil is decreased by 76% and is replaced by light naphtha. The overall fuel savings is nearly 23%. If it is assumed that the new central station generating capacity for the utility serving the large petroleum refinery will be coal-fired rather than oil-fired, the discounted cash flow return on equity for utility ownership becomes negative also because of the relatively low cost of coal compared to that of oil.

TABLE C.6-2

FUEL SPECIFICATIONS

LIGHT NAPHTHA PROPERTIES

Gravity (°API) - 70

H/C ratio - 2.25 (assumed)

Gross Heating Value (Btu/lb) - 20,350

Net Heating Value (Btu/lb) - 19,045

Ratio of net/gross Heating Values - 0.936

TABLE C.6-3

LOW SULFUR RESIDUAL OIL
(Compliance LSFO)

Sulfur - % by wt.	0.25 - 0.50
Ni + V, ppm by wt.	< 0.5
Gravity - °API	26.8
Specific Gravity -	0.893
Gross Heating Value (Btu/lb) -	19,230
Net Heating Value (Btu/lb) -	18,090
Ratio of net/gross Heating Values -	0.941

TABLE C.6-4
STATEPOINTS FOR CONVERSION SUBSYSTEM IN
LARGE REFINERY

	Pressure (psia)	Temperature (°F)	Enthalpy (Btu/lb)	Flow (lb/s)
1	14.70	59	0.0	1595.2
2	183.30	695.3	156.8	1595.2
3	183.80	695.3	156.8	1472.01
4	175.60	2100	571.0	1460.67
5	15.36	450	95.3	168.70
6	15.36	1051.0	265.1	1460.67
7	15.28	993.2	245.1	1628.79
8	15.21	1551.9	408.6	1643.62
9	15.00	1381.8	358.5	1643.62
10	14.85	642.2	151.6	1643.62
11	14.70	290.0	60.0	1643.62
20	39.8	163.0	131.4	444.44
21	29.8	250.0	218.6	485.84
22	963.6	525.1	518.1	485.84
23	945.0	540.1	536.9	2115.45
24	945.0	540.1	668.4	2115.45
25	945.0	540.1	1194.2	485.84
26	929.0	739.2	1357.9	485.84
27	895.0	739.2	1357.9	402.51
28	895.0	739.2	1357.9	83.33
29	565.0	635.0	1315.0	161.11
30	165.0	403.0	1219.8	241.40
31	165.0	403.0	1219.8	41.40
32	165.0	403.0	1219.8	200.00

TABLE C.6-5

POWER SUMMARY - LARGE REFINERY

Net Gas Turbine Power	=	210.38 MW*
Steam Turbine Power	=	41.94 MW
Total Gross Power	=	252.32 MW
Gas Turbine Auxiliaries	=	1.59 MW
Steam Turbine Auxiliaries	=	2.90 MW
Net Power	=	247.83 MW

Net Steam Generated

High Pressure Mechanical Drive Steam	=	83.33 lb	at 895 psia / 739°F
Medium Pressure Mech Drive Steam	=	161.11 lb	at 565 psia / 635°F
Low Pressure Process Steam	=	200.00 lb	at 165 psia / 403°F

Ratio of process heat to electricity: RPHEE = 2.2507
(corrected for part-load operation)

Ideal energy utilization factor: IEUF = 0.8453
(corrected for part-load operation)

*Two (2) gas turbine modules

TABLE C.6-6

LARGE PETROLEUM REFINERY
SUMMARY OF CAPITAL COSTS: DEC. 1978\$

GAS TURBINE COST	= \$ 30419900.3
GAS TURBINE BOP	= \$ 10646965.1
STEAM TURBINE/GEN COST	= \$ 2855659.3
STEAM TURBINE/GEN BOP	= \$ 2855659.3
HRSG COST	= \$ 10308000.0
HRSG BOP	= \$ 10308000.0
TOTAL DIRECT CAPITAL COST	= \$ 67394183.0
INDIRECT COSTS	= \$ 6230590.2
ENGINEERING	= \$ 6739418.3
CONTINGENCY (20%)	= \$ 13478836.5
SUBTOTAL	= \$ 93843025.8
INTEREST DURING CONSTR.	= \$ 11222573.3
ESCALATION DURING CONSTR.	= \$ 8291449.9
TOTAL CAPITAL COST	= \$113357049.0

SPECIFIC CAPITAL COST(\$/KWT) = 118.747

TABLE C.6-7

RATE OF RETURN ON EQUITY SUMMARY
FOR INDUSTRIAL COGENERATION

ENERGY UTILIZATION SYSTEM CHARACTERIZATION
LARGE PETROLEUM REFINERY

REQUIRED RATIO OF PROCESS HEAT/ELECTRICITY	=	4.9000
REQUIRED PROCESS HEAT	=	4397647872.0 (KWH/YR)
REQUIRED ELECTRIC ENERGY	=	897479160.0 (KWH/YR)
EXCESS ELECTRIC ENERGY SOLD	=	1134351136.0 (KWH/YR)
ASSUMED CAPACITY FACTOR	=	.9000
ASSUMED STANDBY POWER FRACTION	=	1.0000

ENERGY CONVERSION SYSTEM CHARACTERIZATION
NAPHTHA/RESID-FIRED COMBINED CYCLE

ACTUAL RATIO OF PROCESS HEAT/ELECTRICITY	=	2.1644
IDEAL ENERGY UTILIZATION FACTOR	=	.8423
SPECIFIC CAPITAL COST OF CONVERSION SYSTEM	=	118.7472 (\$/KWT)
INCR. LABOR COST (INDUSTRY) (1ST YEAR)	=	169093.0664 (\$)
INCR. LABOR COST (UTILITY) (1ST YEAR)	=	169093.0664 (\$)
INCR. LABOR COST (3RD PARTY) (1ST YEAR)	=	676372.2656 (\$)

TABLE C.6-7 (cont'd)

LARGE PETROLEUM REFINERY
ECONOMIC AND FINANCIAL ASSUMPTIONS

DEBT / EQUITY RATIO (INDUSTRY)	=	.2000
DEBT / EQUITY RATIO (UTILITY)	=	.9000
DEBT / EQUITY RATIO (3RD PARTY)	=	5.0000
LIFE OF PROJECT	=	28 (YEARS)
LIFE OF INVESTMENT FOR TAX PURPOSES	=	28 (YEARS)
INCOME TAX RATES (FEDERAL + STATE)	=	.5500 (%/100)
INTEREST RATE ON DEBT	=	.1000 (%/YR/100)
INVESTMENT TAX CREDIT RATE	=	.0000 (%/100)
ITCR UNDER SEPARATE GENERATION (INDUSTRY)	=	.2000 (%/100)
ITCR UNDER SEPARATE GENERATION (UTILITY)	=	.0000 (%/100)
PROPERTY TAX RATE (1ST YEAR)	=	.0150 (%/100)
INSURANCE RATE (1ST YEAR)	=	.0150 (%/100)
CHARGE FOR STANDBY POWER	=	19.4310 (\$/KW)
MAINTENANCE & SUPPLIES COST FACTOR (1ST YR)	=	.0375 (%/100)
BOILER HEAT RATE (SEPARATE GENERATION)	=	3750.0000 (BTU/KWH)
CENTRAL STATION BUS BAR HEAT RATE	=	8200.0000 (BTU/KWH)
TRANSMISSION LOSSES OF PURCHASED POWER	=	.1000 (%/100)
SPECIFIC CAPITAL COST OF NEW UTILITY STATION	=	785.0000 (\$/KW)
PRICE OF PROCESS STEAM (1ST YR)	=	4.6659 (\$/10^6 BTU)
PRICE OF POWER AT CENTRAL STATION BUS BAR	=	.0237 (\$/KWH)
PRICE OF POWER BOUGHT FROM UTILITY (1ST YR)	=	.0498 (\$/KWH)
PRICE OF POWER SOLD TO UTILITY (1ST YR)	=	.0237 (\$/KWH)
PRICE OF FUEL (COGENERATION)	=	3.5585 (\$/10^6 BTU)
PRICE OF FUEL, (SEP.GEN.: INDUSTRY)	=	2.3370 (\$/10^6 BTU)
PRICE OF FUEL (SEP.GEN.: UTILITY)	=	3.0248 (\$/10^6 BTU)
GENERAL INFLATION RATE	=	.0750 (%/100/YR)
FUEL PRICE RELATIVE ESC.(COGENERATION FUEL)	=	.0750 (%/100/YR)
FUEL PRICE REL. ESC.(SEP.GEN.: INDUSTRY)	=	-.0031 (%/100/YR)
FUEL PRICE REL. ESC.(SEP.GEN.: UTILITY)	=	.0760 (%/100/YR)
RELATIVE ESC. OF ELECTRICAL ENERGY COSTS	=	.0256 (%/100/YR)
RELATIVE ESC. OF PROCESS STEAM COSTS	=	.0375 (%/100/YR)

TABLE C.6-8a

LARGE PETROLEUM REFINERY
FOR INDUSTRIAL OWNERSHIP

INCREMENTAL CAPITAL INVESTMENT = -36358642 (\$)
NET INCREMENTAL EQUITY CAPITAL INVESTMENT = -5346254 (\$)

YEAR	NET SAVINGS IN ELECT.	DELTA FUEL COSTS	DELTA O AND M	DELTA PROP. TAX & INSUR.	DELTA INCOME TAXES ON SAVINGS
1	69348584.	54218700.	4419982.	-1090759.	8202772.
2	76458197.	65892242.	4751481.	-1172566.	5506026.
3	84296690.	79614379.	5107842.	-1260509.	2073138.
4	92938785.	95720540.	5490930.	-1355047.	-2240056.
5	102466867.	114599552.	5902750.	-1456675.	-7602926.
6	112971767.	136702028.	6345456.	-1565926.	-14214249.
7	124553630.	162550068.	6821365.	-1683370.	-22307055.
8	137322864.	192748504.	7332967.	-1809623.	-32154313.
9	151401200.	227997856.	7882940.	-1945345.	-44075464.
10	166922848.	269109348.	8474160.	-2091246.	-58444058.
11	184035774.	317022256.	9109722.	-2248089.	-75696600.
12	202903116.	372823956.	9792951.	-2416696.	-96342792.
13	223704740.	437773136.	10527422.	-2597948.	-120977473.
14	246638942.	513326584.	11316979.	-2792794.	-150294404.
15	271924356.	601170152.	12165752.	-3002253.	-185102266.
16	299802032.	703254648.	13078183.	-3227422.	-226343262.
17	330537736.	821837184.	14059047.	-3469479.	-275114620.
18	364424456.	959529056.	15113475.	-3729690.	-332693528.
19	401785244.	1119351104.	16246986.	-4009416.	-400566060.
20	442976244.	1304797616.	17465509.	-4310123.	-480460640.
21	488390168.	1519910352.	18775422.	-4633382.	-574386904.
22	538459912.	1769363792.	20183579.	-4980885.	-684680552.
23	593662808.	2058564192.	21697347.	-5354452.	-814055544.
24	654525096.	2393763584.	23324648.	-5756036.	-965664344.
25	721627000.	2782191520.	25073996.	-6187738.	*****
26	795608184.	3232207968.	26954546.	-6651818.	*****
27	877173912.	3753479264.	28976136.	-7150705.	*****
28	967101752.	4357182016.	31149346.	-7687008.	*****

YEAR	BASIC CASH FLOW
1	4203866
2	2086991
3	-632182
4	-4071605
5	-8369855
6	-13689566
7	-20221399
8	-28188693
9	-37852810
10	-49519380
11	-63545541
12	-80348327
13	-100414423
14	-124311447
15	-152701060
16	-186354140
17	-226168420
18	-273188880
19	-328631408
20	-393910144
21	-470669352
22	-560820056
23	-666582776
24	-790536792
25	-935677192
26	-1105481232
27	-1303984720
28	-1535870800

DISCOUNTED CASH FLOW RATE OF RETURN ON EQUITY(ROE)= <0 %
ANNUAL ENERGY SAVED UNDER COGENERATION = 7903218.0000 MBTU/YR

TABLE C.6-8b

LARGE PETROLEUM REFINERY
FOR UTILITY OWNERSHIP

INCREMENTAL CAPITAL INVESTMENT = -98878734 (\$)
NET INCREMENTAL EQUITY CAPITAL INVESTMENT = -52041439 (\$)

YEAR	STEAM REVENUE	DELTA ELECT. REVENUE	DELTA FUEL COSTS	DELTA O AND M	DELTA PROP. TAX & INSUR.	TAXES
1	70072285	23475411	39888762	-3538859	-2966362	39416908
2	78152493	25882109	46039613	-3804274	-3188839	41936129
3	87164451	28535542	53138785	-4089594	-3428002	44602066
4	97215599	31461005	61332462	-4396314	-3685102	47408832
5	108425772	34686387	70789366	-4726037	-3961485	50346499
6	120928617	38242435	81704216	-5080490	-4258596	53400134
7	134873196	42163047	94301744	-5461527	-4577991	56548636
8	150425758	46485602	108841324	-5871141	-4921340	59763363
9	167771726	51251305	125622296	-6311477	-5290440	63006488
10	187117902	56505588	144990128	-6784837	-5687223	66229063
11	208694930	62298539	167343544	-7293700	-6113765	69368696
12	232760058	68685384	193142688	-7840728	-6572297	72346860
13	259600200	75727008	222918648	-8428782	-7065219	75065642
14	289535344	83490539	257284312	-9060941	-7595111	77403975
15	322922380	92049985	296947048	-9740511	-8164744	79213150
16	360159360	101486946	342723192	-10471049	-8777100	80311579
17	401690236	111891388	395554904	-11256378	-9435382	80478602
18	448010128	123362490	456529472	-12100606	-10143036	79447220
19	499671292	136009608	526901760	-13008151	-10903763	76895617
20	557289624	149953308	608119936	-13983763	-11721545	72437156
21	621552080	165326520	701855328	-15032545	-12600661	65608704
22	693224792	182275788	810036704	-16159985	-13545711	55856955
23	773162264	200962698	934890080	-17371984	-14561639	42522420
24	862317520	221565388	1078984448	-18674882	-15653761	24820696
25	961753496	244280266	1245284448	-20075498	-16827793	1820779
26	1072655672	269323872	1437211456	-21581161	-18089878	-27580587
27	1196346256	296934948	1658714080	-23199747	-19446618	-64688635
28	1334299904	327376708	1914348928	-24939728	-20905114	-111045113

	BASIC CASH FLOW	DISCOUNTED ADJUSTED CASH FLOW
1	22464613	2042238
2	24546862	202867
3	26732464	20084
4	29015352	1982
5	31386059	195
6	33830921	19
7	36331117	2
8	38861543	0
9	41389451	0
10	43872865	0
11	46258657	0
12	48480348	0
13	50455429	0
14	52082262	0
15	53236406	0
16	53766311	0
17	53488225	0
18	52180259	0
19	49575399	0
20	45353327	0
21	39130841	0
22	30450631	0
23	18768172	0
24	3436363	0
25	-16312239	0
26	-41386444	0
27	-72860771	0
28	-112003751	0

DISCOUNTED CASH FLOW RATE OF RETURN ON EQUITY(ROE)= 1000.00 %

ANNUAL ENERGY SAVED UNDER COGENERATION = 7903218.0000 MBTU/YR

TABLE C.6-8c

LARGE PETROLEUM REFINERY
FOR THIRD PARTY OWNERSHIP

CAPITAL INVESTMENT	= 113357047 (\$)
NET EQUITY CAPITAL INVESTMENT	= 18892841 (\$)

YEAR	STEAM REVENUE	ELECT. REVENUE	FUEL COSTS	O AND M	PROP. TAX & INSUR.	TAXES
1	70072285.	69348584.	92759155.	4927261.	3400711.	11588277.
2	78152493.	76458197.	107194795.	5296806.	3655765.	11813110.
3	87164451.	84296690.	123876981.	5694066.	3929947.	11689925.
4	97215599.	92938785.	143155334.	6121121.	4224693.	11124686.
5	108425772.	102466867.	165433880.	6580205.	4541545.	10004323.
6	120928617.	112971767.	191179524.	7073721.	4882161.	8193270.
7	134873196.	124553630.	220931830.	7604250.	5248323.	5529427.
8	150425758.	137322864.	255314338.	8174568.	5641947.	1819429.
9	167771726.	151401200.	295047628.	8787661.	6065093.	-3166883.
10	187117902.	166922848.	340964412.	9446735.	6519975.	-9702924.
11	208694930.	184035774.	394026988.	10155240.	7008973.	-18112929.
12	232760058.	202903116.	455347428.	10916883.	7534646.	-28780774.
13	259600200.	223704740.	526210860.	11735649.	8099744.	-42160251.
14	289535344.	246638942.	608102416.	12615823.	8707225.	-58787118.
15	322922380.	271924356.	702738328.	13562009.	9360266.	-79293032.
16	360159360.	299802032.	812101960.	14579160.	10062286.	-104421948.
17	401690236.	330537736.	938485320.	15672597.	10816958.	-135049076.
18	448010128.	364424456.	1084537072.	16848041.	11628229.	-172203036.
19	499671292.	401785244.	1253318128.	18111644.	12500346.	-217091626.
20	557289624.	442976244.	1448365712.	19470017.	13437872.	-271131848.
21	621552080.	488398168.	1673767616.	20930268.	14445712.	-335984768.
22	693224792.	538459912.	1934247632.	22500038.	15529141.	-413596112.
23	773162264.	593662808.	2235264864.	24187541.	16693826.	-506243540.
24	862317520.	654525096.	2583127904.	26001606.	17945863.	-616591352.
25	961753496.	721627000.	2985127136.	27951726.	19291802.	-747754360.
26	1072655672.	795608184.	3449687488.	30048106.	20738687.	-903371928.
27	1196346256.	877173912.	3986544960.	32301713.	22294088.	-1068598473.
28	1334299904.	967101752.	4606950976.	34724341.	23966145.	-1212304394.

YEAR	BASIC CASH FLOW
1	17299044
2	17203794
3	16823802
4	16082130
5	14886265
6	13125289
7	10666577
8	7351919
9	2993004
10	-2633870
11	-9793988
12	-18801430
13	-30027481
14	-43910484
15	-60967255
16	-81806484
17	-107144248
18	-137822148
19	-174828384
20	-219322316
21	-272663004
22	-336442404
23	-412524052
24	-503087844
25	-610682224
26	-738284912
27	-889373040
28	-1068005296

DISCOUNTED CASH FLOW RATE OF RETURN ON EQUITY (ROE) = 0 %

ANNUAL ENERGY SAVED UNDER COGENERATION = 7903218.0000 MBTU/YR

TABLE C.6-9

FUEL UTILIZATION

LARGE PETROLEUM REFINERY

	Separate Generation (MBtu/yr)	Cogeneration (MBtu/yr)	Savings (MBtu/yr)
Gas	--	--	--
Oil	33970648	7986691	25983957
Coal	--	--	--
Naphtha	--	18080739	-18080739
Overall	33970648	26067430	7903218
Percent Energy Savings = 23.3%			

C.7 MEDIUM CAPACITY PETROLEUM REFINERY

The medium capacity petroleum refinery is located in Oklahoma (DOE Region VI). The application under consideration is an energy recovery system for a catalyst regenerator servicing a proposed heavy oil catalytic cracker. The analysis was undertaken not to compare the economic feasibility of a cogeneration system with respect to a conventional separately generated system, but to determine which of several cogeneration systems compared most favorably with a minimally cogenerated facility. The reference case was determined to be that in which sufficient electrical energy would be generated to supply on-site power requirements while satisfying process steam needs as well.

The flow diagram for the reference case is shown in Figure C.7-1. Steam generation is effected in two places: the catalyst regenerator at 600 psig, and elsewhere in the catalytic cracker at 250 psig. Two additional heat exchangers supply superheated process steam and power steam to drive a wet gas compressor and a pump, as well as to generate 10,005 kW in electric power for use on-site. Note that the process effluent itself is pressurized to 55 psia and is subsequently throttled to 17 psia. Note also that the exhaust temperature from the final superheater is 949°F.

The first cogeneration configuration examined is shown in Figure C.7-2. Thermal recovery is achieved by installing larger heat exchangers for superheating power steam for the wet gas compressor and pump and for a double extraction condensing steam turbine producing a peak of 28.4 MW. Further recovery is accomplished by subsuming a Fluorinol Rankine cycle in the exhaust gas path which produces an additional 7 MW. No pressure recovery from the exhaust gas is included. The economic analysis shows that the industrial owner (the only ownership option considered in this case) could expect a return on equity of 53% at a projected energy savings of 2,119,000 MBtu/yr.

The second cogeneration configuration examined is shown in Figure C.7-3. This configuration added pressure recovery equipment which resulted in additional 22.6 MW of power for export. The exhaust gases from the process are cleaned and expanded through a turboexpander before being directed to the heat recovery superheaters. The thermal recovery equipment is similar to the previous case. Two larger superheaters replace the minimal surface in the reference case and a double extraction steam turbine/generator provides a peak of 23.2 MW. The bottoming cycle for this option was a methanol Rankine cycle generating 2.2 kW. The return on equity computed for this configuration was 88% with an energy savings of 3,150,760 MBtu/yr. Having performed better both financially and as an energy conservation measure, the second case was chosen as the preferred cogeneration concept.

Figure C.7-4 presents the energy utilization system corresponding to the preferred concept. The conditions and flows at the indicated state points are given in Table C.7-1.

Fig. C. 7-1 - Medium petroleum refinery (Case C1 reference case)

Fig. C. 7-2 - Medium petroleum refinery (Case 82)

Fig. C. 7-3 - Medium petroleum refinery (Case A1)

Fig. C.7-4 — Model of process heat utilization subsystem for medium size petroleum refinery

TABLE C.7-1

STATEPOINTS FOR ENERGY UTILIZATION SUBSYSTEM IN
MEDIUM SIZE PETROLEUM REFINERY

Station	Pressure (psia)	Temperature (°F)	Enthalpy (Btu/lb)	Flow Rate (lb/s)
1	165	420	1228	44.01
2	65	298	1179	13.89
3	>15	210	178	28.95
4	15	100	68	28.95
5	>15	155	123	57.90
6	39.8	155	123	57.90

The preliminary costs for the cogeneration components are given in Table C.7-2. Since all other components are common to both the preferred concept and the reference case, only those items which differ or appear in the preferred configuration need be used in the analysis.

The economic and financial assumptions used in the ROE analysis are given in Table C.7-3. The detailed results of that analysis are shown in Table C.7-4 for the industrial ownership case.

The difference in fuel utilization to be expected as a result of the installation of this preferred concept is shown in Table C.7-5. The energy saved is accomplished simply by displacing the utility - produced power (332.6×10^6 kWh/yr). No other fuel is involved.

TABLE C.7-2

MEDIUM CAPACITY PETROLEUM REFINERY
SUMMARY OF CAPITAL COSTS : DEC. 1978\$

COMPONENT/SYSTEM	COGENERATION FACILITY	REFERENCE FACILITY
EXPANDER/GENERATOR COST	= \$ 1605000	--
EXPANDER GENERATOR BOP COSTS	= \$ 561750	--
PARTICULATE REMOVAL (Incl. BOP)	= \$ 677900	--
SUPERHEATER #1 (Incl. BOP)	= \$ 881125	\$ 550793
SUPERHEATER #2 (Incl. BOP)	= \$ 174828	\$ 128578
ORGANIC RANKINE CYCLE (METHANOL)		
TURBINE/GENERATOR	= \$ 327845	--
CONDENSER/CIRC/ H2O	= \$ 207320	--
BOILER	= \$ 129868	--
BOP COSTS	= \$ 665052	--
STEAM TURBINE/GENERATOR COST	= \$ 6021228	\$2505970
TURB/GEN BOP COSTS	= \$ 6021228	\$2505970
TOTAL DIRECT COSTS	= \$17273144	\$5691311
INCREMENTAL CAPITAL COSTS	= \$11581833	
INDIRECT COSTS	= \$ 1496530	
ENGINEERING	= \$ 1158183	
CONTINGENCY (20%)	= \$ 2316372	
SUBTOTAL	= \$16552918	
INTEREST DURING CONSTR. (27 mo.)	= \$ 1979543	
ESCALATION DURING CONSTRUCTION	= \$ 1462524	
TOTAL INCREMENTAL CAPITAL COST	= \$19994985	

TABLE C.7-3

RATE OF RETURN ON EQUITY SUMMARY
FOR INDUSTRIAL COGENERATION

ENERGY UTILIZATION SYSTEM CHARACTERIZATION
MEDIUM CAPACITY PETROLEUM REFINERY

REQUIRED RATIO OF PROCESS HEAT/ELECTRICITY	=	5.9000
REQUIRED PROCESS HEAT	=	486639320.0 (KWH/YR)
REQUIRED ELECTRIC ENERGY	=	82481241.0 (KWH/YR)
EXCESS ELECTRIC ENERGY SOLD	=	332598356.0 (KWH/YR)
ASSUMED CAPACITY FACTOR	=	1.0000
ASSUMED STANDBY POWER FRACTION	=	1.0000

ENERGY CONVERSION SYSTEM CHARACTERIZATION
TURBOEXPANDER/STEAM/ORGANIC BOTTOMER

ACTUAL RATIO OF PROCESS HEAT/ELECTRICITY	=	1.1724
IDEAL ENERGY UTILIZATION FACTOR	=	.0000
ACTUAL INCREMENTAL COST	=	19994985.0000 (\$)
INCR. LABOR COST (INDUSTRY) (1ST YEAR)	=	.0000 (\$)
INCR. LABOR COST (UTILITY) (1ST YEAR)	=	314798.0156 (\$)
INCR. LABOR COST (3RD PARTY) (1ST YEAR)	=	314798.0156 (\$)

TABLE C.7-3 (cont'd.)

MEDIUM CAPACITY PETROLEUM REFINERY
ECONOMIC AND FINANCIAL ASSUMPTIONS

DEBT / EQUITY RATIO (INDUSTRY)	=	3.0000
LIFE OF PROJECT	=	28 (YEARS)
LIFE OF INVESTMENT FOR TAX PURPOSES	=	28 (YEARS)
INCOME TAX RATES (FEDERAL + STATE)	=	.5000 (%/100)
INTEREST RATE ON DEBT	=	.1000 (%/YR/100)
INVESTMENT TAX CREDIT RATE (COGENERATION)	=	.1000 (%/100)
ITCR UNDER ALTERNATE SYSTEM (INDUSTRIAL)	=	.1000 (%/100)
PROPERTY TAX RATE (1ST YEAR)	=	.0150 (%/100)
INSURANCE RATE (1ST YEAR)	=	.0150 (%/100)
CHARGE FOR STANDBY POWER	=	74.0426 (\$/KW)
MAINTENANCE & SUPPLIES COST FACTOR (1ST YR)	=	.0375 (%/100)
PRICE OF POWER AT CENTRAL STATION BUS BAR	=	.0187 (\$/KWH)
GENERAL INFLATION RATE	=	.0750 (%/100/YR)
RELATIVE ESC. OF ELECTRICAL ENERGY COSTS	=	.0603 (%/100/YR)

TABLE C.7-4

MEDIUM CAPACITY PETROLEUM REFINERY
FOR INDUSTRIAL OWNERSHIP

INCREMENTAL CAPITAL INVESTMENT = 19994985 (\$)
NET INCREMENTAL EQUITY CAPITAL INVESTMENT = 4498871 (\$)

YEAR	NET SAVINGS IN ELECT.	DELTA FUEL COSTS	DELTA O AND M	DELTA PROP. TAX & INSUR.	DELTA INCOME TAXES ON SAVINGS
1	8073697.	0.	749812.	599850.	1922723.
2	9202581.	0.	806048.	644838.	2461178.
3	10489308.	0.	866501.	693201.	3074758.
4	11955949.	0.	931489.	745191.	3774214.
5	13627660.	0.	1001351.	801081.	4571818.
6	15533113.	0.	1076452.	861162.	5481578.
7	17704992.	0.	1157186.	925749.	6519481.
8	20180547.	0.	1243975.	995180.	7703773.
9	23002242.	0.	1337273.	1069818.	9055276.
10	26218472.	0.	1437568.	1150055.	10597750.
11	29884404.	0.	1545386.	1236309.	12358305.
12	34062915.	0.	1661290.	1329032.	14367871.
13	38825677.	0.	1785887.	1428709.	16661739.
14	44254379.	0.	1919828.	1535862.	19280167.
15	50442136.	0.	2063815.	1651052.	22269082.
16	57495081.	0.	2218601.	1774881.	25680871.
17	65534185.	0.	2384996.	1907997.	29575292.
18	74697337.	0.	2563871.	2051097.	34020506.
19	85141704.	0.	2756161.	2204929.	39094252.
20	97046430.	0.	2962873.	2370299.	44885199.
21	110615702.	0.	3185089.	2548071.	51494465.
22	126082262.	0.	3423970.	2739176.	59037376.
23	143711398.	0.	3680768.	2944614.	67645451.
24	163805482.	0.	3956826.	3165460.	77468667.
25	186709170.	0.	4253587.	3402870.	88678049.
26	212815310.	0.	4572607.	3658085.	101468626.
27	242571672.	0.	4915552.	3932442.	116062782.
28	276488644.	0.	5284218.	4227375.	132714094.

YEAR	BASIC CASH FLOW	DISCOUNTED ADJUSTED CASH FLOW
1	3301687	1753698
2	3790893	1069496
3	4355224	652630
4	5005431	398398
5	5753787	243247
6	6614298	148524
7	7602952	90681
8	8737996	55356
9	10040250	33784
10	11533475	20613
11	13244781	12573
12	15205099	7667
13	17449718	4673
14	20018897	2848
15	22958563	1735
16	26321104	1056
17	30166276	643
18	34562241	391
19	39586739	238
20	45328436	145
21	51888454	88
22	59382116	54
23	67940943	33
24	77714909	20
25	88875043	12
26	101616371	7
27	116161277	4
28	132763340	3

DISCOUNTED CASH FLOW RATE OF RETURN ON EQUITY (ROE) = 88.27 %
ANNUAL ENERGY SAVED UNDER COGENERATION = 3150760.0625 MBTU/YR

TABLE C .7-5

FUEL UTILIZATION

MEDIUM CAPACITY PETROLEUM REFINERY

	Minimal Cogeneration (MBtu/yr)	Preferred Concept (MBtu/yr)	Savings (MBtu/yr)
Oil	-	-	-
Gas	-	-	-
Coal	3,150,760	-	3,150,760
Overall	3,150,760	-	3,150,760

Percent Energy Savings = 100% relative to reference system

C.8 WRITING PAPER MILL

The writing paper mill is a medium-sized facility located in Pennsylvania (DOE Region III). The required ratio of process heat to electricity is fairly typical at 5.23. The gross annual energy requirements are as follows:

- Process heat (sat'd steam @ 180 psia) 635.1×10^6 kWh/yr
- Electricity 120.9×10^6 kWh/yr

The choice of an energy conversion subsystem in this case was simplified for this application by price considerations. A large percentage of the existing coal-fired process steam boiler capacity is more than 60 years old and must be replaced. Current fuel contracts for the site indicate that oil prices have recently doubled, making the cost of coal approximately one-fifth that of oil. Natural gas prices are also considerably higher than the price of coal. A coal-fired steam system with BPT and FGD is therefore the only reasonable choice of configuration.

The energy utilization system model is shown in Figure C.8-1. In Table C.8-1, the conditions in the process energy utilization subsystem are given. The coal-fired boiler configuration is shown in Figure C.8-2. The significant operating parameter, the turbine throttle pressure, was varied to provide a correlation between the energy savings attainable for each point and the characteristic return on equity. The ROE's for industrial and third-party were very poor. The ROE for the utility ownership case was, however, acceptable but demonstrated little sensitivity to the system pressure level (see Figure C.8-3). The optimum case was, therefore, determined to correspond to the highest allowable steam conditions feasible in this size-range (1215 psia). Table C.8-2 contains the conditions and flows associated with the state points indicated in the cycle schematic.

The cogeneration system burns pulverized Ohio Pittsburgh #8 seam coal having the composition and properties indicated in Table C.8-3. Steam is generated at 1215 psia and is expanded to 180 psia in a back pressure turbine generator (22.2 MW/gross). The exhaust steam is used to deaerate the make-up water and to heat it to the saturation condition at 29.8 psia, to reheat the flue gas from the desulfurization system, and to provide process heat at a peak rate of 471.4×10^6 Btu/hr. In Table C.8-4, the energy distribution for the facility is shown. The ideal energy utilization factor (IEUF) for this case is 0.874 and the gross ratio of process heat to electricity is 8.2974 kWh/kWe.

The preliminary capital costs of the components are listed in Table C.8-5. Table C.8-6 contains the financial and economic assumptions used in analyzing the cash flow to be attained. The results of that analysis for the three ownership cases are given in Tables C.8-7a, b, and c.

The fuel utilization comparison between separate generation and a cogeneration installation is performed in Table C.8-8. As can be seen, the net result is a transfer from oil and natural gas to a reliance on coal with overall energy savings of 14%. A small amount of energy is still derivable from a black liquor boiler which operates in the same fashion in both cases and, thus, is not shown in the comparison.

Fig. C. 8-1 — Model of process heat utilization subsystem for writing paper mill

TABLE C.8-1

STATEPOINTS FOR ENERGY UTILIZATION SUBSYSTEM

IN WRITING PAPER MILL

Station	Pressure (psia)	Temperature (°F)	Enthalpy (Btu/lb)	Flow Rate (lb/s)
1	180.0	540.7	1293.0	106.9
2	-	-	-	-
3	15	100	68	106.9
4	>15	100	68	106.9
5	39.8	100	68	106.9

Fig. C.8-2 - Model of pulverized coal-fired steam energy conversion subsystem with FGD and back-pressure steam turbine for writing paper mill

Fig. C.8-3 - Annual energy saving vs return on equity, utility ownership option

TABLE C.8-2

STATEPOINTS FOR CONVERSION SUBSYSTEMIN WRITING PAPER MILL

Station	Pressure (psia)	Temperature (°F)	Enthalpy (Btu/lb)	Flow (lb/s)
1	14.7	77.0	0	185.43
2	16.0	85.0	2.0	185.43
3	15.8	540.0	112.7	185.43
4	15.5	3212.9	929.4	199.81
5	15.3	2006.5	541.4	199.81
6	15.1	1423.0	364.5	199.81
7	15.1	1423.0	364.5	199.81
8	14.9	682.1	155.6	199.81
9	14.7	279.0	50.8	199.81
20	39.8	100.1	68.2	106.91
21	29.8	250.0	218.6	124.14
22	1340.0	253.5	224.8	124.14
23	1315.0	558.9	560.5	124.14
24	-	-	-	-
25	-	-	-	-
26	1265.0	573.9	580.8	641.64
27	1265.0	573.9	701.4	641.64
28	1265.0	573.9	1183.7	124.14
29	1215.0	945.5	1467.9	124.14
30	180.0	540.7	1293.0	124.14
31	180.0	540.7	1293.0	1.99
32	180.0	540.7	1293.0	122.15
33	180.0	540.7	1293.0	15.24
34	180.0	540.7	1293.0	106.91

TABLE C.8-3

OHIO PITTSBURGH NO. 8 SEAM COAL

(Source of data: Monthly Progress Report 10
May 1973; OCR Contract No. 14-32-0001-1514)

SAMPLE: Run of mine		Dry Basis	As fired ⁽¹⁾
PROXIMATE ANALYSIS (wt %):			
	Volatile matter	41.72	47.55
	Fixed carbon	47.90	43.11
	Ash	10.38	9.34
		100.0	100.0
ULTIMATE ANALYSIS (wt %):			
(includes moisture)	C	71.14	64.03
	H	5.20	5.79
	O	8.41	16.45
	N	0.98	0.89
	S(2)	3.89	3.50
	Ash	10.38	9.34
		100.00	100.00
GROSS HEATING VALUE:	(Btu/lb)	12524	11272
NET HEATING VALUE:	(Btu/lb)	-	10730
ASH ANALYSIS (wt %):			
	SiO ₂	45.9	
	Al ₂ O ₃	23.8	
	Fe ₂ O ₃	23.5	
	TiO ₂	1.4	
	P ₂ O ₅	-	
	CaO	1.5	
	MgO	0.7	
	Na ₂ O	0.5	
	K ₂ O	1.9	
	SO ₃	-	
FUSIBILITY OF ASH:	Initial deformation temperature	--	2560°F
	Softening temperature	--	2600°F
	Fluid temperature	--	2685°F
GRINDABILITY (Hardgrove):	-		
FREE SWELLING INDEX:	2		
(1)	10% moisture assumed		
(2)	Sulfur forms (%):		
	Pyritic	-	46
	Sulfate	-	53
	Organic	-	1

TABLE C.8-4

POWER SUMMARY - WRITING PAPER MILL

HP STEAM PWR= 14511.3910 KW
LP STEAM PWR= 7701.7369 KW
ST POWER= 22213.1279 KW

GROSS POWER = 22213.1279 KW
FGD AUXILIARIES = 3471.5942 KW
AUXILIARY POWER = 1323.9604 KW
BOILER FEED PUMP POWER = 771.4177 KW
NET POWER GENERATED = 16646.1558 KW

TOTAL FUEL= 14.3853 LB/SEC
THERMAL RATING = 602490264.0000 BTU/HR

HEAT RATE 36193.9580 BTU/KWHR
TOTAL PROCESS HEAT = .4714+009 BTU/HR
PROCESS HEAT AT 180.0 PSIA = .4714068+009 BTU/HR

RPHEE = 8.2974 KWT/KWE

IEUF = .8740

TABLE C.8-5

WRITING PAPER MILL
SUMMARY OF CAPITAL COSTS: DEC. 1978\$

STEAM GENERATOR COSTS (INSTALLED)	= \$11762855.7
STEAM GENERATOR BOP COSTS	= \$14703569.6
TURBINE GENERATOR COST (INSTALLED)	= \$ 2998320.2
TURB-GEN BOP COSTS	= \$ 2998320.2
FLUE GAS DESULF COSTS (INST+BOP)	= \$ 3502599.1
TOTAL DIRECT COSTS	= \$35965664.8
INDIRECT COSTS	= \$ 5394849.7
ENGINEERING	= \$ 3596566.5
CONTINGENCY (20%)	= \$ 7193133.0
SUBTOTAL	= \$52150214.0
INTEREST DURING CONSTRUCTION (36 mo.)	= \$ 8630860.4
ESCALATION DURING CONSTRUCTION	= \$ 6317916.9
TOTAL CAPITAL COST	= \$67098991.3
SPECIFIC CAPITAL COST (\$/kWt)	= 379.32

TABLE C.8-6

RATE OF RETURN ON EQUITY SUMMARY
FOR INDUSTRIAL COGENERATION

ENERGY UTILIZATION SYSTEM CHARACTERIZATION
WRITING PAPER MILL

REQUIRED RATIO OF PROCESS HEAT/ELECTRICITY	=	5.2340
REQUIRED PROCESS HEAT	=	635218240.0 (KWH/YR)
REQUIRED ELECTRIC ENERGY	=	121363820.0 (KWH/YR)
SUPPLEMENTAL ELECTRIC ENERGY PURCHASED	=	44807521.0 (KWH/YR)
ASSUMED CAPACITY FACTOR	=	.5250
ASSUMED STANDBY POWER FRACTION	=	1.0000

ENERGY CONVERSION SYSTEM CHARACTERIZATION
COAL-FIRED STEAM WITH BPT

ACTUAL RATIO OF PROCESS HEAT/ELECTRICITY	=	8.2974
IDEAL ENERGY UTILIZATION FACTOR	=	.8740
SPECIFIC CAPITAL COST OF CONVERSION SYSTEM	=	379.3200 (\$/KWT)
INCR. LABOR COST (INDUSTRY) (1ST YEAR)	=	209948.1641 (\$)
INCR. LABOR COST (UTILITY) (1ST YEAR)	=	314798.0156 (\$)
INCR. LABOR COST (3RD PARTY) (1ST YEAR)	=	314798.0156 (\$)

TABLE C.8-6 (cont'd.)

WRITING PAPER MILL
ECONOMIC AND FINANCIAL ASSUMPTIONS

DEBT / EQUITY RATIO (INDUSTRY)	=	.5000
DEBT / EQUITY RATIO (UTILITY)	=	1.0000
DEBT / EQUITY RATIO (3RD PARTY)	=	5.0000
LIFE OF PROJECT	=	28 (YEARS)
LIFE OF INVESTMENT FOR TAX PURPOSES	=	28 (YEARS)
INCOME TAX RATES (FEDERAL + STATE)	=	.5650 (%/100)
INTEREST RATE ON DEBT	=	.1000 (%/YR/100)
INVESTMENT TAX CREDIT RATE	=	.2000 (%/100)
ITCR UNDER SEPARATE GENERATION (INDUSTRIAL)	=	.2000 (%/100)
ITCR UNDER SEPARATE GENERATION (UTILITY)	=	.1000 (%/100)
PROPERTY TAX RATE (1ST YEAR)	=	.0150 (%/100)
INSURANCE RATE (1ST YEAR)	=	.0150 (%/100)
CHARGE FOR STANDBY POWER	=	66.1108 (\$/KW)
MAINTENANCE & SUPPLIES COST FACTOR (1ST YR)	=	.0375 (%/100)
BOILER HEAT RATE (SEPARATE GENERATION)	=	3750.0000 (BTU/KWH)
CENTRAL STATION BUS BAR HEAT RATE	=	9500.0000 (BTU/KWH)
TRANSMISSION LOSSES OF PURCHASED POWER	=	.1000 (%/100)
SPECIFIC CAPITAL COST OF NEW UTILITY STATION	=	1000.0000 (\$/KW)
PRICE OF PROCESS STEAM (1ST YR)	=	3.8464 (\$/10 ⁶ BTU)
PRICE OF POWER AT CENTRAL STATION BUS BAR	=	.0190 (\$/KWH)
PRICE OF POWER BOUGHT FROM UTILITY (1ST YR)	=	.0317 (\$/KWH)
PRICE OF POWER SOLD TO UTILITY (1ST YR)	=	.0190 (\$/KWH)
PRICE OF FUEL (COGENERATION)	=	1.4775 (\$/10 ⁶ BTU)
PRICE OF FUEL, (SEP.GEN.: INDUSTRY)	=	1.4775 (\$/10 ⁶ BTU)
PRICE OF FUEL (SEP.GEN.: UTILITY)	=	1.4775 (\$/10 ⁶ BTU)
GENERAL INFLATION RATE	=	.0750 (%/100/YR)
FUEL PRICE RELATIVE ESC.(COGENERATION FUEL)	=	.0560 (%/100/YR)
FUEL PRICE REL. ESC.(SEP.GEN.: INDUSTRY)	=	.0560 (%/100/YR)
FUEL PRICE REL. ESC.(SEP.GEN.: UTILITY)	=	.0560 (%/100/YR)
RELATIVE ESC. OF ELECTRICAL ENERGY COSTS	=	.0210 (%/100/YR)
RELATIVE ESC. OF PROCESS STEAM COSTS	=	.0280 (%/100/YR)

TABLE C.8-7a

WRITING PAPER MILL
FOR INDUSTRIAL OWNERSHIP

INCREMENTAL CAPITAL INVESTMENT = 37541664 (\$)

NET INCREMENTAL EQUITY CAPITAL INVESTMENT = 20022221 (\$)

YEAR	NET SAVINGS IN ELECT.	DELTA FUEL COSTS	DELTA O AND M	DELTA PROP. TAX & INSUR.	INCOME TAXES ON SAVINGS
1	1328876.	589632.	2720971.	1126250.	-3925872.
2	1458541.	669351.	2925044.	1210719.	-4008435.
3	1600858.	759847.	3144423.	1301522.	-4102165.
4	1757062.	862578.	3380254.	1399137.	-4208106.
5	1928507.	979199.	3633773.	1504072.	-4327412.
6	2116681.	1111586.	3906306.	1616877.	-4461365.
7	2323216.	1261873.	4199279.	1738143.	-4611386.
8	2549904.	1432478.	4514225.	1868504.	-4779053.
9	2798711.	1626149.	4852792.	2008642.	-4966126.
10	3071795.	1846004.	5216751.	2159290.	-5174561.
11	3371526.	2095584.	5608007.	2321236.	-5406541.
12	3700502.	2378907.	6028608.	2495329.	-5664505.
13	4061579.	2700535.	6480753.	2682479.	-5951174.
14	4457887.	3065648.	6966810.	2883665.	-6269597.
15	4892865.	3480123.	7489321.	3099939.	-6623182.
16	5370287.	3950636.	8051020.	3332435.	-7015755.
17	5894292.	4484762.	8654846.	3582367.	-7451603.
18	6469428.	5091102.	9303959.	3851045.	-7935541.
19	7100682.	5779418.	10001756.	4139873.	-8472981.
20	7793531.	6560795.	10751888.	4450364.	-9070006.
21	8553985.	7447815.	11558279.	4784141.	-9733468.
22	9388639.	8454760.	12425150.	5142951.	-10471077.
23	10304736.	9597843.	13357036.	5528673.	-11291529.
24	11310220.	10895471.	14358814.	5943323.	-12204628.
25	12413815.	12368538.	15435724.	6389072.	-13221439.
26	13625093.	14040764.	16593404.	6868252.	-14354456.
27	14954561.	15939076.	17837908.	7383371.	-15617796.
28	16413752.	18094039.	19175751.	7937124.	-17027415.

YEAR	BASIC CASH FLOW
1	-433494
2	-589526
3	-754157
4	-928190
5	-1112513
6	-1308112
7	-1516081
8	-1737638
9	-1974134
10	-2227078
11	-2498149
12	-2789226
13	-3102403
14	-3440027
15	-3804724
16	-4199437
17	-4627469
18	-5092526
19	-5598773
20	-6150898
21	-6754171
22	-7414533
23	-8138675
24	-8934148
25	-9809469
26	-10774260
27	-11839387
28	-13017136

DISCOUNTED CASH FLOW RATE OF RETURN ON EQUITY (ROE) = < 0 %

ANNUAL ENERGY SAVED UNDER COGENERATION = 456326.7500 MBTU/YR

TABLE C.8-7b

WRITING PAPER MILL
FOR UTILITY OWNERSHIP

INCREMENTAL CAPITAL INVESTMENT = 47382200 (\$)
NET INCREMENTAL EQUITY CAPITAL INVESTMENT = 21321990 (\$)

YEAR	STEAM REVENUE	DELTA ELECT. REVENUE	DELTA FUEL COSTS	DELTA O AND M	DELTA PROP. TAX & INSUR.	TAXES
1	8343787	1540505	2915238	2091631	1421466	-1232203
2	9220719	1690820	3309378	2248503	1528076	-957427
3	10189817	1855801	3756806	2417140	1642682	-663563
4	11260766	2036881	4264726	2598426	1765883	-349238
5	12444273	2235630	4841317	2793308	1898324	-13037
6	13752166	2453771	5495863	3002806	2040698	346484
7	15197518	2693198	6238904	3228016	2193750	730786
8	16794777	2955987	7082403	3470118	2358282	1141327
9	18559908	3244417	8039944	3730376	2535153	1579538
10	20510554	3560991	9126944	4010154	2725289	2046799
11	22666213	3908455	10360907	4310916	2929686	2544398
12	25048431	4289822	11761702	4634235	3149412	3073493
13	27681021	4708401	13351884	4981802	3385618	3635057
14	30590296	5167824	15157058	5355437	3639540	4229816
15	33805335	5672074	17206292	5757095	3912505	4858174
16	37358275	6225526	19532582	6188877	4205943	5520121
17	41284630	6832982	22173387	6653043	4521389	6215127
18	45623644	7499710	25171229	7152021	4860493	6942012
19	50418688	8231494	28574378	7688422	5225029	7698799
20	55717691	9034682	32437633	8265054	5616907	8482529
21	61573620	9916241	36823201	8884933	6038175	9289054
22	68045006	10883818	41801697	9551303	6491038	10112789
23	75196535	11945807	47453285	10267650	6977865	10946423
24	83099690	13111419	53868969	11037724	7501205	11780575
25	91833467	14390765	61152052	11865553	8063795	12603399
26	101485163	15794944	69419809	12755470	8668580	13400118
27	112151251	17336135	78805367	13712130	9318723	14152485
28	123938346	19027708	89459850	14740539	10017628	14838156

YEAR	BASIC CASH FLOW	DISCOUNTED ADJUSTED CASH FLOW
1	3740516	3024594
2	3941974	2577419
3	4166124	2202618
4	4414623	1887279
5	4689204	1620979
6	4991673	1395275
7	5323899	1203315
8	5687805	1039513
9	6085356	899304
10	6518536	778944
11	6989336	675348
12	7499713	585966
13	8051569	508679
14	8646697	441722
15	9286738	383617
16	9973111	333120
17	10706945	289182
18	11488981	250913
19	12319472	217555
20	13198047	188461
21	14123563	163077
22	15093925	140924
23	16105872	121592
24	17154730	104722
25	18234117	90007
26	19335600	77176
27	20448294	65996
28	21558399	56262

DISCOUNTED CASH FLOW RATE OF RETURN ON EQUITY(ROE)= 23.67 %

ANNUAL ENERGY SAVED UNDER COGENERATION = 456326.7500 MBTU/YR

TABLE C.8-7c

WRITING PAPER MILL
FOR THIRD PARTY OWNERSHIP

CAPITAL INVESTMENT = 66960623 (\$)
NET EQUITY CAPITAL INVESTMENT = 8928083 (\$)

YEAR	STEAM REVENUE	DELTA ELECT. REVENUE	DELTA FUEL COSTS	DELTA O AND M	DELTA PROP. TAX & INSUR.	TAXES
1	8343787.	1328876.	4109228.	2825821.	2008819.	-5350115.
2	9220719.	1458541.	4664795.	3037758.	2159480.	-5206967.
3	10189817.	1600858.	5295475.	3265590.	2321441.	-5062401.
4	11260766.	1757062.	6011423.	3510509.	2495549.	-4917136.
5	12444273.	1928507.	6824168.	3773797.	2682715.	-4772112.
6	13752166.	2116681.	7746795.	4056832.	2883919.	-4628529.
7	15197518.	2323216.	8794162.	4361094.	3100213.	-4487905.
8	16794777.	2549904.	9983132.	4688176.	3332729.	-4352132.
9	18559908.	2798711.	11332851.	5039789.	3582683.	-4223550.
10	20510554.	3071795.	12865053.	5417773.	3851384.	-4105029.
11	22666213.	3371526.	14604408.	5824106.	4140238.	-4000066.
12	25048431.	3700502.	16578923.	6260914.	4450756.	-3912897.
13	27681021.	4061579.	18820393.	6730483.	4784563.	-3848629.
14	30590296.	4457887.	21364910.	7235269.	5143405.	-3813392.
15	33805335.	4892865.	24253446.	7777914.	5529160.	-3814517.
16	37358275.	5370287.	27532511.	8361257.	5943847.	-3860738.
17	41284630.	5894292.	31254906.	8988351.	6389636.	-3962433.
18	45623644.	6469428.	35480569.	9662478.	6868858.	-4131896.
19	50418688.	7100682.	40277541.	10387163.	7384022.	-4383657.
20	55717691.	7793531.	45723064.	11166201.	7937824.	-4734851.
21	61573620.	8553985.	51904821.	12003666.	8533161.	-5205636.
22	68045006.	9388639.	58922353.	12903940.	9173148.	-5819693.
23	75196535.	10304736.	66888653.	13871736.	9861134.	-6604776.
24	83099690.	11310220.	75931998.	14912116.	10600718.	-7593381.
25	91833467.	12413815.	86198002.	16030524.	11395772.	-8823480.
26	101485163.	13625093.	97851972.	17232813.	12250455.	-10339398.
27	112151251.	14954561.	111081556.	18525274.	13169239.	-12192792.
28	123938346.	16413752.	126099780.	19914669.	14156932.	-14443808.

YEAR	BASIC CASH FLOW
1	498858
2	444142
3	390517
4	337431
5	284159
6	229778
7	173118
8	112724
9	46793
10	-26884
11	-110999
12	-208814
13	-324261
14	-462060
15	-627853
16	-828367
17	-1071590
18	-1366990
19	-1725751
20	-2161067
21	-2688458
22	-3326155
23	-4095527
24	-5021593
25	-6133588
26	-7465638
27	-9057516
28	-10955526

DISCOUNTED CASH FLOW RATE OF RETURN ON EQUITY (ROE) = 0 %
ANNUAL ENERGY SAVED UNDER COGENERATION = 456326.7500 MBTU/YR

TABLE C.8-8

FUEL UTILIZATION

WRITING PAPER MILL

	Separate Generation (MBtu/yr)	Cogeneration (MBtu/yr)	Savings (MBtu/yr)
Oil	-	-	-
Gas	501485	-	501485
Coal	2735955	2781118	-45163
Overall	3237440	2781118	456322

Percent Energy Savings = 14.1%

C.9 KRAFT PAPER MILL

The Kraft paper mill located in DOE Region I is really two plants interconnected electrically but not thermally. Plant No. 1 is a paper mill which currently has a limited amount of cogeneration, both mechanical drive and electrical generation ($\sim 2,100$ kW). A model of the energy utilization subsystem for Plant No. 1 is shown in Figure C.9-1. The corresponding state point data is shown in Table C.9-1. Process steam is required at three pressure levels; 265, 155, and 55 psia. Power steam is required at 155 psia. The overall* steam generation profile for Plant No. 1 is as follows:

Maximum monthly average	- 208,000 lb/hr
Minimum monthly average	- 147,000 lb/hr
Annual average rate	- 179,000 lb/hr
Capacity factor	- 0.86

Plant No. 2 is a pulp and paper mill which currently has a substantial amount of cogeneration, both mechanical drive and electric generation ($\sim 12,600$ kW). Process and power steam are required at 415 psia and process steam at 155 psia. The overall* steam generation profile for Plant No. 2 is as follows:

Maximum monthly average	- 647,000 lb/hr
Minimum monthly average	- 501,000 lb/hr
Annual average rate	- 570,000 lb/hr
Capacity factor	- 0.88

This company has plans to install a bark-burning boiler in Plant No. 2, capable of generating 200,000 lbs. per hour of steam at 850 psig, 735°F. Initially, this boiler will be operated at 400 psig to supply an existing 400 psig header. The installation of a steam turbine generator with 850 psig, 735°F throttle conditions would be made at a future date.

Since the proposed installation of a bark-fired boiler in Plant No. 2 would substantially reduce the consumption of fuel oil there, it was decided that Plant No. 1 had the greatest potential for improvement and should be the subject of optimization in this study. The reference configuration for Plant No. 2 was assumed to be with the bark-fired boiler producing 400 psig steam.

Consumption of electrical power by the Kraft paper mill complex is very nearly constant around the year. In addition to the 2,100 kW generated in Plant No. 1 and the 12,000 kW generated in Plant No. 2, there are 5 hydro-electric facilities owned by the company which generate about 6,000 kW. About 8,000 kW are purchased from the local power company.

* Includes steam used for feedwater heating and boiler feed pump drive.

Fig. C.9-1 — Model of energy utilization subsystem for Plant No.1 of Kraft Paper Mill (Region I)

TABLE C.9-1

STATEPOINTS FOR ENERGY UTILIZATION SUBSYSTEM
IN KRAFT PAPER MILL (REGION I)

Station	Pressure (psia)	Temperature (°F)	Enthalpy (Btu/lb)	Flow Rate (lb/s)
1	265	620	1324	7.51
2	155	530	1288	25.22
3	55	368	1218	18.64
4	>15	200	168	25.69
5	15	100	68	25.69
6	>15	150	118	51.37
7	39.8	150	118	51.37

It was stipulated that the low-pressure steam turbine generator set in Plant No. 1 would be eliminated in the optimized cogeneration system. The net power demand for the two plants would then be the sum of the power currently being purchased and the power now being generated in Plant No. 1 ($8,000 + 2,100 = 10,100$ kW).

The energy conversion subsystem design factors for the Plant No. 1 cogeneration system are:

Process steam

265 psig* - 27,050 lb/hr

140 psig - 90,780 lb/hr

40 psig - 67,090 lb/hr

QS = 461×10^6 kWh/year

EP = 87.95×10^6 kWh/year

RPHEP = 5.24

Condensate recycle fraction - 50%

Recycle condensate temperature - 200°F

The candidate energy conversion subsystems considered for this application were

- Coal-fired steam with extraction/back pressure turbine
- Low sulfur residual-fired steam with extraction/back pressure turbine

The optimization analysis showed that both the utility and third-party ownership options are viable and that the ROE is relatively insensitive to the turbine throttle pressure. Figures C.9-2a and C.9-2b are the optimization curves. The coal-fired steam energy conversion subsystem for this application is shown in Figure C.9-3. State point conditions are given in Table C.9-2. A pulverized coal-fired boiler** with economizer and air preheater generates steam at 915 psia/875°F. The steam turbine has double automatic extraction to supply process steam at 265 and 140 psig and exhausts at a pressure of 40 psig.

The energy distribution for Plant No. 1 is given in Table C.9-3. The ideal energy utilization factor is 0.8647 and the RPHEE is 7.87. The preliminary capital costs are given in Table C.9-4.

* Pressure of 265 psia was inadvertently used in performance calculations

**Ohio Pittsburgh No. 8 seam coal

Fig. C.9-2a - Annual energy savings vs return on equity, utility ownership

Fig. C.9-2b - Annual energy savings vs return on equity, third-party ownership

KRAFT PAPER MILL:

COAL-FIRED DOUBLE EXTRACTION
STEAM TURBINE FOR PLANT SITE #1

Fig. C.9-3 - Model of coal-fired steam energy conversion subsystem for kraft paper mill

TABLE C.9-2STATEPOINTS FOR CONVERSION SUBSYSTEMIN KRAFT PAPER MILL (SITE #1)

Station	Pressure (psia)	Temperature (°F)	Enthalpy (Btu/lb)	Flow (lb/s)
1	14.7	77.0	0.0	83.21
2	15.9	85.0	2.0	83.21
3	15.7	540.0	112.7	83.21
4	15.5	3212.9	929.4	89.67
5	15.2	1864.5	497.6	89.67
6	14.9	1351.7	343.6	89.67
7	14.5	682.1	155.6	89.67
8	14.3	279.0	50.8	89.67
9	14.7	175.0	23.8	89.67
20	39.8	150.0	118.1	51.37
21	29.8	250.0	218.6	57.07
22	1040.0	252.7	223.4	57.07
23	965.0	540.3	537.1	104.33
24	965.0	540.3	668.8	104.33
25	965.0	540.3	1195.6	57.07
26	915.0	875.0	1437.1	57.07
27	265.0	620.0	1324.0	7.51
28	155.0	530.0	1280.0	25.22
29	55.0	367.9	1218.0	24.34
30	55.0	367.9	1218.0	5.21
31	55.0	367.9	1218.0	19.13
32	55.0	367.9	1218.0	0.49
33	55.0	367.9	1212.0	18.64

TABLE C.9-3

POWER SUMMARY FOR KRAFT PAPER MILL (SITE #1)

Steam Turbine Power	10283 kW
Flue Gas Desulfurization Auxiliaries	1657 kW
Auxiliary Power	594 kW
Boiler Feed Pump Power	<u>273 kW</u>
Net Power Generated	7757 kW
Fuel Flow (Pittsburgh Seam)	6.456 lb/s
Fuel Energy Input	270.37×10^6 Btu/hr
RPHEE	7.872 kWt/kWe
IEUF	0.8647

TABLE C.9-4

KRAFT PAPER MILL
SUMMARY OF CAPITAL COSTS: DEC. 1978\$

STEAM GENERATOR COST (INSTALLED)	= \$ 5105597.4
STEAM GENERATOR BOP COSTS	= \$ 6381996.7
TURBINE GENERATOR COST (INSTALLED)	= \$ 2243600.5
TURB-GEN BOP COSTS	= \$ 2243600.5
FLUE GAS DESULF COSTS (INST+BOP)	= \$ 2163630.0
TOTAL DIRECT COSTS	= \$18138425.0
INDIRECT COSTS	= \$ 2720763.7
ENGINEERING	= \$ 1813842.5
CONTINGENCY (20%)	= \$ 3627685.0
SUBTOTAL	= \$26300716.2
INTEREST DURING CONSTRUCTION (36 mo.)	= \$ 4352768.5
ESCALATION DURING CONSTRUCTION	= \$ 3186290.6
TOTAL CAPITAL COST	= \$33839775.3
SPECIFIC CAPITAL COST (\$/kWt)	= 426.974

This information, with the data given in Table C.9-5 was used to develop the financial analysis shown in Tables C.9-6a, -6b, and -6c for the ownership options. As was indicated the industrial option was not successful.

The fuel utilization under both separate generation and cogeneration is given in Table C.9-7. While effecting an overall energy savings of 13.7%, the use of oil is entirely eliminated, being replaced by coal.

TABLE C.9-5

RATE OF RETURN ON EQUITY SUMMARY
FOR INDUSTRIAL COGENERATION

ENERGY UTILIZATION SYSTEM CHARACTERIZATION
KRAFT PAPER MILL

REQUIRED RATIO OF PROCESS HEAT/ELECTRICITY	=	5.2400
REQUIRED PROCESS HEAT	=	460818140.0 (KWH/YR)
REQUIRED ELECTRIC ENERGY	=	87942392.0 (KWH/YR)
SUPPLEMENTAL ELECTRIC ENERGY PURCHASED	=	29433233.0 (KWH/YR)
ASSUMED CAPACITY FACTOR	=	.8600
ASSUMED STANDBY POWER FRACTION	=	1.0000

ENERGY CONVERSION SYSTEM CHARACTERIZATION
COAL-FIRED STEAM WITH 2-EXTR EPT

ACTUAL RATIO OF PROCESS HEAT/ELECTRICITY	=	7.8760
IDEAL ENERGY UTILIZATION FACTOR	=	.8647
SPECIFIC CAPITAL COST OF CONVERSION SYSTEM	=	426.9740 (\$/KWT)
INCR. LABOR COST (INDUSTRY) (1ST YEAR)	=	163237.8027 (\$)
INCR. LABOR COST (UTILITY) (1ST YEAR)	=	122366.2373 (\$)
INCR. LABOR COST (3RD PARTY) (1ST YEAR)	=	244856.7051 (\$)

TABLE C.9-5 (cont'd)

KRAFT PAPER MILL

ECONOMIC AND FINANCIAL ASSUMPTIONS

DEBT / EQUITY RATIO (INDUSTRY)	=	.5000
DEBT / EQUITY RATIO (UTILITY)	=	1.0000
DEBT / EQUITY RATIO (3RD PARTY)	=	5.0000
LIFE OF PROJECT	=	28 (YEARS)
LIFE OF INVESTMENT FOR TAX PURPOSES	=	28 (YEARS)
INCOME TAX RATES (FEDERAL + STATE)	=	.5100 (%/100)
INTEREST RATE ON DEBT	=	.1000 (%/YR/100)
INVESTMENT TAX CREDIT RATE	=	.2000 (%/100)
ITCR UNDER SEPARATE GENERATION (INDUSTRIAL)	=	.2000 (%/100)
ITCR UNDER SEPARATE GENERATION (UTILITY)	=	.1000 (%/100)
PROPERTY TAX RATE (1ST YEAR)	=	.0150 (%/100)
INSURANCE RATE (1ST YEAR)	=	.0150 (%/100)
CHARGE FOR STANDBY POWER	=	63.5608 (\$/KW)
MAINTENANCE & SUPPLIES COST FACTOR (1ST YR)	=	.0375 (%/100)
BOILER HEAT RATE (SEPARATE GENERATION)	=	3750.0000 (BTU/KWH)
CENTRAL STATION BUS BAR HEAT RATE	=	9500.0000 (BTU/KWH)
TRANSMISSION LOSSES OF PURCHASED POWER	=	.1000 (%/100)
SPECIFIC CAPITAL COST OF NEW UTILITY STATION	=	1000.0000 (\$/KW)
PRICE OF PROCESS STEAM (1ST YR)	=	5.0907 (\$/10 ⁶ BTU)
PRICE OF POWER AT CENTRAL STATION BUS BAR	=	.0267 (\$/KWH)
PRICE OF POWER BOUGHT FROM UTILITY (1ST YR)	=	.0445 (\$/KWH)
PRICE OF POWER SOLD TO UTILITY (1ST YR)	=	.0267 (\$/KWH)
PRICE OF FUEL (COGENERATION)	=	2.1375 (\$/10 ⁶ BTU)
PRICE OF FUEL, (SEP.GEN.: INDUSTRY)	=	2.1375 (\$/10 ⁶ BTU)
PRICE OF FUEL (SEP.GEN.: UTILITY)	=	2.1375 (\$/10 ⁶ BTU)
GENERAL INFLATION RATE	=	.0750 (%/100/YR)
FUEL PRICE RELATIVE ESC.(COGENERATION FUEL)	=	.0332 (%/100/YR)
FUEL PRICE REL. ESC.(SEP.GEN.: INDUSTRY)	=	.0332 (%/100/YR)
FUEL PRICE REL. ESC.(SEP.GEN.: UTILITY)	=	.0332 (%/100/YR)
RELATIVE ESC. OF ELECTRICAL ENERGY COSTS	=	.0077 (%/100/YR)
RELATIVE ESC. OF PROCESS STEAM COSTS	=	.0175 (%/100/YR)

TABLE C.9-6a

KRAFT PAPER MILL
FOR INDUSTRIAL OWNERSHIP

INCREMENTAL CAPITAL INVESTMENT = 20475313 (\$)
NET INCREMENTAL EQUITY CAPITAL INVESTMENT = 10920167 (\$)

YEAR	NET SAVINGS IN ELECT.	DELTA FUEL COSTS	DELTA O AND M	DELTA PROP. TAX & INSUR.	INCOME TAXES ON SAVINGS
1	2109581.	690270.	1431634.	614259.	-1387803.
2	2285261.	766672.	1539006.	660329.	-1389709.
3	2475572.	851539.	1654432.	709853.	-1394335.
4	2681732.	945796.	1778514.	763092.	-1401978.
5	2905060.	1050486.	1911903.	820324.	-1412969.
6	3146986.	1166764.	2055295.	881849.	-1427676.
7	3409059.	1295914.	2209443.	947987.	-1446510.
8	3692957.	1439358.	2375151.	1019086.	-1469931.
9	4000497.	1598681.	2553287.	1095518.	-1498449.
10	4333648.	1775639.	2744784.	1177682.	-1532637.
11	4694543.	1972184.	2950642.	1266008.	-1573133.
12	5085493.	2190485.	3171940.	1360958.	-1620648.
13	5509000.	2432950.	3409836.	1463030.	-1675980.
14	5967776.	2702253.	3665574.	1572758.	-1740016.
15	6464757.	3001365.	3940492.	1690714.	-1813749.
16	7003126.	3333586.	4236028.	1817518.	-1898287.
17	7586328.	3702581.	4553730.	1953832.	-1994869.
18	8218099.	4112420.	4895260.	2100369.	-2104877.
19	8902481.	4567623.	5262405.	2257897.	-2229859.
20	9643858.	5073213.	5657085.	2427239.	-2371539.
21	10446974.	5634767.	6081366.	2609282.	-2531847.
22	11316971.	6258480.	6537469.	2804978.	-2712939.
23	12259420.	6951230.	7027779.	3015351.	-2917221.
24	13280354.	7720662.	7554862.	3241503.	-3147385.
25	14386309.	8575262.	8121477.	3484615.	-3406434.
26	15584364.	9524458.	8730587.	3745961.	-3697729.
27	16882191.	10578720.	9385381.	4026908.	-4025018.
28	18288097.	11749679.	10089285.	4328926.	-4392495.

YEAR	BASIC CASH FLOW
1	78710
2	26448
3	-28427
4	-86203
5	-147195
6	-211757
7	-280284
8	-353218
9	-431050
10	-514329
11	-603668
12	-699752
13	-803346
14	-915302
15	-1036576
16	-1168230
17	-1311456
18	-1467583
19	-1638095
20	-1824651
21	-2029104
22	-2253526
23	-2500229
24	-2771798
25	-3071121
26	-3401424
27	-3766310
28	-4169808

DISCOUNTED CASH FLOW RATE OF RETURN ON EQUITY (ROE) = 0 %
ANNUAL ENERGY SAVED UNDER COGENERATION = 325729.5937 MBTU/YR

TABLE C.9-6b

**KRAFT PAPER MILL
FOR UTILITY OWNERSHIP**

INCREMENTAL CAPITAL INVESTMENT = 24760430 (\$)
NET INCREMENTAL EQUITY CAPITAL INVESTMENT = 9450998 (\$)

YEAR	STEAM REVENUE	DELTA ELECT. REVENUE	DELTA FUEL COSTS	DELTA O AND M	DELTA PROP. TAX & INSUR.	TAXES
1	8011217.	1565112.	3063886.	1050882.	742813.	904286.
2	8762769.	1695451.	3403028.	1129699.	798524.	1143582.
3	9584826.	1836644.	3779709.	1214426.	858413.	1400081.
4	10484002.	1989595.	4198085.	1305508.	922794.	1675111.
5	11467533.	2155283.	4662770.	1403421.	992004.	1970094.
6	12543331.	2334770.	5178892.	1508677.	1066404.	2286544.
7	13720052.	2529203.	5752144.	1621828.	1146384.	2626081.
8	15007164.	2739829.	6388849.	1743465.	1232363.	2990427.
9	16415023.	2967995.	7096030.	1874225.	1324790.	3381415.
10	17954957.	3215162.	7881490.	2014792.	1424149.	3800993.
11	19639356.	3482913.	8753892.	2165901.	1530961.	4251228.
12	21481773.	3772961.	9722860.	2328344.	1645783.	4734310.
13	23497032.	4087164.	10799083.	2502970.	1769216.	5252554.
14	25701347.	4427532.	11994433.	2690693.	1901908.	5808405.
15	28112454.	4796246.	13322097.	2892494.	2044551.	6404442.
16	30749753.	5195666.	14796719.	3109431.	2197892.	7043372.
17	33634464.	5628348.	16434568.	3342639.	2362734.	7728037.
18	36789796.	6097062.	18253710.	3593337.	2539939.	8461411.
19	40241139.	6604810.	20274213.	3862837.	2730434.	9246596.
20	44016260.	7154842.	22518365.	4152550.	2935217.	10086817.
22	52662187.	8396136.	27779381.	4798790.	3392010.	11945841.
23	57602558.	9095346.	30854280.	5158699.	3646410.	12971633.
24	63006397.	9852783.	34269540.	5545602.	3919891.	14066409.
25	68917184.	10673298.	38062836.	5961522.	4213883.	15233841.
26	75382477.	11562143.	42276010.	6408636.	4529924.	16477626.
27	82454293.	12525010.	46955541.	6889283.	4869668.	17801456.
28	90189536.	13568061.	52153049.	7405979.	5234893.	19208981.

YEAR	BASIC CASH FLOW	DISCOUNTED ADJUSTED CASH FLOW
1	3319252	2333721
2	3543889	1751853
3	3789232	1316975
4	4056871	991348
5	4348509	747110
6	4665964	563630
7	5011180	425600
8	5386230	321629
9	5793326	243224
10	6234823	184040
11	6713226	139325
12	7231199	105515
13	7791568	79935
14	8397326	60571
15	9051645	45905
16	9757874	34793
17	10519546	26372
18	11340379	19989
19	12224281	15149
20	13175348	11480
21	14197863	8698
22	15296289	6588
23	16475269	4989
24	17739608	3777
25	19094262	2858
26	20544327	2162
27	22095000	1635
28	23751566	1236

DISCOUNTED CASH FLOW RATE OF RETURN ON EQUITY(ROE)= 42.23 %

ANNUAL ENERGY SAVED UNDER COGENERATION = 325729.5937 MBTU/YR

TABLE C.9-6c

KRAFT PAPER MILL
FOR THIRD PARTY OWNERSHIP

CAPITAL INVESTMENT = 33823896 (\$)
NET EQUITY CAPITAL INVESTMENT = 4509852 (\$)

YEAR	STEAM REVENUE	ELECT. REVENUE	FUEL COSTS	O AND M	PROP. TAX & INSUR.	TAXES
1	8011217.	2109581.	4383990.	1513253.	1014717.	-990676.
2	8762769.	2285261.	4869254.	1626747.	1090821.	-819479.
3	9584826.	2475572.	5408231.	1748753.	1172632.	-639508.
4	10484002.	2681732.	6006868.	1879909.	1260580.	-450347.
5	11467533.	2905060.	6671768.	2020902.	1355123.	-251584.
6	12543331.	3146986.	7410266.	2172470.	1456757.	-42823.
7	13720052.	3409059.	8230509.	2335405.	1566014.	176308.
8	15007164.	3692957.	9141543.	2510561.	1683465.	406155.
9	16415023.	4000497.	10153421.	2698853.	1809725.	647018.
10	17954957.	4333648.	11277303.	2901266.	1945454.	899146.
11	19639356.	4694543.	12525587.	3118861.	2091363.	1162723.
12	21481773.	5085493.	13912044.	3352776.	2248215.	1437844.
13	23497032.	5509000.	15451968.	3604234.	2416832.	1724503.
14	25701347.	5967776.	17162346.	3874552.	2598094.	2022569.
15	28112454.	6464757.	19062046.	4165143.	2792951.	2331757.
16	30749753.	7003126.	21172024.	4477529.	3002422.	2651600.
17	33634464.	7586328.	23515555.	4813343.	3227604.	2981415.
18	36789796.	8218099.	26118491.	5174344.	3469674.	3320262.
19	40241139.	8902481.	29009547.	5562420.	3729900.	3666898.
20	44016260.	9643858.	32220613.	5979601.	4009642.	4019725.
21	48145535.	10446974.	35787112.	6428071.	4310365.	4376729.
22	52662187.	11316971.	39748386.	6910176.	4633643.	4735414.
23	57602558.	12259420.	44148135.	7428440.	4981166.	5092717.
24	63006397.	13280354.	49034891.	7985572.	5354753.	5444926.
25	68917184.	14386309.	54462563.	8584490.	5756360.	5787572.
26	75382477.	15584364.	60491023.	9228327.	6188086.	6115316.
27	82454293.	16882191.	67186773.	9920451.	6652193.	6421812.
28	90189536.	18288097.	74623676.	10664485.	7151107.	6699562.

YEAR	BASIC CASH FLOW	DISCOUNTED ADJUSTED CASH FLOW
1	1380856	1008145
2	1462030	779301
3	1551632	603827
4	1650066	468813
5	1757724	364606
6	1874988	283953
7	2002216	221377
8	2139738	172726
9	2287846	134833
10	2446777	105279
11	2616707	82201
12	2797729	64165
13	2989836	50063
14	3192903	39033
15	3406656	30405
16	3630646	23658
17	3864217	18384
18	4106466	14263
19	4356198	11046
20	4611879	8538
21	4871573	6585
22	5132882	5065
23	5392862	3885
24	5647950	2971
25	5893849	2263
26	6125430	1717
27	6336596	1297
28	6520144	974

DISCOUNTED CASH FLOW RATE OF RETURN ON EQUITY(ROE)= 36.97 %

ANNUAL ENERGY SAVED UNDER COGENERATION = 325729.5937 MBTU/YR

TABLE C.9-7

FUEL UTILIZATION, KRAFT PAPER MILL (SITE NO. 1)

	Separate Generation (MBtu/yr)	Cogeneration (MBtu/yr)	Savings (MBtu/yr)
Gas	-	-	-
Oil	1728068	-	1728068
Coal	648941	2051118	-1402177
Overall	2377009	2051118	325891

Percent Energy Savings = 13.7%

C.10 TEXTILE FINISHING MILL

The textile finishing mill is located in South Carolina (DOE Region IV). The energy demands for the plant are as follows:

- Process steam (325 psia) 410.49×10^6 kWh/yr
- Process steam (165 psia) 165.84×10^6 kWh/yr
- Electricity 65.02×10^6 kWh/yr
- RPHEP 8.86 kWt/kWe

A small amount of hot gas heating for drying and curing, which is lumped in the above tabulation with the process steam, is also required.

Three alternatives for fulfilling these needs suggest themselves. The first two represent partial cogeneration cases. Currently, natural gas is burned to provide the hot gas heat while dual fuel (oil/gas) boilers are used to generate process steam. The first alternative would replace the natural gas burners with a combustion turbine using exhaust gases for the direct heating. The existing boilers would continue to provide process steam. The second alternative would convert the existing boilers to an unfired mode, using the existing heat transfer surface to generate process steam with the exhaust from a new combustion turbine. Natural gas would continue to be used for drying and curing.

Neither of these options would provide significant energy savings and both would require the continued use of economically sensitive fuels. The third option, the one eventually chosen, is a conventional coal-fired power boiler with a single extraction back pressure turbine providing the main process steam (at 165 psia) as well as sufficient steam (at 325 psia) for use in steam/air heaters to satisfy the direct heating requirements.

The energy utilization system model is given in Figure C.10-1. The conditions at the indicated statepoints are given in Table C.10-1. The system to be optimized for energy savings is shown in Figure C.10-2. A range of throttle pressures was analyzed in order to assess the effect on cycle performance and cost. Figures C.10-3a and C.10-3b represent the optimization plots for the utility and third-party ownership. Both show a reasonable return on equity. The maximum energy savings occur at the highest allowable steam turbine throttle pressure (1215 psia). The optimum case was, therefore, determined to correspond to the highest allowable steam conditions feasible in this size-range (1215 psia). Table C.10-2 contains the pertinent data on steam and gas conditions and flow rates corresponding to the points in Figure C.10-2.

Steam is generated in conventional boiler, fed with pulverized Alabama coal having the composition noted in Table C.10-3. The turbine expands the steam from its throttle pressure of 1215 psia to 165 psia, extracting a fraction of the flow at 325 psia. The gross power generated by the turbine is 19.7 MW at design load. A quantity of steam is recycled to the deaerating feedwater heater to bring the recycled and make-up condensate to saturation at the return pressure of 29.8 psia. Another side-stream is used to reheat the flue gas from the desulfurization system to a temperature adequate to provide a draft at the stack. Table C.10-4

Fig. C.10-1 – Model of energy utilization subsystem for textile finishing mill

TABLE C.10-1

STATEPOINTS FOR ENERGY UTILIZATION
SUBSYSTEM IN TEXTILE FINISHING MILL

Station	Pressure psia	Temperature °F	Enthalpy (Btu/lb)	Flow Rate (lb/s)
1	165	514.7	1280.6	77.13
2	335	661.8	1345.0	28.42
3	>15	200	132	21.60
4	15	100	68	55.53
5	>15	100	68	77.13
6	39.8	100	68	77.13
7	335	350	321.8	28.42
8	39.8	189	157.1	105.55

Fig. C.10-2 - Model of coal-fired single extraction steam turbine energy conversion subsystem for textile finishing mill

Fig. C.10-3a - Annual energy savings vs return on equity, utility ownership

Fig. C.10-3b - Annual energy savings vs return on equity, third-party ownership

TABLE C.10-2

STATEPOINTS FOR CONVERSION SUBSYSTEM
IN TEXTILE FINISHING MILL

Steam Turbine Throttle Pressure: 1215 psia

	Pressure (psia)	Temperature (°F)	Enthalpy (Btu/lb)	Flow (lb/s)
1	14.7	77.0	0.0	140.06
2	15.9	85.0	2.0	140.06
3	15.7	540.0	112.7	140.06
4	15.5	3613.8	1071.5	152.34
5	15.2	2235.1	612.1	152.34
6	14.9	1550.8	401.8	152.34
7	14.5	678.9	154.4	152.34
8	14.3	279.0	50.6	152.34
9	14.7	175.0	23.8	152.34
20	39.8	189.0	157.1	105.55
21	29.8	250.0	218.6	112.07
22	1340.0	253.5	224.8	112.07
23	1265.0	573.9	580.8	580.31
24	1265.0	573.9	701.4	580.31
25	1265.0	573.9	1183.7	112.07
26	1215.0	948.6	1469.0	112.07
27	335.0	661.8	1345.0	28.42
28	165.0	514.7	1280.6	83.65
29	165.0	514.7	1280.6	6.13
30	165.0	514.7	1280.6	77.52
31	165.0	514.7	1280.6	0.39
32	165.0	514.7	1280.6	77.13

TABLE C.10-3

FUEL SPECIFICATIONS
COAL FOR TEXTILE FINISHING MILL

State - Alabama

Locality - Clift

Bid - Pratt

Category - R.O.M.

Proximate analysis (as-fired)

Moisture - %	10.0
Volatile matter - %	27.4
Fixed carbon - %	54.9
Ash - %	7.7
	<hr/>
	100.0

Ultimate analysis (as-fired)

Hydrogen - %	5.60
Carbon - %	72.02
Oxygen - %	11.38
Sulfur - %	1.77
Ash - %	7.74
Nitrogen - %	1.49
	<hr/>
	100.00

Heating values

Higher	12732 Btu/lb
Lower	12208 Btu/lb

TABLE C.10-4

POWER SUMMARY

TEXTILE FINISHING MILL

HP STEAM PWR=	12498.1104 KW
IP STEAM PWR=	1673.2007 KW
LP STEAM PWR=	5546.1967 KW
ST POWER=	19717.5076 KW

GROSS POWER	=	19717.5076 KW
FGD AUXILIARIES	=	859.4674 KW
AUXILIARY POWER	=	1184.8886 KW
BOILER FEED PUMP POWER	=	696.3968 KW
NET POWER GENERATED	=	16976.7551 KW

TOTAL FUEL=	12.2790 LB/SEC
THERMAL RATING =	539203320.0000 BTU/HR

HEAT RATE	31761.2708 BTU/KWHR
TOTAL PROCESS HEAT =	.4314+009 BTU/HR
PROCESS HEAT AT 165.0 PSIA =	.4313972+009 BTU/HR

RPHEE =	8.2643 KWT/KWE
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IEUF =	.9158
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presents the energy distribution for the finishing mill cogeneration plant. The ideal energy utilization factor (IEUF) for the plant was 0.9158 and the actual ratio of process heat to electricity was 8.2643 kWt/kWe, quite close to the desired ratio of 8.86 kWt/kWe.

The preliminary capital cost of the system is given in Table C.10-5. The economic and financial assumptions detailed in Table C.10-6 are used to perform an analysis of the cash flow for the facility. Tables C.10-7a, C.10-7b, and C.10-7c contain the results of that analysis, including the breakdown of the specific cash flow components and the return on equity to be expected.

The fuel utilization for this installation in both the separate generation and cogeneration modes is given in Table C.10-8. As can be seen, the use of natural gas and oil is curtailed, at the expense of higher coal consumption. An overall energy savings of 17% is expected.

TABLE C.10-5

TEXTILE FINISHING MILL
SUMMARY OF CAPITAL COSTS: DEC. 1978\$

STEAM GENERATOR COST (INSTALLED)	= \$ 8806772.1
STEAM GENERATOR BOP COSTS	= \$ 11008465.1
TURBINE GENERATOR COST (INSTALLED)	= \$ 2589177.7
TURB-GEN BOP COSTS	= \$ 2589177.7
FLUE GAS DESULF COSTS (INST+BOP)	= \$ 3272934.2
TOTAL DIRECT COSTS	= \$ 28266526.2
INDIRECT COSTS	= \$ 4239978.9
ENGINEERING	= \$ 2826652.6
CONTINGENCY (20%)	= \$ 5653305.2
SUBTOTAL	= \$ 40986462.9
INTEREST DURING CONSTRUCTION (36 mo.)	= \$ 6783259.5
ESCALATION DURING CONSTRUCTION	= \$ 4965445.9
TOTAL CAPITAL COST	= \$ 52735168.3
SPECIFIC CAPITAL COST (\$/kWt)	= 333.798

TABLE C.10-6

RATE OF RETURN ON EQUITY SUMMARY
FOR INDUSTRIAL COGENERATION

ENERGY UTILIZATION SYSTEM CHARACTERIZATION
TEXTILE FINISHING MILL

REQUIRED RATIO OF PROCESS HEAT/ELECTRICITY	=	8.8700
REQUIRED PROCESS HEAT	=	593485240.0 (KWH/YR)
REQUIRED ELECTRIC ENERGY	=	66909271.5 (KWH/YR)
EXCESS ELECTRIC ENERGY SOLD	=	4903857.0 (KWH/YR)
ASSUMED CAPACITY FACTOR	=	.5360
ASSUMED STANDBY POWER FRACTION	=	1.0000

ENERGY CONVERSION SYSTEM CHARACTERIZATION
COAL-FIRED STEAM WITH 1-EXTR BPT

ACTUAL RATIO OF PROCESS HEAT/ELECTRICITY	=	8.2643
IDEAL ENERGY UTILIZATION FACTOR	=	.9158
SPECIFIC CAPITAL COST OF CONVERSION SYSTEM	=	333.7980 (\$/KWT)
INCR. LABOR COST (INDUSTRY) (1ST YEAR)	=	175163.8516 (\$)
INCR. LABOR COST (UTILITY) (1ST YEAR)	=	131372.8887 (\$)
INCR. LABOR COST (3RD PARTY) (1ST YEAR)	=	262745.7773 (\$)

TABLE C.10-6 (cont'd.)

TEXTILE FINISHING MILL
ECONOMIC AND FINANCIAL ASSUMPTIONS

DEBT / EQUITY RATIO (INDUSTRY)	=	.7000
DEBT / EQUITY RATIO (UTILITY)	=	.9000
DEBT / EQUITY RATIO (3RD PARTY)	=	5.0000
LIFE OF PROJECT	=	28 (YEARS)
LIFE OF INVESTMENT FOR TAX PURPOSES	=	28 (YEARS)
INCOME TAX RATES (FEDERAL + STATE)	=	.5200 (%/100)
INTEREST RATE ON DEBT	=	.1000 (%/YR/100)
INVESTMENT TAX CREDIT RATE	=	.2000 (%/100)
ITCR UNDER SEPARATE GENERATION (INDUSTRIAL)	=	.2000 (%/100)
ITCR UNDER SEPARATE GENERATION (UTILITY)	=	.1000 (%/100)
PROPERTY TAX RATE (1ST YEAR)	=	.0150 (%/100)
INSURANCE RATE (1ST YEAR)	=	.0150 (%/100)
CHARGE FOR STANDBY POWER	=	69.0676 (\$/KW)
MAINTENANCE & SUPPLIES COST FACTOR (1ST YR)	=	.0375 (%/100)
BOILER HEAT RATE (SEPARATE GENERATION)	=	3750.0000 (BTU/KWH)
CENTRAL STATION BUS BAR HEAT RATE	=	9500.0000 (BTU/KWH)
TRANSMISSION LOSSES OF PURCHASED POWER	=	.1000 (%/100)
SPECIFIC CAPITAL COST OF NEW UTILITY STATION	=	1000.0000 (\$/KW)
PRICE OF PROCESS STEAM (1ST YR)	=	4.6714 (\$/10 ⁶ BTU)
PRICE OF POWER AT CENTRAL STATION BUS BAR	=	.0196 (\$/KWH)
PRICE OF POWER BOUGHT FROM UTILITY (1ST YR)	=	.0326 (\$/KWH)
PRICE OF POWER SOLD TO UTILITY (1ST YR)	=	.0196 (\$/KWH)
PRICE OF FUEL (COGENERATION)	=	1.7894 (\$/10 ⁶ BTU)
PRICE OF FUEL, (SEP.GEN.: INDUSTRY)	=	1.7894 (\$/10 ⁶ BTU)
PRICE OF FUEL (SEP.GEN.: UTILITY)	=	1.7894 (\$/10 ⁶ BTU)
GENERAL INFLATION RATE	=	.0750 (%/100/YR)
FUEL PRICE RELATIVE ESC (COGENERATION FUEL)	=	.0484 (%/100/YR)
FUEL PRICE REL. ESC (SEP.GEN.: INDUSTRY)	=	.0484 (%/100/YR)
FUEL PRICE REL. ESC (SEP.GEN.: UTILITY)	=	.0484 (%/100/YR)
RELATIVE ESC. OF ELECTRICAL ENERGY COSTS	=	.0360 (%/100/YR)
RELATIVE ESC. OF PROCESS STEAM COSTS	=	.0242 (%/100/YR)

TABLE C.10-7a

TEXTILE FINISHING MILL
FOR INDUSTRIAL OWNERSHIP

INCREMENTAL CAPITAL INVESTMENT = 28878642 (\$)
NET INCREMENTAL EQUITY CAPITAL INVESTMENT = 13589949 (\$)

YEAR	NET SAVINGS IN ELECT.	DELTA FUEL COSTS	DELTA O AND M	DELTA PROP. TAX & INSUR.	INCOME TAXES ON SAVINGS
1	1293929.	456870.	2152731.	866359.	-2788647.
2	1441049.	514906.	2314186.	931336.	-2823080.
3	1604896.	580314.	2487750.	1001186.	-2861480.
4	1787372.	654032.	2674331.	1076275.	-2904006.
5	1990597.	737113.	2874906.	1156996.	-2950818.
6	2216928.	830749.	3090524.	1243771.	-3002073.
7	2468992.	936279.	3322313.	1337053.	-3057925.
8	2749717.	1055214.	3571486.	1437332.	-3118523.
9	3062359.	1189258.	3839348.	1545132.	-3184008.
10	3410550.	1340329.	4127299.	1661017.	-3254514.
11	3798329.	1510591.	4436846.	1785594.	-3330161.
12	4230199.	1702482.	4769610.	1919513.	-3411060.
13	4711172.	1918748.	5127330.	2063477.	-3497300.
14	5246833.	2162486.	5511880.	2218237.	-3588955.
15	5843397.	2437187.	5925271.	2384605.	-3686073.
16	6507792.	2746783.	6369666.	2563450.	-3788675.
17	7247728.	3095707.	6847391.	2755709.	-3896753.
18	8071794.	3488954.	7360945.	2962387.	-4010261.
19	8989557.	3932156.	7913016.	3184566.	-4129111.
20	10016009.	4431658.	8506492.	3423409.	-4253172.
21	11149996.	4994611.	9144479.	3680164.	-4382257.
22	12417750.	5629077.	9830315.	3956177.	-4516120.
23	13829649.	6344138.	10567588.	4252890.	-4654450.
24	15402079.	7150034.	11360157.	4571856.	-4796863.
25	17153295.	8058303.	12212169.	4914746.	-4942892.
26	19103625.	9081949.	13128081.	5283352.	-5091978.
27	21275707.	10235629.	14112687.	5679603.	-5243468.
28	23694755.	11535860.	15171139.	6105573.	-5396595.

YEAR	BASIC CASH FLOW	DISCOUNTED ADJUSTED CASH FLOW
1	-582504	-762839
2	-685419	-1175504
3	-791995	-1778790
4	-902379	-2654149
5	-1016720	-3916262
6	-1135162	-5726144
7	-1257847	-8309336
8	-1384913	-11981055
9	-1516491	-17180923
10	-1652702	-24520836
11	-1793661	-34850993
12	-1939466	-49350441
13	-2090202	-69651615
14	-2245936	-98010902
15	-2406713	-137542016
16	-2572553	-192534908
17	-2743446	-268890612
18	-2919352	-374713864
19	-3100190	-521117528
20	-3285837	-723314976
21	-3476122	-1002098760
22	-3670818	-1385837920
23	-3869637	-1913171424
24	-4072225	-2636631872
25	-4278150	-3627503232
26	-4486898	-4982325120
27	-4697865	-6831569216
28	-4910342	-9351165696

DISCOUNTED CASH FLOW RATE OF RETURN ON EQUITY(ROE)= -23.64 %

ANNUAL ENERGY SAVED UNDER COGENERATION = 497536.4375 MBTU/YR

TABLE C.10-7b
TEXTILE FINISHING MILL
FOR UTILITY OWNERSHIP

INCREMENTAL CAPITAL INVESTMENT = 35857296 (\$)
NET INCREMENTAL EQUITY CAPITAL INVESTMENT = 16985035 (\$)

YEAR	STEAM REVENUE	DELTA ELECT. REVENUE	DELTA FUEL COSTS	DELTA O AND M	DELTA PROP. TAX & INSUR.	TAXES
1	9467784.	872495.	3092207.	1476021.	1075719.	272954.
2	10424172.	971698.	3485010.	1586723.	1156398.	564011.
3	11477170.	1082180.	3927710.	1705727.	1243128.	877760.
4	12636536.	1205223.	4426647.	1833657.	1336362.	1216087.
5	13913015.	1342257.	4988964.	1971181.	1436589.	1581004.
6	15318438.	1494872.	5622712.	2119020.	1544333.	1974657.
7	16865830.	1664839.	6336965.	2277946.	1660158.	2399326.
8	18569531.	1854131.	7141950.	2448792.	1784670.	2857431.
9	20445332.	2064946.	8049192.	2632451.	1918521.	3351526.
10	22510616.	2299730.	9071680.	2829885.	2062410.	3884305.
11	24784526.	2561209.	10224056.	3042126.	2217090.	4458598.
12	27288134.	2852419.	11522817.	3270286.	2383372.	5077363.
13	30044645.	3176739.	12986561.	3515557.	2562125.	5743682.
14	33079604.	3537934.	14636243.	3779224.	2754284.	6460743.
15	36421139.	3940197.	16495485.	4062666.	2960856.	7231831.
16	40100220.	4388197.	18590906.	4367366.	3182920.	8060303.
17	44150943.	4887135.	20952509.	4694918.	3421639.	8949558.
18	48610850.	5442802.	23614106.	5047037.	3678261.	9903005.
19	53521274.	6061649.	26613806.	5425565.	3954131.	10924021.
20	58927724.	6750858.	29994557.	5832482.	4250691.	12015891.
21	64880307.	7518431.	33804765.	6269918.	4569493.	13181746.
22	71434189.	8373276.	38098984.	6740162.	4912204.	14424479.
23	78650113.	9325318.	42938697.	7245674.	5280620.	15746654.
24	86594952.	10385606.	48393200.	7789099.	5676666.	17150379.
25	95342340.	11566449.	54540588.	8373282.	6102416.	18637178.
26	104973345.	12881555.	61468878.	9001278.	6560097.	20207818.
27	115577225.	14346187.	69277269.	9676373.	7052104.	21862114.
28	127252256.	15977349.	78077558.	10402101.	7581012.	23598698.

YEAR	BASIC CASH FLOW	DISCOUNTED ADJUSTED CASH FLOW
1	3800593	2928715
2	4061622	2411853
3	4349647	1990358
4	4666865	1645614
5	5015620	1362866
6	5398418	1130370
7	5817927	938746
8	6276986	780471
9	6778605	649489
10	7325972	540907
11	7922451	450757
12	8571582	375811
13	9277080	313433
14	10042823	261466
15	10872850	218137
16	11771339	181986
17	12742590	151808
18	13790999	126607
19	14921027	105557
20	16137149	87971
21	17443805	73279
22	18845337	61006
23	20345902	50754
24	21949376	42193
25	23659238	35046
26	25478422	29083
27	27409153	24110
28	29452743	19964

DISCOUNTED CASH FLOW RATE OF RETURN ON EQUITY(ROE)= 29.77 %
ANNUAL ENERGY SAVED UNDER COGENERATION = 497536.4375 MBTU/YR

TABLE C.10-7c

TEXTILE FINISHING MILL
FOR THIRD PARTY OWNERSHIP

CAPITAL INVESTMENT = 52735126 (\$)
NET EQUITY CAPITAL INVESTMENT = 7031350 (\$)

YEAR	STEAM REVENUE	DELTA ELECT. REVENUE	DELTA FUEL COSTS	DELTA O AND M	DELTA PROP. TAX & INSUR.	TAXES
1	9467784.	1293929.	4439386.	2240313.	1582054.	-2876400.
2	10424172.	1441049.	5003321.	2408336.	1700708.	-2677352.
3	11477170.	1604896.	5638893.	2588962.	1828261.	-2467800.
4	12636536.	1787372.	6355202.	2783134.	1965380.	-2247252.
5	13913015.	1990597.	7162503.	2991869.	2112784.	-2015252.
6	15318438.	2216928.	8072356.	3216259.	2271243.	-1771403.
7	16865830.	2468992.	9097787.	3457478.	2441586.	-1515379.
8	18569531.	2749717.	10253479.	3716789.	2624705.	-1246959.
9	20445332.	3062359.	11555978.	3995548.	2821558.	-966043.
10	22510616.	3410550.	13023934.	4295214.	3033174.	-672698.
11	24784526.	3798329.	14678364.	4617355.	3260662.	-367188.
12	27288134.	4230199.	16542956.	4963657.	3505212.	-50027.
13	30044645.	4711172.	18644408.	5335931.	3768103.	277966.
14	33079604.	5246833.	21012806.	5736126.	4050711.	615606.
15	36421139.	5843397.	23682063.	6166335.	4354514.	961261.
16	40100220.	6507792.	26690395.	6628810.	4681102.	1312764.
17	44150943.	7247728.	30080876.	7125971.	5032185.	1667313.
18	48610850.	8071794.	33902049.	7660419.	5409599.	2021344.
19	53521274.	8989557.	38208626.	8234950.	5815319.	2370393.
20	58927724.	10011669.	43062267.	8852571.	6251467.	2708935.
21	64880307.	11149996.	48532466.	9516514.	6720327.	3030189.
22	71434189.	12417750.	54697545.	10230252.	7224352.	3325904.
23	78650113.	13829649.	61645773.	10997521.	7766178.	3586106.
24	86594952.	15402079.	69476635.	11822335.	8348641.	3798797.
25	95342340.	17153295.	78302252.	12709010.	8974789.	3949625.
26	104973345.	19103625.	88248987.	13662186.	9647898.	4021491.
27	115577225.	21275707.	99459253.	14686849.	10371491.	3994102.
28	127252256.	23694755.	112093562.	15788363.	11149352.	3843450.

YEAR	BASIC CASH FLOW	DISCOUNTED ADJUSTED CASH FLOW
1	981766	815353
2	1035613	714286
3	1099156	629610
4	1172850	557946
5	1257114	496663
6	1352317	443714
7	1458756	397507
8	1576640	356806
9	1706057	320649
10	1846947	288290
11	1999067	259143
12	2161941	232752
13	2334815	208756
14	2516593	186869
15	2705770	166860
16	2900345	148542
17	3097731	131759
18	3294639	116381
19	3486949	102296
20	3669560	89405
21	3836213	77623
22	3979291	66870
23	4089588	57074
24	4156029	48170
25	4165365	40095
26	4101814	32791
27	3946642	26202
28	3677689	20278

DISCOUNTED CASH FLOW RATE OF RETURN ON EQUITY (ROE) = 20.41 %

ANNUAL ENERGY SAVED UNDER COGENERATION = 497536.4375 MBTU/YR

TABLE C.10-8

FUEL UTILIZATION

TEXTILE FINISHING MILL

	Separate Generation (MBtu/yr)	Cogeneration (MBtu/yr)	Savings (MBtu/yr)
Gas	1889766	-	1889766
Oil	763475	-	763475
Coal	895478	2957617	-2062139
Overall	3548719	2957617	591102

Percent Energy Savings = 16.7%

C.11 INTEGRATED TEXTILE MILL

The integrated textile mill is a medium-sized facility located in Alabama (DOE Region IV). The energy requirements for the plant are in the form of process steam (saturated at 265 psia), direct process heat, electrical energy, and direct power steam for mechanical drives. The physical configuration of the plant precludes the use of exhaust gas from a gas turbine as a source of direct process heat, making it possible to combine the requirement for direct process heat with that for steam. The need for power steam for mechanical drives has been accounted for by combining the drive steam demand with the conventional electrical demand. The overall ratio of process heat to electricity is 2.34. The annual energy needs of the plant may be given as follows:

- Process heat (sat'd steam) 302.5 million kWh/yr
- Electricity 129.6 million kWh/yr

The preferred fuel, identified by the company, was wood which is available in plentiful supply locally. Thus, the only energy conversion subsystems considered were a gas-fired combustion turbine with WHB and a wood-fired boiler generating steam for a back pressure steam turbine. The gas turbine case, upon investigation, proved to result in unacceptable ROE's and was therefore eliminated. The wood-fired steam plant, on the other hand, provided an acceptable ROE only for the utility and the third-party ownership cases.

Figure C.11-1 shows the energy utilization system model for the integrated textile plant. The conditions at each of the indicated state points are given in Table C.11-1. In Figure C.11-2, the system configuration of the wood-fired boiler/BPT system is shown schematically. The analysis was based upon the wood composition shown in Table C.11-2, a southern yellow pine having 40% moisture content. The throttle pressure of the steam turbine was varied, producing the optimization plot for utility ownership shown in Figure C.11-3. The industrial and third-party ownership plots are not given due to their poor (negative) ROE. In this case, the optimum plant was not dictated by the ROE hurdle rate, but by the maximum practical throttle pressure in the steam turbine. Table C.11-3 gives the state point data for the optimum case at 1215 psia throttle pressure.

The boiler is a wood-fired unit with no combustion air preheater. Rather than an ESP, particulate control is achieved with either a bag filter or cyclone separators. Since wood contains little sulfur, no flue gas desulfurization system is required. After partial expansion through the steam turbine, steam exhausts to the process at 265 psia. A fraction of that steam is used to deaerate the recycled condensate.

The energy distribution for the cogeneration facility is shown in Table C.11-4. The ideal energy utilization factor (IEUF) is 0.908 and the ratio of process heat to electricity (RPHEE) is 10.58. Since the latter value exceeds the required ratio, supplemental power must still be imported. The preliminary capital costs of the facility are shown in Table C.11-5.

Fig. C.11-1 — Flowsheet of process heat utilization subsystem for integrated textile mill with wood-fired steam energy conversion subsystem

TABLE C.11-1

STATEPOINTS FOR ENERGY UTILIZATION SUBSYSTEM

IN INTEGRATED TEXTILE MILL

Station	Pressure (psia)	Temperature (°F)	Enthalpy (Btu/lb)	Flow Rate (lb/s)
1	265	617.1	1327.1	52.99
2	265	617.1	1327.1	47.53
3	265	617.1	1327.1	5.46
4	-	-	-	0
5	15	100	68	47.53
6	>15	100	68	47.53
7	39.8	100	68	47.53
8	265	406	1201.7	5.46
9	39.8	103.1	71.2	52.99

TABLE C.11-2

FUEL SPECIFICATIONS

INTEGRATED TEXTILE MILL

Type: Wood (yellow pine)

Moisture Content (as fired): 40%

Heating values (HHV): 5766 Btu/lb

(LHV): 4961 Btu/lb

Composition (wt %)

C	0.3128
H	0.0416
S	0.0000
O	0.2378
N	0.0000
H ₂ O	0.4000
Ash	0.0078

Integrated Textile Mill:

- No FGD
- Replace ESP with bag filter or cyclones
- No air preheater
- Replace coal with wood

Fig. C.11-2 - Model of conventional coal-fired steam energy conversion subsystem for integrated textile mill

Fig. C.11-3 - Annual energy savings vs return on equity, utility ownership

TABLE C.11-3

STATEPOINTS FOR CONVERSION SUBSYSTEMIN INTEGRATED TEXTILE MILL

Station	Pressure (psia)	Temperature (°F)	Enthalpy (Btu/lb)	Flow (lb/s)
1	14.7	77	0	75.96
2	16.0	85	2	75.96
3	16.0	85	2	75.96
4	15.8	2811.6	896.1	92.51
5	15.6	1800.0	521.3	92.51
6	15.3	1230.3	336.5	92.51
7	15.0	1056.5	282.3	92.51
8	14.7	303.2	64.0	92.51
9	14.7	303.2	64.0	92.51
20	39.8	103.1	71.2	52.99
21	29.8	250.0	218.6	60.03
22	1340.0	253.5	224.8	60.03
23	1315.0	558.9	560.5	60.03
24	1265.0	573.9	580.8	41.58
25	1265.0	573.9	701.4	41.58
26	1265.0	573.9	580.8	287.50
27	1265.0	573.9	701.4	287.50
28	1265.0	573.9	1183.7	60.03
29	1215.0	945.5	1467.9	60.03
30	265.0	617.1	1327.1	60.03
31	-	-	-	-
32	265.0	617.1	1327.1	60.03
33	265.0	617.1	1327.1	7.04
34	265.0	617.1	1327.1	52.99

TABLE C.11-4

POWER SUMMARY - INTEGRATED TEXTILE MILL

HP STEAM PWR= 7018.1581 KW
LP STEAM PWR= 1631.2933 KW
ST POWER= 8649.4513 KW

GROSS POWER = 8649.4513 KW
FGD AUXILIARIES = .0000 KW
AUXILIARY POWER = 649.2589 KW
BOILER FEED PUMP POWER = 373.0815 KW
NET POWER GENERATED = 7627.1109 KW

TOTAL FUEL= 16.5433 LB/SEC
THERMAL RATING = 295456108.0000 BTU/HR

HEAT RATE 38737.6177 BTU/KWHR
TOTAL PROCESS HEAT = .2396+009 BTU/HR
PROCESS HEAT AT 265.0 PSIA = .2395868+009 BTU/HR

RPHEE = 10.5844 KWT/KWE

IEUF = .9000

TABLE C.11-5

INTEGRATED TEXTILE MILL
SUMMARY OF CAPITAL COSTS: DEC. 1978\$

STEAM GENERATOR COST (INSTALLED)	= \$ 5738761.7
STEAM GENERATOR BOP COSTS	= \$ 7173452.2
TURBINE GENERATOR COST (INSTALLED)	= \$ 1741710.8
TURBINE GENERATOR BOP COSTS	= \$ 1741710.8
TOTAL DIRECT COSTS	= \$16395635.4
INDIRECT COSTS	= \$ 2459345.3
ENGINEERING	= \$ 1639563.5
CONTINGENCY (20%)	= \$ 3279127.1
SUBTOTAL	= \$23773671.1
INTEREST DURING CONSTRUCTION (36 Mo.)	= \$ 3934542.6
ESCALATION DURING CONSTRUCTION	= \$ 2880143.1
TOTAL CAPITAL COST	= \$30588256.8
SPECIFIC CAPITAL COST (\$/kWt)	=352.907

These costs, as well as the financial and economic data specified for the company and the region involved, are used to analyze the cash flow over the desired project life. The DCFROE for the optimum case was based on the assumptions detailed in Table C.11-6. The results of the DCFROE calculations, as well as the specific contributors to the cash flow vector, are reported in Tables C.11-7a, C.11-7b, and C.11-7c.

The fuel utilization shift to be expected as a result of the installation of the specified cogeneration facility is shown in Table C.11-8. A small amount of overall conservation is accomplished. The most significant factor, though, is the replacement of over a million MBtu/yr of natural gas with wood.

TABLE C.11-6

RATE OF RETURN ON EQUITY SUMMARY
FOR INDUSTRIAL COGENERATION

ENERGY UTILIZATION SYSTEM CHARACTERIZATION
INTEGRATED TEXTILE MILL

REQUIRED RATIO OF PROCESS HEAT/ELECTRICITY	=	2.3400
REQUIRED PROCESS HEAT	=	302549056.0 (KWH/YR)
REQUIRED ELECTRIC ENERGY	=	129294468.0 (KWH/YR)
SUPPLEMENTAL ELECTRIC ENERGY PURCHASED	=	100710037.0 (KWH/YR)
ASSUMED CAPACITY FACTOR	=	.4920
ASSUMED STANDBY POWER FRACTION	=	1.0000

ENERGY CONVERSION SYSTEM CHARACTERIZATION
WOOD-FIRED STEAM WITH BPT

ACTUAL RATIO OF PROCESS HEAT/ELECTRICITY	=	10.5844
IDEAL ENERGY UTILIZATION FACTOR	=	.9080
SPECIFIC CAPITAL COST OF CONVERSION SYSTEM	=	352.9070 (\$/KWT)
INCR. LABOR COST (INDUSTRY) (1ST YEAR)	=	98141.4492 (\$)
INCR. LABOR COST (UTILITY) (1ST YEAR)	=	146591.0254 (\$)
INCR. LABOR COST (3RD PARTY) (1ST YEAR)	=	293182.0508 (\$)

TABLE C.11-6 (cont'd.)

INTEGRATED TEXTILE MILL
ECONOMIC AND FINANCIAL ASSUMPTIONS

DEBT / EQUITY RATIO (INDUSTRY)	=	3.7000
DEBT / EQUITY RATIO (UTILITY)	=	1.1000
DEBT / EQUITY RATIO (3RD PARTY)	=	5.0000
LIFE OF PROJECT	=	28 (YEARS)
LIFE OF INVESTMENT FOR TAX PURPOSES	=	28 (YEARS)
INCOME TAX RATES (FEDERAL + STATE)	=	.5060 (%/100)
INTEREST RATE ON DEBT	=	.1000 (%/YR/100)
INVESTMENT TAX CREDIT RATE	=	.2000 (%/100)
ITCR UNDER SEPARATE GENERATION (INDUSTRY)	=	.0000 (%/100)
ITCR UNDER SEPARATE GENERATION (UTILITY)	=	.1000 (%/100)
PROPERTY TAX RATE (1ST YEAR)	=	.0150 (%/100)
INSURANCE RATE (1ST YEAR)	=	.0150 (%/100)
CHARGE FOR STANDBY POWER	=	69.0676 (\$/KW)
MAINTENANCE & SUPPLIES COST FACTOR (1ST YR)	=	.0375 (%/100)
BOILER HEAT RATE (SEPARATE GENERATION)	=	3750.0000 (BTU/KWH)
CENTRAL STATION BUS BAR HEAT RATE	=	9500.0000 (BTU/KWH)
TRANSMISSION LOSSES OF PURCHASED POWER	=	.1000 (%/100)
SPECIFIC CAPITAL COST OF NEW UTILITY STATION	=	1000.0000 (\$/KW)
PRICE OF PROCESS STEAM (1ST YR)	=	5.4843 (\$/10 ⁶ BTU)
PRICE OF POWER AT CENTRAL STATION BUS BAR	=	.0196 (\$/KWH)
PRICE OF POWER BOUGHT FROM UTILITY (1ST YR)	=	.0326 (\$/KWH)
PRICE OF POWER SOLD TO UTILITY (1ST YR)	=	.0196 (\$/KWH)
PRICE OF FUEL (COGENERATION)	=	2.7415 (\$/10 ⁶ BTU)
PRICE OF FUEL, (SEP.GEN.: INDUSTRY)	=	2.9070 (\$/10 ⁶ BTU)
PRICE OF FUEL (SEP.GEN.: UTILITY)	=	1.7894 (\$/10 ⁶ BTU)
GENERAL INFLATION RATE	=	.0750 (%/100/YR)
FUEL PRICE RELATIVE ESC.(COGENERATION FUEL)	=	.0475 (%/100/YR)
FUEL PRICE REL. ESC.(SEP.GEN.: INDUSTRY)	=	.0468 (%/100/YR)
FUEL PRICE REL. ESC.(SEP.GEN.: UTILITY)	=	.0484 (%/100/YR)
RELATIVE ESC. OF ELECTRICAL ENERGY COSTS	=	.0360 (%/100/YR)
RELATIVE ESC. OF PROCESS STEAM COSTS	=	.0300 (%/100/YR)

TABLE C.11-7a

INTEGRATED TEXTILE MILL
FOR INDUSTRIAL OWNERSHIP

INCREMENTAL CAPITAL INVESTMENT = 30550403 (\$)
NET INCREMENTAL EQUITY CAPITAL INVESTMENT = 5200068 (\$)

YEAR	NET SAVINGS IN ELECT.	DELTA FUEL COSTS	DELTA O AND M	DELTA PROP. TAX & INSUR.	INCOME TAXES ON SAVINGS
1	473777.	116085.	1243782.	916512.	-3195166.
2	527646.	133201.	1337065.	985250.	-3220477.
3	587639.	152785.	1437345.	1059144.	-3250087.
4	654453.	175189.	1545146.	1138580.	-3284282.
5	728865.	200811.	1661032.	1223974.	-3323367.
6	811737.	230105.	1785609.	1315772.	-3367667.
7	904031.	263591.	1919530.	1414454.	-3417533.
8	1006819.	301860.	2063495.	1520538.	-3473335.
9	1121295.	345585.	2218257.	1634579.	-3535474.
10	1248786.	395532.	2384626.	1757172.	-3604377.
11	1390773.	452576.	2563473.	1888960.	-3680502.
12	1548904.	517710.	2755733.	2030632.	-3764340.
13	1725014.	592069.	2962413.	2182930.	-3856421.
14	1921148.	676941.	3184594.	2346649.	-3957313.
15	2139583.	773794.	3423439.	2522648.	-4067629.
16	2382853.	884301.	3680196.	2711846.	-4188029.
17	2653783.	1010362.	3956211.	2915235.	-4319228.
18	2955519.	1154142.	4252927.	3133877.	-4461999.
19	3291561.	1318103.	4571896.	3368918.	-4617180.
20	3665811.	1505049.	4914789.	3621587.	-4785682.
21	4082614.	1718165.	5283398.	3893206.	-4968497.
22	4546807.	1961078.	5679652.	4185196.	-5166707.
23	5063779.	2237911.	6105626.	4499086.	-5381492.
24	5639531.	2553353.	6563548.	4836518.	-5614149.
25	6280745.	2912736.	7055814.	5199256.	-5866100.
26	6994866.	3322122.	7585000.	5589201.	-6138909.
27	7790182.	3788407.	8153875.	6008390.	-6434304.
28	8675926.	4319423.	8765416.	6459020.	-6754195.

YEAR	BASIC CASH FLOW
1	-1012467
2	-1112425
3	-1216580
4	-1325211
5	-1438616
6	-1557113
7	-1681043
8	-1810770
9	-1946683
10	-2089199
11	-2238766
12	-2395863
13	-2561008
14	-2734754
15	-2917701
16	-3110493
17	-3313828
18	-3528460
19	-3755208
20	-3994962
21	-4248689
22	-4517445
23	-4802384
24	-5104770
25	-5425993
26	-5767580
27	-6131217
28	-6518769

DISCOUNTED CASH FLOW RATE OF RETURN ON EQUITY(ROE)= <0 %

ANNUAL ENERGY SAVED UNDER COGENERATION = 297191.1406 MBTU/YR / C-144

TABLE C.11-7b

INTEGRATED TEXTILE MILL
FOR UTILITY OWNERSHIP

INCREMENTAL CAPITAL INVESTMENT = 20584909 (\$)
NET INCREMENTAL EQUITY CAPITAL INVESTMENT = 8822104 (\$)

YEAR	STEAM REVENUE	DELTA ELECT. REVENUE	DELTA FUEL COSTS	DELTA O AND M	DELTA PROP. TAX & INSUR.	TAXES
1	5666370.	1678852.	2874343.	918525.	617547.	221071.
2	6274088.	1869738.	3236168.	987415.	663863.	409443.
3	6946983.	2082327.	3643538.	1061471.	713653.	614358.
4	7692047.	2319087.	4102188.	1141081.	767177.	837373.
5	8517019.	2582767.	4618573.	1226662.	824715.	1080177.
6	9430469.	2876428.	5199959.	1318662.	886569.	1344599.
7	10441886.	3203478.	5854529.	1417561.	953062.	1632618.
8	11561778.	3567713.	6591494.	1523878.	1024541.	1946372.
9	12801779.	3973362.	7421228.	1638169.	1101382.	2288167.
10	14174769.	4425133.	8355407.	1761032.	1183985.	2660492.
11	15695013.	4928271.	9407178.	1893109.	1272784.	3066018.
12	17378303.	5488615.	10591342.	2035092.	1368243.	3507619.
13	19242125.	6112671.	11924567.	2187724.	1470861.	3988372.
14	21305843.	6807681.	13425614.	2351803.	1581176.	4511571.
15	23590894.	7581715.	15115608.	2528189.	1699764.	5080729.
16	26121016.	8443755.	17018332.	2717803.	1827246.	5699590.
17	28922495.	9403810.	19160565.	2921638.	1964290.	6372126.
18	32024432.	10473023.	21572454.	3140761.	2111612.	7102546.
19	35459051.	11663806.	24287941.	3376318.	2269982.	7895291.
20	39262032.	12989981.	27345244.	3629542.	2440231.	8755026.
21	43472885.	14466941.	30787386.	3901757.	2623248.	9686643.
22	48135350.	16111832.	34662810.	4194389.	2819992.	10695232.
23	53297865.	17943747.	39026055.	4508968.	3031491.	11786071.
24	59014060.	19983951.	43938522.	4847140.	3258853.	12964596.
25	65343317.	22256126.	49469347.	5210676.	3503267.	14236355.
26	72351386.	24786648.	55696361.	5601477.	3766012.	15606973.
27	80111070.	27604889.	62707200.	6021587.	4048463.	17082079.
28	88702980.	30743564.	70600521.	6473206.	4352098.	18667231.

YEAR	BASIC CASH FLOW	DISCOUNTED ADJUSTED CASH FLOW
1	2253024	1681236
2	2432543	1354512
3	2631686	1093514
4	2849509	867590
5	3096117	716360
6	3365420	581053
7	3662399	471851
8	3989490	383548
9	4349319	312023
10	4744715	254003
11	5178722	206878
12	5654607	168561
13	6175875	137377
14	6746279	111981
15	7369825	91285
16	8050790	74412
17	8793719	60651
18	9603436	49426
19	10485050	40268
20	11443944	32797
21	12485782	26701
22	13616494	21729
23	14842261	17674
24	16169496	14368
25	17604808	11674
26	19154965	9478
27	20826836	7690
28	22627329	6234

DISCOUNTED CASH FLOW RATE OF RETURN ON EQUITY(ROE)= 34.01 %
ANNUAL ENERGY SAVED UNDER COGENERATION = 297191.1406 MBTU/YR

TABLE C.11-7c

INTEGRATED TEXTILE MILL
FOR THIRD PARTY OWNERSHIP

CAPITAL INVESTMENT = 30550403 (\$)
NET EQUITY CAPITAL INVESTMENT = 4073387 (\$)

YEAR	STEAM REVENUE	DELTA ELECT. REVENUE	DELTA FUEL COSTS	DELTA O AND M	DELTA PROP. TAX & INSUR.	TAXES
1	5666370	473777	3414260	1438822	916512	-2166813
2	6274088	527646	3844670	1546734	985250	-2101148
3	6946983	587639	4329339	1662739	1059144	-2033562
4	7692047	654453	4875106	1787444	1138580	-1964130
5	8517019	728865	5489674	1921503	1223974	-1892981
6	9430469	811737	6181716	2065615	1315772	-1820311
7	10441886	904031	6960999	2220536	1414454	-1746398
8	11561778	1006819	7838520	2387076	1520538	-1671620
9	12801779	1121295	8826663	2566107	1634579	-1596475
10	14174769	1248786	9939374	2758565	1757172	-1521604
11	15695013	1390773	11192357	2965458	1888960	-1447821
12	17378303	1548904	12603293	3187867	2030632	-1376146
13	19242125	1725014	14192095	3426957	2182930	-1307841
14	21305843	1921148	15981186	3683979	2346649	-1244456
15	23590894	2139583	17995814	3960277	2522648	-1187881
16	26121016	2382853	20264411	4257298	2711846	-1140406
17	28922495	2653783	22818994	4576595	2915235	-1104790
18	32024432	2955519	25695613	4919839	3133877	-1084341
19	35459051	3291561	28934866	5288827	3368918	-1083012
20	39262032	3665811	32582467	5685489	3621587	-1105505
21	43472885	4082614	36689893	6111901	3893206	-1157398
22	48135350	4546807	41315112	6570293	4185196	-1245288
23	53297865	5063779	46523398	7063065	4499086	-1376956
24	59014060	5639531	52388253	7592795	4836518	-1561556
25	65343317	6280745	58922447	8162255	5199256	-1809837
26	72351386	6994866	66429182	8774424	5589201	-2134391
27	80111070	7790182	74803409	9432505	6008390	-2549944
28	88702980	8675926	84233313	10139943	6459020	-3073690

YEAR	BASIC CASH FLOW
1	-8501
2	-19641
3	-28905
4	-36367
5	-42153
6	-46453
7	-49541
8	-51783
9	-53667
10	-55819
11	-59034
12	-64306
13	-72868
14	-86234
15	-106248
16	-135146
17	-175622
18	-230905
19	-304854
20	-402061
21	-527971
22	-689024
23	-892816
24	-1148286
25	-1465926
26	-1858030
27	-2338976
28	-2925548

DISCOUNTED CASH FLOW RATE OF RETURN ON EQUITY(ROE)= < 0 %

ANNUAL ENERGY SAVED UNDER COGENERATION = 297191.1406 MBTU/YR C-146

TABLE C.11-8

FUEL UTILIZATION - INTEGRATED TEXTILE MILL

	Separate Generation (MBtu/yr)	Cogeneration (MBtu/yr)	Savings (MBtu/yr)
Natural Gas	1134559	--	1134559
Oil	--	--	--
Coal	1471080	1063049	408031
Wood	--	1245397	-1245397
Overall	2605639	2308446	297192

Percent Energy Savings = 11.4%

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