5.3 Water Quality (Cont'd.)

5.3.2 Permits and Regulations (Cont'd.)

5.3.2.1 Federal (Cont'd.)

Whether SPS' coal gasification system will be classified as a new or modified source is within DEP's discretion.

(b) Thermal Discharge - Section 316A - Clean Water Act

Existing discharge to Bridgeport Harbor from once-through cooling at the Steel Point Station have permits in accorcance with Section 316A of Public Law 92-500 (Clean Water Act). A new (or modified) permit may be required for any change in heated water discharge.

5.3.2.2 State

Connecticut DEP administers the NPDES and Section 316A permit programs. Also, the state has established water quality standards for all of the state's surface waters (pursuant to Section 25-541 of the Connecticut General Statutes). The Bridgeport Harbor waters have been classified as Class SB. The Appendix presents the Class SB water regulations.

5.4 Other Environmental Considerations

5.4.1 Cooling Tower

Bridgeport Harbor is an estuary of Long Island Sound at the mouth of the Pequonnock River. However, the harbor's seawater is measurably diluted by freshwater from land drainage.

Normandeau Associates' report, "Bridgeport Harbor Ecological Studies (1971-1972) - Biological and Hydrographic Study Report", describes the circulation pattern and existing thermal regions of Bridgeport Harbor, with respect to the possible thermal effects of the Bridgeport Harbor (BHS) and Steel Point Stations (SPS).

In general, the Normandeau report found that the discharges from BHS and SPS collectively occupy the upper 6 to 10 feet of water column, and rarely interact with the bottom (except for the BHS unit No. 3 thermal plume). Hence, a continuous zone of passage for migratory and swimming organisms is available at 10 feet or more below the surfaces, at all stages of the tide.[1]

5.4 Other Environmental Consideration (Cont'd.)

5.4.1 Cooling Tower (Cont'd.)

The issue of the harbor's ability to handle additional thermal discharge must be evaluated, if a once-thorough cooling system were used. Such an evaluation is beyond the scope of the present report.

The present study scheme, based on using city water for make-up, the cooling tower, would have minimal possibility of emitting toxic and hazardous substances to the atmosphere. However, if cooling tower make-up were drawn from Bridgeport Harbor, further study of potential cooling tower toxic emissions would be necessary, due to contaminants in the harbor's waters.

Operation of the cooling tower may also increase the incidence of fogging and icing on the elevated roadway adjacent to the site; and require an FAA permit.

The environmental and economic advantages of a cooling tower and a once-through cooling system are summarized in Table 5-6.

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[1]The theoretical temperature rise in ebbing harbor waters (due to heat release to Long Island Sound) ranges from about 0.2° to 0.5°F throughout the water column under reduced loading conditions; and from about 0.5° to 1.1°F throughout the water column under peak load conditions. Practically, though, the "mixing zome" is defined by the extent of a 4°F rise above ambient temperature levels adjacent to the thermal source.

TABLE 5-6

A COMPARISON OF ADVANTAGES FOR A COOLING TOWER AND A ONCE-THROUGH COOLING SYSTEM

	Advantages of Cooling Tower	Advantages of Once-through Cooling
Water Quality (Chemical)		Less concentrated pollutants in blowdown Less need for chemical additives to treat bio-fouling and corrosion
Water Quality (Thermal)	Smaller thermal effect	
Aquatic life	Entrains small quantity of organisms (although loss of organisms entrained is 100%)	Selective cropping of entrained organisms as opposed to 100% loss (although larger quantity entrained)
Meteorology		No potential for fogging and icing of adjacent roadway as with cooling tower
Air Quality	Note: Effect on air quality can be minimized by using relatively clean municipal makeup water	No effect on air quality as with cooling tower (from drift loss)
Land Use		Uses significantly less land area
Costs		Construction and operation costs are almost an order of magnitude less
Generating Capability		Capacity losses are at least 1.5% less

5.4 Other Environmental Consideration (Cont'd.)

5.4.2 Navigable Airspace

The height of the main stack (and cooling tower) may require an FAA permit(s), if more than 200 feet above ground.

The Federal Aviation Act of 1958, and the Federal Aviation Regulations, Part 77, "Objects Affecting the Navigable Airspace" require that notice of construction affecting the "navigable airspace" be sent to the FAA Administrator, U.S. Department of Transportation. Notice of proposed construction or alteration is required so that the FAA may: issue notices for pilots and air traffic controllers; depict obstructions on aeronautical charts; and recommend appropriate marking and lighting.

5.4.3 Vehicular Traffic

Transportation of ash and sulfur for off-site disposal will require consideration of potential effects on local traffic.

5.4.4 Dredging & Construction in Navigable Waters

A U.S. Army Corps of Engineers (COE) 404 permit is required for consturction or excavation in a navigable waterway, or to discharge dredged or fill material into waters of the United States (or to transport dredged material for the purpose of dumping it into ocean waters). This permit program is authorized by both Section 10 of the River and Harbor Act of 1899, and Section 404 of the Federal Water Pollution Control Act. Since the latter has taken over the function of the former, the COE permit is commonly called a 404 permit. This would apply to construction, excavation, dredging and fill operations in Bridgeport Harbor.

Materials dredged from Connecticut harbors have been disposed of in Long Island Sound, but the Corps has been enjoined to stop this. However, since the Corps has responsibility for maintaining navigability (which requires periodic dredging), the Corps will probably develop a solution to the dredged materials' disposal problem.

5.4.5 Noise

Adverse noise impacts are not expected. The site is in an industrial setting, and surrounded by existing highway and power plant structures. The facilities to be installed on the site will be designated in compliance with state noise regulations.

5.4 Other Environmental Consideration (Cont'd.)

5.4.6 Flaring

Low Btu gas generated by the proposed coal gasification plant may be flared on an intermittent basis during periods of emergency. Flaring of the low Btu gas must be done in accordance with Section 19-508-20(e) of Connecticut's Abatement of Air Pollution regulations.

APPENDIX
CONNECTICUT WATER QUALITY
STANDARDS FOR CLASS SB WATERS

Suitable for bathing, other recreational purposes, industrial cooling and shellfish harvesting for human consumption after deputation; excellent fish and wildlife habitat; good aesthetic value.

1. Dissolved oxygen	Not less than 5.0 mg/l at any time.
2. Sludge deposits - solid refuse - floating solids, oils and grease - scum	None except for small amounts that may result from the discharge from a waste treatment faci-ity providing appropriate treatment. (See Note 8)
3. Sand or silt deposits	None other than of natural origin except as may result from normal agricultural, road maintenance, construction activity, or dredge material disposal provided all resonable controls are used. (See Notes 6 and 8).
4. Color and turbidity	A secchi disc shall be visible at a minimum of 1 meter, SBd - criteria may be exceeded. (See Notes 8 and 14)
5. Coliform bacteria per 100 ml	Not to exceed a median value of 700 and not more than 2300 in more than 10 percent of the samples. (See Notes 3 and 12)
6. Taste and odor	None in such concentrations that would impair any usages specifically assigned to this class and none that would cause taste and odor in edible fish or shellfish.

7.	pH	6.8 - 8.5
8.	Allowable temperature increase	None except where the increase will not exceed the recommended limit on the most sensitive receiving water use and in no case exceed 83°F or in any case raise the normal temperature of the receiving water more than 4°F. During the period including July, August, and September, the normal temperature of the receiving water shall not be raised more than 1.5°F unless it can be shown that spawning and growth of indigenous organisms will not be significantly affected. (See Note 19)
9.	Chemical constituents	None in concentrations or combinations which would be harmful to human, animal, or aquatic life or which would make the waters unsafe or unsuitable for fish or shellfish or their propagation, or impair the water for any other usage assigned to this class. (See Note 4)

APPLICABLE NOTES

NOTE #3 - All sewage treatment plant effluent shall receive disinfection before discharge to the surface waters with the exception of discharges to the following streams for which disinfection shall be required only during the period from May 1st to October 1st.

Housatonic River (north of I-95 Bridge)

Naugatuck River

Quinnipiac River (north of I-95 Bridge)

Farmington River

Pequabuck River

Connecticut River (north of I-95 Bridge)

Hockanum River

Willimantic River

Shetucket River

Quinebaug River

Thames River (north of I-95 Bridge)

It is recognized that the coliform bacteria may not be met on the above streams during the period when disinfection of sewage treatment plant effluent is not required.

The degree of treatment and disinfection shall be as required by the Commissioner and shall be consistent with the health standards as established by the State Department of Health.

NOTE #4 - The waters shall be free from chemical constituents in concentrations or combinations which would be harmful to human, animal or aquatic life for the most sensitive and governing water use class. Criteria for chemical constituents contained in the "Quality Criteria for Water" published by the Environmental Agency shall be considered and used as a guidance. In areas where fisheries are the governing considerations and approved limits have not been established, bioassays are necessary to establish limits on toxic substances, the recommendations for bioassay procedures contained in "Standard Methods for the Examination of Water and Wastewater" and the application factors contained in "Quality Criteria for Water" shall be considered. For public drinking water supplied, the raw water sources must be of such a quality that U.S. Environmental

Protection Agency limits as defined by the Safe Drinking Water Act (Public Law 93-523), or state limits if more stringent, for finished water can be met after conventional treatment.

NOTE #6 - Reasonable controls may be defined by the Commissioner on a case by case basis or the Commissioner may require that it be affirmatively demonstrated by any person or municipality engaged in such activities that all reasonable controls will or are being used.

NOTE #8 - Except within designated dredged material disposal areas, waters shall be substantially free of pollutants that: (a) unduly affect the composition of bottom fauna; (b) unduly affect the physical or chemical nature of the bottom; and (c) interfere with the propagation and habitats of shellfish, finfish, and wildlife. Dredged materials dumped at approved disposal areas shall not pollute the waters of the state and shall not result in: (a) floating residues of any sort; (b) release of any substance, biological or chemical constituents which may result in long-term or permanent degradation of Water Quality Standards overlying or adjacent to the dumping grounds; (c) unintentional dispersal of sediments outside a mixing zone enclosing the designated dump points; and (d) biological mobilization and subsequent transport of toxic substances to food chains.

NOTE #12 - Coliform bacteria criteria are intended to provide a standard for coliform data evaluation and related to the probability of contamination by undisinfected sewage. High results may be due to soil bacteria from the feces of warm blood animals which are not of sanitary significance. High results should therefore be investigated by sanitary survey or other appropriate means to confirm the cause. Fecal coliform (i.e., coliform organisms from the feces of warm blooded animals), may be useful as a secondary indicator. Although the reliability of fecal coliform analysis is not yet adequate to use as a standard, it is desirable that correlation data be generated. The Region I Office of the U.S. Environmental Protection Agency has suggested criteria for fecal coliform data evaluation. Such criteria should be considered only as a guideline and can be found in Appendix A.

NOTE #14 - The use of subscript b in Class Sb is intended to identify those areas where natural conditions or conditions which cannot be expected to be appreciably altered by the control of discharges may preclude bathing. It may also be used in Classes Bb and SBb to designate areas in the immediate vicinity of treated sewage outfalls where bathing is not advisable.

NOTE #19 - Upstream of the mouths of the Housatonic River, Connecticut River, and Thames River, the allowable temperature increase shall be consistent with the corresponding Inland Waters Class.

6.0 ITEM LIST

Area 01

Item Number	Description	Process Flow Diagram
101-34001	Hopper (Existing)	101-001
101-34002	Hopper	101-002
101-35001-1, 4	Transfer Barge	101-001
101-41001	Sump Pump	101-001
101-41002	Sump Pump	101-002
101-43001	Conveyor #13 (Existing)	101-001
101-43002	Stacker #16 (Existing)	101-001
101-43003	Conveyor #31A (Existing)	101-001
101-43004	Loading Conveyor	101-001
101-43005	Boom Conveyor	101-001
101-43006	Feeder	101-002
101-43007	Feed Conveyor	101-002
101-43008	Feed Elevator	101-002
101-48001	Barge Haul (Existing)	101-001
101-48002	Barge Unloader (Existing)	101-001
101-48003	Dust Suppressant System	101-001
101-48004	Telescopic Chute (Existing)	101-001
101-48005	Barge Haul	101-002
101-48006	Clam Sheel Unloader	101-002
101-48007	Dust Suppressant System	101-002
101-49001	Front End Loader	101-001
101-49002	Front End Loader	101-002

Area 02

Item Number	Description	Process Flow Diagram
102-34001-1, 4	Sized Coal Storage Bin	102-001
102-35001	Raw Coal Surge Bin	102-001
102-43001-1, 4	Storage Bin Live Bottom	102-001
102-43003	Sized Coal Conveying System	102-001
102-43004	Feed Coal Conveyor System	102-001
102-45001-1, 4	Sized Coal Feeder	102-001
102-47001	Coal Drying and Sizing System	102-001

6.0 ITEM LIST (Cont'd.)

Area 03

Item Number	Description	Process Flow Diagram
103-33001-1, 4	Gasifier	103-001
103-34001-1, 2	Ash Bunker (Existing)	103-001
103-35001-1, 4	Feed Coal Surge Bin	103-001
103-43001	Ash Conveyor System	103-001
103-45001-1, 4	Gasifier Multi-Cyclones	103-001
103-47001-1, 4	Feed Coal Lock Hopper System	103-001
103-47002-1, 4	Ash Removal Lock Hopper System	103-001
103-47003-1, 4	Recycle Solids Lock Hopper System	103-001

Area 04

Item Number	Description	Process Flow Diagram
104-31001	Interchanger	104-001
104-35001	COS Hydrolyzer	104-001
104-41001-1, 2	Recycle Pump	104-001
104-44001-1, 4	Heat Recovery System	104-001
104-45001	Particulate Scrubber	104-001
104-45002-1, 2	Hydroclone	104-001

Area 05

Item Number	Description	Process Flow Diagram
105-31001	Scrubber Interchanger	105-001
105-31002	Scrubber Recycle Cooler	105-001
105-31003	Stripper Bottoms Cooler	105-001
105-31004	Stripper Recycle Cooler	105-001
105-32001	Ammonia Scrubber	105-001
105-32002	Ammonia Stripper	105-001
105-35001	Knock Out Pot	105-001
105-41001-1, 2	Ammonia Recycle Pump	105-001
105-41002-1, 2	Stripper Pump	105-001
105-42001-1, 2	Recycle Booster Compressor	105-001
105-44001	Stripper Condenser	105-001

6.0 ITEM LIST (Cont'd.)

Area 05 (Cont'd.)

Item Number	Description	Process Flow Diagram
105-47001	Partial Phosam	105-001
Area 06		
106-31001	Fuel Heater	106-001
106-47001	Selexol System	106-001
Area 07		
107-31001 107-31002	Gasifier Air Interchanger Booster Compressor Precooler	107-001 107-001
107-42001	Air Booster Compressor	107-001
107-47001	Combustion Turbine	107-001
107-48001	Electric Generator	107-001
Area 08		
108-41001-1, 2 108-41002-1, 2	Secondary BFW Pump Primary BFW Pump	108-001 108-001
108-44001	Heat Recovery Unit	108-001
108-45001	Deaerator	108-001
Area 09		
109-31001 109-31002	Incinerator Feed Heater Fuel Gas Heater	109-002 109-002
109-42001	Incinerator Blower	109-002
109-47001 109-47002 109-47003	Claus Plant SCOT Unit Incinerator	109-001 109-002 109-002
109-49001	Sulfur Loader	109-001
Area 10		
110-35001	Air Receiver	110-001
110-42001-1, 2	Instrument/Plant Air Compressor	110-001

6.0 ITEM LIST (Cont'd.)

Area 10 (Cont'd.)

Item Number	Description	Process Flow Diagram
110-47001	Air Dryer	110-001

Area 11

111-47001	Turbine Generator #11 (Existing)	111-001

Area 12

112-47001	Turbine Generator # 9 (Existing)	112-001

Area 13

Primary treatment is done in the municipal water system.

Area 14

114-34001	Demineralized Water Tank	114-001
114-41001-1, 2	Demineralized Water Pump	114-001
114-41002	Distribution Pump	114-001
114-47001	Demineralization System	114-001

Area 15

115-41001-1, 4	Cooling Water Pump	115-001
115-44001	Cooling Tower	115-001
115-47001	Cooling Water pH Unit	115-001
115-47002	Cooling Water Inhibitor Unit	115-001

Area 16

116-31001	Cooling Tower Blowdown Cooler	116-003
116-35001	Stripped Condensate Surge Tank	116-002
116-35002	Blowdown Surge Tank	116-002
116-35003	Char Letdown Tank	116-003

6.0 ITEM LIST (Cont'd.)

Area 16 (Cont'd.)

Item Number	Description	Process Flow Diagram
116-41001-1, 3	Blowdown/Condensate Pump	116-002
116-41002-1, 2	Process Sewer Pump	116-003
116-45001	Blowdown Separator	116-002
116-45002	Blowdown Separator	116-002
116-45003	Blowdown Separator	116-002
116-45004	Blowdown Separator	116-002
116-47001	Bridgeport Station Treatment System	116-001
116-47002	Steel Point Station Treatment System	116-001
116-47003	Equalization System	116-003
116-47004	Ozone Odor Control System	116-003
116-47005	Flotation System	116-003
116-47006	Bio-Plant	116-004
116-47007	Bed Filter System	116-005
116-47008	Sludge Thickening System	116-005
116-47009	Sludge Press System	116-006
116-47010	Sludge Digestion System	116-006

Area 17

117-35001	Diesel Fuel Tank	117-001
117-34001	Fire Water Tank	117-001
117-41001-1, 2	Fire Water Pump	117-001
117-41002	Jockey Pump	117-001

Area 18

118-47001	Flare	118-001

7.0 PARAGRAPH SPECIFICATIONS

7.1 Area 01

7.1.1 Process Flow Diagram 101-001 Coal Unloading and Handling - Bridgeport Harbor Station.

101-35001-1, 4 Transfer Barge

Type:	River going, no power
Size:	195 feet long by 35 feet wide and 12 feet high
Capacity:	1500 tons

101-41001 Sump Pump

Type:	Vertical centrifugal
Drive:	Electric
Material:	Stainless Steel
Capacity:	50 gpm at 60 foot head

101-43004 Loading Conveyor

Type:	Belt, totally enclosed
Capacity:	550 tons per hour
Length:	400 feet
Width:	35 inches

101-43005 Boom Conveyor

Type:	Belt with cover and walkway
Capacity:	600 tons per hour
Length:	40 feet
Width:	48 inches

101-48003 Dust Suppressant System

Type:	Wetting Solution
Equipment:	Proportioner, pump, mixing tank, nozzles, spray headers, self-cleaning filters and automatic controls.

Flow automatically controlled at each station and spray only when material moving.

101-49001 Front End Loader

Type:	Diesel-hydraulic, four wheel drive, air-conditioned/heated, with sound suppression and power assist controls
Capacity:	6.17 cubic yard bucket

7.1.2 Process Flow Diagram 101-002 Coal Unloading and Handling - Steel Point Station.

7.1 Area 01 (Cont'd.)

7.1.2 Process Flow Diagram 101-002 Coal Unloading and Handling - Steel Point Station. (Cont'd.)

101-34002 Hopper

Top Opening:	12 foot by 12 foot covered by heavy duty 6 inch by 6 inch grating
Bottom Opening:	3 feet wide by 9 feet long
Valleys:	50 degree minimum
Material:	Carbon steel
Capacity:	30 tons

101-41002 Sump Pump

Type:	Vertical centrifugal
Drive:	Electric
Material:	Stainless steel
Capacity:	50 gpm at 60 foot head

101-43006 Feeder

Type:	Vibrating
Material:	Carbon steel
Capacity:	150 tons per hour

Supplied with skirt board and rack and pinion gate

101-43007 Feed Conveyor

Type:	Belt, covered, with a walk on each side
Capacity:	150 tons per hour
Length:	220 feet
Width:	24 inches

101-43008 Feed Elevator

Type:	Bucket
Capacity:	150 tons per hour
Height:	100 feet center to center
Material:	Steel
Dust:	Hood at discharge

101-48005 Barge Haul

Type:	Wire rope pull, double drum, reversible
Travel:	600 feet
Starting Pull:	56,000 pounds
Traveling Pull:	28,000 pounds

101-48006 Clam Shell Unloader

Type:	Pedestal mounted
Capacity:	15 cubic yard bucket
Radius:	55 feet
Unloading Rate:	500 tons per hour

7.1 Area 01 (Cont'd.)

7.1.2 Process Flow Diagram 101-002 Coal Unloading and Handling - Steel Point Station. (Cont'd.)

101-48007 Dust Suppressant System

Type:	Wetting solution
Equipment:	Proportioner, pump, mixing tank, nozzles, spray headers, self-cleaning filters and automatic controls

Flow automatically controlled at each station and spray only when material is moving.

101-49002 Front End Loader

Type:	Diesel - hydraulic, four wheel dirve, air conditioned/heated, with sound suppression and power assist controls
Capacity:	6.17 cubic yard bucket

7.2 Area 02

7.2.1 Process Flow Diagram 102-001 Coal Preparation

102-34001-1, 4 Sized Coal Storage Bin

Capacity:	1650 tons each
Material:	Carbon steel
Diameter:	30 feet
Straight Shell:	85 feet
Bottom:	60 degree cone to 10 foot diameter opening

102-35001 Raw Coal Surge Bin

Capacity:	10 tons
Diameter:	7 feet
Straight Shell:	10 feet
Bottom:	60 degree cone adapted to a 4 foot by 4 foot opening
Material:	Carbon steel

102-43001-1,4 Storage Bin Live Bottom

Type:	Electric driven eccentric weights
Material:	Carbon steel with stainless liner plates. Neoprene flexible connector to bin.
Size:	10 foot diameter top opening, 45 degree cone to 6 inch bottom opening.

7.2 Area 02 (Cont'd.)

7.2.1 Process Flow Diagram 102-001 Coal Preparation (Cont'd.)

102-43003 Sized Coal Conveying System
System: Belt conveyor, bucket elevator and a belt shuttle conveyor
Capacity: 135 tons per hour
Material: Carbon steel, except belts
Belt Conveyor
Length: 50 feet
Width: 24 inches
Continuous covered skirt boaro
Elevator
Height: 80 feet center to center
Dust hood at discharge
Shuttle Conveyor
Length: 60 feet
Width: 24 inches
Full lenght skirt boards with discharge chute at each end, reversible.

102-43004 Feed Coal Conveyor System
System: Three belt conveyors, two bucket elevators and one drag flight conveyor
Capacity: 75 tons per hour
Material: Carbon steel except belts
One cross belt and one elevator are spare.
Collecting Conveyor, Reversible
Length: 150 feet
Width: 24 inches
Cross Conveyors (two)
Length: 50 feet
Width: 24 inches
Bucket Elevators (two)
Height: 120 feet center to center
Drag Flight Conveyor
Length: 150 feet
Outlets: four, equipped with totally enclosed shut off gates

102-45001-1, 4 Sized Coal Feeder
Type: Vibrating
Capacity: 75 tons per hour, each
Material: Carbon steel with abrasive resistant line
Skirt boards and rack and pinion gate

7.2 Area 02 (Cont'd.)

7.2.1 Process Flow Diagram 102-001 Coal Preparation (Cont'd.)

102-47001 Coal Drying and Sizing System

Capacity:	135 tons per hour
Reduction:	From 2 inch by 0 to 1/4 inch by 0
Drying Capacity:	Dry from 9.6 percent moisture to 6 percent moisture, when required
Equipment:	A dual screw feeder, a crusher, a classifier, a primary cyclone, a bag collector with exit screw and rotary feeder, a recycle gas blower and exhaust fan, and a combustion chamber with a combustion air blower. All motors and all interconnecting duct work will be included.
Controls:	A prewired automatic control panel will set the sequence and timing for all motors. Malfunction will be indicated and shut down will be automatic.

The dryer will be locked out manually when the surface moisture does not exceed four percent. The dryer will operate on 147 BTU per SCF lower heating value gas.

7.3 Area 03

7.3.1 Process Flow Diagram 103-001 Pressurization, Gasification and Ash Removal.

103-33001-1, 4 Gasifier System

Equipment:

Gasifier

Type:	Single fluid bed
Temp.:	1850°F
Pressure:	340 psig

Coal Feed

Type:	Lock hopper
Control:	Volumetric

Ash Removal

Type:	Lock hopper
Control:	Star feeder

Solids Recycle

Type:	High efficiency cyclones, solids cooling and lock hopper with star feeder

7.3 Area 03 (Cont'd.)

7.3.1 Process Flow Diagram 103-001 Pressurization, Gasification and Ash Removal (Cont'd.)

103-34001-1 Ash Bunker (Existing)

Diameter:	Approx. 18 feet
Height:	Approx. 21 feet
Capacity:	Approx. 200 cubic feet
Material:	Carbon steel

103-34001-2 Ash Bunker (Existing)

Diameter:	Approx. 18 feet
Height:	Approx. 21 feet
Capacity:	Approx. 200 cubic feet
Material:	Masonry Tile

103-35001-1, 4 Feed Coal Surge Bin

Diameter:	8 feet
Straight Shell:	14 feet
Bottom:	50 degree cone
Top:	Flat
Material:	Carbon steel

103-43001 Ash Conveyor System

System:	One collecting belt and one elevating belt
Capacity:	12 tons per hour
Material:	Carbon steel with hot material belts to withstand 500°F ash.

Collecting Belt
- Length: 150 feet
- Width: 18 inches

Elevating Belt
- Length: 260 feet
- Width: 18 inches

Both belts covered and with walkways on both sides.

7.4 Area 04

7.4.1 Process Flow Diagram 104-001 Heat Recovery, COS Pryrolysis and Particulate Removal

104-31001 Interchanger

Type:	Shell and tube
Area:	4,484 square feet
Material:	Carbon steel
Duty:	11,103,000 BTU per hour

104-35001 COS Hydrolizer

Diameter:	11 feet 6 inches
Straight Shell:	120 feet
Catalyst Volume:	1400 cubic feet
Material:	Carbon steel

7.4 Area 04 (Cont'd.)

7.4.1 Process Flow Diagram 104-001 Heat Recovery, COS Pyrolysis and Particulate Removal (Cont'd.)

104-41001-1, 2 Recycle Pump

Type:	Horizontal centrifugal
Drive:	Electric
Material:	Ductile iron
Capacity:	205 gpm at 139 foot head (differential)

104-44001-1, 4 Heat Recovery System

The raw gas contacting unit contains five banks of coils. The first and fourth banks are connected and contain water which recirculates to the steam drum supplied with the recovery unit. The second and the third coils superheat steam for the power turbines. The fifth bank preheats the coal gas feed to the combustor.

104-45001 Particulate Scrubber

Type:	Venturi, adjustable throat
Material:	304 stainless steel

Supplied with a separator and mist eliminator.

104-45002-1, 2 Hydroclone

Type:	Multiple cyclone unit containing 300 cones.
Material:	304 stainless steel, cones refractory lined.

7.4 Area 05

7.5.1 Process Flow Diagram 105-001 Ammonia Removal

105-31001 Scrubber Interchanger

Type:	Shell and finned tube
Area:	836 square feet (bare basis)
Material:	304 stainless steel
Duty:	8,727,000 BTU per hour

105-31002 Scrubber Recycle Cooler

Type:	Shell and tube
Area:	10,977 square feet
Material:	Carbon steel
Duty:	51,678,000 BTU per hour

105-31003 Stripper Bottoms Cooler

Type:	Shell and tube
Area:	1564 square feet
Material:	Carbon steel
Duty:	18,389,000 BTU per hour

7.5 Area 05 (Cont'd.)

7.5.1 Process Flow Diagram 105-001 Ammonia Removal (Cont'd.)

105-31004 Stripper Recycle Cooler

Type:	Shell and tube
Area:	1150 square feet
Material:	Carbon steel
Duty:	4,250,000 BTU per hour

105-32001 Ammonia Scrubber

Type:	Packed, 1 inch Raschig rings
Beds:	Two, 15 feet deep each
Diameter:	15 feet 9 inches
Straight Shell:	41 feet 4 inches
Material:	304 stainless steel

105-32002 Ammonia Stripper

Type:	Valve trayed
Trays:	14
Diameter:	6 feet 3 inches
Straight Shell:	27 feet 6 inches
Material:	304 stainless steel

105-35001 Knock Out Pot

Diameter:	5 feet 2 inches
Straight Shell:	10 feet
Material:	304 stainless steel

105-41001-1, 2 Ammonia Recycle Pump

Type:	Horizontal centrifugal
Drive:	Electric
Material:	304 stainless steel
Capacity:	2800 gpm at 70 foot head (differential)

105-41002-1, 2 Stripper Pump

Type:	Horizontal centrifugal
Drive:	Electric
Material:	304 stainless steel
Capacity:	435 gpm at 822 foot head (differential)

105-42001-1, 2 Recycle Booster Compressor

Type:	Reciprocating
Drive:	Electric
Capacity:	11,015 scfm
Pressure Rise:	43 psi

105-44001 Stripper Condenser

Type:	Air cooled
Duty:	11,791,000 BTU per hour

7.5 Area 05 (Cont'd.)

7.5.1 Process Flow Diagram 105-001 Ammonia Removal (Cont'd.)

105-47001 Partial Phosam
Absorber, stripper and other equipment associated with the Phosam W process exclusive of ammonia recovery.

7.6 Area 06

7.6.1 Process Flow Diagram 106-001 Acid Gas Removal (Selexol).

106-31001 Fuel Heater

Type:	Shell and finned tube
Area:	5,774 square feet (fin area)
Material:	304 stainless steel
Duty:	16,266,000 BTU per hour

106-47001 Selexol System
Proprietary system designed to reduce the sulfur content of the gas to 200 parts per million.

7.7 Area 07

7.7.1 Process Flow Diagram 107-001 Gas Turbine Power Generator

107-31001 Gasifier Air Interchanger

Type:	Shell and tube
Area:	49,360 square feet
Material:	Carbon steel
Duty:	42,609,000 BTU per hour

107-31002 Booster Compressor Precooler

Type:	Shell and finned tube
Area:	5,836 square feet fin area
Material:	Carbon steel
Duty:	22,774,000 BTU per hour

107-42001 Air Booster Compressor

Type:	Three stage centrifugal
Drive:	Steam turbine
Fluid:	Air
Inlet:	200 psia at 100°F
Discharge:	410 psia at 253°F
Capacity:	427,000 pounds per hour

7.7 Area 07 (Cont'd.)

7.7.1 Process Flow Diagram 107-001 Gas Turbine Power Generation (Cont'd.)

107-47001 Combustion Turbine

Manufacturer:	Westinghouse Electric Corp.
Gas Turbine:	Model 501D5
Combustor:	Designed to be fired with coal gas
Compressor:	Common shaft unit supplied to provide combustor air and process air

Air Silencer and an Air Cooler are provided.

107-48001 Electric Generator

Manufacturer:	Westinghouse Electric Corp.
Generator:	Model

Selected to produce 107.8 MW at fully loaded gas turbine operation.

7.8 Area 08

7.8.1 Process Flow Diagram 108-001 Waste Heat Steam Generator

108-41001-1, 2 Secondary BFW Pump

Type:	Horizontal centrifugal
Drive:	Electric
Capacity:	540 gpm

108-41002-1, 2 Primary BFW Pump

Type:	Horizontal centrifugal
Drive:	Electric
Capacity:	1600 gpm

108-44001 Heat Recovery Unit

The gas turbine exhaust contacting unit contains four banks of coils. The first bank superheats steam produced in the second bank combined with steam produced in the first and fourth banks in the Area 04 heat recovery unit. A steam drum is provided for the second bank. The third bank preheats BFW for Area 03 and the fourth bank heats water from the deaerator.

108-45001 Deaerator

This unit deaerates all return condensate and demineralized water make-up using bleed off steam from the steam turbine generators and exhaust steam from the air booster compressor in Area 07.

Operation Pressure:	15 psig
BFW Capacity:	1945 gpm

7.9 Area 09

7.9.1 Process Flow Diagram 109-001 Sulfur Recovery (Claus)

109-47001 Claus Plant
This is a proprietary process designed to remove a minimum of 96 percent of the sulfur in the feed gases and to recover it as liquid elemental sulfur.

109-49001 Sulfur Loader

Type:	Diesel - hydraulic four wheel drive, air conditioned/heated, with sound suppression and power assist controls.
Capacity:	6.17 cubic yard bucket

7.9.2 Process Flow Diagram 109-002 Sulfur Recovery (SCOT)

109-31001 Incinerator Feed Heater

Type:	Shell and tube
Area:	2,215 square feet
Material:	Carbon steel shell, 304 stainless steel tubes
Duty:	2,497,000 BTU per hour

109-31002 Fuel Gas Heater

Type:	Shell and tube
Area:	349 square feet
Material:	Carbon steel shell, 304 stainless steel tubes
Duty:	592,000 BTU per hour

109-42001 Incinerator Blower

Type:	Single stage
Pressure Rise:	2 psi
Capacity:	1435 scfm
Drive:	Electric

Supplied with inlet air filter

109-47002 SCOT Unit
This is a proprietary process to treat the tail gas from the Claus Plant. The sulfur compounds are reduced to H_2S and the major part is recycled to Claus, leaving 200 ppmv in the tail gas for incineration.

109-47003 Incinerator

Type:	Vertical, dual chamber
Fuel:	Ammonia rich stream 14.b and coal

Special Design: Ammonia rich stream is fixed in the first chamber and quick quenched with stream 19 to minimize NO_x formation. Combustion is completed in the second chamber with coal gas.

7.10 Area 10

7.10.1 Process Flow Diagram 110-001 Instrument/Plant Air.

110-35001 Air Receiver

Diameter:	48 inches
Straight Shell:	10 feet
Material:	Carbon steel

110-42001-1, 2 Instrument/Plant Air Compressor

Type:	Screw
Capacity:	1250 scfm
Pressure:	110-psig nominal

Supplied with inlet air filter and aftercooler with separator and automatic drain.

110-47001 Air Dryer

Type:	Dessicant, dual tower, automatic four hour cycle.
Capacity:	1250 scfm

7.11 Area 11

7.11.1 Process Flow Diagram 111-001 Steam Power Generator No. 11

Steam turbine and auxiliaries existing.

7.12 Area 12

7.12.1 Process Flow Diagram 112-001 Steam Power Generator No. 9.

Steam turbine and auxiliaries existing.

7.14 Area 14

7.14.1 Process Flow Diagram 114-001 Demineralization.

114-34001 Demineralized Water Tank

Type:	Atmospheric, cone roof storage tank
Size:	24' -0" dia. x 28' -0" high
Operating Temp.:	75°F
Operating Press.:	Atmospheric
Materials of Constr.:	Carbon steel w/304 SS cladding or carbon steel w/PVC lining
Material Stored:	Demineralized water

7.14 Area 14 (Cont'd.)

7.14.1 Process Flow Diagram 114-001 Demineralization (Cont'd.)

114-41001-1, 2 Demineralized Water Pump

Type:	Horizontal centrifugal
Capacity:	100 gpm operating 120 gpm design
Head Required, Ft.:	100
Materials of Constr.:	304 stainless steel
Material Handled:	Demineralized water

114-41002 Distribution Pump

Type:	Horizontal centrifugal
Capacity:	50 gpm design
Head Required, Ft.:	50
Materials of Constr.:	304 stainless steel
Material Handled:	Demineralized water

114-47001 Demineralization System

This system produces demineralized BFW from city water.

Equipment included:	Carbon filter (2), backwash feed tank, backwash feed pump, backwash collection tank, backwash disposal pump, cation exchanger (2), cation dilution tank, cation feed pump, sulfuric acid storage tank, sulfuric acid transfer pump, anion exchanger (2), anion dilution tank, anion feed pump, caustic storage tank, caustic transfer pump, Regeneration collection tank, regeneration disposal pump. AUTOMATIC OPERATION.
System Sizing:	114 gpm Operating 140 gpm Design

7.15 Area 15

7.15.1 Process Flow Diagram 115-001 Cooling Water System

115-41001-1, 4 Cooling Water Pump

Type:	Horizontal centrifugal
Drive:	Electric
Capacity:	6700 gpm at 100 foot head

7.15 Area 15 (Cont'd.)

7.15.1 Process Flow Diagram 115-001 Cooling Water System (Cont'd.)

115-44001 Cooling Tower

Type:	Two bay induced draft
Capacity:	19,000 gpm
Design Air Dewpoint:	78°F
Return Temp.:	106°F
Water Discharge Temp.:	85°F

For installation on above ground sump

115-47001 Cooling Water pH Unit

Type:	H_2SO_4 addition
Equipment:	Mix tank, agitator, and addition pump

115-47002 Cooling Inhibitor Unit

Equipment:	Mix tank, agitator, and addition pump

7.16 Area 16

7.16.1 Process Flow Diagram 116-001 Waste Treatment, Coal Pile Runoff.

116-47001 Bridgeport Harbor Station Treatment System

Package system consisting of:

- Feed pump
- Lime treatment sump with agitator
- Lime bin (20 ton capacity) with bag filter and pneumatic fill pipe.
- Lime feeder
- Lime slaker
- Aeration sump with aerators
- Clarifier feed pump
- Clarifier
- Filter feed pump
- Filter
- Instrumentation and controls

Design Rate 248 gpm

116-47002 Steel Point Station Treatment System

Package same as 116-47001

Design Rate 78 gpm

7.16 <u>Area 16</u> (Cont'd.)

7.16.2 Process Flow Diagram 116-002 Waste Treatment-Boiler Blowdown and Stripped Condensate.

116-35001 Blowdown Surge Tank

Type:	Horizontal
Diameter:	5 feet 6 inches
Straight Shell:	10 feet 7 inches
Material:	Carbon steel

116-35002 Stripped Condensate Surge Tank

Type:	Horizontal
Diameter:	5 feet 6 inches
Straight Shell:	16 feet 3 inches
Material:	Carbon steel

116-41001-1, 3 Blowdown/Condensate Pump

Type:	Horizontal centrifugal
Drive:	Electirc
Capacity:	345 gpm at 60 foot head

116-45001 Blowdown Separator

Blowdown Rate:	15 gpm at 530°F
Mixing Water Rate:	156 gpm at 85°F

Supplied with steam head.

116-45002 Blowdown Separator

Blowdown Rate:	11.4 gpm at 540°F
Mixing Water Rate:	130 gpm at 85°F

Supplied with steam head

116-45003 Blowdown Separator

Blowdown Rate:	0.6 gpm at 312°F
Mixing Water Rate:	3.3 gpm at 85°F

Supplied with steam head.

116-45004 Blowdown Separator

Blowdown Rate:	0.1 gpm at 312°F
Mixing Water Rate:	0.6 gpm at 85°F

Supplied with steam head.

7.16 Area 16 (Cont'd.)

7.16.3 Process Flow Diagram 116-003 Wastewater Collection Odor Control and Colloid Removal.

116-31001 Cooling Tower Blowdown Cooler

Type:	Double pipe
Area:	272 square feet
Material:	Carbon steel
Duty:	360,000 BTU per hour

116-35003 Char Letdown Tank

Type:	Vertical
Diameter:	18 inches
Straight Shell:	7 feet
Material:	304 stainless steel

116-41002-1, 2 Process Sewer Pump

Type:	Vertical, centrifugal
Drive:	Electric
Capacity:	110 gpm at 50 foot head
Material:	Carbon steel

116-47003 Equalization System

This system performs two functions:

1. It provides surge for the bio-plant feed, minimizing the possibility that slugs of contaminants could enter the bio-plant and destroy the activated sludge.
2. It serves as a stripping system for the removal of sulfur-bearing gases from the wastewater.

Equipment Included:	Equalization tank w/static mixing system, stripping air blowers, and effluent pumps.
System Sizing:	Based on 111 gpm Wastewater Feedrate.

116-47004 Ozone Odor Control System

This system produces ozone and uses it to destroy objectionable sulfur containing gases, such as H_2S and COS.

Equipment Included:	Atmospheric air blower, air dryer, ozone generator, ozone-waste gas contactor.

7.16 Area 16 (Cont'd.)

7.16.3 Process Flow Diagram 116-003 Wastewater Collection Odor Control and Colloid Removal (Cont'd.)

116-47005 Flotation System

This system removes colloidal solids and emulsified oil droplets from the bio-plant feed. This prevents fouling of the bio-plant activated sludge.

Equipment Included:	Polymer feed station, static mixer, flocculation tank, flotation tank, sludge skimmer, sludge pumps.
System Sizing:	Based on 111 gpm Wastewater Feedrate.

116-47006 Bio-Plant

This system will destroy the organic content of the plant wastewater through the biological action of the active sludge.

Equipment Included:	Reaction basins, basin aerators, ploymer feed system, feed cooler, clarifier w/rake mechanism, sludge recycle skimmings tank, skimmings pump, system feed pumps, acid and base feed stations.
System Sizing:	Based on 115 gpm Wastewater Feedrate.

7.16.5 Process Flow Diagram 116-005 Bio-Plant Effluent Filtration and Sludge Thickening.

116-47007 Bed Filter System

This system removes bio-sludge flocs from the bio-plant effluent prior to discharging the effluent from the plant. These flocs cannot be discharged since they are biologically active.

Equipment Included:	Feed pumps, bed filter, clearwell, clearwell pumps, backwash sump, backwash pump.
System Sizing:	Based on 111 gpm Wastewater Feedrate.

7.16 <u>Area 16</u> (Cont'd.)

7.16.5 Process Flow Diagram 116-005 Bio-Plant Effluent Filtration and Sludge Thickening.

116-47008 Sludge Thickening System

This system thickens the bio-sludge to the proper consistency for press filtration.

Equipment Included: Flocculation tank, flotation tank w/skimmer, sludge pumps, effluent tank, effluent recycle pumps.

System Sizing: Based on 4 gpm feed rate at 1% suspended solids with 3 gpm recycle effluent.

116-47009 Sludge Press System

This system will produce a filter cake for off-site disposal out of the sludges from the flotation and sludge digestion systems.

Equipment Included: Feed tank w/mixer, feed pumps, press, filtrate tank, filtrate pumps, polymer feed station.

System Sizing: Based on 1.4 gpm Feedrate at 3.5% solids. Filtrate rate = 1 gpm.

116-47010 Sludge Digestion System

This system, through aerative oxidation, transforms active bio-sludge into a biologically inert sludge.

Equipment Included: Aerobic digestor tank, digestor aerator.

System Sizing: Based on 1 gpm flowrate with 4% bio-sludge.

7.17 <u>Area 17</u>

7.17.1 Process Flow Diagram 117-001 Fire Protection

117-35001 Diesel Fuel Tank

Type:	Horizontal
Diameter:	2 feet 6 inches
Straight Shell:	8 feet
Material:	Carbon steel

117-34001 Fire Water Tank

Type:	Vertical, pad mounted
Diameter:	28 feet
Height:	40 feet

7.17 Area 17 (Cont'd.)

7.17.1 Process Flow Diagram 117-001 Fire Protection (Cont'd.)

117-41001-1, 2 Fire Water Pump

Type:	Horizontal centrifugal
Capacity:	1500 gpm at 230 foot head
Drive:	One electric, one diesel
Material:	Manufacturer's standard

117-41002 Jockey Pump

Type:	Horizontal centrifugal
Capacity:	25 gpm at 230 foot head
Drive:	Electric
Material:	Manufacturer's standard

7.18 Area 18

7.18.1 Process Flow Diagram 118-001 Flare.

118-47001 Flare

Type:	Ground level, shielded and accoustically treated
Fuel:	No. 2 fuel oil
Operation:	Intermittent, automatic on demand
Capacity:	163,000 scfm low BTU gas

8.0 CAPITAL COST ESTIMATES

8.1 Basis

This list presents the basis for the capital costs in each plant area for the proposed combined cycle system. The costs, as presented in Section 8.2, are total installed costs in late 1979 and early 1980 dollars and include, where applicable, the following items for each area on an individual basis.

- Purchased equipment and freight for all process equipment
- Direct Construction Labor
- Intra-area Piping and Electrical
- Instrumentation
- Insulation, Refractory
- Foundations, Piling, Excavation
- Structural Steel, erected
- Control Room

The capital cost for each area includes all material and labor necessary to install a module that is complete and connected to the adjacent areas with process lines and utility supplies so that it is ready to operate.

Area 01 - Coal Unloading and Handling

Preliminary equipment specifications were prepared and costs obtained by telephone for new equipment items needed in this area. Installation costs were estimated by Dravo.

Equipment was sized to provide 75 days storage at Bridgeport Harbor Station and 15 days storage at Steel Point Station.

Adequate to receive and store coal requirements in a 40-hour week.

Area 02 - Coal Preparation

Mechanical equipment and river type barge costs estimated by vendors and vessel costs estimated by Dravo. Installation costs estimated by Dravo.

8.1 Basis (Cont'd.)

Adequate to Classify and dry 135 TPH of coal so that a four day supply of sized coal can be built up and maintained.

Area 03 - Gasification

Equipment and installation costs for coal pressurization, gasification and ash handling were estimated by Dravo from in-house data on similar installations.

Area 04 - Heat Recovery, Particulate Removal and COS Hydrolysis

Equipment costs for heat exchangers and vessels were estimated by Dravo. Pumps, hydroclones, and catalyst costs were from vendors. Installation costs were estimated by Dravo.

Area 05 - Ammonia Removal

Costs for pumps, recycle compressor and air-cooled heat exchanger obtained from vendors. All heat exchanger and vessel costs and partial Phosam cost were estimated by Dravo. Installation costs estimated by Dravo.

Area 06 - Acid Gas Removal

The fuel heater and its installation costs estimated by Dravo. Installed cost of the Selexol unit and license fee estimated from Dravo in-house information.

Area 07 - Gas Turbine Power Generation

Gas combustor turbine generator set price obtained from Westinghouse. Booster compressor cost from vendor and gasifier air interchanger cost estimated by Dravo. All installation costs estimated by Dravo.

Area 08 - Waste Heat Steam Generation

Costs for equipment in this area were obtained from vendors. Installation costs estimated by Dravo.

Area 09 - Sulfur Recovery

Installed cost of the Claus & Scot plants estimated by Dravo from in-house information. Front end loader cost from vendor. Incinerator, and blower costs from vendors. Heat exchangers estimated by Dravo. Installation costs of incinerator system estimated by Dravo.

Area 10 - Instrument/Plant Air

Equipment costs from vendor. Installation cost estimated by Dravo.

8.1 Basis (Cont'd)

Area 11 - Steam Power Generator #11

Existing.

Area 12 - Steam Power Generator #9

Exisiting.

Area 13 - Primary Water Treatment

Not required at present time.

Area 14 - Demineralization

Demineralizers and pumps costs from vendors. Storage tank and all installation costs estimated by Dravo.

Area 15 - Cooling Water System

Equipment costs from vendors. Installation costs estimated by Dravo.

Area 16 - Water Treatment, Coal Pile Run-Off

Installed costs estimated by vendor for coal pile run-off systems. Pump costs from vendor. Installation costs for collection ponds, blowdown system and stripped condensate system estimated by Dravo. Vessel costs estimated by Dravo. Installed costs of other systems estimated by Dravo from in-house data for similar systems.

Area 17 - Fire Protection

Fire pump costs from vendors. Tanks estimated by Dravo. Installation costs estimated by Dravo.

Area 1 - Flare

Installed cost estimated by Dravo from in-house data for a similar system.

8.2 CAPITAL COST SUMMARY

Area	Equipment Cost	Installation Cost	Total
01 Fuel Supply	$ 2,635,700	$ 334,300	$ 2,970,000
02 Fuel Preparation	1,925,000	* 1,269,200	3,194,200
03 Coal Gasification	4,669,400	701,700	5,371,100
04 Heat Recovery, COS Hydrolysis & Particulate Removal	9,639,500	151,300	9,790,800
05 Ammonia Removal	1,415,100	607,900	2,023,000
06 Acid Gas Removal	1,920,000	359,400	2,279,400
07 Combustion Gas Turbine-Generator	14,959,000	5,841,800	20,800,800
08 Waste Heat Steam Generation	5,000,000	3,888,800	8,888,800
09 Sulfur Recovery	362,600	*11,825,400	12,188,000
10 Instrument/Plant Air	102,400	181,500	283,900
14 Demineralization	655,200	739,000	1,394,200
15 Cooling Water System	106,100	* 1,227,900	1,334,000
16 Waste Water Treatment	505,300	3,591,700	4,097,000
17 Fire Protection	90,200	130,900	221,100
18 Flare	----	* 2,763,700	2,763,700
Subtotals	$43,985,500	$33,614,500	$77,600,000
Engineering			$ 3,700,000
G & AE Fees			8,300,000
Project Management			400,000
Subtotal			$90,000,000
Allowance for renovation of existing dock area.			400,000
Total Capital Cost			$90,400,000

*Part or all of the equipment in these areas was estimated on an installed basis and equipment costs were not available.

8.2 CAPITAL COST SUMMARY (Cont'd.)

A breakout of those items and systems costing over $250,000 and the methods by which these costs were determined is presented in the following table. Except where noted, these are bare, unerected costs.

Item Number	Item Name	Cost	Method
32501	Ammonia Scrubber	$ 330,000	Eng. Est.
33701	Gasifier	1,120,000	Eng. Est.
34201	Sized Coal Storage Bin	250,000	Eng. Est.
42701	Air Booster Compressor	900,000	I.R. Budget Price 4-75-80
4415-01	Cooling Tower	400,000	Sub Contract
44401	Heat Recovery System	4,500,000	Eng. Est.
45301	Gasifier Multi-Cyclone	1,500,000	Eng. Est.
47001 48001	Combustion Turbine/Compressor Electric Generator	12,000,000	Eng. Est.
47201	Coal Drying and Sizing System	1,230,000	Eng. Est.
47501	Partial Phosam System	476,600	Eng. Est.
47601	Selexol System	1,770,000	Eng. Est.
47301	Feed Coal Lock Hopper System	617,000	Eng. Est.
47302	Ash Removal Lock Hopper System	617,000	Eng. Est.
47303	Recycle Solids Lock Hopper System	617,000	Eng. Est.
49106	Clam Shell Unloader	875,000	Anderson Equip. 12-31-79
47901	Claus Plant	2,780,000	Incl. Labor
47902	SCOT Unit	4,000,000	Incl. Labor

8.3 PAYMENT SCHEDULE

A suggested schedule of payments to be made during the life of the project is presented on the following page.

PAYMENT SCHEDULE

(Payments in Millions of Dollars)

Month	Monthly Payment	Cumulative Payment	%	Cumulative %	Month	Monthly Payment	Cumulative Payment	%	Cumulative %
1	0.3	0.3	0.3	0.3	27	3.5	30.4	3.8	33.7
2	0.3	0.6	0.4	0.7	28	3.8	34.2	4.3	38.0
3	0.3	0.9	0.3	1.0	29	4.1	38.3	4.6	42.6
4	0.3	1.2	0.3	1.3	30	4.2	42.5	4.6	47.2
5	0.4	1.6	0.4	1.7	31	4.5	47.0	5.0	52.2
6	0.4	2.0	0.5	2.2	32	5.6	52.6	6.2	58.4
7	0.4	2.4	0.5	2.7	33	4.5	57.1	5.0	63.4
8	0.5	2.9	0.5	3.2	34	4.0	61.1	4.5	67.9
9	0.6	3.5	0.7	3.9	35	3.9	65.0	4.3	72.2
10	0.7	4.2	0.7	4.6	36	3.6	68.6	4.0	76.2
11	0.8	5.0	1.0	5.6	37	3.4	72.0	3.8	80.0
12	0.9	5.9	1.0	6.6	38	3.3	75.3	3.7	83.7
13	1.0	6.9	1.1	7.7	39	2.3	77.6	2.5	86.2
14	1.0	7.9	1.1	8.8	40	2.0	79.6	2.2	88.4
15	1.0	8.9	1.1	9.9	41	1.7	81.3	1.9	90.3
16	1.1	10.0	1.2	11.1	42	1.5	82.8	1.7	92.0
17	1.1	11.1	1.2	12.3	43	1.4	84.2	1.6	93.6
18	1.1	12.2	1.3	13.6	44	1.3	85.5	1.4	95.0
19	1.2	13.5	1.4	15.0	45	1.1	86.6	1.2	96.2
20	1.2	14.7	1.4	16.4	46	1.0	87.6	1.1	97.3
21	1.2	16.9	1.4	18.8	47	0.8	88.4	0.9	98.2
22	1.2	18.1	1.3	20.1	48	0.4	88.8	0.6	98.6
23	1.2	19.3	1.3	21.4	49	0.4	89.2	0.5	99.1
24	1.9	21.2	2.2	23.6	50	0.4	89.6	0.5	99.6
25	2.5	23.7	2.7	26.3	51	0.4	90.0	0.4	100.0
26	3.2	26.9	3.3	29.9					

5% retainage to be subtracted from the above monthly payments and to be paid on project completion.

9.0 OPERATING AND MAINTENANCE COSTS

9.1 Basis

Operating costs for the proposed combinined cycle plant were developed by Dravo with input from United Illuminating Co. U. I. has concurred with the methods used and the costs determined thereby. The various bases are as follows:

A. Coal

The delivered price of $34.90/ton for this cost was obtained by Dravo in their studies of possible coal suppliers.

B. Catalysts & Chemicals

Calculated by Dravo, based on the estimated annual quantities required, and early 1980 prices.

C. Utilities

Electric Power - is produced internally to operate the plant and is thus included in the charges for coal, equipment and manpower.

City Water - is costed at U.I.'s purchasing price of 30¢/100 cu. ft.

Steam - is also generated internally in the plant and is included in the charges for ccal, equipment and manpower.

D. Labor

A manning chart for operating the plant was developed based on the manning requirements of similar plants previously studied by Dravo. These requirements were changed where necessary to reflect the differences between the present plant and those used as a guideline. This chart is shown in Figure 9-1 titled Operating Labor Breakdown. The labor cost of $70/Man day was supplied by U. I.

The maintenance labor rate used is 60% of the total maintenance cost as recommended in the "Coal Gasification Commercial Concepts Gas Cost Guidelines" written by Robert Skamser of C. F. Braun and Company for the USERDA and the American Gas Association. The total maintenance costs are based on percentages of the capital costs for each area and are shown in Fig. 9-2, Maintenance Costs. These percentages are based on those contained in the above reference document with slight modifications based on Dravo's and U. I.'s judgement. Supervisory labor is 15% of combined operating and maintenance labor.

9.1 Basis (Cont'd.)

It should be noted that manning of the coal gasification facility will require a different type of people than those employed for U. I.'s normal staff.

E. Administration and General Overhead Costs

These costs are figured at 60% of the total labor cost (operating, maintenance, supervision) as recommended in the above referenced publication.

F. Supplies

Operating supplied are costed at 30% of the operating labor cost and maintenance supplies are calculated to cost 40% of the total maintenance costs. These are as recommended in the above referenced publication.

G. By-Product Credit

No credit was taken for the sale of the by-product sulfur or the possible sale of the ash from this plant. It may be possible to sell the sulfur for various uses including asphaltic road surfacing material. It is also conceivable that a use, such as cinder block manufacture, can be found for the ash.

H. Costs Not Included

The following costs are not included in Dravo's operating and maintenance cost summary as these are best determined by U. I. from their internal information and records.

1. Ash disposal
2. Depreciation
3. Finance charges
4. Executive office overheads
5. Sales and marketing overheads
6. Research and development costs
7. Corporate income taxes
8. Local taxes and insurance
9. Profit

OPERATING LABOR BREAKDOWN

Area 01		
Barge unloader operator	Day only, 5D/Wk	1
Barge unloader helper	Day only, 5D/Wk	1
Front end loader operator	Day only, 5D/Wk	1
Area 02		
Crane operator	Day only	1
Front end loader operator	3 shifts, 5D/Wk	3
Coal prep operator	3 shifts, 5D/Wk	3
Area 03 & 04		
Gasifier operator	2 x 4 shifts, 7D/Wk	8
Gasifier operator helper	2 x 4 shifts, 7D/Wk	8
Area 05, 06, 09		
Operator	1 x 4 shifts, 7D/Wk	4
Helper	2 x 4 shifts, 7D/Wk	8
Area 07		
Turbine operator	1 x 4 shifts, 7D/Wk	4
Turbine helper	1 x 4 shifts, 7D/Wk	4
Area 08		
Boiler operator	1 x 4 shifts, 7D/Wk	4
Boiler helper	1 x 4 shifts, 7D/Wk	4
Area 10, 14, 15, 16		
Operator	2 x 4 shifts, 7D/Wk	8
Helper	2 x 4 shifts, 7D/Wk	8
Area 11, 12		
Operator	1 x 4 shifts, 7D/Wk	4
Helper	1 x 4 shifts, 7D/Wk	4
	Total	78

Figure 9-1

MAINTENANCE COSTS

Area	% of Capital Cost	$/Yr. (in M's)
01, 02 Fuel Supply and Preparation	2	$ 155
03 Coal Gasification	6	501
04, 05, 06, 09 Fuel Gas Cleanup	3	560
07 Gas Combustion Turbine Generator	1	184
04, 08 Heat Recovery	1	276
10, 15, 17 Utilities and Facilities	1	12
14 Water Treatment	1	13
16, 18 Waste Treatment and Disposal	1	67
	Subtotal	$1,768
Area 11 #11 Steam turbine generator (by UI) Area 12 #9 Steam turbine generator (by UI)		1,000
	Total	$2,768

Figure 9-2

OPERATING AND MAINTENANCE COST SUMMARY

Category		$/Yr.
Raw Materials		$20,137,200
Coal Transfer from BHS to SPS		245,400
Catalysts and Chemicals		211,500
Utilities		
City Water		106,400
Labor		
Operating	$1,992,900	
Maintenance	1,660,800	
Supervision	548,100	
	$4,201.800	4,201,800
Administration and General Overhead		2,521,100
Supplies		
Operating	$ 597,900	
Maintenance	1,107,200	
	$1,705,100	1,705,100
By-Product Credit		-0-
	"Net" Operating Cost	$29,128,500*

*Excluding those costs listed in 9.1H that are best determined by U.I.

Figure 9-3

INDEX

10.0 ECONOMIC ANALYSIS REPORT

10.1 Introduction

This report contains the results of a study investigating the economic feasibility of repowering Units 9 and 11 at Steel Point Station with a coal gasification/combined cycle (CG/CC) system.

In the normal mode of operation, coal is gasified and then combusted in a gas turbine-generator to produce electricity. The heat from the gas turbine exhaust gases is then used to produce steam for generating electricity in the existing #9 and #11 turbine-generators. The combined cycle can also be operated with only one turbine-generator, or it can be fueled using No. 2 oil if the coal gasifier is unavailable, or units 9 and 11 would even be capable of operating with their original boilers. The system contains equipment for removing sulfur from the coal gas so that the present State of Connecticut limits on sulfur emissions can be met when using high-sulfur coal.

The operating flexibilities discussed above and others not mentioned tend toward justifying the economic feasibility of the project. For this preliminary analysis, however, we assume that the total system is not available if any major component of it is not available. This assumption simplifies the analysis. If the project is determined to be economic under these circumstances then it will certainly be economic under the more flexible operating conditions.

The CG/CC system would have the affects of increasing net capability, reducing oil consumption and diversifying UI's present fuel mix of nuclear and oil to include coal. The evaluation of the project is based on the cost savings that would be accrued if the less costly coal were to displace oil for generating electricity. The additional capacity (approximately 100 MW) that would be obtained by installing the CG/CC system is of little economic consequence to UI assuming a low-band growth rate. However, under high-band load growth the additional capacity would have significant economic value.

UI is presently studying other alternatives that would reduce its heavy dependence on oil. The ones that appear to have the greatest potentail of achieving success in the near term are (1) burning refuse-derived-fuel (RDF) in conjunction with oil in Bridgeport Harbor Units 1 & 2 and (2) conversion of Bridgeport Harbor Unit 3 from oil to coal firing. These other alternatives are reflected in the economic evaluation of the CG/CC system in the following manner:

The RDF project at Bridgeport Harbor Station is well along; in fact, test burnings of RDF in BPH 1 are presently underway.

10.1 Introduction (Cont'd.)

We have assumed that this project will be successful and, therefore, have reflected the cost of RDF in the dispatch of BPH 1 & 2. (Another RDF project is being considered for English Station but this study is at a preliminary stage and so is not reflected in the CG/CC study.)

The economic feasibility of the CG/CC system is compared to the conversion of BPH 3 to coal, and to the simultaneous conversion of BPH 3 to coal and installation of the CG/CC system.

The following cases are analyzed in the study:

Low-Sulfur-Oil-Scenario

Base Case - No CG/CC, all Fossil Units on Low-Sulfur (LS) Oil.

Case 1 - CG/CC on High-Sulfur (HS) Coal, all other Fossil Units on LS-Oil.

Case 2 - No CG/CC, BPH 3 on HS-Coal with Scrubber, all other Fossil Units on LS-Oil.

Case 3 - CG/CC On HS-Coal, BPH 3 on HS-Coal with Scrubber, all other Fossil Units on LS-Oil.

The low-sulfur-oil-scenario assumes compliance with present State of Connecticut regulations on sulfur dioxide emissions. A high-sulfur-oil-scenario depicting the situation if the State regulations are relaxed to allow the burning of high-sulfur fuels is defined and discussed in Section VI.

10.2 Summary and Conclusions

10.2.1 Cost Savings

The results of this study show that an early installation of the CG/CC system (Case 1) in 1987 is only marginally economic, assuming a low-band load growth scenario. In the analysis, the prices of oil and coal escalate at about 7% per year and loads increase according to the UI low-band forecast. Installation of the CG/CC system in 1987 would become a more attractive investment if either the cost differential between oil and coal increases at a higher rate or if load growth is higher than the low-band. Although some savings did occur in 1987, the earliest date the CG/CC system is assumed to be ready for service, the sensitivity studies indicate that the

10.2 Summary and Conclusions (Cont'd.)

savings could easily become penalties. When the effective forced outage rate of the CG/CC system is increased from 20% to 40% or when the capital and O&M costs are increased by 25%, penalties result for the first five years. In the sixth year (1992) a net annual savings does occur. Based on the study assumptions, it may be desirable from an economic standpoint to consider installing the CG/CC at a later date.

The above conclusions are based on the premise that it is not feasible to convert BPH 3 to coal. Converting BPH 3 to coal (Case 2) is more economic than installing the CG/CC system (Case 1) or doing both projects (Case 3). If BPH is converted to coal in mid-1985 then the installation of the CG/CC system will not be economically justifiable until after 1998.

The cumulative saving of each case for the entire study period (1985-2004) is presented in Table 1.

TABLE 1

TOTAL SAVINGS
(1985-2004)

	Savings (Millions of Dollars)	% of Total Prod. Cost of Base Case
1 (CG/CC)	443	4.4
2 (BPH 3 converted to coal)	1,742	17.3
3 (Both Projects)	1,763	17.5

The saving realized by installing the CG/CC system is substantially lower than the saving that can be obtained by converting BPH 3 to coal. An important point to keep in mind when comparing Cases 1 & 2 is that the capital cost for installing the CG/CC system is approximately equal to the cost of converting BPH 3 to coal with a scrubber. Also, although the total savings realized in Cases 2 and 3 are essentially equal, the capital required for Case 3 is about twice that of Case 2. Completing both projects (Case 3) is not economically attractive at low-load growths to UI. Converting BPH 3 to coal (Case 2) stands out as the most economic alternative producing the highest total savings (approximately equal to completing both projects) and with the lowest investment cost of the three case studies.

10.2 Summary and Conclusions (Cont'd.)

10.2.2 Reduced Oil Dependency

In 1979 UI generated 92% of its electricity with imported oil (7.6 million barrels), oil that has been escalating in cost at an alarming rate. By 1990 the construction of Seabrook 1 & 2, Millstone 3, and Pilgrim 2 will reduce cur oil dependency to 3.97 millions barrels. The installation of the CG/CC system (Case 1) would further reduce UI's heavy dependence upon foreign oil. In 1990 it could reduce UI's oil consumption by 34% (1.35 million barrels). Conversion of BPH 3 to coal saves even more oil and completing both projects reduces UI's oil consumption the most. An annual reduction of 85% is possible in 1990. That amounts to 3.4 million barrels of oil saved. Figure 1 shows plots of barrels of oil burned for all cases studied including the base case.

10.2.3 Diversifying Fuel Mix

Just as important as the cost of a fuel is its availability - will it be a reliable source of fuel in the future and will it be priced competitively? No matter what fuel we are considering - nuclear, coal, oil - no one can answer these questions with certainty.

One thing is certain though: UI is presently very dependent on oil. This situation will be improved considerably when UI's committed nuclear entitlements come on line in the mid-1980's. Further diversification of UI's fuel mix to include coal could be obtained by installing the CG/CC system, converting BPH 3 to coal or by completing both projects. Moreover, any of these can be accomplished at a savings based on the assumptions used in this study. Annual load duration curves of year 1992 (low-band) have been prepared and the annual percentages of megawatthours generated by nuclear, coal and oil have been identified for each case including the base case. The plots are presented in Figures 2 through 5. Note that the flexibility exists should there be a need to substitute oil as a fuel in the combined cycle and also in BPH 3 if it is converted to coal.

10.2.4 Uncertainty

No matter how consistent and thorough an economic evaluation between alternatives is carried out, a degree of undertainty always exists because of assumptions used in

10.2 Summary and Conclusions (Cont'd.)

the analysis. What actually will be the future cost differential between coal and oil? What will be the capital and operating costs of the CG/CC system and will it be reliable (EFOR), etc? Because of the inherent uncertainty in these and other study assumptions, a variety of sensitivity analyses were performed and are presented in Section VI.

10.3 Method of Analysis

The calculation to determine whether or not the project is economically feasible is performed in two steps. The following example is for Case 1 with the CG/CC system.

First, the annual production cost saving is estimated using the production cost simulator (PCS) computer program which simulates the operation of our generating units. The production cost is calculated for the base case with all generating units burning oil, and then again with the CG/CC system installed. The annual savings in production cost resulting from the operation of the CG/CC system is the difference between the cost with all units on oil and the cost with the CG/CC system installed.

Next, we determine the additional non-fuel expenses incurred as a result of installing and operating the CG/CC system. The annual fixed charges (income taxes, depreciation, return) associated with the investment for new equipment is determined using the economic analysis computer program (ECAN). Increases in annual operation and maintenance costs (O & M), property tax, and insurance are added to the annual fixed charges to arrive at the total additional charges. The net annual saving (or penalty) resulting from the CG/CC system is the difference between the production savings and the additional expenses.

10.4 Major Assumptions

The major assumptions used in this study are listed here. They are believed to be conservative so that an economic justification of the CG/CC project with them would assure the same conclusion under a wide range of predictable future occurrences.

10.4.1 Costs

10.4.1.1 Total project cost based on indicated start-up date.

- o Installing CG/CC system for start-up in January, 1987.

10.4 Major Assumptions (Cont'd.)

$127,076,000	
16,716,000	AFC
15,416,000	Working Capital
$159,208,000	Total

- Converting BPH 3 to coal with SO_2 scrubber for start-up date in mid-1985.

$ 97,114,000	
8,766,000	AFC
31,468,000	Working Capital
$137,348,000	Total

- Converting BPH 3 to coal with a baghouse (no scrubber) for start-up in mid-1985.

$ 30,470,000	
2,701,000	AFC
37,299,000	Working Capital
$ 70,470,000	Total

10.4.1.2 Additional variable expenses (by-product disposal and raw material consumption by scrubber) resulting from burning coal. (Additional expenses for taxes, insurance and O & M, etc. are presented in Appendix A.)

- BPH 3 with scrubber - 26.1 per million Btu in 1980 esc. at 7% per year.
- BPH 3 without scrubber - 10.2 per million Btu in 1980 esc. at 7.5%* per year.
- CG/CC system - 10.2 per million Btu in 1980 esc. at 7.5%* per year.

*The annual escalation rate used for the variable expenses when BPH 3 is burning coal with a baghouse (no scrubber) and for the CG/CC system is higher than the rate used when BPH 3 is burning coal with a scrubber because in the formwer two situations the items comprising the variable expenses are more labor intensive and it is believed that labor cost will escalate at a higher rate (8%) than material cost (7%).

10.4 <u>Major Assumptions</u> (Cotn'd.)

10.4.1.3 Low-sulfur coal -- 1-1/2% sulfur costing 200¢ per million Btu in 1980 and escalated annually at 7%.

10.4.1.4 High-sulfur coal -- 3-1/2% sulfur costing 180¢ per million Btu in 1980 and escalated annually at 7%.

10.4.1.5 Low-sulfur oil -- 0.5% sulfur costing 459¢ per million Btu at the end of 1979 and escalated annually at 7%.

10.4.1.6 High-sulfur oil -- 2.2% sulfur costing $12/barrel (194¢ MBtu) less than low-sulfur oil.

10.4.1.7 Refuse-derived-fuel -- 20% less expensive than oil. BFH 1 & 2 burning 60% oil and 40% RDF.

10.4.1.8 Ash disposal cost -- $17.50 per ton* escalated annually at 7-1/2% from 1979.

10.4.2 <u>Financial</u>

10.4.2.1 Cost of Money (Non-Certifiable)

	Amount	Rate	Cost
Debt	50%	10.00%	5.00%
Pref. Stock	15%	10.00%	1.50%
Common Stock	35%	15.00%	5.25%
	100%		11.75%

10.4.2.2 Cost of Money (Certifiable Air and Water Pollution)

	Amount	Rate	Cost
Debt	50%	7.50%	3.75%
Pref. Stock	15%	10.00%	1.50%
Common Stock	35%	15.00%	5.25%
	100%		10.50%

*From report by C. E. Maguire for Connecticut State Department of Environmental Protection, per New Haven Register article, "New Coal Woe: Disposing Ash", Nov. 28, 1979. This cost is consistent with the expenses in Section IV (A) 2b and 2c.

10.4 Major Assumptions (Cont'd.)

10.4.2.3 State and Federal Taxes:

Federal income tax rate - 46%
Investment tax credit rate - 10%
Connecticut corporation business tax rate - 10%
Credit on state gross earnings tax - 5% of investment cost of air and water pollution control equipment.

10.4.2.4 Local taxes:

Property tax - Estimated Bridgeport mill rate, 66.9 applied to all non-certifiable capital expenditures after depreciation and equalization to 60% and 70% respectively.

Sales tax - 7.5% for all non-certifiable investments.

10.4.2.5 Depreciation:

	Book	Tax
Method	Straight Line	Sum-of-the-years digits
Life	30 years	23 years

10.4.2.6 Insurance Cost:

0.1% of investment cost.

10.4.2.7 Escalation

7% per year for capital investments
8% per year for highly labor-intensive work (e.g., O & M)
5 mills per year for local property taxes

10.4.3 Other

10.4.3.1 Load Growth

UI low-band forecast (3-1-80 PFEC Report) of 1.9% (1980-1989) and 1.1% (1989-2004)

10.4.3.2 Study Period

1985 to 2004

10.4 Major Assumptions (Cont'd.)

10.4.3.3 Design Coal

Avg. Heat Value 12,500 Btu/lb, Ash 10%,
Low Sulfur 1-1/2%, High Sulfur 3-1/2%

10.4.3.4 Unit data

o Coal Gasification/Combined Cycle System

The CG/CC system is not allowed to come off line except for scheduled overhauls (must-run unit)

Net capacity - 165.5 MW

Minimum load conditions - 912 MBtu/hr @ 76 MW

	Block Size	Heat Rate
Block 1	76.0 MW	@ 7.80 MBtu/MWH
Block 2	13.5 MW	@10.51 MBtu/MWH

EFOR 20%

Overhaul schedule cycle - 6 weeks, 4 weeks, 4 weeks, 4 weeks, etc.

o BPH 3 burning coal with a SO_2 scrubber

When burning coal, BPH 3 is not allowed to come off line except for scheduled overhauls (must-run unit).

Net capacity - 384.7 MW

Minimum load conditions - 1100 MBtu/hr @ 86 MW

	Block Size	Heat Rate
Block 1	58.0 MW	@ 8.23 MBtu/MWH
Block 2	76.6 MW	@ 8.68 MBtu/MWH
Block 3	75.0 MW	@ 9.33 MBtu/MWH
Block 4	93.1 MW	@ 9.88 MBtu/MWH

EFOR 27.5% (year 1)
23.5% (year 2)
21.5% (years 3 and beyond)

Overhaul schedule cycle - 6 weeks, 4 weeks, 4 weeks, 4 weeks, etc.

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10.4 Major Assumptions (Cont'd.)

- BPH 3 burning coal with a baghouse (no scrubber)

  When burning coal, BPH 3 is not allowed to come off line except for scheduled overhauls (must-run unit)

  Net capacity - 388 MW

  Minimum load conditions - 1095 MBtu/hr @ 89.5 MW

	Block Size	Heat Rate
Block 1	56.5 MW	@ 8.23 MBtu/MWH
Block 2	73.9 MW	@ 8.80 MBtu/MWH
Block 3	75.0 MW	@ 9.33 MBtu/MWH
Block 4	93.1 MW	@ 9.88 MBtu/MWH

  EFOR 22.5% (year 1)
  18.5% (year 2)
  16.5% (year 3 and beyond)

  Overhaul schedule cycle - 6 weeks, 4 weeks, 4 weeks, 4 weeks, etc.

10.4.3.5 UI Nuclear Entitlements

The nuclear units must run at full load and are not allowed to come off line except for scheduled overhauls. CTF estimates of effective forced outage rates are used for new nuclear units and the fuel budget estimate of EFOR is used for Connecticut Yankee.

Overhaul schedule cycle - 9 weeks, 8 weeks, 9 weeks, 8 weeks, etc.

Unit	MW	Comm. Operation Date
Seabrook 1	189.8 (16.5%)	June, 1984
Seabrook 2	189.8 (16.5%)	April, 1986
Millstone 3	42.4	May, 1986
Pilgrim 2	37.9	June, 1987

10.4.3.6 Forced Outages of Generating Units

Forced outages of generating units are simulated by derating the unit using its estimated effective forced outage rate.

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10.5 Other Considerations

10.5.1 Justification of CG/CC System

For low-band load growth, at least for the near term, the installation of the CG/CC system will have to be justified on fuel based economic considerations only. Additional capacity is not required until the year 2016 (1990 for high-band load growth).

Case 2 (BPH 3 converted to coal) is the most economic alternative. IF BPH 3 is converted to coal in mid-1985, the installation of the CG/CC system (Case 3) cannot be economically justified until sometime after 1998 based on low-band load growth. If for some reason it is not feasible to convert BPH 3 to coal, then the installation of the CG/CC system (Case 1) is marginally economic in January, 1987 which is the earliest date the CG/CC system is assumed to be ready for service.

10.5.2 Capacity Factor

Scheduled and unscheduled outages limit the maximum obtainable capacity factor (MOCF) of UI's two largest generating units (NHHBR1 and BPH 3) and the CG/CC system to the following:

Unit	MOCF
NHHBR1	82%
BPH 3 (On LS-Oil)	81%
BPH 3 (On HS-Coal with a scrubber	72%
CG/CC	74%

How close a unit comes to operating at its MOCF depends on a number of factors, namely: expense for operating the unit (efficiency and fuel cost), load demand and unit constraints (minimum load, minimum run and down times). None of these units reaches its MOCF, although the CG/CC system comes very close in its initial year of operation. All units operate at their highest capacity factor of the study at the very beginning. The capacity of factors of these fossil units then drop because of the considerable amount of nuclear base load capacity coming on line and maturing in the mid-1980's. Over the remainder of the study period the capacity factors of the fossil units increase gradually because of low-load growth.

10.5 Other Considerations (Cont'd.)

10.5.3 Capacity Gains and Losses

More savings can be realized by converting BPH to coal (Case 2) than by installing the CG/CC system (Case 1). The cost of the two projects are essentially equal but more coal fired capacity is gained by converting BPH 3 to coal so more coal can be burned to displace more oil. There is, however, a gain in capacity of 101.8 MW with the installation of the CG/CC system and a loss of 11.3 MW if BPH is converted to coal with a scrubber. Neither of these capacity changes are reflected as capacity costs or credits in the study results.

10.5.4 Capacity Sales

In addition to obtaining coal-fired capacity, the option of selling excess capacity is open to UI for reducing operating expenses. The following table lists the excess capacity that will exist in 1990 based on low-band growth for each of the cases:

Table 3
Excess Capacity in 1990
(low-Band Load Growth)
Megawatts

	Capacity Responsibility	Capacity	Excess
Base Case	1340.7	1759.24	418.54
Case 1	1340.7	1861.04	520.34
Case 2	1340.7	1747.94	407.24
Case 3	1340.7	1849.74	509.04

Approximately 400 MW's of excess capacity exist in the cases that do not contain CG/CC system and an additional 100 MW's (approx.) of excess capacity are available for sale if the CG/CC system is installed (Cases 1 and 3).

A detailed market analysis for this excess capacity was not made. However, it does appear from the 1980 "New England Load and Capacity Report" that more pool capacity will be needed in 1992/3 or 1993/4. This could occur a year earlies if Pilgrim 2 is not built.

10.6 Analysis

The results of the economic evaluation of each case are presented graphically as potential savings (or penalties). All dollars are actual and are plotted on a cumulative basis where either accrued penalties are subtracted or accrued savings are added to the previous year's total costs to give an indication of when breakeven occurs. A variety of sensitivity studies of Case 1 were performed because of the uncertainity of the estimated costs used in the study. Total annual revenue requirements for each case analyzed are shown on the computer summary output sheets contained in Appendix A.

10.6.1 Coal-Fired Capacity Options

As described in the introduction three options are studied for obtaining coal-fired capacity. They are Case 1, installing the CG/CC system; Case 2, converting BPH 3 to coal and Case 3, completing both projects.

The cumulative savings (or penalties) for each of these cases are shown in Figure 6. The results are based on compliance with present SO_2 emission limits (low-sulfur oil scenario). From the initial year of operation, savings occur in all three cases. However, the savings realized in Case 1 (installation of CG/CC system only) are substantially lower than the savings for Cases 2 and 3. For example, in 1992 the cumulative saving for Case 1 (approx. $30 million) is about 10% of the saving of Case 2 (approx. $330 million) or Case 3 (approx. $280 million). It is important to note when comparing these cases that the capital cost for installing the CG/CC system is approximately equal to the cost of converting BPH 3 to coal with a scrubber.

The cumulative savings of Cases 2 and 3 for the entire study period are essentially equal. However, since the initial investment cost for Case 3 is about twice that of Case 2, the return on initial investment for Case 2 would be much higher.

Throughout most of the study period the cumulative saving in Case 2 (converting BPH 3 to coal) is greater than in Case 3 (both projects). In the very last year of the study period the cumulative savings in Case 3 surpasses Case 2. This occurs because the load has increased to the point where the savings produced by the operation of BPH 3 on coal and the CG/CC system balance the added expenses of both projects.

10.6 Analysis (Cont'd.)

A second analysis of Cases 1, 2 and 3 was performed to determine how the results would be affected if State regulations were relaxed to allow burning high-sulfur fuels. The following cases were analyzed:

High-Sulfur-Oil-Scenario

Base Case - No CG/CC, all Fossil Units on HS-Oil.
Case 1 - CG/CC on HS-Coal with baghouse (no scrubber), all other Fossil Units on HS-Oil.
Case 2 - No CG/CC, BPH 3 on LS-Coal with baghouse (no scrubber), all other Fossil Units on HS-Oil.
Case 3 - CG/CC on HS-Coal, BPH 3 on LS-Coal with baghouse (no scrubber), all other Fossil Units on HS-Oil.

The cumulative savings for each case for the high-sulfur-oil-scenario are shown in Figure 7. The results of the evaluation based on the high-sulfur-oil scenario further substantiates our earlies conclusion in Section II, that installing the CG/CC system (Case 1) is only marginally economic. With the high-sulfur-oil scenario, penalties occur in the first seven years of operation of CG/CC system. It is not until the fourteenth year (2000) that a saving is realized on a cumulative basis. When BPH 3 is converted to coal without a scrubber (Case 2), substantial savings occur throughout the study period.

10.6.2 Fuel Price Sensitivity

The low-sulfur (LS) oil prices used in the study are based on information from the UI Planning Coordinating Committee. They conservatively project that the price of LS-Oil will escalate at the general rate of inflation (7% per year). The price o. high-sulfur (HS) oil is assumed to remain at $12 per barrel below the cost of LS-Oil for each year of the study. This is the price differential that existed between LS and HS-Oil in May, 1980. Prices of LS and HS-Coal were chosen based on a review of recent industrial publications.

Because of the uncertainty of future fuel prices, an analysis of Case 1 (installing the CG/CC system) was made assuming a constant price differential between oil and coal of 279¢ per million Btu (see Figure 8). This is the price differential between LS-Oil and HS-Coal before escalation that was used in this study.

10.6 Analysis (Cont'd.)

A penalty resulted. By 1995 the cumulative increase in cost above the base case (all fossil units on LS-Oil) amounted to $225 million. The annual penalty resulting from the CG/CC system increases with time because the additional expenses associated with operating the CG/CC system are escalated at the same time the difference in price between coal and oil is kept constnat. The assumption of constant price differential between oil and coal implies that the real price of coal is getting closer to the real price of oil.

Fuel prices used in this study are plotted in Figure 9 for reference.

10.6.3 Cost of Money Sensitivity

The plots in Figure 10 show how the study results are affected by changes in the assumptions of cost of money. The original cost of money assumptions used in the study are as follows:

Cost of Money (Non-Certifiable)

	Amount	Rate	Cost
Debt	50%	10.00%	5.00%
Pref. Stock	15%	10.00%	1.50%
Common Stock	35%	15.00%	5.25%
	100%		11.75%

Cost of Money (Certifiable Air and Water Pollution)

	Amount	Rate	Cost
Debt	50%	7.50%	3.75%
Pref. Stock	15%	10.00%	1.50%
Common Stock	35%	15.00%	5.25%
	100%		10.50%

When the capital structure is changed to 46% debt, 16% preferred stock and 38% common stock, the cost of money increases to 11.9% for non-certifiable investments and 10.75% for certifiable investments. This change of capital structure reduces the savings only slightly in Case 1 (installing the CG/CC system).

10.6 Analysis (Cont'd.)

Another analysis of Case 1 was made with the original capital structure but with higher rates of 12% for debt (9% for certifiable investments), 12% for preferred stock and 16% for common stock. The higher rates increase the cost of money to 13.4% for non-certifiable investments and 11.9% for certifiable investments. The total savings for Case 1 are reduced even more in the change of rate sensitivity analysis. Although penalties result in the first year of operation of the CG/CC system for the change of capital structure analysis and in the first two years of operation for the change of rate analysis, the effects of the changes in assumptions of cost of money used in this study are much less significant than the effects of the other sensitivity studies made in this report.

10.6.4 Capital and O&M Sensitivity

The effects of changes in capital and O&M estimates on the study results are shown by the plots in Figure 11. Both the capital cost and the initial O&M expenses of the CG/CC system were increased by 25%. These increases are enough to cause the saving in the initial year of operation of the CG/CC system in Case 1 to become a penalty. It is not until 1995 that a saving will be realized on a cumulative basis.

10.6.5 Effective Forced Outage Rate Sensitivity

Increasing the EFOR of the CG/CC system from 20% to 40% (see Figure 12) has a similar affect on the economics of the CG/CC system as increasing capital and O&M costs by 25%. The penalty for the higher EFOR in the early years of the study is lower than the penalty resulting from the 25% increase in capital and O&M costs but its negative effect on economics soon surpasses that of the increase of capital on O&M costs.

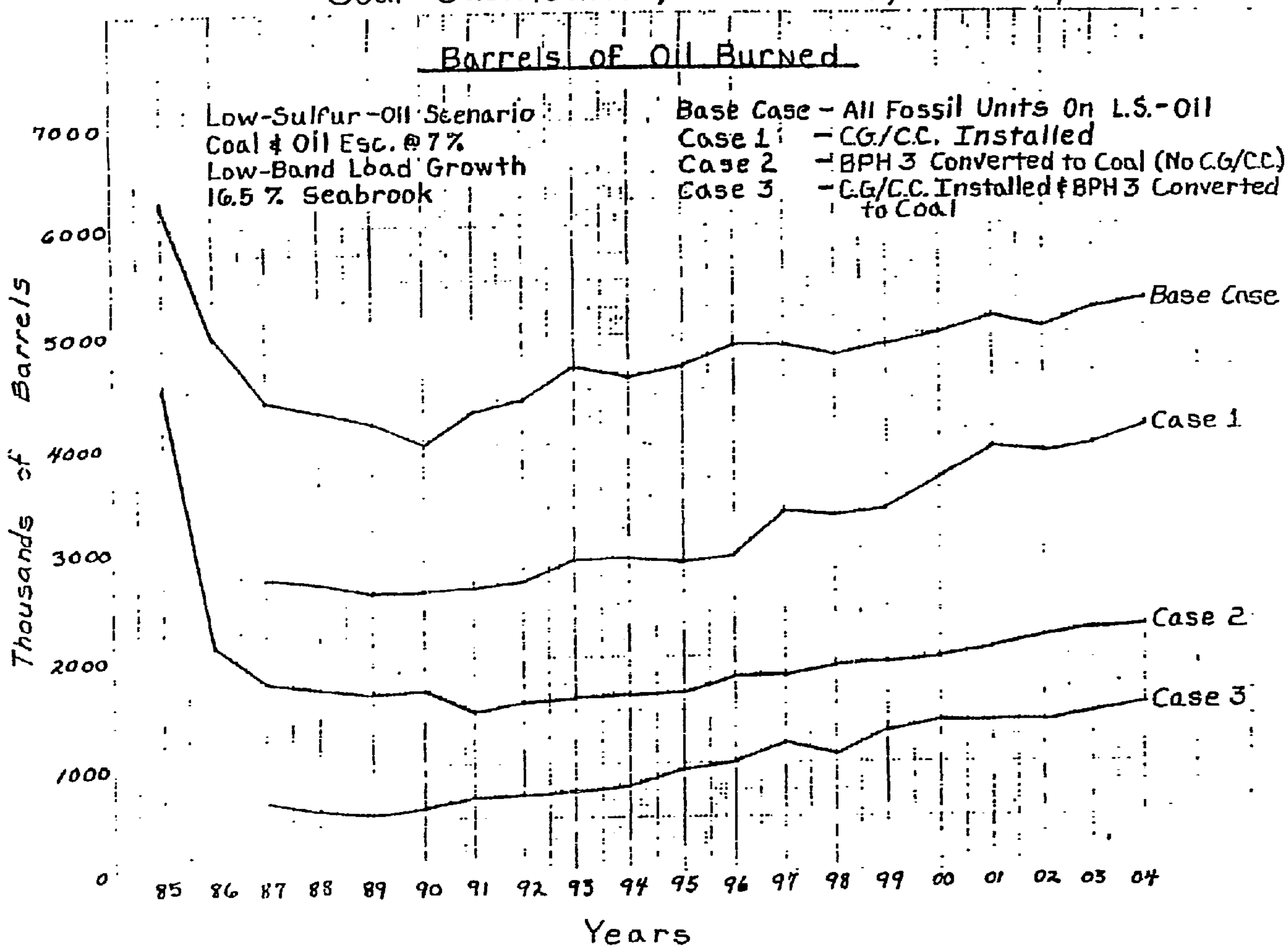
10.6.6 Load Management

A brief analysis is presented here to show what effects load management would have on the study results. The analysis and assumptions are the same as for the "Coal-Fired Capacity Options" (Figure 6) except that the daily loads are flattened by 25% for all cases including the base case. Expenses and capital charges to accomplish load flattening are not included. Plots of cumulative savings (or penalties) for Cases 1, 2 and 3 with load

10.6 Analysis (Cont'd.)

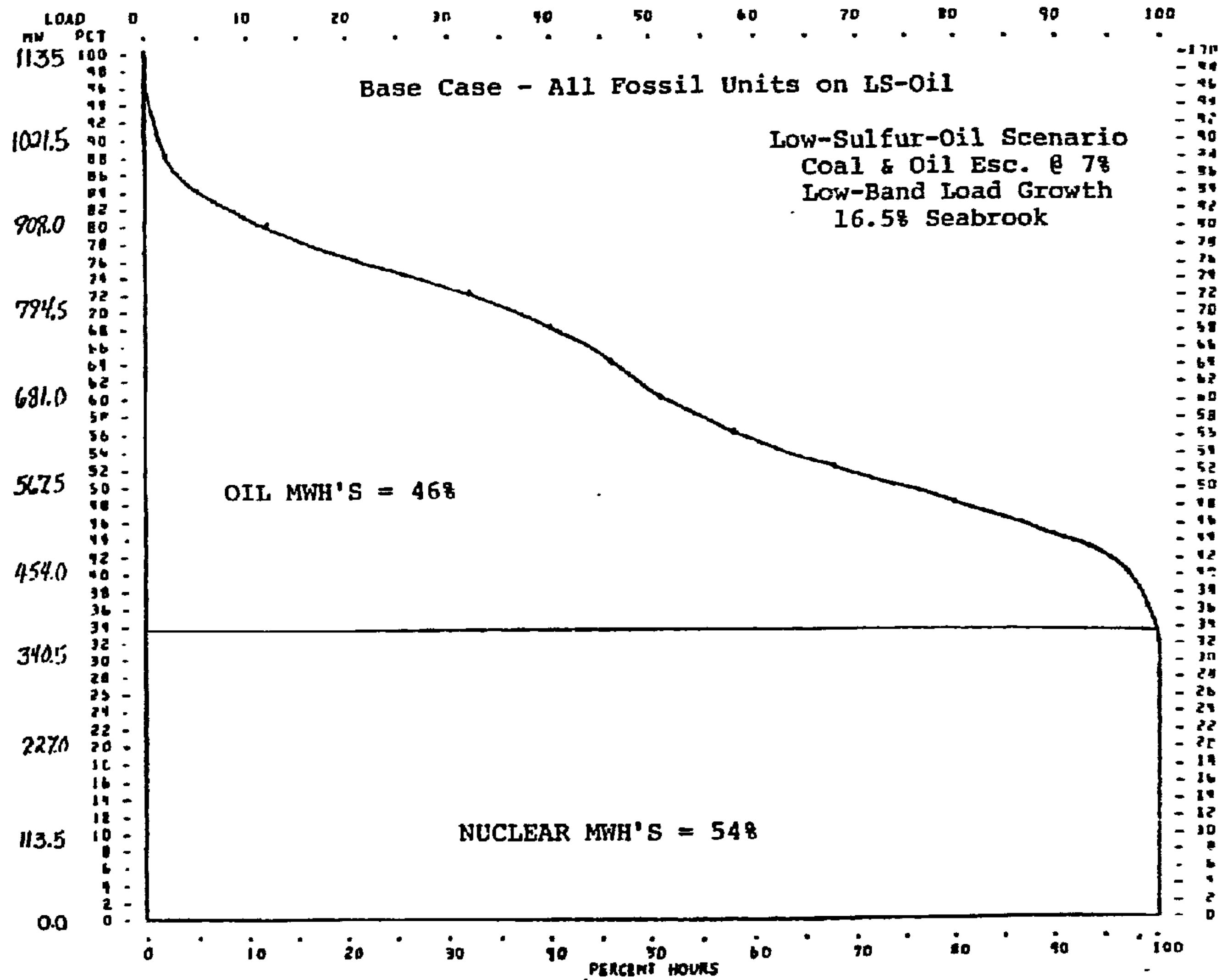
flattening are shown in Figure 13. Note that the cumulative saving in Case 3 surpasses the saving in Case 2 in the year 2000. Without load flattening the cumulative saving in Case 3 surpasses the saving in Case 2 in the year 2004.

Steel Point
Coal Gasification/Combined Cycle Study



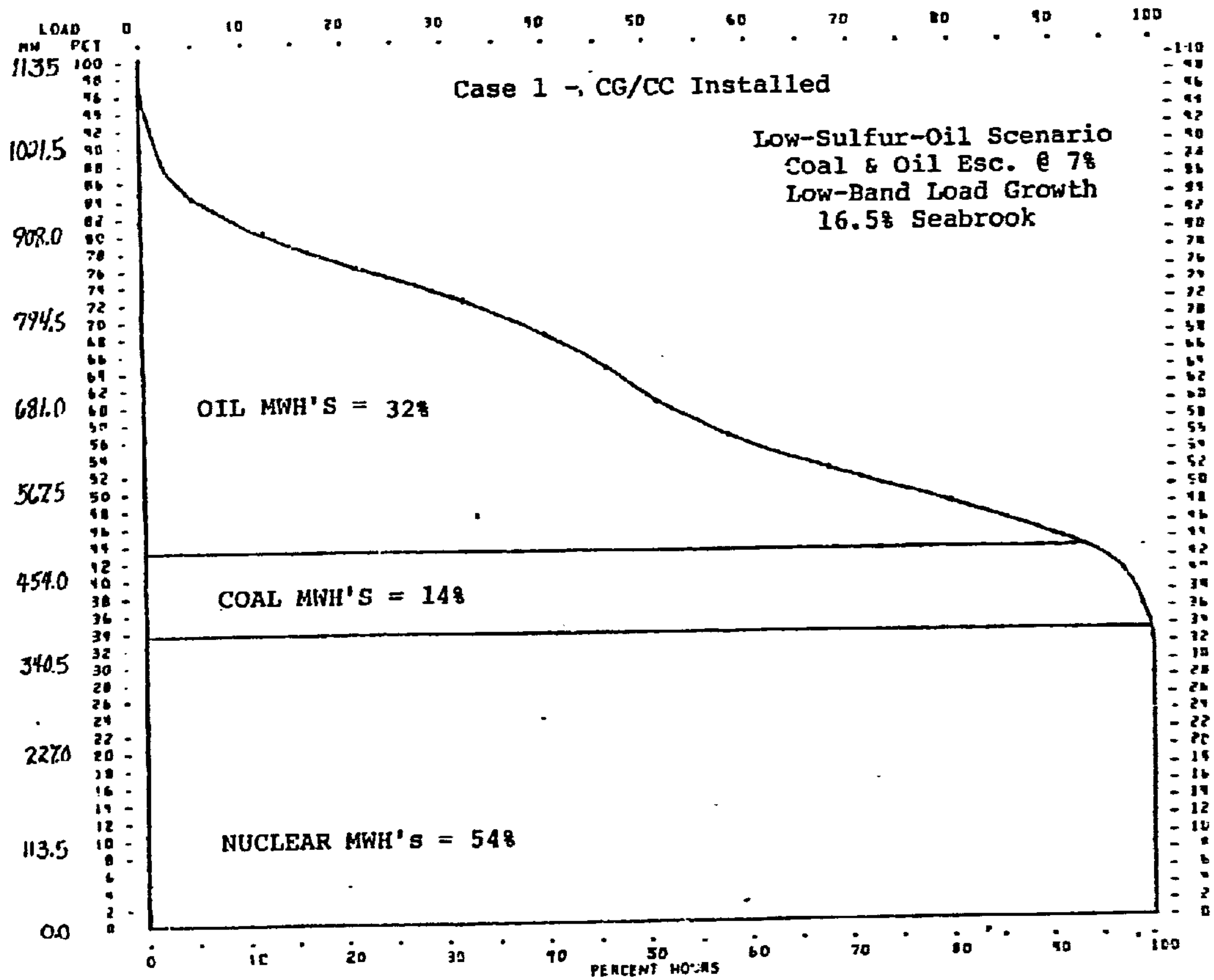
Steel Point
Coal Gasification/Combined Cycle Study

Annual Load Duration Curve for 1992 Low-Band
Fuel Mix Identified for Base Case



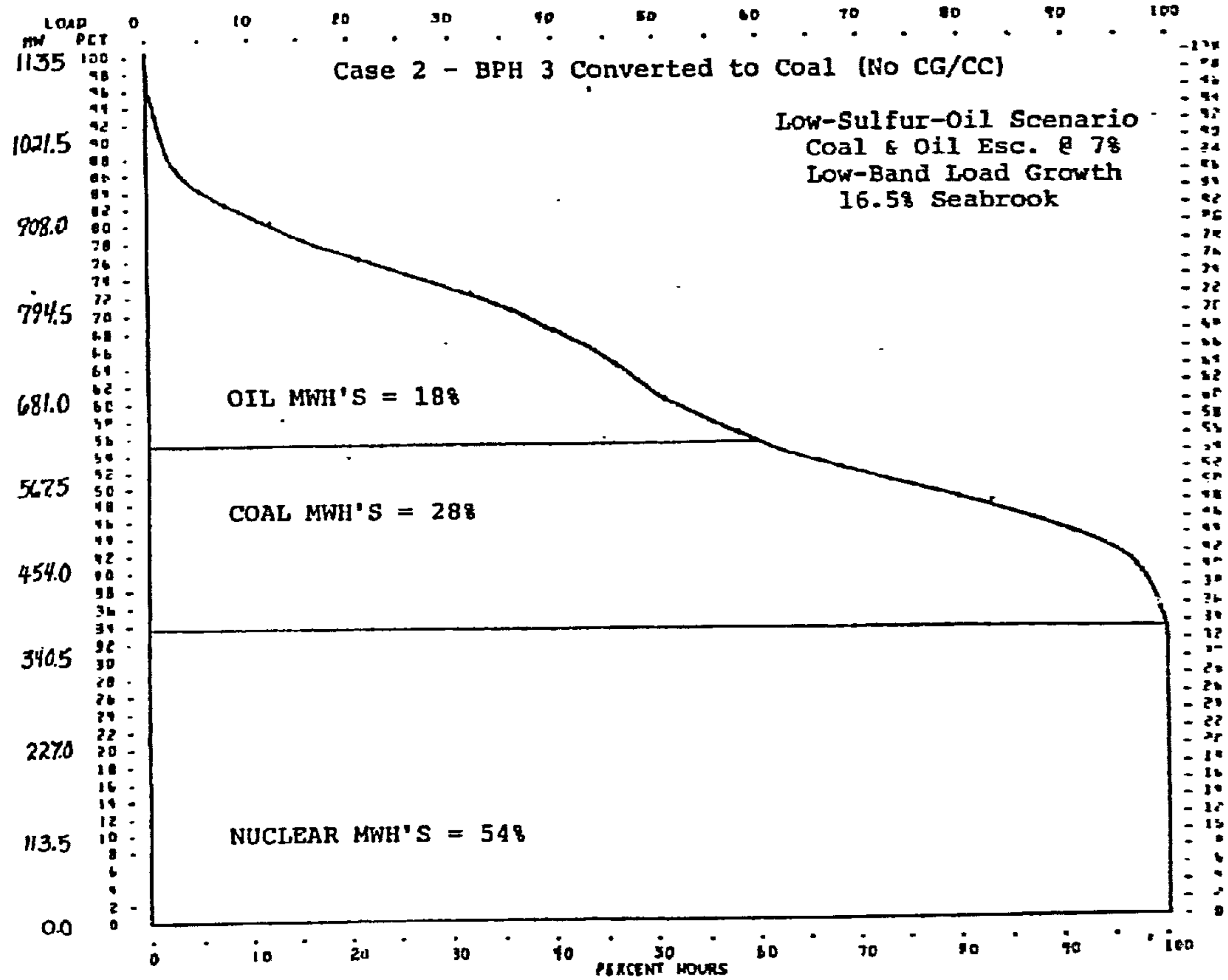
Steel Point
Coal Gasification/Combined Cycle Study

Annual Load Duration Curve for 1992 Low-Band
Fuel Mix Identified for Case 1



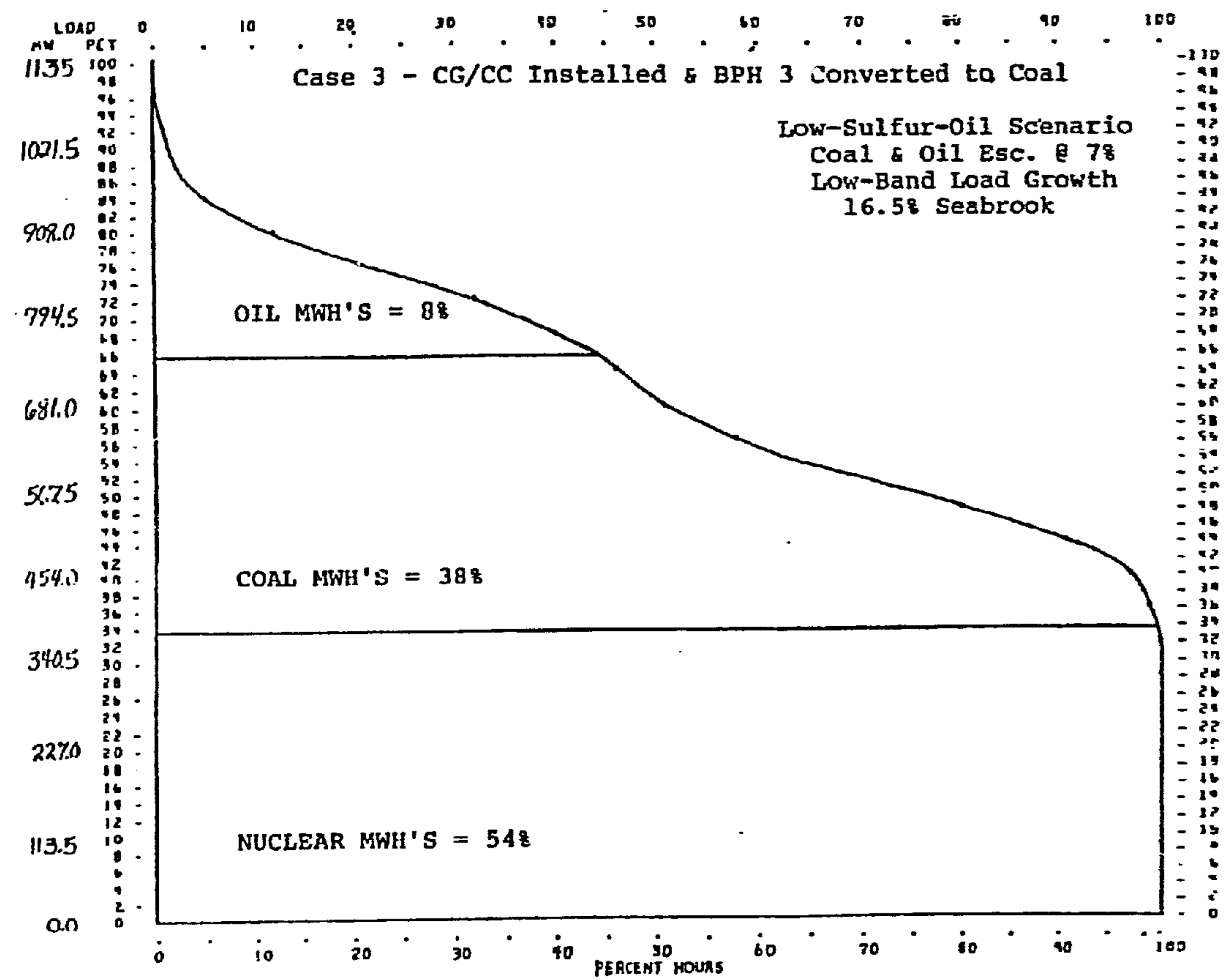
Steel Point
Coal Gasification/Combined Cycle Study

Annual Load Duration Curve for 1992 Low-Band
Fuel Mix Identified for Case 2



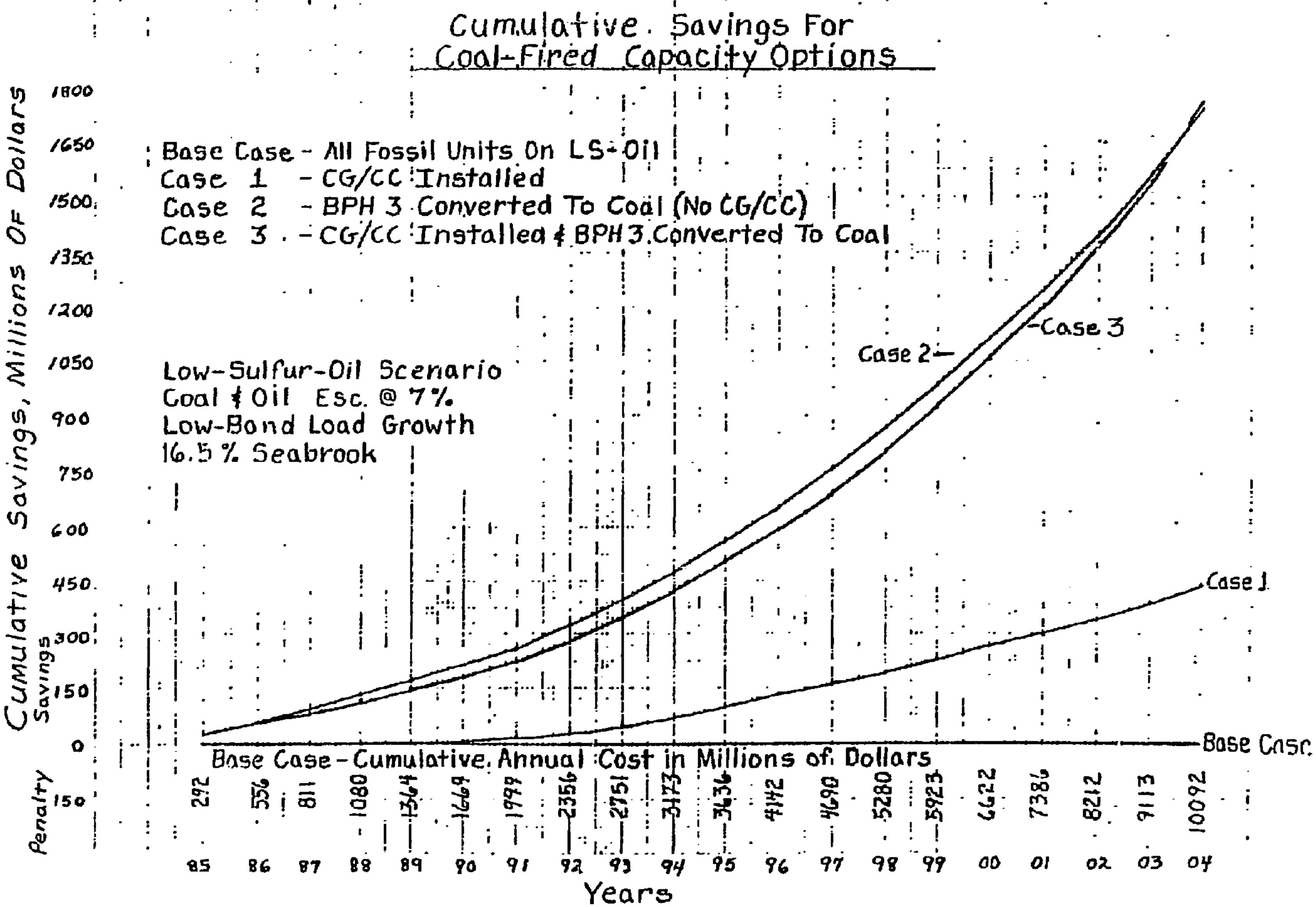
Steel Point
Coal Gasification/Combined Cycle Study

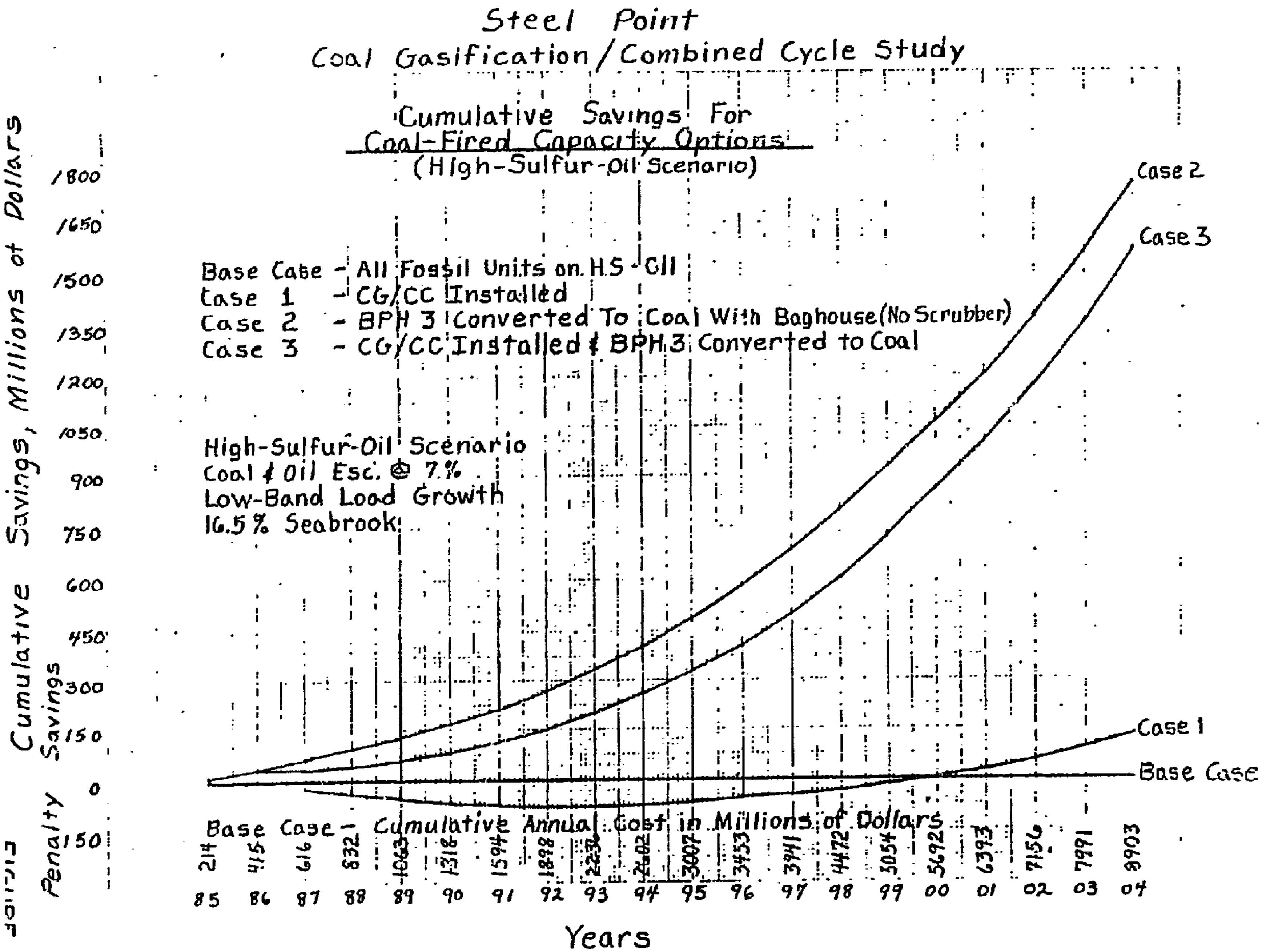
Annual Load Duration Curve for 1992 Low-Band
<u>Fuel Mix Identified for Case 3</u>



Steel Point

Coal Gasification / Combined Cycle Study

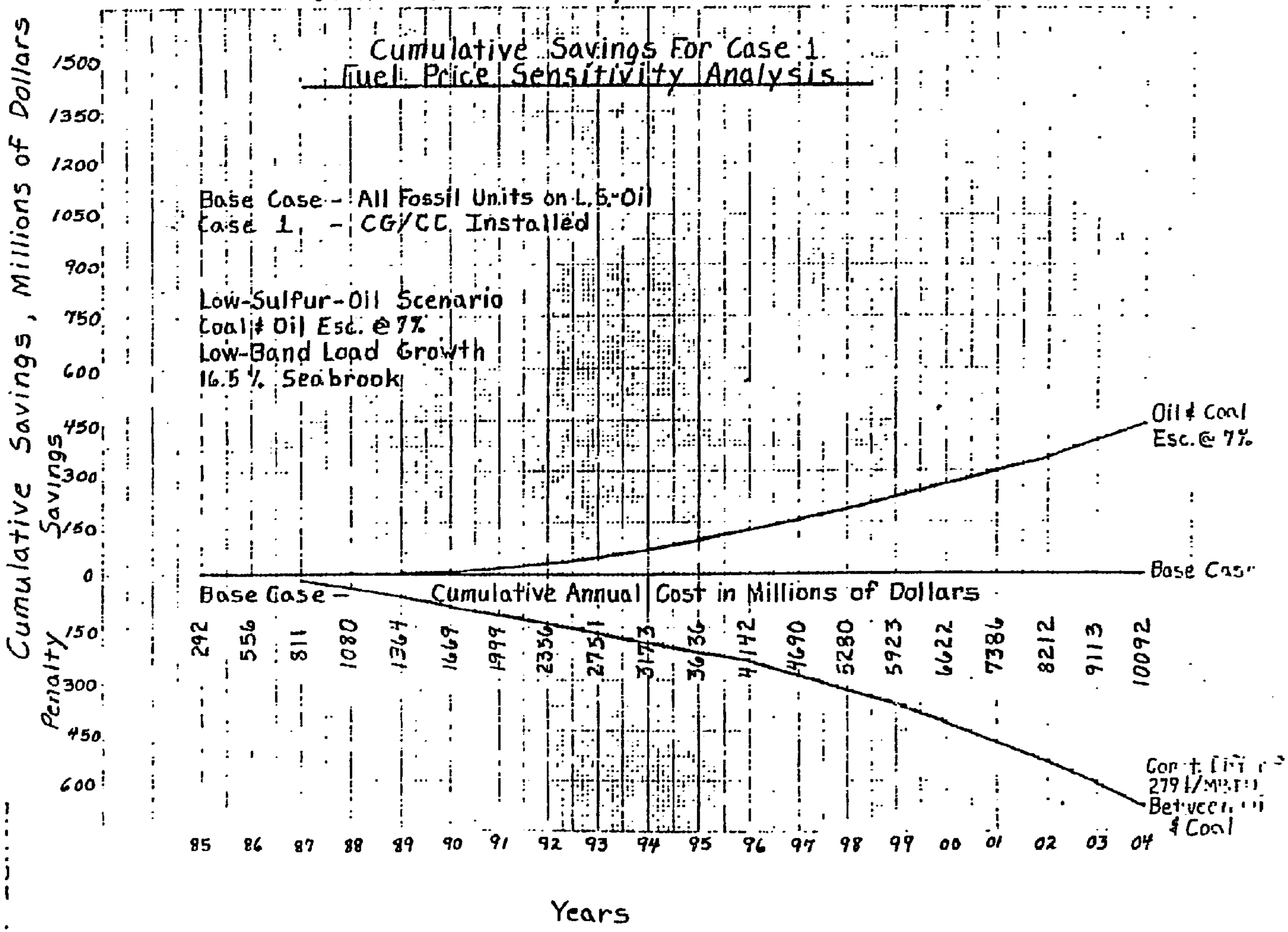




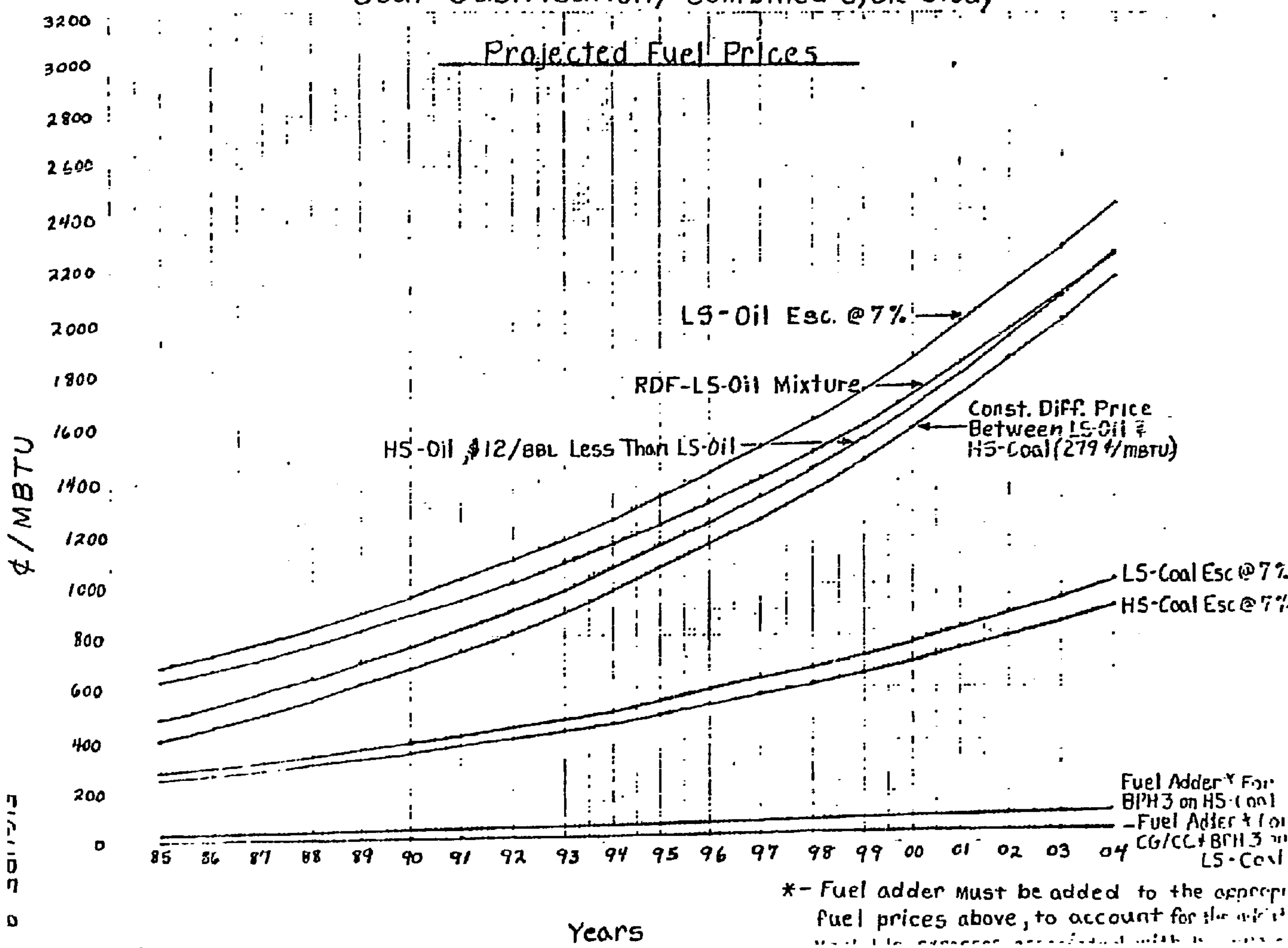
Steel Point
Coal Gasification/Combined Cycle Study
Cumulative Savings For
Coal-Fired Capacity Options
(High-Sulfur-Oil Scenario)
Base Case - All Fossil Units on H.S. Oil
Case 1 - CG/CC Installed
Case 2 - BPH 3 Converted To Coal With Baghouse (No Scrubber)
Case 3 - CG/CC Installed & BPH 3 Converted to Coal
High-Sulfur-Oil Scenario
Coal & Oil Esc. @ 7%
Low-Band Load Growth
16.5% Seabrook
Case 2
Case 3
Case 1
Base Case
Cumulative Savings, Millions of Dollars
Savings
Penalty
1800
1650
1500
1350
1200
1050
900
750
600
450
300
150
0
150
Base Case - Cumulative Annual Cost in Millions of Dollars
214 415 616 832 1063 1318 1594 1898 2232 2602 3007 3453 3941 4472 5054 5692 6393 7156 7991 8903
85 86 87 88 89 90 91 92 93 94 95 96 97 98 99 00 01 02 03 04
Years

FIGURE 7

Steel Point
Coal Gasification / Combined Cycle Study



Steel Point
Coal Gasification/ Combined Cycle Study
Projected Fuel Prices

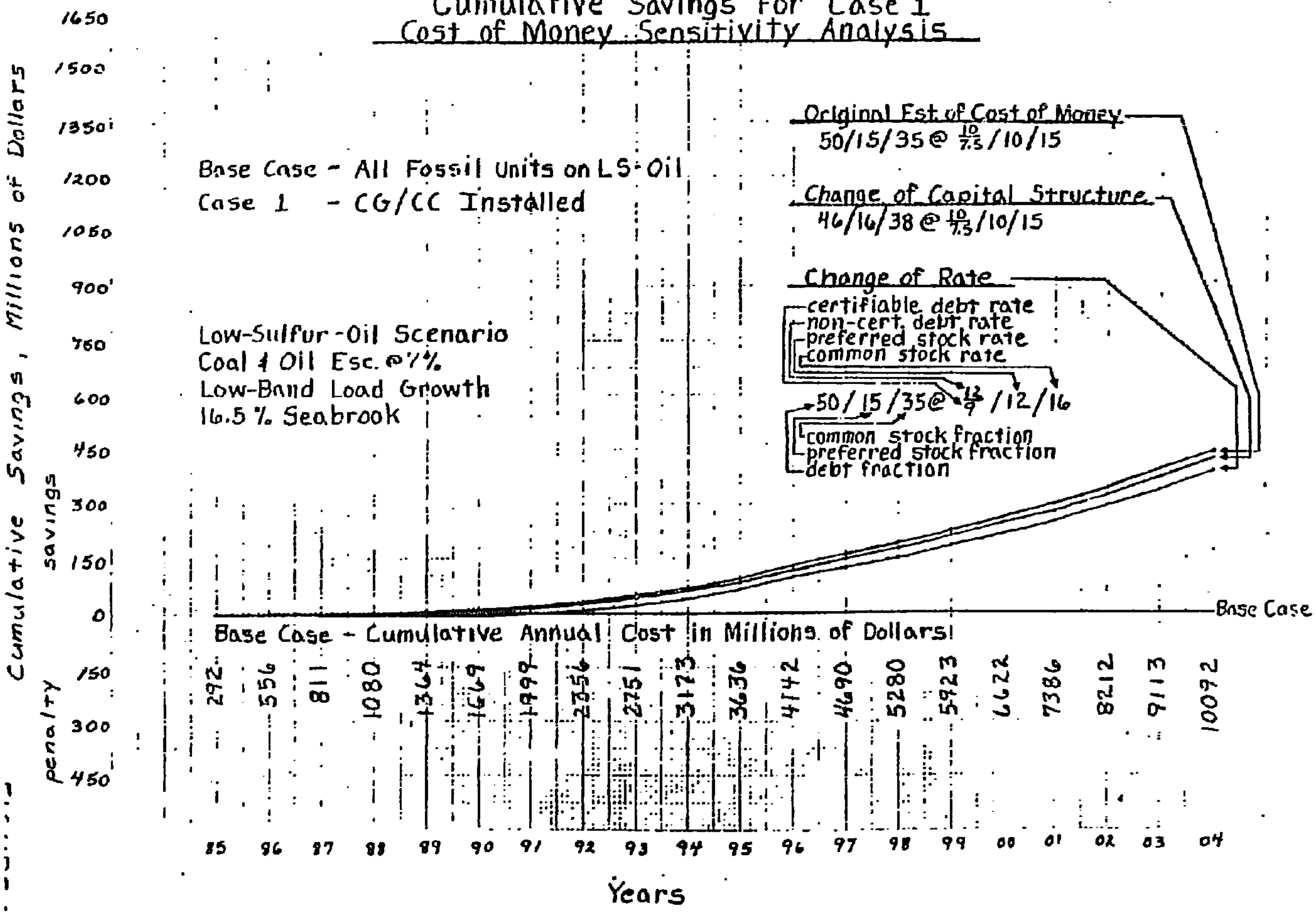


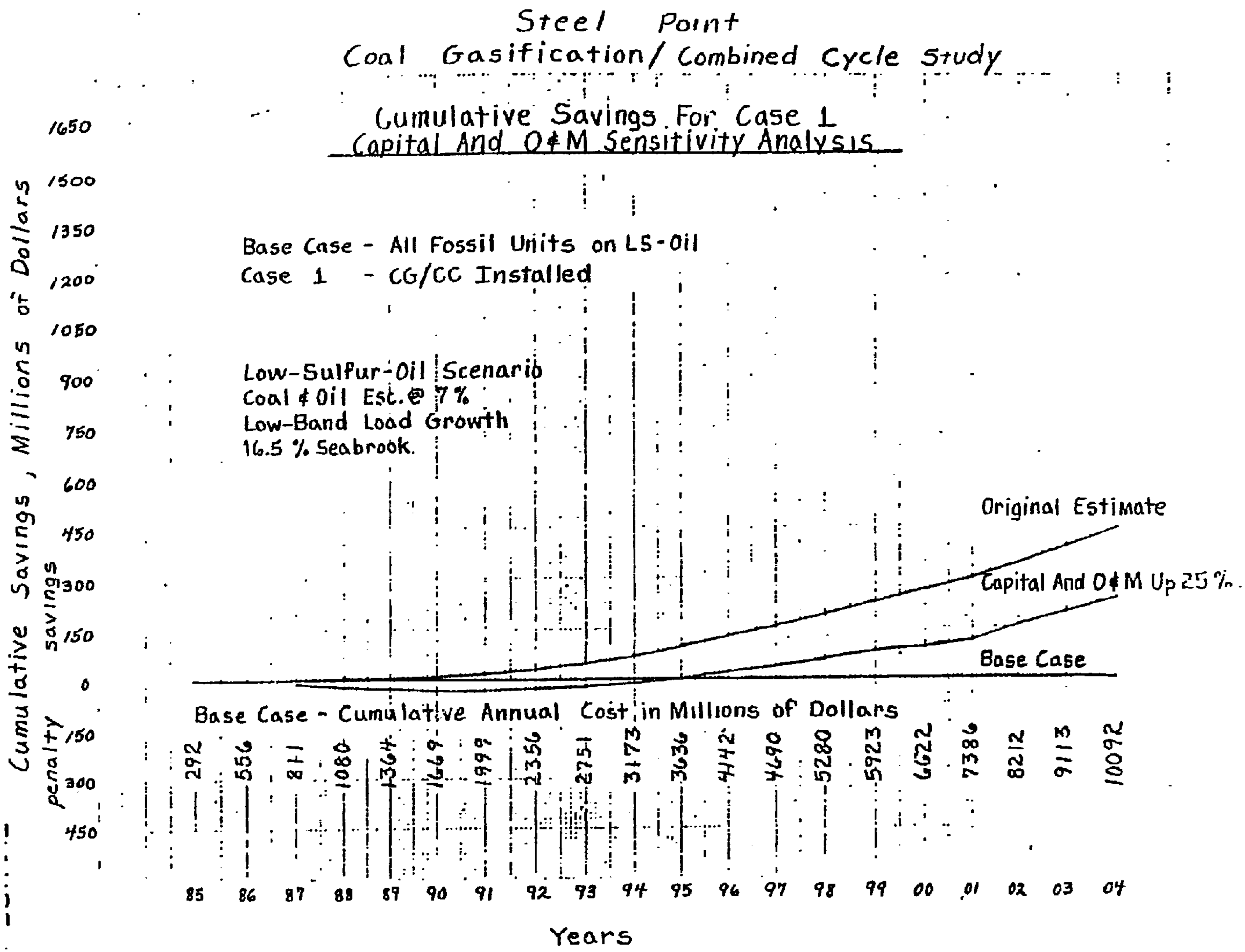
*- Fuel adder must be added to the appropriate fuel prices above, to account for the additional

FIGURE 8

Steel Point
Coal Gasification / Combined Cycle Study

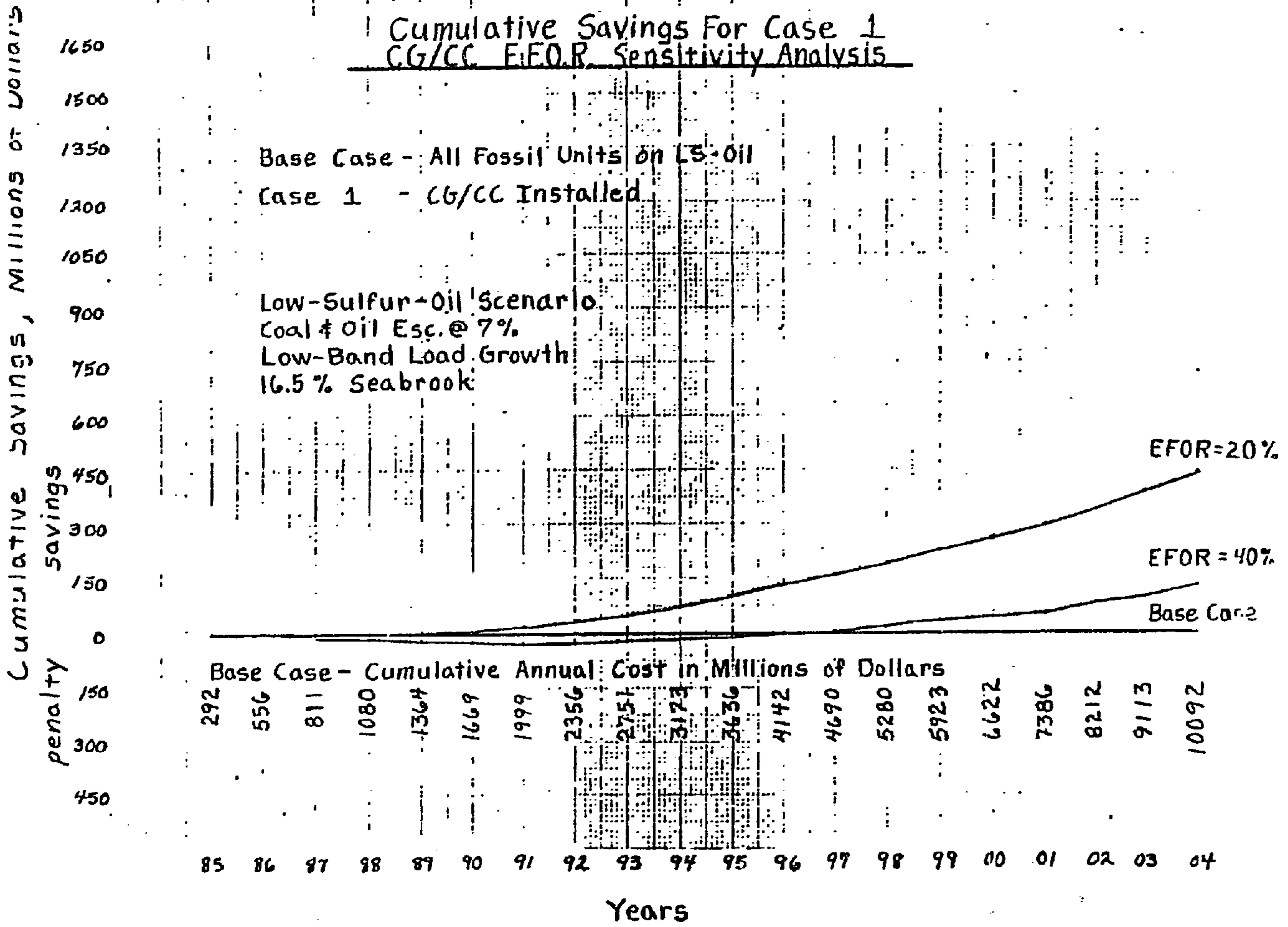
Cumulative Savings For Case 1
Cost of Money Sensitivity Analysis



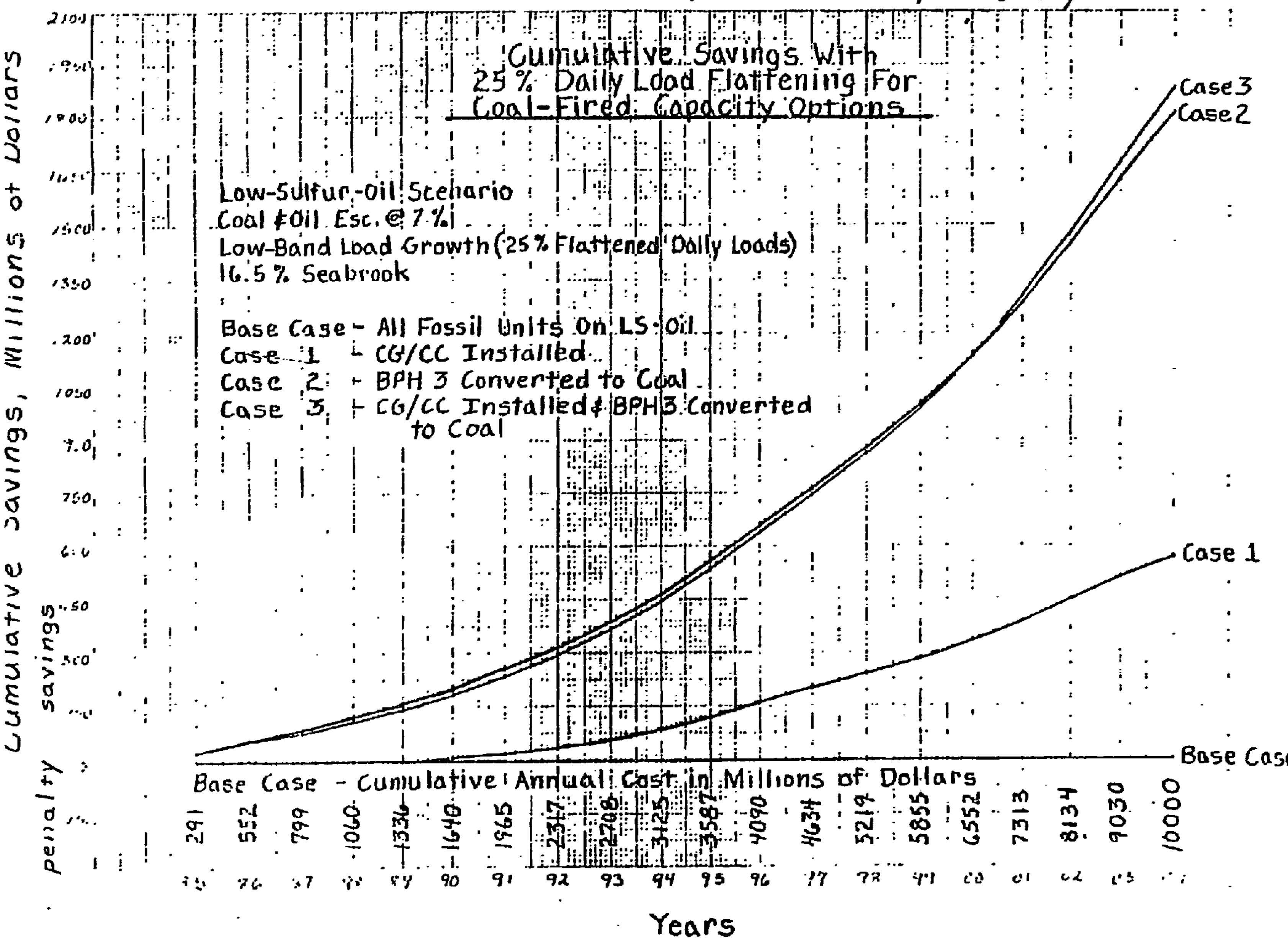


Steel Point
Coal Gasification/ Combined Cycle Study
Cumulative Savings For Case 1
Capital And O&M Sensitivity Analysis
Base Case - All Fossil Units on LS-Oil
Case 1 - CG/CC Installed
Low-Sulfur-Oil Scenario
Coal & Oil Est. @ 7%
Low-Band Load Growth
16.5 % Seabrook.
Original Estimate
Capital And O&M Up 25%
Base Case
Base Case - Cumulative Annual Cost in Millions of Dollars
292
556
811
1080
1364
1669
1999
2356
2751
3173
3636
4142
4690
5280
5923
6622
7386
8212
9113
10092
Cumulative Savings, Millions of Dollars
savings
penalty
1650
1500
1350
1200
1050
900
750
600
450
300
150
0
150
300
450
85
86
87
88
89
90
91
92
93
94
95
96
97
98
99
00
01
02
03
04
Years

Steel Point
Coal Gasification / Combined Cycle Study



Steel Point
Coal Gasification/Combined Cycle Study



10.8 APPENDIX A

Computer Summary Sheets

Of

Annual Revenue Requirements For Each Case Studied

BASE CASE = NO CG/CC; ALL UNITS ON CS-OIL   RUN ON 7/02/80

BASE CASE

DUMP POWER COST DUE TO PRESENT UNIT CONSTRAINTS IS INCLUDED IN FUEL COST

STUDY PARAMETERS FOR THIS CASE WERE READ FROM CARDS

THIS STUDY WILL START IN 1985

ALL PRESENT WORTH CALCULATIONS TO BEGINNING OF 1985 AT 11.75 PERCENT

PRESENT WORTH CALCULATONS BASED ON THE FOLLOWING

DEBT FRACTION (PERCENT) = 50.00 DEBT RATE (PERCENT) = 10.00

PREF. STOCK FRACTION = 15.00 PREF. STOCK RATE = 10.00

COMM. STOCK FRACTION = 35.00 COMM. STOCK RATE = 15.00

THE LENGTH OF THIS STUDY IS 31 YEARS

CALCULATED COST OF MONEY = 11.75

COST OF MONEY CALCULATIONS BASED ON THE FOLLOWING

DEBT FRACTION (PERCENT) = 50.00 DEBT RATE (PERCENT) = 10.00

PREF. STOCK FRACTION = 15.00 PREF. STOCK RATE = 10.00

COMM. STOCK FRACTION = 35.00 COMM. STOCK RATE = 15.00

BOOK DEPRECIATION METHOD = STRAIGHT LINE

TAX DEPRECIATION METHOD = SUM OF YEARS DIGITS

FEDERAL INCOME TAX RATE (PERCENT) = 46.00

STATE INCOME TAX RATE (PERCENT) = 10.00

INVESTMENT TAX CREDIT PERCENT = 10.00 SPREAD OVER 30 YEARS

SURCHARGE (PCT OF F.I.T.) = 0.0 FOR 0 YEARS

PREOPERATIVE AFFECT NOT TAKEN INTO ACCOUNT

DEPRECIATION CALCULATIONS BASED ON FLOW THROUGH

BASE CASE - NO CG/CC, ALL UNITS ON LS-OIL

RUN ON 7/02/88

THE "STUDY" ESCALATION FACTORS ARE LISTED BELOW; THEY WERE READ FROM CARDS

ESCALATION FACTORS	ESC	YEAR	ESC	YEAR	ESC	YEAR	ESC	YEAR
INVESTMENT COST - PERCENT/YR	0.0	3000	0.0	0	0.0	0	0.0	0
NUCLEAR FUEL INITIAL - PERCENT/YR	0.0	3000	0.0	0	0.0	0	0.0	0
NUCLEAR FUEL EQUIL - PERCENT/YR	0.0	3000	0.0	0	0.0	0	0.0	0
OCM PAYROLL - PERCENT/YR	8.00	3000	0.0	0	0.0	0	0.0	0
OCM MATERIALS - PERCENT/YR	7.00	3000	0.0	0	0.0	0	0.0	0
OCM CONTRACT LABOR - PERCENT/YR	0.0	3000	0.0	0	0.0	0	0.0	0
PROPERTY TAX - MILLS/YR	5.00	3000	0.0	0	0.0	0	0.0	0
INSURANCE - PERCENT/YR	7.00	3000	0.0	0	0.0	0	0.0	0

THE PROPERTY TAX FLAG FOR THIS DATA SET IS 1

CASE 3 WITH CG/CC FDR=20,BPH3 HS-COAL, OTHERS LS-OIL,COALOIL ESC 7%   7/02/80

	CG/CC		BPH 3 CONVERTED TO COAL WITH A SCRUBBER	
ITEM NAME	CERTIF	NONCER	U3CERT	U3NONC
YR OF INST	1987	1987	1985	1985
MONTH OF INST	1	1	7	7
INVESTMENT DOLLARS	90261000.	118997000.	91720000.	95628000.
NONREC EXP INIT YR	0.	0.	0.	693000.
NUC FL INIT Y $/YR	0.	0.	0.	0.
NUC FUEL EQIL $/YR	0.	0.	0.	0.
O&M PAYRLL INIT YR	6151861.	0.	9997180.	0.
O&M MATRLS INIT YR	2266699.	0.	1825228.	0.
O&M LABOR INIT YR	0.	0.	0.	0.
INSUR PREP INIT YR	90261.	118997.	91720.	95628.
BOOK LIFE YEARS	30	30	29	29
TAX LIFE YEARS	23	23	23	23
PROP VALUE ASSESMT	0.	93987023.	0.	5995320.
PROP TAX RATE MILS	0.0	66.90	0.0	66.90
DEPR INVEST BOOK $	90261000.	103531969.	87851952.	19158368.
DEPR INVEST TAX $	35582672.	91999032.	79365316.	13081598.
ICC DOLLARS	0.	0.	0.	0.
LAND DOLLARS	0.	0.	0.	0.
OTHER EXCL FM OIT	0.	0.	0.	0.
ITC EXCL FM INVEST	9678320.	27952960.	12359689.	32596952.
PURCH INST INDIC	INSTAL	INSTAL	INSTAL	INSTAL
DEBT FRACTION P.U.	0.5000	0.5000	0.5000	0.5000
DEBT RATE P.U.	0.0750	0.1000	0.0750	0.1000
COST OF MONEY P.U.	0.1050	0.1175	0.1050	0.1175
BOOK DEPREC METHOD	STL	STL	STL	STL
TAX DEPREC METHOD	SYD	SYD	SYD	SYD
S.I.T. RATE P.U.	0.1000	0.1000	0.1000	0.1000
YEAR RETIRED	0	0	0	0
MONTH RETIRED	0	0	0	0
DETAIL OUTPT INDIC	0	0	0	0
NAME OF UNIT REPL.				
S.I.T. BASED ON	RETURN	RETURN	RETURN	RETURN

9 IS THE LAST RECORD CONTAINING DATA

0 UNITS WERE DELETED

SUMMARY — BASE CASE : NO CG/CC; ALL UNITS UNTLS-OIL 7/02/80

OUTPUT IN THOUSANDS OF DOLLARS

YEAR	FUEL COST	OPR AND MAINT	PROPERTY TAX	INSURANCE PREMIUM	BOOK DEPREC	TOTAL RETURN	INCOME TAX	ANNUAL COST	CUMULAT ANN. COST	1985 PW AT 11.75 PCT TOTAL ANN. COST	1985 PW AT 11.75 PCT CUMULAT ANN. COST
1985	292091.	0.	0.	0.	0.	0.	0.	292091.	292091.	261379.	261379.
1986	263725.	0.	0.	0.	0.	0.	0.	263725.	555816.	211182.	472561.
1987	255003.	0.	0.	0.	0.	0.	0.	255003.	811819.	182727.	655288.
1988	269215.	0.	0.	0.	0.	0.	0.	269215.	1080734.	172627.	827915.
1989	289026.	0.	0.	0.	0.	0.	0.	289026.	1369760.	162975.	990890.
1990	305197.	0.	0.	0.	0.	0.	0.	305197.	1669257.	156709.	1147599.
1991	329950.	0.	0.	0.	0.	0.	0.	329950.	1999207.	151606.	1299205.
1992	357350.	0.	0.	0.	0.	0.	0.	357350.	2356557.	146931.	1446136.
1993	394107.	0.	0.	0.	0.	0.	0.	394107.	2750664.	145006.	1591142.
1994	422585.	0.	0.	0.	0.	0.	0.	422585.	3173249.	139136.	1730278.
1995	462830.	0.	0.	0.	0.	0.	0.	462830.	3636079.	136314.	1866592.
1996	506107.	0.	0.	0.	0.	0.	0.	506107.	4142186.	133936.	2000078.
1997	547983.	0.	0.	0.	0.	0.	0.	547983.	4690169.	129285.	2129363.
1998	590316.	0.	0.	0.	0.	0.	0.	590316.	5280485.	124629.	2253992.
1999	642526.	0.	0.	0.	0.	0.	0.	642526.	5923011.	121389.	2375381.
2000	698827.	0.	0.	0.	0.	0.	0.	698827.	6621838.	118143.	2493524.
2001	764174.	0.	0.	0.	0.	0.	0.	764174.	7386012.	115607.	2609131.
2002	826329.	0.	0.	0.	0.	0.	0.	826329.	8212341.	111866.	2720997.
2003	900972.	0.	0.	0.	0.	0.	0.	900972.	9113313.	109196.	2830193.
2004	978565.	0.	0.	0.	0.	0.	0.	978565.	10091878.	106081.	2936224.

SUMMARY

CASE 1 WITH CG/CC FOR=20, ALL FOSSIL UNITS ON LS-OIL,COALGOIL ESC 7% 7/82/80

OUTPUT IN THOUSANDS OF DOLLARS

YEAR	FUEL COST	CFR AND MAINT	PROPERTY TAX	INSURANCE PREMIUM	BOOK DEPREC	TOTAL RETURN	INCOME TAX	ANNUAL COST	CUMULAT ANN. COST	1985 PW AT 11.75 PCT TOTAL ANN. COST	1985 PW AT 11.75 PCT CUMULAT ANN. COST
1985	292091.	0.	0.	0.	0.	0.	0.	292091.	292091.	261379.	261379.
1986	263725.	0.	0.	0.	0.	0.	0.	263725.	555816.	211182.	472561.
1987	210115.	8919.	2909.	159.	9793.	18203.	18201.	259799.	810615.	182581.	655142.
1988	227786.	9069.	3127.	170.	9793.	17657.	9613.	267215.	1077830.	171395.	826987.
1989	240572.	9771.	3399.	182.	9793.	17111.	9755.	280521.	1358358.	160968.	987955.
1990	262183.	10526.	3562.	195.	9793.	16565.	9997.	302721.	1661079.	155938.	1142893.
1991	278907.	11391.	3779.	209.	9793.	16818.	5039.	328886.	1901165.	147873.	1289966.
1992	381998.	12210.	3996.	223.	9793.	15972.	5180.	393088.	2325895.	141393.	1431359.
1993	331070.	13169.	4219.	239.	9793.	19925.	5323.	373720.	2698773.	137568.	1568967.
1994	360369.	14163.	4431.	256.	9793.	14379.	5965.	403871.	3102699.	132979.	1701691.
1995	391296.	15281.	4699.	273.	9793.	13832.	5607.	435681.	3538325.	128365.	1830206.
1996	427879.	16965.	4866.	293.	9793.	13286.	5748.	473330.	4011655.	124799.	1955888.
1997	471879.	17740.	5089.	313.	9793.	12739.	5890.	521433.	4533088.	123821.	2072021.
1998	510840.	19115.	5301.	335.	9793.	12193.	6033.	558610.	5091698.	117935.	2195956.
1999	556306.	20597.	5519.	359.	9793.	11696.	6175.	605395.	5697093.	119379.	2310330.
2000	615219.	22193.	5736.	384.	9793.	11101.	6316.	665737.	6362830.	112599.	2422879.
2001	676797.	23919.	5953.	411.	9793.	10559.	6458.	728880.	7091710.	110268.	2533147.
2002	727249.	25769.	6171.	439.	9793.	10098.	6600.	781029.	7872739.	105733.	2638888.
2003	793811.	27768.	6380.	470.	9793.	9961.	6793.	849539.	8722168.	102903.	2791703.
2004	868630.	29922.	6606.	503.	9793.	8915.	6889.	926253.	9648921.	100918.	2872193.

SUMMARY

CASE 2 W/O CG/CC, 6PH3 HS-COAL, OTHERS LS-OIL,COAL & OIL ESC 7% (REV)
OUTPUT IN THOUSANDS OF DOLLARS

YEAR	FUEL COST	OPR AND MAINT	PROPERTY TAX	INSURANCE PREMIUM	BOOK DEPREC	TOTAL RETURN	INCOME TAX	ANNUAL COST	CUMULAT ANN. COST	1985 PW AT 11.75 PCT TOTAL ANN. COST	1985 PW AT 11.75 PCT CUMULAT ANN. COST
1985	249124.	6554.	149.	64.	1795.	7496.	2314.	267503.	267503.	239376.	239376.
1986	193193.	12750.	427.	147.	3990.	14806.	4988.	229751.	497254.	183976.	423352.
1987	189115.	13751.	457.	157.	3990.	14433.	5091.	221544.	718798.	158716.	582068.
1988	194137.	14830.	487.	168.	3990.	14061.	5194.	232367.	951165.	148999.	731067.
1989	205082.	15944.	517.	180.	3990.	13600.	5297.	244198.	1195363.	140150.	871217.
1990	222608.	17250.	546.	193.	3990.	13315.	5400.	262802.	1458165.	134941.	1006158.
1991	232742.	18604.	576.	206.	3990.	12943.	5503.	274064.	1732229.	125927.	1132085.
1992	253912.	20065.	606.	221.	3990.	12570.	5606.	296470.	2028699.	121899.	1253984.
1993	279465.	21691.	636.	236.	3990.	12190.	5709.	323875.	2352574.	119165.	1373149.
1994	300624.	23341.	665.	253.	3990.	11825.	5812.	346010.	2698584.	113924.	1487073.
1995	328573.	25174.	695.	270.	3990.	11453.	5915.	375570.	3074154.	110654.	1597727.
1996	360738.	27152.	725.	289.	3990.	11080.	6018.	409492.	3483646.	107963.	1705690.
1997	396534.	29286.	754.	309.	3990.	10708.	6121.	447202.	3930848.	105508.	1811198.
1998	430434.	31580.	784.	331.	3990.	10335.	6224.	483691.	4414539.	102118.	1913316.
1999	464815.	34071.	814.	354.	3990.	9962.	6328.	524834.	4939373.	99159.	2012475.
2000	513124.	36750.	844.	379.	3990.	9593.	6431.	570608.	5509981.	96467.	2108942.
2001	566190.	39634.	873.	405.	3990.	9217.	6534.	626348.	6136329.	94756.	2203698.
2002	615690.	42756.	903.	434.	3990.	8845.	6637.	678755.	6815084.	91888.	2295586.
2003	671729.	46119.	933.	464.	3990.	8472.	6740.	737947.	7553031.	89397.	2384983.
2004	727344.	49747.	963.	497.	3990.	8100.	6843.	797039.	8350070.	86403.	2471386.

SUMMARY

CASE 3 (REV) CS/CC FOR=20,BPH3 HS-COAL, OTHERS LS-OIL,COAL&OIL ESC 7%
OUTPUT IN THOUSANDS OF DOLLARS

YEAR	FUEL COST	OPR AND MAINT	PROPERTY TAX	INSURANCE PREMIUM	BOOK DEPREC	TOTAL RETURN	INCOME TAX	ANNUAL COST	CUMULAT ANN. COST	1985 PW AT 11.75 PCT TOTAL ANN. COST	1985 PW AT 11.75 PCT CUMULAT ANN. COST
1985	249126.	6554.	199.	69.	1745.	7496.	2314.	267503.	267503.	239376.	239376.
1986	188193.	12750.	427.	197.	3490.	19806.	4989.	229751.	497254.	183976.	423352.
1987	157665.	22169.	3366.	316.	8283.	32637.	15291.	239727.	731981.	168190.	591542.
1988	161016.	23699.	3619.	339.	8283.	31713.	4907.	238676.	970657.	153045.	744595.
1989	171225.	25765.	3961.	362.	8283.	30744.	10352.	250347.	1221004.	143650.	888245.
1990	186635.	27776.	4108.	368.	8283.	29880.	10297.	267367.	1488371.	137285.	1025530.
1991	201491.	29995.	4355.	415.	8283.	28961.	10542.	283982.	1772353.	130484.	1156014.
1992	219172.	32263.	4602.	444.	8283.	28042.	10787.	303613.	2075966.	124836.	1280850.
1993	239771.	34805.	4849.	475.	8283.	27123.	11032.	326339.	2402304.	120071.	1400921.
1994	260368.	37524.	5097.	508.	8283.	26204.	11277.	349261.	2751565.	114994.	1515915.
1995	285751.	40456.	5344.	544.	8283.	25285.	11522.	381185.	3132750.	112309.	1628224.
1996	321919.	43617.	5591.	582.	8283.	24366.	11767.	415625.	3548375.	109580.	1737804.
1997	353080.	47026.	5838.	623.	8283.	23447.	12012.	450309.	3998684.	106291.	1844095.
1998	377615.	50703.	6085.	666.	8283.	22528.	12257.	478188.	4476872.	100956.	1945051.
1999	418754.	54667.	6332.	713.	8283.	21609.	12502.	522860.	4999732.	98781.	2043742.
2000	459591.	58943.	6580.	763.	8283.	20690.	12747.	567097.	5566829.	95873.	2139655.
2001	501895.	63553.	6827.	816.	8283.	19771.	12992.	614137.	6180966.	92409.	2232564.
2002	540532.	68525.	7074.	873.	8283.	18852.	13237.	657376.	6838342.	88993.	2321557.
2003	593331.	73887.	7321.	934.	8283.	17933.	13482.	715171.	7553513.	86638.	2408195.
2004	647851.	79669.	7568.	1000.	8283.	17014.	13727.	775112.	8328625.	84026.	2492221.

CASE 2- W/O CG/CC, BPH3 LS-COAL, OTHERS HS-OIL,COAL & OIL ESC 7%   7/02/80

BPH 3 CONVERTED TO
COAL WITHOUT A SCRUBBER

ITEM NAME	U3CERT	U3NONC
YR OF INST	1985	1985
MONTH OF INST	7	7
INVESTMENT DOLLARS	19059000.	51911000.
NONREC EXP INIT YR	0.	693000.
NUC FL INIT Y $/YR	0.	0.
NUC FUEL EQIL $/YR	0.	0.
OEM PAYRLL INIT YR	596597.	0.
OEM MATRLS INIT YR	995539.	0.
OEM LABOR INIT YR	0.	0.
INSUR PREM INIT YR	19059.	51911.
BOOK LIFE YEARS	29	29
TAX LIFE YEARS	23	23
PROP VALUE ASSESMT	0.	5998253.
PROP TAX RATE MILS	0.0	66.90
DEPR INVEST BOOK $	19009997.	19158589.
DEPR INVEST TAX $	17307526.	13089100.
ICC DOLLARS	0.	0.
LAND DOLLARS	0.	0.
OTHER EXCL FM OIT	0.	0.
ITC EXCL FP INVEST	1671979.	38326900.
PURCH INST INDIC	INSTAL	INSTAL
DEBT FRACTION P.U.	0.5000	0.5000
DEBT RATE P.U.	0.0750	0.1000
COST OF MONEY P.U.	0.1050	0.1175
BOOK DEPREC METHOD	STL	STL
TAX DEPREC METHOD	SYD	SYD
S.I.I. RATE P.U.	0.1000	0.1000
YEAR RETIRED	0	0
MONTH RETIRED	0	0
DETAIL OUTPT INDIC	0	0
NAME OF UNIT REPL.		
S.I.I. BASED ON	RETURN	RETURN

2 IS THE LAST RECORD CONTAINING DATA

0 UNITS WERE DELETED

SUMMARY

BASE CASE NO CG/CC, ALL UNITS ON HS-OIL
OUTPUT IN THOUSANDS OF DOLLARS

7/02/80

YEAR	FUEL COST	OPR AND MAINT	PROPERTY TAX	INSURANCE PREMIUM	BOOK DEPREC	TOTAL RETURN	INCOME TAX	ANNUAL COST	CUMULAT ANN. COST	1985 PW AT 11.75 PCT TOTAL ANN. COST	1985 PW AT 11.75 PCT CUMULAT ANN. COS-
1985	214305.	0.	0.	0.	0.	0.	0.	214305.	214305.	191772.	191772.
1986	201043.	0.	0.	0.	0.	0.	0.	201043.	415348.	160988.	352760.
1987	200624.	0.	0.	0.	0.	0.	0.	200624.	615972.	143761.	496521.
1988	215675.	0.	0.	0.	0.	0.	0.	215675.	831647.	138296.	634817.
1989	231830.	0.	0.	0.	0.	0.	0.	231830.	1063477.	133025.	767842.
1990	254094.	0.	0.	0.	0.	0.	0.	254094.	1317571.	130470.	898312.
1991	276806.	0.	0.	0.	0.	0.	0.	276806.	1594377.	127187.	1025499.
1992	303978.	0.	0.	0.	0.	0.	0.	303978.	1898355.	124986.	1150485.
1993	337326.	0.	0.	0.	0.	0.	0.	337326.	2235681.	124114.	1274599.
1994	366452.	0.	0.	0.	0.	0.	0.	366452.	2602133.	120654.	1395253.
1995	405007.	0.	0.	0.	0.	0.	0.	405007.	3007140.	119327.	1514580.
1996	446021.	0.	0.	0.	0.	0.	0.	446021.	3453161.	117599.	1632179.
1997	488102.	0.	0.	0.	0.	0.	0.	488102.	3941263.	115153.	1747332.
1998	530971.	0.	0.	0.	0.	0.	0.	530971.	4472234.	112100.	1859432.
1999	581758.	0.	0.	0.	0.	0.	0.	581758.	5053992.	109908.	1969340.
2000	637847.	0.	0.	0.	0.	0.	0.	637847.	5691839.	107834.	2077174.
2001	700894.	0.	0.	0.	0.	0.	0.	700894.	6392733.	106034.	2183208.
2002	762777.	0.	0.	0.	0.	0.	0.	762777.	7155510.	103262.	2286470.
2003	835779.	0.	0.	0.	0.	0.	0.	835779.	7991289.	101248.	2387718.
2004	912181.	0.	0.	0.	0.	0.	0.	912181.	8903470.	98885.	2486603.

SUMMARY

CASE 1- WITH CG/CC FOR=20, ALL FOSSIL UNITS ON HS-OIL,COALOIL ESC 7% 7/02/80

OUTPUT IN THOUSANDS OF DOLLARS

YEAR	FUEL COST	OPR AND MAINT	PROPERTY TAX	INSURANCE PREMIUM	BOOK DEPREC	TOTAL RETURN	INCOME TAX	ANNUAL COST	CUMULAT ANN. COST	1985 PW AT 11.75 PCT TOTAL ANN. COST	1985 PW AT 11.75 PCT CUMULAT ANN. COST
1985	214305.	0.	0.	0.	0.	0.	0.	214305.	214305.	191772.	191772.
1986	201043.	0.	0.	0.	0.	0.	0.	201043.	415348.	160988.	352760.
1987	175261.	8419.	2909.	159.	4793.	18203.	10201.	219945.	635293.	157606.	510366.
1988	192891.	9069.	3127.	170.	4793.	17657.	4613.	232320.	867613.	148969.	659335.
1989	206299.	9771.	3344.	182.	4793.	17111.	4755.	246255.	1113868.	141302.	800637.
1990	227297.	10526.	3562.	195.	4793.	16565.	4897.	267835.	1381703.	137525.	938162.
1991	244388.	11341.	3779.	209.	4793.	16018.	5039.	285567.	1667270.	131213.	1069375.
1992	266883.	12218.	3996.	223.	4793.	15472.	5180.	308765.	1976035.	126954.	1196329.
1993	294829.	13164.	4214.	234.	4793.	14925.	5323.	337482.	2313517.	124172.	1320501.
1994	321676.	14183.	4431.	256.	4793.	14379.	5465.	365183.	2678700.	120236.	1440737.
1995	353173.	15281.	4649.	273.	4793.	13832.	5607.	397608.	3076308.	117147.	1557884.
1996	388827.	16465.	4866.	293.	4793.	13286.	5748.	434278.	3510586.	114498.	1672382.
1997	431952.	17740.	5084.	313.	4793.	12739.	5890.	478511.	3989097.	112895.	1785277.
1998	469364.	19115.	5301.	335.	4793.	12193.	6033.	517134.	4506231.	109179.	1894456.
1999	513344.	20597.	5519.	359.	4793.	11646.	6175.	562433.	5068664.	106257.	2000713.
2000	569281.	22193.	5736.	384.	4793.	11101.	6316.	619804.	5688468.	104784.	2105497.
2001	628139.	23914.	5953.	411.	4793.	10554.	6458.	680222.	6368690.	102906.	2208403.
2002	678749.	25769.	6171.	439.	4793.	10008.	6600.	732529.	7101219.	99167.	2307570.
2003	744046.	27768.	6388.	470.	4793.	9461.	6743.	799669.	7900888.	96874.	2404444.
2004	817023.	29922.	6606.	503.	4793.	8915.	6884.	874646.	8775534.	94816.	2499260.

SUMMARY

CASE E- W/O CG/CC, BPH3 LS-COAL, OTHERS HS-OIL,COAL‾E OIL ESC 7% (REV)
OUTPUT IN THOUSANDS OF DOLLARS

YEAR	FUEL COST	OPR AND MAINT	PROPERTY TAX	INSURANCE PREMIUM	BOOK DEPREC	TOTAL RETURN	INCOME TAX	ANNUAL COST	CUMULAT ANN. COST	1985 PW AT 11.75 PCT TOTAL ANN. COST	1985 PW AT 11.75 PCT CUMULAT ANN. COST
1985	194510.	1189.	199.	35.	572.	4021.	1641.	202167.	202167.	180910.	180910.
1986	163439.	1174.	428.	75.	1144.	7979.	3401.	177640.	379807.	142245.	323155.
1987	160567.	1263.	457.	81.	1144.	7853.	3436.	174801.	554608.	125257.	448415.
1988	171037.	1359.	487.	86.	1144.	7727.	3470.	185310.	739918.	118825.	567240.
1989	183560.	1461.	517.	92.	1144.	7600.	3505.	197879.	937797.	113543.	680783.
1990	199804.	1572.	547.	99.	1144.	7474.	3539.	214179.	1151976.	109974.	790757.
1991	214707.	1690.	576.	106.	1144.	7348.	3573.	229144.	1381120.	105287.	896044.
1992	233719.	1818.	606.	113.	1144.	7222.	3608.	248230.	1629350.	102069.	998130.
1993	259592.	1956.	636.	121.	1144.	7096.	3642.	274187.	1903537.	100883.	1098991.
1994	278800.	2104.	666.	130.	1144.	6969.	3677.	293490.	2197027.	96631.	1195622.
1995	306984.	2263.	695.	139.	1144.	6843.	3711.	321779.	2518806.	94806.	1290428.
1996	337009.	2434.	725.	148.	1144.	6717.	3746.	351923.	2870729.	92765.	1383213.
1997	373502.	2618.	755.	159.	1144.	6591.	3780.	388549.	3259278.	91670.	1474883.
1998	401336.	2817.	785.	170.	1144.	6465.	3814.	416531.	3675809.	87439.	1562322.
1999	439483.	3030.	814.	182.	1144.	6338.	3849.	454840.	4130649.	85930.	1648252.
2000	484570.	3260.	844.	194.	1144.	6212.	3883.	500107.	4630756.	84548.	1732800.
2001	536611.	3507.	874.	208.	1144.	6086.	3918.	552348.	5183104.	83561.	1816361.
2002	579226.	3773.	904.	223.	1144.	5960.	3952.	595182.	5778286.	80579.	1897935.
2003	633425.	4059.	933.	238.	1144.	5834.	3987.	649620.	6427916.	76697.	1974632.
2004	692445.	4367.	963.	255.	1144.	5707.	4021.	708902.	7136808.	76844.	2052991.

SUMMARY

CASE 3-(REV) CG/CC FOR=20,BPH3 LS-COAL, OTHERS HS-OIL,COAL&OIL ESC 7%
OUTPUT IN THOUSANDS OF DOLLARS

YEAR	FUEL COST	OPR AND MAINT	PROPERTY TAX	INSURANCE PREMIUM	BOOK DEPREC	TOTAL RETURN	INCOME TAX	ANNUAL COST	CUMULAT ANN. COST	1985 PW AT 11.75 PCT TOTAL ANN. COST	1985 PW AT 11.75 PCT CUMULAT ANN. COST
1985	194510.	1184.	144.	35.	572.	4021.	1641.	202167.	202167.	180910.	180910.
1986	163439.	1174.	428.	75.	1144.	7474.	3401.	177690.	379807.	142248.	323158.
1987	191384.	9682.	3357.	213.	5937.	26056.	13636.	200302.	580109.	143530.	466698.
1988	152142.	10428.	3614.	257.	5937.	25384.	8383.	205845.	785954.	131993.	598691.
1989	163832.	11232.	3861.	275.	5937.	24711.	8259.	218107.	1004061.	125150.	723831.
1990	178231.	12098.	4108.	294.	5937.	24039.	8436.	232993.	1237064.	119609.	843440.
1991	191581.	13031.	4355.	314.	5937.	23366.	8612.	247196.	1484200.	113582.	957022.
1992	207540.	14036.	4603.	336.	5937.	22693.	8789.	263934.	1748154.	108521.	1065543.
1993	230925.	15120.	4850.	360.	5937.	22021.	8965.	288178.	2036312.	106031.	1171574.
1994	250275.	16287.	5097.	385.	5937.	21348.	9141.	308470.	2344782.	101563.	1273137.
1995	275488.	17544.	5344.	412.	5937.	20676.	9318.	334719.	2679501.	98618.	1371755.
1996	301056.	18899.	5591.	441.	5937.	20003.	9494.	361421.	3040922.	95289.	1467044.
1997	339897.	20359.	5838.	472.	5937.	19330.	9671.	401454.	3442376.	94715.	1561759.
1998	364867.	21932.	6086.	505.	5937.	18658.	9847.	427832.	3870208.	90325.	1652084.
1999	396397.	23626.	6333.	540.	5937.	17985.	10023.	460891.	4331099.	87069.	1739148.
2000	440126.	25453.	6580.	578.	5937.	17312.	10200.	506186.	4837235.	85576.	1824724.
2001	487893.	27421.	6827.	619.	5937.	16640.	10376.	555663.	5392898.	84063.	1908787.
2002	521693.	29541.	7074.	662.	5937.	15967.	10552.	591916.	5984314.	80064.	1988851.
2003	573277.	31826.	7322.	708.	5937.	15295.	10729.	645094.	6629408.	78348.	2066999.
2004	629270.	34289.	7569.	758.	5937.	14622.	10905.	703350.	7332758.	76247.	2143246.

SUMMARY CASE 1 W/CG/CC FOR=20,REST LS-OIL ESC 7%,COAL CONST DIFF OF 274¢/MBTU 7/30/80

OUTPUT IN THOUSANDS OF DOLLARS

YEAR	FUEL COST	OPR AND MAINT	PROPERTY TAX	INSURANCE PREMIUM	BOOK DEPREC	TOTAL RETURN	INCOME TAX	ANNUAL COST	CUMULAT ANN. COST	1985 PW AT 11.75 PCT TOTAL ANN. COST	1985 PW AT 11.75 PCT CUMULAT ANN. COST
1985	292091.	0.	0.	0.	0.	0.	0.	292091.	292091.	261379.	261379.
1986	263725.	0.	0.	0.	0.	0.	0.	263725.	555816.	211182.	472561.
1987	231476.	8419.	2909.	159.	4793.	10203.	10201.	276660.	832476.	198246.	670807.
1988	251336.	9069.	3127.	170.	4793.	17657.	4613.	290765.	1123241.	186446.	857253.
1989	267453.	9771.	3344.	182.	4793.	17111.	4755.	307409.	1430650.	176392.	1033645.
1990	292685.	10526.	3562.	195.	4793.	16565.	4897.	333223.	1763873.	171100.	1204745.
1991	313700.	11341.	3779.	209.	4793.	16018.	5039.	354879.	2118752.	163060.	1367805.
1992	340318.	12216.	3996.	223.	4793.	15472.	5180.	382200.	2500952.	157149.	1524954.
1993	374829.	13169.	4219.	239.	4793.	14925.	5323.	417487.	2918439.	153608.	1678562.
1994	408993.	14183.	4431.	256.	4793.	14379.	5465.	452500.	3370939.	148485.	1827047.
1995	445322.	15281.	4649.	273.	4793.	13832.	5607.	489757.	3860696.	144297.	1971344.
1996	486721.	16465.	4866.	293.	4793.	13286.	5748.	532172.	4392868.	140808.	2112152.
1997	540826.	17740.	5084.	313.	4793.	12734.	5890.	587385.	4980253.	138581.	2250733.
1998	585071.	19115.	5301.	335.	4793.	12193.	6033.	632841.	5613094.	133607.	2384340.
1999	635531.	20597.	5514.	359.	4793.	11646.	6175.	684620.	6297714.	129341.	2513681.
2000	701490.	22143.	5736.	384.	4793.	11101.	6316.	751963.	7049677.	127126.	2640807.
2001	772622.	23914.	5953.	411.	4793.	10559.	6458.	824705.	7874382.	124764.	2765571.
2002	831403.	25764.	6171.	434.	4793.	10008.	6600.	885183.	8759565.	119833.	2885404.
2003	909284.	27768.	6388.	470.	4793.	9461.	6743.	964907.	9724472.	116891.	3002295.
2004	987694.	29922.	6606.	503.	4793.	8915.	6884.	1045317.	10769789.	113318.	3115613.

CASE 1 - COST OF MONEY SENSITIVITY = CHANGE OF CAPITAL STRUCTURE = RUN ON 7/07/80

BASE CASE ADDED TO FILE 16 AS CHANGE CASE 19
WITH CG/CC FUR=20. ALL FOSSIL UNITS ON LS-OIL,COALCOIL ESC 7%
DUMP POWER COST DUE TO PRESENT UNIT CONSTRAINTS IS INCLUDED IN FUEL COST
$2,033,000 CREDIT ON STATE GROSS EARNINGS TAX REFLECTED IN FUEL COST IN 1987

STUDY PARAMETERS FOR THIS CASE WERE READ FROM CARDS

THIS STUDY WILL START IN 1985

ALL PRESENT WORTH CALCULATIONS TO BEGINNING OF 1985 AT 11.90 PERCENT

PRESENT WORTH CALCULATONS BASED ON THE FOLLOWING

DEBT FRACTION (PERCENT) = 46.00 DEBT RATE (PERCENT) = 10.00

PREF. STOCK FRACTION = 16.00 PREF. STOCK RATE = 10.00

COMM. STOCK FRACTION = 38.00 COMM. STOCK RATE = 15.00

THE LENGTH OF THIS STUDY IS 31 YEARS

CALCULATED COST OF MONEY = 11.90

COST OF MONEY CALCULATIONS BASED ON THE FOLLOWING

DEBT FRACTION (PERCENT) = 46.00 DEBT RATE (PERCENT) = 10.00

PREF. STOCK FRACTION = 16.00 PREF. STOCK RATE = 10.00

COMM. STOCK FRACTION = 38.00 COMM. STOCK RATE = 15.00

BOOK DEPRECIATION METHOD = STRAIGHT LINE

TAX DEPRECIATION METHOD = SUM OF YEARS DIGITS

FEDERAL INCOME TAX RATE (PERCENT) = 46.00

STATE INCOME TAX RATE (PERCENT) = 10.00

INVESTMENT TAX CREDIT PERCENT = 10.00 SPREAD OVER 30 YEARS

SURCHARGE (PCT OF F.I.T.) = 0.0 FOR 0 YEARS

PREOPERATIVE AFFECT NOT TAKEN INTO ACCOUNT

DEPRECIATION CALCULATIONS BASED ON FLOW THROUGH

SUMMARY ----- CASE 1 - COST OF MONEY SENSITIVITY - CHANGE OF CAPITAL STRUCTURE - 7/07/80

OUTPUT IN THOUSANDS OF DOLLARS

1985 PW AT 11.90 PCT

YEAR	FUEL COST	OPR AND MAINT	PROPERTY TAX	INSURANCE PREMIUM	BOOK DEPREC	TOTAL RETURN	INCOME TAX	ANNUAL COST	CUMULAT ANN. COST	TOTAL ANN. COST	CUMULAT ANN. COST
1985	292091.	0.	0.	0.	0.	0.	0.	292091.	292091.	261029.	261029.
1986	263725.	0.	0.	0.	0.	0.	0.	263725.	555816.	210616.	471645.
1987	210115.	8419.	2909.	159.	4793.	18483.	11109.	255987.	811803.	182695.	654340.
1988	227786.	9069.	3127.	170.	4793.	17928.	5993.	268366.	1080169.	171162.	825502.
1989	240572.	9771.	3394.	182.	4793.	17373.	5608.	281693.	1361812.	160527.	986029.
1990	262183.	10526.	3562.	195.	4793.	16818.	5722.	303794.	1665611.	159741.	1140770.
1991	278907.	11341.	3779.	209.	4793.	16263.	5838.	321130.	1986741.	146174.	1286944.
1992	301448.	12218.	3996.	223.	4793.	15708.	5952.	344888.	2331629.	140293.	1427237.
1993	331076.	13164.	4219.	239.	4793.	15153.	6067.	374700.	2706329.	136211.	1563448.
1994	360364.	14183.	4431.	256.	4793.	14598.	6181.	409806.	3111135.	131506.	1694954.
1995	391246.	15281.	4649.	273.	4793.	14043.	6296.	436581.	3547716.	126746.	1821700.
1996	427874.	16465.	4866.	293.	4793.	13489.	6411.	474196.	4021912.	123026.	1944726.
1997	474874.	17740.	5081.	313.	4793.	12933.	6525.	522262.	4544174.	121087.	2065813.
1998	510810.	19115.	5301.	335.	4793.	12378.	6640.	559402.	5103576.	115405.	2181218.
1999	556306.	20597.	5519.	359.	4793.	11829.	6754.	606152.	5709728.	112235.	2293453.
2000	615214.	22193.	5736.	384.	4793.	11269.	6869.	666458.	6376186.	110274.	2403232.
2001	676797.	23914.	5953.	411.	4793.	10713.	6984.	724565.	7105751.	107883.	2512115.
2002	727244.	25769.	6171.	439.	4793.	10159.	7099.	781674.	7887425.	103246.	2615911.
2003	793811.	27768.	6388.	470.	4793.	9609.	7213.	850047.	8737472.	100386.	2715297.
2004	868630.	29922.	6606.	503.	4793.	9048.	7328.	926830.	9664302.	97813.	2813610.

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CASE 1 - COST OF MONEY SENSITIVITY - CHANGE OF RATE -                                    RUN ON 7/07/80

BASE CASE ADDED TO FILE 16 AS CHANGE CASE 20
WITH CG/CC FOR=20, ALL FOSSIL UNITS ON LS-OIL,COALOIL ESC 7%
DUMP POWER COST DUE TO PRESENT UNIT CONSTRAINTS IS INCLUDED IN FUEL COST
$2,013,000 CREDIT ON STATE GROSS EARNINGS TAX REFLECTED IN FUEL COST IN 1987

STUDY PARAMETERS FOR THIS CASE WERE READ FROM CARDS

THIS STUDY WILL START IN 1985

ALL PRESENT WORTH CALCULATIONS TO BEGINNING OF 1985 AT 13.90 PERCENT

PRESENT WORTH CALCULATONS BASED ON THE FOLLOWING

DEBT FRACTION (PERCENT) = 50.00   DEBT RATE (PERCENT) = 12.00

PREF. STOCK FRACTION = 15.00   PREF. STOCK RATE = 12.00

COMM. STOCK FRACTION = 35.00   COMM. STOCK RATE = 16.00

THE LENGTH OF THIS STUDY IS   31 YEARS

CALCULATED COST OF MONEY = 13.90

COST OF MONEY CALCULATIONS BASED ON THE  FOLLOWING

DEBT FRACTION (PERCENT) = 50.00   DEBT RATE (PERCENT) = 12.00

PREF. STOCK FRACTION = 15.00   PREF. STOCK RATE = 12.00

COMM. STOCK FRACTION = 35.00   COMM. STOCK RATE = 16.00

BOOK DEPRECIATION METHOD = STRAIGHT LINE

TAX DEPRECIATION METHOD = SUM OF YEARS DIGITS

FEDERAL INCOME TAX RATE (PERCENT) = 46.00

STATE INCOME TAX RATE (PERCENT) = 10.00

INVESTMENT TAX CREDIT PERCENT = 10.00 SPREAD OVER 30 YEARS

SURCHARGE (PCT OF F.I.T.) = 0.0  FOR  0 YEARS

PREOPERATIVE AFFECT NOT TAKEN INTO ACCOUNT

DEPRECIATION CALCULATIONS BASED ON FLOW THROUGH
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SUMMARY

CASE 1 - COST OF MONEY SENSITIVITY - CHANGE OF RATE = 7/07/80

OUTPUT IN THOUSANDS OF DOLLARS

YEAR	FUEL COST	OPR AND MAINT	PROPERTY TAX	INSURANCE PREMIUM	BOOK DEPREC	TOTAL RETURN	INCOME TAX	ANNUAL COST	CUMULAT ANN. COST	1985 PW AT 13.40 PCT TOTAL ANN. COST	1985 PW AT 13.40 PCT CUMULAT ANN. COST
1985	292091.	0.	0.	0.	0.	0.	0.	292091.	292091.	257576.	257576.
1986	263725.	0.	0.	0.	0.	0.	0.	263725.	555816.	205081.	462657.
1987	210115.	8419.	2909.	159.	4793.	20730.	11274.	258399.	814215.	177195.	639852.
1988	227786.	9069.	3127.	170.	4793.	20107.	5654.	270706.	1084921.	163699.	803551.
1989	240572.	9771.	3344.	182.	4793.	19486.	5763.	283911.	1368832.	151397.	954948.
1990	262183.	10526.	3562.	195.	4793.	18864.	5873.	305996.	1674828.	143842.	1098790.
1991	278907.	11341.	3779.	209.	4793.	18241.	5983.	323253.	1998081.	134095.	1232885.
1992	301998.	12218.	3996.	223.	4793.	17620.	6092.	346940.	2345021.	126867.	1359752.
1993	331070.	13164.	4219.	239.	4793.	16992.	6202.	376679.	2721700.	121466.	1481218.
1994	360369.	14183.	4431.	256.	4793.	16375.	6312.	406719.	3128419.	115653.	1596871.
1995	391246.	15281.	4644.	273.	4793.	15752.	6422.	438411.	3566830.	109937.	1706808.
1996	427879.	16465.	4866.	293.	4793.	15131.	6531.	475958.	4042788.	105248.	1812056.
1997	474879.	17740.	5084.	313.	4793.	14503.	6641.	523953.	4566741.	102170.	1914226.
1998	510840.	19115.	5301.	335.	4793.	13886.	6751.	561021.	5127762.	96471.	2010697.
1999	556306.	20597.	5519.	359.	4793.	13265.	6859.	607698.	5735460.	92149.	2102846.
2000	615219.	22193.	5736.	384.	4793.	12642.	6964.	667931.	6403391.	89315.	2192161.
2001	676797.	23914.	5953.	411.	4793.	12020.	7079.	730967.	7134358.	86194.	2278355.
2002	727249.	25764.	6171.	439.	4793.	11398.	7189.	783003.	7917361.	81420.	2359775.
2003	793811.	27768.	6388.	470.	4793.	10776.	7298.	851304.	8768665.	78061.	2437836.
2004	868630.	29922.	6606.	503.	4793.	10153.	7408.	928015.	9696680.	75040.	2512876.

CASE 1 WITH CG/CC FOR=20,ALL FOSSIL UNITS ON LS-OIL,CAP.& O+M UP 25% 7/02/80

CG/CC

ITEM NAME	CERTIF	NUNCER
YR OF INST	1987	1987
MONTH OF INST	1	1
INVESTMENT DOLLARS	50326000.	198689000.
NONREC EXP INIT YR	0.	0.
NUC FL INIT Y $/YR	0.	0.
NUC FUEL EOIL $/YR	0.	0.
O&M PAYRLL INIT YR	7609613.	0.
O&M MATRLS INIT YR	2633359.	0.
O&M LABOR INIT YR	0.	0.
INSUR PREM INIT YR	50326.	198689.
BOOK LIFE YEARS	30	30
TAX LIFE YEARS	23	23
PROP VALUE ASSESMT	0.	59358870.
PROP TAX RATE MILS	0.0	66.90
DEPR INVEST BOOK $	50326000.	129914559.
DEPR INVEST TAX $	44978119.	119367733.
ICC DOLLARS	0.	0.
LAND DOLLARS	0.	0.
OTHER EXCL FM DIT	0.	0.
ITC EXCL FM INVEST	5647881.	39316267.
PURCH INST INDIC	INSTAL	INSTAL
DEBT FRACTION P.U.	0.5000	0.5000
DEBT RATE P.U.	0.0750	0.1000
COST OF MONEY P.U.	0.1050	0.1175
BOOK DEPREC METHOD	STL	STL
TAX DEPREC METHOD	SYD	SYD
S.I.T. RATE P.U.	0.1000	0.1000
YEAR RETIRED	0	0
MONTH RETIRED	0	0
DETAIL OUTPT INDIC	0	0
NAME OF UNIT REPL.		
S.I.T. BASED ON	RETURN	RETURN

2 IS THE LAST RECORD CONTAINING DATA

0 UNITS WERE DELETED

SUMMARY

CASE 1 WITH CG/CC FOR-20,ALL FOSSIL UNITS ON LS-OIL,CAP.& O+M UP 25%
OUTPUT IN THOUSANDS OF DOLLARS

7/02/80

YEAR	FUEL COST	OPR AND MAINT	PROPERTY TAX	INSURANCE PREMIUM	BOOK DEPREC	TOTAL RETURN	INCOME TAX	ANNUAL COST	CUMULAT ANN. COST	1985 PW AT 11.75 PCT TOTAL ANN. COST	1985 PW AT 11.75 PCT CUMULAT ANN. COST
1985	292091.	0.	0.	0.	0.	0.	0.	292091.	292091.	261375.	261379.
1986	263725.	0.	0.	0.	0.	0.	0.	263725.	555816.	211182.	472561.
1987	209612.	10523.	3637.	194.	5992.	22759.	12750.	265467.	821283.	190225.	662786.
1988	227786.	11337.	3908.	213.	5992.	22071.	5767.	277079.	1098357.	177667.	840453.
1989	240572.	12213.	4180.	228.	5992.	21389.	5993.	290517.	1388874.	166699.	1007152.
1990	262183.	13158.	4452.	244.	5992.	20706.	6121.	312856.	1701730.	160692.	1167794.
1991	278407.	14176.	4724.	261.	5992.	20023.	6299.	330382.	2032112.	151804.	1319598.
1992	301998.	15273.	4996.	280.	5992.	19390.	6976.	359355.	2366467.	145700.	1465298.
1993	331070.	16455.	5267.	299.	5992.	18656.	6653.	389392.	2770859.	141932.	1606730.
1994	360369.	17729.	5539.	320.	5992.	17973.	6831.	414798.	3185607.	136555.	1743285.
1995	391296.	19102.	5811.	341.	5992.	17290.	7008.	446790.	3632397.	131638.	1874923.
1996	427879.	20581.	6083.	366.	5992.	16608.	7186.	484695.	4117092.	127790.	2002713.
1997	474679.	22175.	6355.	391.	5992.	15925.	7363.	533075.	4650167.	125768.	2128481.
1998	510690.	23894.	6626.	419.	5992.	15292.	7541.	570554.	5220721.	120457.	2248938.
1999	556306.	25746.	6898.	448.	5992.	14559.	7718.	617667.	5838388.	116692.	2365630.
2000	615219.	27741.	7170.	479.	5992.	13875.	7896.	678367.	6516755.	114689.	2480319.
2001	676797.	24892.	7442.	511.	5992.	13192.	8073.	741401.	7256656.	112237.	2592551.
2002	727249.	32211.	7714.	544.	5992.	12509.	8250.	796469.	8053125.	107553.	2700104.
2003	793811.	34709.	7985.	588.	5992.	11826.	8428.	863339.	8916464.	104587.	2804691.
2004	868630.	37402.	8257.	629.	5992.	11144.	8606.	940660.	9857124.	101972.	2906663.

SUMMARY

CASE 1 WITH CG/CC FOR=4B, ALL FOSSIL UNITS ON LS-OIL,COALCOIL ESC 7% — 7/02/80

OUTPUT IN THOUSANDS OF DOLLARS

YEAR	FUEL COST	OPR AND MAINT	PROPERTY TAX	INSURANCE PREMIUM	BOOK DEPREC	TOTAL RETURN	INCOME TAX	ANNUAL COST	CUMULAT ANN. COST	1985 PW AT 11.75 PCT TOTAL ANN. COST	1985 PW AT 11.75 PCT CUMULAT ANN. COST
1985	292091.	0.	0.	0.	0.	0.	0.	292091.	292091.	261379.	261379.
1986	263725.	0.	0.	0.	0.	0.	0.	263725.	555816.	211182.	472561.
1987	219201.	8919.	2909.	159.	9793.	18203.	10281.	263885.	819701.	189042.	661653.
1988	235485.	9849.	3127.	170.	9793.	17657.	9613.	274919.	1094615.	176281.	837934.
1989	248687.	9771.	3394.	182.	9793.	17111.	9755.	288693.	1383258.	165624.	1003558.
1990	272465.	10526.	3562.	195.	9793.	16565.	9897.	313003.	1696261.	165718.	1169276.
1991	290281.	11391.	3779.	209.	9793.	16018.	5839.	331966.	2027721.	152299.	1316575.
1992	312979.	12218.	3996.	223.	9793.	15472.	5180.	359361.	2382082.	145702.	1462277.
1993	348973.	13169.	4219.	239.	9793.	14925.	5323.	391131.	2773213.	143911.	1606188.
1994	373370.	14183.	4431.	256.	9793.	14379.	5465.	416835.	3190048.	137243.	1743431.
1995	412479.	15201.	4644.	273.	9793.	13832.	5607.	456919.	3646962.	134621.	1878052.
1996	450019.	16465.	4866.	293.	9793.	13286.	5748.	495965.	4142927.	130630.	2008682.
1997	497112.	17790.	5084.	313.	9793.	12739.	5890.	543671.	4686098.	128268.	2136950.
1998	530853.	19115.	5301.	335.	9793.	12193.	6033.	578623.	5264721.	122160.	2259110.
1999	579169.	20597.	5519.	354.	9793.	11646.	6175.	623258.	5887979.	117748.	2376858.
2000	640344.	22193.	5736.	384.	9793.	11101.	6316.	690667.	6578646.	116764.	2493622.
2001	701596.	23419.	5953.	411.	9793.	10554.	6458.	753679.	7332325.	114019.	2607641.
2002	743946.	25769.	6171.	439.	9793.	10008.	6600.	797226.	8129551.	107926.	2715567.
2003	621590.	27768.	6388.	470.	9793.	9461.	6743.	877213.	9006764.	106268.	2821835.
2004	895730.	29922.	6606.	503.	9793.	8915.	6885.	953353.	9960117.	103398.	2925193.

SUMMARY

BASE CASE - NO CG/CC, ALL UNITS ON LS-OIL, 25% FLAT LOADS (RERUN)
OUTPUT IN THOUSANDS OF DOLLARS

7/02/80

YEAR	FUEL COST	OPM AND MAINT	PROPERTY TAX	INSURANCE PREMIUM	BOOK DEPREC	TOTAL RETURN	INCOME TAX	ANNUAL COST	CUMULAT ANN. COST	1985 PW AT 11.75 PCT TOTAL ANN. COST	1985 PW AT 11.75 PCT CUMULAT ANN. COST
1985	290735.	0.	0.	0.	0.	0.	0.	290735.	290735.	260166.	260166.
1986	261014.	0.	0.	0.	0.	0.	0.	261014.	551749.	209011.	469177.
1987	247703.	0.	0.	0.	0.	0.	0.	247703.	799452.	177496.	646673.
1988	260319.	0.	0.	0.	0.	0.	0.	260319.	1059771.	166923.	813596.
1989	275941.	0.	0.	0.	0.	0.	0.	275941.	1335712.	158336.	971932.
1990	304353.	0.	0.	0.	0.	0.	0.	304353.	1640065.	156276.	1128208.
1991	325253.	0.	0.	0.	0.	0.	0.	325253.	1965318.	149447.	1277655.
1992	351938.	0.	0.	0.	0.	0.	0.	351938.	2317256.	144706.	1422361.
1993	390979.	0.	0.	0.	0.	0.	0.	390979.	2708235.	143855.	1566216.
1994	416429.	0.	0.	0.	0.	0.	0.	416429.	3124664.	137109.	1703325.
1995	461865.	0.	0.	0.	0.	0.	0.	461865.	3586529.	136079.	1839404.
1996	503259.	0.	0.	0.	0.	0.	0.	503259.	4089788.	132685.	1972089.
1997	544661.	0.	0.	0.	0.	0.	0.	544661.	4634449.	128502.	2100591.
1998	585009.	0.	0.	0.	0.	0.	0.	585009.	5219458.	123509.	2224100.
1999	635807.	0.	0.	0.	0.	0.	0.	635807.	5855265.	120119.	2344219.
2000	696754.	0.	0.	0.	0.	0.	0.	696754.	6552019.	117793.	2462012.
2001	760959.	0.	0.	0.	0.	0.	0.	760959.	7312978.	115121.	2577133.
2002	821517.	0.	0.	0.	0.	0.	0.	821517.	8134495.	111214.	2688347.
2003	895556.	0.	0.	0.	0.	0.	0.	895556.	9030051.	108490.	2796837.
2004	970044.	0.	0.	0.	0.	0.	0.	970044.	10000095.	105158.	2901995.

SUMMARY CASE 1 WITH CO/CC FOR=20, ALL FOSSIL UNITS ON LS-OIL, 25% FLAT LOADS 7/02/80

OUTPUT IN THOUSANDS OF DOLLARS

YEAR	FUEL COST	OPN AND MAINT	PROPERTY TAX	INSURANCE PREMIUM	BOOK DEPREC	TOTAL RETURN	INCOME TAX	ANNUAL COST	CUMULAT ANN. COST	1985 PW AT 11.75 PCT TOTAL ANN. COST	1985 PW AT 11.75 PCT CUMULAT ANN. COST
1985.	290735.	0.	0.	0.	0.	0.	0.	290735.	290735.	260166.	260166.
1986	261019.	0.	0.	0.	0.	0.	0.	261019.	551754.	209011.	469177.
1987	206277.	8419.	2909.	159.	4793.	18203.	10201.	250961.	802710.	179831.	649008.
1988	222844.	9069.	3127.	170.	4793.	17657.	4613.	262273.	1064983.	160176.	809184.
1989	234661.	9771.	3344.	182.	4793.	17111.	4755.	274617.	1339600.	157576.	966760.
1990	255328.	10526.	3562.	195.	4793.	16565.	4897.	295866.	1635466.	159918.	1126678.
1991	271640.	11341.	3779.	209.	4793.	16018.	5039.	312819.	1948285.	143734.	1270412.
1992	293298.	12218.	3446.	223.	4793.	15972.	5180.	335130.	2283415.	137795.	1408207.
1993	322763.	13169.	4219.	239.	4793.	14925.	5323.	365431.	2648846.	134452.	1542659.
1994	348428.	14183.	4431.	256.	4793.	14379.	5465.	391935.	3040771.	129044.	1671703.
1995	381647.	15281.	4699.	273.	4793.	13832.	5607.	426132.	3466903.	125551.	1797254.
1996	417108.	16465.	4866.	293.	4793.	13286.	5748.	462559.	3929462.	121954.	1919208.
1997	455508.	17740.	5084.	313.	4793.	12739.	5890.	502067.	4431529.	118452.	2037660.
1998	498098.	19115.	5301.	335.	4793.	12193.	6033.	545868.	4977397.	115295.	2152955.
1999	543659.	20592.	5519.	359.	4793.	11696.	6175.	592793.	5570190.	111883.	2264838.
2000	597908.	22193.	5736.	384.	4793.	11101.	6316.	648431.	6218621.	109682.	2374520.
2001	655695.	23914.	5953.	411.	4793.	10554.	6458.	707778.	6926399.	107075.	2481595.
2002	709199.	25769.	6171.	439.	4793.	10008.	6600.	762979.	7689378.	103290.	2584885.
2003	776935.	27768.	6388.	420.	4793.	9461.	6793.	832558.	8521936.	100858.	2685743.
2004	851734.	29922.	6606.	503.	4793.	8515.	6884.	908957.	9430893.	98535.	2784278.

SUMMARY

CASE 2 W/O CG/CC, BPH3 HS-COAL; OTHERS LS-OIL; 25% FLAT LOADS (REV)
OUTPUT IN THOUSANDS OF DOLLARS

YEAR	FUEL COST	OPR AND MAINT	PROPERTY TAX	INSURANCE PREMIUM	BOOK DEPREC	TOTAL RT.URN	INCOME TAX	ANNUAL COST	CUMULAT ANN. COST	1985 PW AT 11.75 PCT TOTAL ANN. COST	1985 PW AT 11.75 PCT CUMULAT ANN. COST
1985	246687.	6559.	199.	69.	1795.	7996.	2319.	265069.	265069.	237199.	237199.
1986	190169.	12750.	427.	197.	3990.	19806.	4988.	226772.	491836.	181591.	418795.
1987	181111.	13751.	457.	157.	3990.	19933.	5091.	218490.	710326.	156563.	575358.
1988	190036.	14830.	487.	168.	3990.	19361.	5199.	228266.	938592.	146370.	721728.
1989	201602.	15999.	517.	180.	3990.	13688.	5297.	240768.	1179360.	138153.	859881.
1990	217632.	17250.	546.	193.	3990.	13315.	5400.	257826.	1437186.	132386.	992267.
1991	228459.	18609.	576.	206.	3990.	12943.	5503.	269781.	1706967.	123959.	1116216.
1992	250115.	20065.	606.	221.	3990.	12570.	5606.	292673.	1999640.	120338.	1236555.
1993	275460.	21641.	636.	236.	3990.	12198.	5709.	318870.	2318510.	117329.	1353878.
1994	294769.	23391.	665.	253.	3990.	11825.	5912.	340155.	2658665.	111996.	1465874.
1995	323158.	25179.	695.	270.	3990.	11453.	5915.	370155.	3028820.	109059.	1574933.
1996	353448.	27152.	725.	289.	3990.	11080.	6018.	402202.	3431022.	106041.	1680974.
1997	388744.	29286.	759.	309.	3990.	10708.	6121.	439912.	3870934.	103670.	1784644.
1998	418444.	31588.	789.	331.	3990.	10335.	6229.	471246.	4341180.	99491.	1884135.
1999	459927.	34071.	819.	359.	3990.	9962.	6328.	514442.	4856622.	97285.	1981420.
2000	501209.	36750.	849.	379.	3990.	9590.	6431.	558581.	5415204.	94451.	2075871.
2001	553098.	39634.	873.	405.	3990.	9217.	6534.	613256.	6028562.	92276.	2168147.
2002	598976.	42756.	903.	434.	3990.	8845.	6637.	661971.	6690533.	89616.	2258263.
2003	652316.	46119.	933.	461.	3990.	8472.	6740.	718534.	7409067.	87095.	2345398.
2004	709910.	49747.	963.	497.	3990.	8100.	6843.	779570.	8188637.	84529.	2429917.

SUMMARY

CASE 3 (REV) CG/CC FOR=20;BPNS MS=COAL, OTHERS LS=OIL, 25% FLAT LOADS
OUTPUT IN THOUSANDS OF DOLLARS

YEAR	FUEL COST	OPR AND MAINT	PROPERTY TAX	INSURANCE PREMIUM	BOOK DEPREC	TOTAL RETURN	INCOME TAX	ANNUAL COST	CUMULAT ANN. COST	1985 PW AT 11.75 PCT TOTAL ANN. COST	CUMULAT ANN. COST
1985	246697.	6554.	199.	69.	1745.	7996.	2314.	265069.	265069.	237199.	237199.
1986	190169.	12750.	427.	197.	3990.	19806.	9988.	226772.	491836.	181591.	418795.
1987	196579.	22169.	3368.	316.	8283.	32637.	15291.	228611.	720477.	163837.	582622.
1988	153398.	23899.	3619.	339.	8283.	31718.	9807.	231098.	951525.	148154.	730776.
1989	164796.	25765.	3861.	362.	8283.	30799.	10052.	244418.	1195943.	140249.	871029.
1990	179356.	27776.	4108.	388.	8283.	29880.	10297.	260088.	1456031.	133547.	1004571.
1991	191020.	29995.	4355.	415.	8283.	28961.	10542.	273521.	1729552.	125678.	1130249.
1992	206723.	32283.	4602.	444.	8283.	28042.	10787.	291164.	2020716.	119717.	1249966.
1993	221119.	34805.	4849.	475.	8283.	27123.	11032.	317681.	2338397.	116886.	1366852.
1994	252369.	37524.	5097.	508.	8283.	26204.	11277.	340953.	2679350.	112258.	1479115.
1995	277423.	40956.	5344.	544.	8283.	25285.	11522.	368857.	3048207.	109676.	1588786.
1996	309595.	43617.	5591.	582.	8283.	24366.	11767.	398751.	3446958.	105131.	1693917.
1997	341783.	47026.	5838.	623.	8283.	23447.	12012.	439012.	3885970.	103576.	1797493.
1998	368033.	50703.	6085.	666.	8283.	22528.	12257.	468555.	4354525.	98923.	1896416.
1999	409131.	54667.	6332.	713.	8283.	21609.	12502.	507237.	4861762.	95824.	1992245.
2000	443354.	58443.	6580.	763.	8283.	20690.	12747.	551375.	5413137.	93215.	2085450.
2001	487034.	63553.	6827.	816.	8283.	19771.	12992.	599281.	6012418.	90661.	2175121.
2002	527351.	68529.	7074.	879.	8283.	18852.	13237.	644195.	6656613.	87209.	2262330.
2003	575352.	73887.	7321.	934.	8283.	17933.	13482.	697192.	7353805.	84960.	2347290.
2004	635604.	79669.	7568.	1000.	8283.	17014.	13727.	762870.	8116675.	82699.	2429989.

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10.9 Addendum 1 - Economic Analysis

10.9.1 Introduction

This addendum contains the results of an additional study of the economic feasibility of repowering Units 9 and 11 at Steel Point Station with a coal gasification/combined cycle (CG/CC) system. The intent of this additional work is to determine if less conservative, but still realistic assumptions would make the installation of the CG/CC system economically attractive.

The conclusions in the original report are based on the following key assumptions:

Low-Band Load Growth
Coal and Oil Prices Escalate Annually @ 7%
EFOR of CG/CC - 20% and 40%

The assumptions of low-band load growth and 7% escalation of oil price are conservative. With them, the CG/CC system is only marginally economic at best when the EFOR of the CG/CC system is optimistically assumed to be 20%. When the EFOR is changed to 40% or when it is assumed that BPH 3 is converted to coal then installing the CG/CC system becomes uneconomic.

In the analysis presented in this addendum, the key assumptions are changed to the following:

Servable Load Growth (2.3% per year)
Coal and Oil Prices Escalate annually @ 7% and 9% respectively
EFOR Schedule for CG/CC System:

Year	EFOR
1	64.5%
2	43.0%
3	36.6%
4	28.0%
5	28.0%
6 & Beyond	21.5%

The new assumptions of servable load growth and 9% escalation of oil price make the installation of the CG/CC system more attractive. Unlike the original report, in which a single value of the EFOR of the CG/CC system was assumed for the entire study period, in this addendum a schedule is used. The EFOR schedule was chosen to model

10.9 Addendum 1 - Economic Analysis (Cont'd.)

the expected decrease in unscheduled outages as the CG/CC system matures. The schedule is based on the GTF "immature multipliers" for coal-fired steam generating units. The new treatment of the CG/CC system appear less attractive than when it was assumed to be 20% in the original report and more attractive than when it was assumed to be 40%.

The same cases studied in the original report are analyzed in this addendum except that specific key assumptions are changed in each sensitivity study. These cases are defined as follows. For reasons mentioned in Section III, only Cases 2 and 3 are analyzed in detail.

Low-Sulfur-Oil-Scenario

Base Case - No CG/CC, all Fossil Units on Low-Sulfur (LS) Oil.

Case 1 - CG/CC on High-Sulfur (HS) Coal, all other Fossil Units on LS-Oil.

Case 2 - No CG/CC, BPH 3 on HS-Coal with Scrubber, all other Fossil Units on LS-Oil.

Case 3 - CG/CC On HS-Coal, BPH 3 on HS-Coal with Scrubber; all other Fossil Units on LS-Oil.

The following three sensitivity studies are analyzed. All assumptions are the same as those used in the original report unless stated otherwise.

Sensitivity Study A

o Low-Band Load Growth (1.9% per year 1985-1989, 1.1% 1989-2004)

o LS-Oil Esc. @ 9%, HS-Coal Esc. @ 7%

o EFOR of CG/CC - Schedule

Sensitivity Study B

o Servable Load Growth (2.3% per year)

o LS-Oil Esc. @ 9%, HS-Coal Esc. @ 7%

o EFOR of CG/CC - Schedule

10.9 Addendum 1 - Economic Analysis (Cont'd.)

Sensitivity Study C

- o Low-Band Load Growth (1.9% per year 1985-1989, 1.1% 1989-2004)
- o LS-Oil Esc. @ 7%, HS-Coal Esc. @ 7%
- o EFOR of CG/CC - Schedule

10.9.2 Summary and Conclusions

10.9.2.1 Economic Feasibility

An important conclusion made in the original report is that converting BPH 3 to coal is much more attractive economically than installing the CG/CC system. For this reason the conclusions in this addendum regarding the economic feasibility of installing the CG/CC system is based on the assumption that BPH 3 is converted to coal (Case 2) in mid-1985.

With the less conservative, but still realistic assumptions of servable load growth and 9% oil price escalation, installation of the CG/CC system in 1987 is not economically attractive. Sensitivity Study B contains both of these assumptions and with them, penalities occur during the early years of operation of the CG/CC system. A net cumulative savings does not occur until after nine years of operation.

The results of the economic analysis for all cases and sensitivity studies analyzed in the original report and in this addendum are summarized and are presented in bar chart form in Figure 1. The results constitute 20-year (1985-2004) total costs for production and the additional costs pertaining to BPH 3 on coal and the CG/CC system where appropriate.

10.9.2.2 Reduced Oil Dependency

Aside from any economic benefit that the CG/CC system may or may not offer, it can help to achieve the important national goal of energy independence by reducing UI's consumption of imported oil.

10.9 Addendum 1 - Economic Analysis (Cont'd.)

Oil savings resulting from installing the CG/CC system, when dispatched against UI load, average approximately 800 thousand barrels per year for low-band load growth and 1 million barrels per year for servable load growth. These oil savings are in addition to the savings that can be achieved by converting BPH 3 to coal.

On a New England dispatch, the CG/CC system may operate at a higher annual capacity factor and thus may displace in excess of 1.6 million barrels of oil annually.

10.9.3 Analysis

As determined in the original study the economics for converting BPH 3 to coal (Case 2) are extremely attractive and coupled with the benefits of reduced oil dependency and diversifying UI's present fuel mix, it is a very appealing project for UI. From an economic standpoint it is much more attractive than installing the CG/CC system. For these reasons it is assumed that BPH 3 is converted to coal in mid-1985 and all savings (or penalties) from the CG/CC system are calculated relative to Case 2 (BPH 3 on HS-Coal) and not the base case with all fossil units burning LS-Oil.

10.9.3.1 Cost Savings

Figure 2 shows the cumulative savings (or penalties) that occur if the CG/CC system is installed (Case 3) for each of the sensitivity studies (A, B and C) and for the assumptions used in the original study. The original study is similar to Sensitivity Study C. The only difference is that in the original study the EFOR of the CG/CC system is 20% and in Sensitivity Study C the EFOR schedule is used.

Penalties relative to Case 2 (BPH 3 on HS-Coal) occur in the initial years of operation of the CG/CC system for all studies made. A cumulative savings does occur at the end of the study period (2004) for all studies except Sensitivity Study C (see Table 1).

10.9 Addendum 1 - Economic Analysis (Cont'd.)

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Addendum 1

Table 1

Total Savings* For CG/CC System
From 1987 to 2004
(Case 2 - Case 3)

Study	Savings (Millions of Dollars)	Percent of Total Production Cost of Case 2
Original	21	0.3
Sensitivity A	418	5.1
Sensitivity B	705	6.4
Sensitivity C	- 31	0.5

*Annual savings are relative to Case 2 (BPH 3 on HS-Coal with Scrubber).

10.9 Addendum 1 - Economic Analysis (Cont'd.)

The cumulative savings for the original study occurs only at the very end of the study period and it is relatively small. In fact, within the accuracy of the analysis it is considered a breakeven proposition. More importantly, throughout most of the study period a new penalty exists. In Sensitivity Studies A and B the cumulative savings at the end of the study period are relatively large. They amount to 5.1% and 6.4%, respectively, of the cumulative production cost of Case 2 (BPH 3 on HS-Coal). A serious concern, however, is that a net penalty results during approximately the first 9 years of operation of the CG/CC system in both Sensitivity Studies A and B. The savings occur in the later years of the study when the uncertainty in the study assumptions is the greatest.

It is clear that the higher escalation of oil price and the higher load growth do not improve the economics to the point where an installation of the CG/CC system is justified in 1987.

The cumulative annual savings (Case 2 - Case 3) for all of the sensitivity studies and the original study are shown again in Figure 3 except this time the fixed charges (return, depreciation and income taxes) for financing the CG/CC system are not included. The expenses of property tax, insurance and O & M associated with the CG/CC system are accounted for in the savings. This presentation shows the potential savings available for attracting capital to finance the installation of the CG/CC system. Table 2 contains a list of the annual savings for each year of the study period (fixed charges not included) for each of the sensitivity studies and the original study.

Steel Point
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Table 2

Annual Savings* Excluding Fixed Charges for CG/CC System
(Case 2 - Case 3)

Thousands of Dollars

Year	Original Study	Sensitivity Studies A	B	C
1985	-	-	-	-
1986	-	-	-	-
1987	17,951	882	2,177	(661)
1988	20,754	15,290	16,288	11,365
1989	20,560	17,600	18,073	12,359
1990	21,690	26,822	23,164	18,877
1991	15,932	21,543	22,589	13,585
1992	18,303	29,390	24,316	18,022
1993	22,578	35,324	30,698	21,613
1994	21,386	36,630	38,504	20,108
1995	18,617	34,801	44,419	17,891
1996	17,695	35,620	48,972	16,720
1997	20,316	43,059	65,538	19,997
1998	28,522	55,974	73,370	26,424
1999	24,588	54,384	84,251	23,412
2000	25,720	60,936	97,968	25,469
2001	34,016	77,003	114,885	32,863
2002	42,779	97,191	130,628	42,050
2003	43,772	104,766	146,517	43,418
2004	42,518	107,401	158,657	41,397
Total	457,697	854,516	1,141,014	404,909

*Annual savings are relative to Case 2 (BPH 3 on HS-Coal) and fixed charges (return, depreciation and income taxes) for financing the CG/CC system are not included. Property tax, insurance and O & M expenses associated with the CG/CC system are included.

10.9.3.2 Oil Savings

Perhaps the most important reason for considering the CG/CC system is to reduce UI's heavy dependence on imported oil.

Figure 4 shows plots of barrels of oil burned for all cases analyzed based on the assumptions of Sensitivity Study B. The barrels of oil burned reflect those that would be burned by UI for own load operation. A portion of the electricity required would be generated by other utilities in the form of outage service (scheduled and unscheduled). Most likely this electricity would be generated with oil-fired capacity.

An estimate of the total barrels of oil burned to meet UI's load is shown in Figure 5. These quantities were determined using a conversion factor of 1.618 barrels of oil per megawatthour to convert the outage service generated electricity to barrels of oil burned.

It is easy to determine from Figure 5 that the CG/CC system saves approximately 1 million barrels of oil per year in addition to the approximately 3 million barrels of oil already saved by converting BPH 3 to coal. These oil savings estimates are for servable load growth. Oil savings estimates for low-band load growth can be determined from Figure 1 in the original report. However, note that the barrels of oil indicated on this plot do not include those burned as a result of outage service, and that the oil saved by the CG/CC system in the early years of the original study is overly optimistic since an EFOR schedule was not used to reflect unit immaturity.

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TOTAL PRODUCTION & ADDITIONAL COSTS*
(1985-2004)

*- Additional Costs For CG/CC and/or Converting BPH 3 to Coal.
1. Fixed Charges (Return, Depreciation Income Tax).
2. Property Taxes
3. Insurance
4. Operation & Maintenance

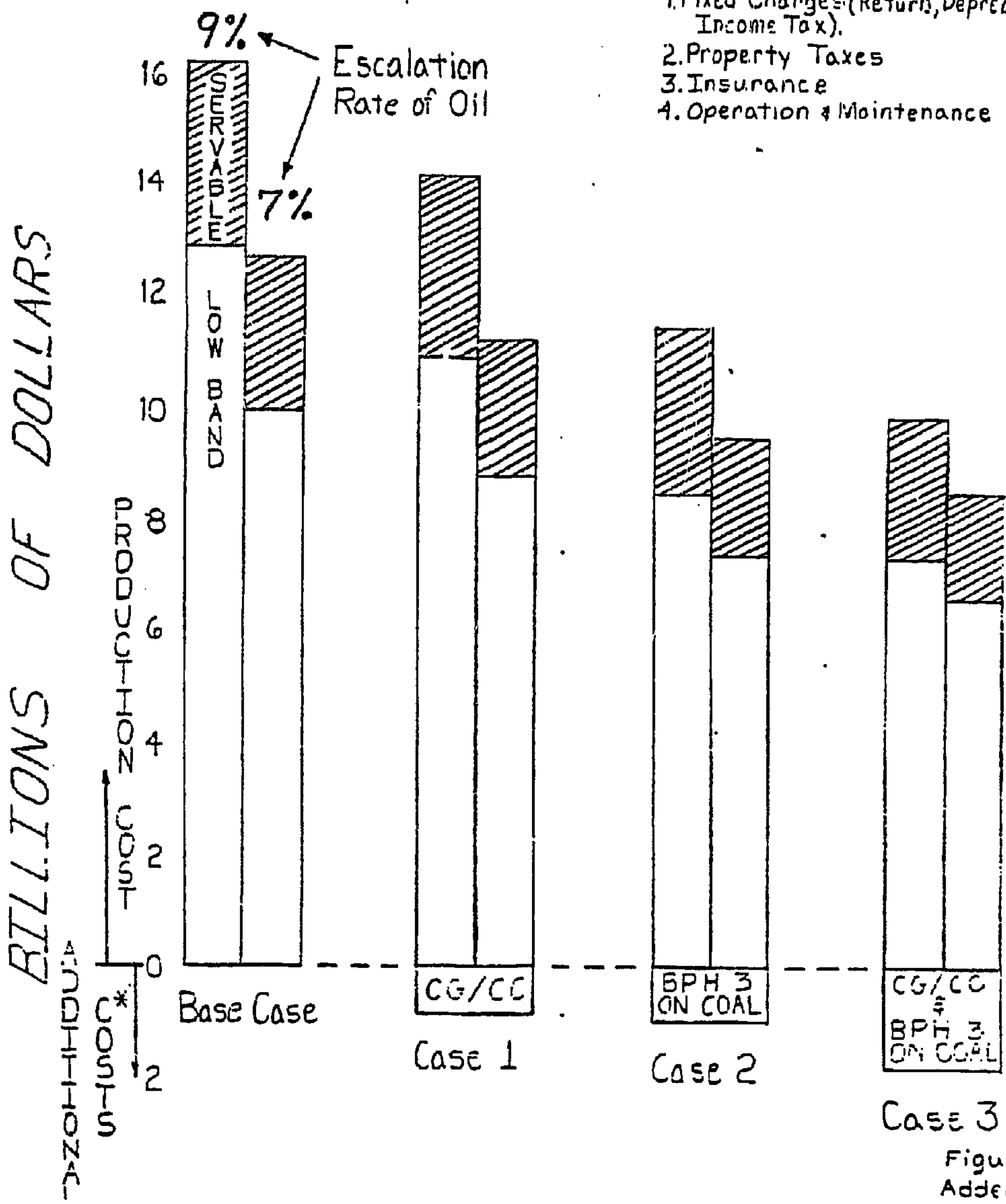

Figure 1
Addendum

Steel Point
Coal Gasification / Combined Cycle Study
Addendum 1
Cumulative Savings for CG/CC System
(Case 3 - Case 2)

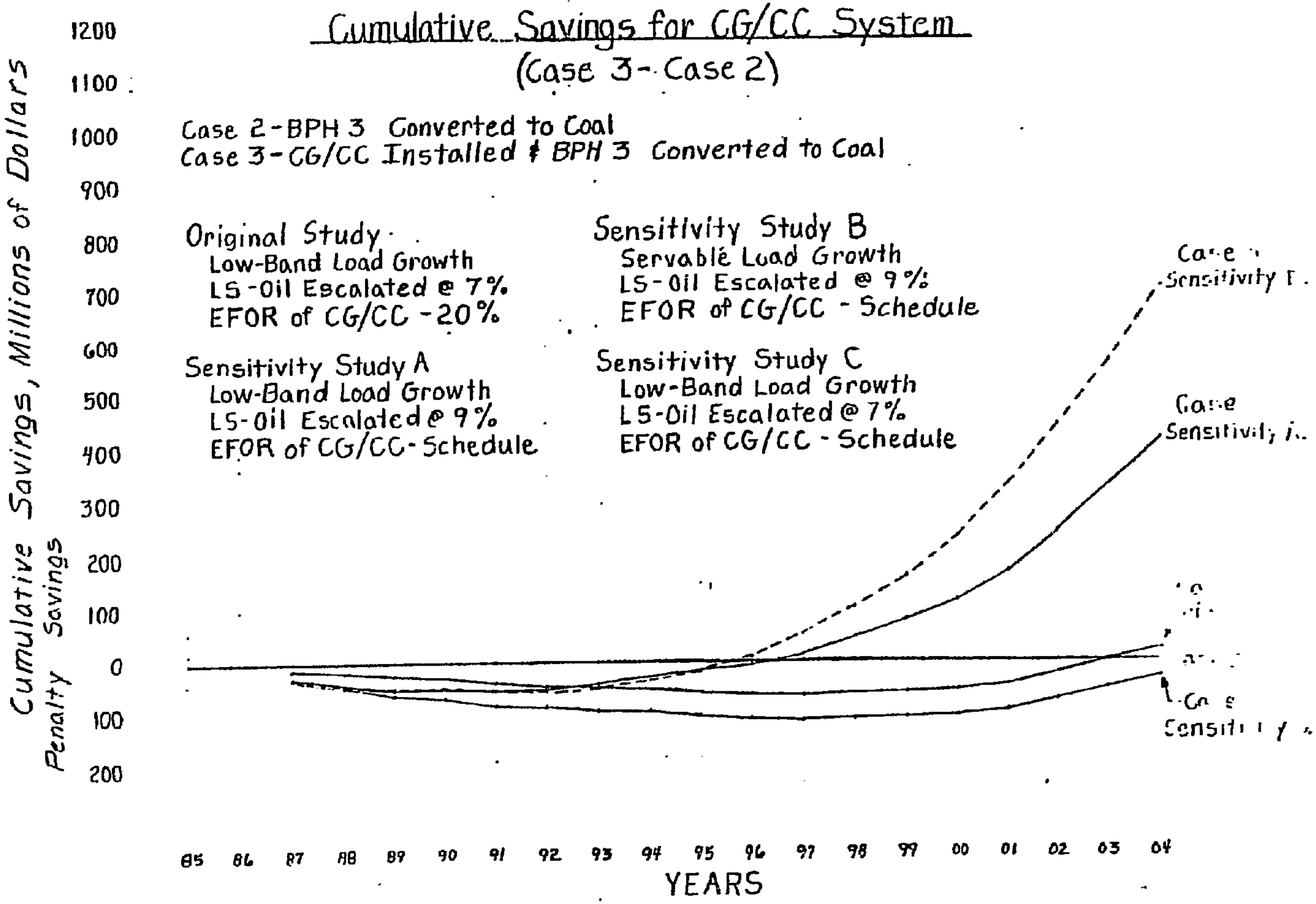

Figure 2 of

Steel Point.
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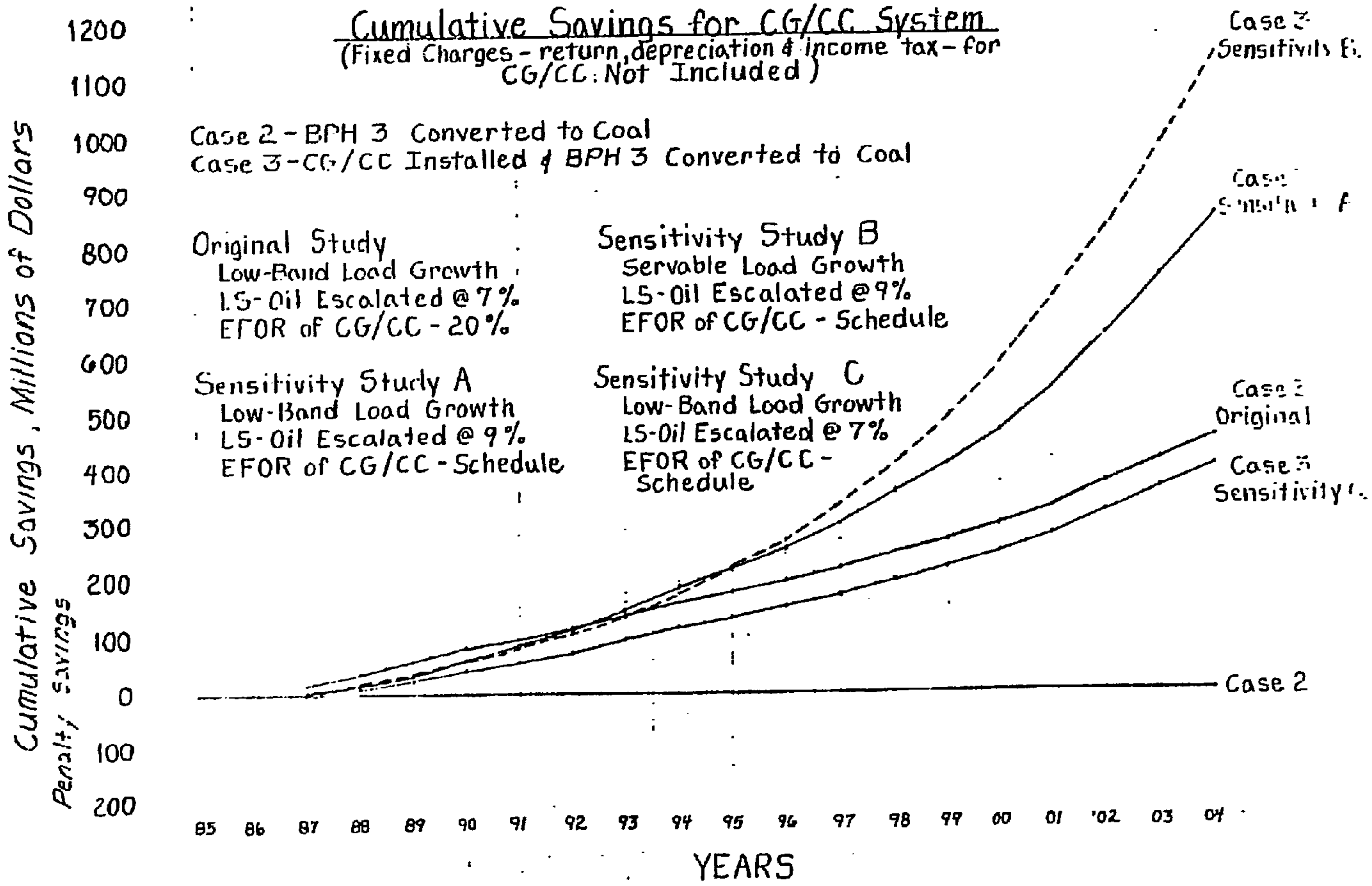

Figure 3 of

Steel Point

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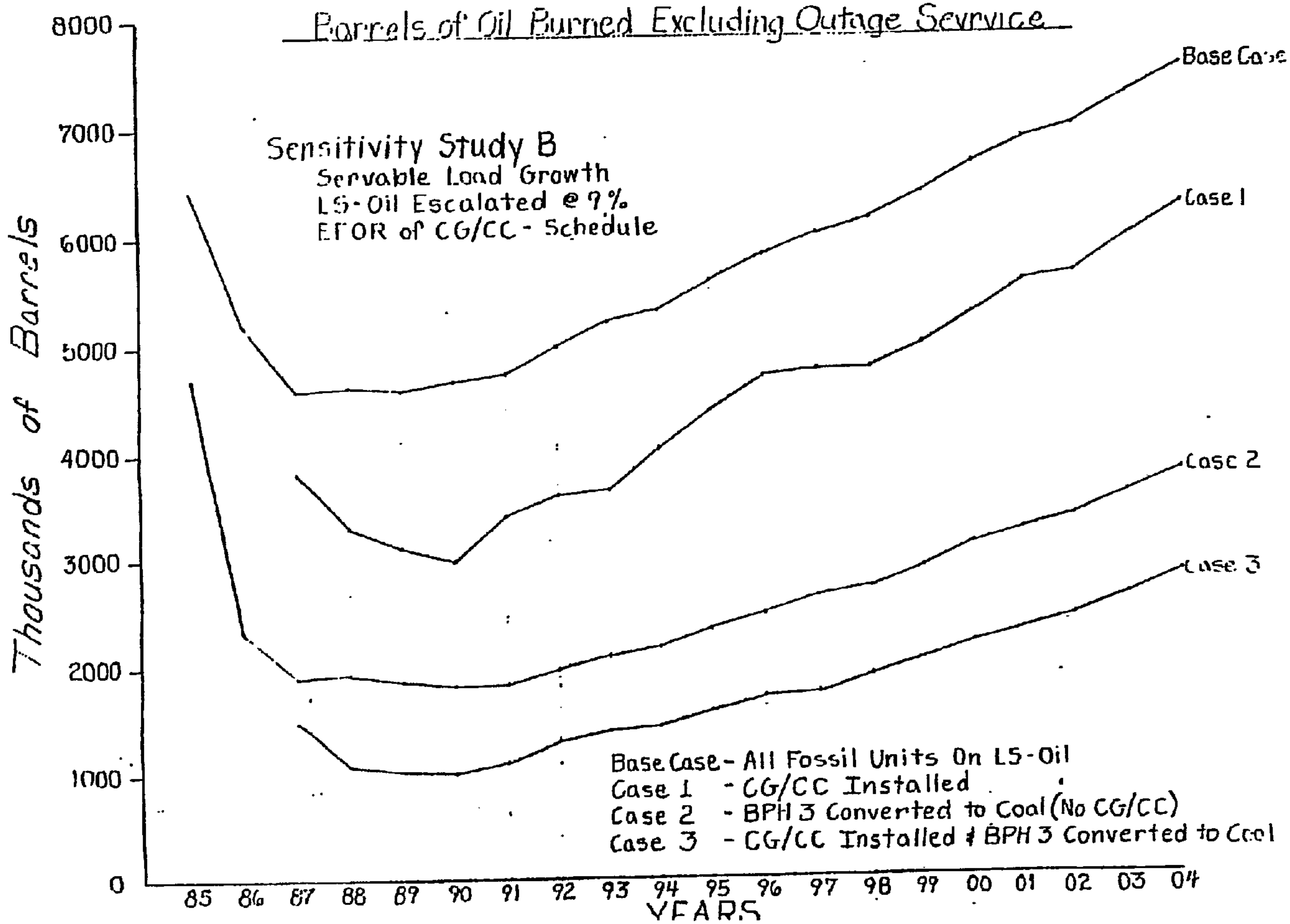

Figure 4 of

Steel Point
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Barrels of Oil Burned Including Outage Service

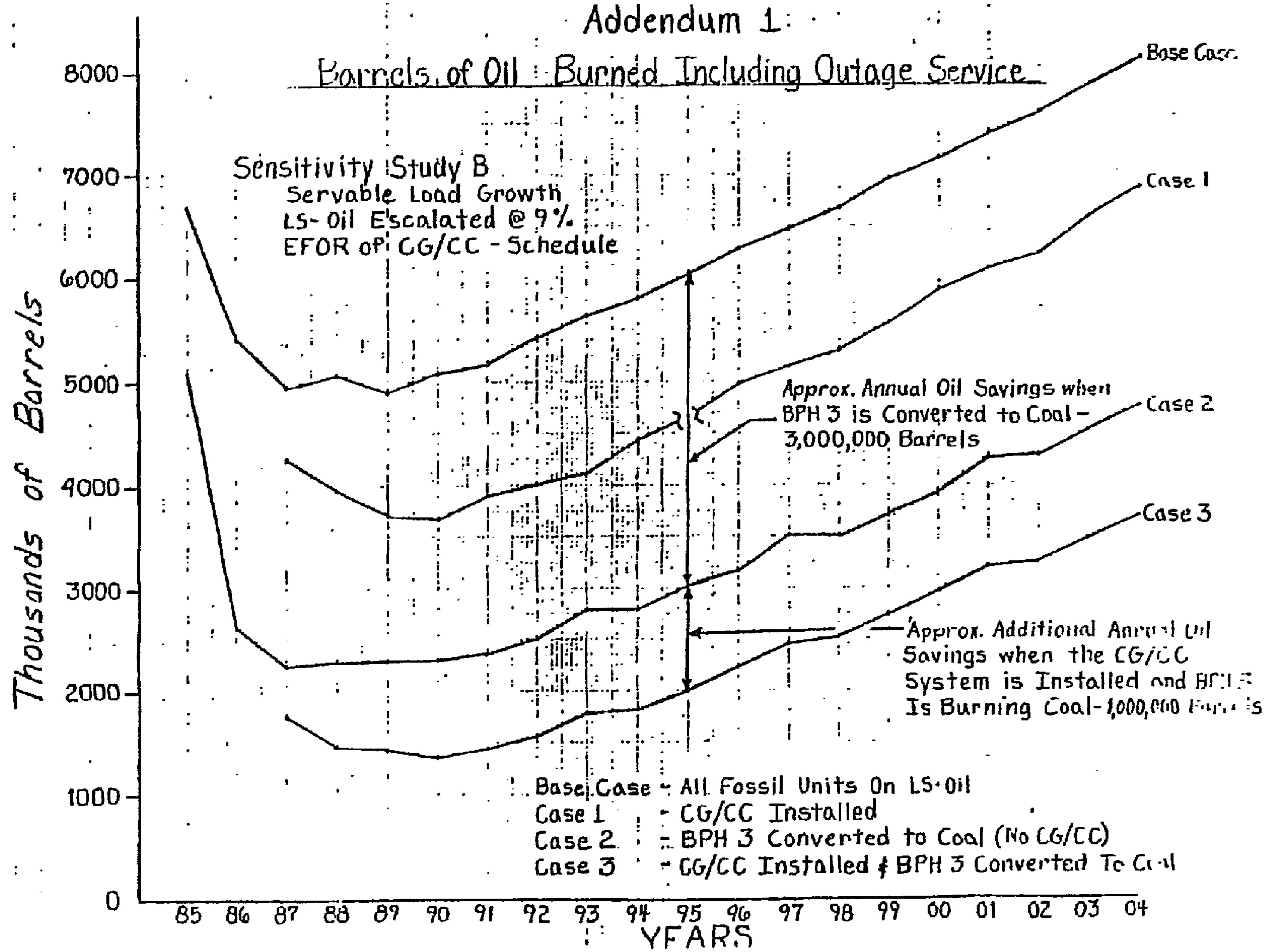

Figure 5 of

11.0 REGULATORY ENVIRONMENT

No permit requirement has been found which would rule out the project. Also, contacts with environmental regulatory agency personnel (in which we avoided reference to the specific project and client) found no attitude or evolving policy which would prevent the project.

The main areas of concern are:

a) the air pollution PSD review process; and

b) disposal of solid wastes from the gasification system.

The PSD review may be affected by:

a) The 1/81 approval of Connecticut's revised State Implemention Plan; and

b) The conversion of Bridgeport Harbor Station's Unit #3 to coal, this reducing the available PSD increment.

Solid waste disposal will be affected by:

a) The lack of local disposal sites;

b) The technology needed to make ash disposal environmentally acceptable.

12.0 GOVERNMENT IMPACT

Government agencies and administrative bodies at the federal and lower levels can do a great deal to improve the economics and encourage the use of low Btu gas in industry. This can be accomplished by the introduction of new laws and regulations and more importantly by modification or elimination of existing laws and regulations.

At the federal level, some of the actions possible are as follows:

- Create a free market in competitive fuels. Artifically low prices for petroleum products and natural gas tend to discourage the use of low Btu gas. As a side effect, they also discourage domestic exploration for gas and oil.

- Restrict imports of oil and natural gas. This action is highly desirable in order to reduce our dependence on foreign, and possibly unstable, supply sources. A reduction in availability of these supplies will create a demand for alternate fuels.

- Create a mechanism to guard against precipitous price drops of foreign fuels. Potential investors in synthetic fuels plants are apprehensive about the fact that foreign oil and gas exporters can reduce their prices substantially and still make a good profit. This could be used as a weapon to destroy competition.

- Pass legislation to ease the installation of coal slurry pipelines. This will tend to increase competition among coal transporters and keep shipping costs low.

- Restrict the use of natural gas and petroleum products. While there are already laws purporting to do this, many exceptions exist, and the federal government is even encouraging increased use of natural gas in some areas.

- Provide economic incentives and reduce financial risk. Many mechanisms are already in place to achieve these goals. These include tax writeoffs, guaranteed purchase contracts, grants, loan guarantees and others. It remains for the government to implement them or make them more easily available.

At state and local levels, some of the helpful actions possible are as follows:

- Keep coal severance taxes at a reasonably low level. Some states have set severance taxes at levels high enough to make coal prices almost non-competitive with other fuels.

12.0 GOVERNMENT IMPACT (Cont'd.)

- Reduce restrictions on land fill or ash disposal sites. Some states and localities restrict siting and transportation to the extent that it is nearly impossible to dispose of coal ash.

- Amend regulations, in the case of utilities, to permit easier and quicker recovery of development and construction costs related to synthetic fuels.

Other actions which can be taken at either the federal level or lower levels may include the following:

- Revise environmental laws and regulations to eliminate unnecessary controls and restrictions. Many environmental regulations are based on reduction of pollutants to the maximum extent practicable, even if the pollutant is not definitely known to be harmful to humans, or if the lower harmful limits are not established. Also the definition of what is "practicable" often is not clear. A warning that health risks may exist should be adequate rather than the imposition of high cost cleanup systems which may not be necessary. Also the owner of the facility should not be exposed to the possibility of retroactive laws or expensive changes to existing installations unless health hazards are clearly established.

- Streamline permitting and approval procedures. Existing procedures can result in delays of plant construction for years. Participation in hearings should be limited and possibilities of nuisance litigation should be eliminated. Time required for action by governing bodies on approvals or permits should be limited and the limitations adhered to.

- Eliminate unnecessary record keeping and reporting requirements. Several recent studies indicate that industry's costs for maintaining government required records and producing reports are extremely high. Government agency costs for reviewing the reports and administration of the program are also high. The necessity for many of these should be evaluated and the requirements eliminated to help industry reduce its cost.

In summary, it is clear that government bodies can do much to reduce costs and eliminate risks for industries which could produce or utilize synthetic fuels such as low Btu gas.

13.0 MANAGEMENT REVIEW

13.1 COMMERCIAL READINESS AND FUTURE DEVELOPMENTS

Introduction

An integrated coal gasification combined cycle system (GCC) is a developing technology. It is a technology which requires no foreseeable extension of existing engineering know-how or theory for implementation and yet has not been demonstrated as an integrated system.

The key word here is integrated. Coal gasification systems have been and are being successfully operated at capacities well beyond that required for this system. Combined cycle systems have of course been well proven with the combustion turbines fired on conventional fuels.

All of the basic building blocks required to build a coal gasification combined cycle system have been successfully demonstrated in commercial operation. An integrated, operating GCC plant, according to the selected design, however, does not exist.

To completely and unarguably demonstrate commercial readiness requires an identical operating plant with a long and highly successful history. This is not the case with a coal gasification combined cycle system. The overall system, therefore, may not be considered completely commercialized.

General

As the system has not been operated on an integrated basis, an initial design objective is to use as much proven technology as possible and to keep the system vis-a-vis integration as simple or manageable as possible. This then minimizes the step from individually proven, commercially available processes to an integrated plant.

That this may be successfully accomplished without inordinate efficiency penalties is shown by the results of this study. Subsequent studies by EPRI indicate that this may have been expected, and that a wide variation in plant configuration and design parameters results in a narrow range of overall system efficiencies. This is particularly important in the present case which, as a repowering application, fixes many parameters normally considered as modifiable.

An additional advantage provided by less interdependence between systems and components is the possibility of staged implementation. This may be important in a repowering case where existing operations must be affected as little as possible.

13.1 COMMERCIAL READINESS AND FUTURE DEVELOPMENTS (Cont'd.)

The system is basically a conventional combined cycle system, i.e., a combustion turbine with a heat recovery steam generator and condensing turbine/generator bottoming cycle augmented by additional steam from the gasification system. As such, the system incorporates a maximum of commercially available equipment and controls.

Other systems have been proposed for the design of integrated GCC plants which do not employ condensing turbines. These cycles are conceptual and like the proposed cycle exist on paper only. Most, however, have an additional drawback. Unlike the proposed design, the power generating portion of the cycle has not been commercially demonstrated. In addition, the design of these alternate cycles depends heavily on advanced hardware development to obtain efficiencies competitive with the standard condensing cycle.

The major thrust for development of the alternate cycles is not projected efficiency increase, but is reduced capital costs. The capital costs eliminated are those associated with the condensing turbine/generator portion of the cycle. As the condensing turbine/generators are existing for this study, it is difficult to reduce capital costs by not employing them in the cycle.

In a repowering case such as the Steel Point Station, therefore, the combined cycle/condensing turbine design is preferred in relation to commercial readiness, with little chance of significant efficiency penalties.

Other repowering cycle configurations are possible and given other plant sites perhaps even desirable. For the Steel Point Station, however, the steam condition and size of the existing turbines set the basic system configuration and parameters.

System Design Parameters

A discussion of GCC system parameters can be very misleading as there is a high degree of interdependence between the variables. Trends are reasonably clear although difficult to quantify. As much of the discussion involves efficiency, it is important at this time to emphasize that an increase in efficiency is not necessarily related either to a lower cost of electricity or to increased reliability.

Improvements in efficiency available with reheat, and higher pressure and temperature steam conditions, have been estimated between 1.5 and 3.0%. For reference, these improvements are for systems that changed from 800 psia/800°F to 2400 psia/1000°F/1000°F and 1800 psia/850°F to 2400 psia/1000°F/1000°F respectively. Although significant, it is not felt that these changes would counter-balance the economic advantage of employing the existing turbine/generator system.

13.1 COMMERCIAL READINESS AND FUTURE DEVELOMPENTS (Cont'd.)

Another major design parameter that could impact on the design of the Steel Point Station system is the gasifier pressure. By raising gasifier pressure to 600 to 1200 psi an expander power recovery system is possible. Such a system has been estimated to add 0.5 to 1.5% in efficiency for oxygen blown systems. In those systems the expander can be conveniently employed for driving the oxygen plant air compressor. In an air blown system this is, of course, not possible. Although power could be generated in an air blown system, the improvement in efficiency may not be comparable with that in an oxygen blown system.

The addition of an expander system is questionable at this time. The use of an expander has not been demonstrated in this service, and the expander itself is not available. In addition, the system becomes more complex and inter-related, thereby increasing the problems of integration and the departure from a commercially available system.

Note that there is no indication that an oxygen blown system has an advantage in GCC systems. Most studies in fact indicate either equal efficiencies or an advantage for the air blown systems.

The efficiency increases associated with changed steam conditions when combined with those associated with an expander do not result in a range of 2 to 4.5% but rather a range of from 3 to 3.5%. This is an indication of the problem of attempting a parametric study with highly interdependent parameters.

Gas turbine inlet temperature is a significant variable and will be discussed below in context of the equipment. Other system parameters also have an affect on the design, however, these parameters do not affect the basic system configuration or equipment selection to the extent of those mentioned above.

Hypothetically it is possible to design a GCC system with reheat, 1000°F steam temperature, 1200 psi gasifier pressure, and a hot gas expander. Such a plant could theoretically have an 8 to 10% better heat rate than the Steel Point Station repowering. However, with no existing equipment, development required for major hardware, and more time required for development and construction, this hypothetical plant would not necessarily produce a lower cost of electricity than the Steel Point Station repowering. This hypothetical plant would require using the most extreme design conditions and advanced equipment available at this time.

A moderate design basis is more likely to be employed, even in the design of a grass roots case where there are no restraints due to existing equipment. The heat rate reasonably expected for a more moderate system would be estimated in the range of 4 to 6% improvement.

13.1 <u>COMMERCIAL READINESS AND FUTURE DEVELOPMENTS</u> (Cont'd.)

One future development which might effect the competitive position of the Steel Point Station design is the development of a hot gas desulfurization system. Hot gas desulfurization systems, however, are still very developmental and the improvement in cycle efficiency is not well determined. For some systems such as a Lurgi dry ash system the impact could be very significant. For the Westinghouse gasifier used in the Steel Point Station design, however, the improvement in efficiency is expected to be much lower. In addition the implementation of these systems may be hindered by requirements for ammonia removal, alkali metals removal, very efficient particulate removal, etc.

<u>Equipment</u>

The gasifier is a good example of the problem of balancing current technology against obsolescence. Lurgi dry ash gasifiers are considered by many people as the most commercially developed gasifier available. Upon closer examination, however, specific questions regarding Lurgi dry ash operation are as difficult to answer as those of the so called "second generation" gasifiers. For instance, Lurgi's experience with eastern highly caking coals as required for this study is minimal, consisting of experimental runs of about 24 hours duration. This lack of experience with the feedstock combined with low efficiency; high output of tars, oils, phenols, HCN, NH_3, and coal fines; and a reported 85% on-stream time seriously mitigate against selection of a Lurgi dry ash system when compared against other technology.

The low efficiency of the Lurgi gasifier is inherent in a system that has a low gas exit temperature and partially depends upon directly quenching the product gas without heat recovery because of the highly contaminated product gas. The much higher efficiency of the Westinghouse gasifier, due to its higher exit temperature and its tar free product gas, tends to obsolete the Lurgi dry ash system for coal gasification combined cycle applications.

Unlike Lurgi, the Westinghouse gasifier has been well tested on highly caking eastern coals such as Pittsburgh No. 8 but at a 15 TPD rate. The probability of problems in the scale up from a 15 TPD to a 1800 TPD Westinghouse gasifier must be balanced against a 10 to 15% efficiency increase in the gasifier.

Along with the gasifier the state of the development of the hot gas cooler must be examined. Although equipment for similar duty has been designed and operated in Germany at a 15 MW size, these heat exchangers are not off the shelf items. The design of the gas cooler for the Steel Point Station repowering is not as difficult, however, as that required for some systems, 1800 to 2400°F and 600 to 1200 psi for the Texaco gasifier, for instance.

13.1 COMMERCIAL READINESS AND FUTURE DEVELOPMENTS (Cont'd.)

The inclusion of the superheating section must be considered further. This is an area ignored by many of the design studies performed to date. At part load the temperature of the gas turbine exhaust decays below that necessary for superheating of the steam. The final superheater, therefore, for the Steel Point Station repowering was located in the gas cooler. The design of the gas cooler could be simplified by eliminating the superheating section, perhaps via supplemental firing in the heat recovery steam generator (HRSG).

The Steel Point Station repowering employed a commercially available gas turbine design with a fuel gas inlet of 500°F and 300 psig. Exhaust gas at approximately 1030°F is employed in an HRSG to generate 920 psig/825°F steam and to preheat boiler feedwater to 500°F. The specific design requirements of the HRSG are unique to this design, and therefore, the unit is not of standard design. Although not available off the shelf as part of a packaged design, fabrication of the HRSG is well within the present state of the art.

As the selected combustion turbine is state of the art and commercially available, the impact of a high temperature gas turbine must be addressed. At first glance, studies on the subject have produced widely scattered results. Estimates of the improvement in system efficiency associated with higher firing temperatures have ranged from 2% to 10%. This is because the impact of higher firing temperatures is higher in systems with low overall efficiency. One study indicated that with an increase from 1950°F to 2600°F, efficiency increased 9% from approximately 30 to 39%. When starting with a 39% efficiency, however, the efficiency increase is 4% to 43%. The 9% difference in starting efficiency being related to changes in steam conditions, reheat and gasifier pressure.

For the repowering design at Steel Point Station a change in firing temperature to 2400°F would be expected to produce increases in efficiency of from 2 to 2.5%.

Commercial Warranties

As most of the basic building blocks used in the design of this GCC system have been proved in commercial operation, commercial warranties should be available for these systems. These would be the new coal handling, drying and sizing system; coal storage bins; ammonia removal and partial Phosam; Selexol, Claus and SCOT systems; combustion gas turbine; heat recovery steam generator; water demineralization and cooling systems, including pumps; flare systems and air compressors and drying systems. It is also thought that most, if not all, of the waste water treatment system could be covered by commercial warranties.

The Westinghouse coal gasification system has not yet been proven in commercial service and warranties for this system have not been developed at this time.

13.1 COMMERCIAL READINESS AND FUTURE DEVELOPMENTS (Cont'd.)

The hot gas cooler is a developmental piece of equipment and commercial warranties on this item would probably be limited to workmanship only.

14.0 RECOMMENDATIONS

The conclusions of this preliminary study effort demonstrate that unique opportunities exist for a number of different but interested groups to attain desired goals. The study is also realistic in identifying constraints that exist in the form of possible regulatory impediments, financing requirements and the relative untried and unproven nature of the system proposed. The latter constraint is of particular significance when considering the estimated project investment of $160 million in 1987 dollars.

Though there have been demonstration projects with respect to the individual components proposed in the project, experience with an integrated package operating as an electric generating plant subject to daily dispatch is essentially lacking. The concept is very attractive though not only for re-powering applications, as analyzed herein, but also for wider application to new and larger electric generating facilities. Because of the lack of operating experience with such facilities and because it is well recognized that any new technology involves a learning curve, there will be a natural reluctance for the industry to commit to large electric generating facilities, absent proven experience on at least a smaller scale. The industry can only reasonably develop such technology and experience through progressive steps starting with the construction of smaller "no or low risk" facilities leading eventually to larger facilities fully supported by the operating utilities.

UI recognizes that Steel Point Station may be uniquely suited to be part of a demonstration effort designed to accumulate such operating experience on a Combined Cycle Coal Gasification electric generating facility. It also recognizes that this facility may have further potential as part of a co-generation district heating system now under study for the City of Bridgeport.

Despite the positive aspects listed above, the level of risk associated with such a project and the fact that a need does not presently exist for the additional capacity that would be created by this system, are cause for considerable concern regarding the prospects for this program moving forward. The situation is further compounded by the uncertainties associated with future load growth and the resultant point in time that the facility would be economically justified assuming support of fixed and variable costs.

Given these constraints and uncertainties combined with substantial capital requirements for UI's nuclear construction program over the next several years, UI finds itself unable to commit financially to such a project at this time.

14.0 RECOMMENDATIONS (Cont'd.)

However, recognizing that there may be ancillary benefits in the broader context for such a project, UI is anxious to cooperate to the extent possible consistent with its anticipated long-term needs. Toward this end UI would be willing to consider further the desirability of making available the facilities at Steel Point Station for conversion to a coal gasification combined cycle system if adequate governmental, regulatory and financial support for such a project were forthcoming.

Some suggestions as to how this program could possibly be moved forward include:

14.1 The required front-end capital costs would be made availalbe in the form of government grants and/or vendor investments adequate to complete the installation of the required facilities.

14.2 Other electric utilities from the New England Region would support the project and the capacity that would be available from this system consistent with their own needs for additional generation. This support would be in the form of providing the required front-end capital costs.

Such a program, developed around UI's Steel Point site and equipment with financing being provided by others who are also interested and who would benefit from the operation and testing of such a system and its components is, we believe, a reasonable scenario and one which could allow this project to move ahead. It acknowledtes the significant potential for the yet unproven coal gasification/combined cycle technology for electric generation while at the same time recognizes and accounts for some of the previously identified uncertainties and/or constraints associated with such a project. It also makes good use of a site and existing equipment which appear to be ideally suited for such a program and which would contribute significantly to the viability of the project.

If sufficient expression of interest in furthering the project results from this study, there are several areas in which additional work would be required. These include:

14.3 Details of the nature of support to be offered would have to be developed.

14.4 Priorities for the allocation of any savings (or penalties) associated with the construction and operation of the facilities would have to be established.

14.5 Final agreements outlining the role of each participant would be executed.

14.0 RECOMMENDATIONS (Cont'd.)

We could then proceed with the following:

14.6 Detailed designs, cost estimates and schedules would be developed consistent with UI's needs and those of any other participants.

14.7 Construction and operation of the facility would be initiated.

With a cooperative effort such as is suggested above, it is reasonable to assume that this project could move ahead.

If such a scenario did develop, there are also several areas in the basic system design that should receive further review and study. These include the following:

14.8 The design of the gas cooler section should be reviewed with an attempt to simplify the duty. Particularly, the possibilities of removing the superheating section should be investigated.

14.9 The pinch points of all heat exchangers should be scrutinized to determine if improvements in efficiency or economy can be realized.

14.10 The addition of a resaturator to the system should be analyzed in regard to gas turbine operation.

It has been recognized that modifications in these and perhaps other areas could result in simplifying the system and further improve its flexibility, reliability and/or efficiency.

Although a number of different scenarios were evaluated in which different combinations of fuels were burned in other units in the system, the relative degree of difficulty in disposing of wastes resulting from the various sources was not fully investigated. On the surface, however, there appear to be some possible advantages to the form in which the waste products resulting from the coal gasification process are produced which may favor such a system over other alternatives in this regard. This is another area that should be addressed more thoroughly if sufficient interest is expressed in furthering the project.

15.0 SCHEDULE FOR BUILDING PROPOSED PLANT

It is envisioned that the scope of the work required to engineer, design, procure equipment, construct and start-up the proposed combined cycle repowering of United Illuminating's Steel Point Station will require approximately 4.25 years to complete. A bar chart showing the major activities and their duration is shown in Fig. 1-15, Project Schedule.

Dravo Engineers and Constructors

APPENDIX A

EVALUATION OF COAL GASIFIERS FOR USE
WITH A COMBINED CYCLE SYSTEM
FOR UNITED ILLUMINATING COMPANY

Dravo Contract CPD-7073

November 14, 1979

Reference: DOE Grant FG01-79RA20224

I. Introduction

One of the major areas of study under the DOE grant to United Illuminating (UI) is the feasibility of coal gasification for electric power generation. In particular, a study will be made on repowering UI's 35 MW steam driven generating Unit #11 at the Steel Point plant in Bridgeport, Connecticut.

It is visualized that a coal gasification system will be added to produce a fuel gas which will be burned in a new gas turbine, of approximately 65 MW rating, and the exit gas will be used to produce steam for the above mentioned 35 MW unit. It is the purpose of this report to discuss gasifier candidates and recommend one to serve as a basis for the study.

II. Major Constraints and Considerations

A. Coal

It is desirable to select a gasifier which can utilize the coal currently specified for UI's existing coal fired boiler. The specifications for this coal include the following:

Ash fusion temperature	2000-2400°F
Sulfur	4% maximum
Ash	13% maximum
Free Swell Index	No limitation

Since there is no limitation on FSI, we must assume that the gasifier should have the flexibility of utilizing coals with high FSI.

B. Gas Turbine

Fuel gas to the gas turbine must have certain characteristics as follows:

1. The Btu value is not limited on the high side except that a temperature of 1800°F may not be exceeded in turbine components.

2. The Btu value of the gas may be as low as 100 Btu/SCF HHV but preferably not lower.

3. A very low level of particulates is required in the gas. In particular, alkali metal content must be very low.

4. Fuel gas pressure should preferably not be below about 150 psig.

II. Major Constraints and Considerations (Cont'd.)

C. Other Considerations

The system must have a high degree of reliability.

III. Preliminary Screen

In order to achieve a fuel gas pressure of 150 psig, one may generate gas at the required pressure or one may generate at a low or near atmospheric pressure and compress gas to the required pressure. Numerous studies by Dravo and others indicate that it is more economical to generate gas at pressure. A few studies indicate that there is no significant economic advantage either way, but in no case has gas generation at a low pressure been found more economical when the product gas is required at pressure. Consequently, gasifiers have been limited to pressure types in this evaluation.

Low Btu gasifiers produce fuel gas with a heating value from about 125 to 160 Btu/SCF. Since medium Btu gasifiers are inherently more expensive than lower Btu gasifiers, only air blown gasifiers are considered in this evaluation.

Using the above limitations and considering only processes which have been operated on at least pilot scale of 5 tons/day, the following gasifiers appear suitable and worthy of further consideration:

Babcock & Wilcox
Lurgi
Texaco
U-Gas
Westinghouse

IV. Gasifier Descriptions and Data

A. Babcock & Wilcox - Entrained Bed

Atmospheric pressure version of gasifier has been commercially operated for continuous runs of 2 to 3 months at a capacity of 400 tons/day. A pressurized version has been operated in small scale equipment at 450 psig. Only slag and sulfur are byproducts. Export high pressure steam is produced. Thermal efficiency is estimated at 65-70%. Turndown is 3 or 4 to 1.

B. Lurgi - Fixed Bed

Commercial dry bottom Lurgi's operate at about 85% on-stream time at capacities of 500 to 900 tons/day of non-caking coal. Pressures range from 200 to 450 psig. Experimental runs on caking coals have been only about 24 hours long. Byproducts include HCN, tars, NH_3, oils, phenols, ash, sulfur, and possibly coal fines.

IV. Gasifier Descriptions and Data (Cont'd.)

B. Lurgi - Fixed Bed (Cont'd.)

Thermal efficiency is estimated at 66-70% and turndown is 3 or 4 to 1. A combined cycle system utilizing Lurgi has been in operation for several years but on-stream time has not always been satisfactory.

C. Texaco - Entrained Bed

A demonstration scale gasifier has been operated in West Germany at 6 tons/hour at pressures up to 650 psig. Reliability is unknown. Other features are similar to the Babcock & Wilcox gasifier.

D. U-Gas - Fluid Bed

The process has been operated at a pilot scale of 6 tons/day up to a pressure of 50 psig. Caking coals can be processed only if a pretreatment section is added. Thermal efficiency is reported at 68%. The longest recorded run lasted 10 days. Turndown of 2 or 3 to 1 can be expected. Some NH_3 and HCN are formed in the gas. There are no liquid byproducts.

E. Westinghouse - Fluid Bed

The gasifier has been operated at a rate of 15 tons/day at 150 psig. The longest recorded run has been 300 hours. Thermal efficiency of 79 to 82% has been estimated. Turndown of 2 or 3 to 1 can be expected. Liquid byproducts are nearly negligible.

V. Gasifier Recommendation

The gasifier systems have been judged on a partially subjective basis as shown in the attached chart. While economics are not directly included in the evaluation, they are heavily reflected in thermal efficiency. Two independent ratings tend to favor the Westinghouse process by a very narrow margin. The Westinghouse gasifier is representative of the type of gasifier suitable for combined cycle use, having been developed specifically for that use. It shows promise of additional improvement and data is easily available from the developers. We, therefore, recommend the selection of the Westinghouse gasifier for the study.

PROCESS SELECTION CHART

	Relative Weight	Babcock & Wilcox	Lurgi-Dry Ash	Texaco	U-Gas	Westinghouse
Degree of Development	20	17	20	15	15	15
Reliability	20	13	18	12	10	12
Thermal Efficiency	20	10	10	10	10	20
Operability	10	8	7	7	5	6
Environmental	10	10	5	10	9	[illegible]
Byproducts	5	5	1	5	3	3
Total		63	61	59	52	64