SECTION 10

MAJOR EQUIPMENT SUMMARY

The major items of equipment in all nonproprietary units are listed in Tables 10-1 through 10-15 of this section.

Items of equipment listed are shown with dimensions and/or capacity; also materials of construction in most cases. Note that the size or capacity shown is the design requirements for the most demanding condition resulting from use of feed coal with a range of compositions. These capacity ratings will in most cases exceed the requirements for conditions shown on the process flowsheets which, on all drawings, describe the typical case.

Units 13-2, 14-2, 16-1, and 16-2 are proprietary processes for which equipment is not listed.

Table 10-1 - Major Equipment Summary
Unit 10-1 - Coal Mine

Item No.	Description	Size
10-0201-01 through 12	Portable Light Towers	
10-0801-01, 02, 03	Mine Pumping Systems	
10-1001-01, 02, 03	Hydraulic Cranes	15 ton
10-1002-01, 02, 03	Mobil Cranes	50 ton
10-1801-01, 02, 03	Screw Compressors	600 cu ft
10-2801-01 through 12	Rotary Blasthole Drills	
10-2802-01, 02, 03	Track Drills	
10-3501-01, 02, 03	Stripping Shovels	140 cu yd
10-3502-01, 02, 03	Holland Loaders	
10-3503-01, 02, 03	DD9Gs	
10-3504-01, 02, 03	Coal Shovels	12 cu yd
10-3505-01, 02, 03	Front-End Loaders	10 cu yd
10-3601-01 through 15	Coal Haulers	120 ton
10-3602-01 through 06	D-9s with Ripper & Dozer	
10-3603-01, 02, 03	D-8s with Dozer	
10-3604-01, 02, 03	Wheel Dozer	
10-3605-01, 02, 03	Grader	
10-3606-01, 02, 03	Lube-Fuel Trucks	
10-3607-01, 02, 03	Water Sprinkler Trucks	
10-3608-01, 02, 03	ANFO Trucks	
10-3609-01, 02, 03	Trucks	3 ton
10-3610-01, 02, 03	Trucks	5 ton
10-3611-01, 02, 03	Lowboy with Tractor	50 ton
10-3612-01	Passenger Bus	40 passenger
10-3613-01	Fire Truck	
10-3614-01 through 15	Pickup Trucks	
10-3615-01 through 05	Flat Bed Trucks	3 ton
10-3616-01 through 05	Flat Bed Trucks	5 ton

Table 10-2 - Major Equipment Summary
Unit 10-2 - Coal Preparation

Item No.	Description	Size	Design Press/Temp	Material/ Remarks
Pumps				
10-1551-01, 02, 03	Waste Dewatering Screen Undersize Pumps	300 gpm ea 15 ft TDH	amb	CI Rubber Lined
10-1552-01 through 04	Clean Coal Fines Pumps	4,000 gpm ea 100 ft TDH	amb	CI Rubber Lined
10-1553-01, 02, 03	Cyclone Feed Pumps	2,200 gpm ea 55 ft TDH	amb	CI Rubber Lined
10-1554-01, 02, 03	Cyclone Feed Pumps	2,200 gpm ea 55 ft TDH	amb	CI Rubber Lined
10-1555-01, 02	Tailings Pumps	200 gpm ea 50 ft TDH	amb	CI Rubber Lined
10-1556-01, 02	Recycle Water Pumps	5,000 gpm ea 150 ft TDH	amb	CI Rubber Lined
10-1557-01, 02	Gland Water Pumps	50 gpm ea 150 ft TDH	amb	CI Rubber Lined
Other Major Equipment				
10-1951	Recycle Water Tank	200,000 gal	Atmos/amb	CS
10-1952	Head Tank	100,000 gal	Atmos/amb	CS
10-2051-01, 02	Reciprocating Plate Feeders	750 TPH	Atmos/amb	CS/ABR Res Wear P1
10-2052	54" ROM Coal Conveyor	1,500 TPH	Atmos/amb	CS/Rayon Belting
10-2053	54" Coal Conveyor	1,300 TPH	Atmos/amb	CS/Rayon Belting
10-2054	54" Rev Conveyor	1,300 TPH	Atmos/amb	CS/Rayon Belting
10-2055-01 through 12	Vibrating Feeders	200 TPH ea	Atmos/amb	CS/ABR Res Stl Wear P1
10-2056-01, 02	36" Jig Feed Conveyors	600 TPH ea	Atmos/amb	CS/Rayon Belting
10-2057-01, 02	Middling Recycle Conveyors	14 TPH ea	Atmos/amb	CS/Rayon Belting

Table 10-2 (Contd)

Item No.	Description	Size	Design Press/Temp	Material/ Remarks
10-2058-01, 02	Middling Recycle Conveyors	14 TPH ea	Atmos/amb	CS/Rayon Belting
10-2059	Clean Coal Conveyor No. 1	800 TPH	Atmos/amb	CS/Rayon Belting
10-2060	Clean Coal Conveyor No. 2	800 TPH	Atmos/amb	CS/ABR Res Stl Wear Pl
10-2061-01 through 12	Vibrating Feeders	135 TPH ea	Atmos/amb	CS/ABR Res Stl Wear Pl
10-2062	Clean Coal Collecting Conveyor	800 TPH	Atmos/amb	CS/Rayon Belting
10-2063	Clean Coal Tripper Conveyor	800 TPH	Atmos/amb	CS/Rayon Belting
10-2064-01 through 06	Belt Feeders	135 TPH ea	Atmos/amb	CS/Rayon Belting
10-2065	Drying and Classification Feed Belt Conveyor	2,500 TPH	Atmos/amb	CS/Rayon Belting
10-2066-01, 02	Waste Conveyors	45 TPH ea	Atmos/amb	CS/Rayon Belting
10-2067	Waste Conveyor	90 TPH	Atmos/amb	CS/Rayon Belting
10-2068	Waste Conveyor	150 TPH	Atmos/amb	CS/Rayon Belting
10-2069	Centrifuge Cake Conveyor	310 TPH	Atmos/amb	CS/Rayon Belting
10-2070-01 through 03	Belt Feeders	105 TPH ea	Atmos/amb	CS
10-2071-01	Transfer Belt Conveyor to Stockpile	1,300 TPH	Atmos/amb	CS/Rayon Belting
10-2072-01	Transfer Belt Conveyor from Stockpile	1,300 TPH	Atmos/amb	CS/Rayon Belting
10-2151-01, 02	2-Stage, 4 Roll Crushers	7 TPH ea	Atmos/amb	*Frame: CS Frame Liners: C Manganese Stl Breaker Plate: CS Roll Shell: Stl Casting Roll Shaft: Forged Stl

Table 10-2 (Contd)

Item No.	Description	Size	Design Press/Temp	Material/ Remarks
10-2152-01 through 06	Coal Crushers	800 TPH ea	Atmos/amb	CS Alloy Stl
10-2251	10' x 20' Rotary Coal Breaker	1,500 TPH	Atmos/amb	CS Alloy Stl Mar Alloy Stl
10-2252-01 through 04	Centrifuges	500 gpm ea	Atmos/amb	CS Alloy Stl
10-2253-01, 02	Baum Type Coal Jigs	180 f^2, 600 TPH ea	Atmos/amb	CS Alloy St Cor Res Liner
10-2254	75' Dia Thickener	5,000 gpm	Atmos/amb	CS Alloy Stl Concr Constr
10-2651	ROM Hopper	300 tons	Atmos/amb	CS Alloy Stl Wear Pl
10-2652-01, 02	Unwashed Coal Silos	10,000 tons ea	Atmos/amb	CS Alloy Stl Wear Pl
10-2653-01, 02	Clean Coal Silos	10,000 tons ea	Atmos/amb	CS Alloy Stl Wear Pl
10-2654	Clean Coal Crusher Feed Bin	1,500 tons	Atmos/amb	CS
10-2751	8' x 16' Scalping Screen	1,300 TPH	Atmos/amb	CS Alloy Stl
10-2752-01 through 04	8' x 16' DD Clean Coal Screens	300 TPH ea	Atmos/amb	CS Alloy Stl, SS
10-2753-01, 02	4' x 6' DD Middling Screens	11 TPH ea	Atmos/amb	CS Alloy Stl, SS
10-2754-01, 02	Waste Dewatering Screens	45 TPH ea	Atmos/amb	CS Alloy Stl, SS
10-2755-01 through 16	14" Dia Cyclones	15,000 gpm total	30 psi/amb	CS Cor Res Liner
10-2756-01 through 04	6' Stationary Cross-Flow Screens	100 TPH ea	Atmos/amb	CS SS
10-2757-01 through 04	7' x 16' Single Deck Screens	80 TPH ea	Atmos/amb	CS SS
10-2758-01 through 24	12" Dia Cyclones	4,300 gpm total	25 psi/amb	CS Cor Res Liner
10-2760-01 through 04	3' Stationary Cross-Flow Screens	3 TPH ea	25 psi/amb	CS SS

Table 10-2 (Contd)

Item No.	Description	Size	Design Press/Temp	Material/ Remarks
10-2851	Belt Scale	2,000 TPH	Atmos/amb	CS
10-2852	Tramp Iron Magnet	54" wide	Atmos/amb	CS Al Alloy SS
10-2853-01, 02	Tramp Metal Detector		Atmos/amb	CS Alloy Stl
10-2854-01, 02	Belt Scales	750 TPH ea	Atmos/amb	CS
10-2855-01, 02	Automatic Belt Samplers		Atmos/amb	CS Alloy Stl
10-2856	Weigh Scale	1,000 TPH		CS
10-3601-01	Rail Mounted Stacker/ Reclaimer	2,250 TPH Stacking	Atmos/amb	Mfg Standard
10-3602-01 02	Diesel Engine Bull-dozer	Heavy Duty	Atmos/amb	Mfg Standard

Table 10-3 - Major Equipment Summary
Unit 11-1 - Pyrolysis and Gasification

Item No.	Description	Size	Design Press/Temp	Material/ Remarks
		Columns		
11-1101-01 through 09	Raw Low-Btu Fuel Gas Scrubber	60' x 12.5' x 22.5' ea 28,706 acfs 77,140 gpm	15 psig, 200°F	CS Clad 1/8" 316 SS
11-1103	Ash Cooling System Scrubber	4'D x 15.0' 115 acfs, 780 gpm	15 psig, 210°F	CS Clad 1/8" 316 SS
		Vessels		
11-1201	Pyrolysis Vessel No. 1	28'D x 115' overall	35 psig, 875°F	SA-515-70 1/8" CA Refractory Lined
11-1202	Pyrolysis Vessel No. 2	28'D x 115' overall	35 psig, 975°F	SA-515-70 1/8" CA Refractory Lined
11-1203	Pyrolysis Vessel No. 3	28'D x 115' overall	35 psig, 1,100°F	SA-515-70 CA Refractory Lined
11-1204	Char Burner No. 1	57'D x 135' overall	35 psig, 2,000°F	SA-515-70 Refractory Lined and Incoloy Internals
11-1205	Char Burner No. 2	57'D x 135' overall	35 psig, 2,000°F	SA-515-70 Refractory Lined and Incoloy Internals
11-1206	Char Burner No. 3	57'D x 135' overall	35 psig, 2,000°F	SA-515-70 Refractory Lined and Incoloy Internals
11-1207	Steam Drum	20'D x 40' overall	100 psig, 330°F	CS Clad 1/8" 316 SS

Table 10-3 (Contd)

Item No.	Description	Size	Design Press/Temp	Material/ Remarks
		Exchangers		
11-1301	Raw Low-Btu Fuel Gas Scrubber Air Cooler	922 x 10^6 Btu/hr, 46 Bays 4.328 x sq ft 92 Motors @ 40 hp ea	95 psig, 210°F	Tube: CS Header: CS 1/4" CA
11-1302	Raw Low-Btu Fuel Gas Scrubber Water Cooler	S&T 748 x 10^6 Btu/hr 44 Shells 349 x 10^3 sq ft	75 psig, 160°F-SH 95 psig, 170°F-T	Inhibited Admiralty: Tube: CS Shell and Chan: CS, 1/8" CA
11-1303-01 through 09	Raw Low-Btu Fuel Gas Finish Cooler (inside 11-1101)	115 x 10^6 Btu/hr 9 Tube Bundles 90,730 sq ft	75 psig, 160°F-T	SH & CH: CS 1/8" CA Tube inh Adm Tubesheet: CS Clad 1/8" inh Adm
11-1304	Ash Cooling System Cooler	Air Cooler 15 x 10^6 Btu/hr 1 Bay 63,370 sq ft 2 Motors @ 25 hp ea	105 psig, 230°F	Tube: CS Header: CS, 1/4" CA
		Furnaces		
11-1402	Raw Low-Btu Gas Trim Cooler	Vertical 1,068 x 10^6 Btu/hr 6 Units 279.9 x 10^3 sq ft	75 psig, 340°F-T 75 psig, 1,150°F-SH	Tube: 316 SS

Table 10-3 (Contd)

Item No.	Description	Size	Design Press/Temp	Material/ Remarks
		Pumps		
11-1501-01, 02, 03	Raw Low-Btu Fuel Gas Scrubber No. 1 Pump and Turbine	47,704 gpm 2,590 hp Driver	80 psi TDH, 160°F	CS Case CA6NM Impeller
11-1502-01, 02, 03	Raw Low-Btu Fuel Gas Scrubber No. 2 Pump and Turbine	37,076 gpm 2,050 hp Driver	80 psi TDH, 120°F	CA6NM Impeller
11-1504-01, 02	Char Burner Water Feed Pump and Motor	280 gpm 15 hp Driver	40 psi TDH 287°F	CA6NM Impeller
11-1505	Fine Ash Slurry Pump and Motor	50 gpm 10 hp Driver	80 psi TDH, 180°F	CA6NM Impeller
11-1506	Ash Cooling System Circulating Water Pump and Motor	750 gpm 25 hp Driver	35 psi TDH, 180°F	CS Case CA6NM Impeller
		Material Handling		
11-2001-01, 02, 03	Raw Coal Weigh Belt	2,800 TPH total @ 45-lb/ft^3	amb	CS/Rayon Belting
11-2002-01 through 06	Raw Coal Screw Feeder	700 TPH ea, @ 55-lb/ft^3	amb	
11-2003-01, 02	Coarse Coal Screw Feeder	1,200 TPH total @ 45-lb/ft^3	amb	
11-2004	Coarse Coal Weigh Belt	1,200 TPH @ 40-lb/ft^3	amb	CS/Rayon Belting
11-2005-01, 02	Medium Coal Screw Feeder	1,200 TPH total @ 45-lb/ft^3	amb	CS/Rayon Belting
11-2006	Medium Coal Weigh Belt	1,200 TPH @ 40-lb/ft^3	amb	CS/Rayon Belting
11-2007	Coarse Coal Return Belt	1,600 TPH @ 40-lb/ft^3	amb	CS/Rayon Belting

Table 10-3 (Contd)

Item No.	Description	Size	Design Press/Temp	Material Remarks
11-2008	Ash Weigh Belt	200 TPH @ 30-lb/ft^3	amb	CS/Rayon Belting
11-2009	Ash Disposal Belt	200 TPH @ 30-lb/ft^3	amb	CS/Rayon Belting
		Separators		
11-2201	Pyrolysis Vessel No. 1 Cyclone	3,000 cfs, 13.0' x 24.0'	850°F	321 SS
11-2202	Pyrolysis Vessel No. 2 Cyclone	3,000 cfs, 13.0'D x 24.0'	950°F	321 SS
11-2203	Pyrolysis Vessel No. 3 Cyclone	3,000 cfs, 13.0'D x 24.0'	1,100°F	321 SS
11-2204-01 through 12	Char Burner No. 1 Cyclone	24,000 cfs, 12 Units 12.0'D x 46.0'	15 psig, 2,000°F	CS-1/8" CA-Refractory Lined
11-2205-01 through 06	Cnar Burner No. 2 Cyclone	12,000 cfs, 6 Units 12.0'D x 46.0'	15 psig, 2,000°F	CS-1/8" CA-Refractory Lined
11-2206-01, 02, 03	Char Burner No. 3 Cyclone	6,000 cfs, 3 Units 12.0'D x 46.0'	15 psig, 2,000°F	CS-1/8" CA-Refractory Lined
11-2211-01 through 13	First Coal Dryer Cyclone	26,000 cfs, 13 Units 12'D x 40'	5 psig, 300°F	CS-1/8" CA-Refractory Lined
11-2212-01 through 07	Second Coal Dryer Cyclone	15,000 cfs, 7 Units 12'D x 40'	7 psig, 600°F	CS-1/8" CA-Refractory Lined
11-2213-01 through 04	Pyrolyzer No. 1 Recycle Gas Preheater Cyclone	2,000 cfs, 4 Units 7.6'D x 25'	24 psig, 850°F	CS-1/8" CA-Refractory Lined
11-2214-01 through 04	Pyrolyzer No. 2 Recycle Gas Preheater Cyclone	1,300 cfs, 4 Units 7.6'D x 25'	24 psig, 950°F	CS-1/8" CA-Refractory Lined
11-2215-01 through 04	Pyrolyzer No. 3 Recycle Gas Preheater Cyclone	1,400 cfs, 4 Units 9.6'D x 25'	24 psig, 1,100°F	CS-1/8" CA-Refractory Lined
11-2216-01 through 20	Pyrolyzer No. 1 Circulating Char Heater Cyclone	40,000 cfs, 20 Units 12'D x 40'	10 psig, 1,100°F	CS-1/8" CA-Refractory Lined

Table 10-3 (Contd)

Item No.	Description	Size	Design Press/Temp	Material/ Remarks
11-2217-01 through 21	Pyrolyzer No. 2 Circulating Char Heater Cyclone	42,300 cfs, 21 Units 12'D x 40'	12 psig, 1,300°F	CS 1/8" CA Refractory Lined
11-2218-01 through 21	Pyrolyzer No. 3 Circulating Char Heater Cyclone	42,700 cfs, 21 Units 12'D x 40'	13 psig, 1,500°F	CS 1/8" CA Refractory Lined
11-2301	Fine Ash Slurry Thickener	780 gpm, 15,000 lb/hr 85' Dia Tank	180°F	Manufacturer's Standard
11-2401	Ash Cooler	96.8 x 10^6 Btu/hr	2,000°F	Drum: CS Clad 1/8" W/316SS Tube: Incoloy 800
11-2402	Ash Moistener	320,000 lb/hr Ash 16,000 lb/hr Water	400°F	Drum: CS Clad 1/8" W/316SS Tube: Titanium
		Hoppers		
11-2601-01, 02, 03	Coal Feed Hopper	1,000 tons ea 55 lb/ft^3	80°F	CS 1/8" CA Rubber Lined
11-2602	Ash Hopper	100 ton, 30 lb/ft^3	200°F	CS 1/8" CA Rubber Lined
11-2611	First Coal Dryer Hopper	36'D x 50'	20 psig, 325°F Top 22 psig, 625°F Btm	CS 1/8" CA
11-2612	Second Coal Dryer Hopper	36'D x 50'	22 psig, 625°F Top 24 psig, 825°F Btm	CS 1/8" CA Refractory Lined
11-2613	Pyrolyzer No. 1 Recycle Gas Preheater Hopper	10'D x 30'	39 psig, 850°F Top 40 psig, 1,400°F Btm	CS 1/8" CA Refractory Lined

Table 10-3 (Contd)

Item No.	Description	Size	Design Press/Temp	Material/ Remarks
11-2614	Pyrolyzer No. 2 Recycle Gas Preheater Hopper	8'D x 30'	39 psig, 950°F Top 40 psig, 1,700°F Btm	CS 1/8" CA Refractory Lined
11-2615	Pyrolyzer No. 3 Recycle Gas Preheater Hopper	8'D x 30'	39 psig, 1,100°F Top 40 psig, 1,700°F Btm	CS 1/8" CA Refractory Lined
11-2616	Pyrolyzer No. 1 Circulating Char Heater Hopper	44'D x 60'	25 psig, 1,100°F Top 26 psig, 1,300°F Btm	CS 1/8" CA Refractory Lined
11-2617	Pyrolyzer No. 2 Circulating Char Heater Hopper	44'D x 60'	27 psig, 1,300°F Top 28 psig, 1,500°F Btm	CS 1/8" CA Refractory Lined
11-2618	Pyrolyzer No. 3 Circulating Char Heater Hopper	44'D x 60'	27 psig, 1,500°F Top 29 psig, 1,700°F Btm	CS 1/8" CA Refractory Lined
Other Major Equipment				
11-2801	Pressure Balance Line (PBL) Between 11-1201 and 11-1202	5'D	35 psig, 975°F	SA-515-70 Refractory Lined
11-2802	PBL Between 11-1202 and 11-1203	6'D	35 psig, 1,100°F	SA-515-70 Refractory Lined
11-2803	PBL Between 11-1203 and 11-1204	6'D	35 psig, 1,100°F	SA-515-70 Refractory Lined
11-2804	PBL Between 11-1204 and 11-1205	6'D	35 psig, 2,000°F	SA-515-70 Refractory Lined
11-2805	PBL Between 11-1205 and 11-1206	6'D	35 psig, 2,000°F	SA-515-70 Refractory Lined

Table 10-3 (Contd)

Item No.	Description	Size	Design Press/Temp	Material/ Remarks
11-2806	PBL Between 11-1206 and 11-2401	2'D	35 psig, 2,000°F	SA-515-70 Refractory Lined
11-2807	PBL Between 11-1204 and 11-1203	3'D	35 psig, 2,000°F	SA-515-70 Refractory Lined
11-2808	PBL Between 11-1204 and 11-1202	3'D	35 psig, 2,000°F	SA-515-70 Refractory Lined
11-2809	PBL Between 11-1205 and 11-2814	3'D	40 psig, 2,000°F	SA-515-70 Refractory Lined
11-2810	PBL Between 11-1205 and 11-2815	3'D	40 psig, 2,000°F	SA-515-70 Refractory Lined
11-2811	First Coal Dryer Lift Pipe	18'D x 155'	22 psig, 625°F	CS 1/8" CA
11-2812	Second Coal Dryer Lift Pipe	18'D x 155'	24 psig, 825°F	SA-515-70, 1/8" CA, Refractory Lined
11-2813	Pyrolyzer No. 1 Recycle Gas Preheater Lift Pipe	5'D x 120'	40 psig, 1,400°F	SA-285C Refractory Lined
11-2814	Pyrolyzer No. 2 Recycle Gas Preheater Lift Pipe	4'D x 120'	40 psig, 1,700°F	SA-285C Refractory Lined
11-2815	Pyrolyzer No. 3 Recycle Gas Preheater Lift Pipe	4'D x 120'	40 psig, 1,700°F	SA-285C Refractory Lined
11-2816	Pyrolyzer No. 1 Circulating Char Heater Lift Pipe	22'D x 120'	26 psig, 1,300°F	CS Refractory Lined
11-2817	Pyrolyzer No. 2 Circulating Char Heater Lift Pipe	22'D x 120'	28 psig, 1,500°F	CS 1/8" CA Refractory Lined
11-2818	Pyrolyzer No. 3 Circulating Char Heater Lift Pipe	22'D x 120'	29 psig, 1,700°F	CS 1/8" CA Refractory Lined

Table 10-3 (Contd)

Item No.	Description	Size	Design Press/Temp	Material/ Remarks
11-2819	Pressure Balance Line (PBL) Between 11-2614 and 11-2813	3'D	40 psig, 950°F	SA-515-70 Refractory Lined
11-2820	PBL Between 11-2615 and 11-2813	3'D	40 psig, 1,100°F	SA-515-70 Refractory Lined
11-2821	PBL Between 11-2611 and 11-2812	5'D	25 psig, 325°F	SA-285-C Refractory Lined
11-2822	PBL Between 11-2612 and 11-1201	5'D	35 psig, 625°F	SA-285-C Refractory Lined
11-2823	PBL Between 11-2613 and 11-1201	3'D	40 psig, 850°F	SA-285-C Refractory Lined
11-2824	PBL Between 11-1201 and 11-2816	6'D	30 psig, 875°F	SA-285-C Refractory Lined
11-2825	PBL Between 11-2616 and 11-1201	6'D	35 psig, 1,100°F	SA-515-70 Refractory Lined
11-2826	PBL Between 11-1202 and 11-2817	6'D	35 psig, 975°F	SA-515-70 Refractory Lined
11-2827	PBL Between 11-2617 and 11-1202	6'D	35 psig, 1,300°F	SA-515-70 Refractory Lined
11-2828	PBL Between 11-1203 and 11-2818	6'D	35 psig, 1,100°F	SA-515-70 Refractory Lined
11-2829	PBL Between 11-2618 and 11-1203	6'D	35 psig, 1,500°F	SA-515-70 Refractory Lined
11-2830	PBL Between 11-1205 and 11-1201	3'D	35 psig, 2,000°F	SA-515-70 Refractory Lined

Table 10-4 - Major Equipment Summary
Unit 11-2 - Oil-Vapor Recovery

Item No.	Description	Size	Design Press/Temp	Material/ Remarks
11-1151	Oil Recovery Tower	40'/32'D x 77'TT	45 psig, 325°F Top 1,025°F Btm	CS 1/8" CA at Top 387 Gr11 Clad 1/8" 410 SS at Bottom 304 or 316 SS Internals
		Vessel		
11-1251	Oil Recovery Tower Overhead Separator	30'D x 30'TT	30 psig, 155°F	SA-285C 1/8" CA
		Exchangers		
11-1351	Oil Recovery Tower Steam Generator	S&T, 460x10^6 Btu/hr, 46,208 ft^2, 4 shells 53"/102"	75 psig, 335°F-SH 95 psig, 900°F-T	Shell:CS Clad 1/8 W/316 Tube: 316 SS Chan CS
11-1352	Oil Recovery Tower Sidecut PA Cooler	S&T, 62x10^6 Btu/hr, 78,035 ft^2, 9 shells, 57"	75 psig, 260°F-SH 75 psig, 500°F-T	Shell:CS Tube:CS
11-1353	Oil Recovery Tower Overhead Cooler	S&T, 271x10^6 Btu/hr, 367,209 ft^2, 36 shells 59"	95 psig, 240°F-SH 75 psig, 260°F-T	Shell:CS Tube:CS
11-1355	Oil Recovery Tower Water Recirculation Cooler	Air Cooler, 333 x 10^6 Btu/hr, 1,745 x 10^6 ft^2, 14 Bays 28 x 40 hp	75 psig, 260°F	Header:CS 1/4" CA Tube:CS
11-1356	Raw High-Btu Gas Compressor Intercooler	S&T, 20.394x10^6 Btu/hr, 9,249 ft^2, 1 Shell 58"	75 psig, 350°F-SH 75 psig, 170°F-T	Shell:CS 1/8" CA Tube: Inhibited Admiralty
11-1357	Recycle Gas Compressor Steam Condenser No. 1	S&T, 100.95x10^6 Btu/hr, 8,343 ft^2, 1 Shell 59"	75 psig, 180°F-SH 75 psig, 170°F-T	Shell:CS 1/8" CA Tube:90/10 CuNi

Table 10-4 (Contd)

Item No.	Description	Size	Design Press/Temp	Material Remarks
11-1358	Recycle Gas Compressor Steam Condenser No. 2	S&T, 63.64x10^6 Btu/hr, 5,260 ft^2, 1 Shell 48"	75 psig, 180°F-SH 75 psig, 170°F-T	Shell:CS 1/8" CA Tube:90/10 CuNi
11-1359	Recycle Gas Compressor Steam Condenser No. 3	S&T, 36.5x10^6 Btu/hr, 3,016 ft^2, 1 Shell 38"	75 psig, 180°F-SH 75 psig, 170°F-T	Shell:CS 1/8" CA Tube:90/10 CuNi
11-1360	Raw High-Btu Gas Compressor Condenser	S&T, 111.76x10^6 Btu/hr, 9,236 ft^2, 1 Shell 62"	75 psig, 180°F-SH 75 psig, 170°F-T	Shell:CS 1/8" CA Tube:90/10 CuNi
		Pumps		
11-1551-01, 02	Oil Recovery Tower Bottoms Pump, Spare, and Motor	9,800 gpm, 400 hp Motor	57 psi TDH, 600°F	Case: CS Imp: CA6NM
11-1552-01, 02	Oil Recovery Tower Sidecut PA Pump, Spare, and Motor	1,400 bpm, 75 hp Motor	48 psi TDH, 380°F	Case: CS Imp: CA6NM
11-1553-01, 02	Oil Recovery Tower, Reflux Pump, Spare, and Motor	800 gpm, 75 hp Motor	65 psi TDH, 130°F	Case: CS Imp: CA6NM
11-1554-01, 02	Oil Recovery Tower Water Recirculation Pump, Spare, and Motor	7,000 gpm, 250 hp Motor	45 psi TDH, 210°F	Case: CS Imp: CA6NM
11-1555-01, 02	Oil Recovery Tower Sour Water Pump, Spare, and Motor	300 gpm, 20 hp Motor	45 psi TDH, 130°F	Case: CF8M Imp: CF8M
		Compressors		
11-1851	Pyrolyzer No. 1 Recycle Gas Compressor and Stm Turbine	394,548-lb/hr, 115,744 acfm, 15,400 hp	19.7 to 44.7 psia 130°F	Case: CS Int: CA6NM

Table 10-4 (Contd)

Item No.	Description	Size	Design Press/Temp	Material/ Remarks
11-1852	Pyrolyzer No. 2 Recycle Gas Compressor and Stm Turbine	241,472-lb/hr, acfm varies, 9,570 hp	19.7 to 44.7 psia, 130°F	Case: CS Int: CA6NM
11-1853	Pyrolyzer No. 3 Recycle Gas Compressor and Stm Turbine	226,380-lb/hr, acfm varies, 8,800 hp	19.7 to 44.7 psia, 130°F	Case: CS Int: CA6NM
11-1854	Raw High-Btu Gas Compressor and Stm Turbine	237,015-lb/hr, acfm varies, 15,850 hp	14.7 to 80 psia, 130°F	Case: CS Int: CA6NM
		Tank		
11-1951	Oil Recovery Tower Water Storage Tank	5,000 bbl, 33'6"D x 32'	API-650 ATM, 135°F	CS 1/8" CA

Table 10-5 - Major Equipment Summary
Unit 12-1 - Oil Filtration

Item No.	Description	Size	Design Press/Temp	Material/ Remarks
		Vessels		
12-1201	Filtrate Receiver	12'0"D x 50' TT	35 psig, 425°F	SA-285C 1/8" CA
12-1202	Compressor Suction Drum	9'6"D x 14' TT	25 psig, 225°F	SA-285C 1/8" CA
12-1203-01, 02	Precoat Tanks	10'0"D x 10'	15 psig, 425°F	SA-285C 1/8" CA
12-1204	Basecoat Tank	10'0" x 10'	15 psig, 425°F	SA-285C 1/8" CA
		Exchangers		
12-1301	Compressor Suction Cooler	Air Cooler, 11.6 x 10^6Btu/hr 2-7 1/2 hp, 19,288ft^2, 1 Bay	75 psig, 450°F	Tube: CS Hdr: CS 1/4" CA
12-1302	Recycle Gas Compressor Steam Condenser	S&T, 32 x 10^6Btu/hr 2,648ft^2, 1 shell 36"	75 psig, 180°F-SH 75 psig, 170°F-T	Shell: CS 1/8" CA Tube: 90/10CuNi
		Pumps		
12-1501-01 through 20	Filter Feed Pumps and Motors	60 gpm, 15 hp	65 psi TDH, 500°F	Case: CS Imp: CA6NM
12-1502-01 through 20	Filter Cake Slurry Pumps and Motors	5 gpm, 65 hp	1,800 psi TDH, 500°F	Case: CS Imp: CA6NM
12-1503-01, 02	Filter Oil Product Pump and Spare (Triplex Stm Pump)	1,000 gpm, 60 hp	65 psi TDH, 500°F	Case: CS Imp: CA6NM
12-1504-01, 02	Light Oil Recycle Pump, Spare, and Motors	50 gpm, 10 hp	65 psi TDH, 400°F	Case: CS Imp: CA6NM
12-1505-01, 02 03	Precoat Pumps, and Spare, and Motors	60 gpm, 15 hp	65 psi TDH, 400°F	Case: CS Imp: CA6NM
12-1507-01, 02	Basecoat Pumps and Motors	50 gpm, 15 hp	65 psi TDH, 500°F	Case: CS Imp: CA6NM
		Compressor		
12-1801	Recycle Gas Compressor and Turbine	93,630-lb/hr, 25,500 acfm, 4,620 hp	24.7 to 69.7 psia, 200°F	Case: CS Int: Cape CA6CN

Table 10-5 (Contd)

Item No.	Description	Size	Design Press/Temp	Material/ Remarks
		Tanks		
12-1901-01, 02	Filter Feed Storage Tank	8,000 bbl, 40'Dx45'	API-650, Atm, 425°F	SA-285-C 1/8" CA
12-1902	Filter Aide Storage Bin	600 bbl, 30'Dx30'	15 psig, 120°F	SA-285-C 1/8" CA
		Elevators		
12-2001	Storage Bin Bucket Elevator	10 TPH, 12-lb/ft^3, 60' lift, 18"x48"		CS 1/8" CA
12-2002	Precoat Tank Bucket Elevator	2 TPH, 12-lb/ft^3, 24' lift, 12"x39"		CS 1/8" CA
		Agitators		
12-2401-01, 02	Filter Feed Tank Agitators	Side Ent. 15 hp Motor		Shafts and Propellers 304 OR 316 SS
12-2402-01, 02	Precoat Tank Agitators	Top Mounted, 15 hp Motor		Shafts and Propellers 304 OR 316 SS
12-2403-01, 02	Basecoat Tank Agitators	Top Mounted, 15 hp Motor		Shafts and Propellers 304 OR 316 SS
		Rotary Filters		
12-2801-01 through 20	Rotary Pressure Precoat Filters	28,000 lb/hr ea 500ft^2 ea	45 spig, 400°F	CS W/304 or 316 SS Screens

Table 10-6 - Major Equipment Summary
Unit 13-1 - Pyrolysis Gas Treating

Item No.	Description	Size	Design Press/Temp	Material/ Remarks
		Columns		
13-1101	Contactor	40 Trays, 13'0" D x 114'0" TT,	70 psig, 175°F	SA 285-C 1/8" CA (SR) & 304 Int
13-1102	Regenerator	40 Trays, 14'6"/11'6" D x 124'0" TT	31 psig, 288°F	SA 285-C 1/4"CA (SR) & 304 Int
		Vessels		
13-1201	Flash Drum	8'0" D x 32'0" TT	25 psig, 175°F	SA-285 C 1/8"CA (SR)
13-1202	Solution Sump	8'0" D x 8'0" TT	15 psig, 205°F	A-285 C 1/8" CA & Cathodic Protected
13-1203	Reclaimer	3'6" D x 32"0" TT	32 psig, 415°F	SA-515-70 1/4" CA (SR) & Monel Tubes
		Exchangers		
13-1301	Solution Cooler	S&T, 34.9 x 10^6 Btu/hr 18,081 ft^2, 4 shells 42"	150 psig, 190°F-SH 75 psig, 170°F-T	Shell: CS 1/8" CA Tube: CS
13-1302	Solution Air Cooler	6-40 hp Motors, 74.2 x 10^6 Btu/hr, 352,357 ft^2, 3 Bays	75 psig, 250°F	Tube: CS Header: CS 1/4" CA
13-1303	Rich/Lean Exchanger	S&T, 100.26 x 10^6 Btu/hr 22.684 ft^2, 2 shells 60"	75 psig, 315°F-SH 75 psig, 270°F-T	Shell: CS 1/4" CA (SR) Tube: CS
13-1304	Reflux Trim Cooler	S&T, 13 x 10^6 Btu/hr, 6,617 ft^2, 2 shells 33"	75 psig, 180°F-SH 75 psig, 160°F-T	Shell: CS 1/8" CA Tube: CS
13-1305	Reflux Air Cooler	34.75 x 10^6 Btu/hr, 4-30 hp Motors 165, 140 ft^2, 2 Bays	75 psig, 220°F	Header: CS 1/4" CA Tube: CS
13-1306	Reclaimer Heater	Tube Bundle in 13-1203, 36.264 x 10^6 Btu/hr 5,181 ft^2 One Shell 42"	75 psig, 640°F-SH 360 psig, 470°F-T	Shell: CS 1/4" CA (SR) Tube: Monel
		Furnace		
13-1401	Reboiler Heater	Gas Fired, 135 x 10^6 Btu/hr, 1.983 x 10^6 lb/hr	100 psig, 315°F	Tube: 304 SS
		Pumps		
13-1501	Rich Solution Pump and Motor	4,180 gpm, 200 hp	50 psi TDH, 150°F	Case: CS Imp.: CA6NM
13-1502	Solution Sump Pump and Motor	50 gpm, 5 hp	50 psi TDH, 180°F	Case: CS Imp.: CA6NM

Table 10-6 (Contd)

Item No.	Description	Size	Design Press/Temp	Material/ Remarks
13-1504 & 1505	Lean Solution Pump, Spare, and Motor (common with 13-1501)	4,500 gpm, 450 hp	125 psi TDH, 130°F	Case: CS Imp.: CA6NM
13-1506 & 1507	Reboiler Pump, Spare, and Motor	5,100 gpm, 300 hp	60 psi TDH, 263°F	Case: CS Imp.: CA6NM
13-1508 & 1509	Reflux Pump, Spare, and Motor	2,350 gpm, 200 hp	75 psi TDH, 170°F	Case: CS Imp.: CA6NM
		Tank		
13-1901	Solution Storage	1,700 bbl, 25'0" D x 20'6"	API-650 2,613 psig, 825°F	CS 1/16" CA
		Separators		
13-2201	Raw Gas Filter/Separator	3.92×10^6 scfh 4'0" D x 28' L	55 psig, 100°F	Shell: CS Internals: SS
13-2202	Solution Filter	355 gpm, 6'5" D x 10' L	125 psig, 130°F	Shell: CS Internals: SS

Table 10-7 - Major Equipment Summary
Unit 14-1 - Hydrogen Plant

The acid gas removal process indicated is one of several proprietary processes available for the purpose intended

Item No.	Description	Size	Design Press/Temp	Material/ Remarks
		Vessels		
14-1201	Process Condensate KO Drum	6'-0" OD x 20' lg	550 psig, 125°F	CS Clad 1/8" x/304-SS
14-1241	Hydrogen Compressor Suction KO Drum	20'-0" ID x 12'-0" TT	550 psig, 125°F	SA-515-70 1/8" CA
		Exchangers		
14-1301	Shift Feed Heater	42.4 x 10^6 Btu/hr	700°F, 650 psig SH 850°F, 550 psig T	Shell, Channel, Tube Sheets: A 204 Gr 6 w/1/8".347 SS Weld Overlay Tubes: 410, 304, OR 316 SS
14-1302	First Shift Effluent Boiler	34.5 x 10^6 Btu/hr	500°F, 650 psig SH 760°F, 600 psig T	Shell: CS 1/8" CA Chan. and Tube Sheet: A 204 Gr 6 w/1/8" 347 SS W.O. Tubes: 410, 304, OR 316 SS
14-1303	Shift Feed Preheater	10 x 10^6 Btu/hr	650°F, 650 psig SH 725°F, 600 psig T	Same as 14-1301
14-1304	Second Shift Effluent Boiler	122.5 x 10^6 Btu/hr	500°F, 750 psig SH 725°F, 600 psig T	Same as 14-1302
14-1305	Boiler Feedwater Heater	1.5 x 10^6 Btu/hr	500°F, 800 psig SH 525°F, 600 psig T	Shell: CS 1/8" CA Chan. & TS C 1/2 Mo 1/4" CA Tubes: 410, 304, OR 316 SS
14-1307-01, 02	Hydrogen Plant Feed Gas Compressor Condensers	S&T 285 x 10^6 Btu/hr, 23,600 ft^2, 1 shell 86"	75 psig, 180°F-SH 75 psig, 170°F-T	Shell: CS 1/8" CA Tubes: 90/10 CuNi
14-1308	Hydrogen Plant Feed Gas Compressor Intercooler No 1	S&T 72 x 10^6 Btu/hr, 30,200 ft^2, 4 shells 52"	75 psig, 380°F-SH 75 psig, 170°F-T	Shell: CS 1/8" CA Tubes: Inhibited Admiralty
14-1309	Hydrogen Plant Feed Gas Compressor Intercooler No 2	S&T 72 x 10^6 Btu/hr, 17,600 ft^2, 2 shells 56"	130 psig, 380°F-SH 75 psig, 170°F-T	Shell: CS 1/8" CA Tubes: Inhibited Admiralty
14-1310	Hydrogen Plant Feed Gas Compressor Intercooler No 3	S&T 72 x 10^6 Btu/hr, 14,100 ft^2, 2 shells 51"	75 psig, 380°F-SH 75 psig, 170°F-T	Shell: CS 1/8" CA Tubes: Inhibited Admiralty
14-1311	Hydrogen Compressor Condenser	S&T 126 x 10^6 Btu/hr, 10,400 ft^2, 1 shell 63"	75 psig, 380°F-SH 75 psig, 170°F-T	Shell: CS 1/8" CA Tubes: 90/10 CuNi
14-1312	Hydrogen Compressor Intercooler	S&T 26 x 10^6 Btu/hr, 3,000 ft^2, 1 shell 34"	75 psig, 380°F-SH 75 psig, 170°F-T	Shell: CS 1/8" CA Tubes: Inhibited Admiralty
14-1340	Methanator Feed/Effluent Exchanger	S&T 18 x 10^6 Btu/hr, 1,300 ft^2, 1 shell 23"	515 psig, 550°F-SH 500 psig, 660°F-T	Tubes: C 1/2 Mo Shell, TS, Chan: C 1/2 Mo 1/8" CA
14-1341	Methanator Effluent Boiler	S&T 28 x 10^6 Btu/hr, 1,700 ft^2, 1 shell 27"	75 psig, 350°F-SH 550 psig, 640°F-T	Shell: CS 1/8" CA Tubes: C 1/2 Mo
14-1342	Methanator Effluent Air Cooler	36 x 10^6 Btu/hr, 87,800 ft, 1 Bay 2 @ 40 hp	500 psig, 400°F	Header: CS 1/4" CA Tubes: CS
14-1343	Methanator Cooler	S&T 8 x 10^6 Btu/hr, 5,000 ft^2, 2 shells 31"	75 psig, 170°F-SH 550 psig, 190°F-T	Shell: CS Clad 1/8" W/Inhibited Admiralty Tubes: Inhibited Admiralty

Table 10-7 (Contd)

Item No.	Description	Size	Design Press/Temp	Material/ Remarks
		Furnaces		
14-1401	Startup Heater	10.6 x 10^6 Btu/hr	700°F, 650 psig	Tubes: 410 SS
14-1402	Methanator Startup Heater	5.8 x 10^6 Btu/hr	550°F, 575 psig	Tubes: C 1/2 Mo
		Compressors		
14-1801	Hydrogen Plant Feed Gas Compressor and Turbine	665,570 lb/hr, 85,000 hp, 203,040 acfm	14.7 to 620 psia 100°F Suction	Case: CA6NM Int: CA6NM
14-1802	Hydrogen Compressor and Turbine	47,162 lb/hr, 18,480 hp, 3,164 acfm	500 to 2,515 psia, 100°F Suction	Case: CA6NM Int: CA6NM
		Reactors		
14-2501	First Shift Reactor	20'-0" ID x 24'-0" TT		A 387 Gr11 w/1/8" 410 Clad or 347 SS Weld Overlay
14-2502	Second Shift Reactor	19'-0" ID x 23'-0" TT		A 387 Gr11 w/1/8" 410 Clad or 347 SS Weld Overlay
14-2503	Methanator	10'-0" ID x 15'-0" TT		A 387 Gr11 & 304 SS Int

Table 10-8 - Major Equipment Summary
Unit 15-1 - Oil Hydrotreating

Item No.	Description	Size	Design Press/Temp	Material/ Remarks
		Column		
15-1101	Stabilizer	7'0"/3'6" D x 38'6" TT	115 psig, 500°F	SA-285-C 1/8" CA & 410 Int
		Vessels		
15-1201	No. 1 Reactor	9'0" D x 31'6" TT	2,662 psig, 825°F	SA-387Gr 22
15-1202	No. 1 Reactor	9'0" D x 31'6" TT	2,662 psig, 825°F	SA-387Gr 22
15-1203	No. 1 Reactor	9'0" D x 31'6" TT	2,662 psig, 825°F	SA-387Gr 22
15-1204	No. 1 Reactor	9'0" D x 31'6" TT	2,662 psig, 825°F	SA-387Gr 22
15-1205	No. 2 Reactor	10'0" D x 27'9" TT	2,635 psig, 825°F	SA-387Gr 22
15-1206	No. 2 Reactor	10'0" D x 27'9" TT	2,635 psig, 825°F	SA-387Gr 22 Weld
15-1207	No. 2 Reactor	10'0" D x 27'9" TT	2,635 psig, 825°F	SA-387Gr 22 Overlay
15-1208	No. 2 Reactor	10'0" D x 27'9" TT	2,635 psig, 825°F	SA-387Gr 22 1/8" 347 SS
15-1209	No. 3 Reactor	10'0" D x 27'9" TT	2,613 psig, 825°F	SA-387Gr 22
15-1210	No. 3 Reactor	10'0" D x 27'9" TT	2,613 psig, 825°F	SA-387Gr 22
15-1211	No. 3 Reactor	10'0" D x 27'9" TT	2,613 psig, 825°F	SA-387Gr 22
15-1212	No. 3 Reactor	10'0" D x 27'9" TT	2,613 psig, 825°F	SA-387Gr 22
15-1213	No. 4 Reactor	10'0" D x 27'9" TT	2,585 psig, 825°F	SA-387Gr 22
15-1214	No. 4 Reactor	10'0" D x 27'9" TT	2,585 psig, 825°F	SA-387Gr 22
15-1215	No. 4 Reactor	10'0" D x 27'9" TT	2,585 psig, 825°F	SA-387Gr 22
15-1216	No. 4 Reactor	10'0" D x 27'9" TT	2,595 psig, 825°F	SA-387Gr 22
15-1217	Feed Surge Drum	9'0" D x 23'0" TT	65 psig, 425°F	SA-385-C 1/4" CA
15-1218	HP Separator	11'0" D x 44'0" TT	2,536 psig, 160°F	SA-516-701/8" CA
15-1219	First IP Separator	10'6" D x 44'0" TT	1,106 psig, 160°F	SA-516-70 1/8" CA
15-1220	Second IP Separator	8'8" D x 32'0" TT	479 psig, 160°F	SA-515-70 1/8" CA
15-1221	LP Separator	8'0" D x 32'0" TT	204 psig, 160°F	SA-515-70 1/8" CA
15-1222	Sour Water Drum	4'6" D x 16'0" TT	90 psig, 160°F	SA-515-70 3/16" CA
15-1223	Stabilizer Overhead Accumulator	5'0" D x 24'0" TT	115 psig, 125°F	SA-515-70 1/8" CA
		Exchangers		
15-1301, 1302, 1303, 1304	Feed Effluent Exchanger S&T	78,504 x 10^6 Btu/hr ea, 6,558 ft^2, 1 Shell 53"	2,570 psig, 800°F-SH 2,720 psig, 650°F-T	Shell: A 387 Gr 22 W/1/8" 347 Weld Overlay Tube: 321 SS

Table 10-8 (Contd)

Item No.	Description	Size	Design Press/Temp	Material/ Remarks
~~15-1305~~	~~Low Pressure Steam Generator~~ S&T	~~174.2 x 10^6Btu/hr,~~ 25,467 ft^2, 4 Shells 52"	~~75 psig, 300°F SH~~ 2,560 psig, 800°F-T	~~Shell:~~ Tube: 321 SS Ch: 387 Gr 22
15-1306	H_2 Gas-Effluent Exchanger	7,672 x 10^6Btu/hr, 1,230 ft^2 1 Shell 34"	2,550 psig, 220°F-SH 2,730 psig, 380°F-T	Shell: A 516 Gr 65 Tube: CS
15-1307	Reactor Effluent Cooler S&T	201.345 x 10^6Btu/hr, 37,250 ft^2 4 Shells 58"	2,540 psig, 360°F-SH 75 psig, 170°F-T	A-516 Gr 65 Tube: Incoloy 800
15-1308	Stabilizer Feed-Bottoms Exchanger S&T	29.988 x 10^6Btu/hr, 1,886 ft^2, 1 Shell 28"	125 psig, 525°F-SH 185 psig, 350°F-T	Shell: CS 1/4" CA Tube: CS
15-1309	Stabilizer Overhead Condenser S&T	4.539 x 10^6Btu/hr, 2,161 ft^2, 1 Shell 29"	75 psig, 170°F-SH 125 psig, 210°F-T	Shell: CS 1/8" CA Tubes: Inh Adm Ch: CS 1/4" CA Epoxy Lined
15-1310	Stabilizer Bottoms Cooler-Air Cooler	60.55 x 10^6Btu/hr, 170,953 ft^2, 2 Bays	115 psig, 110°F	Header: CS 1/4" CA Tube: CS
15-1312, 1313, 1314, 1315	No. 1 Reactor Eff - HP Steam Generators S&T	2,994 x 10^6Btu/hr ea, 163 ft^2, 1 Shell 48"	660 psig, 490°F-SH 2,650 psig, 800°F-T	Shell: 515 Gr 70 1/8" CA Tubes: 321 SS Ch: 516 Gr 65
15-1316, 1317, 1318, 1319	No. 2 Reactor Eff - HP Steam Generators S&T	31.567 x 10^6Btu/hr ea, 1,380 ft^2, 1 Shell 26"	660 psig, 490°F-SH 2,650 psig, 800°F-T	Shell: 515 Gr 20 1/8" CA Tubes: 321 SS
15-1320, 1321, 1322, 1323	No. 3 Reactor Eff - HP Steam Generators S&T	31.559 x 10^6Btu/hr ea, 1,379 ft^2, 1 Shell 26"	660 psig, 490°F-SH 2,650 psig, 800°F-T	Shell: 515 Gr 70 1/8" CA Tubes: 321 SS
15-1324	Recycle Gas Compressor Steam Condenser S&T	32 x 10^6 Btu/hr 2,600 ft^2, 1 Shell 36"	75 psig, 180°F-SH 75 psig, 170°F-T	Shell: 515 Gr 70 1/8" CA Tubes: 90/10 CuNi
		Furnaces		
15-1401	Feed Preheater-Gas Fired	13.53 x 10^6Btu/hr	2,730 psig, 700°F	Tubes: 321 H SS
15-1402	Feed Preheater-Gas Fired	13.53 x 10^6Btu/hr	2,730 psig, 700°F	Tubes: 321 H SS
15-1403	Feed Preheater-Gas Fired	13.53 x 10^6Btu/hr	2,730 psig, 700°F	Tubes: 321 H SS
15-1404	Feed Preheater-Gas Fired	13.53 x 10^6Btu/hr	2,730 psig, 700°F	Tubes: 321 H SS
15-1405	Stabilizer Reboiler-Gas Fired	58.875 x 10^6Btu/hr	165 psig, 525°F	Tube: CS 1/8" CA

Table 10-8 (Contd)

Item No.	Description	Size	Design Press/Temp	Material/ Remarks
		Compressor		
15-1801	Recycle Gas Compressor and Turbine	418,304 lb/hr 297.832 x 10^6scfd	2,550 psig, 120°F	Case: CS Int: CA6NM
		Pumps		
15-1501-01 through 05	Feed Pump and Motor	246 gpm ea, 500 hp	2,425 psi TDH, 400°F	Casing: CS Int: CA6NM
15-1502-01, 02	Recycle Oil Pump and Motor	1,507 gpm ea, 2,500 hp	1,470 psi TDH 135°F	Casing: CS Int: CA6NM
15-1503-01, 02	Wash Water Pump and Motor	439 gpm ea, 1,000 hp	2,275 psi TDH, 110°F	Casing: CS Int: CA6NM
15-1504-01, 02	Stabilizer Reboiler Pump and Motor	1,694 gpm ea, 200 hp	40 psi TDH, 475°F	Casing: CS Int: CA6NM
15-1505-01, 02	Stabilizer Reflux Pump and Motor	338 gpm ea, 50 hp	137 psi TDH, 150°F	Case: CS Int: CA6NM

Table 10-9 - Major Equipment Summary
Steam and Power Generating Plant
Unit 18-1 - Fuel Gas Compression

Item No.	Description	Size	Design Press/Temp	Material/ Remarks
		Exchangers		
18-1301	Pyrolysis Gas Compressor Steam Condenser No. 1 S&T	65,385 x 10^6Btu/hr, 5,441 ft^2, 1 Shell 48"	75 psig, 180°F-SH 75 psig, 170°F-T	Shell: CS 1/8" CA Tube: 90/10 CuNi
18-1302,01, 02, 03	Low-Btu Fuel Gas Compressor Intercooler S&T	155.946 x 10^6Btu/hr, 34,655 ft^2, 4 Shells ea 56"	75 psig, 180°F-SH 75 psig, 170°F-T	Shell: CS 1/8" CA Tube: Inh Adm
18-1303	Pyrolysis Gas Compressor Intercooler S&T	14,692 x 10^6Btu/hr, 4,620 ft^2, 1 Shell 42"	165 psig, 290°F-SH 75 psig, 170°F-T	Shell: CS 1/8" CA Tube: Inh Adm
18-1304-01, 02, 03	Low-Btu Fuel Gas Compressor Steam Condenser No. 1 S&T	315.0 x 10^6Btu/hr, 26,039 ft^2, 1 Shell ea 90"	75 psig, 180°F-SH 75 psig, 170°F-T	Shell: CS 1/8" CA Tube: 90/10 CuNi
18-1305-01, 02, 03	Low-Btu Fuel Gas Compressor Steam Condenser No. 2 S&T	315.0 x 10^6Btu/hr, 26,039 ft^2, 1 Shell ea 90"	75 psig, 180°F-SH 75 psig, 170°F-T	Shell: CS 1/8" CA Tube: 90/10 CuNi
		Compressors		
18-1801	Pyrolysis Gas Compressor and Turbine	190,850 lb/hr, 16,039 acfm, 9,900 hp	205 psi diff	Case: CS Int: CA6NM
18-1802-01, 02, 03	Low-Btu Fuel Gas Compressor Low Pressure and Turbine	945,900 lb/hr ea, 325,000 acfm, 49,500 hp	48 psi diff	Case: CS Int: CA6NM
18-1803-01, 02, 03	Low-Btu Fuel Gas Compressor High Pressure and Turbine	918,600 lb/hr ea, 76,400 acfm, 48,100 hp	208 psi diff	Case: CS Int: CA6NM

Table 10-10 - Major Equipment Summary - Unit 18-2 - Power Generation

Item No.	Description	Size	Design Press/Temp	Material/ Remarks
		Generator Packages		
18-0851-01 through 12	Gas Turbine-Generator-Boiler Package	95 MW ea, 15.8 kV 355,000 lb/hr steam	610 psig, 850°F	
18-0852	Gas Turbine-Generator Boiler Package	95 MW, 13.8 kV, 43,000 lb/hr steam	50 psig, sat	

Table 10-11 - Major Equipment Summary - Unit 19-1 - Plant Air and Instrument Nitrogen

Item No.	Description	Size	Design Press/Temp	Material/ Remarks
		Compressor		
19-1801	Plant Air Compressor and motor	16,000 acfm, 1,750 hp	125 psi diff	Case: CS Imp.: CI
19-1802	Plant Air Compressor and Turbine	16,000 acfm, 1,750 hp	125 psi diff	Case: CS Imp.: CI

Table 10-12 - Major Equipment Summary -
Unit 19-2 - Cooling Water

Item No.	Description	Size	Design Press/Temp	Material/ Remarks
Cooling Towers				
19-1511-01 through 13	Cooling Water Circulating Pumps	55,000 gpm, 1,750 hp Motor	40 psi TDH, 100°F	CI Case and Impeller
19-1711-01, 02, 03, 04, 05	Cooling Tower, equal to Marley No. 6715-4	108,000 gpm ea	120 to 86°F	10 Cells ea 200 hp/Cell Manufacturer's Standard
19-1712	Cooling Tower, equal to Marley No. 6715-4	119,000 gpm	120 to 86°F	11 Cells 200 hp/Cell Manufacturer's Standard

Table 10-13 - Major Equipment Summary
Unit 19-3 - Industrial Water System

Item No.	Description	Size	Design Press/Temp	Material/ Remarks
		Pumps		
19-1531-01, 02	River Water Pumps	13,900 gpm, Motor Driver	100 ft Head, 40-80°F	CI
19-1532	Back Wash Water Recycle Pump	50 gpm, 1 hp Motor Driver	30 ft Head, 40-80°F	CI
19-1533	Rotary Vacuum Filtered Water Recycle Pump	1,010 gpm, 15 hp Motor Driver	30 ft Head, 40-80°F	CI
19-1534	Cooling Water Makeup Pump	24,450 gpm, 250 hp Motor Driver	30 ft Head, 40-80°F	CI
19-1535	Clearwell Pump	3,000 gpm, 65 hp Motor Driver	69 ft Head, 40-80°F	CI
19-1536	Filtered Water Pump	2,950 gpm, 110 hp Motor Driver	92 ft Head, 40-80°F	CI
19-1537	Demineralized Water Pump	2,650 gpm, 35 hp Motor Driver	30 ft Head, 40-80°F	316 SS
19-1538-01 through 04	Boiler Feedwater Pump	3,200 gpm, 2,000 hp Motor Driver	1,740 ft Head, 40-80°F	CS Case CA6NM Impeller
19-1540	Rotary Vacuum Filter Sludge Pump	1,010 gpm, 50 hp Motor Driver	30 ft Head, 40-80°F	CA6NM Case and Impeller
19-1541-01, 02	River Water Sludge Pumps	250 gpm, 25 hp Motor Driver	100 ft Head, 40-80°F	CI
19-1542	Process Water Pump	800 gpm, 40 hp Motor Driver	30 ft Head, 40-80°F	CI
		Tanks		
19-1931-01, 02	River Water Lime Storage Tank	25' ID x 10' x 60° Cone	Atmos Pressure/80°F	CS
19-1932-01, 02	River Water Alum Storage Tank	20' ID x 9' x 60° Cone	Atmos Pressure/80°F	CS
19-1933	River Water Electrolyte Storage Tank	28' ID x 28'		CS with Epoxy-Phenolic Lining
19-1934-01, 02	Clarifier Tank	50' x 200' x 15' deep		Concrete
19-1935	Clearwell Storage Tank	40' ID x 32'		CS with Epoxy-Phenolic Lining
19-1936	Backwash Water Storage Tank	20'ID x 28'		CS with Epoxy-Phenolic Lining
19-1937	Filtered Water Storage Tank	125' ID x 30'		CS with Coal Tar Epoxy Lining

Table 10-13 (Contd)

Item No.	Description	Size	Design Press/Temp	Material/ Remarks
19-1938	Demineralizer Acid Storage Tank	6' ID x 7'		CS 1/8" CA
19-1939	Demineralizer Caustic Storage Tank	8' ID x 8'		CS 1/8" CA
19-1940	Neutralizer Tank	30' x 60' x 9' deep		Concrete
19-1941-01, 02	Demineralizer Storage Tank	125' ID x 30'		CS with Epoxy-Phenolic Lining
19-1942	Sludge Holding Tank	25' ID x 20'		CS with Coal Tar Epoxy
19-1943	River Water Sedimentation Basin	216' x 648' x 16' deep		Concrete
		Separator Equipment		
19-2231	River Water Screen			CS Frame, SS Screen
		Mixers		
19-2431	Sludge Holding Tank Mixer	For Sludge Holding Tank 19-1942		316 Impeller and Shaft
19-2432	Neutralizer Tank Mixer	For Neutralizer Tank 19-1940		316 Impeller and Shaft
		Other Major Equipment		
19-2831	River Water Splitter	27,790 gpm		CS
19-2832-01, 02	Clarifier Mechanical and Control System	Mechanical System for Clarifier Tanks		Manufacturer's Standard
19-2833	Cooling Tower Chemical Feed System			Manufacturer's Standard
19-2834	Water Filter	3,000 gpm		CS Shell, 316 SS Internals
19-2835	Demineralizer	2,950 gpm		Manufacturer's Standard
19-2836	Deaerator	4,100 gpm		CS
19-2837	Deaerator Chemical Feed System			Manufacturer's Standard
19-2838	Boiler Feedwater Chemical Feed System			Manufacturer's Standard
19-2839	Sludge Rotary Vacuum Filter	1,100 gpm		CS Shell, 316 SS Internals

Table 10-14 - Major Equipment Summary
Unit 19-4 - Potable and Sanitary Water System

Item No.	Description	Size	Design Press/Temp	Material/ Remarks
19-1545 01,02	Deep Well Water Pumps	50 gpm		CI
19-2841	Treatment System	50 gpm		Manufacturer's Standard

Table 10-15 - Major Equipment Summary
Unit 19-5 - Fire Water System

Item No.	Description	Size	Design Press/Temp	Material/ Remarks
19-1551	Fire Water Pump	3,000 gpm Motor Driver	130 psi TDH	CI
19-1552	Fire Water Pump	3,000 gpm Turbine Driver	130 psi TDH	CI
19-1553	Fire Water Pump (Spare)	3,000 gpm Diesel Driver	130 psi TDH	CI
19-1554	Jockey Pump	Low Capacity Pressure Maintenance Pump		CI

Table 10-16 - Major Equipment Summary
Unit 19-6 - Waste Water Treatment System

Item No.	Description	Size	Design Press/Temp	Material/ Remarks
19-1561	Sanitary Lift Pump	25 gpm		CI
19-1562	Acid-Caustic Waste Pump	300 gpm		304 SS
19-1563	Boiler Blowdown Pump	500 gpm		CS
19-1961-01, 02	API Separator	20' x 150' x 8' deep		Concrete
19-1261	Boiler Blowdown Condensate Flash Drum	6' ID x 20' TT		CS

Table 10-17 - Major Equipment Summary
Unit 19-7 Product Storage

Item No.	Description	Size	Design Press/Temp	Material/ Remarks
19-1971-01 through 10	Product Oil Storage Tanks	135' Dia x 30' High 77,000 bbl	API Storage Tank	CS

Table 10-18 - Major Equipment Summary -
Unit 20 - Buildings and General Facilities

Administration Building	-	Concrete block, 2-story, 30,000 sq ft
Laboratory	-	Concrete block, 1-story, 10,000 sq ft
Control House	-	Concrete block, 1-story, 8,000 sq ft
Change House	-	Concrete block, 1-story, 5,000 sq ft
Cafeteria	-	Concrete block, 1-story, 8,000 sq ft
Maintenance Shop	-	Metal, insulated, 20' eave, 20,000 sq ft
Warehouse	-	Metal, insulated, 12' eave, 35,000 sq ft
Chemical Storage	-	Metal, insulated, 8' eave, 10,000 sq ft
Miscellaneous Switch Houses and Operator Field Offices	-	Metal, insulated, 8' eave, 10,000 sq ft
Fire Station	-	Metal, insulated, 12' eave, 3,000 sq ft
Medical Building	-	Concrete block, 1-story, 2,000 sq ft
Guard Houses	-	Metal, insulated, 8' eave, 250 sq ft
Security	-	Concrete block, 1-story, 2,000 sq ft

SECTION 11

ENVIRONMENTAL FACTORS

This conceptual plant design has been responsive to requirements for control of gaseous, liquid, and solid emissions from the plant units and ancillary facilities.

The means by which gas, vapor, and solid emissions control, as well as noise level control, have been accomplished are discussed in the paragraphs that follow.

11.1 AIR POLLUTION ABATEMENT

The control of air contaminants released to the environment had a high priority in plant and process design. Applicable new source standards covering the power plant and general process operations were used in design and engineering of the process and equipment.

Fugitive particulate emissions from coal sizing and handling, and from residual ash disposal (char gasifier unit), are prevented from becoming airborne by maintaining a wet condition when not in a closed system.

Most gases generated during the coal-conversion process are used captively as fuel gases. For the most part, inert gases (nitrogen and carbon dioxide) are vented to the air. The major air pollution abatement effort is aimed at desulfurizing the fuel streams to make them environmentally acceptable; the desulfurization procedure is outlined in Figure 11-1, which also shows the nature and amount of all streams vented to the air.

Raw COED oil is generated as a vapor in the pyrolyzers, along with gaseous products. The mixture leaves each of the pyrolyzers through a cyclone separator that removes entrained dust down to a particle size of about 10 microns.

Condensed oil is pressure-filtered, then treated with hydrogen at 700°F (370°C) and 2,400 psig (163 atm) to reduce sulfur content by 95% (from 2.0 to 0.1%). The nitrogen content of the pyrolysis oil from the design coal is sufficiently high so that the hydrogen sulfide released in hydrotreating is tied up as ammonium hydrosulfide. The latter is dissolved in injected water and removed from the hydrotreater condensing train as an aqueous solution that can be separated into salable ammonia and hydrogen sulfide directed to the sulfur conversion unit. The hydrotreater off-gas is sufficiently low in sulfur to be used as fuel and is combined with the higher Btu fuel gas.

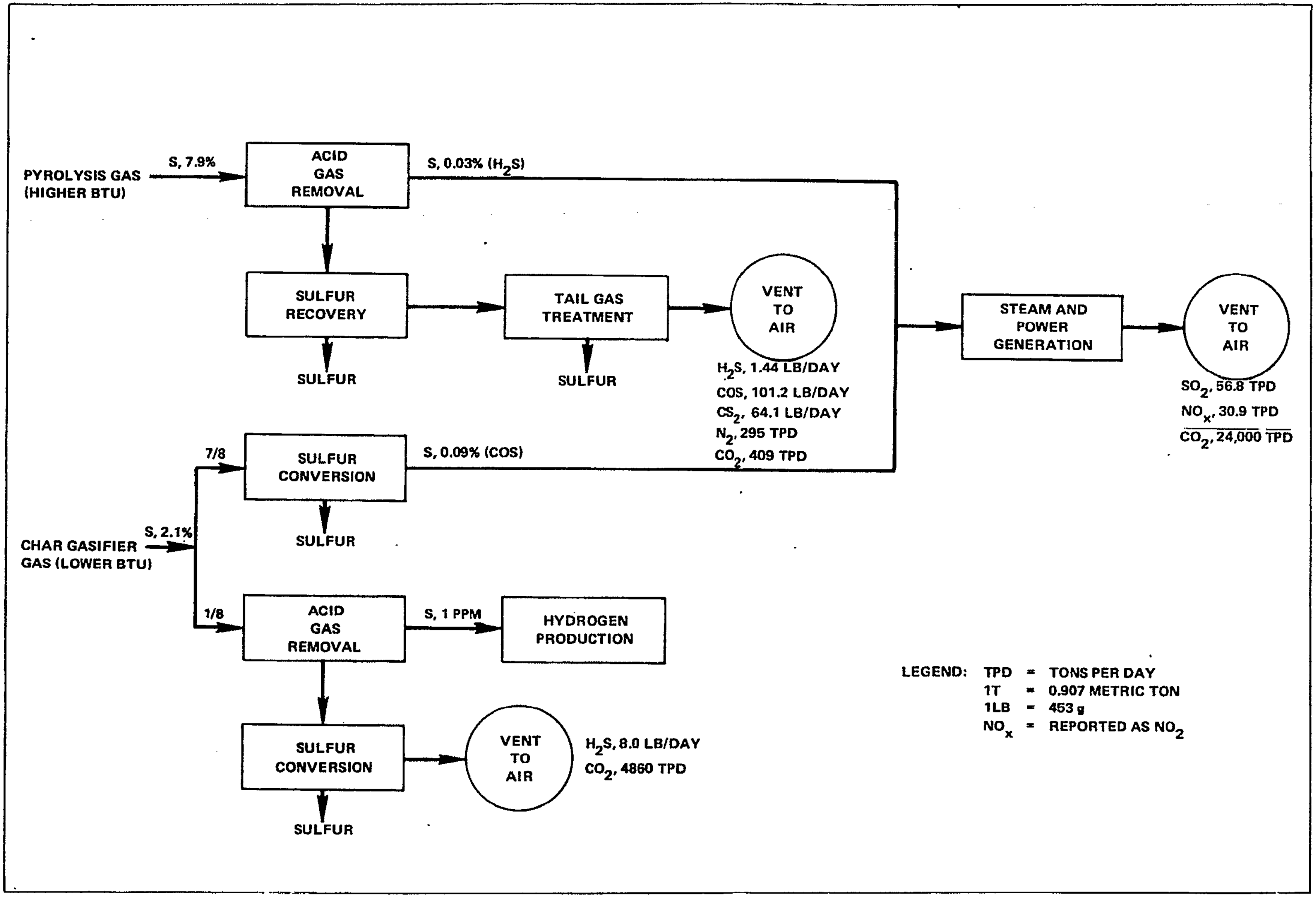

Figure 11-1 - Block Flow Diagram
Air Pollution Abatement

The pyrolysis gas separated from the oil vapor in the condensation tower is washed countercurrently with an amine to remove carbon dioxide and more than 99% of the hydrogen sulfide present. The heated amine solution releases hydrogen sulfide and carbon dioxide as an acid gas stream which is conveyed to the sulfur recovery unit. Effluent gases from the sulfur recovery unit are further desulfurized in a tailgas treatment unit. When the effluent gases are finally vented to the air, they contain approximately 1 ppm of hydrogen sulfide, 40 ppm of carbon oxysulfide, and 20 ppm of carbon disulfide. The desulfurized pyrolysis gas is used as fuel for power and steam generation.

The lower Btu gas stream from the char gasifier is purified from entrained dust down to a particle size of approximately 10 microns by a series of cyclone separators. A water scrubber removes the residual solids, then the gas is divided into two streams.

The major stream (seven-eighths) of the char gasifier gas is contacted with an alkaline solution in a sulfur conversion unit where approximately 96% of the sulfur present is removed, with residual sulfur appearing mainly as carbon oxysulfide. The absorbed hydrogen sulfide is subsequently oxidized to high purity (99.9%) sulfur. The desulfurized gas is used for power and steam generation (approximately 97%) and directly in plant utilities.

The minor stream (one-eighth) of the char gasifier gas is used for hydrogen production. This stream is desulfurized in an intermediate step between shift conversion and methanation; only a trace (1 ppm) of sulfur is left in the stream. The acid gas stream generated as a result of desulfurization is led to a sulfur conversion unit similar to the one used for the major char gasifier gas stream. This sulfur conversion unit vents to the air large amounts (4,860 TPD, 4,408 metric TPD) of carbon dioxide, containing a trace (approximately 1 ppm) of residual hydrogen sulfide.

The various desulfurizing units perform the dual function of sulfur removal and wet scrubbing of streams to eliminate residual particulates which evaded the previous control devices.

The desulfurized higher and lower Btu gas streams are used as fuel for gas turbines. Prior removal from the gaseous fuel streams of most particulates and sulfur assures that the power generating plant emissions are below applicable standards, as discussed later. Nitrogen oxide production is controlled by water injection to decrease the combustion temperature.

11.1.1 SULFUR BALANCE

A typical sulfur balance for the conceptual design of a commercial COED plant is detailed in Table 11-1. A total of 95% of the coal sulfur content is recovered as elemental sulfur. An additional 2% remains in the ash from the char gasifier unit.

11.1.2 COMPLIANCE WITH SOURCE EMISSION STANDARDS

Standards of performance for new stationary sources for coal gasification plants have not been issued by the Federal Government. Standards

Table 11-1 - Sulfur Balance (TPD)

Total Input from the Typical Feed Coal	905.0
Outputs: In the COED oil	1.7
As Elemental Sulfur from Pyrolysis Gas	177.0
As Elemental Sulfur from Char Gasifier Gas	679.0
As Sulfur Dioxide Emissions	28.4
As Reduced Sulfur Emissions	0.1
In the Ash	18.8
	905.0

somewhat related to a coal gasification process are those issued for petroleum refineries and for fossil-fuel-fired steam generators. Among the states, only New Mexico has issued specific regulations covering coal gasification plants. The standards are more strict than either petroleum-refinery or fossil-fuel-fired steam generator Federal standards.

The New Mexico standards are compared in Table 11-2 with the emissions from the Parsons conceptual design of a commercial COED coal gasification plant. This comparison is shown for illustrative purposes only because, as mentioned above, the plant as conceived would be located in the U.S. Eastern Interior (coal) Region. As shown in Table 11-2, all standards are met.

Projected emissions from the COED power generating plant are compared in Table 11-3 with Federal standards for gaseous fossil-fuel-fired steam generators (existing New Mexico standards do not differ from the Federal ones). It can be seen that estimated plant emissions are significantly below the standard for sulfur dioxide and meet the nitrogen oxide standard.

11.1.3 CARBON DIOXIDE EMISSIONS

It is estimated that significant carbon dioxide emissions (on the order of 29,000 TPD, or 26,300 metric TPD for the typical case) would be generated by the COED commercial plant. It appeared desirable to investigate possible effects of these emissions. Carbon dioxide is not toxic, and the natural background concentration in the atmosphere has been estimated at 300 to 500 ppm.

Global weather modification effects have been attributed to increased carbon dioxide generation by fossil-fuel combustion. A gradual warming trend has been predicted, on the order of 0.5°C in 25 years. However, actual temperature trends have shown a cooling of 0.3°C from 1945 to the present.

Table 11-2 - Comparison of Emissions with Standards, Coal Gasification Plant

Pollutant	New Mexico Standards	Emissions, COED Coal Gasification Plant
Total Reduced Sulfur ($H_2S+COS+CS_2$)	100 ppm	62 ppm
Hydrogen Sulfide	10 ppm	2 ppm
Hydrogen Cyanide	10 ppm	Nil
Hydrogen Chloride/ Hydrochloric Acid	5 ppm	Nil
Particulate Matter	0.03 gr/ft^3	Nil
Ammonia	25 ppm	Nil
Gas Burning Process Boilers, Particulate Matter	0.03 lb/MM Btu, LHV	*
Gas Burning Process Boilers, Sulfur Dioxide	0.16 lb/MM Btu, LHV	*
Total Sulfur	0.008 lb/MM Btu of feed (coal) heat input, HHV	0.003 lb/MM Btu

*Not Applicable (none included in the design)

Table 11-3 - Comparison of Emissions with Standards, Power Generating Plant

Pollutant	Federal Standard (lb/MM Btu)	Emissions, COED Power Generating Plant (lb/MM Btu)
Particulate Matter	0.1	Nil
Sulfur Dioxide	0.8	0.33
Nitrogen Oxides	0.2	0.18

On a localized scale, no micrometeorological effects due to increased carbon dioxide have been reported. Emissions from the COED facility could approximately double the average atmospheric carbon dioxide concentrations to 600 to 1,000 ppm in the vicinity of the plant. The lowest concentration at which some physiological effects (dyspnea and headache) have been observed in 30,000 ppm; therefore, no effects are expected at the levels mentioned. However, vegetable life has been reported to benefit from increased atmospheric concentrations of carbon dioxide.

11.2 LIQUID EFFLUENT

All liquid emissions from the plant complex will be treated to render them acceptable to the environment.

Waste streams leaving the system for the typical case, in gpm, are approximately as follows:

(1)	Cooling Water Blowdown	1,500
(2)	Boiler Water Blowdown	380
(3)	Demineralizer Acid-Caustic Waste	200
(4)	Sanitary Sewage	50
(5)	Coal Wash Water Waste	260

Streams 1, 2, 3, and 4 totaling about 2,100 gpm receive treatment as described in Section 5 under Unit 19-6, Wastewater Treatment and Disposal. The final effluent will be neutral, free of suspended solids, and containing no more than 10 ppm of BOD_5. This is below the limit of present government standards and should be suitable for return to the river.

Stream 5 is pumped for settling to a tailing pond, from which the clarified water can be either recycled for process use or dust abatement or released to the river.

Additional aqueous waste streams in the form of sour water condensate from process units are captured before leaving the system and fed to the char burners. The water fed to the char burners contains ammonia produced in the plant. Whether the ammonia will be converted to nitrogen requires verification. The effluent gas, being the fuel gas, is treated as described earlier in the section.

11.3 NOISE

Noise control will be an integral part of the layout and design of the COED Commercial Plant. The Occupational Safety and Health Act of 1970 (OSHA) regulates the amount of weighted noise a worker may be exposed to, in order to protect him from ear damage. Local codes usually regulate the level of noise that an industrial plant is permitted to generate, at the property line, above the normal ambient background level. The applicable regulations and codes will be used as the design basis for noise control in plant design and layout.

Special attention will be given to fans and compressors, pyrolysis, and gasification units, fired heaters, pressure letdown valves, and power plant gas turbine areas to minimize noise-source levels and any excessive noise radiation effect on plant personnel.

11.4 SOLID WASTE

Solid waste from the complex of units consists of:

(1) Ash from the char burners.

(2) Mud and clay from the slurry thickener.

(3) Rocks and clay from the coal crusher.

(4) Reject clay from the coal washer.

All of these waste solids are eventually returned to the mined-out area and buried beneath the backfill of overburden; refer to the description of Coal Mine Unit 10-1 in Section 5 of this report. The ash is moistened to control dust during its transport back to the mine by conveyor and truck. The bottoms from the slurry thickener in the Coal Preparation Unit are pumped to a tailing dam where the coal fines and clay settle out to be periodically trucked back to the mine for burial. The rocks and clay rejected in the coal crushing and washing operations are placed on a waste pile to be returned to the mined-out areas by returning trucks.

The mined areas will be restored as required by the regulating agency having jurisdiction in the area. Essentially this will consist of controlling peaks and ridges to a rolling topography (not more than 15% slope), planting shrubs, grasses, legumes, and trees to provide a vegetative cover similar to that which existed before the disturbance. Slurry will be confined in depressions or levees and screened with border plantings.

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SECTION 12

ECONOMICS

The estimated capital requirements, project and fund drawdown schedules, operating costs, and required selling prices for representative project financial structures are presented in this section. All economics are based on first quarter 1974 dollars.

For further economic analysis, sensitivities of required selling prices to the key parameters of capital investment, operating costs, profitability level, and plant capacity are summarized. Finally, a few interpretations of the estimates are given. Specific conclusions for definitive potential applications are left for the reader.

The sequence of presentation of economic factors in this section is intended to follow a logical inductive development of the economics of a major synfuels project. The reader is referred to the report Summary section for a quick deductive overview of key elements of the estimated project economics.

12.1 FIXED CAPITAL INVESTMENT

12.1.1 SCOPE

The preliminary fixed capital investment was estimated for a grassroots complex producing synthetic crude oil and electric power from coal obtained from a captive coal mine. The complex consists of principal process units described in Sections 4 and 5 and shown on the Block Flow Diagram, Figure 4-1.

Necessary ancillary facilities are included, with such items as: administration, warehouse, laboratory, change house, and related buildings and equipment; computer capability and communications systems; rolling stock (including trucks and automobiles for transportation within the confines of the complex); road paving; utilities distribution; and other items required for the efficient operation of an industrial complex of this magnitude are included.

12.1.2 SUMMARY

The estimated fixed capital investment for this complex is approximately $1,000 million.

The total constructed costs, approximately $925 million, are shown for each of the various process unit areas in Table 12-1. To this have been added engineering and related costs and sales taxes, which result in the total

Table 12-1 - Estimated Fixed Capital Investment

Unit No.	Description	Investment ($000)
10 - 1	Coal Mine	$ 96,300
10 - 2	Coal Preparation	26,700
11 - 1	Pyrolysis and Gasification	117,200
11 - 2	Oil - Vapor Recovery	31,000
12 - 1	Oil Filtration	16,300
13 - 1	Pyrolysis Gas Treating	7,100
13 - 2	Low Btu Gas Treating	27,400
14 - 1	Hydrogen Plant	23,500
14 - 2	H_2 Plant Tail Gas Desulfurizer	5,300
15 - 1	Oil Hydrotreating	61,900
16 - 1	Sulfur Recovery Unit, Pyrolysis Gas H_2S	6,600
16 - 2	Beavon Tail Gas Treating from Unit 16-1	Incl. w/16-1
17	Oxygen Plant	86,400
18 - 1	Fuel Gas Compression	24,500
18 - 2	Power Plant	321,400
19	Utilities	41,500
20	Buildings and General Facilities	29,400
	Total Constructed Cost	$922,500
	Home Office Engineering	58,800
	Sales Tax	18,000
	Total Fixed Capital Investment	$999,300
		Say $1,000,000

project fixed capital investment cost shown above. Costs reflect first quarter 1974 pricing. Major equipment costs, where they were identified, are tabulated in Table 12-2.

12.1.3 PROCEDURES

The fixed capital investment is a preliminary cost estimate for the engineering, design, procurement, and construction of facilities to process a nominal 25,000 TPD of high sulfur coal for producing low sulfur synthetic crude oil and electrical power as principal products, with sulfur as a by-product.

The estimate is considered to be within the -5, +20% accuracy range. It includes the costs of process equipment, construction materials, field labor, field indirect costs, engineering, design and drafting, project management, procurement, contractors fee, and supporting services. Allowances for instrument checkout and mechanical run-in are also included.

12.1.4 BASIS FOR UNIT AREAS

The project is divided into the facilities designated as unit areas, as described in Section 5. The basis for each unit estimate is discussed in the following paragraphs.

The Pyrolysis and Gasification Unit 11-1, Oil Vapor Recovery Unit 11-2, Oil Filtration Unit 12-1, Pyrolysis Gas Treating Unit 13-1, Oil Hydro-treating Unit 15-1, and Fuel Gas Compression portion of Unit 18-1 estimates were developed using a combination of in-house and vendor pricing on major equipment. The totals of major equipment were then used with historical cost multipliers to obtain the total constructed cost estimate for each unit. Major equipment for units where such pricing was made is shown on Table 12-2.

The Utilities (Area 19) and General Facilities (Area 20) units were estimated on the basis of preliminary material takeoffs to which appropriate unit pricing was applied to arrive at constructed costs.

The Low-Btu Gas Treating Unit 13-2, Hydrogen Plant Unit 14-1, Hydrogen Tail Gas Desulfurizer Unit 14-2, Sulfur Recovery Unit 16-1, and Tail Gas Treating Unit 16-2, were estimated on the basis of capacities, using appropriate Parsons in-house historical data. The coal preparation Unit 10-2 was developed on a combination of in-house data and vendor sources. The cost for the oxygen plants was obtained by quotation from a vendor.

The power plant portion of Unit 18-1 was estimated based on its name-plate capacity and the pricing utilized was vendor-sources for the power block portion and in-house historical data for the balance of plant costs.

The coal mine pricing was developed on the basis of equipment and ancillaries required to provide the capital cost for the production of 35,700 TPD of run-of-mine coal. The equipment pricing in the coal mine was obtained through a combination of in-house data and vendor sources.

Table 12-2 - Major Equipment Costs ($000)

Account Code	Equipment Description	Pyrolysis and Gasification Unit 11-1	Oil-Vapor Recovery Unit 11-2	Oil Filtration Unit 12-1	Pyrolysis Gas Treating Unit 13-1	Oil Hydrotreating Unit 15-1	Fuel Gas Compression Unit 18-1	Utilities Unit 19	Summary Listed Units
1100	Columns	1,893	685		412	44			3,034
1200	Vessels	8,310	256	65	57	19,206			27,914
1300	Heat Exchange and Condensers	6,155	4,828	49	876	6,942	2,124		20,974
1400	Furnaces and Heaters	880			540	560			1,980
1500	Pumps and Drivers	1,147	158	231	172	936		2,200	4,844
1700	Cooling Towers							7,400	7,400
1800	Compressors and Drivers		4,100	840		430	10,770	620	16,760
1900	Tanks		60	230	26			9,015	9,331
2000	Materials Handling	4,308		15					4,323
2200	Separation	21,241			67			10	21,318
2300	Concentration	176							176
2400	Agitators, Mixers	1,040		20				20	1,080
2600	Hoppers, Bins and Silos	8,588							8,588
2800	Other Major Equipment			6,000				4,312	10,317
Total Major Equipment		53,738	10,087	7,470	2,150	28,118	12,894	23,577	138,034

12.1.5 BASIS FOR COST CATEGORIES

The basic criteria for determining various cost categories for the estimate are detailed below:

A. Major Equipment Costs

Process and major equipment costs are based on preliminary vendor pricing combined with historical in-house data experience. The vendor-priced equipment was solicited for certain special process equipment where historical in-house pricing data were not completely applicable.

B. Constructed Cost

Constructed Cost is arrived at by applying a factor to major equipment cost for field direct and field indirect costs.

1. Field Direct Materials, Labor, and Other Direct Costs. Estimates for concrete, structural steel, piping, instrumentation, electrical and labor for construction of the various units were made by factoring the major equipment cost with a multiplier. The factoring method relies on previous job experience for similar process type plants, and the multiplier is determined by using the ratio of constructed costs to major equipment costs.

Included in this category are other direct costs such as miscellaneous freight, instrument checkout and run-in services, soil investigation, nonproductive time, and taxes that cannot be allocated to specific unit areas but are considered direct costs.

The included labor costs reflect first-quarter 1974 average hourly rates for the eastern interior area and expected labor productivity for that area. The estimate is based on the work being performed during a standard work week defined as five 8-hour days, Monday through Friday. No provision for premium costs for scheduled overtime work is included. However, an allowance for limited nonscheduled overtime has been included.

2. Field Indirect Costs. The following field indirect costs are included:

(1) Temporary construction facilities and job conditions, including craft subsistence and transportation.

(2) Field administration and field office expense.

(3) Construction equipment, small tools, and consumables.

(4) Payroll taxes, insurance, union welfare, fringe benefits, permits, and bonds.

C. Home Office Costs

Engineering-construction Home Office costs include management and administration, process and project engineering, construction support, design, drafting, accounting, estimating, scheduling, cost engineering, procurement, expediting, inspection, stenographic, clerical, engineering construction fee, overhead, and direct expenses such as printing, reproduction, computer charges, communications, and travel.

D. Spare Parts

Costs for spare parts are included in working capital.

E. Sales Tax

5% sales tax and/or use tax is included for materials and equipment.

F. Escalation

Escalation for the period after first quarter 1974 is not included.

G. Contingency

No contingency allowance has been included.

H. Exclusions from Fixed Capital Investment

The following cost items are excluded from the estimate:

(1) Owner's expenses connected with project.

(2) All taxes, except sales and payroll taxes.

(3) Client's local, state and federal permits.

(4) Premium time costs, except nonscheduled overtime premium.

(5) Piling and unusual foundation conditions.

(6) Process licensing fees.

Allowances for the following items, while not included in the fixed capital investment estimate, are included in the total capital requirements estimate:

(1) Land acquisition, water rights, right-of-way, and mineral rights.

(2) Working capital, interest, and financing.

(3) Raw materials and supplies for initial operation.

(4) Startup cost, operator training, and preparation of operating manuals.

12.2 TOTAL CAPITAL REQUIREMENTS

In addition to the fixed capital investment of approximately $1 billion, the costs of total capital requirements include land acquisition and rights of way, initial charges of catalysts and chemicals, startup costs and provision for working capital. These items are estimated to total approximately $126.5 million as follows:

Item	Value ($ million)
Initial Raw Materials, Catalysts, and Chemicals (See Table 12-3)	4.5
Allowance for Startup Costs (See Table 12-4)	51.0
Initial Working Capital (See Table 12-5)	70.0
Allowance for Land Acquisition, Right-of-Way	1.0
	126.5

The estimate of startup costs is summarized in Table 12-4 with construction changes and additional first-year maintenance based on experience factors for the types of units used. The estimated working capital requirements are shown in Table 12-5.

The estimated total capital requirement for the project, therefore, amounts to about $1,125 million. This is exclusive of interest burden during construction, which depends on the project schedule, fund drawdown and method of financing the project. This is discussed in Sections 12.4, 12.5, and 12.7.

Capital expenditures for replacement of coal mining equipment are based on the costs and useful lives shown in Table 12-6.

The allowance for mineral rights is included in annual operating expenses in the form of royalties.

Total capital costs in five cost centers used for estimating operating costs are summarized in Table 12-7, which includes interest burden during construction.

Table 12-3 - COED Process Plant Catalyst and Chemicals Cost Summary

Unit	Catalyst or Chemical	Initial Charge	Basis or Makeup Requirement	Cost ($)	
				Initial Charge	Annual Use
11-1	<u>Pyrolysis and Gasification</u>				
	None			None	None
11-2	<u>Oil-Vapor Recovery</u>				
	None			None	None
12-1	<u>Oil Filtration</u>				
	Base Coat		2,000 lb/yr	None	nil
	Precoat		5,490 ton/yr	None	494,000
	Total				494,000
13-1	<u>Pyrolysis Gas Treating</u>				
	DGA (diglycolamin) 100%	400,000 lb	500 lb/day	120,000	136,875
	Antifoam Agent		1 qt/day		nil
	Corrosion Inhibitor		1 qt/day		nil
	Filter Media		100 lb/mo	None	nil
	Activated Carbon		50 lb/mo		nil
	Total			120,000	137,000
13-2	<u>Low-Btu Gas Treating</u>				
	Stretford Solution	12.87×10^6 gal	81,840 lb/day	1,850,000	1,500,000

Table 12-3 (Contd)

Unit	Catalyst or Chemical	Initial Charge	Basis or Makeup Requirement	Cost ($)	
				Initial Charge	Annual Use
14-1	Hydrogen Plant				
	CO Shift	12,300 cu ft	3-year life	400,000	133,333
	Methanation	700 cu ft	5-year life	44,800	8,960
	ZnO (Guard)	360 cu ft	3-year life	23,400	7,800
	Aluminum Balls	1,600 cu ft	None	32,000	None
	K_2CO_3 and additives		18,000 lb/mo	60,000	20,000
	Catacarb				
	Activated Carbon				
	Antifoam Agent		10 gal/mo	Nil	1,800
	Total			560,200	172,000
14-2	H_2 Plant Tail Gas Desulfurizer	---	---	218,000	206,000
15-1	Oil Hydrotreating				
	NiMo Catalyst	1,330,000 lb	1.4 x 10^6 lb/yr	1,700,000	1,750,000
16-1	Sulfur Recovery Unit/ Pyrolysis Gas				
	Catalyst	244,000 lb	3-year life	48,800	16,000
16-2	Tail Gas Treating Unit	---	---	50,000	52,000
17-1	Oxygen Plant				
	None			None	None
					4,385,000
	Times Operating Rate (330 days per year, or 0.904) = Total Cost			4,547,000	3,912,000

Table 12-4 - Startup Costs ($ Million)

Expense Item	Coal Mine	Coal Preparation	COED Process	Power Plant	Offsites	Total
Pre-Startup						
Construction Changes	0	0.870	12.450	3.740	0.780	17.840
Advance Hiring						
Recruiting, Settling, Etc.	0.553	0.058	0.924	0.400	0.075	2.010
Payroll						
Operating Personnel	0.090	0.034	0.580	0.307	0.045	1.056
Administrative	0.481	0.025	0.375	0.106	0.033	1.020
Payroll Burden	0.200	0.021	0.334	0.145	0.027	0.727
Subtotal	1.324	0.138	2.213	0.958	0.180	4.813
Total Pre-Startup	1.324	1.008	14.663	4.698	0.960	22.653
Operating						
Contract Operative Assistance	0	0.080	1.289	0.558	0.105	2.032
Support Maintenance	0	0.870	20.750	3.740	0.780	26.140
Total Operating	0	0.950	22.039	4.298	0.885	28.172
Total Startup	1.324	1.958	36.702	8.996	1.845	50.825
Say	1.000	2.000	37.000	9.000	2.000	51.000

Table 12-5 - Estimate of Working Capital Requirement
($ million)

Item	Coal Mine	Coal Prep	COED Process	Power Plant	Offsites	Total
Intermediate Inventory (30 days)	5.175	0	0	0	0	5.175
Finished Product Inventory (30 days)	5.175	0.450	6.955	0	0	12.580
Spare Parts Inventory (4% of Major Equipment)	2.750	0.240	5.800	8.840	0.940	18.570
Budget for Current Expenses (30 days)	5.175	0.450	6.955	4.370	1.245	18.195
Accounts Receivable (30 days)	6.320	0.760	10.280	5.855	1.680	24.895
Credit for Accounts Payable (30 days)	3.395	0.215	3.450	1.680	0.660	9.400
Total	21.200	1.685	26.540	17.385	3.205	70.015
Say	21.000	1.750	26.500	17.500	3.250	70.000

Table 12-6 - Coal Mine Equipment Replacement Schedule

Equipment Item	Delivered Cost ($000)	Useful Life (yr)	Annual Depreciation ($)
Stripping Shovels (3)	52,770	20	2,638,500
Holland Loaders (3)	614	5	122,800
DD9G-s for Holland Loaders (3)	748	4	187,000
Coal Shovels, 12 cu yd (3)	2,136	7	305,143
Coal Haulers, 120 ton (15)	3,391	4	847,750
Front-End Loaders, 10 cu yd (3)	580	3	193,333
D-9's w/Ripper and Dozer (6)	950	3	316,667
D-9's w/Dozer (6)	859	3	286,333
D-8's w/Dozer (3)	302	3	100,667
Wheel Dozer (3)	405	3	135,000
Grader (3)	182	3	60,667
Rotary Blast-Hole Drills (12)	3,878	5	775,600
Portable Light Towers (12)	72	5	14,400
Track-Drills (3)	106	3	35,333
Screw Compressors, 600 cu ft (3)	85	3	28,333
Lube-Fuel Truck (3)	90	3	30,000
Water Sprinkler Truck (3)	423	3	141,000
AN/FO Trucks (3)	85	4	21,250
Trucks, 3 ton	16	5	3,200
Trucks, 5 ton	19	5	3,800
Mine Pumping Systems	150	10	15,000
Hydraulic Cranes, 15 ton (3)	207	4	51,750
Mobile Crane, 50 ton (3)	431	20	21,550

Table 12-6 (Contd)

Equipment Item	Delivered Cost ($000)	Useful Life (yr)	Annual Depreciation ($)
Lowboy w/Tractor, 50 ton (1)	37	20	1,550
Bus, 40 Passenger (1)	21	7	3,000
Tire Truck (1)	51	7	7,285
Pickup Trucks (15)	53	3	17,667
Flatbed Trucks, 3 ton (8)	26	5	5,200
Flatbed Trucks, 5 ton (8)	32	5	6,400
Total Equipment	68,719		6,376,478
Preproduction Costs	27,581	10	2,758,100
Subtotal	96,300		9,134,578
Home Office Engineering and Sales Tax	7,700	10	770,000
Total	104,000		9,904,578

Table 12-7 - Capital Costs ($ million)

Item	Coal Mine	Coal Prep	COED Process	Power Plant	Offsites	Total
Fixed Capital Investment[a]	104.000	29.000	415.000	374.000	78.000	1,000.000
Initial Catalysts and Chemicals (see Table 12-3)	0.000	0.000	4.500	0.000	0.000	4.500
Startup Costs (see Table 12-4)	1.000	2.000	37.000	9.000	2.000	51.000
Construction Financing[b]	8.500	3.750	54.000	45.000	10.250	121.500
Depreciable Investment	113.500	34.750	510.500	428.000	90.250	1,177.000
Working Capital (see Table 12-5)	--	--	--	--	--	70.000
Land, Rights of Way						1.000
Total Capital Requirement						1,248.000
Plant Operation Life	20 yr	20 yr	20 yr	20 yr	20 yr	
Useful Life for Depreciation	See Table 12-6	11 yr	11 yr	28 yr	20 yr	
Depreciation Method	Straight-line	DDB[c]	DDB	DDB	DDB	
Average Recurring Capital Investment (see Table 12-6)	$6.375					$6.375

[a]Includes home office engineering and sales tax.
[b]Applicable to cases using 65% debt at 9% interest and 0.75% commitment fee only.
[c]Double declining balance.

12.3 PROJECT SCHEDULE

The estimated project schedule is summarized in Figure 12-1. This schedule was developed based on analysis of the design, procurement of schedule-controlling equipment, and construction schedules. The results indicate a schedule with the mechanical completion date 57 months and achievement of capacity production rate one year later.

12.4 FUND DRAWDOWN SCHEDULE

The fund requirements during the design, engineering, procurement, construction and startup period are illustrated in Figure 12-2; fund requirements are shown for six-month intervals. The cumulative fund drawdowns are shown in Figure 12-3.

The Figure 12-2 and 12-3 fund drawdown schedules were developed based on the sum of the estimated individual fund requirement schedules for the separate sections consisting of coal mine, coal preparation plant, coal conversion plant, power plant and offsites.

12.5 OPERATING COSTS

Operating cost estimates are based on first quarter 1974 prices. For estimating purposes, the complex was divided into five cost centers:

(1) Coal mine

(2) Coal preparation plant

(3) COED process plant

(4) Power plant

(5) Offsites

Estimated operating costs for each of these cost centers are summarized in Table 12-8 with reference made to supporting tables.

12.5.1 GENERAL BASIS

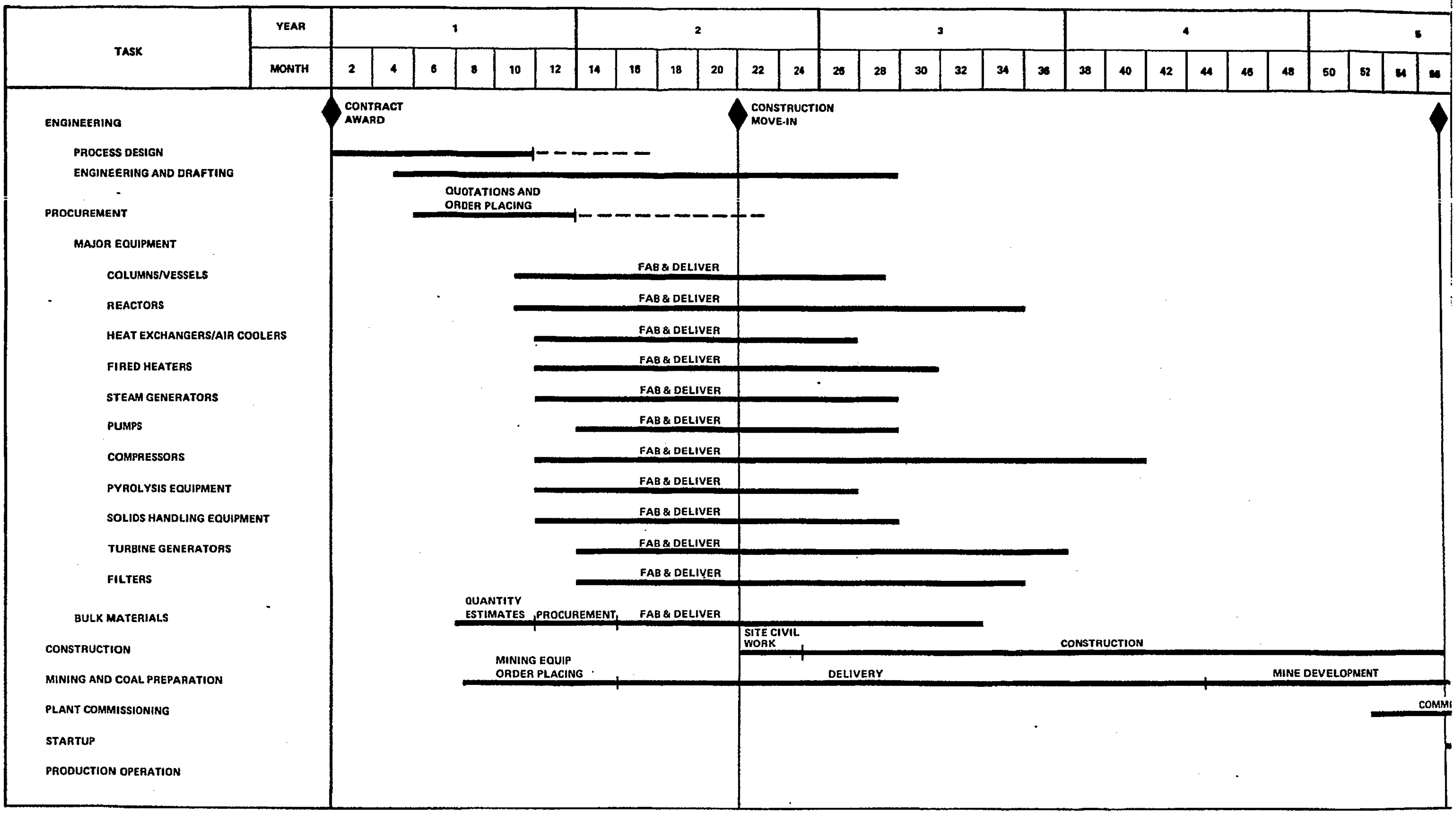
The economic analysis is based on a plant operating period of 20 years. The operating rate is 330 stream·days per year, equal to 90.4% operating efficiency except for the first year of operation, when the complex is assumed to produce at a rate equal to 50% of capacity.

Plant overhead is based on an estimated requirement for 355 administrative and support prersonnel consisting of plant management, accounting, personnel, first aid, cafeteria, fire and safety, quality assurance, engineering, motor pool, material control, and other support personnel and associated indirect materials and supplies. A payroll burden of 35% of total payroll cost including plant overhead personnel was used. The general and administrative

Table 12-8 - Annual Operating Cost Summary ($million/yr)

Item	Coal Mines	Coal Preparation	COED Process	Power Plant	Offsites	Total
Mine Royalty	11.781					11.781
Materials and Supplies						
Operating Supplies	2.817	0.145	2.075	nil	0.390	5.427
Equipment Operation	10.520 (10)	--	--	--	--	10.520
Maintenance Materials and Contract Labor	--	1.110	15.770	6,800	1.112	24.792
Catalysts and Chemicals	--	--	3.962 (3)	--	1.777 (17)	5.739
Water	--	--	--	--	1.345	1.345
Total Materials and Supplies	13.337	1.255	21.807	6,800	4.624	47.823
Labor						
Operating Labor and Supervision	6.159 (11)	0.137 (13)	2.318 (14)	1,229 (16)	0,268 (18)	10.111
Maintenance Labor and Supervision	1.537 (12)	0.250 (13)	3.702 (15)	0,472 (16)	0,332 (18)	6.293
Plant Overhead	1.924	0.099	1.500	0,425	0.150	4.098
Payroll Burden	3.367	0.172	2.628	0,743	0.262	7.172
Union Welfare	7.234	--	--	--	--	7.234
Total Labor Costs	20.221	0.658	10.148	2,869	1.012	34.908
G and A Overhead	0.743	0.042	0.676	0.318	0.121	1.900
Miscellaneous Costs						
Reclamation	0.042					
Permits and Bonds	0.275					
Miscellaneous	0.030					
Total Miscellaneous Costs	0.347					0.347
Taxes and Insurance	3.120	0.870	12.450	11,220	2.340	30.000
Total Operating Costs	49.549	2.825	45.081	21,207	8.097	126.759

NOTE: All numbers in parenthesis are Section 12 table numbers.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PROCESS DESIGN
ENGINEERING AND DRAFTING
PROCUREMENT
MAJOR EQUIPMENT
COLUMNS/VESSELS
REACTORS
HEAT EXCHANGERS/AIR COOLERS
FIRED HEATERS
STEAM GENERATORS
PUMPS
COMPRESSORS
PYROLYSIS EQUIPMENT
SOLIDS HANDLING EQUIPMENT
TURBINE GENERATORS
FILTERS
BULK MATERIALS
CONSTRUCTION
MINING AND COAL PREPARATION
PLANT COMMISSIONING
STARTUP
PRODUCTION OPERATION
CONTRACT AWARD
CONSTRUCTION MOVE-IN
QUOTATIONS AND ORDER PLACING
FAB & DELIVER
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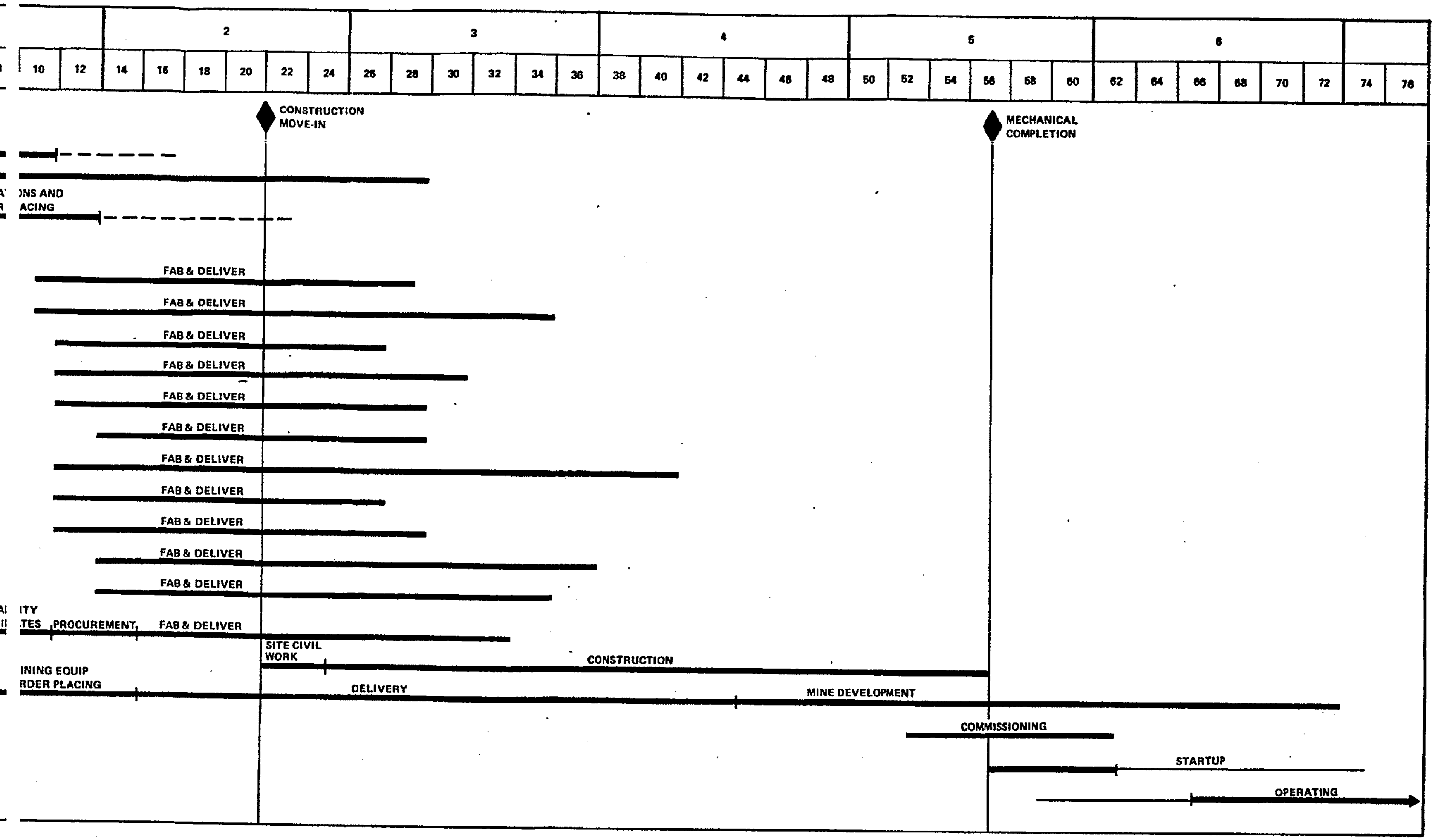

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Figure 12-1 - Project Overall Schedule

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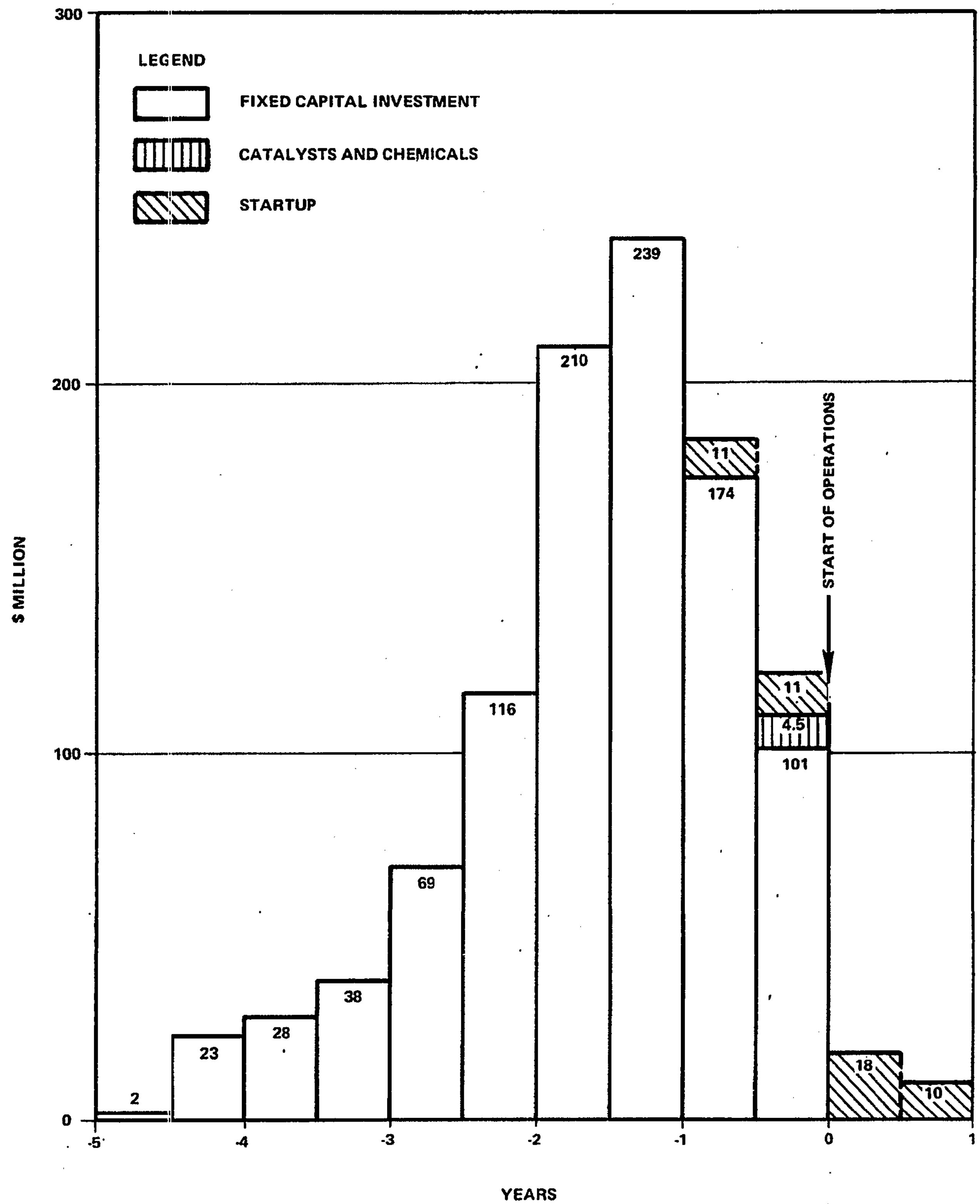

Figure 12-2 - Fund Drawdown Schedule (Semiannual Basis)

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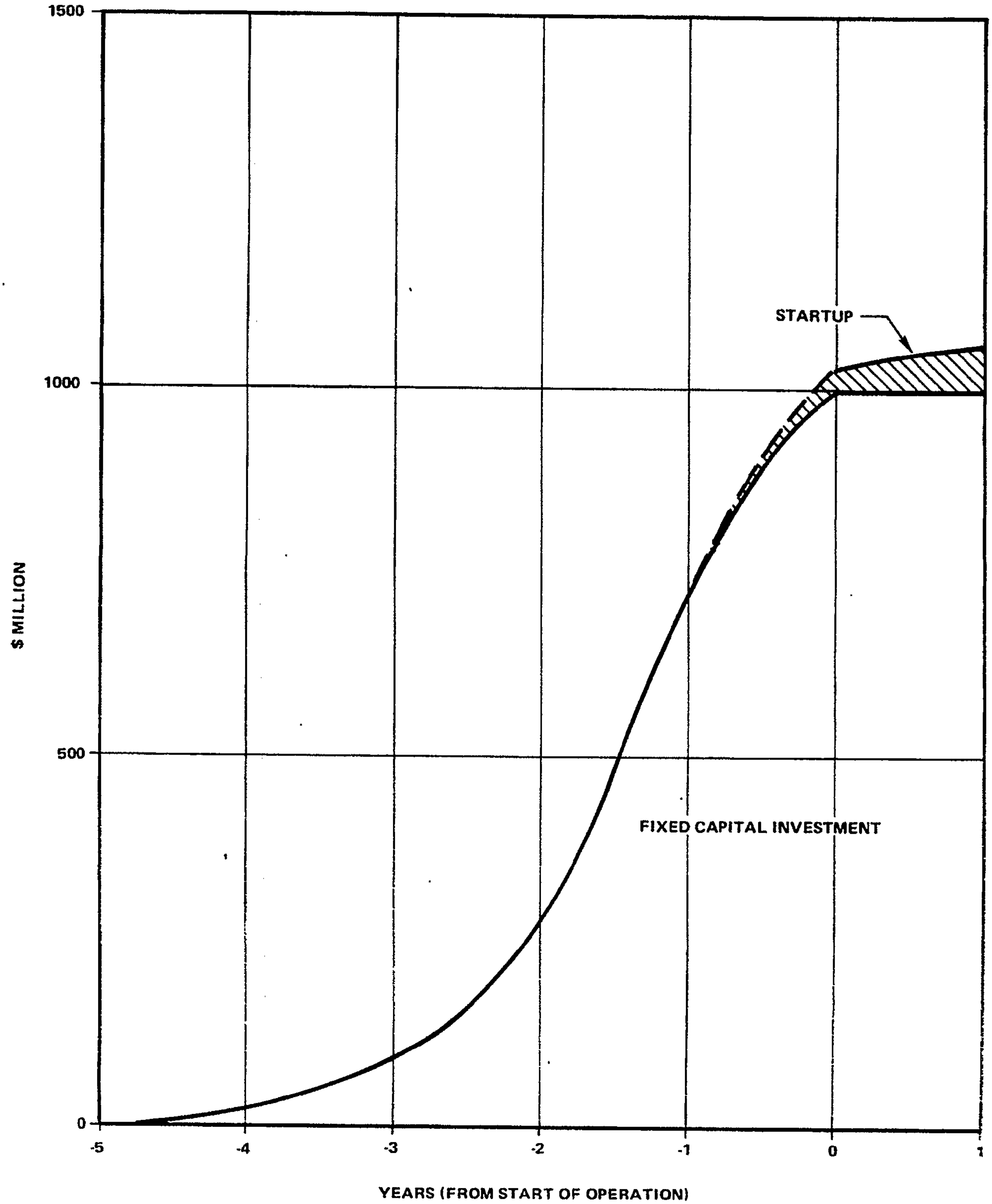

Figure 12-3 - Fund Drawdown Schedule - Cumulative

expense amounts to 1.5% of the total operating cost. Property tax and insurance is based on 3% of the initial fixed capital investment.

Estimated manpower requirements for the complex are summarized in Table 12-9.

12.5.2 BASIS FOR COST CENTERS

The basis for estimating the annual operating costs for each cost center are presented below.

A. Coal Mine

A royalty of $1.30 per ton of clean coal was used. Operating supplies consist of explosives and associated supplies used in the mining operation. Equipment operating costs shown in Table 12-10 include operating and maintenance materials. Direct costs for operating labor and supervision are shown in Table 12-11. Maintenance labor is shown in Table 12-12. Payments to the union welfare fund of $0.80 per ton of clean coal are also included together with the expenses of permits and bonds and land reclamation.

B. Coal Preparation

Operating and maintenance labor for the coal preparation area are shown on Table 12-13. The total cost of maintenance is approximately 5% of the fixed capital investment. This is considered to be composed of preventive and routine work (60%) carried out by plant maintenance labor and major maintenance tasks (40%) and by contract labor during unit shutdowns. The routine work is composed of 40% plant labor and 60% material.

Table 12-9 - Manpower Summary

Item	Operating	Maintenance	Administration	Total
Administration			355	355
Coal Mine	529	125		654
Coal Preparation	12	21		33
COED Process	181	300		481
Power Plant	101	40		141
Offsites	21	26	—	47
Total	844	512	355	1,711

Table 12-10 - Coal Mine Equipment Operating Costs
(Excluding Operating and Maintenance Labor)

Item	Quantity	Scheduled (hr/day)	Use Factor (%)	Mechanical Availability (%)	Scheduled (days/yr)	Operated (hr/yr)	Unit Cost ($/hr)	Annual Cost ($)
Stripping Shovels	3	24	100	72.5	350	18,270		3,085,200
Holland Loaders	3	13	100	95	350	12,967	22.11	286,700
DD 9G for Hollands	3	13	100	95	350	12,967	24.75	320,900
Coal Loaders	3	24	73	90	330	15,610	24.03	375,100
Coal Haulers	15	24	73	83.5	330	72,415	21.19	1,534,500
Front End Loaders	3	24	73	80	330	13,876	24.73	343,200
D9 Ripper/Dozers	6	24	73	83.5	330	28,966	13.42	388,700
D9 Dozers	6	24	73	83.5	350	30,721	12.52	384,600
D8 Dozers	3	24	73	83.5	350	15,361	9.11	139,900
Wheel Dozers	3	24	73	80	350	14,717	17.23	253,600
Graders	3	24	73	83.5	350	15,361	5.50	84,500
Light Towers	12	10	90	90	350	34,020	0.86	29,300
Rotary Drills	12	24	73	90	350	66,226	40.99	2,714,600
Track Drill w/Compressor	3	24	73	80	350	13,876	8.29	115,000
Lube/Fuel Trucks	3	24	73	83.5	350	15,361	2.21	33,900
Sprinkler Trucks	3	24	73	83.5	330	14,483	13.92	201,600
AN/FO Trucks	3	16	73	95	350	11,650	2.34	27,300
Mobile Crane, 5 Ton	3	8	10	95	350	798	7.02	5,600
Hydraulic Crane, 15 Ton	3	24	50	95	350	11,970	3.97	47,500
Lowboy/Tractor, 50 Ton	1	8	20	95	350	532	2.97	1,600
Bus, 40 Passenger	1	24	25	95	350	1,995	2.46	4,900
Flatbed Trucks, 3 Ton	8	24	40	90	350	24,192	1.52	36,800
Flatbed Trucks, 5 Ton	8	24	40	90	350	24,192	1.42	34,400
Tire Truck	1	24	40	90	350	3,024	2.22	6,700
Pickup Trucks	15	24	50	90	350	59,850	1.06	63,400
								10,519,500

Table 12-11 - Coal Mine Operating Labor and Supervision

Category	Number of Employees Per Shift	Number of Employees Total	Salaries and Wages ($/day)	Salaries and Wages ($/yr)	Payroll Cost[a] ($/yr)
Mine Superintendent		1		27,500	27,500
General Foreman		1		22,000	22,000
Shovel Foreman		1		19,800	19,800
Blasting Foreman		1		19,800	19,800
Shift Bosses		13		17,600	228,800
Mine Engineer		1		16,500	16,500
Surveyor		2		13,200	26,400
Stripping Shovel Operator	3	13	57.72	15,000	195,000
Stripping Shovel Oiler	3	13	47.48	12,345	160,485
Stripping Shovel Groundman	3	13	44.99	11,700	152,100
Holland Loader Operator	3	13	46.75	12,155	158,015
Belt Conveyor Operator	3	13	46.75	12,155	158,015
Coal Shovel Operator	3	13	46.75	12,155	158,015
Coal Shovel Groundman	3	13	44.99	11,700	152,100
Coal Hauler Drivers	15	63	44.99	11,700	737,100
Rotary Drill Operator	12	51	44.99	11,700	596,700
Rotary Drill Helpers	12	51	43.45	11,300	576,300
FEL Operators	3	13	46.75	12,155	158,015
Dozer Operators	15	63	44.99	11,700	737,100

[a] Excluding payroll taxes and fringe benefits, etc., included in payroll burden.

Table 12-11 (Contd)

Category	Number of Employees		Salaries and Wages		Payroll Cost[a]
	Per Shift	Total	($/day)	($/yr)	($/yr)
Wheel Dozer Operators	3	13	44.99	11,700	152,100
Grader Operators	3	13	44.99	11,700	152,100
Water Sprinkler Driver	3	13	44.99	11,700	152,100
Track Driller	3	13	44.99	11,700	152,100
Lube/Fuel Truck Driver	3	13	42.90	11,155	145,015
Lube/Fuel Truck Driver Mechanic/Helper	3	13	43.45	11,300	146,900
AN/FO Truck Driver	3	8	42.90	11,155	89,240
Loaders/Shooters	6	16	44.99	11,700	187,200
Loaders/Shooters, Laborers	12	30	42.35	11,010	330,300
Conveyor Movers	10	21	42.85	11,140	233,940
Miscellaneous Drivers	2	8	42.90	11,155	89,240
Miscellaneous Operators	2	6	44.99	11,700	70,200
Crane Operator, 15 Ton	3	10	44.99	11,700	117,000
Total		529			6,159,165

[a]Excluding payroll taxes and fringe benefits, etc., included in payroll burden.

Table 12-12 - Coal Mine Maintenance
Labor and Supervision

Category	Number of Employees		Salaries and Wages		Payroll Cost[a]
	First Shift	Total	($/day)	($/yr)	($/yr)
Superintendent	1			19,800	19,800
Shop Foremen	4			17,600	70,400
Draftsman	1			13,200	13,200
Agronomist/ Environmentalist	1			16,500	16,500
Safety Engineer	1			16,500	16,500
Mechanics 1st	12	25	46.75	12,155	303,875
Mechanics 2nd	4	11	44.99	11,700	128,700
Electricians 1st	4	11	46.75	12,155	133,705
Electricians 2nd	2	7	44.99	11,700	81,900
Welders	10	21	46.75	12,155	255,255
Mechanics Helpers	3	7	43.45	11,300	79,100
Parts Man	1	4	44.99	11,700	46,300
Tool Man	1	4	44.99	11,700	46,800
Tire Man	1	4	44.99	11,700	46,800
Laborers	5	10	42.35	11,035	110,350
Agronomist Helpers	3	3	43.45	11,300	33,900
Rodmen	4	4	43.45	11,300	45,200
Clerks	3	7	33.00	8,580	60,060
Typist	4	4	27.50	7,150	28,600
Total		125			1,537,445

[a]Excluding payroll taxes and fringe benefits included in payroll burden.

Table 12-13 - Coal Preparation Operating and Maintenance Labor

Category	Number of Employees		Salaries and Wages		Payroll Cost[a]
	Per Shift	Total	($/day)	($/yr)	($/yr)
Operating Labor					
Operator	1	4	46.75	12,150	48,600
Helper	2	8	42.35	11,000	88,000
Total	3	12			136,600
Maintenance Labor	-	21	45.87	11,925	250,400

[a]Excluding payroll taxes and fringe benefits included in payroll burden.

C. COED Process Plant

Catalysts and chemicals required for the COED process plant are shown in Table 12-3. Operating labor is detailed in Table 12-14 and maintenance forces in Table 12-15. The cost of maintenance amounts to approximately 5% of the fixed capital investment. This is considered to be composed of preventive and routine work (60%) carried out by plant maintenance labor, and major maintenance tasks (40%) carried out by contract labor during unit shutdowns. The routine work is composed of 40% labor and 60% material.

D. Power Plant

Operating and maintenance labor are shown in Table 12-16. Total annual maintenance costs correspond to 1 mil per average production kW-hr (820 MW), plus 1 mil per kW/hr equivalent compressor horsepower.

E. Offsites

Annual consumption and cost of chemicals for water treatment are shown in Table 12-17. Operating and maintenance labor are shown in Table 12-18. Total maintenance cost corresponds to 2% of fixed capital investment with about 30% allocated to labor and the balance to contract labor and materials.

Table 12-14 - Process Plant Operating Labor

Category	Number of Employees		Salaries and Wages		Payroll Cost[a]
	Per Shift	Total	($/day)	($/yr)	($/yr)
Operations Manager		1		35,000	35,000
Shift Supervisors	7	28	6.60	14,760	413,300
Operators					
Unit 11	8	32			
Unit 12	5	20			
Unit 13	5	20			
Unit 14	4	16			
Unit 15	4	16			
Unit 16	5	20			
Unit 17	7	28			
Subtotal Operators	38	152	5.50	12,300	1,869,600
Total Operators plus Supervisors	45	181			2,317,900

[a]Excluding payroll taxes and fringe benefits included in payroll burden.

Table 12-15 - Process Plant Maintenance Labor

Category	Number of Employees Total	Salaries and Wages ($/yr)	Payroll Cost[a] ($/yr)
Craft Foreman	30	20,000	600,000
Craftsmen and Helpers	176	12,000	2,112,000
Labor Foreman	10	15,000	150,000
General Labor	84	10,000	840,000
Total	300		3,702,000

[a]Excluding payroll taxes and fringe benefits included in payroll burden.

Table 12-16 - Power Plant Labor

Category	Number of Employees		Salaries and Wages		Payroll Cost[a]
	Per Shift	Total	($/day)	($/yr)	($/yr)
Operating Labor					
Control Room	4	16			
Gas Turbine	13	52			
Compressors	7	28			
Subtotal Operating	24	96	5.30	11,850	1,137,600

[a]Excluding payroll taxes and fringe benefits included in payroll burden.

Table 12-16 (Contd)

Category	Number of Employees		Salaries and Wages		Payroll Cost[a]
	Per Shift	Total	($/day)	($/yr)	($/yr)
Supervision and Support					
Plant Superintendent		1		35,000	35,000
Assistant Plant Supt.		1		25,000	25,000
Chemist		1		15,000	15,000
Secretary/ Clerk		2		8,000	16,000
Subtotal Supervision and Support		5			91,000
Total Operating and Supervision Labor					1,228,600
Maintenance Shop					
Crafts		36		12,000	432,000
Janitorial/ Gardening		4		10,000	40,000
Subtotal Maintenance Labor		40			472,000
Total Power Plant		141			1,700,600

[a]Excluding payroll taxes and fringe benefits included in payroll burden.

Table 12-17 - Offsites Chemical Cost Summary

Unit	Catalyst or Chemical	Basis or Makeup Requirement	Annual Use Cost ($)
19-2	<u>Cooling Water System</u>		
	H_2SO_4	11,550 lb/stream day	126,290
	Chemicals		626,340
19-3	<u>Industrial Water System</u>		
	Demineralizer		
	H_2SO_4	18,500 lb/stream day	202,575
	NaOH	14,776 lb/stream day	323,390
	Clarifier		
	Lime	47,500 lb/stream day	216,810
	Aluminate	13,000 lb/stream day	260,975
	Poly	750 lb/stream day	172,280
	Boiler Feed Water		
	Chelant	38.4 lb/stream day	18,250
	Hyd	38.4 lb/stream day	18,250
	Total		1,965,960
	Times Operating Rate (330 stream days per year, or 0.904 year) = Total Cost		1,776,500

Table 12-18 - Offsites Labor

Category	Number of Employees		Salaries and Wages		Payroll Cost[a]
	Per Shift	Total	($/day)	($/yr)	($/yr)
Operation					
Shift Foreman	1	4	6.60	14,750	59,000
Gauger		1			
Pumpers	2	8			
Disposal Plant	1	4			
Utility Plant	1	4			
		17	5.50	12,300	209,100
Total		21			268,100
Maintenance					
Shift Foreman		1		20,000	20,000
Electricians		2		12,000	24,000
Instrument		2		12,000	24,000
Pipers and Mechanics	3	12		12,000	144,000
Painters		3		10,000	30,000
General Laborers		4		10,000	40,000
Total		26			332,000

[a]Excluding payroll taxes and fringe benefits included in payroll burden.

12.6 FINANCIAL PARAMETERS

12.6.1 FINANCIAL STRUCTURE

Economics were developed for three types of project financial structures.

(1) Private ownership with 100% equity capital fully taxed.

(2) Private ownership with borrowed capital, fully taxed; interest during construction including a loan commitment fee at 0.75%, 65% of the total investment borrowed at 9% interest with principal repaid in equal installments over the 20-year project term; and working capital borrowed for the 20-year term.

(3) A nontaxable and nonprofit (0% discounted cash flow rate of return) boundary case. This case provides a profitability boundary limit based on the hypothetical assumption that there are no fiscal or financial costs.

12.6.2 RETURN ON INVESTMENT

For each of the above cases a discounted cash flow (DCF) rate of return after tax is specified and the revenue required to meet this objective calculated. The DCF computations take into consideration the 10% depletion allowance on the coal mine operation, depreciation allowances as shown in Table 12-7, an investment tax credit of 7% of 90% of the fixed capital investment, and a combined income tax rate of 52% for state and Federal taxes. Note that the computations were made before the current investment tax credit of 10% became applicable.

Useful lives for asset depreciation purposes conform with Depreciation Guidelines and Rules, Revenue Procedure 62-21. The double declining balance method of depreciation was used for all assets except the coal mine. Coal mine depreciation is based on the schedules shown in Table 12-6. The guidelines for the chemicals and allied products industry under group three, Guidelines for Manufacturing, were used for the Coal Preparation and COED Process Plant. The guidelines for a steam production plant for the production of electricity for electric utilities, group four, were used for the power plant.

12.7 REQUIRED PRODUCT SELLING PRICE

The revenue required to achieve a specified rate of return based on the DCF method is calculated for each of the three financial structure cases. Sensitivities of required selling price to variations in operating costs, fixed capital investment, and profitability levels are presented in subsection 12.9.

The results for the base cases are summarized in Table 12-19, showing the contribution of each of the five cost centers to the total required revenue. The printouts of cash flow case evaluations for the base cases representative

Table 12-19 - Contribution of Cost Centers to Required Revenue

Category	Boundary Case Nonprofit - Nontaxed		Private Ownership 10% Return (DCF)			
			100% Equity		65% Debt	
	$MM	%	$MM	%	$MM	%
Coal Mine	55.030	38.5	70.844	20.7	69.350	23.0
Coal Preparation	3.583	2.5	9.380	2.8	8.261	3.0
COED Process	44.056	31.0	128.658	37.5	112.422	37.5
Power Plant	29.834	21.0	107.675	31.5	87.701	29.2
Offsites	9.904	7.0	26.088	7.5	21.965	7.3
Total Required Revenue	142.407	100.0	342.071	100.0	298.128	100.0

of each of the types of financing are shown in Tables 12-20 through 12-22. Table 12-20 contains the cash flow for the case of private ownership with 100% equity financing with a 10% DCF after tax rate of return. The required revenue is $342 million per year. Table 12-21 contains the cash flow for the case of private ownership with 65% debt at 9% per year interest. The required revenue is reduced to $298 million by the debt financing. Table 12-22 contains the cash flow for the boundary case with no return on invested funds and no property or income taxes. The resulting revenue requirement is $142 million per year.

For the typical case, the plant produces approximately 9.24 MM bbl/yr of liquid product and 6.5 billion kW-hr/yr of electric power. The selling prices required to achieve the required revenue are represented by the following linear equation:

$$\text{Required Revenue} = (\text{oil price}) \times (9.24 \times 10^6)\ \text{bbl}) + (\text{power price}) \times (6.5 \times 10^9\ \text{kW-hr})$$

For the typical cases, the relationship between required selling prices for the three project structures is shown graphically in Figure 12-4.

The plant is designed to provide the flexibility to process feed coal with a range of analysis which might be expected over a 20-year operating life. The maximum, minimum, and typical oil production cases are shown graphically in Figure 12-5 for the case of private ownership with 100% equity.

Table 12-20 - Cash Flow Case Evaluation
Private Ownership - 100% Equity

THE RALPH M. PARSONS COMPANY

CASH FLOW CASE EVALUATION — PAGE 1
U.S. DOLLARS - MILLIONS — COED CONCEPTUAL PLANT — JOB NO. 5435 - 1 — DATE 07/09/75

COED CONCEPTUAL PLANT - TOTAL COMPLEX
PRIVATE OWNERSHIP-100 PCT EQUITY.
REQUIRED REVENUE TO GIVE 10 PCT DISCOUNTED CASH FLOW AFTER TAX - 20 YEAR LIFE

VARIATIONS EVALUATED IN THIS CASE ARE:
COST 0.0 REVENUE 0.0 INVESTMENT 0.0

PERIOD	-5	-4	-3	-2	-1	1	2	3	4	5	6	7
(REVENUE)												
PRODUCT REVENUE	0.000	0.000	0.000	0.000	0.000	171.035	342.071	342.071	342.071	342.071	342.071	342.071
BY-PRODUCT REVENUE	0.000	0.000	0.000	0.000	0.000	6.270	12.540	12.540	12.540	12.540	12.540	12.540
... T O T A L ...	0.000	0.000	0.000	0.000	0.000	177.305	354.611	354.611	354.611	354.611	354.611	354.611
(COSTS)												
OPERATION COAL MINE	0.000	0.000	0.000	0.000	0.000	25.471	46.429	46.429	46.429	46.429	46.429	46.429
OPERATION COAL PREP	0.000	0.000	0.000	0.000	0.000	1.729	1.955	1.955	1.955	1.955	1.955	1.955
OPERATION COED PROC	0.000	0.000	0.000	0.000	0.000	27.151	32.631	32.631	32.631	32.631	32.631	32.631
OPERATION POWER PLT	0.000	0.000	0.000	0.000	0.000	9.002	9.907	9.907	9.907	9.907	9.907	9.907
OPERATION OFF-SITES	0.000	0.000	0.000	0.000	0.000	3.737	5.757	5.757	5.757	5.757	5.757	5.757
PROPERTY TAX + INSUR	0.000	0.000	0.000	0.000	0.000	30.000	30.000	30.000	30.000	30.000	30.000	30.000
... T O T A L ...	0.000	0.000	0.000	0.000	0.000	97.079	126.759	126.759	126.759	126.759	126.759	126.759
DEPRECH. - COAL MINE	0.000	0.000	0.000	0.000	0.000	9.985	9.985	9.985	9.985	9.985	9.985	9.985
DEPRECH. - COAL PREP	0.000	0.000	0.000	0.000	0.000	5.636	4.612	3.773	3.087	2.526	2.067	1.860
DEPRECH. - COED PROC	0.000	0.000	0.000	0.000	0.000	83.006	67.915	55.562	45.460	37.195	30.432	27.309
DEPRECH. - POWER PLT	0.000	0.000	0.000	0.000	0.000	27.351	25.483	23.589	21.905	20.339	18.856	17.937
DEPRECH. - OFF-SITES	0.000	0.000	0.000	0.000	0.000	8.000	7.200	6.480	5.832	5.249	4.724	4.252
DEPLETION COAL MINE	0.000	0.000	0.000	0.000	0.000	0.000	5.695	5.695	5.695	5.695	5.695	5.695
COST + DEPR + DEPL	0.000	0.000	0.000	0.000	0.000	230.971	247.483	231.763	219.642	207.660	198.468	193.397
PROFIT BEFORE TAX	0.000	0.000	0.000	0.000	0.000	-53.666	107.128	122.848	135.969	146.943	156.143	161.214
INCOME TAX	0.000	0.000	0.000	0.000	0.000	0.000	27.000	63.881	70.704	76.410	81.194	83.831
TAX CREDIT	0.000	0.000	0.000	0.000	0.000	0.000	27.000	35.200	0.000	0.000	0.000	0.000
PROFIT AFTER TAX	0.000	0.000	0.000	0.000	0.000	-53.666	107.128	94.167	65.265	70.533	74.949	77.383
AVERAGE ANNUAL NET PROFIT		81.107										
CASHFLOW, OPERATIONS	0.000	0.000	0.000	0.000	0.000	60.276	227.852	199.171	157.140	151.441	146.657	144.020
ACCUM GROSS CASHFLOW	0.000	0.000	0.000	0.000	0.000	60.276	384.875	587.249	664.397	815.838	962.49E	1106.518
(INVESTMENT)												
FIXED CAP INVESTMENT	24.620	66.390	185.015	449.285	274.700	0.000	0.000	0.000	0.000	0.000	0.000	0.000
INITIAL CAT + CHEM.	0.000	0.000	0.000	0.000	4.500	0.000	0.000	0.000	0.000	0.000	0.000	0.000
START-UP	0.000	0.000	0.000	0.000	23.000	20.000	0.000	0.000	0.000	0.000	0.000	0.000
EQUIPMENT REPLACEMNT	0.000	0.000	0.000	0.000	0.000	0.000	0.000	4.035	4.431	4.657	4.035	2.200
TOTAL FIXED INVEST	24.620	66.390	185.015	449.285	302.200	20.000	0.000	4.035	4.431	4.657	4.035	2.200
WORKING CAP PAID IN	0.000	0.000	0.000	0.000	0.000	70.000	0.000	0.000	0.000	0.000	0.000	0.000
NET CASH FLOW	-24.620	-66.339	-185.015	-449.285	-302.200	-17.774	227.852	195.136	152.717	146.796	142.672	141.812
ACCUM NET CASHFLOW	-24.620	-91.333	-276.015	-725.300	-1027.500	-1045.274	-817.422	-622.286	-469.569	-322.785	-180.162	-38.350

----- NET CASH FLOW DISCOUNTED AT 10.000 / PERIOD -----

	-5	-4	-3	-2	-1	1	2	3	4	5	6	7
FACTORS	.909	.826	.751	.683	.621	.564	.513	.467	.424	.386	.350	.319
PRESENT VALUE	-22.382	-54.460	-139.085	-306.068	-187.642	-10.033	116.924	91.032	64.767	56.592	49.940	45.186
CUMULATIVE VALUE	-22.382	-77.241	-216.246	-523.114	-710.756	-720.789	-603.865	-512.832	-444.066	-391.474	-341.498	-296.308

Table 12-20 (Contd)

THE RALPH M. PARSONS COMPANY — PAGE 2

CASH FLOW CASE EVALUATION
U.S. DOLLARS - MILLIONS

COED CONCEPTUAL PLANT
JOB NO. 5435 - 1 DATE 07/09/75

COED CONCEPTUAL PLANT - TOTAL COMPLEX
PRIVATE OWNERSHIP-100 PCT EQUITY
REQUIRED REVENUE TO GIVE 10 PCT DISCOUNTED CASH FLOW AFTER TAX - 20 YEAR LIFE

VARIATIONS EVALUATED IN THIS CASE ARE:
COST 0.0 REVENUE 0.0 INVESTMENT 0.0

PERIOD	8	9	10	11	12	13	14	15	16	17	18	19
(REVENUE)												
PRODUCT REVENUE	342.871	342.871	342.871	342.871	342.871	342.871	342.871	342.871	342.871	342.871	342.871	342.871
BY-PRODUCT REVENUE	12.540	12.540	12.540	12.540	12.540	12.540	12.540	12.540	12.540	12.540	12.540	12.540
... T O T A L ...	354.611	354.611	354.611	354.611	354.611	354.611	354.611	354.611	354.611	354.611	354.611	354.611
(COSTS)												
OPERATION COAL MINE	46.429	46.429	46.429	46.429	46.429	46.429	46.429	46.429	46.429	46.429	46.429	46.429
OPERATION COAL PREP	1.955	1.955	1.955	1.955	1.955	1.955	1.955	1.955	1.955	1.955	1.955	1.955
OPERATION COED PROC	32.631	32.631	32.631	32.631	32.631	32.631	32.631	32.631	32.631	32.631	32.631	32.631
OPERATION POWER PLT	9.987	9.987	9.987	9.987	9.987	9.987	9.987	9.987	9.987	9.987	9.987	9.987
OPERATION OFF-SITES	5.757	5.757	5.757	5.757	5.757	5.757	5.757	5.757	5.757	5.757	5.757	5.757
PROPERTY TAX + INSUR	30.000	30.000	30.000	30.000	30.000	30.000	30.000	30.000	30.000	30.000	30.000	30.000
... T O T A L ...	126.759	126.759	126.759	126.759	126.759	126.759	126.759	126.759	126.759	126.759	126.759	126.759
DEPRECN. - COAL MINE	9.905	9.905	9.905	6.376	6.376	6.376	6.376	6.376	6.376	6.376	6.376	6.376
DEPRECN. - COAL PREP	1.860	1.860	1.860	1.860	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DEPRECN. - COED PROC	27.389	27.389	27.389	27.389	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DEPRECN. - POWER PLT	16.285	15.121	14.041	13.038	12.107	11.242	10.439	9.694	9.694	9.694	9.694	9.694
DEPRECN. - OFF-SITES	3.826	3.444	3.099	2.789	2.789	2.789	2.789	2.789	2.789	2.789	2.789	2.789
DEPLETION COAL MINE	5.695	5.695	5.695	7.084	7.084	7.084	7.084	7.084	7.084	7.084	7.084	7.084
COST + DEPR + DEPL	191.719	190.173	188.749	185.295	155.115	154.250	153.447	152.702	152.702	152.702	152.702	152.702
PROFIT BEFORE TAX	162.891	164.438	165.862	169.316	199.496	200.361	201.164	201.909	201.909	201.909	201.909	201.909
INCOME TAX	84.704	85.508	86.248	88.044	103.738	104.188	104.605	104.993	104.993	104.993	104.993	104.993
TAX CREDIT	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
PROFIT AFTER TAX	78.188	78.930	79.614	81.272	95.758	96.173	96.559	96.916	96.916	96.916	96.916	96.916
AVERAGE ANNUAL NET PROFIT		81.187										
CASHFLOW, OPERATIONS	143.148	142.344	141.603	139.888	124.114	123.664	123.247	122.859	122.859	122.859	122.859	122.859
ACCUM GROSS CASHFLOW	1269.664	1392.008	1533.612	1673.519	1797.533	1921.197	2044.444	2167.303	2290.162	2413.022	2535.881	2659.740
(INVESTMENT)												
FIXED CAP INVESTMENT	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
INITIAL CAT + CHEM.	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
START-UP	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
EQUIPMENT REPLACEMNT	4.431	4.835	4.807	0.000	5.466	0.000	2.204	8.692	4.431	0.000	4.035	0.000
TOTAL FIXED INVEST	4.431	4.835	4.807	0.000	5.466	0.000	2.204	8.692	4.431	0.000	4.035	0.000
WORKING CAP PAID IN	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
NET CASH FLOW	138.717	137.509	136.796	139.888	118.648	123.664	121.043	114.167	118.428	122.859	118.824	122.859
ACCUM NET CASHFLOW	100.367	234.676	375.473	515.280	630.928	754.592	875.631	989.799	1108.226	1231.086	1349.910	1472.769

----- NET CASH FLOW DISCOUNTED AT 10.000 / PERIOD -----

	8	9	10	11	12	13	14	15	16	17	18	19
FACTORS	.290	.263	.239	.218	.198	.180	.164	.149	.135	.123	.112	.102
PRESENT VALUE	40.101	36.421	32.748	30.426	22.890	22.242	19.791	16.970	16.003	15.093	13.270	12.473
CUMULATIVE VALUE	-256.118	-219.697	-186.949	-156.523	-133.663	-111.401	-91.610	-74.640	-58.636	-43.544	-30.273	-17.800

Table 12-20 (Contd)

THE RALPH M. PARSONS COMPANY

PAGE 3

CASH FLOW CASE EVALUATION
U.S. DOLLARS - MILLIONS

COED CONCEPTUAL PLANT
JOB NO. 5635 - 1   DATE 07/09/75

COED CONCEPTUAL PLANT - TOTAL COMPLEX
PRIVATE OWNERSHIP-100 PCT EQUITY
REQUIRED REVENUE TO GIVE 10 PCT DISCOUNTED CASH FLOW AFTER TAX - 20 YEAR LIFE

VARIATIONS EVALUATED IN THIS CASE ARE
COST 0.0   REVENUE 0.0   INVESTMENT 0.0

PERIOD	20
(REVENUE)	
PRODUCT REVENUE	342.071
BY-PRODUCT REVENUE	12.540
... T O T A L ...	354.611
(COSTS)	
OPERATION COAL MINE	46.429
OPERATION COAL PREP	1.955
OPERATION COED PROC	32.531
OPERATION POWER PLT	9.987
OPERATION OFF-SITES	5.757
PROPERTY TAX + INSUR	30.000
... T O T A L ...	126.759
DEPRECN. - COAL MINE	6.375
DEPRECN. - COAL PREP	0.000
DEPRECN. - COED PROC	0.000
DEPRECN. - POWER PLT	3.695
DEPRECN. - OFF-SITES	2.799
DEPLETION COAL MINE	7.885
COST + DEPR + DEPL	152.702
PROFIT BEFORE TAX	201.909
INCOME TAX	104.993
TAX CREDIT	0.000
PROFIT AFTER TAX	96.916
AVERAGE ANNUAL NET PROFIT	81.187
CASHFLOW, OPERATIONS	122.459
ACCUM GROSS CASHFLOW	2781.599
(INVESTMENT)	
FIXED CAP INVESTMENT	0.000
INITIAL CAT + CHEM.	0.000
START-UP	0.000
EQUIPMENT REPLACEMNT	0.000
TOTAL FIXED INVEST	0.000
WORKING CAP PAID IN	-70.000
NET CASH FLOW	192.459
ACCUM NET CASHFLOW	1665.624

----- NET CASH FLOW DISCOUNTED AT 10.000 / PERIOD -----

FACTORS	.092
PRESENT VALUE	17.800
CUMULATIVE VALUE	.000

Table 12-21 - Cash Flow Case Evaluation

Private Ownership - 65% Debt Financing at 9%

THE RALPH M. PARSONS COMPANY

PAGE 1

CASH FLOW CASE EVALUATION
U.S. DOLLARS - MILLIONS

COED CONCEPTUAL PLANT
JOB NO. 5435 - 1 DATE 07/09/75

COED CONCEPTUAL PLANT - TOTAL COMPLEX
PRIVATE OWNERSHIP--65 PERCENT DEBT FINANCING AT 9.0 PERCENT
REQUIRED REVENUE TO GIVE 12 PCT DISCOUNTED CASH FLOW AFTER TAX - 20 YEAR LIFE

VARIATIONS EVALUATED IN THIS CASE ARE
COST 0.0 REVENUE 0.0 INVESTMENT 0.0

PERIOD	-5	-4	-3	-2	-1	1	2	3	4	5	6	7
(REVENUE)												
PRODUCT REVENUE	0.000	0.000	0.000	0.000	0.000	149.064	298.124	298.128	298.128	298.128	298.128	298.128
BY-PRODUCT REVENUE	0.000	0.000	0.000	0.000	0.000	6.270	12.540	12.540	12.540	12.540	12.540	12.540
... T O T A L ...	0.000	0.000	0.000	0.000	0.000	155.334	310.668	310.668	310.668	310.668	310.668	310.668
(COSTS)												
OPERATION COAL MINE	0.000	0.000	0.000	0.000	0.000	25.471	46.429	46.429	46.429	46.429	46.429	46.429
OPERATION COAL PREP	0.000	0.000	0.000	0.000	0.000	1.729	1.955	1.955	1.955	1.955	1.955	1.955
OPERATION COED PROC	0.000	0.000	0.000	0.000	0.000	27.148	32.631	32.631	32.631	32.631	32.631	32.631
OPERATION POWER PLT	0.000	0.000	0.000	0.000	0.000	9.002	9.987	9.987	9.987	9.987	9.987	9.987
OPERATION OFF-SITES	0.000	0.000	0.000	0.000	0.000	3.737	5.757	5.757	5.757	5.757	5.757	5.757
PROPERTY TAX + INSUR	0.000	0.000	0.000	0.000	0.000	30.000	30.000	30.000	30.000	30.000	30.000	30.000
INTEREST ON DEBT	0.000	0.000	0.000	0.000	0.000	65.922	62.453	58.983	55.513	52.044	48.574	45.105
INT. ON WORKING CAP.	0.000	0.000	0.000	0.000	0.000	4.095	4.095	4.095	4.095	4.095	4.095	4.095
... T O T A L ...	0.000	0.000	0.000	0.000	0.000	167.096	193.307	189.837	186.367	182.898	179.428	175.959
DEPRECN. - COAL MINE	0.000	0.000	0.000	0.000	0.000	9.905	9.905	9.905	9.905	9.905	9.905	9.905
DEPRECN. - COAL PREP	0.000	0.000	0.000	0.000	0.000	6.318	5.169	4.238	3.461	2.831	2.317	2.885
DEPRECN. - COED PROC	0.000	0.000	0.000	0.000	0.000	92.818	75.942	62.135	50.837	41.594	34.032	30.628
DEPRECN. - POWER PLT	0.000	0.000	0.000	0.000	0.000	30.571	29.347	26.360	24.477	22.728	21.105	19.597
DEPRECN. - OFF-SITES	0.000	0.000	0.000	0.000	0.000	9.025	8.123	7.310	6.579	5.921	5.329	4.796
DEPLETION COAL MINE	0.000	0.000	0.000	0.000	0.000	0.000	5.695	3.788	3.788	3.788	3.788	3.788
COST + DEPR + DEPL	0.000	0.000	0.000	0.000	0.000	315.733	326.527	303.485	285.334	269.585	255.024	246.670
PROFIT BEFORE TAX	0.000	0.000	0.000	0.000	0.000	-160.399	-15.859	7.183	25.334	41.082	54.844	63.998
INCOME TAX	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	25.020
TAX CREDIT	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	25.020
PROFIT AFTER TAX	0.000	0.000	0.000	0.000	0.000	-160.399	-15.859	7.183	25.335	41.082	54.844	63.998
AVERAGE ANNUAL NET PROFIT		46.491										
CASHFLOW, OPERATIONS	0.000	0.000	0.000	0.000	0.000	-11.762	117.361	120.831	124.301	127.770	131.240	134.709
ACCUM GROSS CASHFLOW	0.000	0.000	0.000	0.000	0.000	-11.762	105.599	226.430	350.731	478.501	609.741	744.450
(INVESTMENT)												
FIXED CAP INVESTMENT	24.620	66.380	185.015	449.285	274.700	0.000	0.000	0.000	0.000	0.000	0.000	0.000
INITIAL CAT + CHEM.	0.000	0.000	0.000	0.000	6.500	0.000	0.000	0.000	0.000	0.000	0.000	0.000
START-UP	0.000	0.000	0.000	0.000	23.000	29.000	0.000	0.000	0.000	0.000	0.000	0.000
EQUIPMENT REPLACEMNT	0.000	0.000	0.000	0.000	0.000	0.000	0.000	5.035	4.431	4.657	5.035	2.200
INT. DURING CONSTR.	0.000	.317	1.077	35.460	63.625	0.000	0.000	0.000	0.000	0.000	0.000	0.000
COMMITMENT FEE	5.746	5.783	5.656	2.791	.444	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL FIXED INVEST	30.366	72.500	191.748	487.536	366.269	29.000	0.000	5.035	4.431	4.657	5.035	2.200
WORKING CAP PAID IN	0.000	0.000	0.000	0.000	0.000	70.000	0.000	0.000	0.000	0.000	0.000	0.000
BORROWED CAPITAL	5.746	6.220	6.733	413.551	330.769	0.000	0.000	0.000	0.000	0.000	0.000	0.000
WORKING CAP BORROWED	0.000	0.000	0.000	0.000	0.000	45.500	0.000	0.000	0.000	0.000	0.000	0.000
LOAN REPAYMENT	0.000	0.000	0.000	0.000	0.000	34.551	34.551	34.551	34.551	34.551	34.551	39.551
WORKING CAP REPAYMNT	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
NET CASH FLOW	-24.670	-66.316	-199.015	[illegible]	-77.583	-102.913	78.918	79.245	81.319	84.562	89.654	93.950
ACCUM NET CASHFLOW	-24.670	-91.010	[illegible]	-364.000	[illegible]	-480.313	-401.593	-323.954	-241.839	-157.377	-67.723	25.277

----- NET CASH FLOW DISCOUNTED AT [illegible] / PERIOD -----

PERIOD	-5	-4	-3	-2	-1	1	2	3	4	5	6	7
FACTORS	.909	.826	.751	.683	.621	.564	.513	.467	.424	.386	.350	.319
PRESENT VALUE	-22.382	-54.951	-129.0[illegible]	-50.[illegible]	-17.479	-58.035	40.462	36.502	34.497	32.602	31.073	29.935
CUMULATIVE VALUE	-22.382	[illegible]	[illegible]	[illegible]	[illegible]	-341.889	-301.447	-264.945	-230.459	-197.856	-166.783	-136.868
DEBT BALANCE	5.746	11.966	[illegible]	[illegible]	771.019	732.468	[illegible]	655.366	616.315	578.264	539.713	501.162
BALANCE W/CAP LOAN	1.000	[illegible]	[illegible]	[illegible]	0.000	45.510	[illegible]	45.500	45.500	45.500	45.500	45.500

Table 12-21 (Contd)

THE RALPH M. PARSONS COMPANY

CASH FLOW CASE EVALUATION
U.S. DOLLARS - MILLIONS

COED CONCEPTUAL PLANT
JOB NO. 5435 - 1 DATE 07/09/75

COED CONCEPTUAL PLANT - TOTAL COMPLEX
PRIVATE OWNERSHIP--65 PERCENT DEBT FINANCING AT 9.0 PERCENT
REQUIRED REVENUE TO GIVE 10 PCT DISCOUNTED CASH FLOW AFTER TAX - 20 YEAR LIFE

VARIATIONS EVALUATED IN THIS CASE ARE:
COST 0.0 REVENUE 0.0 INVESTMENT 0.0

PERIOD	8	9	10	11	12	13	14	15	16	17	18	19
(REVENUE)												
PRODUCT REVENUE	298.128	298.128	298.128	298.128	298.128	298.128	298.128	298.128	298.128	298.128	298.128	298.128
BY-PRODUCT REVENUE	12.540	12.540	12.540	12.540	12.540	12.540	12.540	12.540	12.540	12.540	12.540	12.540
... T O T A L ...	310.668	310.668	310.668	310.668	310.668	310.668	310.668	310.668	310.668	310.668	310.668	310.668
(COSTS)												
OPERATION COAL MINE	46.429	46.429	46.429	46.429	46.429	46.429	46.429	46.429	46.429	46.429	46.429	46.429
OPERATION COAL PREP	1.955	1.955	1.955	1.955	1.955	1.955	1.955	1.955	1.955	1.955	1.955	1.955
OPERATION COED PROC	32.631	32.631	32.631	32.631	32.631	32.631	32.631	32.631	32.631	32.631	32.631	32.631
OPERATION POWER PLT	9.987	9.987	9.987	9.987	9.987	9.987	9.987	9.987	9.987	9.987	9.987	9.987
OPERATION OFF-SITES	5.757	5.757	5.757	5.757	5.757	5.757	5.757	5.757	5.757	5.757	5.757	5.757
PROPERTY TAX + INSUR	30.000	30.000	30.000	30.000	30.000	30.000	30.000	30.000	30.000	30.000	30.000	30.000
INTEREST ON DEBT	41.635	38.165	34.696	31.226	27.757	24.287	20.817	17.348	13.878	10.409	6.939	3.470
INT. ON WORKING CAP.	4.095	4.095	4.095	4.095	4.095	4.095	4.095	4.095	4.095	4.095	4.095	4.095
... T O T A L ...	172.489	169.019	165.550	162.080	158.611	155.141	151.671	148.202	144.732	141.263	137.793	134.324
DEPRECN. - COAL MINE	9.905	9.905	9.905	6.376	6.376	6.376	6.376	6.376	6.376	6.376	6.376	6.376
DEPRECN. - COAL PREP	2.085	2.085	2.085	2.085	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DEPRECN. - COED PROC	30.628	30.628	30.628	30.628	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
DEPRECN. - POWER PLT	16.138	15.878	15.691	14.570	13.529	12.563	11.665	10.832	10.832	10.832	10.832	10.832
DEPRECN. - OFF-SITES	4.317	3.855	3.436	3.147	3.147	3.147	3.147	3.147	3.147	3.147	3.147	3.147
DEPLETION COAL MINE	3.708	3.708	3.708	3.708	3.708	3.708	3.708	3.708	3.708	3.708	3.708	3.708
COST + DEPR + DEPL	241.329	236.129	231.063	222.594	185.371	180.935	176.568	172.265	168.795	165.326	161.856	158.387
PROFIT BEFORE TAX	69.339	74.540	79.605	88.074	125.297	129.733	134.100	138.403	141.873	145.342	148.812	152.281
INCOME TAX	36.056	38.761	41.395	45.798	65.154	67.461	69.732	71.970	73.774	75.578	77.382	79.186
TAX CREDIT	36.056	1.916	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
PROFIT AFTER TAX	69.339	37.695	38.210	42.275	60.143	62.272	64.368	66.433	68.099	69.764	71.430	73.095
AVERAGE ANNUAL NET PROFIT		43.901										
CASHFLOW, OPERATIONS	138.179	104.894	103.724	102.789	86.903	88.068	89.264	90.496	92.162	93.827	95.493	97.158
ACCUM GROSS CASHFLOW	882.529	987.433	1091.156	1193.946	1280.848	1368.914	1458.179	1548.675	1640.837	1734.664	1830.157	1927.315
(INVESTMENT)												
FIXED CAP INVESTMENT	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
INITIAL CAT + CHEM.	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
START-UP	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
EQUIPMENT REPLACEMNT	4.431	4.035	4.507	0.000	4.466	0.000	2.208	5.692	4.431	0.000	4.035	0.000
INT. DURING CONSTR.	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
COMMITMENT FEE	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL FIXED INVEST	4.431	4.035	4.507	0.000	4.466	0.000	2.208	5.692	4.431	0.000	4.035	0.000
WORKING CAP PAID IN	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
BORROWED CAPITAL	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
WORKING CAP BORROWED	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
LOAN REPAYMENT	38.551	38.551	38.551	38.551	38.551	38.551	38.551	38.551	38.551	38.551	38.551	38.551
WORKING CAP REPAYMNT	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
NET CASH FLOW	95.197	62.219	60.366	64.239	39.886	49.515	48.505	43.253	49.180	55.276	52.987	58.607
ACCUM NET CASHFLOW	120.424	182.643	243.011	307.246	347.131	396.646	445.151	488.405	537.585	592.861	645.768	704.375

----- NET CASH FLOW DISCOUNTED AT 10.000 / PERIOD -----

	8	9	10	11	12	13	14	15	16	17	18	19
FACTORS	.230	.263	.239	.218	.198	.180	.164	.149	.135	.123	.112	.102
PRESENT VALUE	27.575	16.394	14.451	13.980	7.891	8.906	7.931	6.429	6.646	6.790	5.909	5.950
CUMULATIVE VALUE	-103.273	[illegible]	[illegible]	[illegible]	-54.566	-47.661	-39.733	-33.300	-26.655	-19.864	-13.956	-8.006
DEBT BALANCE	462.411	424.059	385.513	346.958	308.407	269.856	231.305	132.754	154.203	115.652	77.101	38.550
BALANCE W/CAP LOAN	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500	45.500

Table 12-21 (Contd)

THE RALPH M. PARSONS COMPANY PAGE 3

CASH FLOW CASE EVALUATION
U.S. DOLLARS - MILLIONS

COED CONCEPTUAL PLANT
JOB NO. 5435 - 1 DATE 07/09/75

COED CONCEPTUAL PLANT - TOTAL COMPLEX
PRIVATE OWNERSHIP--65 PERCENT DEBT FINANCING AT 9.0 PERCENT
REQUIRED REVENUE TO GIVE 10 PCT DISCOUNTED CASH FLOW AFTER TAX - 20 YEAR LIFE

VARIATIONS EVALUATED IN THIS CASE ARE:
COST 0.0 REVENUE 0.0 INVESTMENT 0.0

PERIOD	20
(REVENUE)	
PRODUCT REVENUE	298.128
BY-PRODUCT REVENUE	12.540
... T O T A L ...	310.668
(COSTS)	
OPERATION COAL MINE	46.429
OPERATION COAL PREP	1.955
OPERATION COED PROC	32.631
OPERATION POWER PLT	9.987
OPERATION OFF-SITES	5.757
PROPERTY TAX + INSUR	30.080
INTEREST ON DEBT	-.000
INT. ON WORKING CAP.	0.000
... T O T A L ...	126.759
DEPRECN. - COAL MINE	6.376
DEPRECN. - COAL PREP	0.308
DEPRECN. - COED PROC	0.000
DEPRECN. - POWER PLT	10.832
DEPRECN. - OFF-SITES	3.147
DEPLETION COAL MINE	3.788
COST + DEPR + DEPL	150.322
PROFIT BEFORE TAX	159.846
INCOME TAX	83.120
TAX CREDIT	0.000
PROFIT AFTER TAX	76.726
AVERAGE ANNUAL NET PROFIT	43.881
CASHFLOW, OPERATIONS	100.749
ACCUM GROSS CASHFLOW	2028.184
(INVESTMENT)	
FIXED CAP INVESTMENT	0.000
INITIAL CAT + CHEM.	0.000
START-UP	0.000
EQUIPMENT REPLACEMNT	0.000
INT. DURING CONSTR.	0.000
COMMITMENT FEE	0.000
TOTAL FIXED INVEST	0.000
WORKING CAP PAID IN	-70.000
BORROWED CAPITAL	0.000
WORKING CAP BORROWED	0.000
LOAN REPAYMENT	30.551
WORKING CAP REPAYMNT	45.500
NET CASH FLOW	86.738
ACCUM NET CASHFLOW	791.113

----- NET CASH FLOW DISCOUNTED AT 10.000 / PERIOD -----

FACTORS	.092
PRESENT VALUE	1.846
CUMULATIVE VALUE	-.000
DEBT BALANCE	-.001
BALANCE W/CAP LOAN	0.000

Table 12-22 - Cash Flow Case Evaluation
Boundary Case - Nonprofit - Not Taxed

THE RALPH M. PARSONS COMPANY

CASH FLOW CASE EVALUATION
U.S. DOLLARS - MILLIONS

COED CONCEPTUAL PLANT
JOB NO. 5435 - 1 DATE 07/09/75

PAGE 1

COED CONCEPTUAL PLANT - TOTAL COMPLEX
 - NON PROFIT - NOT TAXED
REQUIRED REVENUE TO GIVE 0 PCT DISCOUNTED CASH FLOW AFTER TAX - 20 YEAR LIFE

VARIATIONS EVALUATED IN THIS CASE ARE
COST 0.0 REVENUE 0.0 INVESTMENT 0.0

PERIOD	-5	-4	-3	-2	-1	1	2	3	4	5	6	7
(REVENUE)												
PRODUCT REVENUE	0.000	0.000	0.000	0.000	0.000	71.204	142.407	142.407	142.407	142.407	142.407	142.407
BY-PRODUCT REVENUE	0.000	0.000	0.000	0.000	0.000	6.270	12.540	12.540	12.540	12.540	12.540	12.540
... T O T A L ...	0.000	0.000	0.000	0.000	0.000	77.474	154.947	154.947	154.947	154.947	154.947	154.947
(COSTS)												
OPERATION COAL MINE	0.000	0.000	0.000	0.000	0.000	35.471	46.429	46.429	46.429	46.429	46.429	46.429
OPERATION COAL PREP	0.000	0.000	0.000	0.000	0.000	1.725	1.955	1.955	1.955	1.955	1.955	1.955
OPERATION COED PROC	0.000	0.000	0.000	0.000	0.000	27.146	32.631	32.631	32.631	32.631	32.631	32.631
OPERATION POWER PLT	0.000	0.000	0.000	0.000	0.000	9.082	9.987	9.987	9.987	9.987	9.987	9.987
OPERATION OFF-SITES	0.000	0.000	0.000	0.000	0.000	3.717	5.757	5.757	5.757	5.757	5.757	5.757
... T O T A L ...	0.000	0.000	0.000	0.000	0.000	67.079	96.759	96.759	96.759	96.759	96.759	96.759
CASHFLOW, OPERATIONS	0.000	0.000	0.000	0.000	0.000	10.395	58.188	58.188	58.188	58.188	58.188	58.188
ACCUM GROSS CASHFLOW	0.000	0.000	0.000	0.000	0.000	10.395	68.583	126.771	184.959	243.148	301.336	359.524
(INVESTMENT)												
FIXED CAP INVESTMENT	24.620	66.380	185.015	443.285	276.700	0.000	0.000	0.000	0.000	0.000	0.000	0.000
INITIAL CAT + CHEM.	0.000	0.000	0.000	0.000	4.500	0.000	0.000	0.000	0.000	0.000	0.000	0.000
START-UP	0.000	0.000	0.000	0.000	21.000	28.000	0.000	0.000	0.000	0.000	0.000	0.000
EQUIPMENT REPLACEMNT	0.000	0.000	0.000	0.000	0.000	0.000	0.000	4.035	4.431	4.657	4.035	2.208
TOTAL FIXED INVEST	24.620	66.380	185.015	443.285	302.200	28.000	0.000	4.035	4.431	4.657	4.035	2.209
WORKING CAP PAID IN	0.000	0.000	0.000	0.000	0.000	78.000	0.000	0.000	0.000	0.000	0.000	0.000
NET CASH FLOW	-24.620	-66.380	-185.015	-443.285	-182.200	-87.605	58.188	54.153	53.757	53.531	54.153	55.980
ACCUM NET CASHFLOW	-24.620	-91.000	-276.015	-725.100	-1027.500	-1195.105	-1056.917	-1002.764	-949.007	-895.475	-841.322	-785.342

----- NET CASH FLOW DISCOUNTED AT 0.000 / PERIOD -----

Table 12-22 (Contd)

THE RALPH M. PARSONS COMPANY

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CASH FLOW CASE EVALUATION
U.S. DOLLARS - MILLIONS

COED CONCEPTUAL PLANT
JOB NO. 5435 - 1 DATE 07/03/75

COED CONCEPTUAL PLANT - TOTAL COMPLEX
- NON PROFIT - NOT TAXED
REQUIRED REVENUE TO GIVE 0 PCT DISCOUNTED CASH FLOW AFTER TAX - 20 YEAR LIFE

VARIATIONS EVALUATED IN THIS CASE ARE
COST 0.0 REVENUE 0.0 INVESTMENT 0.0

PERIOD	8	9	10	11	12	13	14	15	16	17	18	19
(REVENUE)												
PRODUCT REVENUE	142.407	142.407	142.407	142.407	142.407	142.407	142.407	142.407	142.407	142.407	142.407	142.407
BY-PRODUCT REVENUE	12.540	12.540	12.540	12.540	12.540	12.540	12.540	12.540	12.540	12.540	12.540	12.540
... T O T A L ...	154.947	154.947	154.947	154.947	154.947	154.947	154.947	154.947	154.947	154.947	154.947	154.947
(COSTS)												
OPERATION COAL MINE	46.429	46.429	46.429	46.429	46.429	46.429	46.429	46.429	46.429	46.429	46.429	46.429
OPERATION COAL PREP	1.955	1.955	1.955	1.955	1.955	1.955	1.955	1.955	1.955	1.955	1.955	1.955
OPERATION COED PROC	32.631	32.631	32.631	32.631	32.631	32.631	32.631	32.631	32.631	32.631	32.631	32.631
OPERATION POWER PLT	9.987	9.987	9.987	9.987	9.987	9.987	9.987	9.987	9.987	9.987	9.987	9.987
OPERATION OFF-SITES	5.757	5.757	5.757	5.757	5.757	5.757	5.757	5.757	5.757	5.757	5.757	5.757
... T O T A L ...	96.759	96.759	96.759	96.759	96.759	96.759	96.759	96.759	96.759	96.759	96.759	96.759
CASHFLOW, OPERATIONS	58.188	58.188	58.188	58.188	58.188	58.188	58.188	58.188	58.188	58.188	58.188	58.188
ACCUM GROSS CASHFLOW	417.712	475.900	534.089	592.277	650.465	708.653	766.842	825.030	883.218	941.406	999.595	1057.783
(INVESTMENTS)												
FIXED CAP INVESTMENT	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
INITIAL CAT + CHEM.	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
START-UP	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
EQUIPMENT REPLACEMNT	6.431	4.035	4.857	0.000	8.466	0.000	2.209	8.592	4.431	0.000	4.035	0.000
TOTAL FIXED INVEST	6.431	4.035	4.857	0.000	8.466	0.000	2.209	8.592	4.431	0.000	4.035	0.000
WORKING CAP PAID IN	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
NET CASH FLOW	51.757	54.153	53.331	58.188	49.722	58.188	55.980	49.596	53.757	58.188	54.153	58.188
ACCUM NET CASHFLOW	-731.545	-677.392	-624.060	-565.872	-516.150	-457.962	-401.982	-352.475	-298.718	-240.530	-186.376	-128.188

----- NET CASH FLOW DISCOUNTED AT 0.000 / PERIOD -----

Table 12-22 (Contd)

THE RALPH M. PARSONS COMPANY

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CASH FLOW CASE EVALUATION
U.S. DOLLARS - MILLIONS

COED CONCEPTUAL PLANT
JOB NO. 5635 - 1 DATE 07/03/75

COED CONCEPTUAL PLANT - TOTAL COMPLEX
- NON PROFIT - NOT TAXED
REQUIRED REVENUE TO GIVE 0 PCT DISCOUNTED CASH FLOW AFTER TAX - 20 YEAR LIFE

VARIATIONS EVALUATED IN THIS CASE ARE:
COST 0.0 REVENUE 0.0 INVESTMENT 0.0

PERIOD	20
(REVENUE)	
PRODUCT REVENUE	142.437
BY-PRODUCT REVENUE	12.540
... T O T A L ...	154.967
(COSTS)	
OPERATION COAL MINE	66.629
OPERATION COAL PREP	1.955
OPERATION COED PROC	12.631
OPERATION POWER PLT	9.997
OPERATION OFF-SITES	5.757
... T O T A L ...	96.759
CASHFLOW, OPERATIONS	59.138
ACCUM GROSS CASHFLOW	1115.971
(INVESTMENT)	
FIXED CAP INVESTMENT	0.030
INITIAL CAT + CHEM.	0.000
START-UP	0.000
EQUIPMENT REPLACEMNT	0.000
TOTAL FIXED INVEST	0.000
WORKING CAP PAID IN	-79.000
NET CASH FLOW	179.145
ACCUM NET CASHFLOW	-.000

----- NET CASH FLOW DISCOUNTED AT 0.000 / PERIOD -----

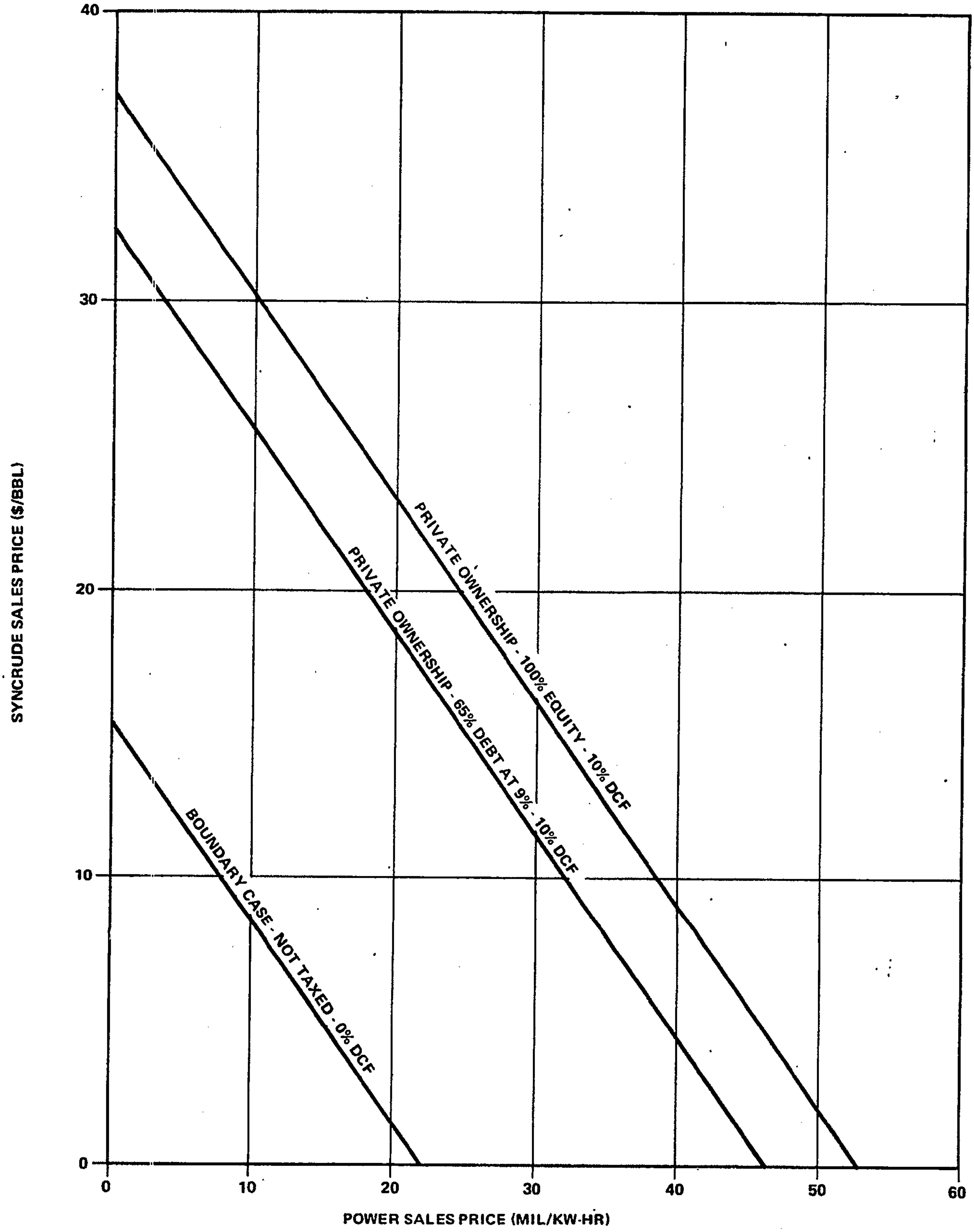

Figure 12-4 - Required Product Selling Prices
Typical Gas Analysis

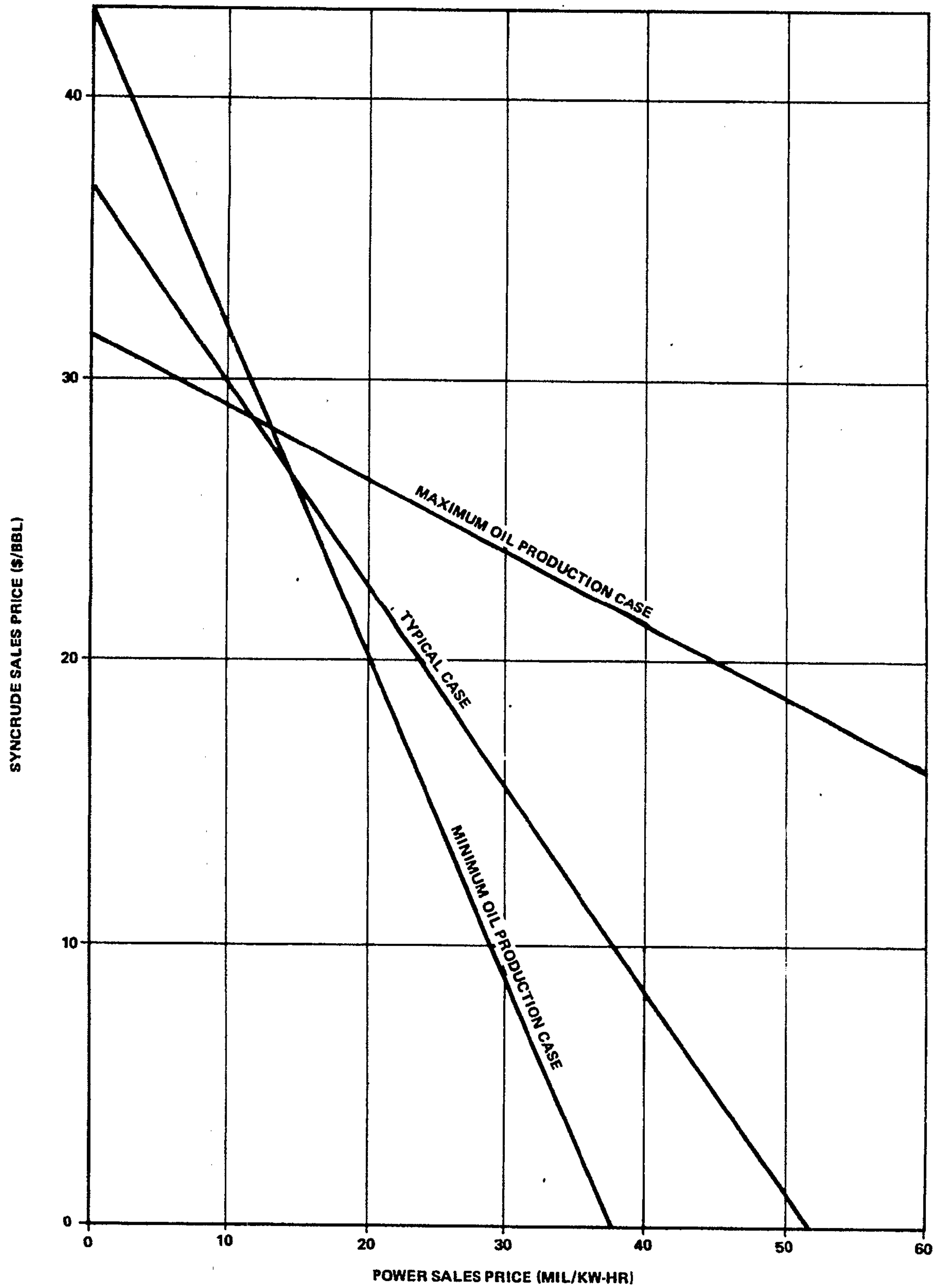

Figure 12-5 - Required Product Selling Prices - 100% Equity 10% DCF for Expected Range of Coal Analysis

12.8 SENSITIVITY ANALYSIS

The sensitivity of the required revenues to variations in selected variables was analyzed, and the results are presented in the paragraphs below. The selected variables are:

(1) Profitability

(2) Operating costs

(3) Total fixed investment cost

12.8.1 EFFECT OF PROFITABILITY LEVELS

The effect on the required revenues for each of the private ownership cases (100% equity and 65% debt) of variations in profitability levels between 0% and 20% DCF after tax rate of return are shown in Figure 12-6. As the rate of return is reduced from 10% to 0% DCF in the case of 100% equity, the required prices are almost cut in half, and as it is doubled to 20%, the required prices increase approximately 85%.

12.8.2 EFFECT ON VARIATIONS IN FIXED CAPITAL INVESTMENT AND OPERATING COSTS

The effect on the required revenue of variations in the fixed capital investment and operating costs between -20 and +20% of the estimated value is shown in Figures 12-7, 12-8, and 12-9.

In each case, and even with the nonprofit, nontaxable boundary case, the required revenue is much more sensitive to capital investment than to operating costs. For example, reducing the fixed capital investment by 20% would reduce the required revenue by about 16%, whereas a similar 20% reduction in operating costs would only reduce the required revenue by only about 4%.

12.8.3 EFFECT OF PLANT CAPACITY

Results are discussed in section 12.9. This is considered a second-order analytical assessment relative to the preceeding sensitivity analysis.

12.9 ECONOMIC DISCUSSION

12.9.1 SINGLE FEED OR POINT DESIGN

The design provides the equipment and operating flexibility to process feed coal with a range of analyses which might be expected over the course of a 20-year operating life, using coal typically mined in the Eastern Region of the U.S. Interior Coal Province. This distinguishes the design from other designs which have been based on a single typical coal analysis and which might be called single feed source or point designs. The use of variable

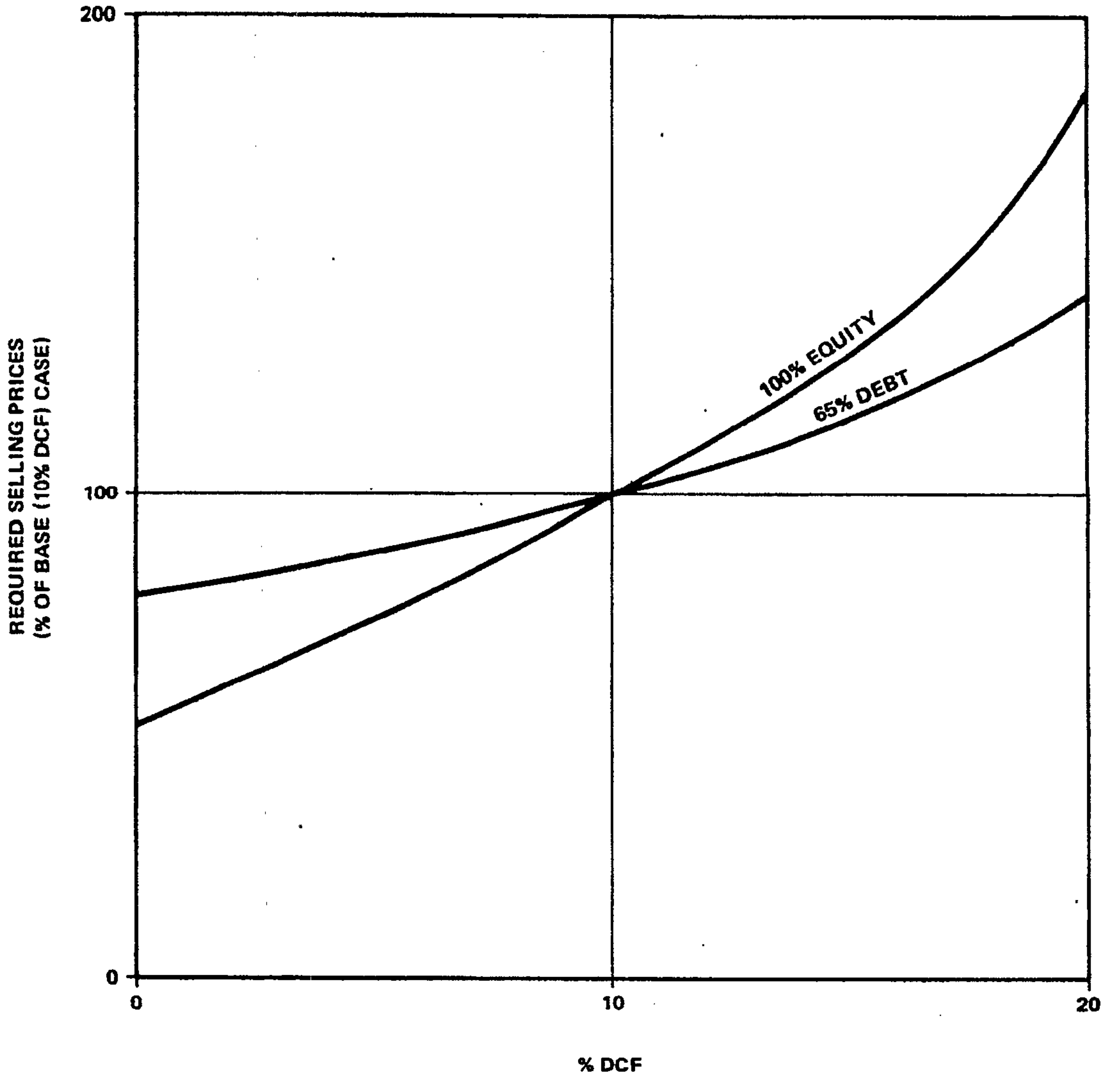

Figure 12-6 - Required Selling Prices as a Function of Changes in DCF Rate of Return

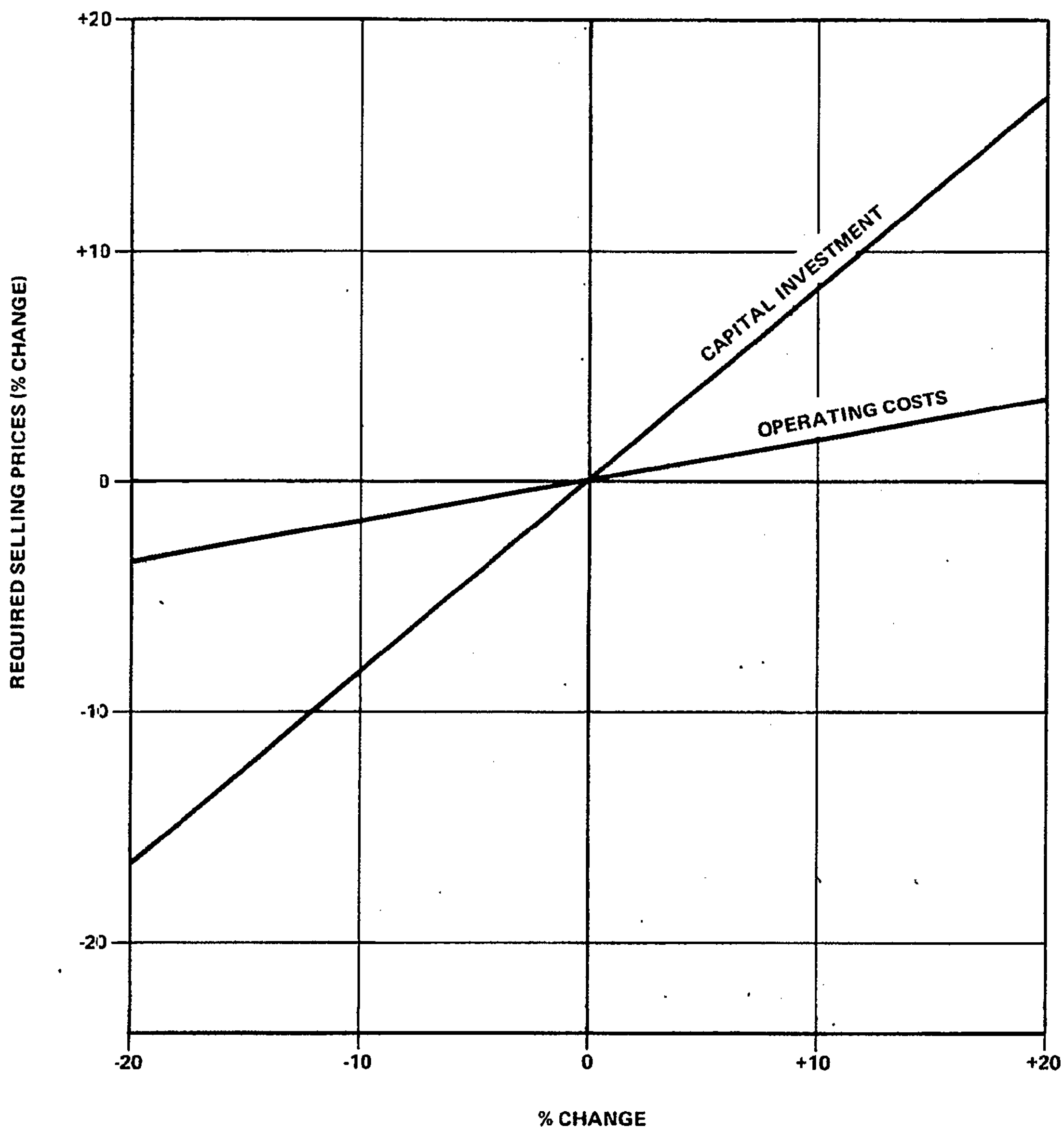

Figure 12-7 - Sensitivity of Required Selling Prices to Changes in Operating Costs and Capital Investment
Case: Private Ownership - 100% Equity - 10% DCF

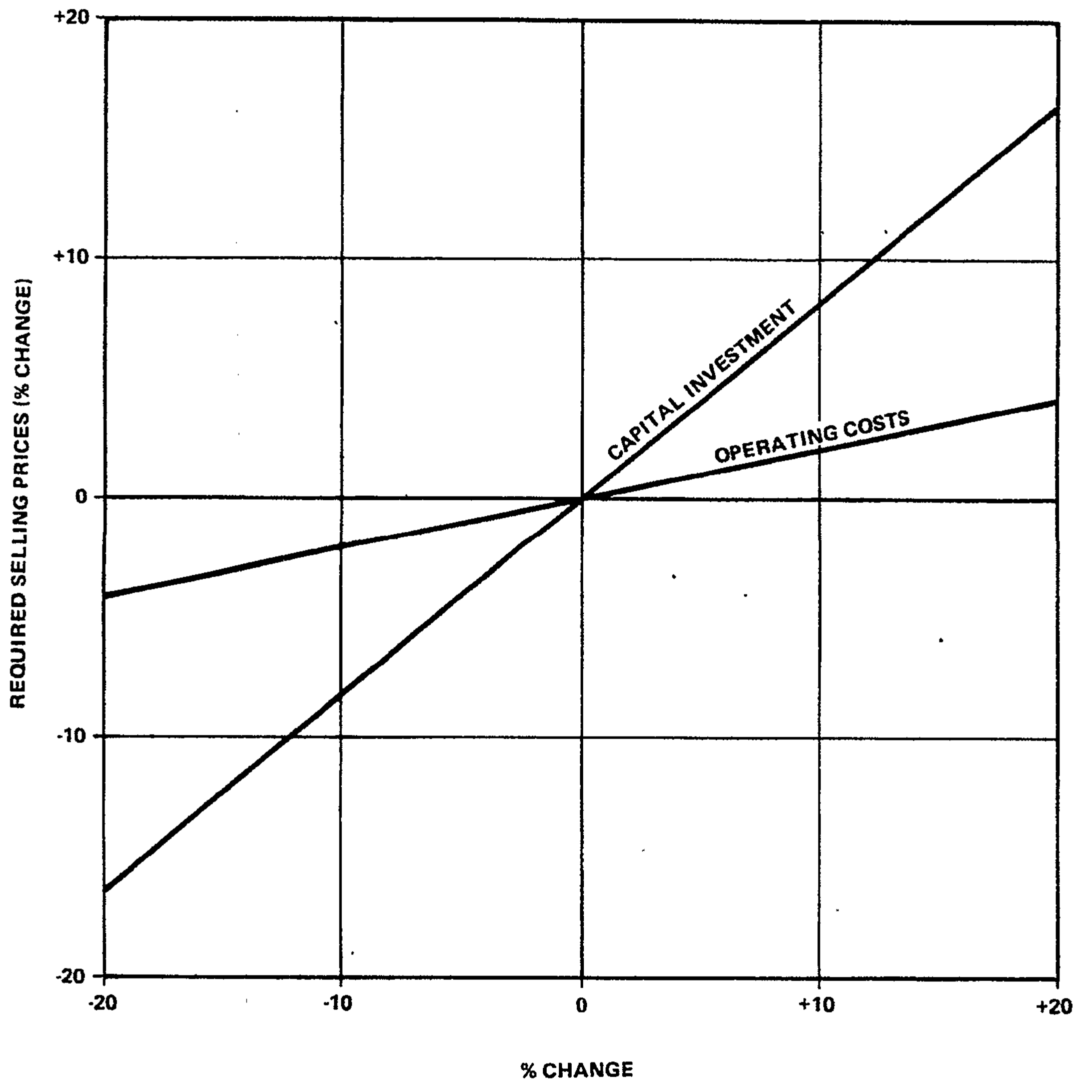

Figure 12-8 - Sensitivity of Required Selling Prices to Changes in Operating Costs and Capital Investment
Case: Private Ownership - 65% Debt 9% Interest

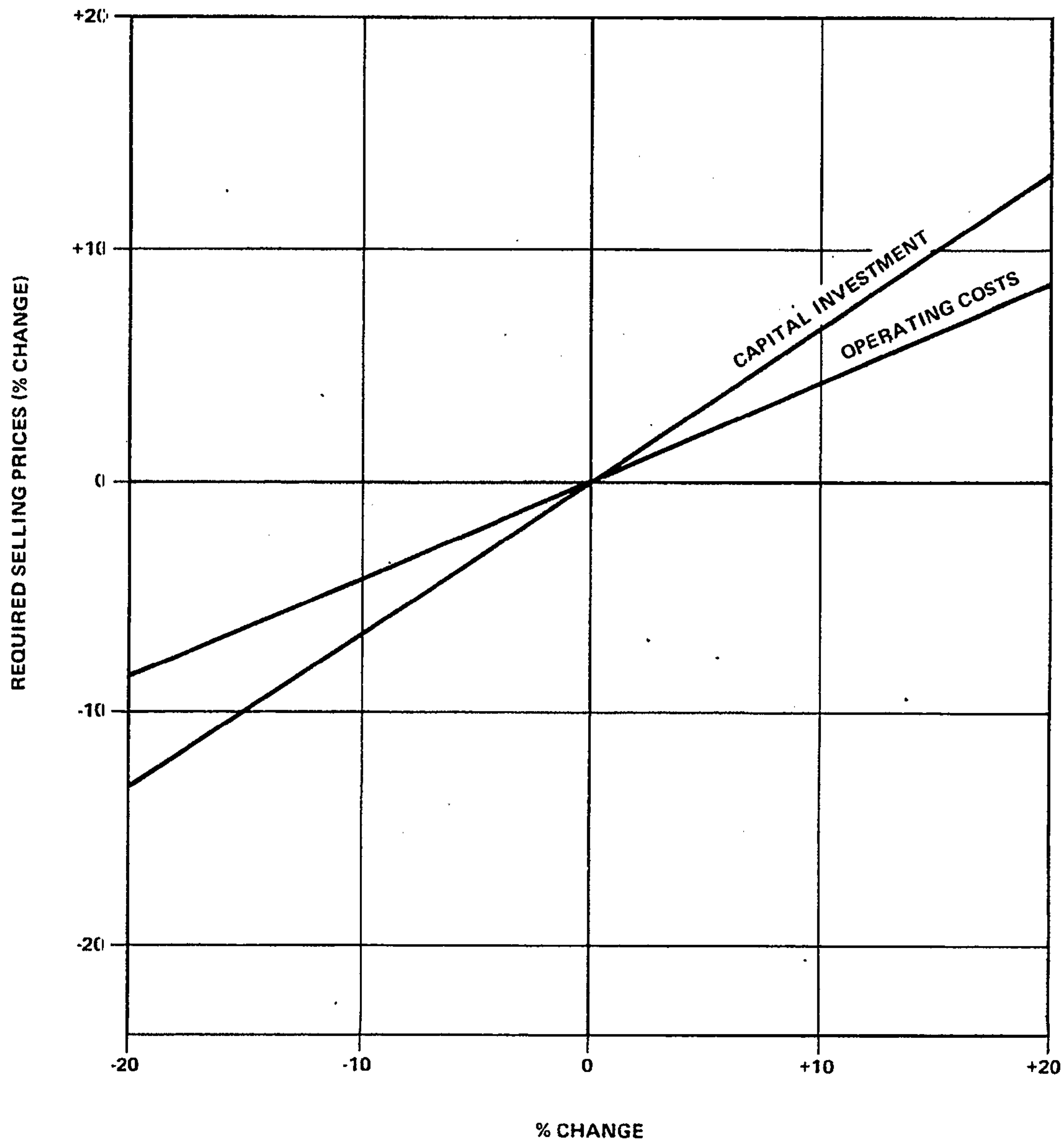

Figure 12-9 - Sensitivity of Required Selling Prices to Changes in Operating Costs and Capital Investment
Case: Boundary Not Taxed - Nonprofit (0% DCF)

feedstock characteristics requires higher fixed capital investment to provide the necessary flexibility and variable product rates.

An accurate estimate of the more traditional point design would require considerable effort; however, a guidance type estimate has been developed as orientation in order to indicate the probable orders of magnitude of the economic impact of designing for a range of coal characteristics such as used here vis-a-vis a point design. The "guesstimate" of the point design economics was obtained by combination of a judgment of the fixed capital investment and operating costs for a point design in combination with the sensitivity curves presented earlier. The results are summarized in the following tabulation:

	Fixed Capital Investment ($ Million)	
	Range of Coals (see Page 5-9)	Single Coal Source
Coal Mine	104	104
Coal Preparation	29	29
COED Process	415	384
Power Plant	374	299
Offsites	78	78
Total	1,000	894

The effect of coal characteristics on operating costs was judged to be minor, the major effect caused by the fixed capital investment requirement. For the typical coal analysis and design case as used in this report, the effect of a 20% reduction in the fixed capital investment for the power plant and a 7-1/2% reduction in the COED process plant was considered.

Using Figures 12-7 and 12-8, it can be seen that the 10.6% reduction in the total fixed investment would result in an 8 to 9% reduction in the required selling prices to achieve a 10% DCF rate of return on either of the two cases with 100% on equity or 65% borrowed capital.

12.9.2 PLANT CAPACITY

The sensitivity of the required selling price to plant capacity can be approximated using the sensitivity curves in the previous section after determining the sensitivity of fixed capital investment and operating costs to capacity change. This second-order-accuracy analytical effort is presented as a planning guidance for economic impacts to be expected for varying plant capacities. The estimated variations in fixed capital investment are shown in Figure 12-10.

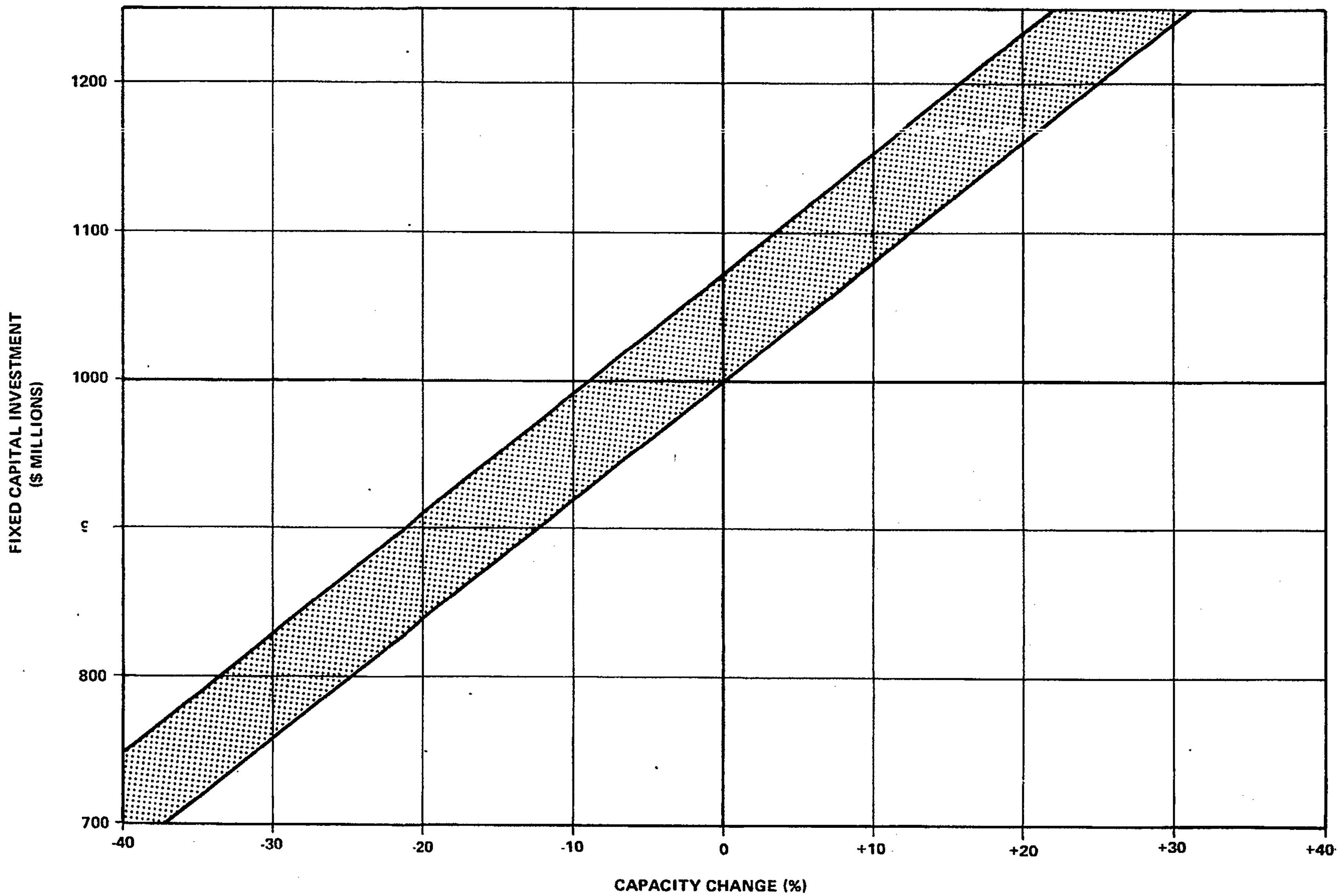

Figure 12-10 - Sensitivity of Fixed Capital Investment to Variations in Capacity

A range of values is shown because of the step-wise nature of the investment-capacity relationship, which recognizes that the coal mine consists of three mines, each with a selected complement of equipment. A significant increase in production would require a fourth mine unit, and a reduction would not have a major impact until elimination of one of the mines. The coal preparation and the COED Process Plant investments are varied using a 0.7 scaling exponent. The power plant investment costs also vary step-wise in 8.33% increments with the addition or reduction of a turbine unit. Changes in offsites investment were judged negligible for purposes of this analysis.

Changes in operating costs were judged negligible with the exception of the coal mine, here it is roughly directly proportional to output. As a result, the total operating costs vary at approximately 36.5% of the rate of variation in capacity.

Using the analytical approaches described above, changes in required selling prices with changes in capacity can be approximated using the sensitivity curves presented in Figures 12-7 and 12-8. The results are shown in Figure 12-11.

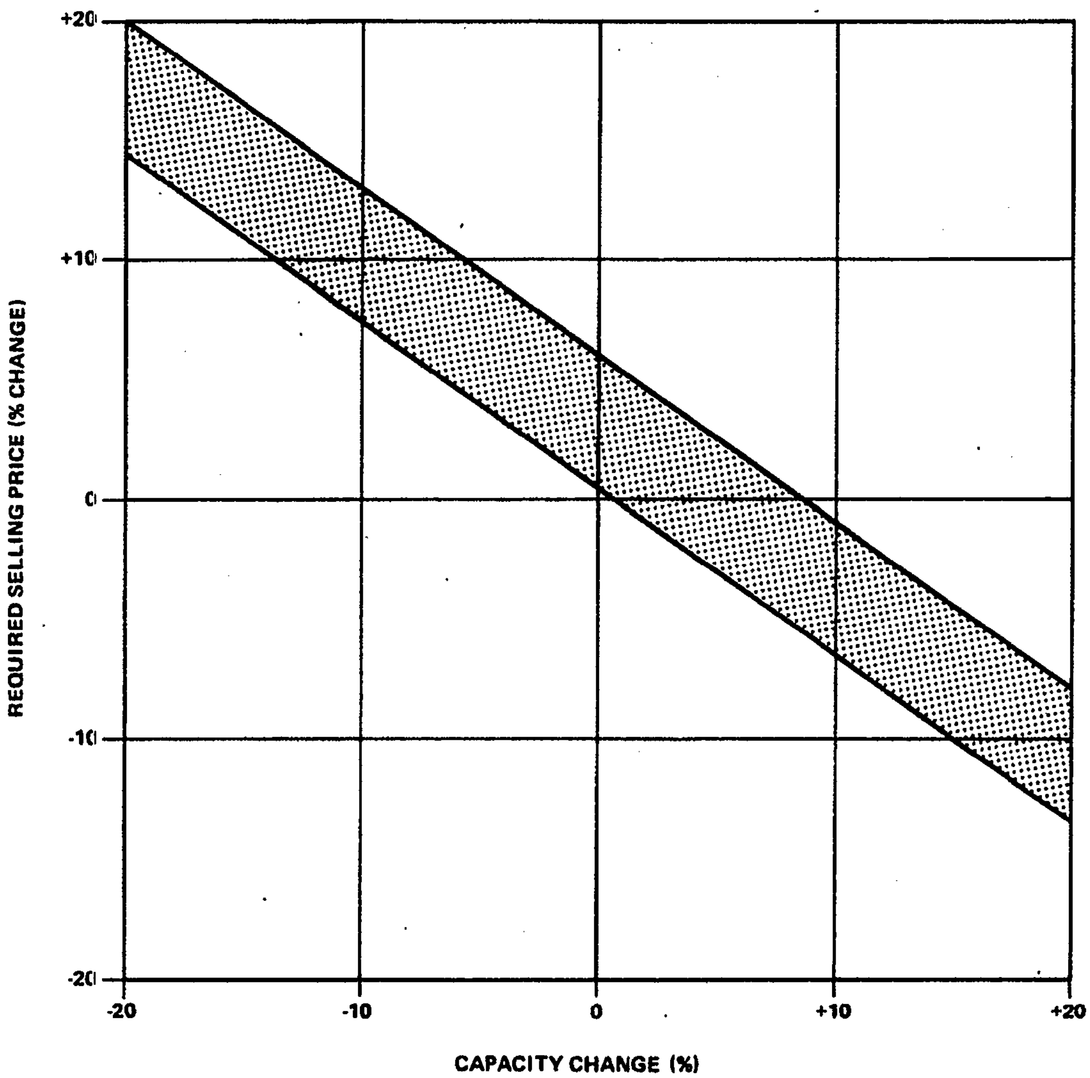

Figure 12-11 - Sensitivity of Required Product Selling Price to Variations in Capacity

SECTION 13

PROJECTED PLANT PERFORMANCE

The conceptual commercial COED process plant described here has been designed to be capable of processing the design feed at the design rate and produce products of design quality and quantity. Where uncertainty in basic information existed, the equipment has been specified to cover this uncertainty.

The design is considered to be workable with the understanding that the estimated cost has the probability of being greater than if additional information were available; this is often the case for first-generation plants.

The design of the char gasifiers for high carbon conversion represents an extension of the COED pilot plant experience. Prior experience obtained in the first-stage gasification step in the pilot plant along with additional available kinetic data, were used to design the commercial-scale units. IGT was authorized to conduct a two-phase experimental program to investigate conditions required to achieve the specified gasification results. The investigation comprised small-scale experimental work using COED char and a resulting kinetic model developed by the Institute of Gas Technology (IGT) to correlate the data. This program was performed under Parsons Subcontract No. 4-SC-5054-3 and consisted of:

Phase I: Thermogravimetric Study.

Phase II: Fluidized-Bed Reactor Gasification in a 6-Inch Diameter Reactor.

The results of the IGT study indicated:

(1) Using the gasifier reactor sizes specified, the bed temperature should be increased to 1,820°F.

(2) Additional experimentation should be conducted with the 6-inch gasifier at temperatures to 1,800°F; with particular attention to determination of fluidization velocities necessary to inhibit sintering at the elevated temperature.

Available experience indicates that the beds can be successfully operated at the 1,800°F level. The gasifiers have been designed to permit operation at that temperature level.

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SECTION 14

POTENTIAL IMPROVEMENTS

A major result of a conceptual commercial design effort such as is described here is a summary of suggested ways and means of improving future designs. This type of information is presented in the following paragraphs.

The estimated quantitative economic effect of the suggested improvements will require further effort; comments are presented on this point as appropriate.

14.1 BASIC DATA; HEAT OF PYROLYSIS AND SPECIFIC HEATS

The availability of additional accurate data for heat of pyrolysis and specific heats of coal and char would permit closer design tolerances in a number of portions of the plant. Specific heat data could be provided by measurement of specific heats of the organic and inorganic portions of the coal and char. Determinations of these values for a range of coal characteristics would provide a further basis for decision regarding design tolerances to be used.

A heat of pyrolysis of 500 Btu/lb of pyrolysis product was used for this design. The actual value is thought to be within plus or minus 400 Btu/lb of this value. This uncertainty translates to an uncertainty of the order of 280 million Btu/hr in energy available for power generation; this is about 3.7% of the energy available in this stream for the typical case.

14.2 COAL PREPARATION

A coal preparation plant designed to produce a higher ash feed coal might present a more economical procedure than that used here. The penalty for handling more ash through the COED process may be less than the cost of reducing the ash in a washing plant; also the modified washing plant should have a higher carbon recovery.

A study of preferred degree of cleaning is recommended prior to final plant design using a specific coal supply.

14.3 COAL CRUSHER

A reduction in crusher cost could result from a better understanding of the size distribution of products produced in different types of crushers.

Crusher operation for the conceptual design was specified based on limiting the amount of crushed coal smaller than 100-mesh size. Of more critical interest is the amount smaller than 325-mesh and 10-micron. An extra allowance in equipment size was made because of the uncertainty in controlling the amount of fines in the crusher product.

14.4 DRYER

This design has limited the coal temperature to 350°F and the gas temperature used for coal drying to 1,050°F; these values were recommendations received based on the results of pilot plant operations. Since the char gasifier flue gas used for heating is highly reducing, and since the coal is in process for only a few seconds, possibly a higher coal-drying temperature can be used. If so, the capital cost of the drying equipment could be reduced.

We recommend that the ability to dry coal at higher temperature in a flash dryer be determined.

14.5 PYROLYZER

14.5.1 TEMPERATURE

This design uses flow rates and residence times considered adequate and realistic to achieve the pyrolysis result. The major degree of freedom provided in the design is operating temperature. The range of temperatures used reflects the current state of knowledge of the pyrolysis kinetics; greater confidence in the kinetics would result in narrower design temperature ranges and decreased capital investment.

14.5.2 RETENTION TIME

Literature on coal pyrolysis indicates that some coals could be pyrolyzed to a sufficient extent in less than half the 6 minutes allowed in the conceptual design; reduction of pyrolysis time could result in smaller pyrolysis vessels and reduced fixed capital investment; size reduction would be limited to about 50% because of space requirements for internal cyclones, draw-off sumps, and inlet and outlet pipe connections.

14.5.3 PRESSURE

An increase in pressure level in the pyrolysis and gasification section offers the potential for reductions in equipment cost and power consumption in handling the several gas streams in the plant. The amount of the potential savings awaits development of data on pyrolysis yields and kinetics at higher pressures.

Preferred devices for feeding coal to, and releasing ash from, higher pressure pyrolysis systems should be an integral part of the elevated pressure pyrolysis development objectives.

14.6 GASIFICATION

14.6.1 HIGH CARBON CONVERSION REQUIREMENTS

The optimum extent of utilization of the fuel value of the coal could vary from the value used for the conceptual design. There is little data on gasification of coals to the target low levels of residual carbon under conditions of dense-phase fluidized bed, nonslagging, oxygen-deficient gasification. Physical limitations, such as agglomeration or decrepitation of ash particles, could be controlling, rather than economic factors. Establishment of physical limitations can be expected to require hardware development to achieve the full potential of large-scale operation.

We recommend further development of the high-carbon utilization gasification procedures and equipment design requirements.

14.6.2 TEMPERATURE LEVEL

An increase in gasification temperature promises savings in capital and operating costs. Since the limitation appears to be on local hot spot temperature, the allowable bulk temperature could be allowed to rise with development of better distributors, appropriate for each scale of operation. Oxygen usage would be reduced since more oxidation would be accomplished by steam. Steam usage would be reduced as the higher $CO:CO_2$ ratio would result in less heat of reaction being dissipated by condensation of excess steam.

An increase in gas residence time, in beds of commercial depth as compared to the shallow bed in the pilot plant, should have the same effects on oxygen and steam used as an increase in temperature. Continuing experimental programs are designed to establish the quantitative relationships needed for plant design.

14.7 HYDROGEN PRODUCTION

There is a potential for reduction in capital and operating costs if the raw low-Btu fuel gas used for hydrogen manufacture is taken hot with its natural steam content rather than being cooled, dried, reheated, and rehumidified. The latter course was used in the conceptual design because of concern that dust and oil vapor might be present in quantities harmful to downstream process steps. Should this concern not be justified, it would be possible to reduce the cooling tower duty by about 100 million Btu/hr, and the amount of 600-psi, 825°F steam consumed by about 100,000 lb/hr. At the same time, the generation of low-pressure steam from waste heat would be reduced by about 100,000 lb/hr.

14.8 WATER UTILIZATION

Water required by the COED complex of units totals about 45,000 acre feet (AF) per year. Usage totaling this amount in AF/yr is approximately as follows:

Cooling water evaporation and drift	36,500
Cooling water blowdown	2,400
Boiler feedwater makeup	4,500
Process makeup	1,600
	45,000

Of this amount, about 3,500 AF per year are treated and returned to the surrounding waters, leaving a net consumption of about 41,500 AF/yr.

One significant reduction in usage considered feasible would be in cooling water losses to the atmosphere, all of which are functions of cooling water circulation rate and thermal load. Of the approximately 610,000 gpm of cooling water typically circulated, nearly 400,000 gpm are used to condense the steam exhaust from turbine drivers. As an alternate, this function could be performed by air coolers; with air temperature as high as 100°F, the required surface would increase and the capital cost would increase by about $21 million.

The use of air coolers in this service instead of cooling water, however, would reduce the net water take to about 17,500 AF/yr, or a saving of some 24,000 AF/yr.

14.9 POWER GENERATION

The present Design Basis calls for a fixed feed rate of MAF coal. This results in a variation of fuel gas produced which when combined with the steam generation requirement variation results in electrical power generation variation from about 345 to 1,227 MWe; the export power for the typical case is about 830 MWe.

It is possible that a more economical design would result from a Design Basis which fixes the level of electrical power generation instead of fixing the feed rate of MAF coal. For instance, if the level of power generation was fixed at 900 MWe, the investment in the power plant would be reduced by some 23% or $80 million due to the need for only 10 turbine-generator sets instead of 13.

The operating profitability should be improved due to the higher rate that could be charged for electrical energy sold on a base load (fixed) level rather than on an energy basis for a variable level.

The effect on the other units in the complex would be to cause a greater variation in the quantity of oil produced than is the case with a fixed feed rate. While this would increase the capital investment in certain equipment, it is believed the increase would be less than the savings in the power plant cost described above. Furthermore, the variation in the quantity of oil produced would have no effect on the selling price of this product.

APPENDIX A

COED PROCESS

CONCEPTUAL COMMERCIAL PLANT

DESIGN BASIS

MAY 2, 1973

TABLE OF CONTENTS

Revised 5/30/75

I. INTRODUCTION

A. Objectives

Following consultations with FMC and OCR, which resulted in agreement on the following Design Basis, Parsons will proceed with the preparations of a conceptual design of a commercial scale COED Process plant using the technology developed by FMC under the sponsorship of OCR. The Design Basis presented here has been prepared in accordance with Item 14.3 of the COED Job Procedure as set forth in our letter P-8, dated November 3, 1972.

The primary objective is a preliminary design, in sufficient detail for a budget-type cost estimate. This will be termed phase I. Parsons' further goal will be to prepare a design package in sufficient detail to permit a competent engineering-construction firm to complete the detailed engineering and construction of the facility. This is called phase II.

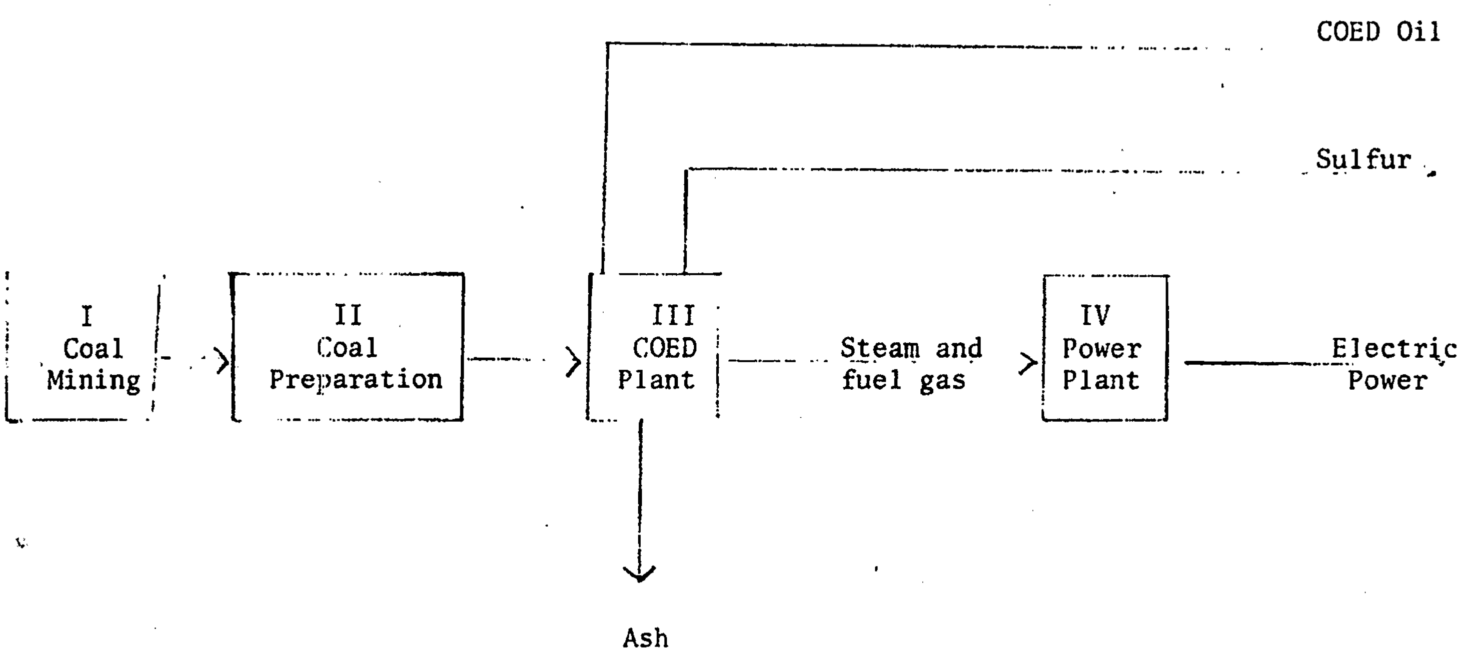
B. General Approach

This Design Basis sets forth the philosophy and data on which the commercial plant will be designed. A consequence of increasing the scale of operation is that some conditions used in the pilot plant must be modified.

5/2/73

The process shall fully utilize the COED product char. As a base case, with which to compare alternate uses for the char, it will be burned (gasified) to supply the heat and power requirements of the plant. The char will be burned under reducing conditions, so that the flue gas contains hydrogen and carbon monoxide, a further source of heat for power generation after hydrogen sulfide is removed. Noncondensible pyrolysis gas, after hydrogen sulfide removal, is another fuel for power generation. Excess electric power will be exported. All stack gases shall meet all emission requirements without scrubbing.

The overall design concept is as follows:



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This Design Basis is concerned only with Unit III, the COED Process plant.

The COED battery limits process plant includes units to:

1. Dry and pyrolyze the coal.
2. Recover and filter oil.
3. Burn/gasify char.
4. Remove sulfur compounds from the pyrolysis gas and flue gas.
5. Convert sulfur compounds to sulfur.
6. Produce hydrogen.
7. Hydrotreat the raw pyrolysis oil.
8. Generate steam from waste heat.

C. Design Summary

1. Coal Dryer

Hot flue gas generated in the char burner/gasifier will be used as the drying medium. Pneumatic conveyor dryers, often called flash dryers, will be used to remove most of the moisture from the feed coal. A fluidized bed will be included to insure complete drying.

2. Preheater

The dried coal will be preheated to about 600°F and mixed with recycle char to prevent agglomeration in the pyrolyzers.

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3. Pyrolyzers

Pyrolysis will be conducted in fluidized beds at successively higher temperatures. The heat of pyrolysis shall be derived from either hot char or hot flue gas from the char burner/gasifier or both.

4. Char Burner/Gasifier

Char will be burned (gasified) under reducing conditions, at least to the extent needed to provide the heat requirements of the drying and pyrolyzing operations.

5. Summary

In summary, the conceptual design of process units and supporting electrical power generation facilities for the COED plant is shown in Figure 1.

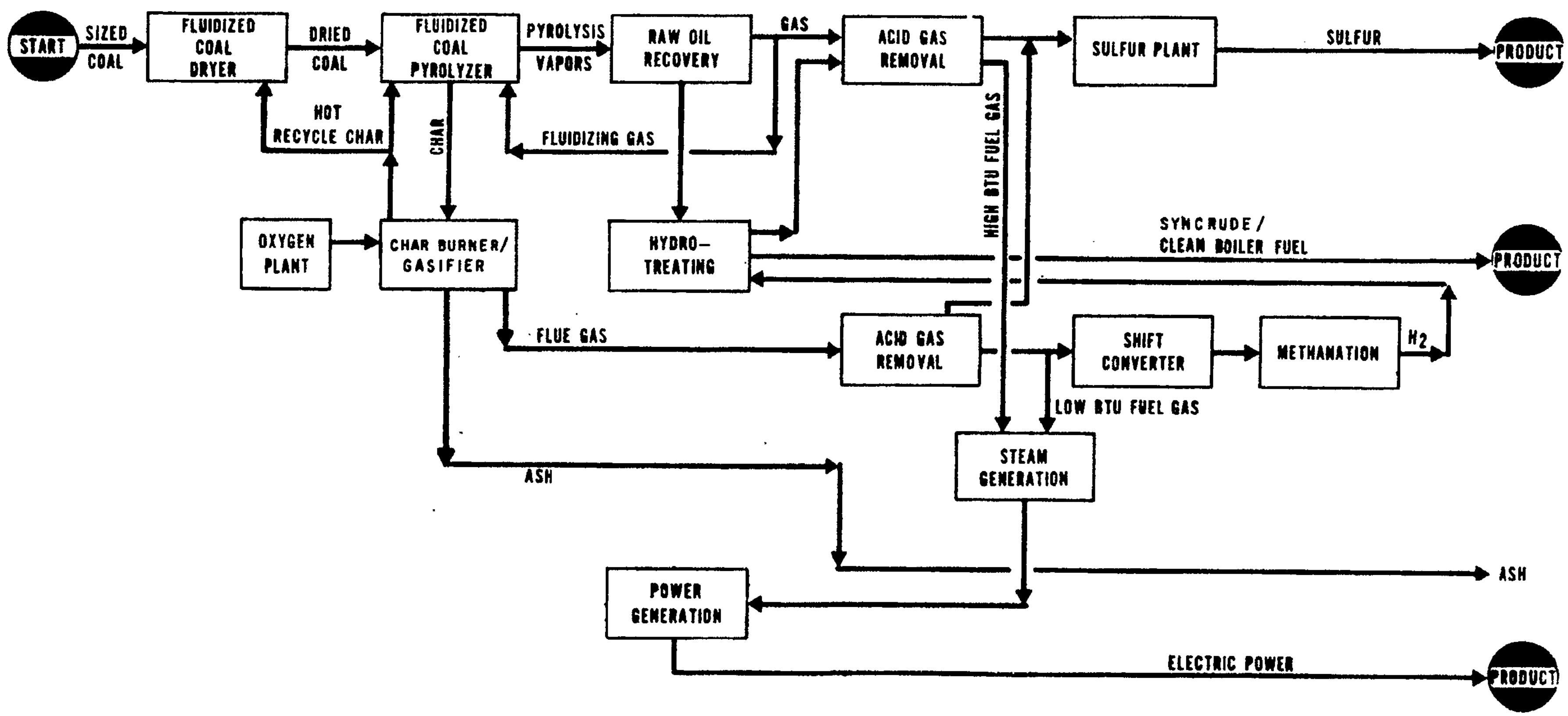
5/2/73

FIGURE I

COED PROCESS

CLEAN ENERGY PLANT DESIGN

COMBINED CLEAN OIL/ELECTRIC POWER FACILITY



II. COED PROCESS PLANT DESCRIPTION

A. General

1. Design Capacity	21,500 tons/day of moisture-and-ash-free coal (26,000 to 29,000 tons per day as received from the cleaning and crushing plant. Keeping the MAF portion of the feed at a constant rate will allow the expensive sections of the plant to operate at or near design capacity. Moisture and ash fluctuations are limited to the front end of the plant).
2. Site conditions	Midwest geological region
3. Coal source	Illinois No. 6 Seam

4. COED Plant Battery Limits Feed and Effluent Streams:

   a. Coal is received crushed to a specified size range. Moisture and ash content are not controlled.

   b. Products are COED oil, electric power and sulfur.

   c. Stack gas meets local pollution control regulations.

   d. Ash is discharged at about 140°F; ash disposal is considered an offsite activity.

B. Dryer

A two-stage pneumatic conveying (flash) dryer will be used to remove the major portion of the moisture. The first stage will heat the coal to about 150°F and evaporate part of the moisture.

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The second stage will continue the drying and heat the coal to about 350°F. The heat requirement will be calculated on the basis of complete drying. Heat will be obtained from char burner flue gas and/or recycle char which has been cooled to a desirable temperature below 1050°F, depending on the moisture content of the coal. Gas flow rates through the dryers must be maintained within narrow ranges. Variations in heat demand, resulting from variations in moisture and ash content, will be matched by regulating the entering flue gas temperature.

A third stage of drying is provided to insure "complete" drying (to about 1 percent moisture) because there is some question of the flash dryer's ability to attain such a low moisture content. Heat requirement for the third stage shall be based on drying to zero moisture.

C. Preheater

Dried coal will be preheated to about 600°F by mixing it with flue gas and/or recycle char, whose temperature is controlled to be no more than 1050°F, in a fluidized bed between the dryers and the pyrolyzer. Considering the dilution with recycle char, a ten minute residence time is deemed sufficient to condition Illinois No. 6 Seam coal for charging to the first pyrolyzer. For heat

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requirement, the moisture content of dried coal will be considered to be 1 percent.

D. Pyrolysis

This design will use the following features:

1. Use continuous flow, fluidized beds in series, heating the coal to successively higher temperatures.

2. Combine vapors from pyrolysis and pass them to a single condensing train.

3. Use recycle char from the char burners at 1600°F as the principal source of heat for pyrolysis. Heat for pyrolysis may be derived from char burner flue gas. Control the pyrolyzer bed temperatures by regulating char flow rates.

4. Remove fine particles from the pyrolysis vapors by use of two-stage cyclones in each pyrolysis vessel. The cyclones will deliver the fines to the outlet of the bed so that these particles, which need the least residence time, will be moved promptly from stage to stage.

5. Let the required total volume of the vessels be set by the feed rate (including recycle char), the fluidized density (to be calculated), and a total residence time of ten minutes.

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6. Fluidizing velocities, bed heights, and size consists, being interdependent, shall be determined by economic considerations, within limits set by industrial and pilot plant practice.

7. Provide control of pyrolyzer temperatures so that the required amount of pyrolysis will occur in each vessel. For example, if two pyrolyzers are used, the equipment will be made capable of attaining temperatures of 815° $\pm$ 25° and 1050°F $\pm$ 25°.

8. Recycle pyrolysis gas will be available to the pyrolyzers to smooth out variations in vapor flow rates as the composition of the coal varies, and thereby maintain fluidization of the beds. The vessels will be tapered if required to compensate for increase in vapor volume from bottom to top. To minimize the expansion of the recycle gas, it will be preheated.

9. Limit solids entrainment from pyrolyzers so that the solids content of oil feed to the filters is no more than 5 Wt%.

E. Char Burner/Gasifier

The carbon content of the ash will be reduced to as low a value as can be economically justified, tentatively assumed to be 2 percent of the original carbon.

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Fresh oxidizing gas consists of oxygen diluted with steam to avoid hot spots. The effluent flue gases from the burner/gasifier contain negligible oxygen and exit at a temperature of 1,600°F.

Combustion temperature will be controlled by varying the ratio of steam to oxygen within limits and/or by regulating the depth of the bed.

Char is circulated from the burner/gasifier to the pyrolysis section to provide pyrolysis heat.

The temperature of the char will be kept safely below the ash softening point. Char temperature will be controllable in the range of 1,500° to 1,650°F in the burner beds. Mechanical design temperature will be 2,000°F.

The combined flue gas stream will first be cooled by contact with lower temperature char streams and/or by heat exchange to produce steam. A portion of the flue gas will be used to dry and preheat the coal (see Section II-B).

The pressure of burner/gasifier operation will be established to provide adequate driving force to transport char to and from the pyrolysis beds and to move the flue gas through the coal dryer.

Revised 5/30/75

F. Oxygen Plant

A proprietary oxygen plant will be incorporated.

G. Vapor Recovery

The combined vapors from the preheater and pyrolyzers will be condensed by contacting them with a recirculating cooled stream of condensed oil. An electrostatic precipitator may be used to remove oil fog from the remaining vapors before they are cooled to condense water and light oil. Condensed water may be used in the char burner/gasifier to meet part of the requirement for steam.

H. Gas Plant

Separate gas plant trains will remove sulfur from the char burner flue gas and from the pyrolysis gas, to make those suitable for use as fuels.

I. Hydrogen Production

Hydrogen will be produced at 96 percent purity from cooled and cleaned char burner flue gas.

J. Oil Hydrotreating

The oil hydrotreating conditions which the COED pilot plant has successfully demonstrated will be used in this design.

Revised 5/30/75

K. <u>Waste Heat Recovery</u>

1. Waste heat will be recovered in the form of steam for use within the plant and for electric power generation.

2. Flue gas from the char burners must be cooled to below 1050°F for that portion used for coal drying, and further for the portion going to cleanup for low BTU fuel gas and hydrogen production.

3. Part of the purified flue gas from the char burner/gasifier will be used to manufacture hydrogen. The rest will be burned to generate steam.

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L. Coal Properties

Temperature	40 to 80°F
Density	84 lb/ft^3
Specific heat	See Figure 2
Moisture	8 - 13.7 wt%, wet basis
Ash	9.7 - 14.3 wt%, dry basis
Volatile Matter	40.7 - 51.4 wt%, MAF basis

Ultimate Analysis:

Carbon	77.5 - 80.5 wt%, MAF basis
Hydrogen	5.2 - 5.9 wt%, MAF basis
Nitrogen	1.3 - 1.8 wt%, MAF basis
Sulfur	1.1 - 5.8 wt%, MAF basis
Oxygen	8.7 - 11.4 wt%, MAF basis

Heat of formation of coal components, BTU/lb:

Coal carbon	58 + 218.1 x H
Coal hydrogen	-18,536 + 654.3 x H
Coal sulfur	1,326 + 81.8 x H
Coal oxygen	-5,308 - 81.8 x H

H = wt% hydrogen, MAF basis

Revised 5/30/75

M. Pyrolysis

1. Pyrolysis yields:

	wt%, MAF basis
CH_4	3.0642 ± .392
C_2H_4	.2090 ± .098
C_2H_6	.5446 ± .120
C_3H_6	.1915 ± .114
C_3H_8	.1336 ± .112
C_4H_{10}	.3768 ± .202
Oil	22.487 ± 3.154
H_2O	6.313 ± 4.222
H_2S	1.6108 ± 1.590
NH_3	TRACE
H_2	.1467
CO	1.0040
CO_2	1.9272
Char (ex-ash)	61.9916 ± 5.20

The data source for these yields is FMC letter of August 1973.

2. Pyrolysis heat, 500 BTU/lb of vapor evolved

3. Char properties:

Specific heat: See Figure 2

4. Green char composition

Green char composition	wt%, MAF basis
C	87 to 93
H	2.0 to 2.3
N	1.0 to 2.0
S	3 to 7
O	.5 to 2
Volatile Matter	3 to 5

The data source is FMC runs P-19 and 20.

Revised 5/30/75

N. Vapor Recovery

1. Pyrolysis Oil Properties:

API Gravity	-3° to -5°

Composition	wt%, MAF basis
C	80.5 to 82.5
H	6.7 to 7.5
N	1.0 to 1.3
S	1.5 to 2.5
O	6 to 10

ASTM distillation	°F
IBP	320
2 Vol %	400
5	450
10	500
20	620
30	730
40	820
50	910
60	1,000

The data source is FMC runs P-16 thru 22.

O. Additional data are available in FMC's COED Data Book.

Revised 5/30/75

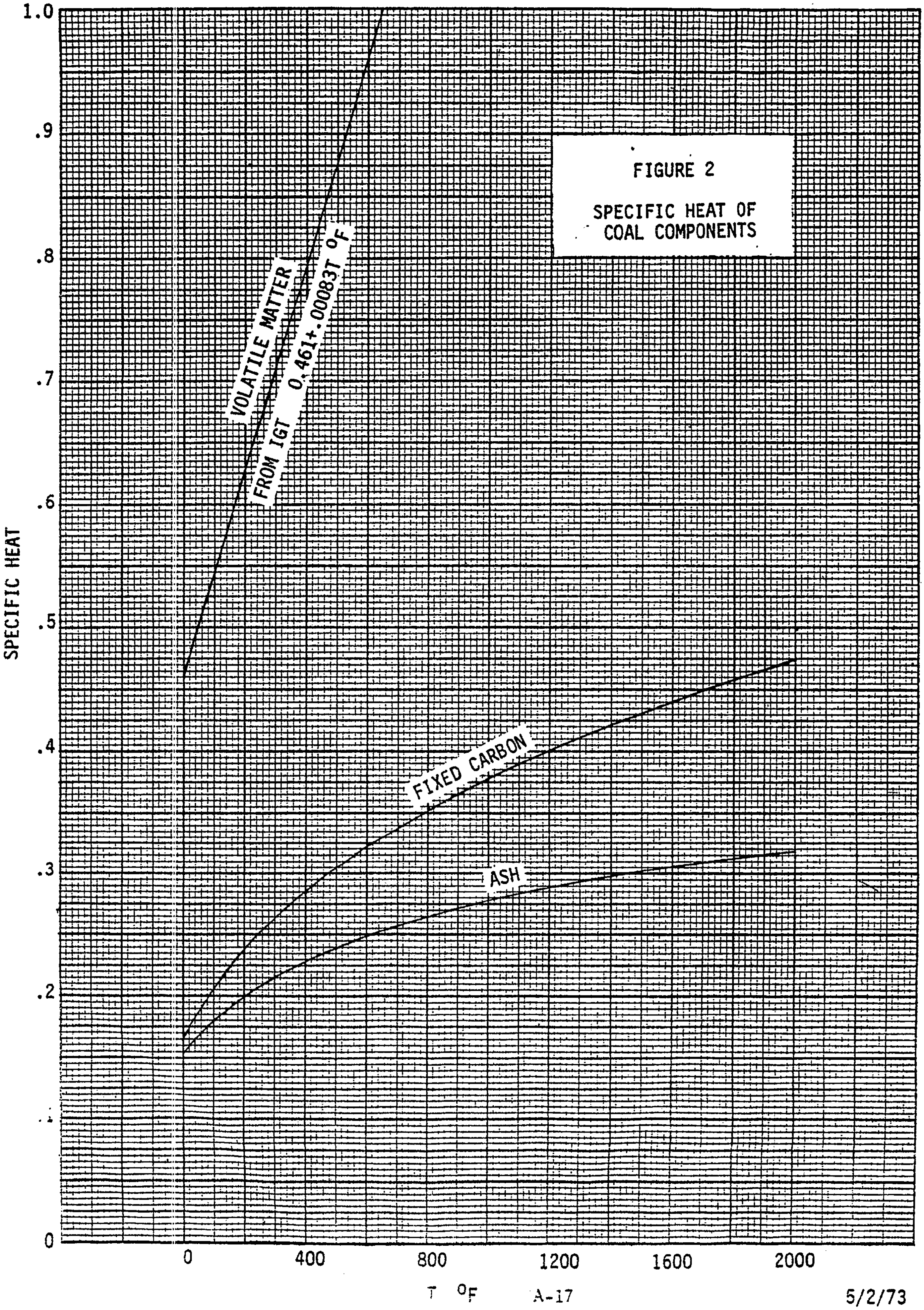

FIGURE 2
SPECIFIC HEAT OF COAL COMPONENTS
VOLATILE MATTER
FROM IGT 0.461+.00083T °F
FIXED CARBON
ASH
SPECIFIC HEAT
1.0
.9
.8
.7
.6
.5
.4
.3
.2
.1
0
0
400
800
1200
1600
2000
T °F

5/2/73

APPENDIX B

SITE CONDITIONS

1.0 GENERAL AND METEOROLOGICAL

1.01 LOCATION: North Central USA

1.02 ELEVATION: 500 feet

1.03 CLIMATIC CONDITIONS:

a. Maximum temperature, 103°F; design for 90°F

b. Minimum temperature, -15°F; design for -15°F

c. Relative humidity, low 20%; high 100%

d. Design wet bulb temperature, 77°F

e. Rainfall, 38 in./yr (average); 0.75 in./hr design

f. Average wind velocity, 12 mph

g. Maximum wind velocity, 50 mph (gusts)

h. Direction of wind, NW 1Q; NW-SW 2Q; S 3Q; S-NW 4Q

i. Average annual snowfall, 20 in./yr

j. Design for 25 lb/sq ft snow pack (omit if roof load known)

k. Frost line - Design for 24 inches depth

l. Lightning storms - Number per year, 50

m. Dust storms - No special provisions required. Hail and tornados occur. Tornado occurrence March through June

2.0 STRUCTURAL DATA

2.01 VERTICAL LIVE LOADS

a. Roofs, tank tops, etc., on horizontal projected area

Area in sq ft:	0-200	200-600	Over 600
Rise less than 4 in./ft	25	2.5	2.5 psf
Rise 4 in./ft and steeper per UBC			

b. Platform, stairs and walks

	Loading (lb/sq ft)
1. Pedestrian traffic only	75
2. Work area - uniform loading	50
3. Work area - concentrated loading	320

c. Floors on ground

	Uniform Load (lb/sq ft)	Concentrated Load
1. Buildings		
Administration bldg and Laboratory	75	
Control houses	100	1,000 on 2-1/2 ft-sq
Maintenance bldg	250	
Stores warehouse	100	15,000 wheel load
Others	75	
2. Paved Areas	100	15,000 wheel load

2.02 EMPTY CONDITION

Weight of equipment in place and empty, with removable internal parts all installed and with dead load attachments such as platforms and operating lines in place, plus wind or earthquake.

2.03 TEST CONDITION

Empty weight plus weight of test water, without wind or earthquake.

2.04 OPERATING CONDITION

Empty weight plus weight of liquid at maximum level, plus wind, earthquake, or expansion forces.

2.05 LATERAL LOADS (Wind)

a. Wind on vertical flat projected areas

	lb/sq ft
0 to 30 feet aboveground	15
30 to 50 feet aboveground	20
50 to 100 feet aboveground	25
100 to 500 feet aboveground	30

b. For circular equipment the wind pressure shall be assumed to act on 0.6 of projected area.

c. For computing wind pressure on exposed open-frame structures, use 130% of projected areas of all members.

2.06 LATERAL LOADS (Earthquake)

Uniform Building Code Zone 2

Note: Wind and earthquake forces are not additive.

2.07 ALLOWABLE STRESSES

Allowable stresses may be increased 1/3 for lateral loadings, and 1/5 during hydrostatic test.

2.08 STABILITY RATIO

a. Minimum allowable stability ratio = $\frac{\text{Stabilizing Moment}}{\text{Overturning Moment}} = 1.5$

b. Soil-bearing foundations to have positive soil pressure over whole footing except for erection load conditions (Provided that toe pressure does not exceed allowable soil bearing pressure).

2.09 BUILDINGS

a. Administration, Change House: Concrete block exterior walls, gypsum board on steel studs for interior walls.

b. Warehouse, Shops, Control Rooms and others: Prefabricated steel frame, siding & roof.

3.0 FOUNDATIONS AND SOIL DATA

3.01 SOIL DATA

a. Type of soil: sand; rocky

b. Subsoil strata not a factor

c. Elevation of water table varies

d. Piling not required

e. Special soil analysis reference: to be determined

3.02 FOUNDATIONS

a. Allowable Bearing Loads

Soil Type	Depth	Vertical Load	Lateral Load
Sand and rocky	3 ft	2,000 lb/sq ft	--

b. Ultimate Compressive Strength After 28 Days:

Reinforced concrete 3,000 psi.

c. Minimum Coverage of Reinforced Steel

1. Formed sections: 2 in. (except 1-1/2 in. for No. 5 and smaller bars)

2. Unformed sections: 3 in.

3. Water contact: 3 in.

d. <u>Minimum Depth of Foundations</u>

1. Exterior walls and/or piers: 3 ft

2. Interior building footings: 3 ft

3. Frost line: 3 ft

4. Ground water depth: 4 - 20 ft

5. Termites and fungi are factors

e. <u>Elevations</u>

1. Base elevation (Refinery Datum): 100.00 ft

2. Existing ground elevation: 500 ft

3. Finished grade: to be determined

4. High point of paving: to be determined

4.0 UTILITIES

4.01 AIR

a. Instrument nitrogen at 30 psi, and maximum dew point -15°F at 30 psi

b. Utility air at 90 psi

4.02 COOLING WATER

a. Type: evaporative tower

b. Design cold water temperature: 86°F

c. Maximum hot water temperature: 120°F

d. Design hot water temperature: 120°F

e. Design water supply pressure at grade: 40 psig

f. Design water return pressure at grade: 30 psig

4.03 COOLING TOWER

a. Water inlet temperature: 120°F

b. Water outlet temperature: 86°F

c. Design wet bulb: 77°F 5% rule

d. Type of tower: induced draft

e. Structural design-lateral load: See Section 2.0

4.04 STEAM AND CONDENSATE

a. High pressure steam at 600 psia and 339°F superheat

b. Low pressure steam at 65 psia and sat

c. Intermediate pressure steam at 165 psia and sat

d. Condensate system at (as required) psig

4.05 BOILER FEEDWATER

a. Supply pressure at plot limit: 15 psig

b. Supply temperature at plot limit: 40 - 80°F

4.06 FUEL GAS

		In-plant-produced Fuel Gas
a.	Pressure at plot limit	45 psig
b.	Heating value at 1 atm	250 Btu/scf

c. Composition: Primarily Hydrogen, CO, and CO_2

4.07 WATER SYSTEMS

	System	Supply Pressure	Supply Temperature	Required Treatment
a.	Drinking	40 psi	Ambient	Yes, well water w/chlorination
b.	Sanitary	40 psi	Ambient	Yes, well water w/chlorination
c.	Fire system	90 psi	Ambient	No, river water
d.	Industrial Water	40 psi	Ambient	Yes, clarified

4.08 SEWERS

a. Types

1. Sanitary

2. Oily water

3. Surface runoff: Ditches only

4. Chemical

5. Combine 2, 3, and 4? Not before storm water surge pond

b. Materials and Installation

Item	Sanitary	Oily Water	Runoff
1. Design velocity	3-5 ft/sec	3-5 ft/sec	3-5 ft/sec
2. Slope (%)	As below*	2%	1%
3. Minimum coverage	3 ft	3 ft	Open ditches
4. Manholes	Yes	Yes	Open ditches
5. Manhole covers	Yes	Yes	Open ditches
6. Junction boxes	Yes	Yes	Open ditches

5.0 ELECTRICAL EQUIPMENT

5.01 POWER SUPPLY AND CHARACTERISTICS

a. Source: In-plant generation - emergency firm power from grid

b. Routing: Overhead - Trays

c. Service:

Service	Volts	Phase	Cycle
1. Main Supply	13.8 kV	3	60
2. Primary distribution	4.16 kV	3	60
3. Secondary distribution	440 V	3	60
4. Lighting	120/240 V	1	60
5. Emergency heating	240 V	-	--
6. Electrical instrumentation	24 VDC	-	--

5.02 MATERIAL CLASSIFICATION

See Drawing

a. Hazardous areas Class 1, Group D, Divison 1

*Minimum 2% to septic tank, 1% beyond.

b. Semihazardous — Class 1, Group D, Division 2

c. Nonhazardous — NEMA

5.03 MOTORS

a. Size:	150 hp and up	4.16 kV	3 phase
b. Size:	3/4 hp to 125 hp	440 volts	3 phase
c. Size:	1/2 hp and smaller	220/110 volts	1 phase

5.04 METERING

a. Main supply by plant power house

b. Others to be determined

6.0 INSTRUMENTS

6.01 Accounting Meters Required	Yes	No
a. Plant feed streams	x	
b. Plant product streams	x	
c. 600 psia steam system	x	
d. 165 psia steam system	x	
e. Industrial water	x	
f. Sanitary water		x
g. Air		x
h. Fuel gas	x	

6.02 PANELBOARD

a. Type: Local panels and main control center

b. Instruments: Pneumatic and electronic

c. Arrangement of instruments: --

d. Chart drives: Electrical

6.03 EMERGENCY SUPPLY OF INSTRUMENT AIR: Yes

6.04 INSTRUMENT AIR COOLER AND DRYER: Yes

6.05 MASTER INSTRUMENT AIR FILTERS: Yes

7.0 PROCESS DATA

7.01 EQUIPMENT DATA

	Normal Contingency
a. Pumps	10-25%
b. Compressors	5-10%
c. Furnaces	10%
d. Cooling tower	10%

7.02 CODES - LATEST EDITIONS

a. API-ASME unfired pressure vessel
   API 650 - Storage tanks
   ASME, Section VIII, Division 1

b. ASA Piping Code
   USAS B31.3 - 1966 - Piping
   USAS B16.3 - Flanges and fittings
   USAS B31.1 - Power piping

c. ASME Code Power Boilers - Section I

d. National Electric Code - NEMA

e. Uniform Building Code (by International Conference of Building Officials)

f. National Plumbing Code - IBC

g. Petroleum Safety Orders - Apply

h. Exceptions to codes - None

8.0 MISCELLANEOUS

8.01 SAFETY

a. Maximum temperature for safety to personnel: 150^{o}F

b. Hazardous chemicals: Protect per OSHA

8.02 WINTERIZATION

a. Design considerations: Yes, -15^{o}F for water, steam condensate and viscous process lines and instrumentation

b. Degree required: As dictated by process requirements

8.03 NOISE ABATEMENT A FACTOR? Yes

8.04 AIR POLLUTION REQUIREMENTS: Yes, per state and local requirements

8.05 WATER POLLUTION REQUIREMENTS: Yes, per above

8.06 AIRCRAFT WARNING REGULATIONS: Yes, per above

8.07 SHIPPING PROBLEMS: None - Truck and railway both available for construction and operation

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