SECTION 6

UTILITIES

The utility summary, presented in Table 6-1, tabulates the utility productions and consumptions by type, by unit, and for each of the three plants. The summary shows the interrelationship of the utility items between the plants.

All utilities required for operation are generated within the plant combinations. The combined cycle power plant is sized to generate approximately 200 MW of electricity. With combined Plant 1 and Plant 2 operation, nearly 30% of the generated power is used captively. Full operation of all three plants consumes almost 35% of the generated electricity. Approximately 140 MW of electricity are available for sale or transfer to outside usage.

The power plant gas turbines can be dual fired, with either fuel gas or fuel oil, or combinations of both. Thus, the power plant gas turbine generators with heat recovery steam generators operating in the combined cycle mode can be used, fueled with oil, for startup electrical power and steam requirements.

Table 6-1 also shows the interrelation of steam flows for each of the plants between the power plant, the process plant units, and for outside transfer. Four steam main-pressure levels are provided: 1250, 550, 150 and 50 psig.

Drawing No. R-130/131-FS-1, located in Section 5.1, depicts the combination of utility water systems. Mechanical draft cross-flow cooling towers provide the cooling water needs. Additions to a planned central cooling tower will be made as additional plants require increased cooling water supply.

Cooling water is required for the power plant steam condensers, oxygen plant process air cooling and some of the plant heat exchangers. Cooling tower blowdown water is reused as quench water for the gasifiers slags, and as spray water for dust control in the coal storage area.

Raw water requirements for supplying cooling tower water makeup is obtained from a nearby river source. Drawing No. R-130/131-FS-1 depicts the river source with the conventional preliminary chemical treatment and sand filtration. Sanitary and potable water requirements may be supplied by wells or a municipal water system.

Compressed air for air-blowing the Plant 1 fuel gas gasifier is supplied at 65 psig by a steam turbine-driven 120,000-scf/m rotary compressor. Instrument and plant compressed air is supplied at 100 psig by small units located in the individual plants.

Table 6-1 - Utilities Summary

Unit		Steam Produced (lb/h)				Steam Used (lb/h)				Condensate and Recovery (lb/h)	Boiler Feedwater (lb/h)	Boiler Feed-water Makeup		Cooling Water (gpm)	Raw Water Makeup (gpm)	Elec Power Used (kW-h)	Elec Power Generated (kW-h)	Fuel Gas (MMBtu/h)
Number	Description	1,300[1]	550[1]	150[1]	50[1]	1,300[1]	550[1]	150[1]	50[1]			(gpm)	(lb/h)					
PLANT 1																		
112	Gasifier (air blown)				26,700									20,000		2,500		
113	Gas Heat Recovery	94,000		10,950					26,700	15,335	146,321	53	26,218			450		
114	Acid Gas Removal							10,950		10,950	15,335	31	15,335			2,400		
130	Water Treatment														1,170	62		
131	Cooling Water															1,116		
132	Effluent Treatment															32		
113	Flare																	
134	Sulfur Storage															5		
150	Lighting and Misc															435		
	Total	94,000		10,950	26,700			10,950	26,700	26,285	161,656	84	41,553	20,000	1,170	7,000		
	Export Steam					94.000				94,000								
	Import Condensate									120,285								
PLANT 2	(does not include Plant 1)																	
212	Gasifier (O_2 blown)					12,082	259,744			12,082						552		
213	Gas Heat Recovery		117,007		246,789					24,626	388,422	179	88,548			312		
214	Acid Gas Removal							5,292	66,150			144	71,234	12,000		5,820		
215	Sulfur Plant			10,700	9,513		8,849			10,049	22,055	2	989			228		
216	Tail Gas				3,875					599	5,026			367		290		8.8
217	Water Reclaimation					4,573				175,789						547		
230	Water Treatment														6,726	350		
231	Cooling Water															6,060		
232	Effluent Treatment															210		
233	Flare																	
234	Sulfur Storage																	
240	Oxygen Plant													30,000		26,300		
241	Power Plant	16,655	151,586						199,135		24,626	113	55,900	66,375		3,300	192,200	
250	Lighting and Misc															231		
	Total	16,655	268,593	10,700	260,177	16,655	268,593	5,292	265,585	223,145	440,129	138	216,671	108,742	6,726	44,200	192,200	8.8
	Steam Produced and Used				556,123	556,123												
	Export Electrical Power															141,000		
PLANT 3	(does not include Plant 1, includes Plant 2 utilities listed in above table)																	
212	Gasifier (O_2 blown)					16,110	346,325			16,110						737		
213	Gas Heat Revovery		156,009		329,052						485,061	352	171,128			400		
214	Acid Gas Removal							7,056	88,200	95,256				16,000		7,760		
215	Sulfur Plant			14,266	12,684		11,798			14,198	36,109	3	1,484			304		
216	Tail Gas				5,166									490		387		11.7
217	Water Reclamation					6,098				234,336						730		
230	Water Treatment														8,691	450		
231	Cooling Water															8,060		
232	Effluent Treatment															250		
233	Flare																	
234	Sulfur Storage																	
240	Oxygen Plant													40,000		35,000		
241	Power Plant		69,563						225,005	99,672				88,500		3,900	202,800	
250	Lighting and Misc															305		
318	F-T Acid Gas Removal							9,110	20,500		7,865			2.2		2,014		1.91
319	F-T	136,588								9,795	112,073	47	23,250	2.2		587		0.14
320	F-T Liquid Product Separation					220	5,236	1,716	396	7,272						353		
321	F-T Methanation	27,243									28,296					433		
322	F-T Chemical Recovery								12,751	24,091						30		
	Total	163,831	225,572	14,266	346,902	22,428	363,359	17,882	346,902	500,780	699,404	402	198,862	144,995	8,691	61,700	202,800	13.75
	Steam Produced and Used				750,571	750,571												
	Export Electrical Power															134,100		

[1]psig

SECTION 7

ENVIRONMENTAL FACTORS

This conceptual design is responsive to requirements for control of gaseous, liquid, and solid emissions from the plant units and ancillary facilities. The means by which gas, vapor, liquid, and solids emission control, as well as noise level control have been accomplished are discussed below.

7.1 AIR POLLUTION ABATEMENT

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

The major air pollution abatement effort is aimed at desulfurizing the gases generated during the coal conversion process to make the fuels produced environmentally acceptable.

7.1.1 GENERATION AND CONTROL OF GASEOUS CONTAMINANTS

The generation and control of gaseous contaminants are outlined in Figure 7-1, which also shows the nature and amount of all streams vented to the air. These consist primarily of inert gases (nitrogen and carbon dioxide). The effluent gases are shown vented separately to the air to identify the contribution of specific process units. In reality, however, all streams with the exception of the particulates from the coal grinding and drying plant are combined into a single stack before venting to the air.

Fugitive particulate emissions from coal handling and from residual ash disposal are prevented from becoming airborne by maintaining a wet condition when not in a closed system. All coal handling units operate under inert gas cover to preclude coal dust explosions.

The coal grinding and drying unit for the intermediate pressure oxygen-blown gasifiers and the coal grinding unit for the low pressure gasifier are the only sources of particulate emissions. A baghouse system removes most of the particulates from the vent streams, with emissions to the air (0.030 gr/ft^3 maximum) meeting both the Federal standard for thermal dryer gases (0.31 gr/ft^3) and the other standards related to coal gasification plants. The source of heat for the drying process is hot effluent gas; no combustion gases are generated by the operation.

The output from each of the two gasifiers is raw gas containing hydrogen, carbon monoxide, carbon dioxide, methane, hydrogen sulfide, entrained char, and lesser amounts of ammonia, carbonyl sulfide, and cyanides. At the elevated reactor temperatures, any oils or tars formed are expected to crack to gaseous products. The entrained char is separated by cyclones followed by hot electrostatic precipitators; the particulates collected are returned to the gasifiers, where the carbon fraction can be gasified and the inorganic fraction is removed as slag. Final cooling of the gas streams occurs in condensate separators, which act as water scrubbers, removing a large portion of the remaining particulates. In addition, the stream from the intermediate pressure gasifier is conveyed through a venturi scrubber to improve the efficiency of particulate removal. The wet scrubbing also removes the ammonia and part of the hydrogen sulfide and hydrogen cyanide present.

The gas stream from the low pressure gasifier is conveyed to an acid gas removal unit. There all sulfur species differing from hydrogen sulfide are converted to the latter by hydrogenation and/or hydrolysis. Hydrogen sulfide is then absorbed by an alkaline solution, and oxidized to high purity elemental sulfur. The cleaned low-Btu fuel gas produced contains only 0.015 gr/ft^3 of H_2S, an amount much lower than mentioned in Federal and State standards for similar products (see subsection 7.1.2). This fuel gas will be utilized by a utility or industrial plant located outside of the Multi-Process Demonstration Plant, but probably in close proximity.

The gas stream from the intermediate pressure gasifier is conveyed to a selective acid gas removal unit where most of the acid gases present are removed by means of a physical solvent process. On selective regeneration of the solvent, a stream of hydrogen sulfide containing part of the carbon dioxide and a stream of nearly pure carbon dioxide are released. The carbon dioxide stream is vented to the air together with very small amounts of hydrogen sulfide and carbon monoxide. The hydrogen sulfide stream is combined with similar streams from sour water stripping and conveyed to the sulfur recovery plant, where 95% of the sulfur present is oxidized to high purity elemental sulfur; any hydrogen cyanide present is oxidized concurrently. The remaining 5% of sulfur is handled in a subsequent unit, the tail gas unit, which operates similarly to the acid gas removal unit handling the gas stream from the low pressure gasifier; additional amounts of high purity elemental sulfur are produced, and the cleaned tail gas, consisting essentially of carbon dioxide, plus traces of carbon oxysulfide, hydrogen sulfide, and carbon monoxide, is vented to the air.

The medium-Btu fuel gas obtained on purification of the gas stream from the intermediate pressure gasifier contains only traces (0.8 ppm) of hydrogen sulfide. This fuel gas is utilized for power generation in a gas turbine (three-fifths), for synthesis of gaseous and liquid fuels in a Fischer-Tropsch reactor (one-fifth), and for future Plant 4 modules (one-fifth).

Combustion of the medium-Btu fuel gas in the gas turbine produces a very small amount of sulfide dioxide and moderate amounts of nitrogen oxides. The generation of the latter contaminant is reduced by the cooling effect of the inert gases (carbon dioxide and nitrogen) present and by the injection of steam into the turbine combustor.

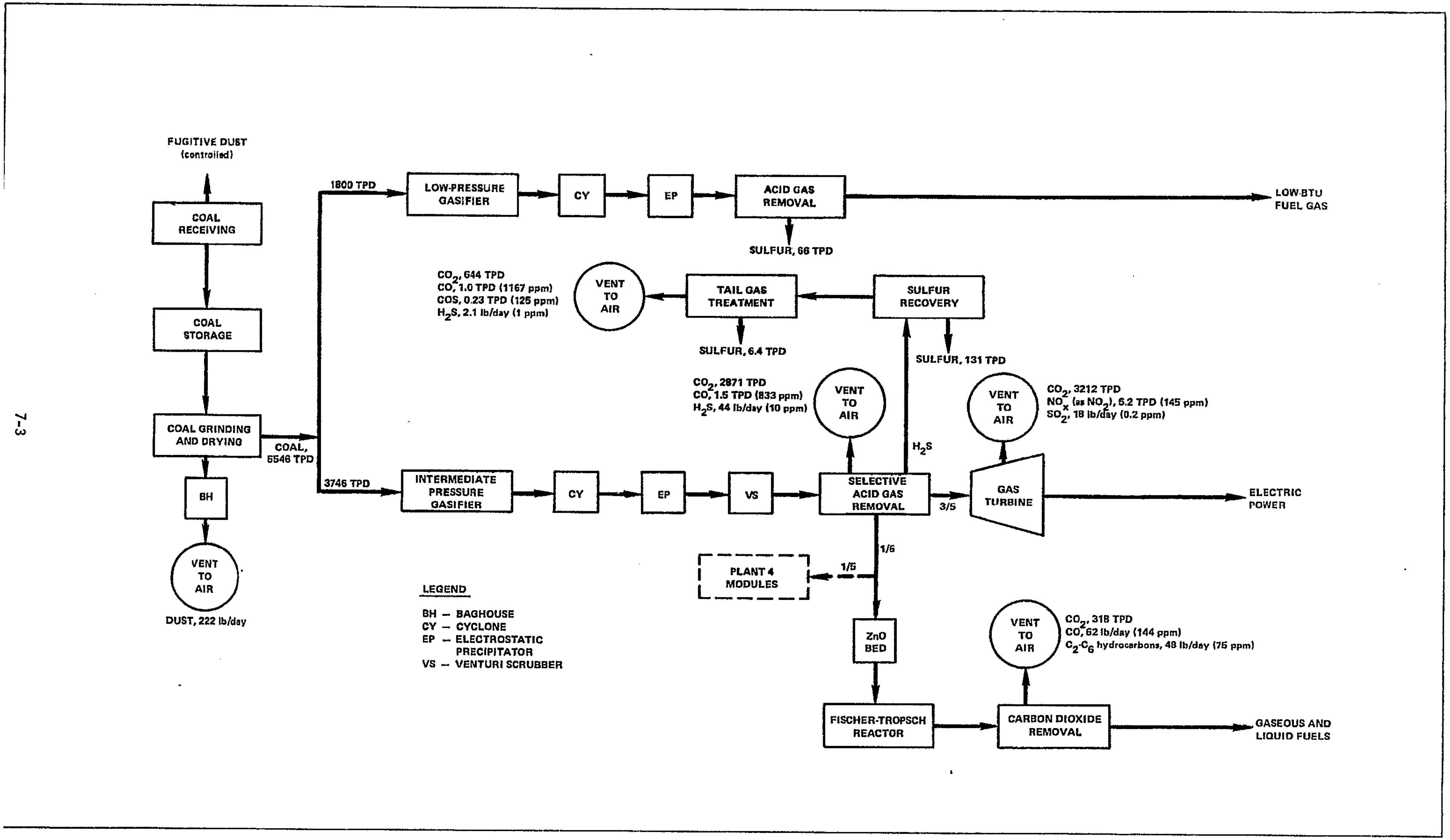

Figure 7-1 - Block Flow Diagram, Air Pollution Abatement
(See text for stack arrangement)

The Fischer-Tropsch synthesis catalyst is inactivated by sulfur compounds. The fraction of medium-Btu gas to be used for the Fischer-Tropsch process therefore undergoes repeated treatment in the selective acid gas removal unit until the hydrogen sulfide content is reduced to 0.1 ppm; then it is conveyed through a zinc oxide guard reactor, which further halves this concentration. As a result, the gaseous and liquid fuels produced contain nil sulfur. Some additional carbon dioxide is produced during the Fischer-Tropsch synthesis. This gas is removed by absorption in hot potassium carbonate; on regeneration of the absorbant, the carbon dioxide stream produced is vented to the air together with traces of carbon monoxide, light boiling hydrocarbons, and methane (a nonpollutant).

With the exception of the particulates from the coal drying and grinding plant, the streams shown vented separately to the air in Figure 7-1 are actually combined in a single stack before venting. The overall amounts and concentrations are shown in Table 7-1.

Table 7-1 - Combined Gaseous Effluents

Gaseous Effluent	Amount	Concentration (ppm)
Carbon dioxide	7,045 ton/d	-
Nitrogen oxides (as NO_2)	5.2 ton/d	129.0
Carbon monoxide	2.5 ton/d	104.0
Carbon oxysulfide	0.2 ton/d	4.4
Hydrogen sulfide	46 lb/d	0.8
C_2-C_6 hydrocarbons	44 lb/d	0.3
Sulfur dioxide	18 lb/d	0.2

All the amounts presented in this section refer to a multi-process demonstration plant operating at full capacity (Plant 4 included). The only exception is the fraction of medium-Btu gas reserved for future Plant 4 modules (one-fifth of total volume); it is expected, however, that the additional pollutant contribution from utilization of this stream will be negligible, and approximately comparable to the pollutant load generated by Fischer-Tropsch operations.

Due to the "demonstration plant" character of the multi-process facility, a number of process options will be tested; two of these have already been considered. The first option involves use of oxygen in place of air in the low-pressure gasifier: this will produce a higher-Btu gas, which will generate more carbon dioxide on combustion. However, the sulfur content will remain unchanged, and it is believed that negligible emission changes will result. The second option deals with use of an agglomerating ash fluid-bed gasifier in place of a two-stage entrainment slagging gasifier for the intermediate pressure gasifier. This modification will introduce some variation in the composition of the gas stream produced (e.g., an 8% increase and 5% decrease, respectively, in the amount of CO_2 and CO). However, as for the first option, the sulfur content will remain unchanged, and it is believed that any changes in emissions would be negligible.

7.1.2 COMPLIANCE WITH SOURCE EMISSION STANDARDS

Source emission standards for coal conversion plants have not been issued by the Federal Government. Guidelines for hydrocarbon (100 ppm) and sulfur dioxide (250 ppm) have been proposed by EPA for Lurgi coal gasification plants. These guidelines are not applicable to the Multi-Process Demonstration Plant because a different technology is used; they are, however, met by the plant effluents. Federal standards for petroleum refinery sulfur recovery plants have been proposed; a similar technology is used for the Multi-Process Demonstration Plant. Federal standards for coal preparation plants have been issued, and standards for stationary gas turbines have been proposed. Where pollutants were covered by more than one standard, the most stringent standard was considered.

An exact geographic location for the Multi-Process Demonstration Plant has not been selected. For illustration purposes only, state standards issued by New Mexico and West Virginia have been considered. The New Mexico standards are of special interest, because New Mexico is the only state which has issued specific regulations covering coal gasification plants.

Federal, New Mexico, and West Virginia source emission standards are compared in Table 7-2 with the emissions from the conceptual Multi-Process Demonstration Plant. As shown in the table, all estimated emissions are projected to either meet or be below the standards. This result has been achieved through the application of "Best Applicable Control Technology," as mandated by the Clean Air Act Amendments of 1977. Other provisions of the Act, such as maintenance of ambient air quality standards, prevention of significant deterioration, and trade-offs in nonattainment areas, depend on local conditions, and will have to be considered after a plant site has been selected.

7.1.3 SULFUR BALANCE

The sulfur balance for the conceptual design of a commercial POGO plant is detailed in Table 7-3. More than 99% of the coal sulfur content is recovered as elemental sulfur. The remainder is emitted as reduced sulfur emissions (mainly carbon oxysulfide), and as sulfur dioxide emissions (on combustion of the medium-Btu fuel gas); a small amount (0.014 gr/ft^3) is present in the low-Btu fuel gas. The gaseous and liquid fuels produced by Fischer-Tropsch synthesis contain nil sulfur.

Table 7-2 - Comparison of Gaseous Emissions with Federal, New Mexico, and West Virginia Source Emission Standards

Pollutant	Federal Standards	New Mexico Standards Coal Gasification Plant	West Virginia Standards	Gaseous Effluents, Multi-Process Demonstration Plant
Particulate matter	0.031 gr/ft^3 [a]	0.03 gr/ft^3	0.07 gr/ft^3 [a]	0.030 gr/ft^3
Sulfur dioxide	150 ppm [b]	-	2000 ppm	0.2 ppm
Nitrogen oxides	145 ppm [b]	-	-	129 ppm
Hydrogen sulfide:				
Emissions	10 ppm [c]	10 ppm	-	0.8 ppm
Fuel content	0.10 gr/ft^3 [c]	-	0.50 gr/ft^3	0.015 gr/ft^3
Total reduced sulfur (H_2S + COS + CS_2)	300 ppm [c]	100 ppm	-	5.2 ppm
Hydrogen cyanide	-	10 ppm	-	nil
Hydrogen chloride/ hydrochloric acid	-	5 ppm	145 ppm	nil
Ammonia	-	25 ppm	-	nil
Gas burning process boilers, particulate matter	-	0.03 lb/MMBtu, LHV	-	d
Gas burning process boilers, sulfur dioxide	-	0.16 lb/MMBtu, LHV	-	d
Total sulfur	-	0.008 lb/MMBtu of feed	-	0.002 lb/MMBtu

[a] Standard for coal thermal dryers.
[b] Proposed standard, stationary gas turbine (42 FR 53782, Oct. 3, 1977).
[c] Proposed standard, petroleum refinery sulfur recovery plant (41 FR 43866, Oct. 4, 1976).
[d] Not applicable (none included in the design).

Table 7-3 - Sulfur Balance (lb/hour)

Total input from the typical feed coal		16,983.0
<u>Outputs:</u>	As elemental sulfur	16,949.3
	As reduced sulfur emissions (18% H_2S, 82% COS)	12.4
	As sulfur dioxide emissions (from combustion of medium-Btu fuel gas in gas turbine)	0.7
	In the low-Btu fuel gas	20.6
	Total output	16,983.0

7.1.4 CARBON DIOXIDE EMISSIONS

It is estimated that significant carbon dioxide emissions (on the order of 7050 ton/d, Table 7-1) would be generated by the Multi-Process Demonstration 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 400 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.

On a localized scale, no micrometeorological effects due to increased carbon dioxide have been reported. Emissions from the Multi-Process Demonstration Plant could cause a slight increase in the average atmospheric carbon dioxide concentration in the vicinity of the plant. The lowest concentration at which some physiological effects (dyspnea and headache) have been observed is 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.

7.2 AQUEOUS EFFLUENTS

Based on adequate availability of water, the wastewater treatment is a combination of recycling and discharge of aqueous effluents. The most heavily contaminated streams are purified by oxidation, then concentrated by evaporation, with residuals undergoing thermal destruction in the coal gasifier, while the distillate is reused as makeup for boiler feedwater. The medium-contaminated streams are treated for removal of oil and other contaminants, then are reused for slag quenching and dust control. The lightly polluted streams are treated to make them acceptable to the environment, then are discharged to natural waters.

7.2.1 GENERATION AND TREATMENT OF AQUEOUS CONTAMINANTS

The generation and treatment of aqueous contaminants is outlined in Figure 7-2. Waste water sources are listed on the left hand side of the figure, with the degree of pollution of the waste water streams decreasing from top to bottom. The progressive treatment and disposition of the streams is also shown; approximate flow values are reported.

The water supply, provided by a nearby river, consists of 11,300 gpm of raw water, which, after purification by flocculation and settling, is used for cooling water makeup and, after further sand filtration and deionization, for boiler feedwater makeup. Potable water is expected to be supplied by wells. The water supply from the river is not used for coal grinding and drying because no wet systems are employed for these operations.

One of the major contaminated streams is the sour water generated by the wet scrubbers cleaning the gases produced by the coal gasifiers. The major contaminants present are hydrogen sulfide, ammonium sulfide, oil, phenols, thiocyanates, cyanides, and solids (ash and char particles). After removal of any oily materials by extraction, most of the gaseous contaminants (hydrogen sulfide and ammonia) are removed by a reboiler-stripper, and then conveyed to the sulfur plant, where the hydrogen sulfide is converted to elemental sulfur and the ammonia is oxidized to nitrogen. The stripped aqueous stream is now treated in an oxidizer with oxygen at high pressure to convert most of the organics present (including cyanides) to inorganic gases such as carbon dioxide, nitric oxide, and sulfur dioxide. These are led back to the coal gasifier; the reducing atmosphere prevailing there is expected to reduce nitric oxide and sulfur dioxide to nitrogen and hydrogen sulfide. After settling and filtration, the aqueous effluent stream from the oxidizer is deionized and reused as boiler feedwater makeup.

The Fischer-Tropsch reactor produces, besides the desired hydrocarbon fuels, a number of oxygenated organic acids. When the product stream is purified by treating with caustic, a waste stream containing alkaline salts of low-molecular weight organic acids is produced. This stream is combined with the boiler water blowdown and the solids slurry obtained as a residue from the settling of the treated sour water, and then concentrated in a triple-effect evaporator. The evaporator condensate is used for boiler feedwater, while the residue is sprayed on the feed coal at the entrance to the coal dryer. A more thorough evaporation occurs in the latter unit; the organic materials are then destroyed when the coal is fed to the gasifier, while the inorganic materials are removed with the ash.

Oily water streams produced during plant operation are combined with contaminated stormwater. Most of the oil present is separated by gravity and returned to the gasifier, with the remainder removed by air flotation. The aqueous effluent is combined with sewage effluent and conveyed to an aerated pond, where the organic materials present are converted to inorganics by bacterial activity. The pond effluent is used for process requirements, such as slag quench, and for surface requirements, such as dust control; it is also used for firewater supply.

The cooling tower blowdown stream is the largest in volume, and is only lightly contaminated by corrosion inhibitors (zinc salts and inorganic phosphates) and scale-control agents (organic phosphate esters); this stream is mixed with deionizer wastes (containing mainly sodium sulfate and other inorganic salts) and with coal pile runoff. After neutralization, this stream is treated with lime in a settler-clarifier. The lime sludge, containing most of the zinc and phosphates, is disposed of in a landfill, while the treated stream is returned to the river.

7.2.2 COMPLIANCE WITH EFFLUENT STANDARDS

No aqueous effluent standards specifically addressed to coal-conversion plants have been issued by the federal government or by state legislatures. Standards that are somewhat related to coal conversion processes are the Federal standards issued for petroleum refining. Maximum concentrations which were the base for petroleum refining new source performance standards[4] are reported in Table 7-4; any discharge from the Multi-Purpose Demonstration Plant is expected to meet these standards.

Table 7-4 - New Source Performance Standards for the Petroleum Refining Industry[a]

Parameter	Maximum Concentration[b] (mg/l)
BOD-5	10
COD	60
Total organic carbon	21
Suspended solids	6
Oil and grease	3
Ammonia-N	10
Phenol	0.06
Sulfide	0.06
Chromium, tertiary	0.16
Chromium, hexavalent	0.003

[a]Based on application of best available demonstrated technology (BADT).

[b]Converted from the mass standards reported in Reference 1 (pp. 145, 147, 176), for the petrochemical subcategory.

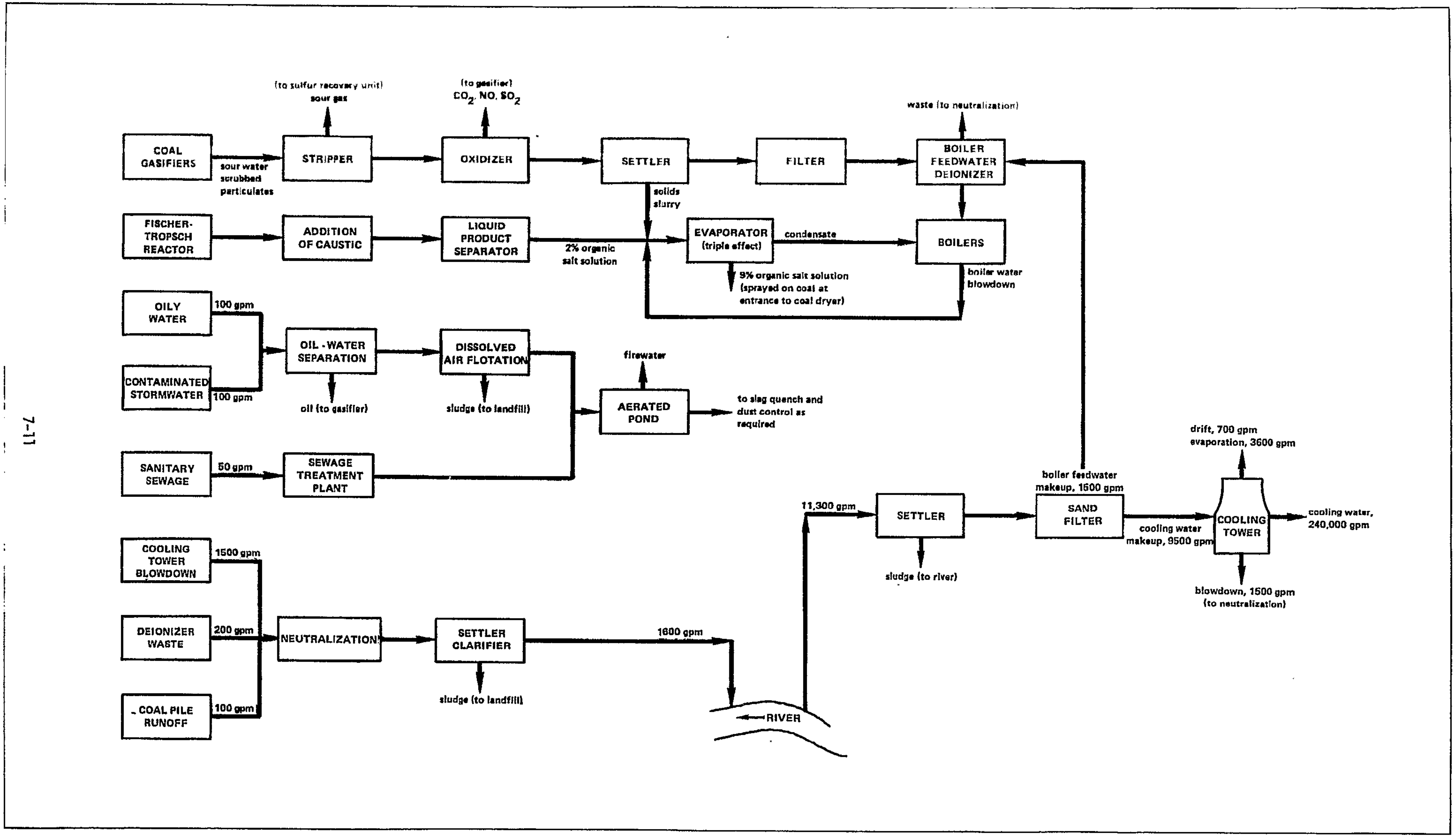

Figure 7-2 - Block Flow Diagram, Water Treatment and Supply

For illustration purposes, typical West Virginia water quality parameters are reported in Table 7-5. These parameters represent water quality criteria for river water; they can be converted to discharge parameters by application of appropriate dilution factors reflecting low-flow periods for the specific river.

Table 7-5 - Water Quality Parameters, State of West Virginia

Constituent	Concentration (mg/1)
Arsenic	0.01
Barium	0.50
Cadmium	0.01
Chromium (hexavalent)	0.05
Lead	0.05
Silver	0.05
Nitrates	45
Chlorides	100
Phenol	0.001
Cyanide	0.025
Fluoride	1.0
Selenium	0.01

7.3 SOLID WASTES

The Multi-Process Demonstration Plant generates two main types of solid waste materials; slag from the coal gasifiers and sludge from various waste water treatment units. Both materials are disposed of using environmentally acceptable procedures.

7.3.1 SLAG

The gasifiers included in the Multi-Process Demonstration Plant design generate up to 1000 ton/d of slag. The slag is withdrawn from the bottom of the gasifiers; on quenching with water, it fragments into sand granules. Gases generated on quenching are returned to the gasifier. The slag slurry is conveyed to a settling basin where the solids separate; they are then collected and disposed of in a landfill. If outlets exist nearby, this material could also be utilized as filler in aggregates for construction blocks or road building. The possibility of leaching trace metals from the ash into ground or surface waters is discussed below.

7.3.2 SLUDGE

Various water treatment units generate sludges (see Figure 7-2) of organic and inorganic origin. The settler-clarifier that treats the raw river water generates an inoffensive sludge, which is returned to the river. The sludges generated on treatment of waste water, however, contain contaminants which could possibly pollute groundwater; for example, the sludge generated on treatment with lime of cooling tower blowdown contains a sizable amount of zinc. These sludges, therefore, are disposed of in a landfill.

7.4 NOISE

Noise control will be an integral part of the layout and design of the Multi-Process Demonstration Plant. The Occupational Safety and Health Act of 1970 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 bases for noise control in plant design and layout.

Special attention will be given to the coal gasifiers and oxygen plant fans, compressors, and pressure letdown valves. The sound exposure standards will be met by a combination of noise-reduction engineering techniques, such as soundproofing of turbines, silencing of valves, and use of sound and vibration absorption materials. Process units not requiring close observation and capable of high noise levels, such as oxygen compressors, will be barricaded.

7.5 SPECIFIC ENVIRONMENTAL ASPECTS

Three specific environmental aspects pertinent to coal conversion, the formation and destruction of metal carbonyls, the fate of trace elements present in coal, and the formation of coal tar carcinogens and biohazards involved, are considered below. General factors and specific applications to technology used in the multi-process demonstration plant are included.

7.5.1 METAL CARBONYLS

Metal carbonyls form by the reaction of the carbon monoxide with free metals in the 100 to 570°F temperature range. Carbonyls form with all transition metals; nickel, cobalt, and iron carbonyls are most significant, since the metals from which they are derived are used as catalysts or for structural equipment[5, 6]. Much higher pressures than achieved in this plant (of the order of 15,000 psi) and the presence of hydrogen favor their formation, while oxygen represses it. They decompose readily in air with half-lives estimated at 10 to 15 sec for cobalt carbonyl, 10 min for nickel carbonyl, and a few hours for iron carbonyl.

These carbonyls are volatile liquids at room temperature. They all exhibit toxicity, directed at the respiratory system. The most harmful among the three carbonyls is the nickel derivative. For this carbonyl only, chronic effects and carcinogenic activity have been observed. Suggested exposure guidelines and chemical formulas are reported in Table 7-6.

Table 7-6 - Suggested Exposure Guidelines for Metal Carbonyls (from Reference 2)

Metal Carbonyl	Air Concentration (ppm)	
	Single Short Term Exposure	Eight-Hour Day
$Ni(CO)_4$	0.04	0.001
$Co(CO)_x + CoH(CO)_4$	0.10	-
$Fe(CO)_5$	0.10	0.01

Iron, nickel, and cobalt catalysts are used in the Multi-Process Demonstration Plant, and low carbon steel is employed for structural equipment. However, at the relatively low pressures and high temperatures prevailing, no metal carbonyls are expected to be formed. In shutdown operations, however, conditions under which metal carbonyls can form may be experienced for short periods of time. In these cases, the normal safe practice of flaring vent streams, along with operation of all contaminant removal systems, will prevent release of carbonyls to the atmosphere. Plant personnel who may be entering vessels or handling catalysts, however, will need to be trained in the proper procedures and supplied with adequate protective equipment to safeguard their health.

7.5.2 TRACE ELEMENTS

Due to its organic origin and its intimate commixture with crustal formations, coal contains a large number of elements in minor or trace quantities. Actually, out of 92 known nontransuranic elements, only 14 have not yet been found in coal.

Average amounts of trace and other elements for 82 coals from the Eastern Region of the Interior Coal Province are shown in Table 7-7. These values were developed during a recent study[7] carried out with thorough analytical procedures; the coals analyzed were mainly composite face channel samples.

A number of studies have analyzed the behavior of trace elements in coal-fired power plants[8,9]. In general, the elements have been divided into two groups, the ones appearing mainly in the bottom ash (elements or oxides having lower volatility) and those appearing mainly in the fly ash particulate collection devices (e.g., electrostatic precipitators). It was believed that the most volatile elements, such as mercury and selenium, could actually escape at the elemental state with the flue gas. Wet scrubbers, however, were believed

Table 7-7 - Mean Analytical Values for 82 Coals from the Illinois Basin (From Reference 4)[a]

Constituent	Mean	Constituent	Mean (%)
As	14.91 ppm	Cl	0.15
B	113.79 ppm	Fe	2.06
Be	1.72 ppm	K	0.16
Br	15.27 ppm	Mg	0.05
Cd	2.89 ppm	Na	0.05
Co	9.15 ppm	Si	2.39
Cr	14.10 ppm	Ti	0.06
Cu	14.09 ppm	ORS	1.54
F	59.30 ppm	PYS	1.88
Ga	3.04 ppm	SUS	0.09
Ge	7.51 ppm	TOS	3.51
Hg	0.21 ppm	SXRF	3.19
Mn	53.16 ppm	ADL	7.70
Mo	7.96 ppm	MOIS	10.02
Ni	22.35 ppm	VOL	39.80
P	62.77 ppm	FIXC	48.98
Pb	39.83 ppm	ASH	11.28
Sb	1.35 ppm	Btu/lb	12748.91
Se	1.99 ppm	C	70.69
Sn	4.56 ppm	H	4.98
V	33.13 ppm	N	1.35
Zn	313.04 ppm	O	8.19
Zr	72.10 ppm	HTA	11.18
Al	1.22 %	LTA	15.22
Ca	0.74 %		

[a]Abbreviations other than standard chemical symbols: organic sulfur (ORS), pyritic sulfur (PYS), sulfate sulfur (SUS), total sulfur (TOS) sulfur by X-ray fluorescence (SXRF), air-dry loss (ADL), moisture (MOIS), volatile matter (VOL), fixed carbon (FIXC), high-temperature ash (HTA), low-temperature ash (LTA).

capable of removing most of the elements from the gas streams and transferring them to the liquid effluent.

Very few data are available for coal conversion plants. A study on trace element disposition for the Sasol (South Africa) facility, reported by the Los Alamos Scientific Laboratory,[10] was able to follow the partitioning of trace elements between solid residue (ash), liquid streams, and gases. Among the elements studied, lead, arsenic and beryllium were found mainly in the ash, selenium and tellurium in the liquid streams, and two-thirds of the fluorine in the ash and one-third in the liquids. Mercury was found present in all phases, but concentrated mainly in the gas; however, 50% of the mercury and 17% of the beryllium could not be accounted for.

The possibility of leaching of trace metals from the ash into ground or surface waters has been questioned. Experimental studies have been carried out on the leaching of power plant fly ash or unslagged bottom ash[11]; the studies showed that selenium, chromium, and boron, and occasionally mercury and barium were released on simulated leaching, and the concentrations reached exceeded the values recommended by EPA for public water supplies.

An on-going study at the University of Montana[12] is investigating leaching of trace elements from solid residues of coal conversion plants under neutral, acidic, and basic conditions. Preliminary results indicate that manganese, mercury, and nickel are occasionally released in amounts exceeding recommended potable water standards. The study is hampered by the unavailability of typical residue specimens.

In the Multi-Process Demonstration Plant, essentially no particulates from coal combustion escape into the atmosphere. Particulate streams, wet or dry, are returned to the bottom of the gasifiers, where ash and salts melt and are removed as slag. Any eventual dispersion of the elements present in the slag depends on the possibility of leaching. Possibly, slagged ash features a glass matrix which would inhibit leaching. Leaching experiments using the slag generated by a slagging gasifier, such as the bi-gas pilot plant or a Koppers-Totzek unit, would be very useful.

The major concern, therefore, is to identify trace elements which may be occurring in the gaseous state. The reducing atmosphere present in the middle and top part of the gasifier may also favor different combinations, absent in the oxidizing atmosphere of a power plant boiler.

Among the trace elements with recognized toxic properties present in the coal, high volatility elements (beryllium, mercury, and lead), do not form gaseous hydrides, will condense on cooling, and very likely be removed by the aqueous condensates formed on gas cooling and/or purification. Arsenic, antimony, and selenium have lower volatility, but can form gaseous (covalent) hydrides, arsine, stibine, and hydrogen selenide. These hydrides, however, have stability characteristics which preclude their formation at the temperature and pressure prevailing in the multi-process demonstration plant gasifiers. From general chemical principles, it would appear, therefore, that harmful trace elements are not released to the atmosphere. Experimental confirmation, however, is desirable, especially for mercury, and should be obtained from specific pilot plant studies.

7.5.3 COAL TAR CARCINOGENS AND BIOHAZARDS INVOLVED

Of particular interest in coal conversion projects is the possible formation of carcinogenic compounds on hydrogenation and pyrolysis of coal. These compounds are polynuclear aromatic hydrocarbons and heterocyclics usually found in coal tar. Nil coal oils and coal tars are expected to be produced under the operation conditions of the coal gasifiers used in the Multi-Process Demonstration Plant. Coal oils and coal tars are produced in large amounts during coal solution or pyrolysis; however, dissolvers or pyrolyzers have not been included in the design of the Multi-Process Demonstration Plant.

Fischer-Tropsch fuels are comparable to petroleum products and consist essentially of aliphatic compounds. Cancer frequency in the oil refining industry is the same as for other industrial occupations. Multi-process demonstration plant operations and products, therefore, will not be subject to coal-derived carcinogenic hazards.

SECTION 8

MAJOR EQUIPMENT SUMMARY

The major equipment items for key operating units are listed in Tables 8-1 through 8-13.

Equipment items are shown with dimensions and/or capacity, as well as operating pressure and temperature, and, in most cases, materials of construction. The size and capacity shown are the design requirements for the most demanding condition. These capacity ratings, in most cases, exceed the requirements for the conditions shown on the process flow sheets that describe the typical case.

Equipment numbers are included; the first digit of the three-digit unit number refers to the specific plant involved. Like units for each plant are given similar second- and third-digit combinations.

Detailed equipment lists are not included for proprietary processes (Units 114, 214, 215, 216, 240, and 318) for the offsite units or the Fischer-Tropsch process units (319, 320, 321, and 322). The F-T plant has been scaled down from one train in a conceptual F-T plant which has earlier been reported[1] and which contains equipment lists.

Table 8-1 - Major Equipment Summary
Unit 110 - Coal Storage and Handling

Item No.	Description	Size
110-0501	Hopper feeder	48" wide x 100' long, 150 hp
110-2001	Belt conveyor No. 1	36" wide x 120' long, 20 hp
110-2002	Belt conveyor No. 2	36" wide x 540' long, 50 hp
110-2003	Belt conveyor No. 3	36" wide x 1080' long, 75 hp
110-2004	Radial stacker No. 1	36" wide x 150' long, 65 hp
110-2201	Car dump bag house dust collector	35,000 cfm @ 15" wg, 100 hp
110-2601	Car dump hopper	12' wide x 100' long 200-ton capacity
110-3501	Rubber tired tractor front end loader, diesel engine driven	4.5 cu yd
110-3601	Car thawer	2-car capacity, 2000 kW
110-3602	Car spotter	55-car capacity, 100 hp
110-3603	Self-propelled hopper	10-ton capacity, 5 hp

Table 8-2 - Major Equipment Summary
Unit 111 - Coal Grinding

Item No.	Description	Size
111-0502	Pulverizer feeder	24" wide x 50' long, 20 hp
111-1801	Blower	100,000 cfm @ 55" wg, 900 hp
111-2101	Table and roller pulverizer	75 ton/hr
111-2202	Bag house dust collector	100,000 cfm @ 25" wg
111-2602	Storage bin	200-ton capacity

Table 8-3 - Major Equipment Summary
Unit 112 - Low Btu Gasifier

Item Number	Description	Size	Operating Pressure (psig)	Operating Temp (°F)	Material and Remarks
	Exchangers				
112-1301	Quench water air cooler	82 MMBtu/hr, 414,000 ft^2, finned, 5 bays, 20' x 40', 10 fans, 31 hp each	5	180 in 120 out	CS
112-1302	Oxygen preheater	23 MMBtu/hr, 4.956 ft^2 1 shell 60" x 16'	100 1500	600 950	SH SS T SS
	Pumps				
112-1501/02	Slag quench circulating pump	2,720 gpm - vertical deep well 15' long - 10' submersion	50	180	CI
112-1503/04	High pressure circulating pump	800 gpm, 50 hp	1,500 max	580	3/6 SS
	Materials Handling Equipment				
112-2001	Gasification zone coal feeder	3 units 300 hp each	100 max	1700 discharge	CS and SS
112-2002	Slagging zone coal feeder	6 Units 300 hp each	100 max	1700 discharge	CS and SS

Table 8-3 (Contd)

Item Number	Description	Size	Operating		Material and Remarks
			Pressure (psig)	Temp (°F)	
112-2003	Slag settler conveyor and elevator	8 Sets 20' wide x 125' long 10 hp each	atm	180	Malleable iron chain CS flights
112-2004	Settled slag cross belt conveyor	24" wide x 160' long 10 hp	atm	amb	Rubber belt
	Reactors				
112-2501	Low pressure gasifier	20'-0" ID, 15'-0" ID refractory x 79'-0" TT, flat bottom	40	3000 bottom, 1800 top 150 shell	CS shell, CS cooling tubes, membrane refractory lining
	Other Major Equipment				
112-2201	Char cyclone	6 units 90" ID, 106" OD, 33' high Diplegs 8" ID 24" OD, 21' long	90 max	1800	CS, refractory lined
112-2801	Slag outlet drilling and plugging unit				Standard blast furnace unit
112-3201	Slag slurry sump	4 units, each 40' wide x 125' long	atm	180	Concrete basin

Table 8-4 - Major Equipment Summary
Unit 113 - Steam Generation

Item Number	Description	Size	Operating Pressure (psig)	Operating Temp (°F)	Material and Remarks
	<u>Vessels</u>				
113-1201	Blowdown receiver	1-6" dia x 6' TT	75	320	A 285C 1/4 CA insulated
113-1202	High pressure feedwater deaerator	8' dia x 20' TT horizontal 311,500 lb/hr	7	230	CS, SS internals, insulated
113-1203	Medium pressure feedwater deaerator	4'-6" dia x 10' TT horizontal 30,000 lb/hr	7	230	CS, SS internals insulated
113-1204	Clean condensate receiver	4'6" dia x 14' TT vertical	7	230	A 285C 1/8 CA insulated
113-1205	Process condensate separator	9' dia x 56' TT horizontal	26	100	A 285C 1/4 CA insulated
113-1206	Condensate return surge drum	9' dia x 15' TT vertical	25	109	A 285C 1/4 CA insulated

Table 8-4 (Contd)

Item Number	Description	Size	Operating Pressure (psig)	Operating Temp (°F)	Material and Remarks
	<u>Exchangers</u>				
113-1301	Surface condenser	132 MMBtu/hr, 133,000 ft^2 1 shell 80" OD x 20' tubes incl hotwell and ejector system	1.24" Hg 35	109 100	SH CS, 1/16 CA T Inhibited Admiralty T
113-1307	Process steam superheater	7.8 MMBtu/hr, 1 shell, 26"-16', BEM 1050	50 40	1100 1800	SH 321 SS, 0.06" CA T Incoloy 800
113-1308	High pressure steam superheater	84 MMBtu/hr, 6660 ft^2, 51"-20', CEU, 1 shell	50 1,300	1800 950	SH Incoloy 800 T Incoloy 800
113-1309	High pressure steam generator	108 MMBtu/hr, 8,100 ft^2, 50"-20' CEN, 2 shells	1305 50	580 1500	SH CS 1/8 CA T 321 SS
113-1310	High pressure feedwater heater	55 MMBtu/hr, 6,020 ft^2, 64"-20' CEN, 1 shell	1310 40	580 1120	SH CS 1/4 CA T 321 SS
113-1311	150-psig steam generator	26 MMBtu/hr, 2,590 ft^2, 46"/66"-16' BKM, 1 shell	200 75	390 1120	SH CS 1/4 CA T 321 SS

Table 8-4 (Contd)

Item Number	Description	Size	Operating Pressure (psig)	Operating Temp (°F)	Material and Remarks
113-1312	Process steam generator	36 MMBtu/hr, 10,190 ft^2, 62"/90"-24' BKM, 1 shell	100 50	300 800	SH CS 1/4 CA T 321 SS
113-1313	Process water heater	3 MMBtu/hr, 2,050 ft^2, 42"-16' AES, 1 shell	60 40	300 425	SH CS 1/4 CA T CS 1/8 CA
113-1314	High pressure feedwater preheater	29 MMBtu/hr, air case, 34 MMBtu/hr, O_2 Case, 14,450 ft^2, 72"-20' BEM, 1 shell	50 30	230 400	SH CS 1/4 CA T CS 1/8 CA
113-1316	Effluent air cooler	81 MMBtu/hr, 73,600 ft^2 bare-tube, 12 bays, 16' x 30', 24 fans, 10-hp motors ea	75	250	CS
113-1317	Blowdown/ feedwater exchanger	0.75 MMBtu/hr, 44 ft^2 1 section, double-pipe type	70 55	140 300	SH CS T CS
113-1318	Excess steam condenser (air cooler)	12.300 MMBtu/hr, 18,761 ft^2 total, 12' x 24' bay, 2 fans, 7-1/2 hp ea	200	390	CS
113-1319	Medium pressure feedwater preheater	4.6 MMBtu/hr, 1,970 ft^2, 31"-16' BEM, 1 shell	50 30	230 400	SH CS T CS

Table 8-4 (Contd)

Item Number	Description	Size	Operating Pressure (psig)	Operating Temp (°F)	Material and Remarks
113-1320	High pressure feedwater heater	54.5 MMBtu/hr, 10,800 ft^2, 70"-20' BEM, 1 shell	1,310 35	405 780	SH CS T 321 SS
113-1321	Medium pressure feedwater heater	4.3 MMBtu/hr, 870 ft^2, 21"-16' BEM, 1 shell	155 35	370 780	SH CS T 321 SS
113-1322	Process feedwater preheater	6.4 MMBtu/hr, 3,210 ft^2, 39"-16' BEM, 1 shell	65 20	230 370	SH CS T CS
113-1323	Process steam superheater	7.8 MMBtu/hr, 1,030 ft^2, 26"-16' BEM, 1 shell	50 40	700 1,035	SH CS T 321 SS
	<u>Pumps</u>				
113-1501/02	High pressure feedwater pump	505 gpm normal, 350 gpm min, 500 hp	1,300	230	CS
113-1503/04	Medium pressure feedwater pump	64 gpm normal, 70 gpm max, 15 hp	200	230	CS

Table 8-4 (Contd)

Item Number	Description	Size	Operating Pressure (psig)	Operating Temp (°F)	Material and Remarks
113-1505/06	Deaerator feed pump	65 gpm normal, 75 gpm max, 5 hp	50	230 max	CS
113-1507/08	Process condensate pump	10 gpm normal, 90 gpm max, 3 hp	50	150	CS
113-1509/10	Clean condensate return pump	200 gpm normal, 340 gpm max, 5 hp	20	109	CI
113-1511/12	Process feed water circulating pump	250 gpm, 30 hp	20	300	CS
113-1801	Air compressor	118,500-scfm turbine driver	65 1,300	80 950	Manufacturer's standard
113-2201	Process condensate filter	Two sets with precoat tank	150		CS
113-2202	Electrostatic precipitator	25' x 50' x 45' high, 3 transformers, 85 kVA ea	30	100	CS
113-2801	Vacuum system	Included with 12-1301			

Table 8-5 - Major Equipment Summary
Unit 210 - Coal Storage and Handling

Item No.	Description	Size
210-2005	Radial stacker No. 2	36" wide x 150' long, 65 hp
210-2006	Belt conveyor No. 4	36" wide x 405' long, 50 hp
210-3502	Rubber tired tractor front end loader, diesel engine driven	4.5 cu yd

Table 8-6 - Major Equipment Summary
Unit 211 - Coal Grinding

Item No.	Description	Size
211-0503	Pulverizer feeder	24" wide x 50' long, 20 hp
211-1802	Blower	100,000 cfm @ 55" wg, 900 hp
211-2102	Pulverizer	75 ton/hr, 800 hp
211-2203	Bag house dust collector	100,000 cfm @ 25" wg
211-2603	Storage bin	200-ton capacity

Table 8-7 - Major Equipment Summary
Unit 212 - Medium Pressure Gasifier

Item Number	Description	Size	Operating Pressure (psig)	Operating Temp (°F)	Material and Remarks
	Vessels				
212-1201	Slag slurry Degasser	5'-0" ID x 10' TT	10	140-240	CS
212-1202	Vent compressor suction pot	2'-6" ID x 5' TT	5	110	CS
212-1203	Slurry feed tank	20'-0" ID x 20' TT, cone bottom	ATM	100-212	CS
212-1204	Ash Slurry Tank	6'-0" ID x 15' TT, cone bottom	495	450	CS
	Exchangers				
212-1301	Oxygen heater	16.8 MMBtu/hr, 1,810 ft^2, 32" dia, 16' tubes, 1 shell	1300 500	950 600	SH 1 1/4 Cr T 304 SS
212-1302	Slag slurry air cooler	40.9 MMBtu/hr, 283,500 ft^2, fin T, 3 bays, 23' x 46' ea, 6 fans @ 40 hp	500	140	T CS
212-1303	Steam condenser (air)	24.8 MMBtu/hr, 114,600 ft^2, fin T, 2 bays, 14' x 46' ea, 4 fans @ 25 hp	10	240	T CS

Table 8-7 (Contd)

Item Number	Description	Size	Operating		Material and Remarks
			Pressure (psig)	Temp (°F)	
	Pumps				
212-1501/02	Slurry circulation pumps	1375 gpm, 50 psi dp, 75 hp	30 ft	100-212	CS
212-1503-01,-02,-03	Slurry feed pump, 6 1/2 x 8, 5 cylinder plunger	575 gpm, 520 psi dp, 250 hp	570	100-212	CS, hardened plungers and valves
212-1504	Slurry feed pump, multi-stage, centrifugal	1150 gpm, 520 dp, 600 hp	570	100-212	CS case
212-1505/06	Condensate pump	46 gpm, 40 psi dp, 5 hp	750	110	CS
212-1507/08	Slag slurry circulation pump	5250 gpm, 30 psi dp, 300 hp	25	180	
212-1509/10	Slag slurry product pump	300 gpm, 40 psi dp, 10 hp	10	140-240	

Table 8-7 (Contd)

Item Number	Description	Size	Operating Pressure (psig)	Operating Temp (°F)	Material and Remarks
	Other Major Equipment				
212-1801	Vent compressor	367 scfm, 495 psi dp, 15-psia inlet	510 outlet	110 inlet	
212-2101	Slag crusher	2 MMlb/hr with 2% slag, 98% water, 18" dia, 15 hp	490	140-467	
212-2201	Coal cyclone	1.2 MMlb/hr, 2 sets, 2 stages ea, 1st stage 4'-0" ID x 18'-6" high, 2nd stage, 2 ea 3'-1" ID x 15'-6" high	485	600	CS, refractory lined
212-2202	Char cyclone	0.9 MMlb/hr, 2 sets, 2 stages ea, 1st stage 5'-5" ID x 29'-0" high, 2nd stage 2 ea 3'-4" ID x 20'-6" high	500	1800	CS, refractory lined
212-2203	Slag slurry cyclone	2 MMlb/hr, 136,000 lb/hr, underflow with apparent density 75-51 lb/ft^3, wet cyclone, 50" dia	700	500	CS
212-2401	Slag slurry agitator				
212-2402	Feed slurry agitator				

Table 8-7 (Contd)

Item Number	Description	Size	Operating Pressure (psig)	Operating Temp (°F)	Material and Remarks
	Reactors				
212-2501	Gasifier, entrainment slagging type	8'-0" ID lower zone, 9'-8" upper zone ID of refractory x 10'-11" ID water bottom 110'-11" TT-hemispherical top and bottom	500	3000 lower 1800 upper 180 max water	2 1/4 Cr 1 Mo upper, lower section same with SS 347 overlay, no overlay in water section, water cooling in refractory lining
212-2502	Gasifier, agglomerating ash fluid bed type with pretreatment section	21'-0" ID x 76'-0" TT - hemispherical top and bottom 11'-4" ID x 10'-0" lower pretreatment section	500	2500 to 1800 fluid bed zone. 800 lower pretreat zone	1 1/2 Cr 1/2 Mo 9" refractory lined gasifier section, 1 1/2" refractory lined pretreat section

Table 8-8 - Major Equipment Summary
Unit 213 - Medium Pressure Gasifier Heat Recovery

Item Number	Description	Size	Operating Pressure (psig)	Operating Temp (°F)	Material and Remarks
	Vessels				
213-1201	Flash dryer	5'-10" ID shell, 4'-4" ID refractory, 100'-0" TT	470	600	A-516-70 1/8" CA refractory lined
213-1202	Hot separator	10'-0" ID x 23'-0" TT, horizontal	450	270	
213-1203	Cold separator	7'-6" ID x 15'-0" TT, horizontal	440	110	A-516-70 1/8" CA
213-1204	50-psig BFW deaerator	10'-0" ID x 13'9" TT, horizontal, vert sect 4 trays, 8'-6" ID x 5'-6" TT	7	230	CS horizontal section SS vertical section
213-1205	550-psig BFW deaerator	8'-0" ID x 14'-0" TT, horizontal, vert sect 4 trays, 6'-6" ID x 14' TT	7	230	CS horizontal section SS vertical section
	Exchangers				
213-1301	Cold slurry/ effluent exchanger	33 MMBtu/hr, 14,600 ft^2 total, 54" dia 20' tubes, 2 shells	450 570	268 230	SH CS 1/8" CA T CS

Table 8-8 (Contd)

Item Number	Description	Size	Operating Pressure (psig)	Operating Temp (°F)	Material and Remarks
213-1302	Warm slurry/ effluent exchanger	30.5 MMBtu/hr, 21,900 ft^2 total, 54" dia 20' tubes, 3 shells	460 560	395 350	SH CS 1/8" CA T CS
213-1303	Hot slurry/ effluent exchanger	30.5 MMBtu/hr, 11,100 ft^2 total, 38" dia 20' tubes, 2 shells	465 550	600 470	SH CS 1/8" CA T CS
213-1304	550-psig steam generator	120 MMBtu/hr 9,085 ft^2 72" dia 20' tubes, 1 shell	557 480	481 1540	SH CS, refractory lined channel T Incoloy 800
213-1305	Steam superheater	120 MMBtu/hr, 1,740 ft^2 50" dia 10' tubes, 1 shell	555 480	910 1800	SH CS, refractory lined channel T Incoloy 800
213-1306	Effluent/hot 500-psig BFW exchanger	83.5 MMBtu/hr, 12,550 ft^2, 60" dia 30' tubes 1 shell	557 465	481 600	SH CS 1/8" CA T CS
213-1307	Effluent/warm 550-psig BFW exchanger	28.5 MMBtu/hr, 7,580 ft^2, 55" dia 20' tubes, 1 shell	562 460	350 395	SH CS 1/8" CA T CS
213-1308	50-psig steam generator	400 MMBtu/hr, 36,340 ft^2 total, 72" dia 40' tubes, 2 shells	53 460	298 395	SH CS 1/8" CA T 316 SS

Table 8-8 (Contd)

Item Number	Description	Size	Operating		Material and Remarks
			Pressure (psig)	Temp (°F)	
213-1309	Effluent/cold 550-psig BFW exchanger	27.8 MMBtu/hr, 5,580 ft^2, 46" dia 20' tubes, 1 shell	50 450	230 268	SH CS 1/8" CA T CS
213-1310	Effluent/cold 50-psig BFW exchanger	16 MMBtu/hr, 4,770 ft^2, 40" dia 20' tubes, 1 shell	50 450	230 268	SH CS 1/8" CA T CS
213-1311	Effluent air cooler	35.6 MMBtu/hr, 518,400 fin T ft^2, 6 bays, 22' x 46' ea, 12 fans @ 35 hp	450	190	CS, Al fins
213-1313	Cold separator water/hot separator water exchanger	9 MMBtu/hr, 940 ft^2, 22" dia 20' tubes, 1 shell	450 440	268 228	SH CS 18" CA T CS
	<u>Pumps</u>				
213-1501/02	50 psig BFW pump	900 gpm, 70 psi dp	75	230	API-S4
213-1503/04	Venturi scrubber water pump	300 gpm, 20 psi dp, 5 hp	750	268	API-S4
213-1505/06	550 psig BFW pump	485 gpm, 575 psi dp	580	230	API-S4

Table 8-8 (Contd)

Item Number	Description	Size	Operating Pressure (psig)	Operating Temp (°F)	Material and Remarks
213-1507/08	Cold separator water pump	200 gpm, 30 psi dp, 5 hp	730	200	API-S1
213-1509/10	Cold separator recycle pump	200 gpm, 30 psi dp, 5 hp	730	200	API-S1
213-1511/12	Electrostatic precipitator flushing pump	25 gpm, 30 psi dp	470	110	API-S1
213-1507	Cooling water circulation pump	100 gpm, 20 psi dp	575	481	API-S1
	Separation Equipment				
213-2201	Venturi scrubber	24" venturi, 60" separator			CS, SS lining
213-2202	Electrostatic precipitator	Wet precipitator 11' dia, 23" high			CS

Table 8-9 - Major Equipment Summary
Unit 217 - Process Water Reclamation

Item Number	Description	Size	Operating		Material and Remarks
			Pressure (psig)	Temp (°F)	
	<u>Columns</u>				
217-1101	Sour water stripper	11'-0" ID x 116'-6" TT, 49 trays	17	254	
	<u>Vessels</u>				
217-1201	BFW settler overhead receiver	3'-0" ID x 9'-0" TT, horizontal	4	120	
217-1203	Evaporator	12'-0" ID sphere, demister pad	2.9 psia	140	316 SS demister
217-1204	Evaporator overhead receiver	10'-0" ID x 20'-0" TT horizontal	2.4 psia	120	
	<u>Exchangers</u>				
217-1301	Sour water feed/ evaporator reboiler	39.7 MMBtu/hr, 4,700 ft^2, 44" dia, 20' tubes, 1 shell	4.2 40	155 268	SH CS 1/8" CA T CS
217-1302	SWS reboiler	85.5 MMBtu/hr, 25,600 ft^2 total, 77" dia, 20' tubes, 4 shells	17 455	254 315	SH Alloy 20 T 316 SS

Table 8-9 (Contd)

Item Number	Description	Size	Operating		Material and Remarks
			Pressure (psig)	Temp (°F)	
217-1303	Oxidizer feed/ effluent exchanger	82.2 MMBtu/hr, 33,000 ft^2 total, 26" dia, 10' tubes, 6 shells	1500 1520	518 500	SH CS, 316 SS clad T 316 SS
217-1304	Oxidizer feed preheater	6.7 MMBtu/hr, 520 ft^3, 19" dia, 10' tubes, 1 shell	1300 1505	950 518	SH 1/2 Mo, 1/16" CA T 316 SS
217-1305	BFW settler overhead air cooler	1.5 MMBtu/hr, 5,370 fin T ft^2, 1 bay, 6' x 16", 2 fans, 10 hp ea	5	227	T CS 1/8" CA
217-1306	BFW settler overhead/ evaporator reboiler	13.9 MMBtu/hr, 1500 ft^2, 30" dia, 16" tubes, 1 shell	4.2 5	155 227	SH CS 1/8" CA T CS
217-1307	SWS feed air cooler	43 6 MMBtu/hr, 191,800 fin T ft^2, 2 bays, 16' x 40' ea, 4 fans, 30 hp ea	25	190	T CS, 1/8" CA
217-1308	Slurry water air cooler	23.3 MMBtu/hr, 50,600 fin T ft^2, 1 bay, 13' x 40', 2 fans, 25 hp ea	30	254	T CS, 1/8" CA
217-1310	Evaporator condenser	93,100 Btu/hr, 632,500 fin T ft^2, 7 bays, 22' x 41' ea, 14 fans, 40 hp ea	3	140	T CS, 1/8" CA

Table 8-9 (Contd)

Item Number	Description	Size	Operating Pressure (psig)	Operating Temp (°F)	Material and Remarks
217-1311	Oxygen cooler	340,000 Btu/hr, double pipe type, 13.8 ft^2	500	250 in 110 out	CS, 1/4" CA
217-1312	Effluent evaporator reboiler	28.9 MMBtu/hr			SH: A 285 C T: A 285 C
217-1313	Slurry water/ BFW Exchanger	9.6 MMBtu/hr			SH: A 285 C T: A 285 C
	Pumps				
217-1501/ 02	Strip water pump and spare	658 gpm, 1513 psi dp	1530	254	API S-4
217-1503/ 04	Cool slurry feed water pump and spare	663 gpm, 13 psi dp	30	254	API S-1
217-1505/ 06	BFW settler bottom pump and spare	56 gpm, 24 psi dp	30	230	API S-1
217-1507/ 08	BFW settler product pump and spare	618 gpm, 44 psi dp	50	230	API S-1
217-1509/ 10	BFW settler reflux pump and spare	30 gpm, 6 psi dp	10	120	API S-1

Table 8-9 (Contd)

Item Number	Description	Size	Operating		Material and Remarks
			Pressure (psig)	Temp (°F)	
217-1511/12	Evaporator bottoms pump and spare	221 gpm, 42 psi dp	30	140	API S-1
217-1513/14	Evaporator product pump and spare	116 gpm, 62 psi dp	50	120	API S-1
	Compressors				
217-1801	Oxygen compressor	215 scfm	514 in 1570 out	110 in	Manufacturer's Standard
217-1802	Vent recovery compressor	5 scfm	4 in 496 out	120 in	Manufacturer's Standard
	Other Major Equipment				
217-2201	BFW settler	9'-6" ID x 38'-6" TT, cone bottom, plus 6'-0" ID x 12'-6" TT top section with 3 trays	6	230	CS 1/16" CA, center section 315 SS-clad
217-2202	BFW filter	613 gpm capacity	75	230	CS
217-2401	Oxidizer mixer	658 gpm, water, 307,000 scfd oxygen	1525	254	304 SS
217-2402	BFW mixer	661 gpm water, 1 gpm chemicals	66	271	304 SS

Table 8-9 (Contd)

Item Number	Description	Size	Operating Pressure (psig)	Operating Temp (°F)	Material and Remarks
217-2501	Oxidizer	8'-0" ID x 34'-0" TT with internals by licensor	1500	518	A-516, 1/4" CA, center section 316 SS-clad.
217-2801	Evaporator vacuum system	250 lb/hr air	2 psia	120	304 SS

Table 8-10 - Major Equipment Summary
Unit 241 - Power Plant

Item Number	Description	Size	Operating Pressure (psig)	Operating Temp (°F)	Material and Remarks
	Power Generators and Drives				
241-0101/02	Gas turbine	75 MW			Manufacturer's standard
241-0103/04	Gas turbine generator	75 MW 0.8 power factor, 13.8 kV, 60 Hz			Manufacturer's standard
241-0105	Steam turbine	60 MW	1250	875	Manufacturer's standard
241-0106	Steam turbine generator	60 MW, 0.8 power factor, 13.8 kV, 60 Hz			Manufacturer's standard
241-0107	Steam turbine	17.5 MW			Manufacturer's standard
241-0108	Steam turbine	17.5 MW, 0.8 power factor, 13.8 kV, 60 Hz			Manufacturer's standard
	Vessels				
241-1201	Blowdown drum	3'-0" dia x 8'-0" high	350	450	CS
	Exchangers				
241-1301	Steam condenser	450 x MM Btu/hr	2.5" HgA	109	SH: CS T: 90-10 Cupro-Nickel

Table 8-10 (Contd)

Item Number	Description	Size	Operating Pressure (psig)	Operating Temp (°F)	Material and Remarks
241-1302	Steam condenser	310 x MM Btu/hr	2.5" HgA	109	SH: CS T: 90-10 Cupro-Nickel
241-1303	Deaerator	650,000 lb/hr	15	250	CS
241-1304	Steam condenser	120 x MM Btu/hr	2.5" HgA	109	SH: CS T: 90-10 Cupro-Nickel
	<u>Pumps</u>				
241-1501/02	Condensate pump and spare	1,600 gpm	100	109	CA 6NM
241-1503/04	Boiler feed pump and spare	1,100 gpm	1500	250	CA 6NM
241-1505/06	LP boiler feed pump and spare	100 gpm	350	250	CS
241-1507/08	LP economizer pump and spare	1,600 gpm	250	250	CS
241-1509/12	Circulating water pump and spare	22,500 gpm	50	86	CS
241-1513/14	Condensate pump and spare	250 gpm	100	109	CS

Table 8-10 (Contd)

Item Number	Description	Size	Operating		Material and Remarks
			Pressure (psig)	Temp (°F)	
	Boilers				
241-1601/ 02	Heat recovery steam generators	250,000 lb/hr	1250	850	Manufacturer's standard
	Compressors				
241-1801	Fuel gas compressor with air expander/ steam turbine drive	716,650 lb/hr	250	500	Manufacturer's standard
	Tanks				
241-1901	Condensate storage	500,000 gal.	Atm	109	CS

Table 8-11 - Major Equipment Summary
Unit 311 - Coal Grinding

Item No.	Description	Size
311-0504	Pulverizer feeder	24" wide x 50' long, 20 hp
311-1803	Blower	100,000 CFM @ 55" wg, 900 hp
311-2103	Table and roller pulverizer	75 ton/hr, 800 hp
311-2204	Bag house dust collector	100,000 cfm @ 25" wg
311-2604	Storage bin	200-ton capacity

Table 8-12 - Major Equipment Summary
Unit 335 - Intermediate Storage

Item Number	Description	Size	Operating Pressure (psig)	Operating Temp (°F)	Material and Remarks
335-1501/02	Butane transfer pump and spare	60 gpm	200	30	CS API-610 S-1
335-1503/04	Light naphtha transfer pump and spare	100 gpm	97	120	CS API-610 S-1
335-1505/06	Heavy naphtha transfer pump and spare	100 gpm	90	110	CS API-610 S-1
335-1507/08	Diesel transfer pump and spare	100 gpm	82	120	CS API-610 S-1
335-1509/10	Fuel oil transfer pump and spare	60 gpm	75	140	CS API-610 S-1
335-1511/12	Solvent transfer pump and spare	100 gpm	75	Amb	CS API-610 S-1
	Tanks				
335-1901/02/03/04	LPG rundown tank	6'-0" - ID x 14' high, 3,000 gal	55	70	CS
335-1905/06	Light naphtha rundown tank	10'-3" ID x 16' high, 10,000 gal	Atm	120	CS

Table 8-12 (Contd)

Item Number	Description	Size	Operating		Material and Remarks
			Pressure (psig)	Temp (°F)	
335-1907/08	Heavy naphtha rundown tank	10'-3" ID x 16' high, 10,000 gal	Atm	110	CS
335-1909/10	Alcohol rundown tank	8'-0" ID x 16' high, 6,000 gal	Atm	110	CS
335-1911/12	Diesel rundown tank	12'6" ID x 16' high, 15,000 gal	Atm	120	CS
335-1913/14	Fuel oil rundown tank	8'0" ID x 16' high, 6,000 gal	Atm	140	CS
335-1915	Solvent storage tank	10'3" ID x 16' high, 10,000 gal	Atm	Amb	CS

Table 8-13 - Major Equipment Summary
Unit 336 - Project Storage and Shipping Facilities

Item Number	Description	Size	Operating		Material and Remarks
			Pressure (psig)	Temp (°F)	
	Pumps				
336-1501/02/03	Tank car and truck loading pumps and spare	300 gpm	120		CS API-610 S-1
	Tanks				
336-1901	LPG product tank	20'-6" ID x 40' high, 100,000 gal	Atm	30	CS
336-1902/03	Light naphtha product tank	25'-3" ID x 40' high, 150,000 gal	Atm	120	CS
336-1904/05	Heavy naphtha product tank	25'-3" ID x 40' high 150,000 gal	Atm	110	CS
336-1906	Alcohol product tank	17'-0" ID x 24' high, 40,000 gal	Atm	110	CS
336-1908	Diesel product tank	28'-3" ID x 48' high, 225,000 gal	Atm	120	CS
336-1910/11	Fuel oil product tank	21'-0" ID x 32' high, 75,000 gal	Atm	140	CS

SECTION 9

ECONOMICS

The estimated capital requirements, project and fund drawdown schedules, operating costs, and cash flows are presented in this section. All economics are based on mid-1977 dollars. Estimates are included for each of the three plant modules to provide the basic data necessary for an independent analysis.

9.1 FIXED CAPITAL INVESTMENT

9.1.1 SCOPE

Preliminary fixed capital investments were estimated for each of three plants.

- Plant 1 will gasify coal at low pressure to provide a clean, low sulfur, low-Btu gas for boiler firing. It consists of the principal units described in Section 5.1.
- Plant 2 provides two medium pressure (400-600 psig), oxygen-blown gasifiers to provide fuel gas to an adjacent captive combined cycle power plant; the fuel gas can be converted to synthesis gas to serve as feed for process units. It consists of the principal process units described in Section 5.2.
- Plant 3 is a Fischer-Tropsch unit to produce liquid fuels plus substitute natural gas. It consists of the principal process units described in Section 5.3.
- Possible subsequent plants or processes are not included.

9.1.2 SUMMARY

The estimated fixed capital investment for this complex is approximately $500 million. The rounded fixed capital investment for each plant is:

Plant	Plant Cost ($ million)	Cumulative Costs ($ million)
1	103	103
2	308	411
3	89	500

The total constructed costs, approximately $400 million, are shown for each plant and for each of the unit areas in Table 9-1. To this have been added home office costs, sales taxes, and contingency which result in the total project fixed capital investment.

9.1.3 PROCEDURES

This is a combination of preliminary and curve type estimates. The accuracy of the estimate is considered to be -5, +20%. The estimate includes the cost of equipment, field direct and field indirect costs, sales tax, engineering fee, and home office services.

9.1.4 BASIS FOR UNIT AREAS

The basis for the estimate for each unit is discussed in the following paragraphs.

The coal receiving, handling, storage and grinding areas, and key process unit estimates for the first and second plant estimates were developed using a combination of in-house pricing and vendor pricing information for major equipment. The total for major equipment costs was then used with historical cost multipliers to obtain the total constructed cost estimate for each unit. Units in this category are listed below.

Plant	Unit	Description
1		Low Pressure Fuel Gas Gasification
	100	Coal Storage (Receiving, Handling)
	111	Coal Grinding
	112	Low Pressure Gasifier
	113	Low Btu Gas Heat Recovery
2		Intermediate Pressure Gasification and Power Generation
	210	Added Coal Storage
	211	Added Coal Grinding
	212	Medium Pressure Gasifiers
	213	Medium Pressure Gas Heat Recovery
	217	Process Water Reclamation
	241	Power Plant
3		Fischer-Tropsch Synthesis
	311	Added Coal Grinding
	335	Intermediate Storage
	336	Product Storage and Shipping Facilities

The Plant 2 and Plant 3 intermediate pressure acid gas removal system (Units 214 and 318) and the oxygen plant (Unit 240) represent proprietary turnkey units. Estimates for these were based on vendor quotations.

The Plant 1 and Plant 2 sulfur recovery and tail gas plants (Units 114, 215, and 216) were estimated on the basis of capacities using in-house historical cost data.

The offsite units for each of the three plants were estimated using a combination of in-house historical information and factoring of previously designed similar unit costs on the basis of capacity. These include;

Plant	Unit	Description
1	130	Water Treatment
	131	Cooling Water System
	132	Effluent Treatment
	133	Flare System
	134	Sulfur Storage
	150	Buildings and General Facilities
2	230	Added Water Treatment
	231	Added Cooling Water System
	232	Added Effluent Treatment
	233	Added Flare System
	250	Added Buildings and General Facilities
3	330	Added Water Treatment
	331	Added Cooling Water System
	332	Added Effluent Treatment
	350	Added Buildings and General Facilities

The Plant 3 Fischer-Tropsch process units, listed below, were estimated by factoring and scaling the detailed estimates for similar units, as designed and contained in a published report describing a Fischer-Tropsch complex conceptual design.[1]

Unit	Description
319	Fischer-Tropsch Synthesis
320	Fischer-Tropsch Liquid Product Recovery
321	Fischer-Tropsch Gas Methanation
322	Fischer-Tropsch Alcohols Mixture Recovery

9.1.5 BASIS FOR COST CATEGORIES

The estimating procedures used for each cost category are detailed below:

A. Major Equipment Costs

Process and major equipment costs are based on vendor pricing combined with historical in-house experience. Vendors' prices were solicited for certain special process equipment items where historical in-house pricing data were not completely applicable.

B. Constructed Cost

Constructed cost is estimated by applying an experience factor to major equipment cost. This factor includes the field direct and field indirect costs.

1. Field Direct Materials, Labor and Other Direct Costs. Field direct costs include:

a. Concrete, structural steel, piping, instrumentation, and electrical.

b. Labor for construction of the various units.

c. Other direct costs such as miscellaneous freight, instrument checkout and run-in services, soils investigation, nonproductive time, and taxes that cannot be allocated to specific unit areas but are considered direct costs.

The labor costs reflect mid-1977 average hourly rates for the Eastern Region of the U.S. Interior Coal Province 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-hr 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. Field indirect costs include:

a. Temporary construction facilities and costs related to the job and its working conditions, including craft subsistence and transportation.

b. Field administration and field office expense.

c. Construction equipment, small tools, and consumables.

d. 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

A 3% sales tax and/or use tax is included for materials and equipment.

F. Escalation

Escalation for the period after mid-1977 is not included.

G. Contingency

A contingency allowance of 10% has been included.

H. Exclusions from Fixed Capital Investment Estimate

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.

9.2 TOTAL CAPITAL REQUIREMENTS

In addition to the fixed capital investment, total capital requirements include: land acquisition and rights of way; initial charges of catalysts and chemicals; startup costs; construction financing; and provision for working capital.

Initial capital requirements for the three plants used for estimating operating costs are summarized in Table 9-2 The estimated total capital requirement of the project amounts to about $560 million exclusive of construction financing costs, which depend on the project schedule, fund drawdown, and method of financing the project.

A detailed list of catalysts and chemicals estimated to cost $0.5 million is presented in Table 9-3. Startup is estimated to cost about $35 million. Provisions for working capital is estimated at about $24.5 million.

9.3 PROJECT SCHEDULE

The estimated project design, engineering, procurement, construction, and startup schedules for each plant are shown in Figure 9-1. These schedules were developed based on an analysis of the design, procurement of schedule-controlling equipment, fabrication, erection, and construction schedules for the three plants.

In the interest of expeditious construction and startup, Plant 1 and Plant 2 portions of the project would proceed concurrently. Thus, electric power from the power plant would be available for both Plant 1 and Plant 2 startups.

Of course, an attempt would be made to schedule the power plant construction for early completion in order to minimize power purchases for construction. The power plant gas turbines, having dual firing capabilities, could be operated initially on purchased oil until one of the Plant 2 gasifiers was operating. A one-year lag is scheduled for the Plant 3 Fischer-Tropsch addition. This allows time to achieve startup and smooth operation of Plant 2 so that synthesis gas supply for the F-T plant startup and operation will be assured.

9.4 OPERATING COSTS

Estimated operating costs for each of the three plants are summarized in Table 9-4. Total projected operating costs are listed below.

Plant	Plant Cost ($ million/yr)	Cumulative Costs ($ million/yr)
1	26.1	26.1
2	48.4	74.5
3	17.0	91.5

The basis for estimating the annual operating costs for each plant is presented in Table 9-5.

The plant will permit testing coal or lignite from any source. However, the economics are based on feeding coal approximately at $1.00/MMBtu or $25/ton and assumes an equivalent cost for other coal or lignite feedstock.

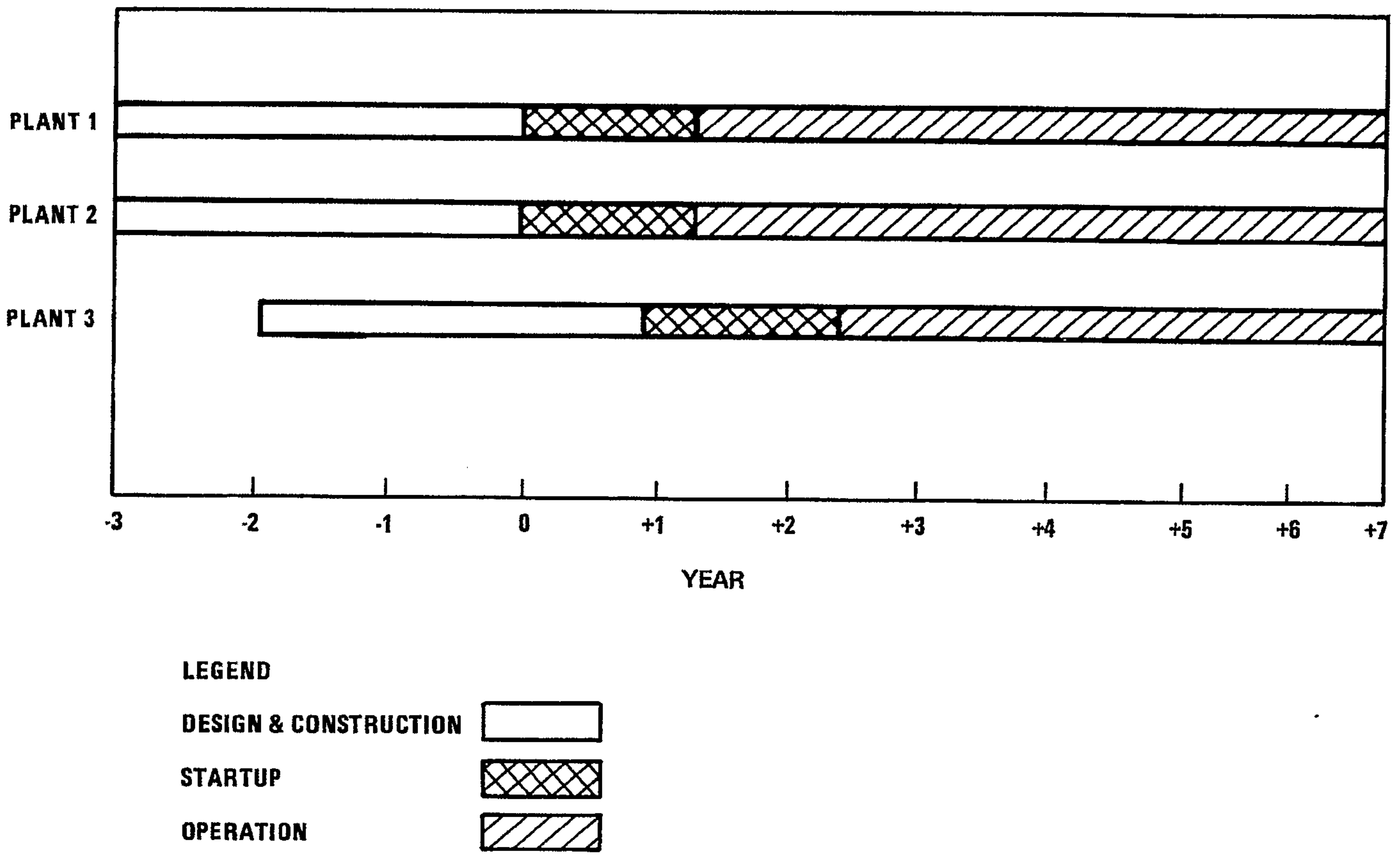

Figure 9-1 - Construction and Operating Schedule

Plant overhead/administration is based on an estimated requirement for administrative and support personnel 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 for direct operation and maintenance labor plus supervision was used. The general and administrative expense amounts to 1.5% of the total operating cost. Property tax and insurance is based on 2.75% of the initial fixed capital investment.

Estimated manpower requirements for the complex are summarized in Table 9-6; they amount to approximately 530 people.

9.5 PROJECT FUND REQUIREMENTS SCHEDULE

The estimated project fund requirements to design, construct, start up, and operate the plant without consideration of the method of funding of taxes are shown in the cash flow analysis, Table 9-7. The cash flow analysis is based on a project life of 10 yr with 4 yr of design and construction overlapping a 7-yr startup and operating period.

The fund drawdown schedules were developed based on the sum of the estimated fund requirement schedules for each plant. Capital fund expenditure estimates were based on the construction schedule and experience gained from prior projects. Operating fund requirements were based on an operating rate of 330 stream days per year, equal to a 90.4% operating factor except for the first 18 mo of operation, when each plant is assumed to produce at a rate equal to 25% of capacity the first 6 mo, 50% the second, and 75% the third. These costs are shown graphically on the project fund drawdown schedule, Figure 9-2, and the cumulative project expenditure schedule, Figure 9-3.

The cumulative costs of the project over the 10-yr project life are approximately $1.15 billion not including possible benefits from product sales or savings resulting from tax writeoffs. The authorization of the project would infer commitment of these funds as shown in Figure 9-3; the secondary possibility of offsetting revenues and tax loss credits is discussed below.

9.5.1 PRODUCT VALUES

One of the primary objectives of the MPDP is to produce adequate product to support functional product testing and assure the production of a marketable product. Consequently, it is premature at this time to establish market values and revenues for the product produced. Nevertheless, it is necessary to establish a base for analysis of the conomics of constructing and operating the plants.

To obtain possible market values, the project characteristics of these products were compared with those of conventional crude oil based products. This comparative evaluation included discussions with major petroleum/chemical companies and utility companies plus review of industry reports and current literature.

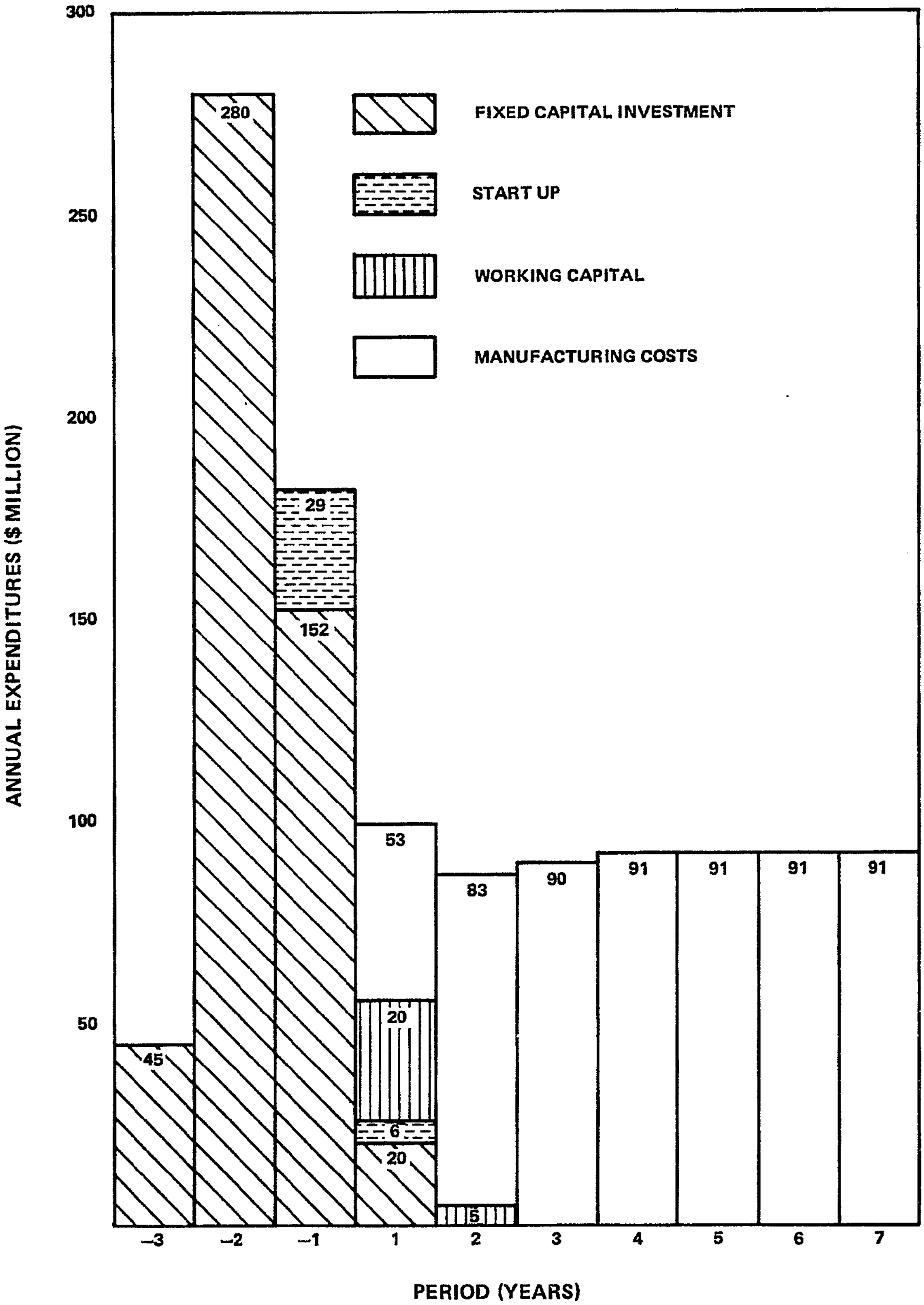

Figure 9-2 - Project Fund Drawdown

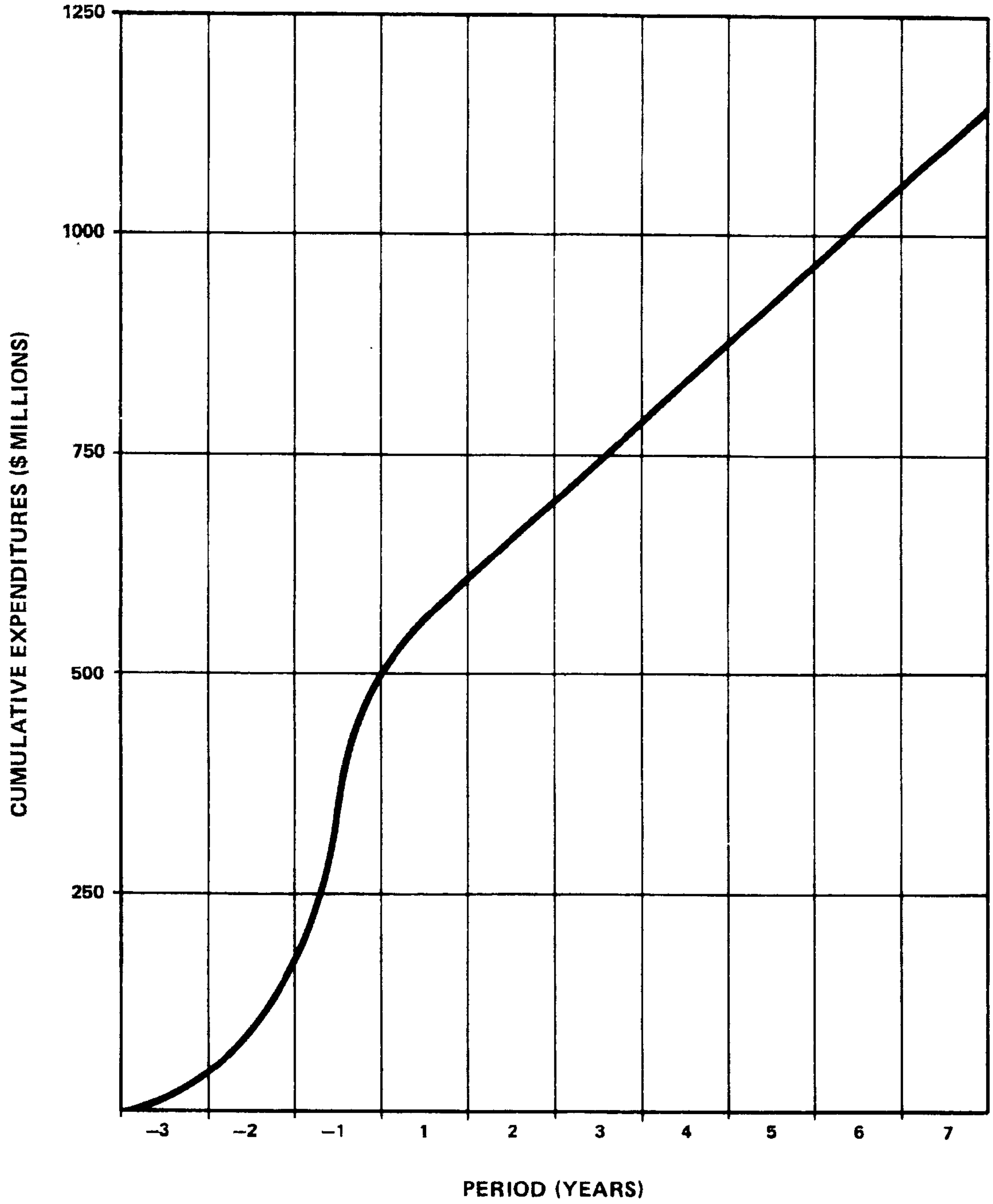

Figure 9-3 · Cumulative Project Expenditures

These products are listed in Table 9-8, together with possible market values for each product and possible annual revenues at capacity operation. These possible revenues were multiplied by the percent capacity production for each plant over the operating period to obtain a total product revenue for the program.

9.5.2 POSSIBLE TAX WRITEOFFS

It is not possible to determine possible tax writeoffs that might be available without knowledge of the project structure and the characteristics of the participants. For purposes of this illustration, it was assumed that the plant was 100% funded with private capital such that the tax losses could be used to offset profits, that it can be depreciated over the 7-yr operating life, and that the participants are able to write off losses against other income.

9.5.3 NET CASH FLOW

The net cash flow assuming the aforementioned benefits from product sales and taxes are shown in the cash flow case evaluation, Table 9-9, and on the cumulative project experience schedule, Figure 9-4. The cumulative cost of the project after credit for possible product sales is $0.8 billion. After taking the maximum possible tax writeoffs, it is possible the net costs could be as low as $0.35 billion.

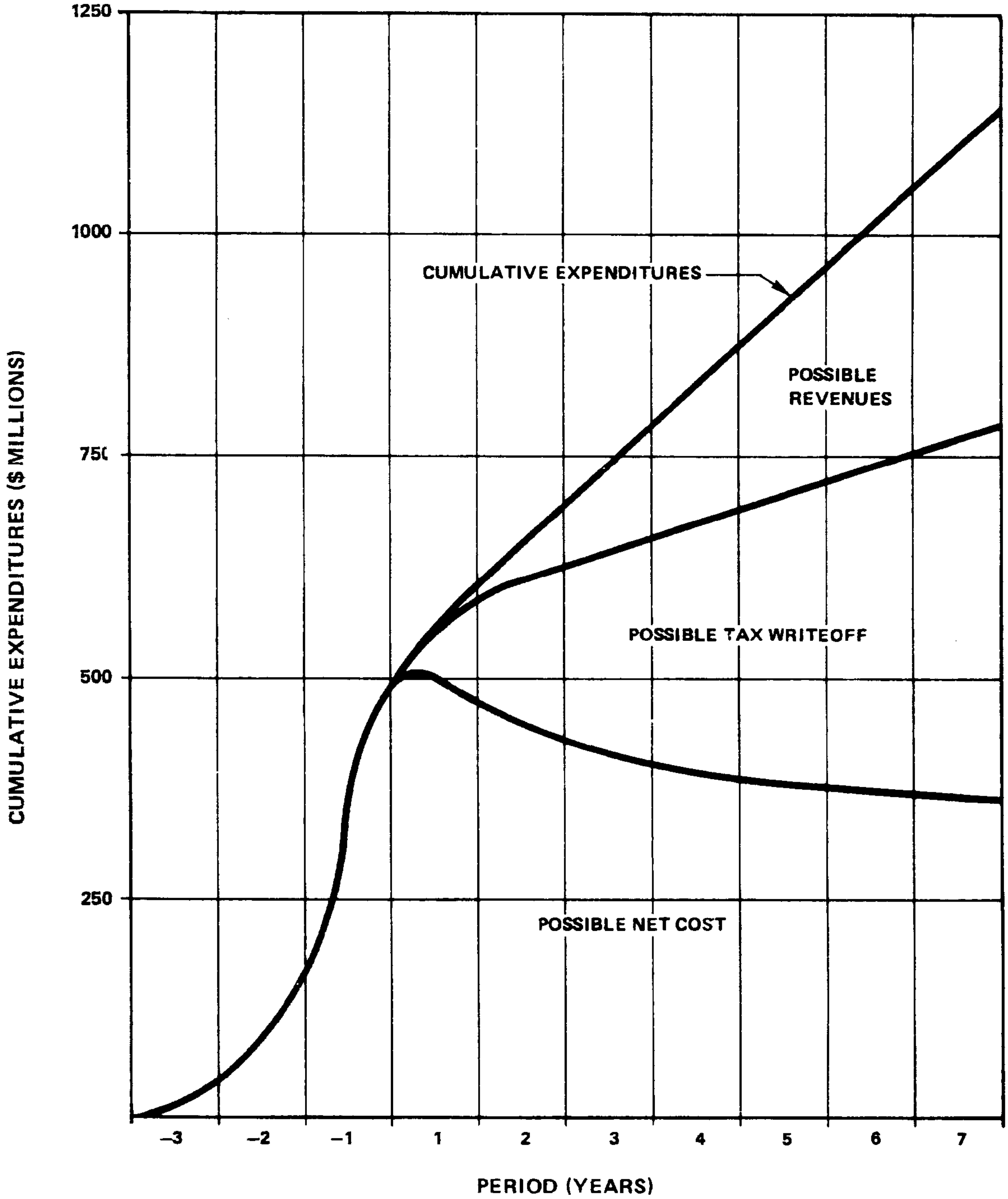

Figure 9-4 - Cumulative Project Expenditures with Credits

Table 9-1

Plants 1, 2, and 3

Estimated Fixed Capital Investment

Unit No.	Unit	Cost ($ thousand) Plant 1	Plant 2	Plant 3	Total
10/11	Coal receiving storage & grinding	5,123	2,945		8,068
12	Gasifiers, one entrained & one fluid bed	20,334	17,906		38,240
13	Gas heat recovery	22,859	38,183		61,042
14	Acid gas sulfur & acid gas removal	13,160	31,060		44,220
15	Sulfur plant		6,032		6,032
16	Tail gas treatment		3,000		3,000
17	Process water treatment		14,623		14,623
18	F-T acid gas removal			26,345	26,345
19	F-T synthesis			14,094	14,094
20	F-T liquid product separator			3,668	3,668
21	F-T gas methanation			5,633	5,633
22	F-T alcohol mixture recovery			1,909	1,909
30	Water treatment	6,899	20,562	9,418	36,879
31	Cooling water system	1,888	6,371	2,190	10,449
32	Effluent treatment	1,525	5,076	1,801	8,402
33	Flare system	520	549		1,069
34	Sulfur storage	174			174
35	Intermediate storage			396	396
36	Product storage & shipping facilities			615	615
40	Oxygen plant		35,612		35,612
41	Power plant		58,000		58,000
50	Buildings	5,301	5,278	3,402	13,981
51/52	Railroads & roads	3,828	1,914	957	6,699
53	General facilities	2,055	3,340	1,222	6,617
	Total constructed costs	83,666	250,451	71,650	405,767
	Home office costs	8,367	25,045	7,165	40,577
	Sales tax	1,079	3,230	924	5,233
	Total	93,112	278,726	79,739	451,577
	Contingency at 10%	9,311	27,873	7,974	45,158
	Total fixed capital investment	102,423	306,599	87,712	496,735
	Say	103,000	308,000	89,000	500,000

Table 9-2 - Total Initial Capital Requirement
($ million)

Item	Plant 1	Plant 2	Plant 3	Total
Land, rights of way	3.000			3.000
Fixed capital investment	102.423	306.599	87.712	496.735
Initial catalysts and chemicals	0.364	0.065	0.068	0.497
Startup cost	7.100	21.500	6.100	34.700
Fixed investment	112.887	328.164	33.880	543.931
Working capital	6.100	13.750	4.600	24.450
Total capital requirement	118.987	341.900	98.480	559.367
Say	119.000	342.000	99.000	560.000

Table 9-3 - Plant 1 Catalyst and Chemicals Requirement

Unit	Catalyst or Chemical	Initial Charge	Basis or Make-up Requirement	Cost: Initial Charge ($)	Cost: Annual Use ($)
114	Sulfur Plant				
	ADA	20,000 lb	132 lb/day	125,000	272,250
	Vanadium	40,000 lb	226 lb/day	234,000	436,300
	Soda ash	150,000 lb	10,790 lb/day	4,500	106,800
130/131	Water Treatment & Cooling Water Systems				
	Soda ash		1,465 lb/day	nil	14,500
	Hydrated lime		24 lb/day	nil	180
	Total			363,500	830,030
	Say			364,000	830,000

Table 9-3 - Plant 2 Catalyst and Chemicals Requirement

Unit	Catalyst or Chemical	Initial Charge	Basis or Make-up Requirement	Cost: Initial Charge ($)	Cost: Annual Use ($)
214	<u>Acid Gas Removal</u>				
	Methanol	30,000 gal	2,400 gal/day	14,400	228,120
215	<u>Sulfur Plant</u>				
	Claus catalyst	1,475 cu ft	3-year life	15,580	nil
216	<u>Tail Gas Plant</u>				
	CoMo catalyst	270 cu ft	3-year life	10,170	nil
	ADA	1,370 lb	6.6 lb/day	8,570	13,610
	Vanadium	2,740 lb	10.7 lb/day	16,030	20,570
	Soda ash	10,300 lb	440 lb/day	310	4,350
217	<u>Water Reclamation</u>				
	Oxygen		7.75 ton/day		30,710
	Hydrated lime		0.90 ton/day		13,370
	Soda ash		0.90 ton/day		17,820
230/231	<u>Water Treatment & Cooling Tower Systems</u>				
	Soda Ash		2.5 ton/day		49,500
	Hydrated lime		72 lb/day		540
	Total			65,060	378,590
	Say			65,000	379,000

Table 9-3 - Plant 3 Catalyst and Chemicals Requirement

Unit	Catalyst or Chemical	Initial Charge	Basis or Make-up Requirement	Cost: Initial Charge ($)	Cost: Annual Use ($)
314	Acid Gas Removal				
	Methanol		1,920 gal/day		304,160
315	Sulfur Plant				
	Claus catalyst	1,965 cu ft	3-year life	20,780	nil
316	Tail Gas Plant				
	CoMo catalyst	360 cu ft	3-year life	13,570	nil
	ADA	1,825 lb	8.8 lb/day	11,410	18,150
	Vanadium	3,650 lb	14.2 lb/day	21,350	27,420
	Soda ash	6.9 ton	0.3 ton/day	410	5,940
317	Water Reclamation				
	Oxygen		10.3 ton/day		40,940
	Hydrated lime		1.2 ton/day		17,820
	Soda ash		1.2 ton/day		23,760
330/331	Water Treatment & Cooling Tower System				
	Soda ash		4.3 ton/day		86,010
	Hydrated lime		0.05 ton/day		740
	Total			67,520	524,940
	Say			68,000	525,000

Table 9-4 - Annual Operating Cost Summary
($ million)

Item	Plant 1	Plant 2	Plant 3	Total
Coal	14.850	18.530	6.190	39.570
Materials and supplies				
Operating supplies	0.165	0.290	0.170	0.625
Maintenance material	3.070	9.195	2.630	14.895
Catalysts & chemicals	0.830	0.380	0.525	1.735
Total material	4.065	9.865	3.325	17.255
Labor				
Operating labor & supervision	0.545	0.965	0.560	2.070
Maintenance	1.520	4.545	2.000	8.065
Payroll burden	0.725	1.930	0.895	3.550
Plant overhead	1.115	2.975	1.380	5.470
Total labor	3.905	10.415	4.835	19.155
G and A overhead	0.425	0.715	0.235	1.375
Property tax & insurance	2.815	8.830	2.415	13.660
Total	26.060	48.355	17.000	91.415

Table 9-5 - Basis of Economics

Item	Plant 1	Plant 2	Plant 3	Total
Operating rate	330 days per year--			
Operating life	7 years	7 years	6 years	7 years
Construction period	3 years	3 years	3 years	4 years
Startup costs	7% of Fixed capital investment-------------------------------------			
Coal consumption	1800 ton/day	2250 ton/day	750 ton/day	4796 ton/day
Coal price	$25.00 per ton (clean coal)--			
Operating supplies	30% of direct operating labor--------------------------------------			
Operating labor including supervision	35 men	62 men	36 men	133 men
Labor rate	$7.50 per hour---			
Maintenance	5% of fixed capital investment			
Labor	40% of total maintenance---			
Materials	60% of total maintenance---			
Payroll burden	35% of total labor---			
Plant overhead	40% of operating and maintenance labor including payroll burden--------			
G & A overhead	1-1/2 of manufacturial cost--			
Property tax and insurance	2.75% of Fixed capital investment----------------------------------			

Table 9-6 - Manpower Summary

Item	Operation	Maintenance	Administration	Total
Plant 1			44	44
Coal receiving & handling	5	10		15
Coal grinding & drying	5	10		15
Gasification & heat recovery	18	41		59
Acid gas sulfur removal	5	10		15
Offsites	2	4		6
Total Plant 1	35	75	44	154
Plant 2 (increase over Plant 1)			68	68
Coal receiving & handling	0	0		0
Oxygen plant	5	10		15
Gasification, heat recovery & process water treatment	20	62		82
Acid gas removal	5	10		15
Sulfur & tail gas plant	5	10		15
Power plant	26	11		37
Offsites (increase)	1	5		6
Total Plant 2	62	108	68	238
Total Plants 1 & 2	97	183	112	392
Plant 3 (increase over Plants 1 & 2)			40	40
F-T synthesis	9	20		29
F-T recovery	13	22		35
Methanation & alcohol recovery	9	16		25
Offsites (increase)	5	5		10
Total Plant 3	36	63	40	139
Total Plants 2 & 3	98	171	108	377
Total Plants 1, 2 & 3	133	246	152	531

Table 9-7 - Project Fund Requirement Schedule

THE RALPH M. PARSONS COMPANY

CASH FLOW CASE EVALUATION
DOLLARS - MILLIONS

MULTI-PROCESS DEMONSTRATN PLNT
JOB NO. 5435 - 5 DATE 03/31/78

COST CASH FLOW WITHOUT POSSIBLE REVENUES FROM PRODUCT SALES

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

PERIOD	-3	-2	-1	1	2	3	4	5	6	7
[REVENUE]										
... T O T A L ...	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000	0.000
[COSTS]										
PLANT 1 COAL FEED	0.000	0.000	0.000	5.570	12.995	14.850	14.850	14.850	14.850	14.850
PLANT 2 COAL FEED	0.000	0.000	0.000	6.950	16.215	18.530	18.530	18.530	18.530	18.530
PLANT 3 COAL FEED	0.000	0.000	0.000	0.000	2.320	5.415	6.190	6.190	6.190	6.190
PLANT 1 OPER. COSTS	0.000	0.000	0.000	3.180	3.180	3.180	3.180	3.180	3.180	3.180
PLANT 2 OPER. COSTS	0.000	0.000	0.000	5.395	5.395	5.395	5.395	5.395	5.395	5.395
PLANT 3 OPER. COSTS	0.000	0.000	0.000	0.000	3.240	3.240	3.240	3.240	3.240	3.240
PLANT 1 MAINTENANCE	0.000	0.000	0.000	5.215	5.215	5.215	5.215	5.215	5.215	5.215
PLANT 2 MAINTENANCE	0.000	0.000	0.000	15.600	15.600	15.600	15.600	15.600	15.600	15.600
PLANT 3 MAINTENANCE	0.000	0.000	0.000	0.000	5.155	5.155	5.155	5.155	5.155	5.155
PLANT 1 TAX + INSUR.	0.000	0.000	0.000	2.815	2.815	2.815	2.815	2.815	2.815	2.815
PLANT 2 TAX + INSUR.	0.000	0.000	0.000	8.830	8.830	8.830	8.830	8.830	8.830	8.830
PLANT 3 TAX + INSUR.	0.000	0.000	0.000	0.000	2.415	2.415	2.415	2.415	2.415	2.415
... T O T A L ...	0.000	0.000	0.000	53.555	83.375	90.640	91.415	91.415	91.415	91.415
COST + DEPR + DEPL	0.000	0.000	0.000	53.555	83.375	90.640	91.415	91.415	91.415	91.415
PROFIT BEFORE TAX	0.000	0.000	0.000	-53.555	-83.375	-90.640	-91.415	-91.415	-91.415	-91.415
GROSS CF, OPERATIONS	0.000	0.000	0.000	-53.555	-83.375	-90.640	-91.415	-91.415	-91.415	-91.415
ACCUM GROSS CASHFLOW	0.000	0.000	0.000	-53.555	-136.930	-227.570	-318.985	-410.400	-501.815	-593.230
[INVESTMENT]										
PLANT 1 FIXED CAPITL	11.266	67.600	23.560	0.000	0.000	0.000	0.000	0.000	0.000	0.000
PLANT 2 FIXED CAPITL	33.725	202.350	70.520	0.000	0.000	0.000	0.000	0.000	0.000	0.000
PLANT 3 FIXED CAPITL	0.000	9.650	57.900	26.175	0.000	0.000	0.000	0.000	0.000	0.000
PLANT 1 OTHER CAPITL	0.000	0.000	7.570	0.000	0.000	0.000	0.000	0.000	0.000	0.000
PLANT 2 OTHER CAPITL	0.000	0.000	21.565	0.000	0.000	0.000	0.000	0.000	0.000	0.000
PLANT 3 OTHER CAPITL	0.000	0.000	0.000	6.170	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL CAPITAL INVEST	44.991	279.600	181.115	26.345	0.000	0.000	0.000	0.000	0.000	0.000
WORKING CAPITAL	0.000	0.000	0.000	19.850	4.600	0.000	0.000	0.000	0.000	0.000
GROSS CASHFLOW TOTAL	-44.991	-279.600	-181.115	-99.750	-87.975	-90.640	-91.415	-91.415	-91.415	-91.415
ACCUM GROSS CF TOTAL	-44.991	-324.591	-505.706	-605.456	-693.431	-784.071	-875.486	-966.901	-1058.316	-1149.731
NET CASH FLOW	-44.991	-279.600	-181.115	-99.750	-87.975	-90.640	-91.415	-91.415	-91.415	-91.415
ACCUM NET CASHFLOW	-44.991	-324.591	-505.706	-605.456	-693.431	-784.071	-875.486	-966.901	-1058.316	-1149.731

Table 9-8 - Possible Product Selling Prices

Item	Price	Plant 1 Daily Production	Plant 1 $Million/Yr	Plant 2 Daily Production	Plant 2 $Million/Yr	Plant 3 Daily Production	Plant 3 $Million/Yr
Steam	$3.75/1000 lb	2,256 lb/d	2.791				
Power	$20/MW-hr	--	--	141.0 MW	17.867	-6.9 MW	1.093
Fuel gas	$2.00/MMbtu	33,000 MMbtu/d	21.780				
SNG	$3.90/MMbtu					5,830 MMbtu/d	7.503
Liquids							
LPG	$15.50/bbl					78.1 bbl/d	0.400
Light naphtha	15.00/bbl					234.3 bbl/d	1.160
Heavy naphtha	16.50/bbl					210.9 bbl/d	1.148
Diesel	14.75/bbl					356.1 bbl/d	1.733
Heavy oil	14.25/bbl					111.7 bbl/d	525
							4.966
Mixed alcohols/chemicals	$25.00/bbl					72.0 bbl/d	0.594
Sulfur	$60/Ston	66 ton/d	1.307	82.4 ton/d	1.631	27.5 ton/d	0.545
Total			$25.878		$19.498		$14.701
Say			$25.9		$19.5		$14.7

Table 9-9 - Possible Net Cash Flow

THE RALPH M. PARSONS COMPANY

CASH FLOW CASE EVALUATION
DOLLARS - MILLIONS

MULTI-PROCESS DEMONSTRATN PLNT
JOB NO. 5435 - 5 DATE 03/31/78

CASH FLOW AFTER TAXES

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

PERIOD	-3	-2	-1	1	2	3	4	5	6	7
[REVENUE]										
PLANT 1 SALES	0.000	0.000	0.000	9.700	22.650	25.900	25.900	25.900	25.900	25.900
PLANT 2 SALES	0.000	0.000	0.000	7.300	17.060	19.500	19.500	19.500	19.500	19.500
PLANT 3 SALES	0.000	0.000	0.000	0.000	5.500	12.860	14.700	14.700	14.700	14.700
... T O T A L ...	0.000	0.000	0.000	17.000	45.210	58.260	60.100	60.100	60.100	60.100
[COSTS]										
PLANT 1 COAL FEED	0.000	0.000	0.000	5.570	12.995	14.850	14.850	14.850	14.850	14.650
PLANT 2 COAL FEED	0.000	0.000	0.000	6.950	16.215	18.530	18.530	18.530	18.530	18.530
PLANT 3 COAL FEED	0.000	0.000	0.000	0.000	2.320	5.415	6.190	6.190	6.190	6.190
PLANT 1 OPER. COSTS	0.000	0.000	0.000	3.180	3.180	3.180	3.180	3.180	3.180	3.180
PLANT 2 OPER. COSTS	0.000	0.000	0.000	5.395	5.395	5.395	5.395	5.395	5.395	5.395
PLANT 3 OPER. COSTS	0.000	0.000	0.000	0.000	3.240	3.240	3.240	3.240	3.240	3.240
PLANT 1 MAINTENANCE	0.000	0.000	0.000	5.215	5.215	5.215	5.215	5.215	5.215	5.215
PLANT 2 MAINTENANCE	0.000	0.000	0.000	15.600	15.600	15.600	15.600	15.600	15.600	15.600
PLANT 3 MAINTENANCE	0.000	0.000	0.000	0.000	5.155	5.155	5.155	5.155	5.155	5.155
PLANT 1 TAX + INSUR.	0.000	0.000	0.000	2.815	2.815	2.815	2.815	2.815	2.815	2.615
PLANT 2 TAX + INSUR.	0.000	0.000	0.000	6.830	8.830	6.830	6.630	8.830	8.830	8.830
PLANT 3 TAX + INSUR.	0.000	0.000	0.000	0.000	2.415	2.415	2.415	2.415	2.415	2.415
... T O T A L ...	0.000	0.000	0.000	53.555	83.375	90.640	91.415	91.415	91.415	91.415
PLANT 1 DEPRECIATION	0.000	0.000	0.000	29.400	21.000	15.000	9.400	9.400	9.400	9.400
PLANT 2 DEPRECIATION	0.000	0.000	0.000	88.000	63.000	45.000	29.000	28.000	28.000	28.000
PLANT 3 DEPRECIATION	0.000	0.000	0.000	0.000	30.000	20.000	13.500	8.500	8.500	8.500
COST + DEPR + DEPL	0.000	0.000	0.000	170.955	197.375	170.640	143.315	137.315	137.315	137.315
PROFIT BEFORE TAX	0.000	0.000	0.000	-153.955	-152.165	-112.380	-83.215	-77.215	-77.215	-77.215
INCOME TAXES	0.000	0.000	0.000	-80.057	-79.126	-56.438	-43.272	-40.152	-40.152	-40.152
TAX CREDIT	0.000	0.000	0.000	37.000	8.000	0.000	0.000	0.000	0.000	0.000
PROFIT AFTER TAX	0.000	0.000	0.000	-36.898	-65.039	-53.942	-39.943	-37.063	-37.063	-37.063
AVERAGE ANNUAL NET PROFIT		-51.169								
GROSS CF, OPERATIONS	0.000	0.000	0.000	80.502	46.961	26.058	11.957	8.837	8.837	8.637
ACCUM GROSS CASHFLOW	0.000	0.000	0.000	80.502	129.462	155.520	167.477	176.314	185.150	193.987
[INVESTMENT]										
PLANT 1 FIXED CAPITL	11.266	67.600	23.560	0.000	0.000	0.000	0.000	0.000	0.000	0.000
PLANT 2 FIXED CAPITL	33.725	202.350	70.520	0.000	0.000	0.000	0.000	0.000	0.000	0.000
PLANT 3 FIXED CAPITL	0.000	9.650	57.903	20.175	0.000	0.000	0.000	0.000	0.000	0.000
PLANT 1 OTHER CAPITL	0.000	0.000	7.570	0.000	0.000	0.000	0.000	0.000	0.000	0.000
PLANT 2 OTHER CAPITL	0.000	0.000	21.565	0.000	0.000	0.000	0.000	0.000	0.000	0.000
PLANT 3 OTHER CAPITL	0.000	0.000	0.000	6.170	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL CAPITAL INVEST	44.991	279.600	181.115	26.345	0.000	0.000	0.000	0.000	0.000	0.000
WORKING CAPITAL	0.000	0.000	0.000	19.850	4.600	0.000	0.000	0.000	0.000	0.000
GROSS CASHFLOW TOTAL	-44.991	-279.600	-181.115	34.307	44.361	26.058	11.957	8.837	8.637	8.837
ACCUM GROSS CF TOTAL	-44.991	-324.591	-505.706	-471.399	-427.039	-400.961	-389.024	-380.167	-371.351	-362.514

SECTION 10

ADVANCED DESIGN ASPECTS

The plants and processes described herein are based, as much as possible, on known proven technology. In a few instances, new developments showing promise of significant economic advantage have been incorporated into the design. These will be mentioned and discussed in this section.

10.1 GASIFIERS

The low pressure fuel gas gasifier design is the result of analyses. Features that have been successfully used in blast furnace operations have been incorporated in its design.

Each of the intermediate pressure gasifiers is based on gasifiers under development in the Department of Energy pilot plant program. These types are projected to be more efficient and having significantly lower capital and operating costs than the smaller older types.

Gasifier performance is subject to successful operation of the in-progress pilot plant units. Their successful pilot plant experience features would be incorporated in the MPDP definitive final design.

10.2 GASIFIER FEEDING

Feeding of dry ground coal to the fuel gas gasifier poses no problem. The Fuller-Kinyon solids pump was selected on the bases of its successful operation in low pressure solids feeding. The 50 psig pressure operation has been demonstrated in commercial solids conveying systems. Coal-water slurry pumping as the mode of feeding the intermediate pressure gasifiers was selected because of successful experience. Two types of slurry pumps are provided, three plunger pumps and a multi-stage centrifugal pump.

Plunger pumps have demonstrated their suitability for coal slurry pumping in pilot plant installations and slurry pipeline transport duty. Two of the plunger pumps will handle the maximum pumping rate of 1150 gpm. The third pump is provided as a standby spare.

The multi-stage centrifugal pump is provided as an alternate demonstration unit. The pump is available, but it has not seen service in this specific type of operation. The main benefit from the inclusion of this type pump will be its future incorporation in larger scale commercial plants, following successful demonstrated performance in this demonstration plant. This is based on the significantly lower cost for large centrifugal pumps compared with equivalent high capacity plunger pumps for commercial plants having six to ten times the coal feeding requirements of this demonstration plant.

It would be preferable to feed the intermediate pressure gasifiers with dry ground coal. The improved thermal efficiency differential of 6-10% to be derived by elimination of the slurry water evaporation heat load is a strong incentive for use of a suitable dry coal feed system. DOE is sponsoring several dry coal feeder development projects. At this time, results are encouraging. It is possible that future progress may dictate substitution of a dry feed system for the slurry feed.

10.3 EXTENDED SURFACE CATALYTIC REACTORS

The Fischer-Tropsch plant contains two catalytic reaction processes, F-T synthesis and methanation. F-T synthesis requires an iron oxide catalyst and the methanation reaction uses Rainey nickel catalyst. The reactors are finned tube heat exchangers with the appropriate catalyst flame sprayed on the fins and tube outer survace. Extensive review of research work on catalyst-coated plate-type reactors by DOE laboratories led to selection of this type of reactor for these catalytic reactions.

It is considered that the success achieved by the DOE (PERC) laboratory at Bruceton, Pa. with experimental catalyst-coated plate reactors in Fischer-Tropsch syntheses and methanation provided the basis for a practical catalytic process. The principal of conducting reaction heat directly from a catalyst coating through the supporting metal into a coolant in contact with that metal is considered basically sound.

The PERC laboratory is currently commencing further pilot work with test reactor configurations similar to that used in this design. It is expected that the data produced from this work will serve as a sound basis for an improved and efficient demonstration plant reactor design.

This type reactor unit precludes the need for high recycle rates characteristic of conventional catalytic reactors with external heat recovery systems. The demonstration of this advanced type reactor/heat recovery unit is considered to be one of the important features of this plant.

10.4 COMBINED CYCLE POWER PLANT

Combined cycle mode systems, utilizing gas turbines and unfired heat recovery steam generators, are being used in power plants for intermediate and peaking load operation. To date, they have not generally been used for base load power generation. Efficiencies in the range of 15-20% greater than conventional power plant fired steam boilers and steam turbine generation systems, and also being environmentally clean, make the combined cycle system a desirable candidate for future base load power generation, particularly since the basic equipment is available. The demonstration of a combined cycle system in base load power generation is another major feature of this multi-process complex.

SECTION 11

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APPENDIX A

SITE CONDITIONS

Date 3/23/78
Page 1 of 12
Job Name Multi-Process Demonstration Plant (DOE) Job. No. 5435-0005

Project Manager A. Bela

1.0 GENERAL AND METEOROLOGICAL

1.01 Location Eastern Region, U.S. Interior Coal Province

1.02 Elevation 490 ft

1.03 Climatic Conditions % Relative Humidity High: 80 Low: 50

a. Maximum temperature 103 °F; Design for 90 °F

b. Minimum temperature -15 °F; Design for -15 °F

c. Design wet bulb temperature 78 °F

d. Rainfall 38 in. per yr. (average): 0.75 in. per hr. (design)

e. Average wind velocity 12 miles per hour

f. Maximum wind velocity 50 miles per hour (gusts)

g. Direction of wind NW 1Q; NW-SSW 2Q; S 3Q; S-NW

h. Average annual snow fall 20 inches per year

j. Design for 25 PSF 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 — Are special provisions required? No Hail & Tornadoes occur March thru 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	25	25	psf
Rise 4 in./ft. and steeper	per UBC	✓	✓	psf

b. Platform, stairs and walks

	Loading	
1. Pedestrian traffic only	75	psf
2. Work area — uniform loading	50	psf
3. Work area — concentrated loading	320	psf

c. Floors on ground

	Uniform Load	Concentrated Load
1. Control houses	100 psf*	1,000 on 2 1/2" sq.**
2. Paved areas	100 psf*	15,000 wheel load
3. Other buildings	100 psf	
a. Maintenance Bldg	250 psf	
b. Lab & Admin Bldg	75 psf	
c. Stores/Whse	100 psf	15,000 wheel load

d. Vessels and piping

1. See detailed sheet for weight of normal operating liquid contents.

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 or earthquake or expansion forces.

*100 Recommended
**1000 Recommended

2.05 Lateral Loads (Wind)

a. Wind on vertical flat projected areas:

0 to 30 feet above ground	15	psf
30 to 50 feet above ground	20	psf
50 to 100 feet above ground	25	psf
100 to 500 feet above ground	30	psf

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 percent of projected areas of all members.

2.06 Lateral Load (Earthquake)

Uniform Building Code Zone #2

Note: Wind and earthquake forces are not additive.

2.07 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).

3.0 FOUNDATIONS AND SOIL DATA

3.01 Soil Data

a. Type of Soil Sand — Rocky

b. Subsoil strata a factor? No

c. Elevations of water table Varies

d. Is piling required? No

e. Special soil analysis reference To be determined

3.01 Soil Data (Continued)

f. Excavation remarks –

3.02 Foundations

a. Allowable Bearing Loads

	Type of Soil	Depth	Vertical Load	Lateral Load
1.	Sand & Rocky	3 ft.	3,000 psf	– psf
2.	–	– ft.	– psf	– psf

b. Ultimate Compressive Strength after 28 days

1. Reinforced concrete 3,000 psf

c. Minimum Coverage of Reinforced Steel

1. Formed sections 2 in. (except 1-1/2 in. for -5 and smaller bars)
2. Unformed sections 3 in.
3. Water contact 3 in.

d. Minimum Depth of Foundations

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. Are termites and fungi a factor? Yes

e. Elevations

1. Base elevation (Refinery Datum) 100.00 ft.
2. Existing ground elevation 460 – 490 ft.
3. Finished grade To be determined ft.
4. High point of paving To be determined ft.

4.0 UTILITIES

4.01 Air

a. Instrument air at 60 psi and maximum dew point -20 °F at 100 psi

b. Utility air at 90 psi

c. Starting air for compressors at Atm psi

4.02 Cooling Water

a. Type Tower — °F

b. Maximum cold water temperature — °F

c. Design cold water temperature 86 °F

d. Maximum hot water temperature 120 °F

e. Design hot water temperature 120 °F

f. Design water supply pressure at grade 50 PSIG

g. Design water return pressure at grade 35 PSIG

4.03 Cooling Tower

a. Water inlet temperature 120 °F

b. Water outlet temperature 86 °F

c. Design wet bulb 78 °F

d. Type of tower Mechanical Draft Cross-Flow

e. Structural design-lateral load: See Section 2.0

4.04 Steam and Condensate

a. High pressure steam at 1250 psi and 300 °F superheat

b. Low pressure steam at 150 & 50 psi and — °F superheat

c. Intermediate pressure steam at 625 psi and 200 °F superheat

d. Condensate system at 50 psi

4.05 Boiler Feedwater

a. Supply pressure at plot limit 60 psi

b. Supply temperature at plot limit 60 °F

4.06 Fuel Gas

		Natural Gas	Refinery Gas
a.	Pressure at plot limit	X psi	60 psig
b.	Heating value at 1 atm	X Btu/cu. ft	X Btu/cu. ft.

c. Composition –

4.07 Air Coolers 30 °F Approach 120 °F min

4.08 Liquid Fuel

a. Type –

b. SP Gravity –

c. Viscosity (poises at 210 °F) –

d. Heating value – Btu/lb.

e. Supply pressure at plot limit – psi

f. Return pressure at plot limit – psi

g. Temperature at plot limit – °F

4.09 Water Systems

		Supply Pressure	Supply Temperature	Required Treatment
a.	Drinking	50-70 psi	Ambient °F	Settled, Demineralized, and Chlorinated
b.	Sanitary	50-70 psi	Ambient °F	Settled, Demineralized, and Chlorinated
c.	Fire System	90 psi	Ambient °F	Raw River Water

4.10 Sewers

a. Types

1. Sanitary Yes

2. Oily Water Yes

3. Surface Runoff Ditches

4. Chemical Yes

5. Combine 2 and 3? No

b. Materials and Installations

Location	Sanitary	Oily Water	Runoff	Other
	Sewer Systems			
1. Inside Buildings	CI	CI	–	–
2. Under concrete	CI	CI	CI	–
3. Under unpaved areas	VC to 12" RC > 12"	VC to 12" RC > 12"	Ditch	–
4. Design Velocity*	3-5 ft/sec	3-5 ft/sec	Under pavement 3-5 ft/sec	–
5. Slope (%)	As Below**	2%	1%	–
6. Minimum Coverage	3 ft	3 ft	3 ft	–
7. Manholes Precast Concrete	At junctions and changes of direction Sealed @ 300' min distance			–
8. Manhole Covers CI	Plain	Bolted & Gasketed	Bolted & Gasketed	–
9. Junction Boxes	None	Sealed	Sealed	–

*3-5 recommended.
**Minimum 2% to septic tank, 1% beyond.

5.0 ELECTRICAL EQUIPMENT

5.01 Power Supply and Characteristics

a. Source In Plant Generation – Emergency Firm Power from local Utility Company

b. Routing Overhead, Trays

c. Service

Service	Volts	Phase	Cycle
1. Main supply	138K	3	60
2. Primary distribution	138K	3	60
3. Secondary distribution	2300/480	3	60
4. Lighting	480/240/120	3	60
5. Emergency heating	–	–	–
6. Electrical Instrumentation	24	–	DC

5.02 Switchgear and Design Details

a. Refer to "Electrical Design Criteria Project No. – "

5.03 Material Classification – See Drawing –

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

b. Semi-hazardous Class 1, Group D, Division 2

c. Non-hazardous NEMA

5.04 Motors

a. Size 150 hp and up 2200 volts 3 phase

b. Size 3/4 hp to 125 up 480 volts 3 phase

c. Size 1/2 hp and smaller 120 volts 3 phase

5.05 Metering

a. Main Supply By plant powerhouse

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. — stream system	X		
d. — stream system	X		
e. Fresh water	X		
f. Sanitary Water			X
g. Cooling water	X	As process requires	
h. Air			X
i. Fuel gas	X		
j. Fuel oil	X		

k. Others Chlorine, Sulfuric Acid, NaOH, KOH (liquid)

6.02 Panelboard

a. Type Local Panels and Main Control Center

b. Instruments Pneumatic and Electronic; Computer Controlled

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 Product to Storage Temperatures

a.	LPG	100 °F		Gas Oil	120	°F
b.	Pen-hex	- °F		Diesel Oil	-	°F
c.	Gasoline	- °F		Fuel Oil	180	°F
d.	Light naphtha	100 °F		Asphalt		°F
e.	Heavy naphtha	100 °F		Two		°F
f.	Kerosene	°F		Pitch		°F
g.	Others			Others		
	Liquid Sulfur: 250 + °F			Solid Sulfur: Ambient		

7.02 Equipment Data

		Normal Contingency	Process Control Contingency	
a.	Pumps			
	Feed	%	10 %	
	Reflux, Furnace, Recirc	%	20 %	
	Product	%	10 %	
b.	Compressors	%	10 %	
c.	Heat exchangers	%	0 %	
d.	Furnaces	%	10 %	IMM Btu Mininum
e.	Cooling tower	%	10 %	
f.	Others	%	%	
		%	%	

*Contingency for large pumps and compressors to be reviewed on a case by case basis (500 HP and over)

7.03 Codes - latest editions

a. API-ASME unfired Pressure Vessel
   API 650 - Storage Tanks
   ASME, Section VIII, Div. 2

b. ASA Piping Code
   USAS B 31.3 — 1966 — Piping
   USAS B 16.5 — Flanges and Fittings
   USAS B 31.1 — Power Piping

c. ASME Code Power Boilers — Section I

d. National Electric Code NEMA

e. Uniform Building Code (by International Conference of Bldg. 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 140 °F

b. Hazardous chemicals Chlorine, Caustic, Sulfuric Acid

8.02 Winterization

a. Design considerations Yes, -5° for water, steam condensate and various process lines and instrumentation

b. Degree required As dictated by process requirements

8.03 Noise abatement a factor Yes, all fans, compressors, generators and pipelines

8.04 Air pollution requirements Yes, per Federal and State of Illincis 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

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