SECTION 5

PLANT UNIT DESCRIPTIONS

Separate units are described in this section.

Unit No.	Description	Flowsheet No.	Paragraph No.
9	Coal Mine		5.1
10	Coal Preparation	R-10-FS-1	5.2
11	Coal Storage, Crushing, & Drying	R-11-FS-1	5.3
12	Coal Slurrying & Dissolving	R-12-FS-1	5.4
13	Filtration & Filter Cake Drying	R-13-FS-1	5.5
14	Product Distillation	R-14-FS-1	5.6
16	Naphtha Hydrogenation	R-16/19-FS-1	5.7
17	Dissolver Acid Gas Removal	R-17-FS-1	5.8
18	SNG and LPG Production	R-18-FS-1 & 2	5.9
19	Methanation	R-16/19-FS-1	5.10
20	Process Gasifier	R-20/21/22-FS-1	5.11
21	Shift Conversion	R-20/21/22-FS-1	5.12
22	Gasifier Acid Gas Removal	R-20/21/22-FS-1	5.13
23	Oxygen Plant	-	5.14
24	Fuel Gas Gasifier	R-24-FS-1	5.15
25	Fuel Gas Sulfur Removal	B-25-FS-1	5.16
26	Sour Water Treating	R-26-FS-1	5.17
27	Sulfur Plant	B-27-FS-2	5.18

28	Deleted		
29	Product Storage	-	5.19
30	Instrument and Plant Air	-	5.20
31	Raw Water Treating	R-31-FS-1	5.21
32	Power Generation	R-32-FS-1	5.22
33	Deleted		
34	Effluent Water Treatment	R-34-FS-1	5.23
35	General Facilities	-	5.24

Process flow diagrams are contained in Section 6.

Utilities are summarized in Section 10, while equipment lists for the various sections are given in Section 13.

5.1 UNIT 9 - COAL MINE

The plant design includes an integrated strip mine to provide coal for the process. The design uses Illinois No. 6 coal with an average seam thickness of 60 feet. The coal is a high volatile C bituminous type.

5.1.1 PRODUCTION REQUIREMENTS

The mine will produce 47,000 TPD of ROM coal 330 operating (stream) days per year. Annual production will total 15,500,000 tons.

Coal density is 1,800 tons per acre-foot. A coal seam 5 feet thick will provide 9,000 tons per acre; allowing for losses during mining, an average of 5.5 acres will be mined each day to produce 47,000 tons of ROM coal.

With an average overburden thickness of 60 feet, overburden stripping requirements will be approximately 515,000 bank cubic yards (BCY) per day.

5.1.2 MINING PLAN

At the scheduled rate of production, and with an average work year of 330 days, about 1,800 acres of coal per year will be mined. Over a 20-year mine life, approximately 57 square miles will be mined out.

The mine has been divided into five separate areas or mining units. Each unit will develop a pit approximately 3 miles long to produce 9,500 TPD of coal. A mining unit consists of the following:

- A large stripping dragline to remove the overburden and expose the coal seam.

- Loading and hauling equipment for coal removal.

- Rotary drills to drill the overburden.

- Auxiliary equipment, such as dozers, graders, and scrapers to support each operation.

The five mining units will be supported by a centralized shop facility and other equipment that will be available when required.

The general mine layout has three rotary breakers located between the five mining areas. Coal will be hauled from the pits to the crushers by truck, and after crushing it will be transported by belt conveyors to the washing plant. This scheme separates the pits sufficiently to avoid congestion, yet permits close supervision. The mine layout is illustrated in Figure 5-1.

The coal mining width in each pit is 150 feet. With a pit length of 3 miles, mining will advance along the cut at about 308 feet per day. Thus, each cut will be completed in about 52 days or 6.4 strip cuts in each pit per operating year.

5.1.3 PREPARATION

During the preproduction period, main haul roads will be constructed, and the initial starting cuts will be made. At each pit, the initial starting cut will be approximately 150 feet wide and 20 feet deep; it will extend the full length of the pit. About 2,000,000 BCY of upper overburden will be removed in this operation. Because the starting cut is made only once during the life of the pit and is done prior to full-scale production, it is treated as a preproduction capital cost.

5.1.4 OVERBURDEN STRIPPING

The overburden covering the coal seam consists of two types of material. The upper 20 feet of overburden consists of top soil, unconsolidated gravels, sands, and soils; the lower 40 feet is made up of limestone and clayey shale that has to be drilled and blasted. Because it is required that the mined-out areas be restored to their approximate original surface contour and that plantings be made on the reclaimed ground, the upper overburden will be placed on top of the spoiled lower overburden and topsoil will be placed on the surface. The topsoil thus replaced will facilitate the growth of plantings.

Stripping of both the blasted lower overburden and of the unconsolidated gravels and soils will be accomplished with one large walking dragline at each pit.

Approximately 103,000 BCY per day of overburden will be removed at each pit to uncover the coal. The large stripping dragline, with an operating radius of 292 feet, equipped with a 170-cubic-yard bucket, has the capability of removing the required yardage and placing the topsoil portion on top of the spoiled overburden.

An initial or starting cut is made during the preproduction period to begin the mining cycle. This cut is approximately 150 feet wide and exposes the lower overburden so it can be drilled and blasted. Rotary drills are used to drill a pattern of holes the full width of the cut. When the drills have advanced along the cut to a safe distance, the holes are blasted.

The dragline operation follows the drilling and blasting.

The dragline operates from within the cut and on top of the blasted lower overburden. With a working radius of 292 feet, it is able to dig and cast the blasted lower overburden to the spoil area and then to swing to the side and make a chop cut to dig the upper overburden from the next adjacent cut.

The overburden is then cast to the spoil area, placing it on top of the spoiled lower overburden. Operating in this manner, the dragline removes the blasted material from the working cut (and exposes the coal seam) and also removes the upper overburden from the next working cut.

Inasmuch as the dragline has the capability of spreading the spoiled overburden, a minimum amount of dozer work will be required in leveling the spoil area to restore the mined-out area to their approximate original surface contours.

5.1.5 COAL MINING

The coal mining will closely follow the stripping operation. At each pit, a dozer will work in the cut on top of the exposed coal, making a final cleanup of the overburden that was left by the dragline. After cleaning the coal seam, the dozer will be available to rip any coal that requires ripping, prior to loading with the mining shovel.

A mining shovel and haulage trucks will operate at the bottom of the coal seam. At each pit, a 12-cubic-yard electric shovel will be used to load coal to the 120-ton-capacity bottom dump coal haulers that will transport the coal out of the pit to the breaker stations. The breakers will be periodically relocated in relation to the shovel locations to minimize truck haulage distances.

5.1.6 WASTE DISPOSAL

Solid waste from the coal preparation plant will be returned to the pits in 120-ton bottom dump coal haulers. This waste product will be dumped in the mined-out strips and will be covered with overburden from subsequent stripping operations.

5.2 UNIT 10 - COAL PREPARATION PLANT

The Flow Diagram R-10-FS-1 in Section 6 describes the flow of coal from the mine trucks to the conveyor delivering washed 3-inch-x-0 coal to the stockpile in Unit 11.

The ROM coal is dumped from mine trucks into 300-ton-capacity field hoppers, 10-2601, -2602, and -2603, through 2-foot-square fixed-opening grizzlies. These hoppers each discharge, via apron feeders 10-0501, -0502, and -0503, directly to vibrating grizzly units 10-2703, -2704, and -2705 having 3-inch square openings. The 3-inch-x-0 grizzly undersize is received by feeder belt conveyor systems 10-2001 and -2002 and main belt -2003, which deliver it to the coal preparation plant. The oversize material, at 2-foot x 3-inch size, discharges from the individual grizzly units to three feeder units, 10-0504, -0505, and -0506, that deliver to three rotary coal breakers (10-2101, -2102, and -2103) having 3-inch apertures. The raw coal in this feed, after breaking to a minus 3-inch size, discharges and combines with the vibrating grizzly undersize material on the raw coal conveyor, 10-2003, and is carried to the preparation plant.

The selection of a rotary breaker is based on its reliability over an extended period of time compared to other size-reduction equipment as well as its ability to scalp rock and other extraneous material that is over breaker perforation size. In addition, the rotary breaker has available capacity per unit to simplify material handling. The breaker, located near the truck dump, will shorten necessary roadway and breaker waste haulage.

The transport conveyor will feed raw sized coal from the breaker, continually sampled by feed sampler 10-0901, directly into a battery of raw coal double-deck vibrating screens, 10-2706 through -2710, equipped with water sprays. They are located inside the preparation plant. Screen oversize (3 inch by 1-1/2 inch and 1-1/2 inch by 3/4 inch) will be directed to two Baum jigs, 10-3101 and -3102, producing a float product that is dewatered by course sieve bends, 10-2711 through -2713, discharging to coarse coal double-deck vibrating screens 10-2714 through -2716 for sizing to 3 inch x 1-1/2 inch and 1-1/2 inch x 28 mesh.

Top deck oversize goes directly to clean coal conveyor, 10-2008, and second deck oversize is dewatered by centrifuges 10-2250 and -2251, whose product is also discharged on the clean coal conveyor. The coarse coal screen underflow is directed into the primary pump sump feeding the primary hydrocyclone circuit.

Jig middlings are reduced in size to minus 3/4 inch by crushers 10-2104 and -2105 and sent to primary cyclone circuit pump sumps 10-3201 through -3205. The raw coal screens, 10-2706 through -2710, are double-decked, and the top deck undersize, at minus 1-1/2 inch x 3/4 inch, may be split either to the primary cyclone or to the jig circuit, along with the second deck underflow at minus 3/4 inch.

Raw coal screen underflow is directed to the primary cyclone circuit pump sumps, 10-3201 through -3205, and pumped to a bank of primary hydrocyclones, 10-2750 through -2769. Cyclone overflow is piped to the tertiary (classifying) cyclone pump sumps, 10-3209 though -3213, and the primary cyclone underflow is piped to the secondary cyclone circuit pump sumps, 10-3206 through -3208, from which feed is pumped to secondary cyclones 10-2770 through -2779. Secondary cyclone overflow is closed-circuited into the primary cyclone pump sump, and the secondary cyclone underflow, containing minus 100-mesh heavy minerals including pyrites, is sent to the tailings pond.

The secondary cyclone overflow, which was directed to the tertiary (classifying) cyclone pump sump, will be pumped to the bank of classifying cyclones, 10-27101 through -27220.

Classifying cyclone overflow, being reasonably clear, will be piped to the plant water head tank, 10-1901, for recirculation. The clean coal product from classifying cyclone underflow will be sized, as will the primary circuit cyclones overflow, by fine coal screens 10-2725 through -2731 and dewatered in centrifuges 10-2201 through -2215. The dewatered coal is directed to the cleaned coal collecting conveyor, 10-2008. The centrifuge filtrate is piped back to the fine coal screens.

The decision to use a jig-hydrocyclone circuit has been based on relevant information secured from designers and operators of the most recently constructed preparation plants who report that approximately 60 to 70% of the pyrite sulfur is thereby removed. The minus 100-mesh tailings from the secondary cyclone underflow is reported to contain from 1.1 to 1.2% coal fines, the approximate total of fine coal losses from the hydrocyclone circuit.

Other plant losses were based on assumptions derived from operating experience. There are three types of Illinois No. 6 seam coal, and impurities vary. For purposes of this study, impurities in place are assumed at 15%, and dilution in mining operation is estimated at 5 to 20%, for a total reject of 20 to 35%.

Jig losses are minimized by crushing the middlings and directing crushed minus 3/4-inch middlings to the cyclone circuit, eliminating the loss of any hutch material that may be discharged on the refuse elevator.

The general design of the preparation plant is based on labor and operational economy. Equipment selection is based on an allowance in capacity for surge conditions and for standardization. Screens have interchangeable mechanisms, support frames, and drives. Cyclone pumps and motors are identical for all cyclone stages. Centrifuges have interchangeable basic frames, drives, and moving parts.

All equipment units are placed according to flowsheet sequence, with attention to maintenance by suitable equipment spacing and provision for hoists with jibs or trolley beams. Coal-treating building designs minimize inside horizontal projections. They have smooth inside walls, using double-wall insulated siding. Concrete floors are sloped to provide drainage for overflows and washdown. The control room is air-conditioned and insulated, and a graphic panel will display readouts from plant instrumentation.

Noise control for equipment such as screens and blowers is obtained by isolating the particular units involved.

The electrical system is designed with explosionproof enclosures in critical areas, and the motor control and switchgear centers are dusttight and pressurized.

5.3 UNIT 11 - COAL STORAGE, CRUSHING, AND DRYING

Drawing R-11-FS-1 details the flow from the transport conveyor to the points where crushed and dried coal is introduced into the process coal users.

The clean coal product is received at the stockpile facility adjacent to the grinding and drying plant area. The stockpile area can accommodate 590,000 tons of the minus 3-inch prepared product when using a 30-foot uncompacted pile depth. This stockpile inventory represents a nominal 14-day feed supply for Unit 11 grinding and drying facilities. The stockpile provides a blending capability to ensure a uniform BTU quality for the feed to the gasifier and dissolver units.

Upon entry to the stockpile facility, the clean coal is diverted at the first transfer tower to one of two longitudinal conveyor systems, 11-2002 and -2052, located at either side of the long axis of the stockpile pad. The second transfer tower connects the transfer conveyor with the second longitudinal belt. As the coal leaves the delivery belt, a continuous sample is taken and reduced in size by a sampler and reduction system (11-0901, -0902). This system provides samples for analyses representative of the feed delivered to the pile during any stacking time, to obtain a quality inventory of the pile. The longitudinal conveyors normally operate continuously, usually one receiving and stacking fresh clean coal, and the other handling reclaimed blended coal. The clean coal, on receipt at the initial transfer tower, is normally directed to the longitudinal belt operating on the stacking cycle and moves to a mobile tripper unit, 11-2003 and -2053, which is located to feed a crawler-mounted self-propelled stacking/reclaiming conveyor, 11-2801 and -2851. These units are programmed to lay down longitudinal windrows of coal in a series of increments to form, in time, two piles 30 feet high, 600 feet long, and 600 feet wide. This mode of building a stockpile provides a wide distribution and blending of the fresh feed along the pile. Recovery of the coal normally is done with a crawler-mounted bucket wheel excavator unit that forms an integrated system with the second mobile stacking/reclaiming conveyor. The latter discharges into a mobile hopper, 11-2803 and -2853, positioned over the longitudinal conveyor on the reclaim cycle.

The bucket wheel reclaimer unit works across the stockpile normal to the windrow, which enhances the blending of the coal taken. During normal operation, one stockpile is being built and the second reclaimed at any given time, thus permitting independent operation at either pile. In an emergency, fresh clean coal can be bypassed around the stockpile and sent directly to the plant feed conveyor.

The reclaimed coal moves to a main plant feed conveyor, 11-2804, that delivers the coal to a splitter chute feeding two conveyors, 11-2005 and 11-2055, each of which serves one of the two grinding trains. Each of these feed conveyors takes the blended coal to a feed bin, 11-2603 and -2653, which delivers it via vibrating feeders to a set of five cage mills, 11-2101 through -2105 and 11-2151 through -2155, operating in parallel. These mills produce a ground material that meets the product size requirements of 5% plus 20 mesh, 25% minus 200 mesh. The conveyors feeding the mill feed bins and feeding the coal dryers are equipped with tramp iron removal magnets. Belt scales and samplers monitor key process steps to control quantity and quality of materials.

The material from the stockpile contains approximately 7.7% moisture, and the product has a nominal 2.7% inherent moisture. Drying is performed using steam from process units. The usual coal drying procedures involve fuel burning to provide the necessary drying heat, and the supplementary sulfur dioxide gas-cleaning train becomes substantial both in capital and power requirements. The use of steam eliminates this gas-cleaning investment. The Hydro-Aire steam dryers, 11-3401, -3431, and -3461, a variant of the fluid bed concept, use a steam-heated inert gas medium from the process units that moves the material over a plenum across a series of compartments separated by weirs. The wet coal particles are further heated by steam tube bundles located over the plenum in the various compartments.

Three of these dryers are provided. Sufficient capacity is provided to furnish the plant with a full coal supply from two dryers to permit maintenance of the third unit. Cross-connecting conveyors, 11-2009, -2013, -2034, and -2069, allow the transport of dried coal from one dryer output distributor to another for full flexibility of dryer operation.

The product from the No. 1 grinding train is split into two streams. Dryer 11-3401 receives two-thirds of the ground product; dryer 11-3431, the remaining one-third. Similarly the No. 2 train product supplies two-thirds to dryer 11-3461 and one-third to dryer 11-3431. Thus, all dryers receive one-third of the total ground product but can handle one-half if required. The dryers supply dried product for the gasifier and dissolver units at a total rate of approximately 36,000 TPD.

Dryer 11-3401 product is split at the dryer discharge into three streams for transport to using points. Two 5,000-TPD streams feed the high-pressure gasifier via enclosed box belt conveyors, 11-2010 and -2011, and belt elevators that deliver to two double-bifurcated feed hoppers serving four feeders at the gasifier. The remaining dryer product is transported to the adjacent dryer, 11-3431, outlet box to supplement the tonnage delivered by that conveyor.

Dryer 11-3461 product is similarly split into three streams with diversion to the adjacent dryer, 11-3431, outlet box. The two approximately 3,000-TPD streams are transported to two-way splitters, each feeding a conveyor and an elevator supplying a double-feed hopper above the four feeders for the low-pressure gasifier.

Dryer 11-3431, plus the coal diverted from the two other dryers, is split into two equal streams. The two streams, totaling 20,000 TPD move via enclosed box belt conveyors, 11-2032 and -2033, and belt elevators, 11-2035 and -2036, to double-bifurcated feed bins that serve the four feeders at the dissolver unit.

Inert gas, CO_2 plus N_2, obtained from the process units, is used to provide an inert atmosphere for all products from grinding through to final feed hoppers. The units and conveyors are all fully grounded to dissipate any static charge. Selection of materials handling units also requires a fully encased design with provision for dedusting at all transfer points. The fluid character of the ground coal material requires a positive means of transport with minimum sparking potential. Thus, box-type rubber belt conveyors and belt elevators are used.

The extensive use of inert gas requires monitoring of operating areas for oxygen deficient atmosphere where personnel are present. Dead air spaces will be minimized. In addition, self-contained air packs and hose-type units will be available locally and maintained in the process area to permit free access to all units and areas. Monitors will also be located to detect dangerous dust concentrations in the operating areas, together with provisions for inert gas flooding. Fire protection at the stockpile includes a fire water line and local foam cylinders.

All operations are based on nominal tonnages, but equipment is sized for an additional 25% above the normal rating. Because of the presence of inert gases at potentially lethal levels, manning of the area is arranged so that no man is working without a backup man nearby for safety.

5.4 UNIT 12 - SLURRYING AND DISSOLVING

Feed coal is liquefied by contact with a hydrogen-rich gas at elevated temperatures and pressure using the SRC II mode of operation. Drawing R-12-FS-1 shows in detail the high-pressure dissolving and pressure letdown section of the plant.

The high-pressure (2,200-psig design) dissolvers use maximum presently available wall thicknesses. A387E steel can be commercially obtained and welded in thickness to 13 inches. The dissolver design uses a 12.75-inch wall thickness. The design pressure results in a 12-foot-6-inch diameter vessel using ASME Division 2 design criteria. Three dissolver trains of this size provide the design-15-minute slurry retention time for 20,000 TPD of coal. Downstream of the high-pressure separation and the high-pressure separator/slurry feed heat exchangers, the three streams are combined, and the remainder of the plant is a single-train design.

5.4.1 DISSOLVING SECTION

The dry, ground coal feed is combined with the total solvent at 25 psia in the slurry mix vessel, 12-1201, to form a pumpable slurry of about 30 wt% solids with a solvent-to-coal weight ratio of approximately 3. The slurry is separated into three parallel streams and pumped at about 2,200 psig through the product heat interchangers, 12-1310, -1340, and -1370 and then to the dissolver preheater furnaces. The dissolver feed pumps, 12-1501, -1502, -1531, and -1561, are multistage centrifugal pumps with tungsten carbide hardfacing at points where slurry velocity exceeds 15 feet per second. Investment castings are used throughout to eliminate rough surfaces, which are a prime cause of erosion. The impeller tip speed is held to 30 feet per second to minimize erosion.

The slurry is combined with the hydrogen feed gas stream, and the mixture is heated to 700°F in the preheater furnaces, 12-1401, -1431, and -1461. The gas-slurry mixture enters the dissolvers, 12-2501, -2531, and -2561, where an exothermic reaction takes place dissolving the coal and raising the temperature to about 850°F. The product mixture from the dissolvers consists of a gas phase and a slurry phase comprised of hydrocarbon liquids and solid ash plus undissolved coal.

The two phases are separated in the primary separators, 12-1204, -1234, and -1264. The gas phase is cooled and depressurized. Downstream Units 17 and 18 are provided for removal of acid gases and hydrogen recovery. The recovered hydrogen-rich gas is used as part of recycle hydrogen to the dissolver. The slurry phase is cooled, depressurized, and sent to downstream distillation Unit 14. A portion of the fractionator bottoms in Unit 14, containing the ash and undissolved coal solids, is returned to constitute approximately one-third of the slurry solvent. The remaining two-thirds of the solvent is produced in Filtration Unit 13.

5.4.2 GAS DEPRESSURIZING SECTION

The gases evolved in the three high-pressure separators are collected and cooled from 850°F to 370°F by exchanger 16-1302 (see Unit 16 description in subsection 5.7) and by exchange with dissolver hydrogen and feed in exchanger 12-1303. Condensed liquids are collected in the high-pressure intermediate flash drum, 12-1207. Vapors are cooled further by exchange with water and air, and the condensed liquids are separated into a hydrocarbon and a water stream. The resultant cool gas at approximately 2,000 psig is reduced in pressure by expander turbine 12-1805, which helps drive the recycle hydrogen compressor. After passing through another flash drum 12-1210, the gas is sent as feed to dissolver acid gas removal, Unit 17, for further treatment.

5.4.3 CONDENSATE DEPRESSURIZING SECTION

The hydrocarbons condensed in the gas depressurizing section are cooled to 100°F by a series of heat exchangers.

The hydrocarbon condensate stream produced in drum 12-1207 is cooled in an exchanger train generating steam, followed by air and water cooling. This liquid hydrocarbon stream produced in drum 12-1208 is cooled by water in exchanger 12-1309, and both streams are subjected to a final flashing in the high-pressure condensate surge drum 12-1209. The resulting liquid, which is at a pressure of about 2,000 psig, must be depressurized before being forwarded to Unit 14, Product Distillation. This depressurizing is accomplished in three stages of hydraulic turbines 12-1511, -1512, and -1513 to recover power used to help drive the dissolver feed pumps. The use of three stages rather than one stage is necessary because of the large quantity of gas that would be evolved in a single-stage operating between 2,000 psia and 250 psia.

5.4.4 SLURRY DEPRESSURIZING SECTION

The slurry phase emanating from the bottom of the high-pressure primary separators, 12-1204, -1234, and -1264, consists of liquefied coal, dissolved gases, and unreacted coal and ash. The stream from each primary separator is cooled from 850°F to 672°F by exchange with feed slurry in exchangers 12-1310, -1340, and -1370. The three streams are combined and cooled to 550°F in a series of heat exchangers 12-1313 and -1314 and by exchange in filter-recycle oil preheaters 13-1302, -1322, -1342, and -1362. Some vaporization takes place because of the reduction in pressure. The vapor thus produced is flashed in the high-pressure slurry flash drum 12-1211. The resultant vapor stream is further cooled by producing 50-psig steam, followed by air and water cooling. The 100°F vapor joins the high-pressure condensate stream mentioned earlier, prior to entry into high-pressure condensate surge drum 12-1209.

The slurry from flash drum 12-1211 is depressured in three stages, similar to those used for the high-pressure condensate. Energy is recovered in turbines 12-1508, -1509, and 1510 and used to help drive the dissolver feed pumps.

The vapor-liquid mixture from each stage is separated in flash drums 12-1212, -1215, and -1218. The liquid is fed to the next stage of the hydraulic turbine. The gas is compressed to 1,000 psia in the low-and high-pressure vent gas compressors 12-1804 and -1803, respectively, and sent to Unit 17, Dissolver Acid Gas Removal, to join the gas from the expander, 12-1805.

Additional equipment is provided as shown on the flowsheet to cool and separate vapor generated at various points in the liquid pressure-letdown system.

5.5 UNIT 13 - FILTRATION AND FILTER CAKE DRYING

Drawing R-13-FS-1 shows in detail the flow of fractionator heavy liquid products to separate the liquids from the unreacted coal and ash.

The objectives of this unit are twofold:

(a) To remove solids, consisting of ash and untreated coal, from the liquefied coal products by filtering and subsequent washing of the filter cake.

(b) To recover the wash solvents and thus produce dry solids.

5.5.1 FILTERING

Filtering of unreacted coal solids from liquid product is a difficult mechanical problem because of the high temperatures, high viscosity characteristics of the liquid, small particle size of the solids, and large volume of materials to be handled. In pilot plant work and in most conceptual plant designs, pressurized rotary precoat filters have been specified to achieve a maximum filtering rate from the high-pressure drop possible with a pressurized filter. The present design, however, uses enclosed rotary vacuum precoat filters for the following reasons:

(a) Even though the filtering rate for vacuum filters may be less than one-half of that for pressure filters, requiring over twice as much filtering area, the capital cost of vacuum equipment is about one-fourth that of pressure equipment per square foot of filtering area. Thus, the equipment cost of vacuum filters is about one-half that of pressure filters. Auxiliary equipment, such as pipes, valves, and controls, will also cost less for vacuum than for pressure filters.

(b) Vacuum filters are used in much larger numbers and installations than pressure-type filters. A large body of operating and maintenance experience for this equipment has been collected over decades of use.

(c) Maintenance of vacuum equipment is easier and less costly than for pressure equipment, because the equipment is lighter and easier to handle. Therefore, we expect more on-stream time for the vacuum equipment.

For the purposes of this design, the filtration rate was set by reference to the Tacoma Pilot Plant reports of filter operation. The liquid filtration rate during a typical run was calculated at 127 pounds per hour/square foot at 22 psi pressure drop. Filtration theory states that the filtration rate is directly proportional to pressure drop. At 10 psi pressure drop in a vacuum filter, the filtering rate is therefore estimated to be 58 pounds per hour/square foot.

To the extent that rotary vacuum filters have not been tested in pilot plant operation, their use in this design is an extrapolation of laboratory work where vacuum leaf-type filters have been extensively used for SRC liquids. The liquid product of the SRC II mode of dissolving is lighter than the product for which pressure-type filters were provided in the SRC pilot plants, which reinforces the likelihood that vacuum filtration will prove technically appropriate.

Based on the rate postulated above, 48 filters of the largest commercially available size are provided; each filter has 912 square feet of filtering area. They were arranged in four groups of filters, 11 operating and 1 spare. Each group is serviced by one precoat system, which allows about 2 hours for precoating each filter daily.

Diatomaceous earth (DE) is used as filter precoat material. No provision is made for body feed. DE is received in hopper cars or trucks and pneumatically transported to a storage hopper, 13-2601. The description hereafter applies to precoat train A. The other three trains are similar except for differences in equipment numbering. As required, the DE is withdrawn from the hopper by a variable-speed screw conveyor that feeds the precoat slurry mix tank, 12-1201, where it is mixed with precoat solvent. Mixer 13-2401 keeps the DE in suspension until pump 13-1501 is activated to precoat a filter with a coat approximately 3 inches thick. Precoat filtrate is returned to the system via tank 13-1202 and associated pumps. A filter pumpout system is provided to prepare a filter for the precoat operation.

In normal filtering operation, filter 12-2201 (typical for 48 units) is fed under level control with bottoms from the main fractionator in Unit 14. This stream at 550°F is drawn through the precoated rotating filter by the action of vacuum pump 13-1803. The solids build up on the outside of the filter drum and are removed by the action of a slowly advancing doctor blade, which shaves the filter cake and some precoat by advancing approximately 1 mil per revolution. After a period of 24 hours, the precoat has been reduced to a thickness of 1/4 inch, and a new precoat is required.

The filter cake is washed with a wash oil with a 500°F to 600°F boiling range. The oil is composed of a recovered stream from the filter cake dryers and of makeup oil originating in the fractionator Unit 14. The filter cake with 50% by weight wash oil is moved from the filter area to the dryers by an enclosed screw conveyor system, 13-2003.

The precoated filter drum is internally separated into three sectors. When sector 1 is in a low position, it is immersed in filter feed. The vacuum pump, 13-1803, pulls filtrate through the filter medium depositing the solids as filter cake on the precoat. After one-third of a revolution, sector 1 is out of the liquid, and accumulated filtrate is transferred to receiver 13-1204. Passage of circulating vapor through the filter cake helps to remove filtrate from the cake. Further revolution brings sector 1 under the wash oil spray, which is drawn through the filter cake to aid in washing the filter cake free of heavy liquid. The resultant mixture of wash oil and recovered filtrate is drawn through the appropriate piping system to the wash oil receiver, 13-1205. Close to the end of the complete revolution, the doctor blade slices off a thin layer of filter cake and precoat; then the cycle begins again. Sectors 2 and 3 of the filter drum pass through the same cycles, 120 and 240 degrees out of phase with sector 1, making the filter a continuously operating device, until precoat replacement is required.

The vapor, consisting of light ends from the filtrate and wash oil, is recirculated to the filter shell and is designed to circulate at a rate of 2 ACFM per square foot of exposed drum area.

Part of the filtrate is used as recycle solvent for the dissolver, and the net product moves through a Unit 14 cooling train to storage tanks as fuel oil product. The wash oil containing displaced filtrate is returned to distillation in Unit 14 as part of the main fractionator feed.

The nitrogen content of the fuel oil product is of the same order of magnitude as the feed coal. This is true of hydroliquefaction-produced fuel oils in general. Removal of 60% of the nitrogen contained in the fuel oil would require severe and expensive treatment. The alternate is control of NO_x emissions during combustion by proper burner design and combustion operation. Therefore, further hydrotreating to reduce the nitrogen level was not included in this design.

5.5.2 FILTER CAKE DRYING

Recovery of the wash oil and drying of the filter cake is accomplished in four kiln dryers, 13-3401, -1421, -1441, and -1461. Note that only dryer 13-3401 is shown with attendant equipment on the flowsheet, and only this train will be described hereafter.

Heat for the drying and recovery is supplied by mixing hot char from the fuel gas gasifier, 24-2501, with the wet filter cake. The direct admixing of dry hot material with the wet cake should eliminate the coking and lumping problem encountered in the heated dryers used in pilot plant work. It also eliminates an inert gas heating and circulating system previously considered for supplying drying heat.

The dryers operate at a positive pressure of approximately 5 inches of water and will be supplied with low-pressure steam as purge gas and seal gas. Vapors from the dryers are cooled by raising steam and by air cooling. The condensed solvent is recycled to the filters from drum 13-1203, and any purge gases are compressed for cleanup in Unit 17. Dried filter cake and char from all four systems are pneumatically conveyed to a single dryer effluent hopper, 13-2602. From here, the solids are pneumatically conveyed to the fuel gas gasifier in Unit 24. The condensed water is pumped to the sour water treating unit, Unit 26.

5.6 UNIT 14 - PRODUCT DISTILLATION

Solvent separation is achieved by atmospheric distillation. The flow through the unit is shown on Drawing R-14-FS-1. The unit will produce the following products:

(1) Naphtha (100°F to 400°F boiling range). Used as feedstock to naphtha hydrogenation unit.

(2) Light distillate (400°F to 500°F boiling range). Used as constituent of fuel oil product.

(3) Heavy distillate (500°F to 650°F boiling range). Used both as wash oil in the vacuum filters in Unit 13 and as a constituent of fuel oil product. Removal of lower boiling components from the wash oil is necessary to minimize volatilization in the vacuum filters.

(4) Atmospheric bottoms containing the solid residue of unreacted coal and ash, as well as some components with a higher boiling range than the wash oil. Atmospheric bottoms are used both as process solvent (slurry recycle) and vacuum filter feedstock.

A slurry stream and a hydrocarbon condensate stream, coming from separators in Unit 12, combine with the recycle wash oil stream line 19 from Unit 13. This combined stream represents the feed to the main fractionator, 14-1101. The slurry flows through a series of heat exchangers and a preheater, 14-1401, and is fed to the lower section of the fractionator at a temperature of 765°F.

The column bottoms are steam stripped (0.1 lb of steam per gallon of bottoms), and an overflash of 5% of the feed is used for design. The fractionator is operated at 18.38 psig and a flash zone temperature of 765°F. It has 20 sieve trays and 6 baffle (shed) trays.

The column overhead product is cooled to 280°F, and the hot reflux is pumped back from reflux drum 14-1201 to the top tray. The remaining vapors are cooled, condensed, and separated at 120°F in the overhead receiver, 14-1202, to produce naphtha and ammonia-contaminated water. The sour gas leaving the receiver is compressed by compressors 14-1801 and 1802, and forwarded to the acid gas removal Unit 17. The naphtha is pressured by pump 14-1513 and -1514 to the naphtha hydrogenation Unit 16.

The light distillate and the heavy distillate are withdrawn from the side of the fractionator. Both streams are stripped of light ends in reboiled strippers 14-1102 and -1103, respectively. The heavy distillate then is pumped at 590°F to Unit 16 for heat exchange and further split to wash oil and heavy distillate product. The latter is combined with the light distillate at 460°F and the filtered bottoms coming from Unit 13. The resulting fuel oil stream is used to provide heat (by exchange) for steam generation and for reboiling in Unit 18. It is further air-cooled to 130°F and forwarded to storage. The column-operating conditions are adjusted to give the desired cut points between the naphtha, the light distillate, and the heavy distillate.

The fractionator has two heat-removal sections, which resulted in decreasing the diameter of the two top rectifying sections considerably. The pumparound duty of the light distillate reflux is used for steam generation in exchanger 14-1303 and, further, for supplying heat to Unit 26. The pump-around duty of the heavy distillate is used for feed preheat in exchanger 14-1301, steam generation in 14-1302, and for reboiling the light distillate stripper reboiler, 14-1305.

The fractionator bottoms are a major product of the distillation. They contain all the solid residue from liquefaction, some high boiling hydrocarbons, and a small fraction of material boiling below 550°F. The stripping section of the tower has four baffle (shed) trays, needed to handle the solids.

The bottoms are pumped at 757°F to a series of heat exchangers 14-1304, for feed preheat and to the heavy distillate stripper reboiler, 14-1306, where they supply heat for reboiling. They are further split to slurry recycle (at 550°F) and Unit 13 vacuum filter feed. Filtered bottoms are returned from Unit 13 to Unit 14 for blending into the product fuel oil stream.

5.7 UNIT 16 - NAPHTHA HYDROGENATION

Drawing R-16/19-FS-1 shows in detail the flow of naphtha recovered by distillation and gas treating through a hydrogenation step to reduce nitrogen and sulfur levels in the product to 5 and 1 ppm, respectively. The composition and purity of this high-quality naphtha make it salable.

Naphtha is hydrogenated in a conventional fixed-bed reactor, 16-2501, at approximately 1,000 psig total pressure. Data from research projects on hydrogenation of coal-derived liquids was used to estimate space velocity, hydrogen usage, and product conversion.

Naphtha streams from Units 14 and 18 are combined as feed and sent to feed surge drum 16-1201. The stream is pressured by charge pump 16-1501 to the 1,010-psig operating pressure of reactor 16-2501. A recycle gas stream and high (95% plus) purity hydrogen stream emanating from Unit 19 are combined with the naphtha feed. The feed is then preheated by exchange with reactor bottoms in exchanger 16-1301 and, further, by heat from the dissolver unit high-pressure separator overhead stream in exchanger 16-1302 (see subsection 5.4). The feed enters the reactor at 750°F.

The reactor has two beds of cobalt-molybdenum catalyst. Quench hydrogen is fed to the reactor between the beds. Water is injected into the reactor effluent, which is subjected to air-cooling prior to product separation in drum 16-1202 at 980 psig. Condensed water is removed in this drum, together with hydrogen sulfide and ammonia, and sent to the sour water treating Unit 26 (see subsection 5.17). Gases evolved in the drum are used partly as reactor recycle stream and approximately 60,000 scfh are pressured by blower 16-1803 to the dissolver acid gas removal Unit 17 (see subsection 5.8).

Light ends are removed from the hydrogenated naphtha stream in stabilizer 16-1101 operating at 192 psig and 350°F. A bottoms reboiler and an overhead reflux circuit are provided. Over 9,000 BPD are removed as the bottoms stream.

This stabilized stream is cooled by exchange with the feed stream, followed by air and water cooling, and it is sent to storage as salable 50° API Naphtha.

Low-pressure vent gas is sent from the overhead reflux system to the sour gas compressor knockout drum, 14-1204, in the product distillation Unit 14. It is combined with low-pressure offgas from this unit and sent to acid gas removal.

This naphtha will have high aromatic and naphthene content, making its primary value as a reformer feed blending component. Its 1 ppm maximum sulfur content is within specifications for modern bimetallic reforming catalysts, but 5 ppm of nitrogen may cause up to 25% reduction in reformer operating time between regenerations. A greater degree of nitrogen removal would require more severe naphtha hydrotreating, with increased hydrogen usage and unit capital cost. Therefore, the potential problem with reformer operation was accepted at a lesser cost to the Oil/Gas plant operations.

5.8 UNIT 17 - DISSOLVER ACID GAS REMOVAL

Drawing R-17-FS-1 shows in detail the flow through a unit designed to remove carbon dioxide and hydrogen sulfide from the dissolver, distillation, and naphtha hydrogenation offgases.

High-pressure flash gas from Units 12, 16, and 14 (compressed in Unit 12) with 62.3 vol % hydrogen is first sent to a gas filter/separator, 17-2201, and then to two contactors installed in parallel where the gas is counter-currently washed with MEA (monoethanalomine) solution for removal of hydrogen sulfide, carbon dioxide, and carbonyl sulfide. The overhead gas from the contactor is routed to the knockout section of the contactor for separation of entrained liquid. Then the gas is sent to the caustic precontactor, 17-1104, where it is contacted with recirculating, partially spent 10% caustic (70% converted to Na_2CO_3). Then, it is contacted in contractor 17-1105 with recirculating fresh caustic (25% converted to Na_2CO_3) to remove carbon dioxide to less than 5 ppm by volume. Afterwards the gas is washed with water in column 17-1106 to remove entrained caustic before being sent to Unit 18, SNG and LPG Production.

The rich MEA solution from the bottom of the amine contactor is released to the flash drum, 17-1201, for separation of hydrocarbons, vapor, and liquid, and then it is routed to the regenerator, 17-1103, through the rich/lean exchanger.

The net stripping steam is condensed out of the regenerator overhead acid-gas stream and returned to the top of the regenerator as reflux.

Low-pressure steam is employed for reboiling the amine regenerator. The lean MEA solution from the bottom of the regenerator is passed through the rich/lean exchanger, 17-1303, and the amine air cooler, 17-1302, prior to entering the suction of the high-pressure amine pumps, 17-1501, etc. The lean solution is then directed under flow control to the two amine contactors. A small slipstream proceeds under flow control to the wash column of the flash drum.

A solution filter, 17-2202, and a reclaimer, 17-1306, are provided for solution conditioning. The amine surge tank, 17-1901, provides for normal operation surge as well as for solution storage. The solution sump, 17-1203, is used for collecting drips and drains and for solution makeup. Equipment for injection of corrosion inhibitor and antifoam is provided, as well as tanks for caustic and major amine storage.

5.9 UNIT 18 - SNG AND LPG PRODUCTION

Drawings R-18-FS-1 and R-18-FS-2 show in detail the flow through equipment provided to treat the sweetened gas stream produced in the acid gas removal Unit 17. The products are salable SNG, propane and butane LPGs, and a light naphtha.

5.9.1 GAS TREATING

See Drawing R-18-FS-1. The sweet gas is dried in molecular sieve dryers 18-1201 through -1203 to a minus 100°F water dewpoint and is sent to a cryogenic hydrogen upgrading step, 18-0801. This step produces 98.5 vol% hydrogen using both autorefrigeration and external refrigeration. A small portion of the hydrogen-rich stream is sent to Unit 19 for removal of final traces of carbon monoxide before feeding the naphtha hydrotreater. The remainder of this hydrogen-rich stream is recycled to Unit 12 as part of the dissolver feed.

Methane-rich gas is produced in the cryogenic upgrading step at 95°F and 21 psia. This gas is compressed to 397 psia in a steam turbine driven, three-stage compressor, 18-1801. Interstage cooling and liquid separation equipment are provided to remove condensable fractions. The gas is preheated by exchange with product gas and passes at 600°F through a zinc oxide guard reactor to reduce hydrogen sulfide content to less than 0.1 ppm for methanation catalyst protection. The clean gas is then sent to a liquid phase methanator, 18-2503, where it is contacted with methanation catalyst suspended in sulfur-free C_{20}-range oil. The reactor converts 95% of the carbon monoxide to methane. The reaction is exothermic, and the released heat is removed from the circulating oil-catalyst stream through steam generator 18-1306.

A small amount of the C_{20} material is degraded to lighter and heavier material in the methanator. This degraded material is removed from the circulating stream by a purge cleanup unit, 18-0802. The gas effluent from the liquid phase methanator exits at 690°F and 350 psia. It is cooled by exchanging it with the feed in exchanger 18-1311 followed by air cooling to 132°F to condense some of the water produced in the liquid phase methanator. The gas is then sent to the polishing methanator, 18-2504, where the final traces of carbon monoxide are converted to methane to meet the SNG specification of 0.10 vol% carbon monoxide.

The polishing methanator effluent is produced at 840°F and 312 psia. After cooling by exchanging it with the feed and by air cooling, the gas is compressed to 1,020 psia in a two-stage compressor, 18-1802. Interstage and after coolers are used in combination with separator drums to remove the major portion of water from the gas streams. The cooled gas stream at 100°F is contacted with glycol in dryer 18-0803 to meet the SNG water specification of 3 ppm scf. The SNG is then spiked with ethane and propane from the deethanizer column to adjust the final SNG HHV to the specification of 1,050 Btu/scf.

5.9.2 ETHANE AND HEAVIER PURIFICATION

See drawing R-18-FS-2. Another stream produced in the cryogenic upgrading unit consists of liquid and vapor containing ethane and heavier material. These streams are sent to deethanizer 18-1101. The vapor is compressed to 218 psia by compressor 18-1803 prior to entering the tower. The remainder of the feed is liquid at 20 psia and is pumped into the tower.

The ethane and some propane are taken overhead as product. This is the spiking gas required to adjust the final SNG heating value to specification. This gas is compressed by compressor 18-1804 from 210 psia to final SNG pressure of 1,015 psia.

The remaining propane and heavier material are then depropanized in column 18-1102 to produce a propane LPG and butane and heavier material bottoms. The propane LPG is pumped to a sweetening package unit, 18-0804, to adjust the sulfur content to specification. The salable product propane LPG is sent to storage.

The butane and heavier material from the depropanizer bottoms are debutanized in column 18-1103 to produce a butane LPG and pentane and heavier material bottoms. The butane LPG is pumped to a sweetening package unit, 18-0805, to remove sulfur compounds. The salable butane LPG product is sent to storage. The pentane and heavier material are sent to Unit 16, Naphtha Hydrogenation.

5.10 UNIT 19 - METHANATION

Drawing R-16/19-FS-1 shows the treatment of hydrogen-rich gas originating in Unit 18 to methanate its carbon monoxide content making it suitable for use in naphtha hydrogenation.

The gas is received at 1,035 psig pressure at 95°F. It is preheated to the reactor entrance temperature of 525°F by exchange with reactor effluent in exchanger 19-1301.

The methanator, 19-2501, is a two-bed column with an upper hydrogen sulfide guard bed of zinc oxide pellets and a lower bed of methanation catalyst. The inlet carbon monoxide (approximately 2%) is converted to methane and water in an exothermic reaction. The resultant effluent stream exits the reactor at 850°F and is cooled by exchange with the feed stream followed by air cooling to 120°F. The water content thus condensed is removed in the knockout drum, 19-1201, and the resultant 95% purity hydrogen stream is sent to Unit 16 for the hydrogenation of naphtha.

5.11 UNIT 20 - PROCESS GASIFIER

Drawing R-20/21/22 shows the flow from the gasifier coal feed to the point of delivery of gas to the sour shift unit.

5.11.1 GASIFIER

The core of the unit is a two-stage, entrained, slagging gasifier, 20-2501. The gasifier is fed coal and is operated at about 1,000 psig. Significant methane is produced in the second (lower temperature) stage of the gasifier. The methane yields, overall material balance, and energy balance are based on information developed during the course of the ERDA-sponsored Bi-Gas program.

The gasification takes place in two zones. The lower, or slagging zone, operates at approximately 3,000°F and is fed by char, oxygen, and superheated steam. A restriction separates this zone from the upper zone operating at approximately 1,700°F. Ground coal and steam are fed to the upper zone.

A slag quench pot is located under the slagging zone. Slag enters this pot continuously through a relatively small (about a 2-foot diameter) opening. The water is circulated through the quench pot at a high rate to keep the water-slag slurry at 160°F outlet temperature. The 3,000°F slag, dropping into the cool water, shatters into sandlike particles.

The wall of the slagging zone is cooled by an internal tube wall through which boiler feed water is circulated, thus generating steam. Figure 5-2 (at the end of this section) shows further details of gasifier design.

Feeding a dry coal to a high-pressure gasifier is one of the difficult aspects of gasifier design. Two approaches that have been used are lock hoppers and slurry pumping, but slurry system requires vaporization of the suspending liquid plus vapor-solid separation. Both of these techniques involve large expenditures of energy. Lock hoppers pose uncertainties in equipment performance and maintainability at the pressures used in this design. The application of high-pressure screw feeders, similar to those used in plastics extruders, has been suggested, and some preliminary tests have been performed with coal feeds.

These tests have been successful in feeding coal against high pressures, and indications are that feed-to-power ratios could be in the order of 100 to 200 pounds of coal feed per hour/hp. We have, therefore, specified this system of feeding, which offers the advantages of simplicity, ruggedness, and a direct approach to control. A feed-to-power ratio of 100 pounds per hour/hp was used.

Four screw feeders are provided, each with a maximum capacity of 3,350 TPD of coal. Thus, one feeder can be out of service for maintenance without imparing the gasifier throughput.

5.11.2 GASIFIER SYSTEM APPURTENANCES

The gasifier product stream is contaminated with entrained char. The total stream is cooled to 945°F by a steam superheating, oxygen heating, and steam generation in waste heat boilers. A high efficiency char cyclone system, 20-2201, is used to remove 99.5% of the char. Dust remaining in the stream is removed in high-pressure dust filters 20-2202 and -2203. Each of these filters is sized to treat the full flow to permit maintenance and filter medium replacement without impairing the flow through the system. The resulting dust-free gas stream is sent as feed to the shift unit.

A hopper under the char cyclones is provided as entry to a feeder system, 20-2005, returning the char to the gasifier.

A boiler feed water system and a 1,000 psia steam drum, 20-1201, are provided to use the heat removed from the lower gasifier section walls and from the effluent gas stream. The system will provide the steam required for the gasifier reactions. Part of the feed water supply to this system will be sour water stripper bottoms that contain dissolved phenolic compounds to allow destruction of these compounds in the gasifier slagging zone. Materials have been specified for the steam system that will handle the phenolics.

The slag quench pot is a feed drum for the quench water circulating pump, 20-1505. This pump is provided with hardened surfaces at all critical points and is of low-speed design to provide reliable service in circulating sandy slag suspended in the water. The slag is removed from the water in a set of hydroclones, 20-2205. The quench water is air cooled to 120°F and returned to the gasifier.

The underflow of the gasifier is reduced in pressure and sent to the slag slurry receiver. Gases evolved at this point are sent to the fuel gas cleanup system and used as plant fuel. The concentrated slag slurry is pumped to slag-settling basins. Water is returned from these basins as the major part of quench water makeup.

5.12 UNIT 21 - SHIFT CONVERSION

Drawing R-20/21/22-FS-1 shows the equipment and flows provided to adjust the hydrogen-to-carbon monoxide ratio in the gasifier product gas to the level required for downstream processes.

Dust-free gas from the gasifier unit is quenched by direct contact with water and steam in quench pot 21-1201 for feed to the shift reactors. Hydrogen sulfide is not removed from the gas prior to shifting, so a sulfur-resistant shift catalyst is used in this unit. Shifting takes place in three reactor stages, with quenching and a steam-to-dry gas ratio adjustment between the stages. Conversion of carbon monoxide in Unit 21 is controlled so that the hydrogen-to-carbon monoxide ratio in the methane-rich gas from the downstream cryogenic unit is 3:1, the correct stoichiometric ratio for methanation.

Using spherical reactors and spherical condensate separators after the shift reactor allows the entire gas stream to be treated in one train. After the shift reaction, the gas is cooled, and heat is recovered by waste heat boilers, including boiler feed water preheating and generation of 155-, 25-, and 10-psig steam, to minimize discard of heat from the plant. The remaining heat is removed by air and water cooling to bring the stream to the 100°F level required as feed for acid gas removal.

5.13 UNIT 22 - SELECTIVE ACID GAS REMOVAL

A selective acid gas removal unit employing a proprietary physical solvent is used to produce a clean gas, a hydrogen sulfide-rich gas, and a vent gas stream. The Rectisol process was used as a representative process. The clean gas is used as makeup hydrogen feed stream for the dissolvers in Unit 12. The hydrogen sulfide-rich stream is used as part of the feed to the sulfur plant, Unit 27. The remaining gas consists primarily of carbon dioxide and nitrogen with traces of hydrogen, methane, and carbon monoxide (250 ppm, approximately). It is vented through the plant main stack (see Section 11, Environmental Factors).

5.14 UNIT 23 - OXYGEN PLANT

This is a conventional plant by a commercial air separation plant supplier.

The facility will consist of three package plants designed to produce 1,500 TPD each, totaling the required 4,500 TPD of 98% purity oxygen. Each plant will include the cold box, distillation columns, heat exchange equipment, air and oxygen compressors, and auxiliary equipment.

The oxygen will be delivered at 1,000 plus psig and approximately ambient temperature. Nitrogen will be supplied to plant units for process use (Unit 22), for instrument operation, for inert gas blanketing in coal drying and product storage, and in parts of the process plant for purging in case of shutdown.

5.15 UNIT 24 - FUEL GAS GASIFIER

Drawing R-24-FS-1 shows flow details for the intermediate-pressure air-blown gasifier used to supply low Btu fuel gas to the complex furnaces and boilers. A sketch of the gasifier is given in Figure 5-3.

Dry coal and dried filter cake are fed to gasifier 24-2501. This is slagging, suspension-type, air-blown gasifier operating at 45 psia. Most of the char, filter cake, and air is fed to the first stage (lower or slagging section), while most of the coal and the remainder of the air are fed to the second stage (upper section). The first stage operates at 2,500°F, and the second stage operates at 1,800°F. The carbonaceous material is gasified and produces primarily a mixture of synthesis gas (carbon monoxide and hydrogen) with nitrogen.

Steam is generated in coils located under a thin layer of refractory in the first stage of the gasifiers, which keeps metal temperatures low and protects the refractory lining.

The design of the gasifier bottom resembles a flat blast furnace bottom. A layer of solid slag will be formed at the bottom of the slag section protecting the refractory. A layer of molten slag will form above the solid slag. Commercially available blast furnace slag tapping and plugging equipment will be used to withdraw molten slag at regular intervals from the gasifier.

The slag runs by gravity into a cool water quench pit, 24-2008, where it shatters into sandlike particles. A conveyor moves the slag to the discharge end of the quench pit. An inclined conveyor picks up the slag, which is essentially dewatered, as it moves up the inclined apron above the pit water level. The resulting slag sludge is returned by truck to the mine for burial.

A water circulating system takes water from an overflow pit adjacent to the quench pit, cools it in air cooler, 24-1301, and returns it for reuse as quench water. Treated plant effluent from Unit 34, Effluent Water Treatment, is used as makeup for the system.

The low heating value gas, plus a large quantity of char, exits the top of the gasifiers and is sent to cyclone 24-2201 where 95% of the solids are removed from the gas. The solids are conveyed to the filter cake dryers in Unit 13, and the gas is cooled. The cooling train consists of air preheat (heat exchangers 24-1302 and -1304) and 1200-, 150-, and 25-psig steam generation in heat exchangers 24-1303, -1305, and -1306, respectively.

Air and water cooling produce a sour water condensate containing some solids that are removed in drum 24-1205. The gas stream proceeds to an electrostatic precipitator, 24-2202, where the remainder of the entrained solids are removed. The gas is then routed to Unit 25 for sulfur removal.

5.16 UNIT 25 - FUEL GAS SULFUR REMOVAL

The Fuel Gas Sulfur Removal Unit is shown on Process Flow Diagram R-25-FS-1. The process is one of several commercial processes that are available for reducing the sulfur content of the fuel gas to an acceptable level. The Stretford process has been used for this design as being representative of this process type.

Fuel gas entering the sulfur removal unit is fed to a contactor where hydrogen sulfide is absorbed by redox solution. The clean fuel gas then flows downstream to process furnaces and stream generation. The redox solution is contacted with air in the oxidizer to convert the absorbed hydrogen sulfide to elemental sulfur by the following overall reaction:

$$H_2S + 1/2\ O_2 \longrightarrow S + H_2O \qquad (1)$$

The regenerated redox solution is then recirculated from the oxidizer to the contactor. Elemental sulfur is removed in the air-blowing step as a froth that is skimmed from the solution in the oxidizer. The froth is deaerated in the froth tank and pumped to a sulfur melter. In the sulfur melter, sulfur in the froth is melted under pressure and separated from adhering redox solution. The purified liquid sulfur product is transferred to storage, and the decanted redox solution is returned to the system.

5.17 UNIT 26 - SOUR WATER TREATING

Drawing R-26-FS-1 shows equipment and flows provided to remove sulfur and ammonia compounds from sour water collected in the various process units.

5.17.1 AMMONIA SULFIDE WATER TREATER

Water contaminated with ammonium sulfides enters feed drum 26-1201, which utilizes an overflow-underflow weir arrangement to separate the water from floating oil. The oil is drained to accumulator 26-1202 and is then pumped to the offplot hydrocarbon recovery system. The water is pumped to the feed surge tank, 26-1901.

The feed surge tank is a floating roof tank, providing 24 hours of retention for ammonia-sulfide water feed. An oil skimmer is attached to the roof of the tank, and skimmed oil is drained to the hydrocarbon accumulator. The water is pumped from the feed surge tank to the top of stripper 26-1101.

Within the stripper, the ammonia and hydrogen sulfide gas are stripped from the water and removed from the top of the column. The gas proceeds to the ammonia separation plant. A portion of the water is vaporized in the reboiler, 26-1302, to provide stripping steam, while the remainder is discharged from the bottom of the column and pumped offplot to Unit 20, Process Gasifier.

5.17.2 AMMONIA SEPARATION

Ammonia-sulfide feed gas enters the ammonia absorber, 26-1151, where it is contacted with lean proprietary liquid. The Phosam process has been used in this design as being representative of this process type. The solution selectively absorbs the ammonia, and the hydrogen sulfide gas is removed overhead and directed to the sulfur plant, Unit 27. Make-up solution acid is added at the bottom of the absorber. The rich solution is pumped from the bottom of the absorber to the top of the ammonia stripper, 26-1152.

Within the ammonia stripper, ammonia and water are vaporized. Steam is added to the column for additional heat. The lean solution is discharged from the bottom of the column and passes through a feed/bottoms exchanger and a water cooler before reentering the ammonia absorber.

The aqueous ammonia gas is discharged from the top of the stripper tower and condensed in feed/overhead exchange followed by a water-cooled exchanger. Under tower pressure, the aqueous ammonia is directed to the ammonia fractionator feed drum, 26-1254, where a caustic solution is added to remove any hydrogen sulfide and free the ammonia.

The aqueous ammonia is then pumped to the ammonia fractionator, 26-1153, where the anhydrous ammonia flashes off and goes overhead. Steam is added directly to the bottom of the column to provide heat. The anhydrous ammonia is condensed in the ammonia condenser, 26-1356, and collected in the ammonia reflux drum from which it is pumped to product storage. The residual wastewater is discharged from the bottom of the column and is used as slag quench water in Unit 20.

5.18 UNIT 27 - SULFUR PLANT

Drawings B-27-FS-1 and B-27-FA-2 show diagrammatically the major components of the sulfur plant required to produce an ecologically acceptable tail-gas.

5.18.1 SULFUR RECOVERY UNIT

A typical, Claus-type, three-stage sulfur recovery unit is shown diagrammatically on Drawing B-27-FS-1. The acid gases from Units 17, 22, and 26 are fed to a knockout drum for removal of any entrained liquids before entering the combustion chamber of the reaction furnace. The chemistry of the process involves burning part of the H_2S with air to form SO_2 which combines with the remaining H_2S in the acid gas to form elemental sulfur according to following equations:

$$H_2S + 3/2\ O_2 \longrightarrow SO_2 + H_2O \qquad (1)$$

$$2H_2S + SO_2 \longrightarrow 3S + 2H_2O \qquad (2)$$

Any hydrocarbons in the acid gas are burned to CO_2 and H_2O.

The reactions are exothermic, and the heat liberated generates 150 psig steam in the reaction furnace boiler and 50 psig steam in the sulfur condensers.

The process gas from the first condenser passes through three stages of catalytic conversion, each stage being composed of a reheater, a catalytic bed, and a sulfur condenser. The sulfur from each condenser is drained to a recovery pit, and the tail gas from the final condenser is fed to the tail gas treating unit.

5.18.2 TAIL GAS TREATING UNIT

The Tail Gas Sulfur Removal Unit is shown diagrammatically on Drawing B-27-FS-2. Several commercial processes are available for reducing the sulfur content of the sulfur recovery unit tail gas to an environmentally acceptable level. A sulfur content of less than 100 ppm is achievable by one of these processes (the Beavon Sulfur Removal Process), and this was used as the basis for the estimates of this study.

In the process taken, for example, hydrogenation and hydrolysis are used to convert essentially all sulfur compounds to hydrogen sulfide. The gas is then cooled and passed into a contactor where the hydrogen sulfide is absorbed by the redox solution and oxidized to commercial sulfur. The purified tail gas is vented to the atmosphere. The reduced redox solution is reoxidized by contact with air and subsequently recirculated to the contactor. Elemental sulfur is removed in the air-blowing step as a froth. The froth is pumped to a sulfur melter where the sulfur is melted under pressure, separated from the redox solution, and transferred to sulfur product storage. The decanted redox solution is returned to the system.

The chemical reactions are:

Hydrogenation and Hydrolysis

$$SO_2 + 3H_2 \longrightarrow H_2S + 2H_2O \qquad (1)$$

$$S + H_2 \longrightarrow H_2S \qquad (2)$$

$$COS + H_2O \longrightarrow H_2S + CO_2 \qquad (3)$$

$$CS_2 + 2H_2O \longrightarrow 2H_2S + CO_2 \qquad (4)$$

Hydrogen Sulfide Extraction

$$H_2S + 1/2\ O_2 \longrightarrow S + H_2O \qquad (5)$$

The purified tail gas is odorless and contains typically less than 1 ppm of H_2S and less than 50 ppm of total sulfur compounds, mainly COS.

The sulfur product is yellow and better than 99.9% pure.

5.19 UNIT 29 - STORAGE

Product storage is provided for 30 days of production. Intermediate process storage for wash oil and process solvent is included to provide for filling the process system plus 4 hours of process flow. These materials will be received at the process temperature of 550°F. To avoid problems of metal expansion, these tanks are designed as insulated spheres, and nitrogen blanketing is provided to prevent oxidation. A naphtha and fuel oil rundown tank of 24-hour production capacity each is provided to store off-specification product prior to rerun to meet specifications.

LPGs and anhydrous ammonia are stored in double-wall, perlite-insulated tanks. Evaporation recovery systems are included as well as refrigeration capacity sufficient to maintain the liquid storage temperature of -40°F for propane and 30°F for butane.

A steam-heated suction heater is provided in each fuel oil tank to improve pumpability of the product after prolonged storage. If necessary, these heaters can be used to heat the tank contents by recirculation. Loading pumps are included for all products.

A storage pile for sulfur is provided. Molten sulfur is conveyed to a tower that carries a pressure gun at the top. The molten sulfur is introduced into the gun and cold water is injected into the output stream. The cooled sulfur is propelled from the gun in "popcorn" form and stored. It is dust-free and easily loaded into hopper cars by front-end loaders.

5.20 UNIT 30 - INSTRUMENT AND PLANT AIR

One motor-driven air compressor with a turbine-driven full capacity spare is provided to furnish 20,000 acfm of 125 psig air for general plant utility use. An air receiver and instrumentation, together with a distribution system, complete the plant air facility.

Nitrogen at 100 psig and dry to minus 40°F dewpoint is normally available in ample quantity from the oxygen plant to supply the pneumatic instrument system. A nitrogen compressor and a storage tank are provided to keep an emergency instrument supply available at 300 psig. This is intended to keep the instrument system operable for orderly plant shutdown in case of catastrophic power failure.

5.21 UNIT 31 - RAW WATER TREATING

5.21.1 INDUSTRIAL WATER TREATING

The water system is shown in Drawing R-31-FS-1. Approximately 18,000 gpm (26,000 acre-ft/year) of water will be pumped from a river. This design is based on the river being about 2 miles from the plant site. Following screening, for trash removal, water flows by gravity to a concrete sedimentation basin at the river bank of about 7 acres, 15 feet deep, which provides about 20 hours residence for settling. The pumps will be mounted in a clear well of this basin.

The entire stream will receive further clarification in two solids contact units with sludge recirculation aided by coagulants and clarifying chemicals.

Clarified water is used as makeup for the cooling water system, which constitutes about 91% of the water requirement. Makeup water for the boilers in the power plant and other areas (about 6% of the total) is filtered and demineralized before joining condensate and flowing to the deaerator and thence along with clean condensate to the boilers. The balance of about 3% needed for various process makeup requirements needs no treatment beyond the clarification step.

5.21.2 POTABLE AND SANITARY WATER SYSTEM

Potable and sanitary water is obtained from a water well feeding a storage tank. A 50-gpm pump with standby ensures reliable supply. The water is sterilized by chlorination to make it suitable for drinking and other sanitary use.

5.22 UNIT 32 - POWER GENERATION

Approximately 210 mW of power is required to meet the demands of the Oil/Gas complex.

Saturated steam is available from the Oil/Gas complex as follows:

Psig	Lb/hr
1200	389,200
600	385,800
150	525,000

This steam can be used for power generation.

On the basis of the foregoing information, a utility power generation heat balance was developed as shown on flow Diagram R-32-FS-1 to use available process steam effectively to meet power demands. Boiler capacity is also required, because the process generated steam is not adequate to meet the total needs of the complex. Four steam generators, each rated at 850,000 lb/hr, 1,200 psig, and 950°F, have been included. Total steam demand from these boiler units for the Oil/Gas complex is 2,700,000 lb/hr, which permits operation at approximately 95% of full capability with one boiler unit out of service.

Electric generation is produced by two condensing turbine generator units having three uncontrolled extractions points for regenerative feed water heating. Extraction pressures have been selected at 600 psig, 300 psig, and 150 psig to integrate extraction pressures with those obtained from process. Using process as well as extraction steam provides feed water at 484°F for the main boiler units as well as for process use.

Automatic extraction condensing steam turbine units were selected for mechanical drive purposes to provide constant 600-psig header pressure required by the smaller straight, condensing mechanical drive turbines.

Arrangement of the steam cycle as shown on Drawing R-32-FS-1 permits use of main turbine extraction steam for process during emergencies, as well as utilizing process steam for regenerative feed water heating during normal operation resulting in maximum usage of available heat while still providing flexibility during operation. Turbine condenser back pressure has been established at 2.5 in. Hg. ABS using 86°F cooling water based on 76°F wet bulb temperature, 10°F approach and a 17.7°F range.

The cycle-integrating process with power generation produces energy at 8,389 Btu/kWh gross equivalent to thermal efficiency of 40.7% requiring a fuel input of 3,200,000 Btu at a boiler efficiency of 85%. The foregoing results in a net station electric heat rate of 9,020 Btu/kWh after correction for station auxiliary consumption and net delivered electric power heat rate of 9,870 Btu/kWh after correction for line losses.

5.23 UNIT 34 - EFFLUENT WATER TREATMENT

Drawing R-34-FS-1 shows equipment and major flows provided to treat the various plant effluents and the pumps required for fire protection. Further detail is given in Section 11, Environmental Factors.

5.23.1 EFFLUENT TREATMENT

Streams originating in curbed process areas are treated as being contaminated with oil and chemicals. They are routed to a gravity separator system, 34-2201, removing all but traces of oil. The water proceeds to the oily water pond equipped with roll skimmers. The clean effluent is used as slag quench water for the gasifiers.

Oily skimmed product is pumped to oily water separator 34-1201. Oil-rich water is returned to the process, and the bottom product, essentially clean water, is sent to the bio-pond for polishing.

Boiler and cooling tower blowdown are received from a separate sewer system in the neutralizing basin, 34-4101. Here the water is neutralized by chemical addition and the chemical oxygen demand (COD) is reduced by aeration. The water is then sent to a combination settler-clarifier unit, 34-2202, where chemicals and other impurities are removed as sludge. The clean effluent is used as slag quench water for the gasifiers. Any excess effluent that may occur from time to time is sent to a final polishing pond.

Sanitary sewage is treated in a two-stage package sewage treatment unit, 34-0801. Treated sewage proceeds to bio-pond 34-5302 where it is treated by aeration to reduce the biological oxygen demand (BOD). The clean effluent from the pond joins the slag quench water system.

Storm water originating in areas that are not contaminated by process liquids (unpaved areas, roads, etc.) is received from a separate clean storm water sewer system. This flow goes directly to the final polishing pond. The clean effluent from this pond is returned to the river.

Sludge generated in the raw water treatment units is used as fill in the mining area. Other sludges are disposed of as landfill.

5.23.2 FIRE WATER SYSTEM

The bio-pond, 34-5302, is used as clear well for three vertical fire pumps of 4,000-gpm capacity each. One pump is driven by an electric motor, one by a steam turbine, and one by a diesel engine. This provides for a fire protection system flow of 8,000 gpm under all but catastrophic circumstances. In case of both electrical and steam system failure, the diesel driven pump supplies 4,000 gpm, which is sufficient for fighting a major fire. A jockey pump is provided to maintain fire system pressure on a continuing basis.

5.24 UNIT 35 - GENERAL FACILITIES

The general facilities provided for the complex form the infrastructure required to create a self-supporting complex. They include, but are not restricted to, the following:

Roads

Railroads

Administration building

Computer facilities

Fire fighting equipment and buildings

Shops and warehouses with equipment

Change houses

Cafeteria

Security facilities (guardhouse, entrance gate house, etc.)

Internal rolling stock (pickups, buses, etc.)

Moving maintenance equipment (mobile crane, cherry pickers, etc.)

Fencing

Landscaping

It was assumed that extra equipment used for major turnarounds of whole units will be rented for the required timespan.

The facilities further include a cooling water system including a natural-draft, hyperbolic cooling tower of 400,000 gpm nominal circulation. The cooling tower has a capability of cooling process and condenser cooling water from 120°F to 86°F with 76°F wet bulb and ambient air. All necessary equipment for cooling water treatment is provided to inhibit corrosion and to control the growth of algae.

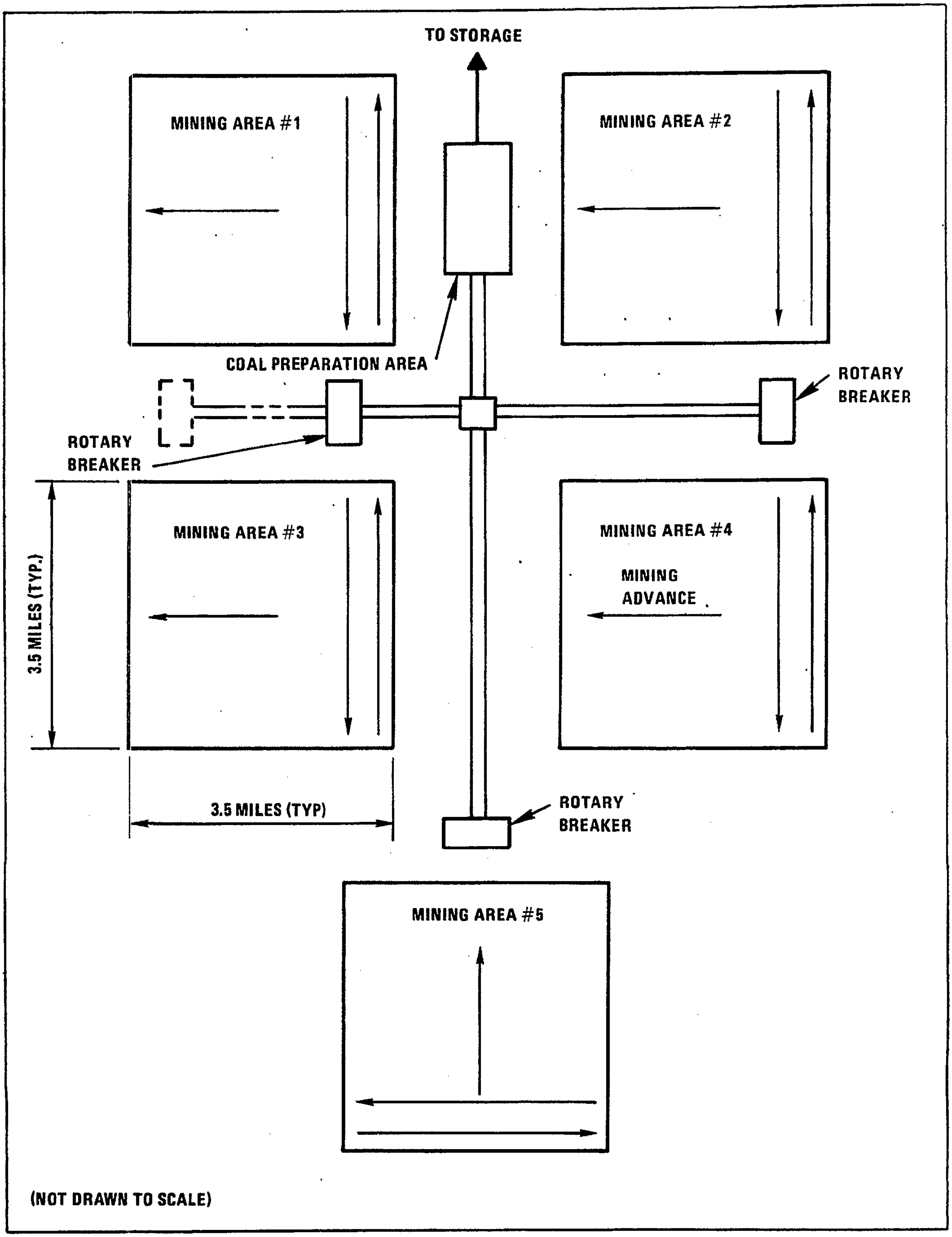


Figure 5-1 - Sketch of Mine and Working Plan

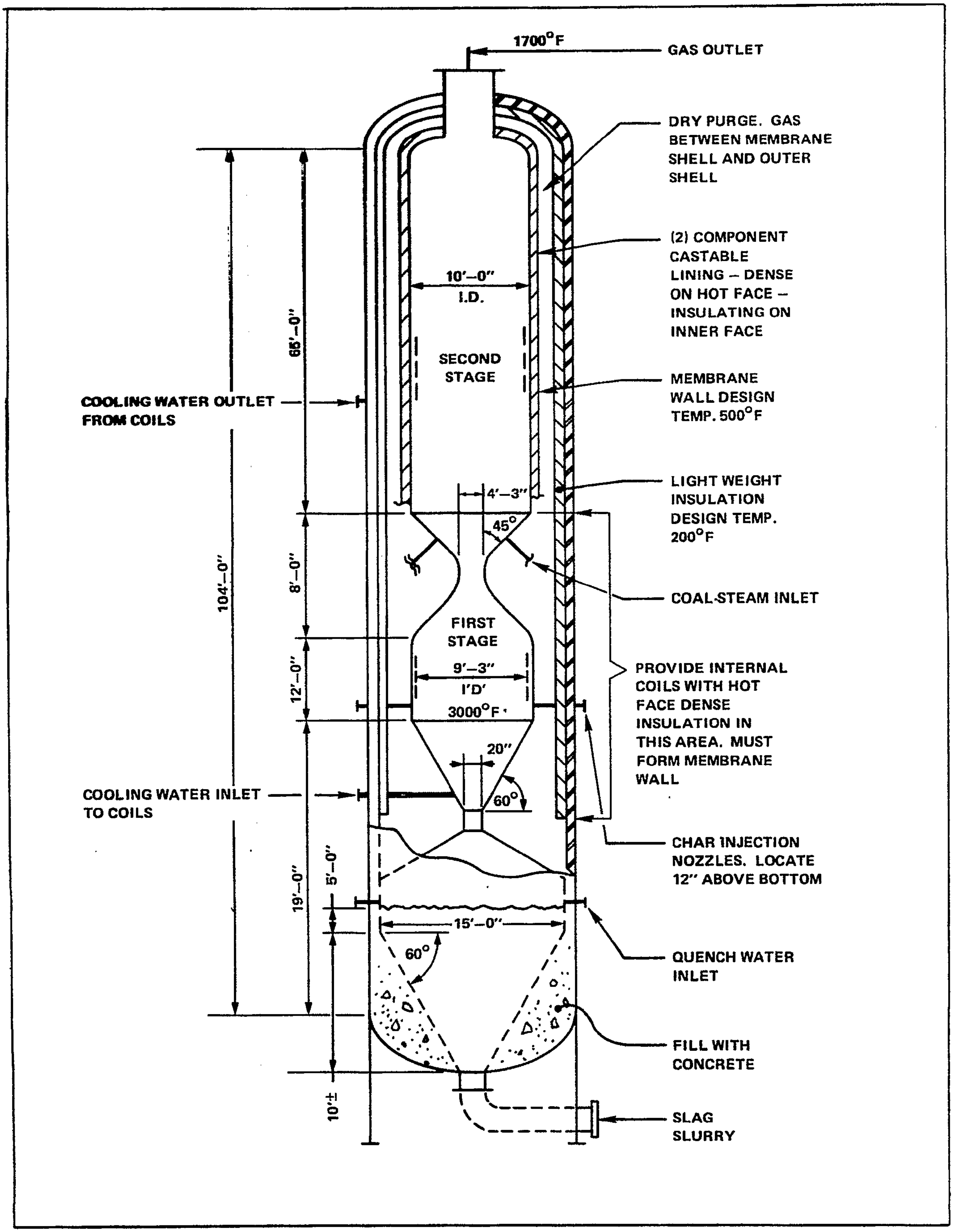
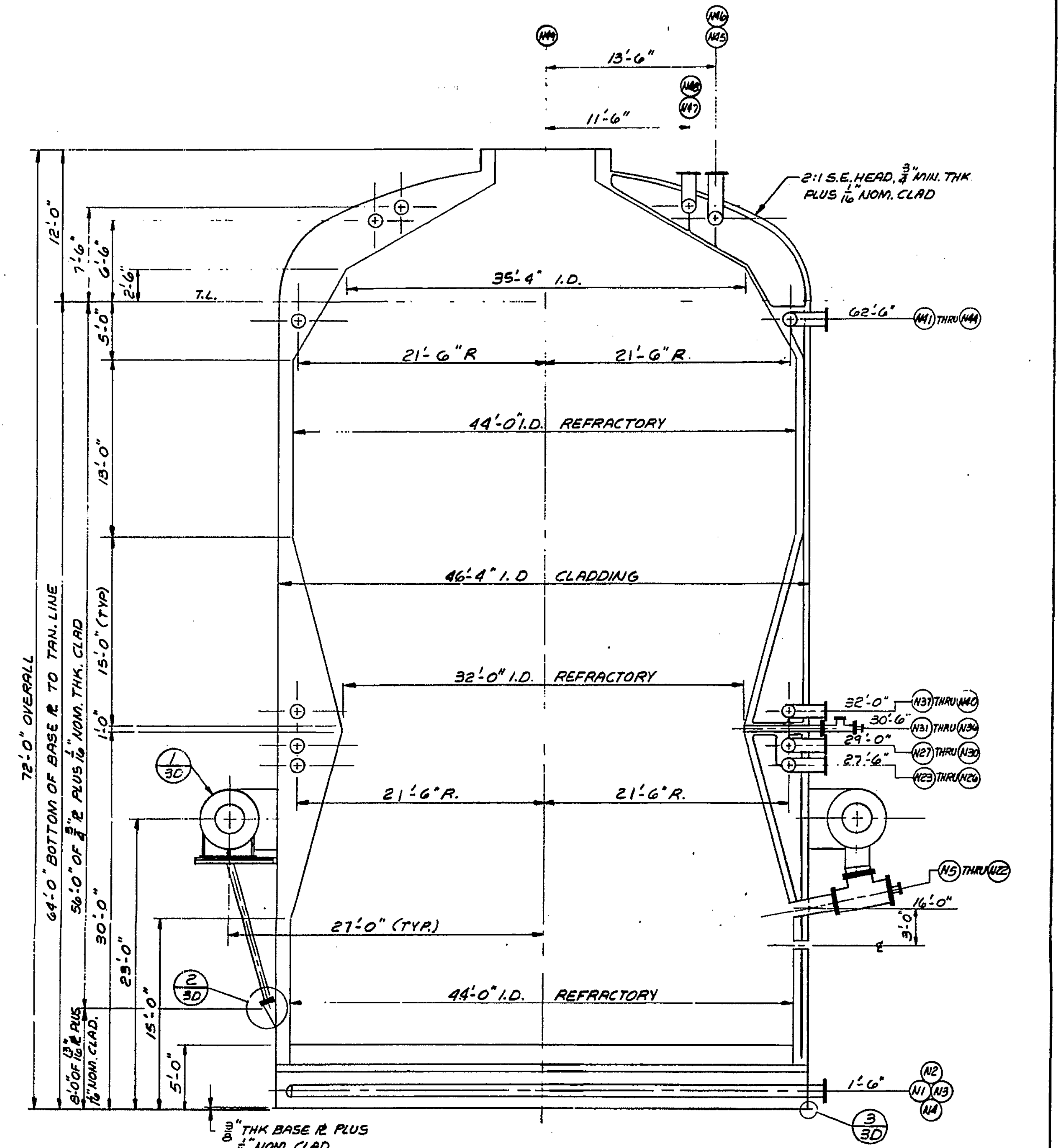


Figure 5-2 - High-Pressure Gasifier Conceptual Design



ITEM	NO. REQ'D	SIZE	SERVICE
N49	1	10'-0"	GAS OUTLET
N47,N48	2	12"	COOLING WATER OUTLET
N45,N46	2	12"	COOLING WATER INLET
N41-N44	4	12"	COOLING WATER OUTLET
N37-N40	4	12"	COOLING WATER INLET
N31-N36	6	10"	STEAM & COAL INLET
N27-N30	4	12"	COOLING WATER OUTLET
N23-N26	4	12"	COOLING WATER INLET
N11-N22	12	16"	STEAM & COAL INLET
N5-N10	6	6"	CHAR INLET
N3,N4	2	12"	COOLING WATER OUTLET
N1,N2	2	12"	COOLING WATER INLET

Figure 5-3 - Fuel Gas Gasifier Conceptual Sketch

Page Intentionally Left Blank