SECTION 5

UNIT DESCRIPTIONS

Descriptions of the separate units which are a part of the POGO conceptual commercial plant design are presented in this section. The following units are described:

Unit No.	No. of Trains	Unit	Flow Sheet No.	Paragraph No.
08	-	Coal Mine	---	5.1
09	-	Coal Preparation	R-9-FS-1	5.2
10	-	Coal Storage, Grinding, and Drying	R-10-FS-1	5.3
11	4	Oxygen Plant	---	5.4
12	3	SRC Dissolving	R-12-FS-1	5.5
13	1	SRC Atmospheric Distillation	R-13/14-FS-1	5.6
14	2	SRC Vacuum Distillation	R-13/14-FS-1	5.7
15	1	Pyrolysis	R-15/18-FS-1	5.8
16	1	Pyrolysis Atmospheric Distillation	R-16-FS-1	5.9
17	1	Sour Gas Compression	R-17/27-FS-1	5.10
18	1	Process Gasification	R-15/18-FS-1	5.11
19	1	Shift Conversion	R-19/20-FS-1	5.12
20	1	Selective Acid Gas Removal	R-19/20-FS-1	5.13
21	3	Heavy Liquids Hydro-treating	R-21-FS-1	5.14
22	1	Thermal Cracking	R-22-FS-1	5.15

Unit No.	No. of Trains	Unit	Flow Sheet No.	Paragraph No.
23	3	Coking	R-23-FS-1	5.16
24	1	Naphtha Hydrotreating	R-24-FS-1	5.17
25	1	Naphtha Reforming	R-25-FS-1	5.18
26	1	Olefinic Gas/Acid Gas Removal	R-26-FS-1	5.19
27	1	Saturate Gas/Acid Gas Removal	R-17/27-FS-1	5.20
28	1	Olefin Recovery and Polymerization	R-28-FS-1	5.21
29	1	Hydrogen Recovery and Purification	R-29-FS-1	5.22
30	1	SNG Purification	R-30-FS-1	5.23
31	1	LPG Fractionation	R-31-FS-1	5.24
32	1	Sulfur Plant	R-32-FS-1	5.25
33	1	Fuel Gas Generation	R-33/34-FS-1	5.26
34	1	Fuel Gas/Acid Gas Removal	R-33/34-FS-1	5.27
35	1	Steam and Power Generation	R-35-FS-1	5.28
36	1	Process Waste Water Treating	F-36-FS-1	5.29
37	-	Shops and Buildings	---	5.30
38	-	Fire Water System	R-38/39/40/41-FS-1	5.31
39	-	Potable and Sanitary Water System	R-38/39/40/41-FS-1	5.32
40	-	Raw Water System	R-38/39/40/41-FS-1	5.33
41	-	Effluent Water Treating	R-38/39/40/41-FS-1	5.34
42	-	Product Storage	---	5.35
43	-	Flare System	---	5.36
44	-	Site Preparation, Roads and Railroads	---	
45	-	Instrument and Plant Air	---	

Process flow diagrams are located in report Section 6. Utilities for each are defined in Section 10 and the equipment lists are presented in Section 13.

5.1 UNIT 8: COAL MINE

The strip mine consists of six integrated mining faces. The average seam thickness is 5 feet and the average overburden depth is 60 feet. The coal is a high volatile C-bituminous variety.

A mining plan was formulated and capital and operating costs were estimated. The economic projection excludes land acquisition and the expense of relocating existing buildings, roads, pipeline and related items that would interfere with the mining operation.

5.1.1 PRODUCTION REQUIREMENTS

The mine will produce 60,000 TPD of run-of-mine (ROM) coal for 330 operation days per year, or 19,800,000 TPY. Design is for a peak rate of 72,000 TPD.

Coal density is 1800 tons per acre-foot. A coal seam 5-feet thick will provide 9000 tons per acre; allowing for losses during mining an average of 6.7 acres will be mined each day.

With an average overburden thickness of 60 feet, overburden stripping requirements will average 648,600 bank cubic yards (BCY) per day or 214,000,000 BCY per year.

5.1.2 MINING PLAN

Approximately 2210 acres of coal per year will be mined. Over a 20-year mine life, 44,200 acres or approximately 70 square miles will be mined out.

The mine has been divided into six separate areas, or mining units. Each unit will develop a pit approximately 3.5 miles in length, and produce 10,000 TPD of coal. A mining unit consists of the following:

- A large stripping dragline, to remove the overburden and expose the coal seam
- Rotary drills to drill the overburden
- Loading and hauling equipment for coal removal
- Auxiliary equipment, such as dozers, graders, scrapers for supporting each operation

The six mining units will be supported by a centralized shop facility and other equipment which will be available to all mine pits as required.

The general mine layout has three primary rotary breakers each located between two adjacent mining areas. Coal will be hauled from the pits to the breakers by truck and after crushing will be transported by belt conveyor to the coal preparation plant. This scheme separates the pits sufficiently to avoid congestion, yet permits close supervision; see sketch - Figure 5-1.

The coal mining width in each pit is 150 feet. With a pit length of 3.5 miles, mining will advance along the cut at about 325 feet per day. Thus each cut will be completed in about 57 days resulting in 6.2 strip cuts in each pit per year.

5.1.3 MINING SEQUENCE

A. Preproduction Stripping

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, 20 feet deep, and will extend the full length of the pit. About 3,200,000 BCY of upper overburden will be removed in this operation. Since 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.

B. Overburden Stripping

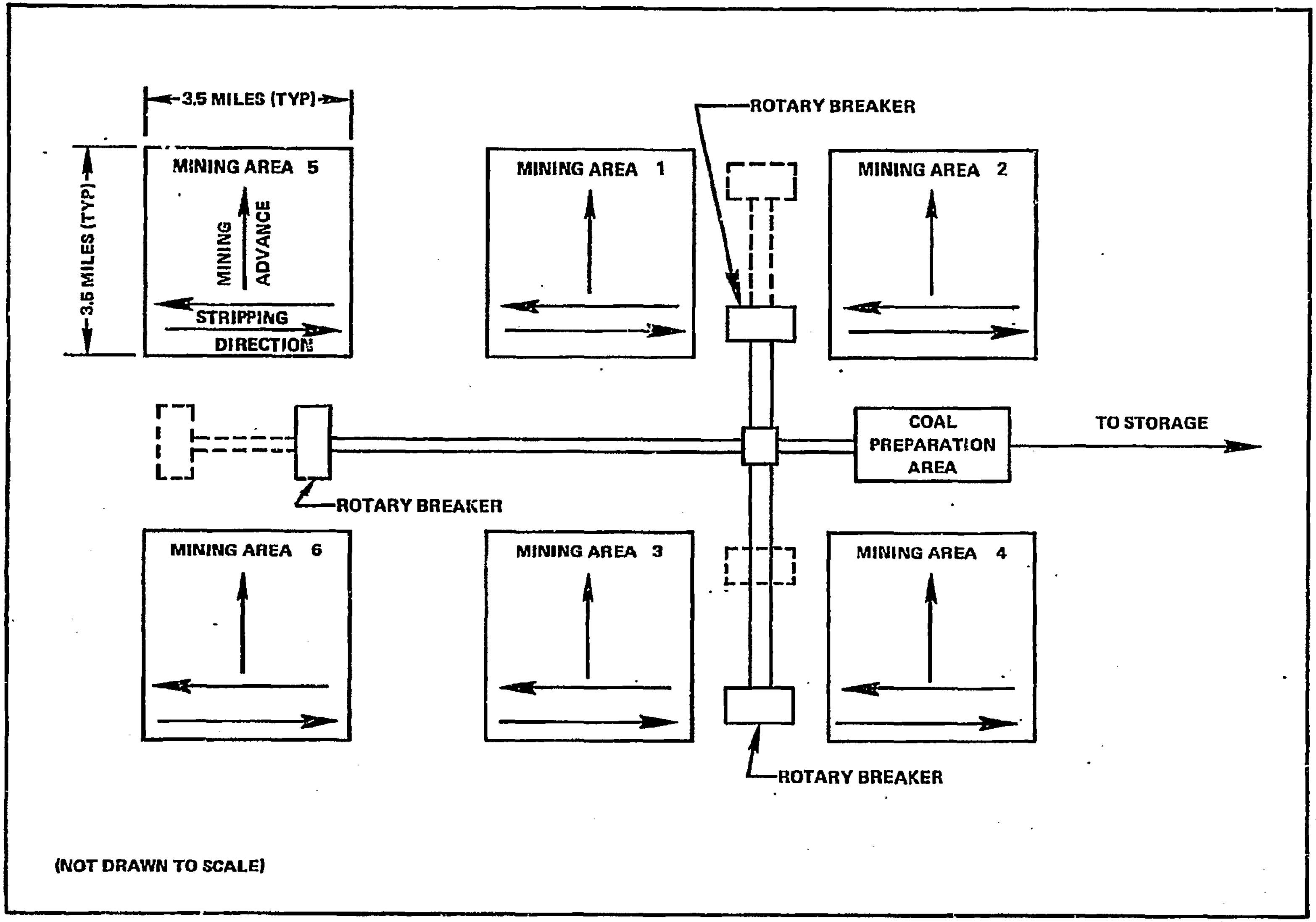
The overburden covering the coal seam consists of two types of material. The upper 20 feet of overburden consists of topsoil and unconsolidated gravels, sands, and soils. The lower 40 feet is made up of limestone and clay-permeated shale that must be drilled and blasted. Since it is required that the mined-out areas be restored to approximately the original surface contour, and that plantings be made on the reclaimed ground, the topsoil and upper overburden must be placed on top of the spoiled lower overburden.

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

An average of about 108,000 BCY per day of overburden will be removed at each pit to uncover the coal. A large stripping dragline, with an operating radius of 292 feet, equipped with a 175-cubic yard bucket, has the capability of removing the required yardage and placing the topsoil portion on top of the spoiled overburden.

The preproduction cut 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, and, with a working radius of 292 feet, it is able to dig and cast



(NOT DRAWN TO SCALE)

Figure 5-1 - Sketch of Mine and Working Plan
Eastern Region - Interior Coal Province

the blasted lower overburden to the spoil area, then swing to the side and make a chop cut to dig the upper overburden from the next adjacent cut. The upper 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, exposing the coal seam, and also removing the upper overburden from the next working cut.

Since the draglines have the capability of spreading the spoiled overburden, a minimum amount of dozer work will be required to level the spoil areas to restore the mined-out areas to their approximate original surface contours.

C. 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 is available to rip any coal that requires ripping prior to loading with the mining shovel.

The mining shovel and haulage trucks will operate at the bottom of the coal seam in each of the six pits. A 15-cubic-yard electric shovel will load coal to the 120-ton capacity bottom-dump coal haulers, which will transport the coal out of the pit to the breaker stations. The breakers will be periodically relocated in relation to the shovel locations in order to minimize truck haulage distances.

D. Waste Disposal

Waste from the rotary breakers and solid waste from the washing 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 9: COAL PREPARATION

The scope of Unit 9 includes a field and transport conveyor system, and a coal preparation plant. The conveyor system is automated to provide a continuous supply of ROM coal. A primary sampling facility is located in the plant structure at the conveyor discharge terminal. This plant is designed to produce both a high-ash (8.0% ash) and a low-ash (6.5% ash) coal. The design objective is to assure the best quality of each fraction by use of optimum size ranges and liquid/solid ratios, and most important, by use of conservative throughput rates for all process units. After size reduction, the raw coal is classified upon vibrating screens to facilitate separation of refuse from coal by gravity difference in succeeding process units. The 3-inch x 5/16-inch high-ash coal is cleaned in Baum type jigs, and the 5/16-inch x 100 mesh, as low-ash coal is cleaned in a three-stage hydrocyclone system. Plant capacity provides for cleaning a nominal 72,000 tons per day of ROM coal, with reject capacity for an approximate total of 44% refuse, from an average of 15% inseam deleterious material, 20% refuse from mining dilution, plus 9% from a 25% ROM surge capacity in plant design.

Flow Sheet R-9-FS-1 shows liquid/solid flow lines, material and water balances, coal size consist, and process equipment. The sequence commences with the conveyor system through unit operations effecting the coal preparation, water treatment to facilitate recovery and recycling through a closed plant water circuit, disposal of refuse, and conveying the two product coals to Unit 10 direct to the plant process, or to stockpile.

Referring to drawing R-9-FS-1, we see that bottom-dump coal haulers are driven over a grizzly with 2-foot square openings, crushing oversize and discharging ROM coal into either of three 400-ton capacity hoppers 9-2601, -2602 and -2603 from which feeders 9-0501, -0502 and -0503 convey it to vibrating bar grizzly screens 9-2703, -2704 and -2705. The oversize from these screens is elevated by flight conveyors 9-0504, -0505 and -0506 to rotary breakers 9-2101, -2102 and -2103. Oversize rock is elevated by conveyors 9-2004, -2005 and -2006 to loadout bins 9-2606, -2607 and -2608 from which coal haulers can return-haul the rock to the mine spoil areas.

The minus 3-inch coal passing breaker perforations is dropped directly upon the transport conveyor where it joins the minus 3-inch originating at the grizzly screens.

ROM 3-inch x 0 coal is conveyed by transport conveyors 9-2002 and -2003 to the preparation plant, where a flight feeder distributes to eight parallel raw coal screens, 9-2706 through -2713. To assist classification, plant water is applied through screen spray bars at approximately 10 gallons per ton of coal.

Oversize from the first and second decks of the raw coal screens is directed to two Baum jigs, 9-3101 and -3102. The minus 3/8-inch x 5/16-inch screen fraction can be temporarily diverted to the cyclone circuit, if jig congestion occurs. Jig refuse is dewatered on vibrating screens 9-2701 and -2702. Screen oversize refuse is conveyed to refuse-loadout bins 9-2604 and -2605. Minus 5/16-inch screen underflow is piped to the secondary cyclone feed sump.

The nominal 3-inch x 5/16-inch high-ash coal, from which minus 1.5/1.6 specific gravity jig product has been removed, is dewatered on sieve bends and vibrating screens. The 3/8-inch x 28 mesh second deck screen fraction is further dewatered in vertical vibrating screen centrifuges, and combined with the first deck oversize 3-inch x 3/8-inch on conveyor 9-2009 to Unit 10, directly to process, or for stockpiling. The 28-mesh x 0 sieve and screen undersize and jig water is piped to the primary cyclone feed sumps, 9-3201 through -3208.

The hydrocyclone circuit is fed primarily from raw coal screens 9-2706 through -2713 third deck 5/16-inch x 0 underflow. The water is applied to facilitate classification upon the raw coal screens; this water plus (1) jig water and 28-mesh x 0 coal from the sieve bends 9-2714 and -2715, and jig coal vibrating screens 9-2716 and -2717, and (2) the 5/16-inch x 0 slurry from secondary hydrocyclone overflows, are combined to provide an optimum liquid/solid ratio for gravity separation in the primary hydrocyclones 9-2744 through -2767. The heavier primary hydrocyclone fraction is combined with jig middlings and jig refuse screen undersize in the secondary hydrocyclone feed sumps 9-3209 through -3212, to feed hydrocyclones 9-2768 through -2779, effecting a closed hydrocyclone circuit.

The specific gravity and/or classification cut point in all hydrocyclones is adjusted by variable speed drives, allowing a maximum range of pressure drop, control of liquid/solid ratios, and preclassification, preceding the desired classification cut points in this plant design. With plant feed coal being classified in hydrocyclones at least twice, the cleaned coal in the primary cyclone overflow is expected to be in the desired 1.5 to 1.6 specific gravity range. Plant losses will be minimized since the heavier hydrocyclone underflow fractions are also recycled for classification.

With the secondary hydrocyclones 9-2768 through -2779 overflows in closed circuit as described above, the heavier refuse fraction underflow is piped to horizontal screen bowl centrifuges 9-2211 through -2214, along with thickener underflow refuse for dewatering. The solids extracted by the centrifuges are conveyed by conveyors 9-2007 and -2008 to the refuse loadout bins 9-2604 and -2605, which are instrumented to permit the truck dispatcher to discharge, as necessary, into coal haulers for subsequent dumping in mine spoil areas. The rock bins 9-2606, -2607 and -2608 are similarly instrumented for backhaul disposal of refuse. The refuse centrifuge centrate is transferred by pump 9-1528 as thickener feed to close the plant water circuit.

The 5/16-inch x 0 cleaned coal from the primary hydrocyclones overflow is dewatered upon sieve bends 9-2718 through -2725 and vibrating screens 9-2726 through -2733. The three deck oversizes, 5/16-inch x 28 mesh cleaned low-ash coal, are further dewatered in vertical vibrating screen centrifuges 9-2201 through -2208, identical to those described above, used to dewater high-ash jig coal. Both centrates are piped to classifying cyclone feed sumps 9-3213 through -3216. The dewatered low-ash coal extracted by the fine coal centrifuges is conveyed via belt conveyor 9-2010 directly to process, or for stockpiling.

In order to separate the 28 mesh x 100 mesh coal combined with fine refuse in the vertical coal centrifuge centrate, and in sieve bend/fine coal screen 28 mesh x 0 underflow, hydrocyclones of lesser diameter are required to achieve the desired cut point. The 10-inch diameter cyclones 9-2780 through -27151 are referenced in the above paragraph as being fed from sumps 9-3213 through -3216. Since the desired separation is a classification largely by size, the 28 mesh x 100 mesh classifying hydrocyclone underflow is a cleaned coal, and is first dewatered by vortex sieves, for final dewatering, along with the fine coal screen oversize in fine coal centrifuges, as described above.

Although the classifying hydrocyclone overflow-to-plant-water head tank 9-1901 is shown on the flowsheet as free of solids, slimes are unavoidable, and do enter the water circuit. Slimes concentration in plant water will of course affect gravity of separation at all relevant process units. To control this, a fourth hydrocyclone circuit, referred to as polishing cyclones 9-27152 through -27175, are employed to deslime the plant water. These polishing cyclones will be controlled to produce a classification by gravity. The overflow from these to the head tank 9-1901 should be reasonably clear of solids. The heavier underflow fraction, combined with the centrate from horizontal screen bowl centrifuges, plus the slag screen 9-2734 underflow, are piped to two lamella settler-thickeners 9-3301 and -3302.

Increased settling rates of suspended solids in the refuse lamella settler-thickeners is accomplished, first by using a lamella (which consists of a pack of parallel inclined tubes directly over a conventional thickener, which increases the projected settling area) and secondly, by chemical treatment of the fine particulates.

The refuse collected in the thickener is a mixture of sands and clays, part of which is colloidal. The sands, being relatively coarse and quick settling, are not an important part of the solids disposal problem. The clay and colloidal particles are effectively settled by addition of flocculating and coagulating agents. This addition is made after the polishing and/or the classifying cyclone feed sumps. A plant water clarity consisting of a maximum of 100 ppm solids content is being achieved in similar applications.

Slag slurry from the Unit 12 gasifier area is dewatered through screen 9-2734. The solids are combined with plant refuse in loadout bins 9-2604 and -2605. The water extracted is in excess of plant makeup water requirements. The surplus is piped to the mine areas for dust control application.

Plant losses incurred in well-designed and -operated coal preparation plants are being held to 1.0 to 1.5 wt %. A conservative allowance of approximately 2.7% for coal losses was used in this design.

5.3 UNIT 10: COAL STORAGE, SIZE REDUCTION, AND DRYING

5.3.1 CLEAN COAL STOCKPILING AND RECLAIMING

Drawing No. R-10-FS-1 shows material flows and equipment for Unit 10. The diagram commences with a schematic of the stockpiling and recovery operation.

The stockpiling system can be operated on a first-in - first-out (FIFO) blending system if necessary. In practice, it is likely that a number of mining units, working in the separate mining areas, will blend the raw coal at least as well as a FIFO or integrated blending system, in handling cleaned coal. Significant handling costs can be saved in conveying cleaned coal directly to process, and stockpiling only the excess. The stockpile then works within the usual definition, that is, for storage and process continuity in case of mining and plant shutdowns.

The direct coal-feed transfer facility, used to supply feed coal to the process, can be utilized as described above due to recent developments in rapid coal ash and sulfur analyses. The ash content has a close correlation with Btu value, so that conventional laboratory testing need only be performed for occasional checking for accuracy against the rapid analyzer readings.

The stockpiling and reclaiming arrangement, with crawler mounted stackers and reclaimers, provides full live storage for a 2-week process supply without additional equipment and manpower for rehandling. Capital cost is minimized with installation at grade level requiring no paving or ballast. Dust control is supplied. Operations are automated, requiring only one operator.

Referring to Drawing No. R-10-FS-1, the handling of 3-inch x 5/16-inch, 8% ash coal and 5/16-inch x 0, 6-1/2% ash coal is similar, although each is handled separately. Prepared coal on conveyors 10-2009 and -2010 is weighed on belt scales 10-3801 and -3802, and sampled on three-stage samplers 10-0901 and -0902 in either the stockpiling or reclaiming mode. Only the conveyors relevant to the particular working areas are operated. The transverse conveyors 10-2003 and -2004 are loaded or unloaded only at transfer points. The transport conveyors 10-2005 through -2008 can be discharged by trippers 10-2019 through -2022 upon one of the self-propelled transfer conveyors (SPTC), 10-2016, -2017 or -2018, each with a working radius of approximately 215 feet. When increased radius is necessary, either SPTCs or bucket wheel stacker reclaimers (BWSR) can be used.

In the reclaim mode, BWSR machines are used. Within their working range of approximately 125 feet, the BWSRs discharge directly into self-propelled hoppers 10-2009 through -2012. When a longer working radius is required, one or any number of SPTCs or BWSRs can be interposed.

Either the SPTC or BWSR can be used in series, but in stacking, the SPTC must be used to receive coal from trippers. Either SPTCs or BWSRs will discharge into hoppers from belt loading in the reclaim mode.

5.3.2 SIZE REDUCTION AND DRYING

Plant conveyor 10-2023, with belt scale 10-3803, metal detector 10-2801, and electromagnet sampler 10-2803, discharges into bin 10-2601, which has a capacity of 1,100 tons. Feeders 10-0501, -0502 and -0503 discharge into two-row cage mills 10-2101, -2102 and -2103, reducing the 5/16-inch x 0 coal to 1/8-inch x 0. Transfer conveyor 10-2025, conveyor 10-2028, and belt scale 10-3806, are instrumented to feed Hydro-Aire dryer 10-3403.

Drying from a nominal 7.7% H_2O to 2.7% is accomplished by using combined contact with hot CO_2 fluidizing gas- and steam-heated tubes in a fluidized bed/steam tube dryer. Dust is collected by dry cyclones and wet scrubbers, and returned with dry 6-1/2% ash coal by elevators 10-2037 and -2038 to bin 10-2613. From there it is transferred by feeders 10-0509 through -0512 to siz-row cage mills 10-2109 through -2112. The 1/8-inch x 0 coal is ground to 70% minus 200 mesh. Elevator 10-2039, and flight conveyor 10-2040, fill 200-ton bins 10-2611 and -2612, which supply the Unit 15 pyrolysis reactor.

From transfer conveyor 10-2025, 1/8-inch x 0 6-1/2% ash coal discharges to conveyor 10-2027-equipped with belt scale 10-3807. The system is instrumented to feed dryer 10-3402, similar to dryer 10-3403 described above. Two elevators, 10-2033 and -2034, and flight conveyors 10-2035 and -2036, fill the 200-ton storage bins 10-2607 through -2610 which supply the Unit 12 solvent refined coal slurry tank.

The 8%-ash coal is carried on plant conveyor 10-2024, with belt scale 10-3804, metal detector 10-2802, and electromagnet 10-2804, to bin 10-2602. Feeders 10-0504 through -0508 discharge to four-row cage mills 10-2104 through -2108, which grind the 3-inch x 5/16-inch coal to 20 mesh x 0. Conveyor 10-2026 is instrumented to feed dryer 10-3401. Dried coal conveyors fill 200-ton capacity storage bins 10-2603 through -2606, which supply the Unit 33 fuel gas gasifier. The dried coal is transferred to the bins via elevators 10-2029 and -2030, and flight conveyors 10-2031 and -2032.

The vertical elevators carrying dry coal from the dryers, the horizontal flight conveyors, and the storage bins, are blanketed with inert gas at a slight positive pressure. The inert gas is provided from the process plant.

Protection against explosions consists of pressure-loss alarms since all coal handling and process equipment is pressurized with inert gas. Gas monitors will be located at any point where unsafe gas concentration or gas loss can occur.

In general, all materials handling equipment is sized at least 25% over nominal capacity to allow for surges.

5.4 UNIT 11: OXYGEN PLANT

This is a plant comprised of four parallel 5,000 TPD modules. Design is established, and tentatively available from commercial air separation plant suppliers. Although this size exceeds that of any installation to date, suppliers have indicated that studies have verified that this scale of commercial oxygen plant modules is feasible.

The oxygen plant will receive 40% of its compressed air requirements from the power generation plant. This will be excess air extracted from the combustion air compressors operating in the power plant combined cycle system.

The oxygen plant will produce 98% purity oxygen as feed for the process gasifier and the fuel gas gasifier in Units 18 and 33 respectively.

5.5 UNIT 12: SRC DISSOLVING

Feed coal is liquefied by contact with a hydrogen-rich gas at elevated temperature 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. A-387E steel can be commercially obtained and welded in thicknesses to 13 inches. The dissolver design uses a 12-3/4-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.

5.5.1 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 product heat interchangers 12-1308, -1338, and -1368, then to the dissolver preheater furnaces. Dissolver feed pumps, 12-1501, -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 preheater furnaces, 12-1401, -1431, and -1461. The gas-slurry mixture enters 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, 27 and 29 are provided for removal of acid gases and recovery of hydrogen. 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 13. A portion of the fractionator bottoms in Unit 13, containing the ash and undissolved coal solids, is returned to constitute approximately two-thirds of the slurry solvent. The remaining one-third of the solvent is produced in SRC Vacuum Distillation Unit 14.

5.5.2 GAS DEPRESSURIZING SECTION

The gases evolved in the three high-pressure separators are collected and cooled from 950°F to 370°F by exchanger 16-1305 (see Unit 16 description in subsection 5.9), and by exchange with dissolver hydrogen feed in exchanger 12-1303. Condensed liquids are collected in the high-pressure intermediate flash drum, 12-1205. Vapors are cooled further by exchange with 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 12-1803, which helps drive the recycle hydrogen compressor. After passing through another flash drum 12-1208, the gas is sent as feed to dissolver acid gas removal, Unit 27, for further treatment.

5.5.3 CONDENSATE DEPRESSURIZING SECTION

The hydrocarbons condensed in the gas depressurizing section are cooled in an exchanger train by air and water cooling. The liquid hydrocarbon stream produced in drum 12-1206 is cooled by water in exchanger 12-1307, and both streams are subjected to a final flashing in the high-pressure condensate surge drum 12-1207. The resulting liquid, which is at a pressure of about

2,000 psig, must be depressurized before being forwarded to Unit 13, SRC Atmospheric Distillation. This depressurizing is accomplished in three stages of hydraulic turbines 12-1511, -1512, and -1513, to recover electrical 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.

5.5.4 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 667°F by exchange with feed slurry in exchangers 12-1308, -1338, and -1368. The three streams are combined and cooled to 550°F in a series of heat exchangers 12-1309 and -1310 and by 16-1304. Some vaporization takes place because of the reduction in pressure. The vapor thus produced is flashed in the high-pressure slurry flash drum 12-1209. 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 12-1207.

The slurry from flash drum 12-1209 is depressurized 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 12-1210, -1213, and -1216. The liquid is fed to the next stage of the hydraulic turbine. The gas is sent to Unit 17, Sour Gas Compression, to join the gas from the expander, 12-1803.

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

5.6 UNIT 13: SRC ATMOSPHERIC DISTILLATION

Solvent separation is achieved by atmospheric distillation. The flow through the unit is shown on Drawing R-13/14-FS-1. The following products are produced:

(1) Naphtha (100°F to 400°F boiling range). Used as feedstock to Unit 24: Naphtha Hydrotreating.

(2) Heavy distillate (400°F to 650°F boiling range). Used as a constituent of the feedstock to Heavy Liquid Hydrotreating Unit 21.

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

A slurry stream and a hydrocarbon condensate stream, coming from the separators in Unit 12 are combined and fed to the main fractionator 13-1101. The slurry flows through the feed-bottom exchanger 13-1301, the feed furnace 13-1401 and enters the lower section of the fractionator at a temperature of 749°F.

The fractionator bottoms are steam stripped (0.1 lb of steam per gallon of bottoms). The design is based on an overflash of 5% of the feed. The fractionator is operated at 17.1 psig and a flash zone temperature of 749°F. It has 11 sieve trays and 6 baffle (shed) trays.

The column overhead product is cooled to 270°F in overhead condenser 13-1302, and the hot reflux is pumped back from reflux drum 13-1201 to the top tray. The remaining vapors are cooled, condensed, and separated at 120°F in the overhead receiver 13-1202, to produce naphtha and ammonia-contaminated water. The sour gas leaving the receiver is combined with the vent gas from Unit 14, compressed by compressor 13-1801 and forwarded to Unit 17. The naphtha is transferred by pump 13-1509 to Unit 24: Naphtha Hydrotreating.

The heavy distillate is withdrawn from the side of the fractionator and stripped of light ends in distillate stripper 13-1102. The column-operating conditions are adjusted to give the desired cut point between the naphtha and the heavy distillate. The heavy distillate product is pumped hot from reboiler 13-1305 to Unit 21.

The fractionator has one heat-removal section, which resulted in decreasing the diameter of the top rectifying section considerably. The pumparound duty is used to reboil fractionators in Units 24 and 25 and to generate 50 psig steam in exchanger 13-1304.

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 650°F. The stripping section of the tower has four baffle (shed) trays, needed to handle contained solids.

The bottoms are split into slurry recycle to Unit 12 and net bottoms. The net bottoms flow under pressure at 741°F to SRC Vacuum Distillation Unit 14. The slurry recycle is pumped to the feed-bottoms exchanger 13-1301 where it is cooled before being forwarded to Unit 12. A small slipstream is bypassed around heat exchanger 13-1301 to reboil the atmospheric heavy distillate in reboiler 13-1305.

5.7 UNIT 14: SRC VACUUM DISTILLATION

Drawing R-13/14-FS-1 shows in detail the flow of the SRC atmospheric bottoms through the vacuum distillation fractionator to separate the recoverable liquids from the coal residue and ash. This unit produces the following products.

(1) Vacuum distillate (boiling range 650°F-1200°F) which is used as distillate solvent in Unit 12 and as a constituent of the feedstock to Unit 21.

(2) Vacuum bottoms slurry containing undissolved coal residue and ash as well as the liquids boiling above 1200°F which is used as feed to Pyrolysis Unit 15.

The net atmospheric bottoms stream from Unit 13 is combined with the atmospheric bottoms stream from Unit 16: Pyrolysis Atmospheric Distillation to form the total feed to this unit. The total feed is split equally and processed in two parallel trains. The feed is heated to 825°F in vacuum tower feed furnaces 14-1401 and -1431 and fed to the lower section of the Vacuum Fractionators 14-1101 and -1431.

The flash zone is operated at 32 mmHg and 825°F. Steam is injected to reduce the hydrocarbon partial pressure to about 15 mmHg to obtain the required vaporization. The solids and flashed liquid are removed from the small boot at the bottom of the tower and pumped hot to Unit 15: Pyrolysis.

The vacuum distillate is withdrawn from the side of the fractionator as two streams, a light vacuum distillate and a heavy distillate. This is done so that the majority of the heat removed in the pumparounds would be at a sufficiently high level to produce steam. The light and heavy vacuum distillates are combined into a single stream with a boiling range of about 650°F to 1200°F. The larger fraction of this stream is returned to Unit 12 as the distillate solvent. The remainder is forwarded hot to Unit 21: Heavy Liquid Hydrotreating as the main feedstock constituent.

The heavy vacuum distillate pumparound duty is used to produce 150 psig steam in exchangers 14-1303 and -1333 and 50 psig steam in exchangers 14-1304 and -1334. In addition, a slipstream is bypassed around the steam generators to exchange heat with the feed to Unit 16. The light vacuum distillate pumparound duty is used to preheat boiler feed water in exchangers 14-1302 and -1332. This stream is then further cooled in air coolers 14-1301 and -1331.

The pressure at the top of the fractionator is maintained at 15 mmHg by vacuum system package 14-0801. The noncondensable gases from 14-0801 are forwarded to Unit 13 for a single stage of compression and then sent to Unit 17: Sour Gas Compression. The naphtha is sent to Unit 24: Naphtha Hydrotreating and the water is sent to Unit 36: Process Wastewater Treating.

5.8 UNIT 15: PYROLYSIS

Flash pyrolysis is accomplished in an entrainment type upflow reactor operating at 1100°F and 500 psig. The process is shown in flow diagram R-15/18-FS-1. A sketch of the pyrolysis reactor is shown in Figure 5-2.

The feed coal is ground to 70% minus 200 mesh. The ground coal is injected into the feed section of the pyrolyzer 15-2501 by two compression type screw feeders 15-2001 and -2002. The heavy oil slurry coming from the vacuum distillation unit at 810°F is pumped to the top of the feed section of the pyrolyzer at two points 180° apart. The heavy oil slurry contains solids, such as unreacted coal from the SRC section and fine primary pyrolysis char carryover, suspended in 1200°F-plus oil. Both coal and slurry are fed to the pyrolyzer through atomizing nozzles, using high pressure carrier gas for atomization.

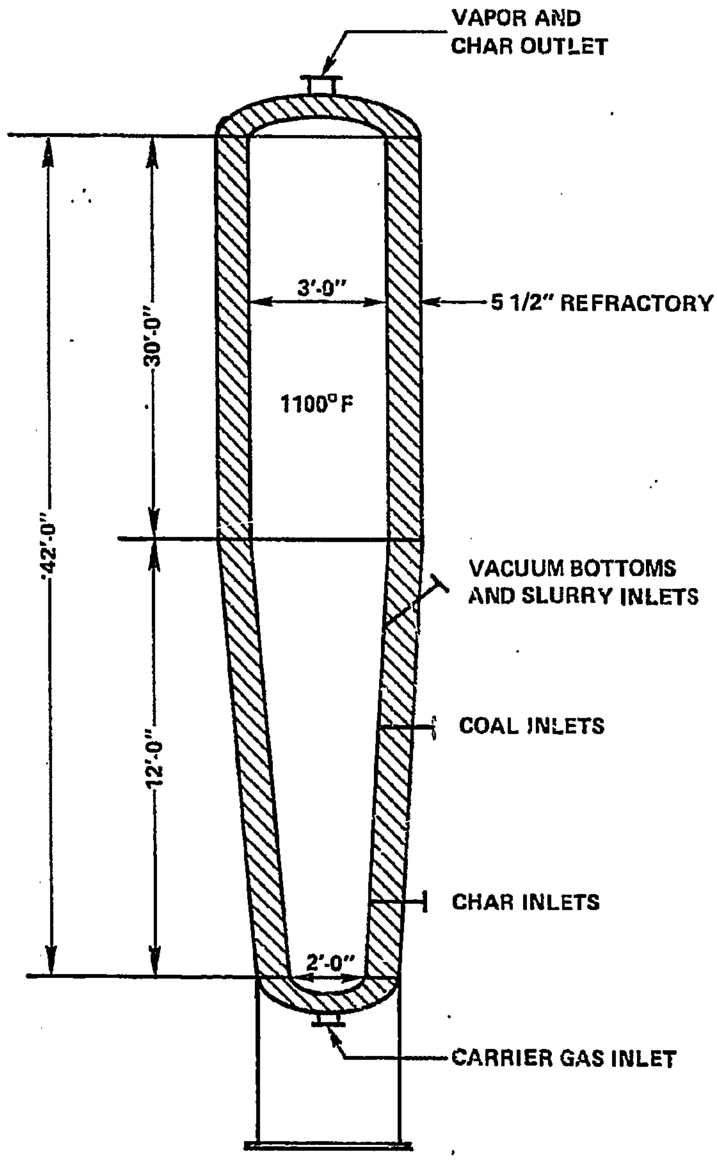


Figure 5-2 - Pyrolyzer

Heat for pyrolysis of the coal is supplied by means of a circulating stream of hot char which transports heat from the process gasifier to Unit 18 to the pyrolyzer. Besides being a heat carrier, the char also counteracts any agglomerating tendency of the feed coal. The recycle char leaves the second stage of the gasifier at 1800°F, after separation from the gas, enters the feeding section of the pyrolyzer by gravity and, together with the coal and the oil slurry, is dispersed and carried upward by the hot carrier gas. Much of the fluidizing gas is generated in the pyrolyzer, but to assure proper fluidization and entrainment, a portion of the product gas is recycled following the removal of pyrolysis liquid products.

Residence time in the pyrolyzer is about 0.7 seconds. The pyrolysis products together with the recycle char and the carrier gas leave the top of the pyrolyzer at 1100°F.

Two high energy cyclone stages 15-2201, -2202 and an ionizer/collector 15-2203 are provided and remove 99.7 wt % of the entrained solids in this stream. The recycle char, leaving the first stage cyclones 15-2201, is gravity fed to the second stage of the process gasifier where it is heated to 1800°F by directly contacting the hot gases generated in the first stage. It is further separated from the gas and finer particles through the Unit 18 two stage cyclone system and recycled to the feeding section of the pyrolyzer as a heat carrier. The desired temperature profile in the pyrolyzer is maintained by temperature control of the pyrolyzer overhead stream, which in turn controls the amount of pyrolysis recycle char, delivered to the second stage of the Unit 18 gasifier for heating. The finer pyrolysis char from the second stage cyclones 15-2202 and the ionizer/collector 15-2203 is gravity fed to the first stage of the process gasifier where it is gasified by reaction with steam and oxygen.

The pyrolysis vapors leaving the ionizer/collector 15-2203, contain approximately 2% of the primary pyrolysis char produced in the pyrolyzer. These are quenched and fractionated in the high pressure fractionator 15-1101. In the bottom section of the fractionator the heavy oil is condensed at 800°F by direct contact cooling of the 1100°F pyrolysis vapors with a circulating stream of heavy oil slurry which is cooled externally to about 620°F in steam generator 15-1305.

The heat removed generates 1300 psig steam. The heavy oil slurry bottoms from the high pressure fractionator 15-1101 are flashed in the low pressure flash drum 15-1205. The resulting vapor is separated and flows to the low pressure contactor 15-1102. The 800°F oil slurry bottoms from the low pressure flash drum 15-1205 is conducted to the main fractionator of Unit 16: Pyrolysis Atmospheric Distillation.

The heat content of the high pressure overhead vapors is utilized to preheat the carrier gas and generate different levels of steam in the steam generators 15-1302 and -1303. By cooling the overhead vapor from 680°F to 120°F the pyrolysis oil along with some water is condensed and accumulated in the high pressure overhead receiver 15-1202. The pyrolysis sour water, containing NH_3 and some H_2S, is separated from the oil and delivered to Unit 36: Process Waste Water Treating. The light pyrolysis oil leaving receiver 15-1202 is flashed in the low pressure contactor 15-1102 and simultaneously stripped with the vapors from the low pressure flash drum 15-1105. The raw pyrolysis oil is then pumped to Unit 16 for fractionation. The low pressure contactor overhead vapors are delivered to Unit 16 for compression and sent to Unit 26 for gas treating. The uncondensed vapors from the high pressure fractionator overhead receiver 15-1202 are further cooled to 100°F in the vapors trim cooler 15-1307, and the net production of pyrolysis sour gas is forwarded to Unit 26 for acid gas removal.

The cold recycle carrier gas is compressed by compressor 15-1801 and preheated to 450°F in the heat exchanger 15-1301. A portion of this gas, after being compressed to a higher pressure by compressor 15-1802, is used as the atomizing agent in the coal and slurry feeding nozzles of the pyrolyzer. The remaining warm carrier gas is heated further to 850°F by heat exchange with the process gasifier syngas in heat exchanger 15-1306 located in Unit 18 and delivered to the bottom of the pyrolyzer.

5.9 UNIT 16: PYROLYSIS ATMOSPHERIC DISTILLATION

Drawing R-16-FS-1 shows the flow of the pyrolysis liquids through this unit. The following products are produced:

(1) Naphtha (100°F to 400°F boiling range); used as a constituent of the feed stock to Unit 24: Naphtha Hydrotreating.

(2) Middle Distillate (400°F to 650°F boiling range): used as a constituent of the feed stock to Unit 21: Heavy Liquid Hydrotreating.

(3) Atmospheric fractionator column bottoms containing ash and char as well as all liquids with a boiling range above about 650°F. Atmospheric bottoms are forwarded to Unit 14: SRC Vacuum Distillation for recovery of higher boiling liquids.

The pyrolysis low pressure contactor bottoms is the major portion of the feed to this unit. This stream is preheated by exchange with the column overhead in the fractionator condenser 16-1301. Additional preheat is obtained by exchange with streams in Units 12 and 14 in heat exchangers 16-1303, -1304, and -1305. A slurry stream from Unit 15: Pyrolysis is combined with the preheated low pressure contactor bottoms and is fed to the lower section of the column at about 625°F.

The column bottoms are steam stripped using 0.1 pound of steam per gallon of bottoms. The design overflash is 5% of the feed. The fractionator is operated at a flash zone temperature of 625°F and a pressure of 14.3 psig. The column has 6 sieve trays and 8 baffle (shed) trays.

The column overhead product is cooled and condensed to 290°F in heat exchanger 16-1301 and then to 120°F in air cooler 16-1302. The vapor, liquid and water are separated in overhead receiver 16-1203. The vapor is combined with the low pressure vapor from Unit 15 and compressed to 465 psig in the three-stage acid gas compressor 16-1801 and forwarded to Unit 26: Saturate Gas Acid Gas Removal. The liquid provides reflux for the column and the naphtha product, which is pumped by pyrolysis naphtha pump 16-1507 to Unit 24: Naphtha

Hydrotreating. The sour water is forwarded to Unit 36: Process Wastewater Treating by water condensate pump 16-1509.

The middle distillate is withdrawn from the side of the column and steam stripped in mid-distillate stripper 16-1102. The higher boiling distillate is removed from the bottom of this column and sent to Unit 21: Heavy Liquid Hydrotreating.

The fractionator bottoms are a major product of the distillation and contain all the ash and char plus hydrocarbons boiling above 650°F. This stream is steam stripped using 4 baffle (shed) trays in the stripping section of the column. The baffle trays are used to properly handle the solids contained in this stream. The bottoms are pumped at 617°F by pyrolysis atmospheric bottoms pump 16-1501 to Unit 14: SRC Vacuum Distillation.

5.10 UNIT 17: SOUR GAS COMPRESSION

Drawing R-17/27-FS-1 shows in detail the flow through equipment provided to compress the mixture of sour gas streams from Unit 12: SRC Dissolving, Unit 13: SRC Distillation, Unit 21: Heavy Liquid Hydrotreating and Unit 24: Naphtha Hydrotreating for delivery to Unit 27: Saturate Gas Acid Gas Removal.

The hot, low pressure gases from Units 13 and 21 are combined and cooled to 120°F in low pressure air cooler 17-1301. This stream is combined with a cold, low pressure stream from Unit 21, compressed in LP compressor 17-1801, and cooled in air cooler 17-1302 to 120°F. Intermediate pressure streams from Units 12 and 24 are added and the total stream is compressed to about 500 psig by the intermediate pressure compressor 17-1803 and cooled in air cooler 17-1303. The gas streams from Units 12 and 21 which are at about 500 psig are added and the total stream is compressed to about 1100 psig by the high pressure compressor 17-1805. After cooling to 120°F in air cooler 17-1304, the gas stream is combined with the high pressure gas streams from Units 12, 21, and 24. The total stream is sent to the high pressure scrubber, 17-1204, and the gas forwarded to Unit 27: Saturate Gas Acid Gas Removal. All condensates produced in the process are collected and pressure transferred to Unit 24: Naphtha Hydrotreating.

5.11 UNIT 18: PROCESS GASIFICATION

Hydrogen required for hydrogenation and solvation of coal in the SRC dissolver is generated in the process gasifier by gasification of pyrolysis char with steam and oxygen. The gasifier also serves as a char heater for transferring heat to the pyrolyzer. The process is shown on flow diagram R-15/18-FS-1.

The gasifier is a two-stage entrainment slagging type, shown in Figure 5-3. Operating pressure is about 490 psig.

5.11.1 PROCESS GASIFIER

Pyrolysis product char, recovered from the solids removal system in Unit 15: Pyrolysis flows by gravity to the first stage of the process gasifier 18-2501 through atomizing nozzles along with high pressure steam and

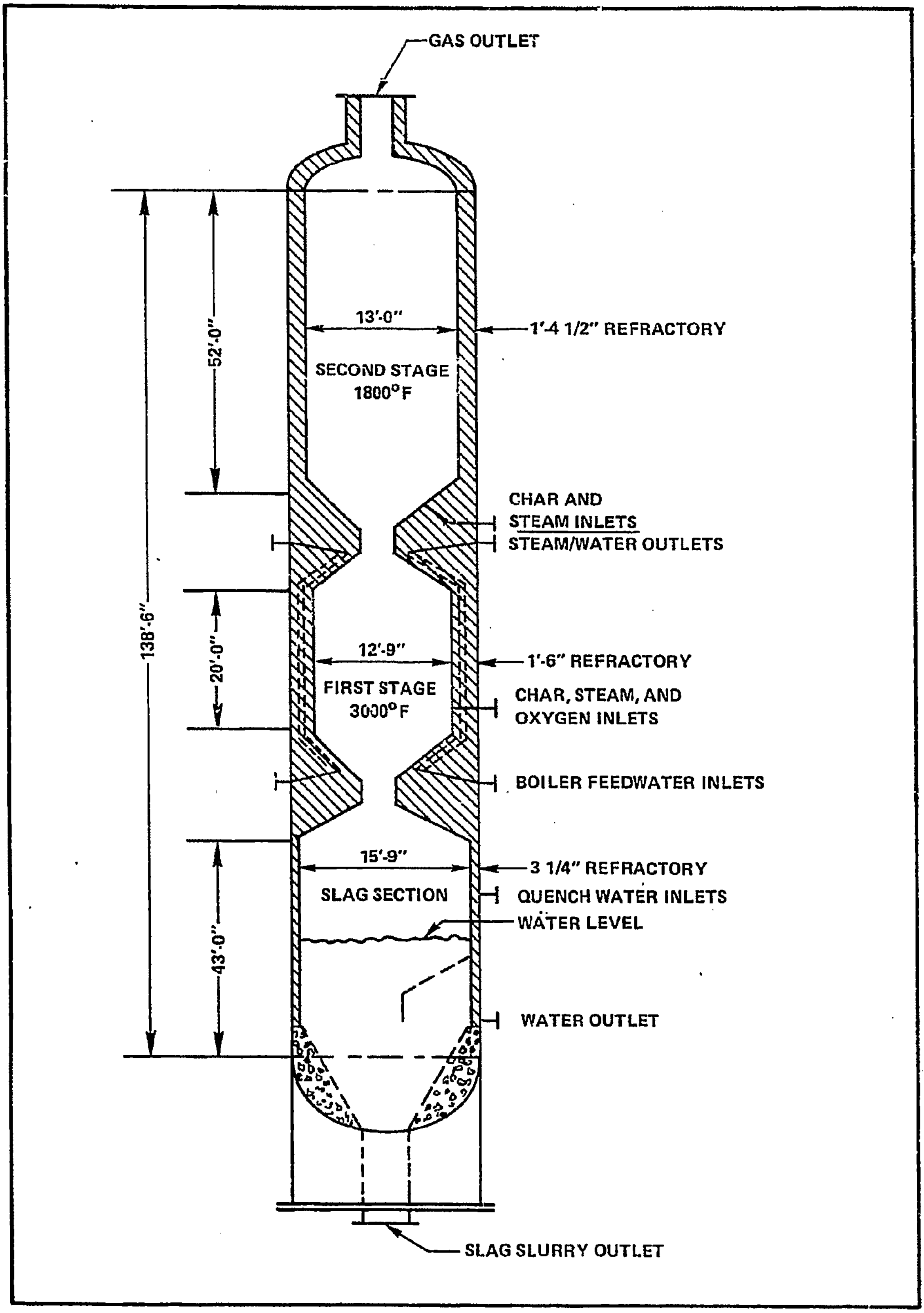


Figure 5-3 - Process Gasifier

preheated oxygen. The char is gasified at about 3000°F by reaction with steam and oxygen; raw synthesis gas is produced. The second stage of the gasifier operates at a product gas exit temperature of 1800°F and functions also as a recycle char heater. The required pyrolysis recycle char from the cyclone 15-2201 is gravity fed to the second stage of the gasifier at 1100°F. Here the char is heated to 1800°F by direct contact with the 3000°F gas rising from stage one.

The gas/char mixture leaves the top of the gasifier at 1800°F and enters the first stage cyclones 18-2201, -2202, -2203, where 94% of entrained solids are removed and transported by gravity to the pyrolyzer as a heat carrier. Another 4.5% of the solids entrained in the gasifier off gas is recovered in the second stage cyclones 18-2204, -2205, -2206 and returned to the first stage of the process gasifier for gasification.

A slag quench pot is located beneath the gasifier combustion zone. Molten ash at approximately 3000°F slides down the sides of stage one and flows through the bottom opening into the quench zone. Here the slag is quenched with 250°F water to approximately 470°F. The generated 500 psig steam under these conditions rises up into stage one and serves as part of the reaction stream. Water at a high rate is circulated and injected through multiple nozzles into the quench pot in order to keep the outlet slag slurry temperature at about 470°F. The gasifier slag slurry underflow passes through the lump remover 18-2210 and enters the slag slurry receiver 18-1203, where it is depressurized and degassed. The slag/water slurry is pumped from the bottom of the receiver at 250°F to the Unit 9: Coal Preparation slag screen for dewatering.

5.11.2 GASIFIER HEAT RECOVERY AND RELATED EQUIPMENT

Syngas, contaminated with char, amounting to 1.5% of the solids entrained in the gasifier off gas, leaves the second stage cyclones 18-2204, -2205, -2206 at 1800°F. The gas is cooled at 770°F in the 1300 psig steam superheater 18-1301, warm pyrolysis carrier gas heat exchanger 15-1306, 1300 psig steam boiler 18-1602 and BFW preheater 18-1303. The solids remaining in the gas are recovered in the electrostatic ionizer/collector 18-2207 and returned to stage one for gasification. The resulting near nil solids content gas stream is sent to Unit 19: Shift Conversion.

A boiler feed water system and three steam drums are provided to utilize the heat from the gasifier effluent gas stream and from the walls of the lower stage of the process gasifier.

The 800 psig steam drum 18-1202 provides part of the steam required for the gasifier reactions. The feed supply to this system is sour water stripper bottoms.

The 1300 psig steam drums 18-1201 and 18-1204 provide steam to the 1300 psig steam superheater 18-1301. The first steam drum 18-1201 utilizes the heat released to the gasifier lower section wall tubes. The steam drum 18-1204 is utilizing the raw syngas heat. Part of the 1300 psig superheated steam from superheater 18-1301 is used for preheating the oxygen in the heat exchanger 18-1302. The feed to both 1300 psig steam drums 18-1201 and 18-1204 is boiler feed water, preheated in the BFW preheater 18-1303. The blowdown from the oxygen preheat exchanger 18-1302 is also pumped to the steam drum 18-1204.

The operation of the process gasifier is closely related to the operation of the pyrolyzer. The coal feed rate to the pyrolyzer determines the char quantity feeding the gasifier. Steam and oxygen are flow controlled to maintain proper heat level in the gasifier combustion zone. Steam is flow-controlled to the upper stage for atomization of char feed. The gasifier overhead temperature serves as the control override to trim oxygen flow. The quantity of steam generated in the wall cooling tubes of the lower stage reflects the temperature in the combustion zone and, in turn, determines the steam flow into it.

5.12 UNIT 19: SHIFT CONVERSION

Drawing R-19/20-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. This involves a conversion of 91% of the carbon monoxide in the feed gas stream.

The hot, essentially dust-free, gas from Unit 18: Process Gasification having a H_2:CO molar ratio of 0.7 is combined with steam and fed to the first stage of a three-stage reactor arrangement using cobalt-molybdate shift catalyst. Four identical trains are required to process the total gas stream. The CO shift-conversion catalytic reactors increase the H_2:CO molar ratio in the sour gas by means of the "water gas shift" reaction:

$$CO + H_2O \longrightarrow CO_2 + H_2$$

The partially shifted gas leaving the first shift reactors 19-2501, -2521, -2541 and -2561 is cooled to 600°F in the first shift effluent boilers 19-1301, -1321, -1341 and -1361. The gas is shifted further in the second shift reactors, 19-2502, -2522, -2542 and -2562 and the effluent is cooled to 600°F in the second shift effluent boilers 19-302, -1322, -1342 and -1362. The final shift takes place in the third shift reactors 19-2503, -2523, -2543 and -2563. The effluent is cooled to 486°F in the third shift effluent boilers 19-1303, -1323 -1343 and -1363. Further cooling and condensing takes place in the boiler feedwater heater, an air cooler and finally a water cooler. The sour condensate is separated from the gas in the shift effluent knockout drums 19-1201, -1221, -1241 and -1261, and the gas having a H_2:CO molar ratio of 17.9 is forwarded to Unit 20: Selective Acid Gas Removal.

Approximately 77% of the 450 psig steam required by the shift conversion process is produced in the shift effluent boilers. The remainder of the required steam is obtained from the plant 600 psig steam system.

5.13 UNIT 20: SELECTIVE ACID GAS REMOVAL

Following the sour shift conversion, the 53% (by volume) hydrogen gas stream is treated to remove carbon dioxide, hydrogen sulfide and organic sulfides. The Rectisol process was used as a representative proprietary selective acid gas removal system employing a physical solvent. Drawing R-19/20-FS-1 contains the material balance for this process.

The clean gas, containing 92% (by volume) hydrogen, is used as the makeup hydrogen feed stream for the SRC dissolvers in Unit 12. The hydrogen sulfide-rich stream is used as part of the feed to Unit 32: Sulfur Plant. The remaining gas consists primarily of carbon dioxide, nitrogen and traces of hydrogen, methane and carbon monoxide.

5.14 UNIT 21: HEAVY LIQUIDS HYDROTREATING

This process is depicted by flow diagram R-21-FS-1. Heavy liquids from Units 13, 14 and 16 are fed into the feed surge drum, 21-1203. The output from this drum is pumped to three identical trains for the reactor hydrogenation and the three subsequent flash separations. The liquids from the low pressure separator drum of each train are combined into one stream for the fractionation operation.

5.14.1 REACTOR HYDROGENATION AND FLASH SEPARATIONS

Each feed train from the surge drum is combined with a preheated recycle and hydrogen makeup stream. After being heated in exchanger 21-1302, -1331 and -1361 with the reactor effluent, this stream is heated to 750°F by furnaces 21-1401, -1402 and -1403 before entering the reactors at a pressure of approximately 2740 psig. Each train has two reactors 21-2501 and -2502; 21-2531 and -2532; 21-2561 and -2562 in series that use a cobalt-molybdenum catalyst.

Water is injected into the reactor effluent, which is subjected to air-cooling prior to product separation at 2655 psig and 120°F in the high pressure separator drum 21-1204, -1234 and -1264. The condensed water with dissolved hydrogen sulfide and ammonia is separated and sent to Unit 36 - Sour Water Treating. Most of the gases evolved are used for reactor recycle but about 312 scfh is sent to Unit 17: Sour Gas Compression in order to pressurize for subsequent sweetening. The hydrocarbon liquid is again flashed at 570 psig and then 70 psig in the intermediate and low pressure separator drums respectively 21-1205, -1235 and -1265; 21-1206, -1236 and -1266. Gases evolved from these separations are sent to Unit 17: Sour Gas Compression. The hydrogen liquid from the three low pressure separators is combined for subsequent heating as feed to the fractionator 21-1101.

5.14.2 FRACTIONATION

The feed to the 15-tray fractionator 21-1101 is first heated from 120°F to 410°F by heat exchange with the fractionator overhead vapor 21-1305, the distillate 21-1307, and the bottoms product 21-1308. It is finally heated in fired heater 21-1402 to 626°F.

The fractionator overhead vapor is air-cooled in condenser 21-1306 to 120°F. The naphtha and reflux are separated from the offgas in the overhead receiver 21-1209. The offgas is compressed in compressor 21-1803 to 73 psig and sent to Unit 17: Sour Gas Compression. The naphtha is sent to Unit 24 - Naphtha Hydrotreating. The condensed water is sent to Unit 36: Sour Water Treating.

A 4-tray side stripper 21-1102, which is fed from the ninth tray of the fractionator, is used to produce the distillate. The distillate is air-cooled in 21-1309 to 120°F and sent to storage as salable 19.4° API fuel oil. The fractionator bottoms are sent to Unit 22: Thermal Cracking.

5.15 UNIT 22: THERMAL CRACKING

Thermal Cracking Unit 22, shown on Process Flow Diagram Drawing No. R-22-FS-1, is designed to recover light hydrocarbons from the heavy fuel oil, and produce thermal tar feed to the coking unit.

The unit consists of two cracking furnaces, a reaction chamber, evaporator, and a fractionator.

Heavy fuel oil feed from the stripper in Unit 21: Heavy Liquids Hydrotreating is preheated in a series of heat exchangers, 22-1301, -1302 and -1304. It is then joined by the flashed distillate from accumulator 22-1204 and introduced into the stripping section of the fractionator 22-1102. In this section, the feed is contacted with the vapors from the evaporator 22-1101 before it is charged to the fuel oil furnace 22-1401. A gas oil stream is drawn off the fractionator to be used as recycle and quench. The recycle gas oil is heated by the flash drum overhead in 22-1305 and charged to the gas oil furnace 22-1402. The quench gas oil is cooled in heat exchangers 22-1301 and -1303 and used for quenching the reaction chamber effluent and the evaporator top tray vapors.

The combined top transfer oil from the two furnaces is a mixture of liquid and vapor, and is discharged at essentially full cracking temperature into the top of the reaction chamber 22-1202. The use of the reaction chamber increases the severity of cracking of the lighter gas oil component of the raw feed, and decreases the severity of cracking of the fuel oil component. This results in production of cracked heavy fuel oil of lower sediment content and increased viscosity, and of cracked gasoline with increased volatility and higher octane number. Use of reaction chambers also results in increased plant capacity due to decrease in the heat requirement for cracking, to reduction in tube coking, and to improved furnace conditions.

The reaction chamber effluent is quenched with gas oil and fed to the evaporator 22-1101 wherein the vapor and liquid are separated. The overhead vapor is passed directly to the fractionating column 22-1102, whereas the heavy liquid oil flows to an auxiliary flash drum 22-1203. The thermal tar product is drawn off the bottom of this flash drum and pumped through heat exchanger 22-1302 to heat the feed, then sent to the Coking Unit 23. The flashed overhead vapor is cooled by heating the fresh feed and the recycle gas oil, followed by generating steam in 22-1306 and air cooling in 22-1307. This cold stream is then flashed in the flash distillate accumulator 22-1204 to recover the small amount of vapor which is compressed by compressor 22-1801 and pumped to the fractionator. The flashed distillate is drawn off as part recycle to the flash drum with the balance pumped to the fractionator.

The fractionator overhead vapor is partially condensed in the air condenser 22-1308, and collected in the overhead receiver 22-1205. Any water settles out in the vessel boot and is sent to Process Waste Water Treating Unit 36. The gas from the receiver is compressed in 22-1802 to Unit 28: Olefin Recovery and Polymerization. The condensed naphtha is drawn off as part reflux back to the top section of the fractionator with the balance pumped to Unit 24: Naphtha Hydrotreating for further processing.

5.16 UNIT 23: DELAYED COKING

Drawing R-23-FS-1 depicts a delayed coker system designed to process the thermal tar from Unit 22 and produce high quality (low sulfur) coke, gas and naphtha. The unit consists of four coke drums, a fired heater, main fractionator, evaporator, soaking drum, a blowdown system and attendant equipment. The green coke will be removed from the drums by means of hydraulic decoking equipment and calcined to the product coke.

The 487°F fresh feed from Unit 22 is preheated to 645°F in the convection section of the coker fired heater 23-1401 and then flows to the top tray of the evaporator tower 23-1102. The purpose of this tower is to provide clean vapors to the main fractionator by condensing the heavy ends of the coke drum vapor. The 830°F coke drum vapors, along with vapors from the soaking drum 23-1207, are fed to the bottom of the evaporator and quenched by contacting the warm fresh feed. The heavy gas oil is condensed in the bottom section of the evaporator at 800°F and pumped to the soaking drum 23-1207. The evaporator overhead vapors at 760°F enter the bottom section of the main fractionator 23-1101.

5.16.1 MAIN FRACTIONATOR

The main fractionator operates at 55 psig in the feeding zone. The primary function of the lower section of the main fractionator is to provide surge capacity for the combined feed (the mixture of fresh feed and recycle) and to collect the entrained coke solids. A screened stand pipe to keep the coke in the bottom head is provided. In addition to being a mixing vessel for the combined feed, the fractionator is used to separate the overhead gas, gasoline, and gas oil. The gas oil is condensed and blended with the fresh feed to provide the required amount of recycle. The unit operates with a recycle ratio of 1:1 and recycles the gas oil product to extinction.

The main fractionator overhead vapors are cooled to 100°F and collected in the fractionator overhead receiver 23-1205. The noncondensed vapors from the receiver are compressed by the overhead receiver vapor compressor 23-1801 and delivered at 100°F to Unit 26 for gas treating. The naphtha is separated from the water condensate, a portion is used as reflux, and the remainder is pumped to Unit 24 for hydrotreating.

From the bottom of the fractionator the combined feed is pumped at 700°F to the coker fired heater 23-1401, where it is heated to 1080°F. The partially cracked combined feed, joined by the evaporator bottoms at 800°F, enters the soaking drum 23-1207, where initial polymerization takes place at 970°F and 350 psig. The overhead vapors are fed to the evaporator bottom and the effluent from the soaking drum enters the bottom of the two coke drums 23-1201 and -1203 operating at 85 psig. Here the coke is formed and accumulated and the coke drum overhead vapors enter the lower section of the evaporator 23-1102 for separation. Each pair of drums is on stream coking for 24 hours and is off stream for cooling, decoking and heating up for the same period. Before switching the oil from one pair of drums to another, the empty drums are preheated by forcing some vapors from the on-stream drums into the top of the drums, through the warm-up separator 23-1206 into the evaporator.

5.16.2 COKER BLOWDOWN SYSTEM

After switching out of the coke drums, steam is immediately added. The full drums are steamed to the main fractionator for 30 minutes and then are depressured to the blowdown system. After 30 minutes of steaming to the blowdown, the steam is shut off and quench water is pumped in. The blowdown line exhausts into the blowdown knockout drum 23-1103, where oil vapors purged from the coking drum are condensed by contacting a circulating oil stream, externally cooled to 300°F.

The heat removed is used to generate 15 psig steam in the steam generator 23-1303. To keep the heavy, waxy material in a fluid state, a spiral steam heating coil is installed in the bottom. The condensed oil is pumped to the evaporator. The saturated steam from the top of 23-1103 is cooled to 220°F and along with the steam generated during quenching and the quench water from the coking drums is fed to the blowdown settling drum 23-1209. Here condensed oil and water are separated and the oil is pumped to the slop tank 23-1901. The steam flows to the blowdown quench tower 23-1104. Inside the tower shower decks distribute the externally cooled water stream entering from above to form a condensing curtain. Some saturated steam is vented from a stack mounted on top of the tower.

The water condensate from the blowdown quench tower, along with the water from the blowdown settling drum 23-1209 and the condensate from fractionator overhead receiver 23-1205, is pumped through the oily water sand filters 23-2201 and -2202 into the oil water separator 23-1210. The oil from the separator is pumped to the slop tank 23-1901 from where it will be returned to the main fractionator. The water from the separator is fed to the thickener 23-2204.

After the coke drums are cooled and drained, the coke is cut and removed from the drums hydraulically. The coke/water slurry discharges onto the sloped bottom of the coke storage pit 23-1902. The water drains into the coke settling basin 23-2203. The relatively clean water from the basin is pumped to the thickener 23-2204, which supplies the water for the jet pump 23-1529.

From the coke storage pit, the green coke is fed to the proprietary calcining system 23-0801. In the rotary kiln of the calcining system, the coke is heated to devolatilization temperatures. The volatile material is burned in an incinerator and the calcined coke is discharged into a rotary cooler where it is quenched to about 300°F and then conveyed to storage.

5.17 UNIT 24: NAPHTHA HYDROTREATING

Process Flow Diagram No. R-24-FS-1 shows the flow sequence of the Naphtha Hydrotreating system. This unit is designed to improve the quality of the naphtha by removal of sulfur, nitrogen and other impurities. This is followed by olefin saturation to produce suitable feedstock for the naphtha reformer.

The unit consists of a furnace, reactor, product separator, stabilizer, and stripper.

A combination of naphtha feeds of up to 400°F ASTM end point from various process units (14, 16, 21, 22, 23) are collected in the feed surge drum 24-1201. The naphtha is pumped through heat exchanger 24-1308 and then combined with hydrogen makeup and recycle gas. This combined stream is heated by the reactor effluent in heat exchanger 24-1301 and in fired heater 24-1401 and then fed to the reactor 24-2501. Here, catalytic hydrogenation to form lower boiling hydrocarbons occurs.

The reactor effluent is cooled by heat exchange with the combined feed of naphtha and treat gas, by generating steam in heat exchanger 24-1309, and by air cooler 24-1302. In the product separator 24-1202, the cold reactor effluent is flashed to separate the vapor and liquid. The vapor splits into recycle gas and high pressure acid gas. Recycle gas is compressed by compressors 24-1801 and -1802 and fed back to the catalytic reactor. The high pressure acid gas is compressed by compressors 24-1803 and -1804 and fed to Unit 27: High Pressure Acid Gas Removal. Sour water is removed from the bottom of the separator and sent to Unit 36: Waste Water Treating. The liquid hydrocarbon is heated by the stabilizer bottoms stream in heat exchanger 24-1303 and fed to the stabilizer column 24-1101.

The feed to the stabilizer is fractionated into a naphtha bottoms stream and an overhead low pressure acid gas. The overheads are partially condensed in the air condenser 24-1304 and collect in the stabilizer reflux drum 24-1203. Contained water settles out in the vessel boot and is sent to the waste water treating unit. The condensed hydrocarbon is totally refluxed to the top section of the stabilizer. Low pressure acid gas from the reflux drum is compressed in 24-1805 and -1806 to the High Pressure Acid Gas Removal Unit 27.

The stabilizer has a reboiler 24-1305 heated by the atmospheric column (Unit 13) pumparound. The stabilizer naphtha bottoms stream flows from the column, preheating the stabilizer feed and the naphtha feed. It is then preheated by the splitter bottoms in heat exchanger 24-1310 before being fed to the naphtha splitter column 24-1102.

The naphtha splitter column produces a fractionated light naphtha overhead and a heavy naphtha bottoms stream. The overhead is totally condensed in the air condenser 24-1311 and collects in the splitter reflux drum 24-1204. The condensed light naphtha is drawn off as part reflux to the column with the balance cooled in water cooler 24-1313 and then sent to storage.

The naphtha splitter has a reboiler 24-1312 heated by the atmospheric column (Unit 13) pumparound stream coming from the Unit 25: Naphtha Reformer Stabilizer. The split heavy naphtha bottoms is drawn off the column preheating the splitter's feed and then either sent to Unit 25 or through the water cooler 24-1314 and on to storage.

5.18 UNIT 25: NAPHTHA REFORMING

The naphtha reforming unit depicted on Process Flow Diagram Drawing No. R-25-FS-1, is designed to reform the naphtha fractions to maximum yield selectivities of high octane reformates for gasoline blending. Severe reforming conditions are used and high hydrogen content gas is produced.

The treated naphtha feed from Unit 24: Naphtha Hydrotreating is joined by the recycle gas stream from flash separator 25-1201 and heated by the No. 4 reactor effluent in heat exchanger 25-1301. This combined stream passes through four catalytic reactors 25-2501 through -2504, each preceded by a fired heater, equipment items 25-1401 through -1404. The last reactor effluent is cooled by heat exchange with the combined feed and recycle gas streams followed by air cooler 25-1302 and fed to a flash separator.

In the flash separator 25-1201, the cooled reactor effluent is flashed to separate the vapor from the liquid. The vapor splits into recycle gas which is compressed to the reactor feed by compressor 25-1801 and reformer product gas that is sent to the two-stage compressor 25-1803 and -1804. The liquid is pumped through heat exchanger 25-1303 where it is heated by the stabilizer column bottoms, and then fed to the stabilizer column 25-1101.

The feed to the stabilizer column is fractionated into an overhead light hydrocarbon vapor and reformate bottoms. The overheads are partially condensed in the air condenser 25-1306 and collected in the stabilizer reflux drum 25-1202. Condensed water settles out in the vessel boot and is sent to Unit 36: Waste Water Treating. The condensed hydrocarbon is totally refluxed to the top section of the stabilizer. Gas from the reflux drum is joined with the product gas from the flash separator to be compressed in the first stage of the product gas compressor 25-1803 and -1804. In the second stage, the product gas of this unit is joined with the product gas from Unit 28: Olefin Recovery and Purification where the total is compressed and transferred to Unit 29: Hydrogen Recovery and Purification.

The stabilizer column reboiler 25-1307 is heated by the atmospheric column (Unit 13) pumparound coming from the naphtha hydrotreater stabilizer reboiler 24-1305. The reformate bottoms flows from the column through heat exchanger 25-1303 to preheat the stabilizer column feed and is then cooled in the air and water coolers 25-1304 and -1305, respectively, before going to storage.

5.19 UNIT 26: OLEFINIC GAS/ACID GAS REMOVAL

Drawing R-26-FS-1 shows the flow through a unit designed to remove carbon dioxide and hydrogen sulfide from the pyrolysis, pyrolysis distillation and coking offgases.

High-pressure gas from Units 15, 16 and 23, containing 22.0% (by volume) hydrogen is first sent to a gas filter/separator, 26-2201, and then to the amine contactor 26-1101 where the gas is countercurrently washed with monoethanolamine (MEA) solution for removal of hydrogen sulfide, carbon dioxide, and carbonyl sulfide. The overhead gas from the contactor is routed to the knockout section at the bottom of the contactor for separation of entrained liquid. The gas flows under pressure to the caustic precontactor, 26-1103, where it is contacted with recirculating, partially spent, 10% caustic (70% converted to Na_2CO_3). Then it is contacted in contactor 26-1104 with recirculating fresh caustic (25% converted to Na_2CO_3) to remove carbon dioxide to less than 5 ppm by volume. The gas is next washed with water in column 26-1105 to remove entrained caustic and is then sent to Unit 28: Olefin Recovery and Polymerization.

The rich MEA solution from the bottom of the amine contactor is released to the flash drum 26-1201 for separation of hydrocarbons, vapor and liquid. It is then routed to the regenerator 26-1102, through the rich/lean amine heat exchanger 26-1303.

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

Low-pressure steam is used to heat the amine regenerator reboiler. The lean MEA solution from the bottom of the regenerator is passed through the rich/lean amine heat exchanger, 26-1303, and the amine air cooler 26-1302, prior to entering the suction of the high-pressure amine pumps 26-1501. The lean solution is then directed under flow control to the amine contactor. A small slipstream proceeds under flow control into the wash column on top of the flash drum.

A solution filter 26-2202 and a reclaimer 26-1306 are provided for solution conditioning. The amine surge tank 26-1901 provides for normal operational surge as well as for solution storage. The solution sump 26-1203 is used for collecting drips and drains and for solution makeup. Equipment for injection of corrosion inhibitor 26-1801 and -1802 and antifoam is provided. Storage tanks 26-1902 and -1903 are included for the storage of MEA and 10% caustic soda solution respectively.

5.20 UNIT 27: SATURATE GAS/ACID GAS REMOVAL

Drawing R-17/27-FS-1 depicts a unit designed to remove carbon dioxide and hydrogen sulfide from the dissolver, distillation, and hydrogenation offgases.

High-pressure gas from Unit 17: Sour Gas Compression with 70% (by volume) hydrogen is first sent to a gas filter/separator, 27-2201, and then to two contactors installed in parallel where the gas is countercurrently washed with MEA solution for removal of hydrogen sulfide, carbon dioxide, and carbonyl sulfide. The overhead gas from the contactor is routed to the knockout section in the lower end of the contactor for separation of entrained liquid. The gas flows to the caustic precontactor 27-1104 where it is contacted with recirculating, partially spent 10% caustic (70% converted to Na_2CO_3). It is then contacted in contactor 27-1105 with recirculating fresh caustic (25% converted to Na_2CO_3) which removes carbon dioxide to less than 5 ppmv. Afterwards, the gas is washed with water in column 27-1106 to remove entrained caustic and then sent to Unit 29: Hydrogen Recovery and Purification.

The rich MEA solution from the bottom of the amine contactor is released to the flash drum 27-1201 for separation of hydrocarbons, vapor, and liquid, and then is routed to the regenerator 27-1103, through the rich/lean amine heat exchanger 27-1303.

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 27-1303 and the amine air cooler 27-1302, prior to entering the suction of the high-pressure amine pumps 27-1501. 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 on the flash drum.

A solution filter 27-2202, and a reclaimer 27-1306 are provided for solution conditioning. The amine surge tank 27-1901 provides for normal operational surge as well as for solution storage. The solution sump 27-1203 is used for collecting drips and drains and for solution makeup. Equipment for injection of corrosion inhibitor and antifoam 27-2801 and -2802 is provided, as well as tanks 27-1902 and -1903 for major amine and caustic storage respectively.

5.21 UNIT 28: OLEFIN RECOVERY AND POLYMERIZATION

Drawing R-28-FS-1 shows the oil absorption process provided to recover the propane and heavier components contained in the sweet gas from Unit 26: Olefinic Gas Acid Gas Removal.

The sweet gas is dried in molecular sieve dryers 28-1201 through -1203 to minus 100°F water dew point. The stream is split and enters the gas/gas exchanger 28-1303 and the gas/deethanizer exchanger 28-1304. The cooled streams recombine at 19°F and 441 psia and are mixed with rich oil from the absorber. The total stream then passes through feed chiller 28-1305 where it is cooled to -20°F. The combined chilled feed and rich oil stream is separated in the feed gas/rich oil separator 28-1205. This vessel acts as the bottom tray of the absorber and the chiller acts as an intertray cooling device. Combining the rich oil and feed gas before entering the chiller optimizes the refrigeration cycle.

Gas from the feed gas/rich oil separator enters the bottom of the absorber 28-1101 at 434 psia and -20°F. It passes up the column, countercurrent to the lean oil flowing down the column. Essentially all of the butane and heavier fractions are recovered. The ethane and methane which are absorbed from the gas into the rich oil stream are removed from the recovered liquid stream.

The absorber overhead at -10°F mixes with lean oil at 25°F. The mix at 8°F is chilled to -20°F in the presaturation chiller 28-1306 and enters the absorber presaturator 28-1206. Presaturating the lean oil optimizes the refrigeration system performance. Presaturated lean oil is pumped to the top of the absorber.

Cold residue gas from the absorber presaturator passes through the gas/gas exchanger 28-1303, where refrigeration is recovered by cooling of the feed stream. Residual gas at 85°F and 407 psia flows to Unit 25 where it is compressed and sent to Unit 29: Hydrogen Recovery and Purification.

Rich oil from the feed gas/rich oil separator 28-1205 passes through two heat exchangers, lean oil presaturation/deethanizer feed exchanger 28-1308, and lean oil/deethanizer feed exchanger 28-1312 for recovery of refrigeration, and enters the rich oil deethanizer 28-1102 at 53°F. In this column, ethane and lighter components are removed from the rich oil by application of heat to the deethanizer side reboiler 28-1310 between Trays 6 and 5 and at the deethanizer reboiler 28-1309 at the bottom of the column. Lean oil at 25°F joins with the vapor from the top of the rich oil deethanizer 28-1102, passes through the lean oil presaturator/deethanizer feed exchanger 28-1308, where the mixture is cooled to 20°F. The mixture is further cooled to -10°F in deethanizer/lean oil chiller 28-1307 and C_{2s} and lighter are separated in deethanizer/lean oil presaturator 28-1207. Presaturated lean oil is pumped to the top of the rich oil deethanizer 28-1102 by presaturated lean oil pump 28-1505 and flows down the column to minimize the loss of propane with the deethanizer overhead. Vapor from the deethanizer lean oil presaturator 28-1207 passes through the gas/deethanizer residue exchanger 28-1304 for recovery of refrigeration.

Deethanized rich oil from the bottom of the rich oil deethanizer 28-1102 now enters the rich oil still 28-1103 where a mixed C_3 and C_4 stream is separated from the lean oil stream. The column is reboiled using steam in rich oil still reboiler 28-1313. The lean oil is removed from the bottom of the column and cooled to 25°F by exchange with deethanizer side reboiler 28-1310, lean oil cooler 28-1311 and lean oil/deethanizer feed exchanger 28-1312.

The total column overhead vapor is condensed in rich oil still condenser 28-1314 and collected in rich oil still reflux drum 28-1208. The reflux is returned to the column by rich oil still reflux pump 28-1509. The net overhead product is a mixed C_3 and C_4 stream which is pumped to the catalytic condensation unit by rich oil still product pump 28-1511.

The catalytic condensation unit is a proprietary process designed to polymerize the C_3 and C_4 olefins to gasoline range product. The polymer gasoline thus produced is stabilized and sent to the gasoline pool storage. The unreacted propane and butane are sent to Unit 31: LPG Fractionation.

5.22 UNIT 29: HYDROGEN RECOVERY AND PURIFICATION

Drawing R-29-FS-1 shows the separation of the sweet gas from Unit 25: Naphtha Reformer and Unit 27: Saturate Gas Acid Gas Removal into a high-purity hydrogen stream, a hydrogen rich stream, a methane rich stream, and an ethane and heavier stream.

The sweet gas is dried in two parallel trains of molecular sieve driers 29-1201 through -1203 and 29-1551 through -1253 to a minus 100°F water dew point and is sent to cryogenic hydrogen upgrading equipment 29-0801. This step produces a methane-rich gas stream, an ethane-and-heavier rich gas stream, a liquid stream, and a 95.7% (by volume) hydrogen stream using a combination of autorefrigeration and external refrigeration. The methane-rich stream is combined with a small excess hydrogen stream and sent to Unit 30: SNG Purification. Both the liquid and ethane gas and heavier streams are sent to Unit 31: LPG Fractionation for Recovery of C_3 and C_4 LPG. The hydrogen-rich stream is split into three streams: Approximately 60% is sent to Unit 12: SRC Dissolving as recycle hydrogen, about 35% is methanated to remove final traces of carbon monoxide to provide a high-purity hydrogen stream for use in hydrotreating, and the remainder is sent to Unit 30: SNG Purification.

The fraction of the hydrogen-rich gas which is to be methanated is first heated to about 450°F in feed effluent exchanger 29-1303 and then enters trace methanator 29-2501. The effluent leaves at about 790°F and is cooled to about 120°F by heat exchange with the feed in effluent cooler 29-1304. The condensed water is removed in hydrogen knockout drum 29-1205, and the cool high-purity hydrogen is then split to provide makeup hydrogen for Unit 21: Heavy Liquid Hydrotreating and Unit 24: Naphtha Hydrotreating.

5.23 UNIT 30: SNG PURIFICATION

Drawing R-30-FS-1 shows the process to upgrade the methane-rich gas stream from Unit 29: Hydrogen Recovery and Purification to saleable SNG.

The methane-rich gas, which is produced in Unit 29 at 95°F and 6 psig, is compressed to 382 psig by a steam turbine driven three-stage compressor 30-1801. Interstage cooling and liquid separation equipment are provided to remove condensable fractions. The gas is preheated to 600°F by exchange with product gas from the methanation step in heat exchanger 30-1303 and then passes through a zinc oxide guard reactor 30-2501 where the hydrogen sulfide content is reduced to less than 0.1 ppm for methanation catalyst protection. The clean gas is then sent to a liquid phase methanator 30-2502 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 30-1304.

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 proprietary methanation oil cleanup unit 30-0801. The gas effluent from the liquid phase methanator exits at 690°F and 328 psig. It is cooled by exchanging heat with the methanation feed in exchanger 30-1303 followed by steam generation in the methanation effluent steam generator 30-1305 and by air cooling to 132°F in air cooler 30-1306 to condense part of the water produced in the liquid phase methanator. The gas is then sent to the polishing methanator 30-2503 where the final traces of carbon monoxide are converted to methane.

The polishing methanator effluent is produced at 856°F and 295 psig. After cooling by exchanging heat with the feed in heat exchanger 30-1307 and by air cooling in air cooler 30-1308 the gas is combined with the ethane stream from Unit 31: LPG Fractionation and compressed to 1005 psig by a two-stage compressor 30-1803. Interstage- and aftercoolers are used in combination with separator drums to remove the major portion of water from the gas streams. The cooled gas stream at 110°F is then sent to a proprietary CO_2 removal unit 30-0802 where about 60% of the CO_2 is removed to improve the SNG interchangeability indices. The gas is then fortified with excess hydrogen rich gas from Unit 29 and is contacted with glycol in drier 30-0803 to meet the SNG water specification of 3 ppm/scf.

5.24 UNIT 31: LPG FRACTIONATION

Drawing R-31-FS-1 shows the fractionation train provided to separate the ethane and heavier hydrocarbons from Units 28 and 29 into saleable propane and butane LPG.

The feed to this unit consists of a vapor stream of combined gases from Units 28 and 29 and a liquid stream from Unit 29. The vapor stream is compressed to 213 psig by a two-stage compressor 31-1801 and sent to deethanizer 31-1101. The liquid feed is pumped directly from Unit 29 into the tower

The ethane and some propane are taken overhead as product. This is the upgrading gas required to adjust the SNG heating value. The gas flows under pressure to Unit 30 where it is compressed and added to the SNG.

The remaining propane and heavier material contained in the deethanizer column bottoms are then depropanized in depropanizer column 31-1102 to produce a propane LPG overhead and a butane and heavier bottoms. The propane LPG is pumped to the proprietary sweetening unit 31-0801 where the sulfur content is adjusted to meet specifications. The saleable propane LPG product flows under pressure to storage.

The butane and heavier material from the depropanizer bottoms are debutanized in debutanizer column 31-1103 to produce a butane LPG overhead and a pentane and heavier bottoms. The butane LPG is pumped to a proprietary sweetening unit 31-0802 where sulfur compounds are removed. The saleable butane LPG product is sent to storage. The pentane and heavier material from the bottom of the debutanizer column flow to Unit 24: Naphtha Hydrotreating.

5.25 UNIT 32: SULFUR PLANT

Drawing R-32-FS-1 shows diagrammatically the major components of the sulfur plant required to produce an ecologically acceptable tail gas. This is achieved using two parallel Claus-type units and two parallel tail gas treating units with a common redox solution unit.

5.21.1 SULFUR RECOVERY UNIT

A typical, Claus-type, three-stage sulfur recovery unit is shown diagrammatically on Drawing R-32-FS-1. The acid gases from Units 20, 26, 27, 34, and 36 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 the following equations:

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

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

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.

5.25.2 TAIL GAS TREATING UNIT

The Tail Gas Sulfur Removal Unit is included on Drawing R-32-FS-1. 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 used, 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 the sulfur separator and melter system where the sulfur is melted under pressure, separated from the redox solution, and transferred to sulfur product storage. The separated redox solution is returned to the system.

The chemical reactions are:

<u>Hydrogenation and Hydrolysis</u>

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

$$(4)\quad S + H_2 \longrightarrow H_2S$$

$$(5)\quad COS + H_2O \longrightarrow H_2S + CO_2$$

$$(6)\quad CS_2 + 2H_2O \longrightarrow 2H_2S + CO_2$$

Hydrogen Sulfide Extraction

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

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.

5.26 UNIT 33: FUEL GAS GENERATION

This unit produces low-Btu fuel gas, 320 Btu/scf, using steam-oxygen gasification of coal. The process is shown on flow diagram R-33/34-FS-1. The major portion of the fuel gas, approximately 76%, following solids and sulfur removal, is used as fuel for the gas turbine generators in a combined cycle power plant. The balance is used as plant fuel for the various fired heaters.

5.26.1 GASIFIER

The core of the unit is a two-stage, entrainment, slagging gasifier, 33-2501. Configuration and general details are shown on Figure 5-4. The gasifier is fed coal by screw feeders 33-2001 through -2005. Operating pressure is 400 psig. The gasification takes place in two zones. The lower, or slagging zone, operates at approximately 3000°F and is fed by recycled char, oxygen, and superheated steam. A restriction separates this zone from the upper zone, which operates at approximately 1800°F. Ground coal and steam are fed to the upper zone. The wall of the slagging zone is cooled by internal tubes set in the refractory wall through which boiler feed water is circulated to generate 1300 psig steam.

A slag quench pot is located under the slagging zone. Molten slag enters this pot continuously through a relatively small (2-foot diameter) opening. Steam is generated at 448°F as the slag cools. The 3000°F slag, upon contact with the cooler water, solidifies and shatters into sandlike particles.

Five screw feeders are used, each handling 3,340 tons per day during normal operations. 20% excess design capacity is provided to allow one feeder to be out of service for maintenance without impairing the gasifier throughput.

5.26.2 FUEL GAS CLEANING AND COOLING

The gasifier product stream is cooled to 120°F by a combination of steam superheating, steam generation in waste heat boilers, boiler feed water heating, and the use of an air cooler. After the condensed sour water is removed at 120°F, the fuel gas is sent to Unit 34 - Fuel Gas Acid Gas Removal.

The 1800°F gasifier product stream contains entrained char. A high efficiency two-stage cyclone system, 33-2201 and -2202, is used to remove most of the char particulates. The remaining dust is removed in the high pressure electrostatic ionizer/collector system 33-2210, -2211, -2212, and

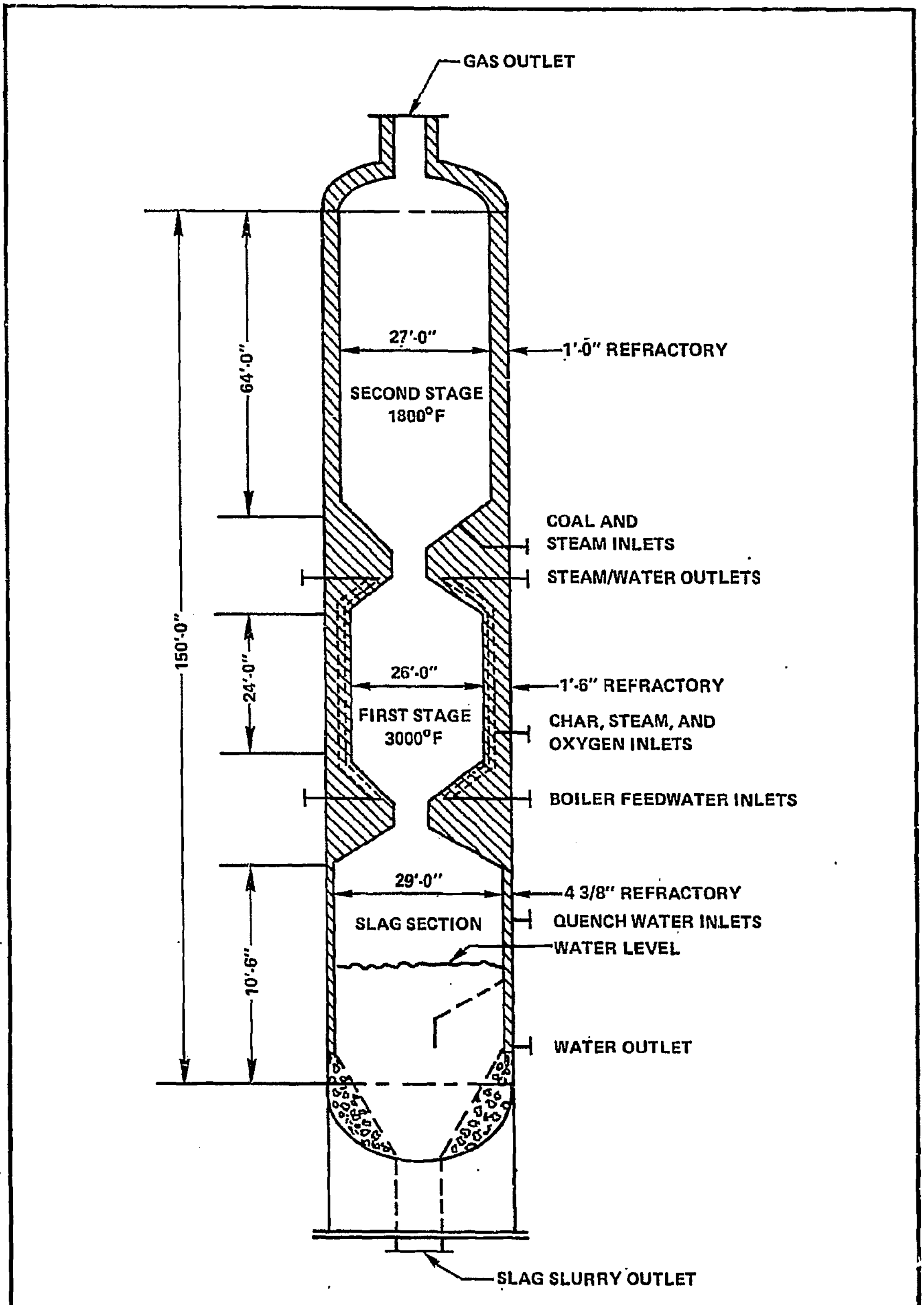


Figure 5-4 - Fuel Gas Gasifier

-2213 following gas cooling to below 1200°F. The collected char from the cyclones and ionizers is recycled back to the gasifier.

The hot fuel gas from the cyclone system flows through 650 psig steam superheater 33-1301, through 1300 psig steam superheater 33-1302 and -1304, then through 1300 psig steam generator 33-1305. The gas then flows through the ionizers 33-2210, -2211, -2212 and -2213 for final char fines removal. It then flows to 650 psig steam generator 33-1307 and on through a series of boiler feed water heat exchangers, -1308, -1309, -1310 and -1311. The cooled raw fuel gas temperature reaches a temperature of 300°F. Further cooling to the 100°F temperature required for the subsequent acid gas removal takes place in heat exchanger 33-1314 where clean fuel gas product is heated, boiler feedwater heater 33-1315, air cooler 33-1312 and heat exchanger 33-1313. Condensed sour water is removed in knock out drum 33-1205.

5.26.3 STEAM SYSTEM

1300 psig saturated steam generated in the gasifier cooling coils and steam generator 33-1305 flows to steam drums 33-1201 and -1202. Steam from these drums is combined and superheated in the hot fuel gas to steam exchangers cited in 5.26.2. Superheated 1300 psig steam is used to heat the oxygen flow stream to the gasifier in heat exchanger 33-1303, superheated again and finally sent to the 1250 psig plant steam main.

The 650 psig steam generated in the raw gas cooling train is fed to steam drum 33-1203 from which it flows through superheater 33-1301. Most of the 650 psig superheated steam is fed to the gasifier for reaction with coal and oxygen. The balance flows to the 625 psig plant steam main.

5.26.4 SLAG REMOVAL

The gasifier slag section is designed to accomplish separation of a fairly clean upper water layer which flows to quench recycle pump 33-1501. 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 particles suspended in the water. The recycled stream is augmented by a cooler quench water stream from heat exchanger 33-1315.

The slag slurry leaving the slag section is reduced in pressure and sent to the slag slurry receiver 33-1204. The vapors released here (primarily water) are sent to disposal and the concentrated slag slurry is pumped to the slag screen in the coal preparation area. The slag slurry pump 33-1503, is provided with hardened surfaces at all critical points to provide reliable service in pumping the slurry.

5.27 UNIT 34: FUEL GAS ACID GAS REMOVAL

The cooled raw fuel gas from Unit 33 contains acid gases consisting of carbon dioxide, hydrogen sulfide, and organic sulfur compounds. These are removed by a proprietary physical solvent absorption process in four identical parallel trains. The Rectisol process was selected as being representative of available physical solvent processes. The material balance is shown in drawing R-33/34-FS-1.

A clean fuel gas, a hydrogen sulfide-rich gas and a vent gas stream are produced. The clean gas is used as fuel in the power plant gas turbines and in the plant fired heaters. The hydrogen sulfide-rich stream is used as part of the feed to Unit 32: Sulfur Plant. The remaining gas consists primarily of carbon dioxide and nitrogen with traces of hydrogen, methane and carbon monoxide.

5.28 UNIT 35: STEAM AND POWER GENERATION

The power generation area consists of gas turbines, heat recovery steam generators and steam turbines in the combined cycle mode. Drawing R-35-FS-1 shows the combined cycle system for the generation of 1,400 MW of electricity gross. After use of approximately 400 MW for operation of the plant and mine, approximately 1,000 MW are available for sale.

Clean fuel gas from Unit 34: Fuel Gas Acid Gas Removal, at 300 psig, is heated by compressed air in heat exchangers 35-1309, -1310, and 1311 to 450°F. The heated fuel gas is then sent to 18 gas turbine generators 13-0101 through 35-0118. Each gas turbine generator compressor in addition to providing combustion air to the combustor, supplies bleed air as part of the compressed air requirements of Unit 11. This bleed air amounts to about 40% of the requirements of the oxygen plant.

The exhaust of each gas turbine generator is fed to heat recovery steam generators 35-1601 through 35-1618. These generators produce about 4.1 million lb/hr of steam at 1250 psig and 875°F. An additional 1.2 million pounds of steam at 1250 psig and 875°F are supplied to Unit 35 from the process areas. This steam is fed to four (4) steam turbine generators 35-0141 through 35-0144 for the generation of additional electrical power. These steam turbine generators are each provided with three extraction points; two provide process plant steam requirements at 650 and 50 psig and the third provides 250 psig steam for injection into gas turbine combustors for NO_x control. Steam not required from extraction points is sent to the main condensers 35-1301 through 35-1304.

Condensate leaving the main condensers, together with plant makeup requirements, is sent to station deaerators 35-1305 through 35-1308 where it is picked up by the boiler feed pumps for return to waste heat steam generators. Demineralized water and condensate are also returned to the process plant heat recovery boilers.

5.29 UNIT 36: PROCESS WASTE WATER TREATING

Drawing R-36-FS-1 shows equipment and flows provided to remove sulfur and ammonia compounds from sour water collected in the various process units.

5.29.1 AMMONIUM SULFIDE WATER TREATER

Water contaminated with ammonium sulfides enters feed drum 36-1201, which utilizes an overflow-underflow weir arrangement to separate the water from floating oil. The oil is drained to accumulator 36-1202 and is then pumped to the offplot hydrocarbon recovery system. The water is pumped to the feed surge tank, 36-1901.

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 strippers 36-1101 and -1131.

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, 36-1301 and -1331, to provide stripping steam, while the remainder is discharged from the bottom of the column and pumped to the process gasifier in Unit 18 and the fuel gas gasifier in Unit 33.

5.29.2 AMMONIA SEPARATION

Ammonia-sulfide feed gas enters the ammonia absorber, 36-1151, 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 Unit 32: Sulfur Plant. Makeup 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, 36-1152.

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, 36-1254, 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, 36-1153, 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, 36-1356, and collected in the ammonia reflux drum from which it is pumped to product storage. The residual waste water is discharged from the bottom of the column and is used as slag quench water in Unit 18.

5.30 UNIT 37: SHOPS AND BUILDINGS

This unit is composed of the various building facilities necessary for the operation of the complex. The buildings are listed in Table 13-30 along with their general type descriptions and approximate sizes. All buildings are of steel frame, metal and insulated construction. This type is considered practical and lowest in cost for the base case location.

The change houses and cafeteria buildings were sized on the basis of 30 and 15 square feet, respectively, per person at expected peak occupancy. Staggered work schedules minimize the sizes of required facilities.

The change houses contain double locker room areas for use by operating and maintenance personnel working in possibly toxic areas. This arrangement provides for a complete change of work clothes every day.

5.31 UNIT 38: FIRE WATER SYSTEM

The water for this system, depicted on Process Flow Diagram Drawing No. R-38/39/40/41-FS-1, is supplied by pumps which take suction from biopond 41-5302. The water is delivered to a fire water loop at 100 psig. One electric motor-driven and one steam-driven pump, each with a capacity of 4200 gpm, provide the 8400 gpm required. One diesel engine-driven pump of 4200 gpm is provided as a standby spare. A steam-driven jockey pump will maintain pressure on the system during periods when there is no demand. Hydrants and monitors connected to the loop are located strategically in all units. Oil-product storage tanks are protected by hydrants and a foam system.

5.32 UNIT 39: POTABLE AND SANITARY WATER SYSTEM

Potable water is obtained from a deep well equipped with a 250 gpm well pump (refer to Process Flow Diagram Drawing No. R-38/39/40/41). A 100 gpm circulating pump and a full-capacity spare pump are included to ensure a reliable supply. The water is sterilized by chlorination to make it suitable for drinking and other sanitary use.

5.33 UNIT 40: RAW WATER SYSTEM

Water in the amount of approximately 24,000 gpm will be pumped from a river. Following screening for trash removal, water flows by gravity to a concrete river water basin 40-4101 which provides about 20 hours residence for settling. The pumps will be mounted in the clear well of this basin. Process Flow Diagram Drawing No. R-38/39/40/41-FS-1 depicts the design of this process.

The entire system will receive further clarification in mechanical sludge blanket clarifier 40-2202, aided by coagulants and clarifying chemicals.

Makeup water for the cooling water system receives additional conventional chemical treatment to inhibit corrosion and to control algae. A cooling tower 40-1701 is provided for handling 690,000 gpm of circulating cooling water.

5.34 UNIT 41: EFFLUENT WATER TREATING

Contaminated water from process areas will be treated to make it suitable for reuse in the plant and the mine. The sources of effluent water are principally cooling tower blowdown, demineralizing system blowdown, and sanitary sewage effluent. Other waste water streams are oily water skimmed from the pumps and compressors cooling water system, laboratory waste water, oily water from unit area drain, and oily surface runoff water from process areas.

Process Flow Diagram Drawing No. R-38/39/40/41-FS-1 shows the flow details of the effluent water treating unit. Oily water from pumps and compressors cooling water system is passed through air cooler 41-1301 before being fed to the oil skimmer 41-1201. The skimmed oil is sent to the oily water sump 41-3201, whereas the essentially oil-free water is drawn off the oil skimmer to be recycled to the pumps and compressors cooling water system.

The skimmed oil in the oily water sump is joined by laboratory waste water, oily drain water, and by oily surface runoff water from curbed process areas after passing through a surge storm water pond 41-5301. Waste water from the oily water sump is pumped through a sand-filtering system after which oil and water are separated in the oil/water separator 41-1202. The separated oil is returned to process, and the bottom product, essentially clean water, is sent to the biopond for polishing.

Boiler and cooling tower blowdown and demineralizer wash water are received separately in the neutralization basin 41-4101. 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 41-2203, where chemicals and other impurities are removed as sludge. The clean effluent is used as quench for the process units, coal preparation water makeup, mine dust control or sent to the storm drain.

Sanitary sewage is treated in sewage treatment unit 41-0801. Treated sewage proceeds to join the water from the oil/water separator in the biopond 41-5302. In this pond, the water is treated by aeration to reduce the biological oxygen demand (BOD). The suspended solids will settle in the pond and will be removed for landfill, while the pond will serve as a reservoir for the Fire Water System Unit 38.

5.35 UNIT 42: PRODUCT STORAGE

Approximately 3 weeks of finished product storage is provided for liquid products. An equivalent of 30 days storage capacity is provided including intermediate storage facilities. A 1-month inventory of chemicals and physical solvents is provided in the areas of the using departments.

Pump facilities for loading product are included. The design is based on the major portion of the liquid products being shipped to contract customers by pipeline and barge. The balance would be shipped by rail and tank trucks.

5.36 UNIT 43: FLARE SYSTEM

A plant flare system provides for combustion of vented gases on operation of pressure safety valves, or manual venting of gas intermediates or product. Knockout drums are provided to accumulate and return condensed liquid to the process system and water to waste water treating.