Section 5

H-COAL LIQUEFACTION
CASE HE - ILLINOIS NO. 6 COAL

GENERAL

This Section describes a preliminary design for a grass roots coal liquefaction plant to produce a nominal 50,000 bbl/sd fuel oil equivalent (FOE) of liquid hydrocarbon products. The design is based on the catalytic hydrogenation of a coal-oil mixture using the H-Coal liquefaction process. The naphtha fraction, hydrotreated and catalytically reformed, is marketed as a quality motor fuel. A 350/650°F distillate fraction is hydrotreated to yield a marketable turbine fuel product. The 650°F+ fuel oil product is marketed without further treatment. The plant consumes 19,264 st/sd of Illinois No. 6 coal (moisture free basis).

The severity of the reaction, as measured by the quantity of hydrogen consumed as a weight percent of dry coal feed, is 4.89 percent. The reaction is carried out at 850°F and 3000 psig.

The facilities supporting the reactor operation are divided into 16 units as shown in Table 5-1. Some units are subdivided into sections to describe distinct process plant operations. Also shown are the number of trains of major equipment.

The overall block flow diagram, drawing number 75-D1, shows all major process and utility areas of the plant for the H-Coal liquefaction process using Illinois No. 6 coal.

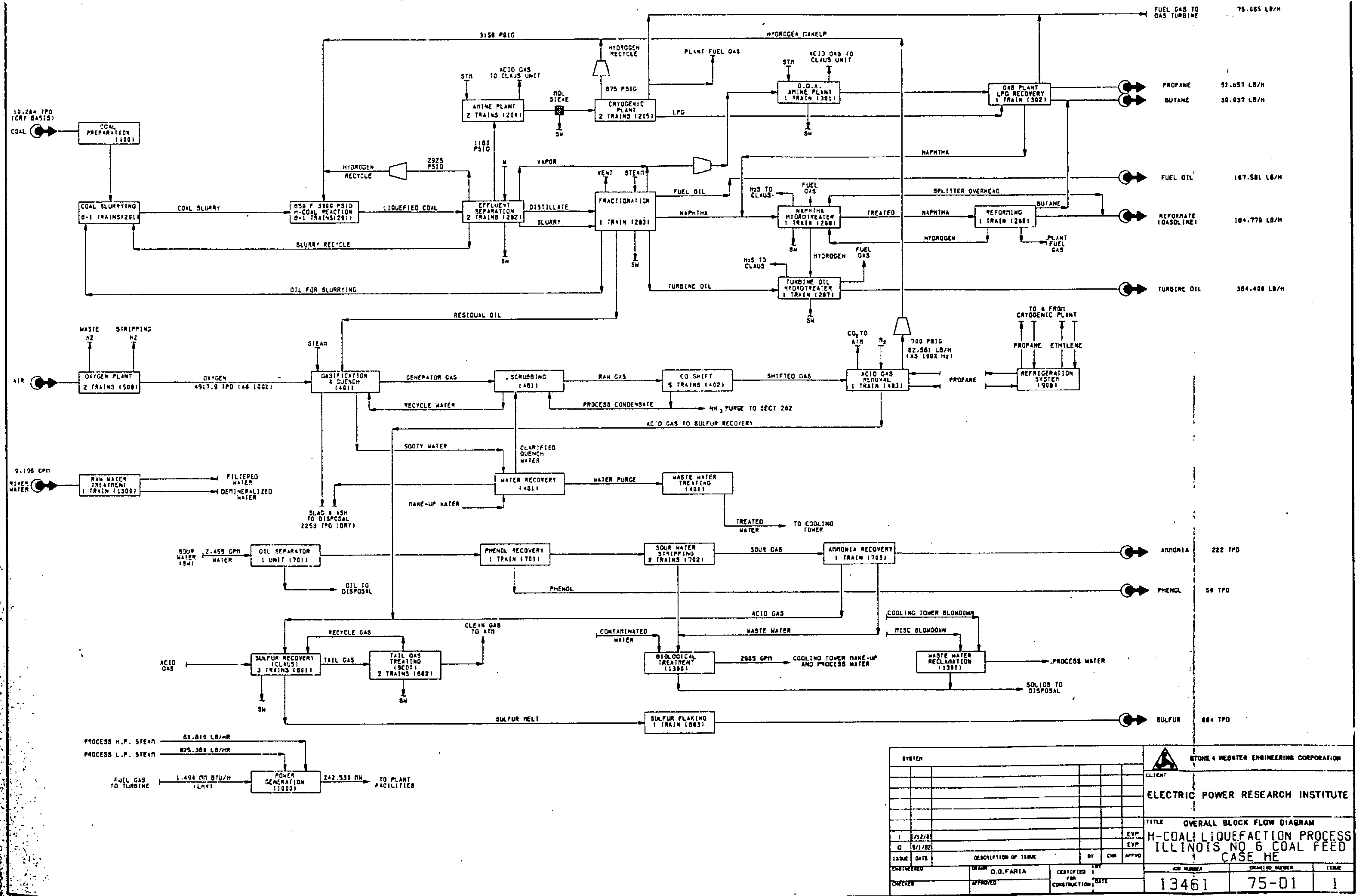
Process descriptions, equipment lists, material balances, and flow diagrams are provided for the major non-proprietary sections.

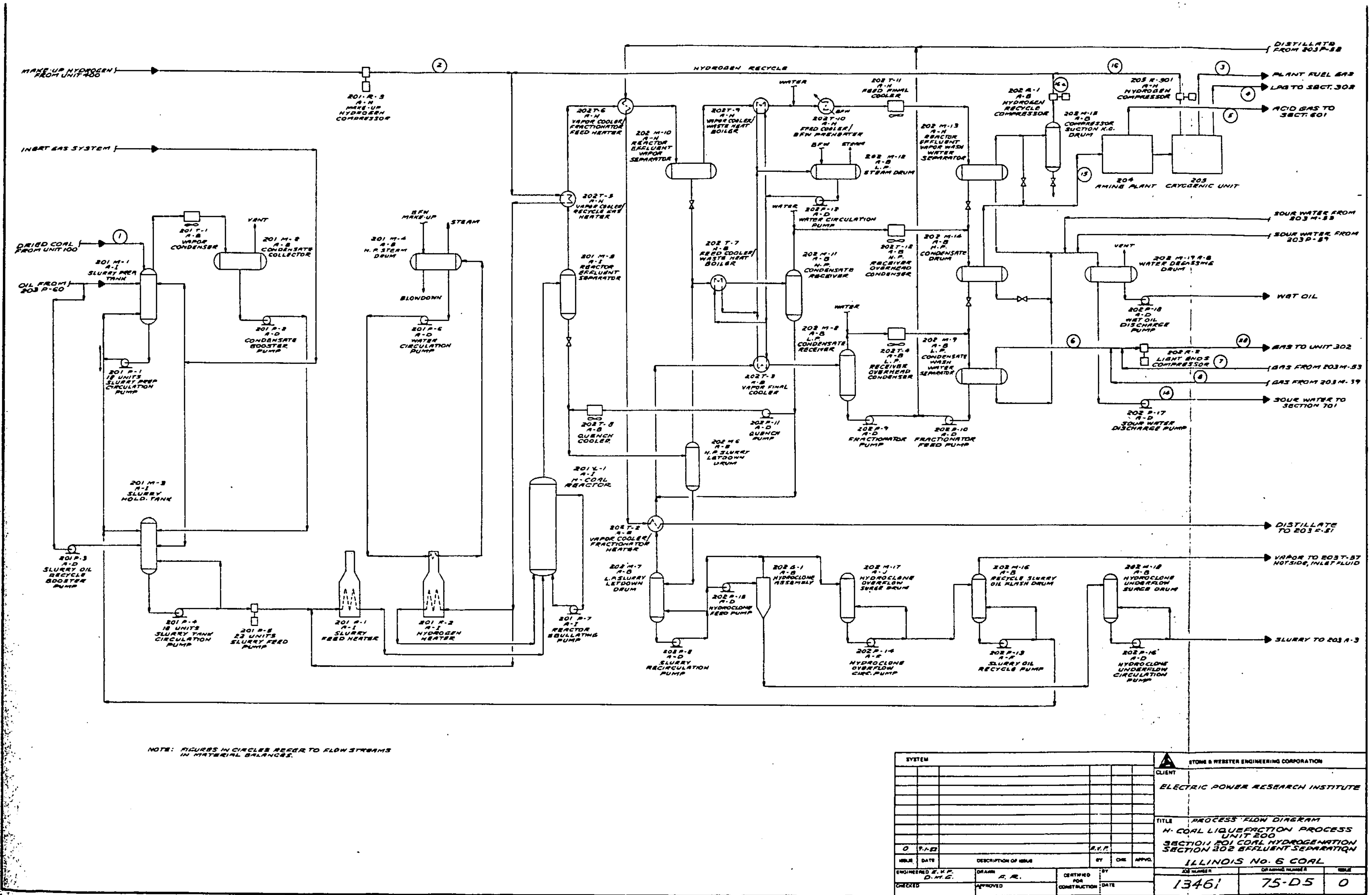
The equipment lists show the number of operating items required as well as the spared items (+1, etc.). The spared items are equal in size to the operating items. The equipment lists for Units 100 and 200 show item numbers which are cross-referenced to the flow diagrams.

Table 5-1

LIST OF PROCESSING UNITS
CASE HE - ILLINOIS COAL

Unit	Section	Description	Number of Trains
100	100	Coal Preparation	
200	-	H-Coal Liquefaction	
	201	Coal Slurrying & H-Coal Reaction	8 + 1 Spare
	202	Effluent Separation	2
	203	Fractionation	1
	204	Amine Plant	2
	205	Cryogenic Plant	2
	206	Naphtha Hydrotreater	1
	207	Turbine Oil Hydrotreater	1
	208	Reformer	1
300	-	Light Ends Processing	
	301	DGA Amine Plant	1
	302	Gas Plant (LPG Recovery)	1
400	-	Hydrogen Plant	
	401	Gasification (Texaco)	
	402	CO Shift	5
	403	Acid Gas Removal	1
500	500	Oxygen Plant	2
600	-	Emission Control	
	601	Sulfur Recovery (Claus)	3
	602	Tail Gas Treating (SCOT)	2
	603	Sulfur Flaking	1
700	-	Effluent Control	
	701	Phenol Recovery	1
	702	Sour Water Stripping	2
	703	Ammonia Recovery (PHOSAM)	1
800		Tank Storage	
900		Refrigeration	2
1000		Power Generation	
1100		Cooling Water System	
1200		Utility and Steam Summary	
1300		Water Management	
1400		Flare System	
1500		Buildings	
1600		Common Facilities	


FUEL GAS TO GAS TURBINE 75,065 LB/H
3150 PSIG
HYDROGEN RECYCLE
HYDROGEN MAKEUP
PLANT FUEL GAS
ACID GAS TO CLAUS UNIT
STM
AMINE PLANT 2 TRAINS (204)
MOL SIEVE
875 PSIG
CRYOGENIC PLANT 2 TRAINS (205)
LPG
D.G.A. AMINE PLANT 1 TRAIN (301)
GAS PLANT LPG RECOVERY 1 TRAIN (302)
PROPANE 52,657 LB/H
BUTANE 30,937 LB/H
19,264 TPD (DRY BASIS)
COAL
COAL PREPARATION (100)
1160 PSIG
HYDROGEN RECYCLE
2925 PSIG
VAPOR
NAPHTHA
FUEL OIL 187,581 LB/H
VENT
STEAM
FUEL OIL
FUEL GAS
H2S TO CLAUS
SPLITTER OVERHEAD
COAL SLURRYING 8-1 TRAINS (201)
COAL SLURRY
850 F 3000 PSIG H-COAL REACTION 8-1 TRAINS (201)
LIQUEFIED COAL
EFFLUENT SEPARATION 2 TRAINS (202)
DISTILLATE
SLURRY
FRACTIONATION 1 TRAIN (203)
NAPHTHA HYDROTREATER 1 TRAIN (206)
TREATED
REFORMING 1 TRAIN (208)
BUTANE
REFORMATE (GASOLINE) 164,779 LB/H
HYDROGEN
PLANT FUEL GAS
SLURRY RECYCLE
SW
H2S TO CLAUS
TURBINE OIL HYDROTREATER 1 TRAIN (207)
OIL FOR SLURRYING
TURBINE OIL
TURBINE OIL 364,496 LB/H
RESIDUAL OIL
TO & FROM CRYOGENIC PLANT
PROPANE
ETHYLENE
WASTE N2
STRIPPING N2
STEAM
CO2 TO ATM
N2
700 PSIG 82,561 LB/H (AS 100% H2)
AIR
OXYGEN PLANT 2 TRAINS (500)
OXYGEN 4917.9 TPD (AS 100%)
GASIFICATION & QUENCH (401)
GENERATOR GAS
SCRUBBING (401)
RAW GAS
CO SHIFT 5 TRAINS (402)
SHIFTED GAS
ACID GAS REMOVAL 1 TRAIN (403)
PROPANE
REFRIGERATION SYSTEM (900)
RECYCLE WATER
PROCESS CONDENSATE
NH3 PURGE TO SECT 202
ACID GAS TO SULFUR RECOVERY
SOOTY WATER
CLARIFIED QUENCH WATER
9,196 GPM
RIVER WATER
RAW WATER TREATMENT 1 TRAIN (1300)
FILTERED WATER
DEMINERALIZED WATER
WATER RECOVERY (401)
WATER PURGE
WASTE WATER TREATING (401)
MAKE-UP WATER
SLAG & ASH TO DISPOSAL 2253 TPD (DRY)
TREATED WATER
TO COOLING TOWER
SOUR WATER (SW)
2,455 GPM WATER
OIL SEPARATOR 1 UNIT (701)
PHENOL RECOVERY 1 TRAIN (701)
SOUR WATER STRIPPING 2 TRAINS (702)
SOUR GAS
AMMONIA RECOVERY 1 TRAIN (703)
AMMONIA 222 TPD
OIL TO DISPOSAL
PHENOL
PHENOL 58 TPD
ACID GAS
COOLING TOWER BLOWDOWN
RECYCLE GAS
CLEAN GAS TO ATM
CONTAMINATED WATER
WASTE WATER
MISC BLOWDOWN
ACID GAS
SULFUR RECOVERY (CLAUS) 3 TRAINS (601)
TAIL GAS
TAIL GAS TREATING (SCOT) 2 TRAINS (602)
BIOLOGICAL TREATMENT (1300)
2985 GPM
COOLING TOWER MAKE-UP AND PROCESS WATER
WASTE WATER RECLAMATION (1300)
PROCESS WATER
SOLIDS TO DISPOSAL
SULFUR MELT
SULFUR FLAKING 1 TRAIN (603)
SULFUR 664 TPD
PROCESS H.P. STEAM 60,610 LB/HR
PROCESS L.P. STEAM 825,368 LB/HR
FUEL GAS TO TURBINE
1,494 MM BTU/H (LHV)
POWER GENERATION (1000)
242,530 MW
TO PLANT FACILITIES
SYSTEM
STONE & WEBSTER ENGINEERING CORPORATION
CLIENT
ELECTRIC POWER RESEARCH INSTITUTE
TITLE OVERALL BLOCK FLOW DIAGRAM
H-COAL LIQUEFACTION PROCESS
ILLINOIS NO 6 COAL FEED
CASE HE
1 7/12/83
0 9/1/82
ISSUE DATE DESCRIPTION OF ISSUE BY CHK APPVD
EVP
EVP
ENGINEERED
DRAWN D.G.FARIA
CERTIFIED FOR CONSTRUCTION
CHECKED
APPROVED
DATE
JOB NUMBER 13461
DRAWING NUMBER 75-01
ISSUE 1


MAKE-UP HYDROGEN FROM UNIT 400
HYDROGEN RECYCLE
DISTILLATE FROM 203 P-38
PLANT FUEL GAS
LPG TO SECT. 302
ACID GAS TO SECT. 601
INERT GAS SYSTEM
204 AMINE PLANT
205 CRYOGENIC UNIT
DRIED COAL FROM UNIT 100
OIL FROM 203 P-60
VENT
BFW MAKE-UP
STEAM
BLOWDOWN
WATER
SOUR WATER FROM 203 M-53
SOUR WATER FROM 203 P-59
WET OIL
GAS TO UNIT 302
GAS FROM 203 M-53
GAS FROM 203 M-39
SOUR WATER TO SECTION 701
DISTILLATE TO 203 F-51
VAPOR TO 203 T-57 HOT SIDE, INLET FLUID
SLURRY TO 203 A-3
201 M-3 A-1 SLURRY HOLD. TANK
201 F-1 A-1 SLURRY FEED HEATER
201 F-2 A-1 HYDROGEN HEATER
201 L-1 A-1 H-COAL REACTOR
NOTE: FIGURES IN CIRCLES REFER TO FLOW STREAMS IN MATERIAL BALANCES.
SYSTEM
STONE & WEBSTER ENGINEERING CORPORATION
CLIENT
ELECTRIC POWER RESEARCH INSTITUTE
TITLE
PROCESS FLOW DIAGRAM
H-COAL LIQUEFACTION PROCESS
UNIT 200
SECTION 201 COAL HYDROGENATION
SECTION 202 EFFLUENT SEPARATION
ILLINOIS No. 6 COAL
ISSUE
DATE
DESCRIPTION OF ISSUE
BY
CHK
APPVD.
ENGINEERED E.K.P. D.M.G.
DRAWN
CHECKED
APPROVED
CERTIFIED FOR CONSTRUCTION
JOB NUMBER
13461
DRAWING NUMBER
75-D5
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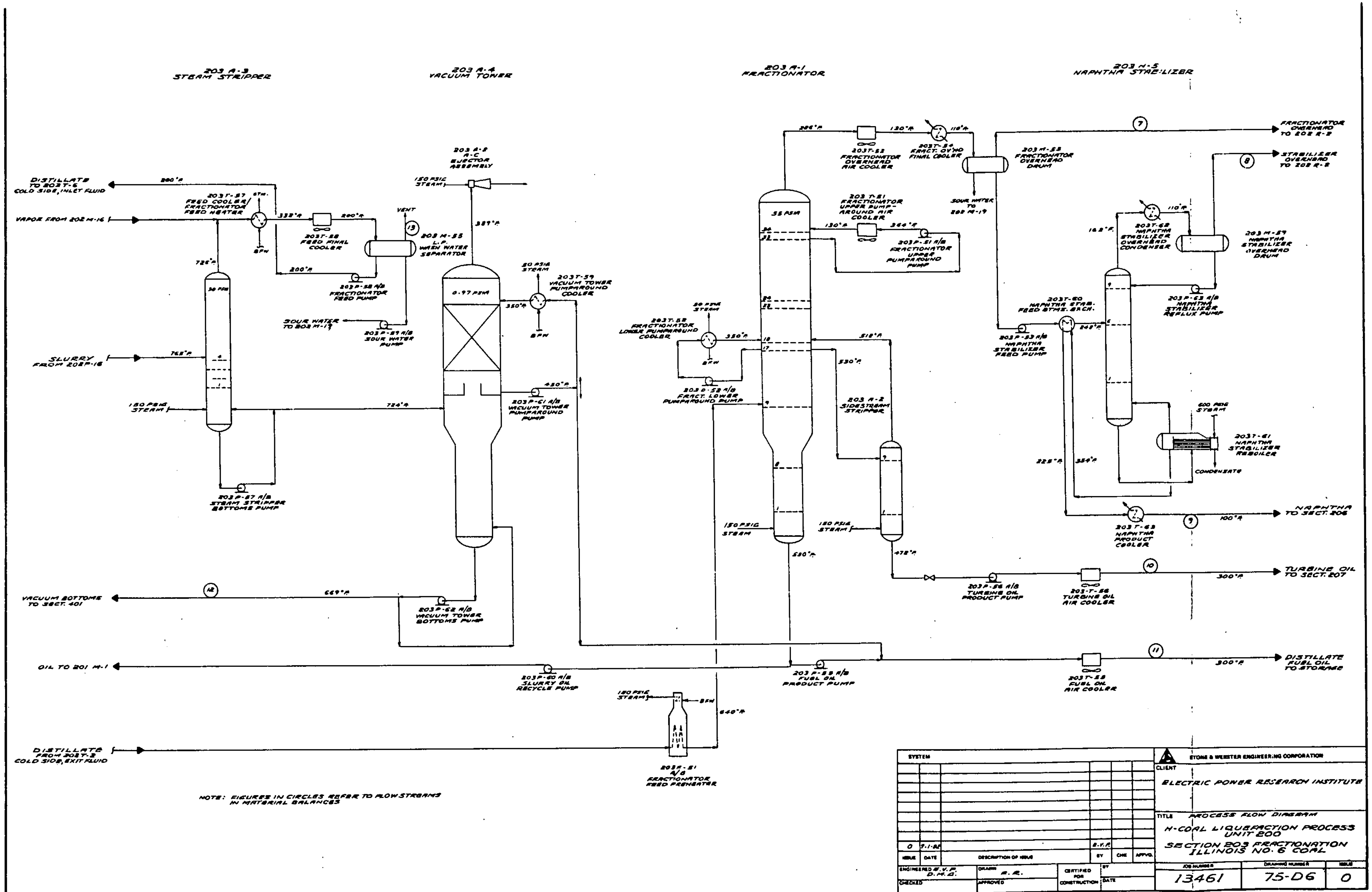


Charrette Corporation

UNIT 100 - COAL PREPARATION

Process Description - Case HE

General. Drawings numbered 75-B1 and 75-B2 are the process flow diagrams for Unit 100. A list of all equipment for Unit 100 is given in Table 5-2. Table 5-3 is a material summary for this Unit. An analysis of the Illinois No. 6 coal feed can be found in Table 3-3 of Section 3 of this report.

Description. The Coal Preparation Unit (100) includes:

- Facilities for receiving and unloading Illinois No. 6 coal which is delivered to the plant by railroad car
- Coal weighing and sampling facilities
- Live storage facilities for coal
- Dead storage facilities for coal
- Facilities for reclaiming coal from storage
- Coal crushing, grinding and drying facilities
- Facilities for transferring the processed coal to the coal slurrying area of Section 201

The quantity of coal processed at various points throughout the Unit under normal operating conditions is summarized below:

	Illinois No. 6 Coal st/sd
Coal, as received, 12% moisture	21,891
Coal, dried to 2% moisture	19,657
Coal, moisture free (MF) basis	19,264

The Coal Preparation Unit is a single train coal conveying system. Storage silos, crushers, dryers, and supporting equipment are in multiple parallel units as required for practical size limitations and for the prevention of solids handling problems. Where there is potential for disruptive failure to occur, or where high frequency of maintenance may be anticipated, standby spare equipment is provided.

Unit railroad trains, consisting of 100-ton cars, deliver washed coal, having a nominal size of two inches by zero inches, to the Coal Preparation Unit. The cars first pass through a thaw shed, which, during cold weather, melts any frozen surface moisture on the coal. A rotary car dumper, enclosed in a dumper house with a dust suppression system, then sequentially overturns each car of the train individually to unload its contents into a receiving hopper. A belt conveyor transports the coal from the receiving hopper to an intermediate storage area. Another belt conveyor transports the coal to an enclosed transfer and sample house, equipped with a dust suppression and collection system. Prior to entering the transfer and sample house, the conveyor passes through a belt scale, which weighs the coal for billing purposes. Coal sampling is performed inside the transfer and sample house. Alternate storage feed belt conveyors transport the coal from the transfer and sample house to either the live or dead storage area.

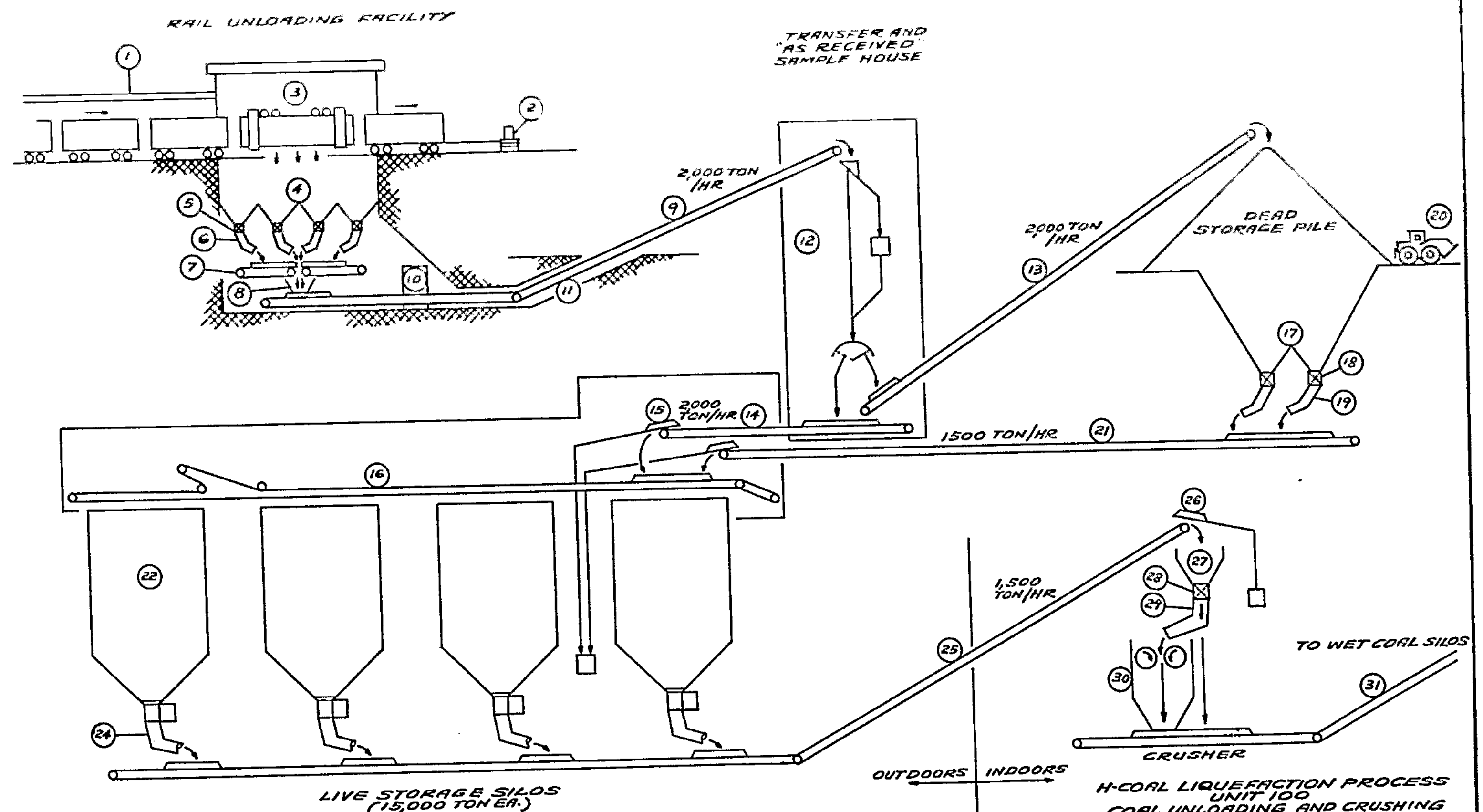
The live storage area has a working storage capacity for a 2½-day coal supply at the normal consumption rate. A series of belt conveyors transfer the coal from the transfer and sample house to concrete storage silos, which provide the live storage capacity. A magnetic separator removes tramp iron from the coal.

The dead storage area has a 30-day coal storage capacity at the normal consumption rate to ensure continued steady state operation of the plant in the event of a disruption in delivery of coal. A belt conveyor transfers coal from the transfer and sample house to an open-air dead storage pile. When required, a bulldozer removes coal from the dead storage pile to the dead storage hopper and a series of belt conveyors transfer coal from the dead storage hopper to the live storage silos.

Rotary plow feeders transport the coal from the live storage silos to a belt conveyor which feeds the coal crushing equipment located in an enclosed building. The coal first passes through a final magnetic separator to remove residual tramp iron and then dumps into a surge bin with a feeder and screening grate. Coal exiting the bin is screened to half-inch size. Undersized material falls onto a belt conveyor. Oversized material discharges into coal crushers which crush the coal to minus half-inch size. The crushed coal from the crushers falls onto the belt conveyor carrying the previously screened minus half-inch coal. This conveyor, in turn, deposits the coal onto another conveyor which distributes the coal to wet storage silos.

Feeders below the wet storage silos discharge the coal to pulverizer mills. The pulverizer mills grind and dry the half-inch coal to a minus 20 mesh end product and to 2 percent moisture content. Drying is accomplished by burning fuel gas and passing the flue gas over the grinding bowl. The pulverized coal passes upward in the hot stream and is dried in the process. The coal then passes through a classifier and the oversize material returns to the bowl for re-grinding.

The pulverized coal flows from the pulverizer mills to cyclone separators, which separate the coal from the carrier-gas. The cyclone separators are equipped with exhaust fans and bag filters for dust collection. Coal from the cyclone separators enters a pneumatic conveyor which distributes the coal to dry storage silos. Pneumatic Fuller-Kinyon pumps convey the coal from the dry storage silos, at a total normal flow rate of 802.5 tons per hour, to the eight slurry preparation tanks in the Slurry Preparation Area of Section 201.



H-COAL LIQUEFACTION PROCESS
UNIT 100
COAL UNLOADING AND CRUSHING
SHEET 1 OF 2

NOTE: EQUIPMENT NUMBERS REFER TO EQUIPMENT LIST.

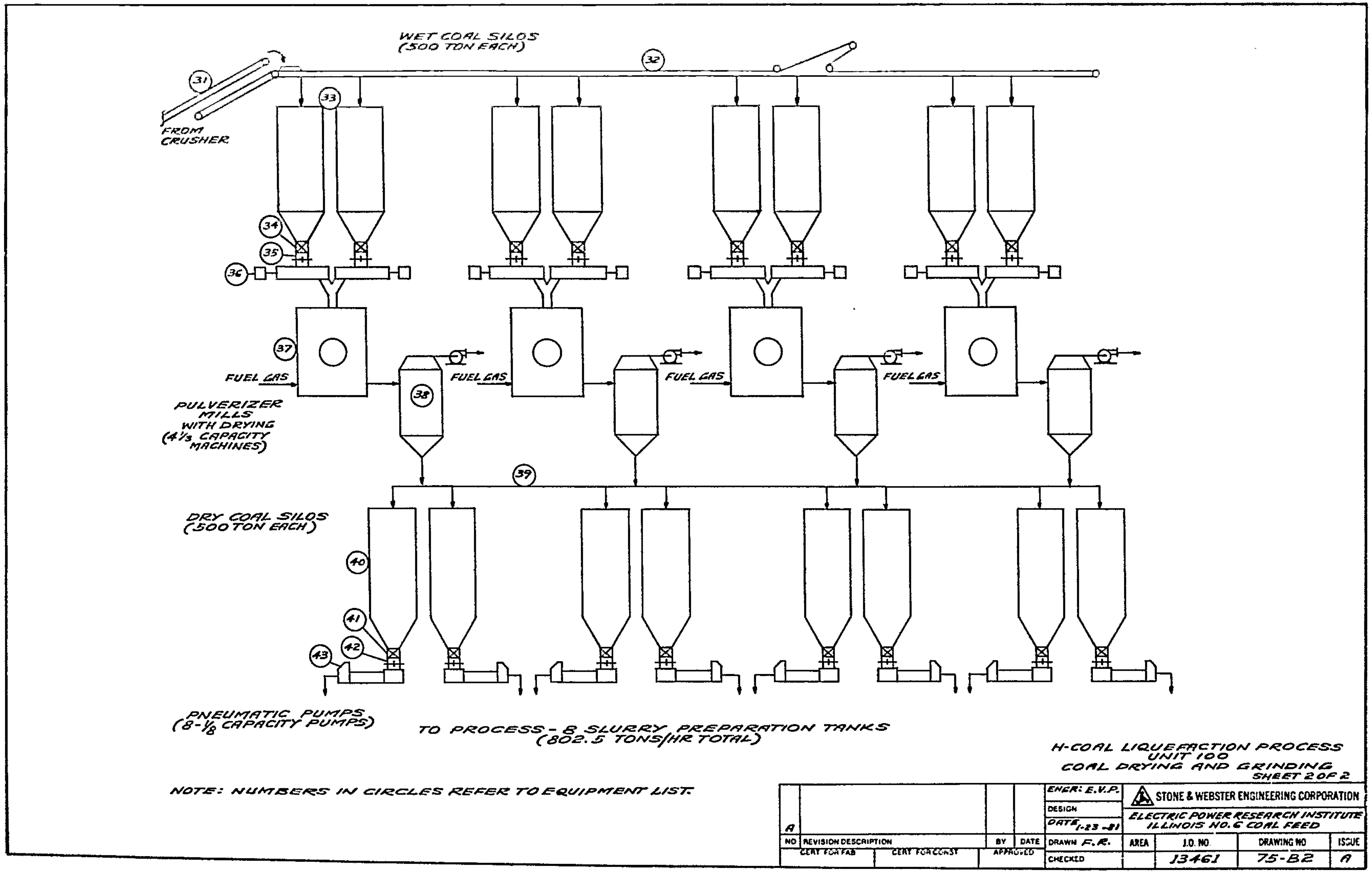
NO	REVISION DESCRIPTION	BY	DATE
A		E.V.P.	1-23-81

CERT FOR FAB | CERT FOR CONST | APPROVED

ENGR: E.V.P.
DESIGN
DATE 1-23-81
DRAWN F.R.
CHECKED

STONE & WEBSTER ENGINEERING CORPORATION
ELECTRIC POWER RESEARCH INSTITUTE
ILLINOIS NO. 6 COAL FEED

AREA	J.O. NO.	DRAWING NO.	ISSUE
	13461	75-B1	A


WET COAL SILOS
(500 TON EACH)
FROM CRUSHER
31
32
33
34
35
36
37
38
39
40
41
42
43
FUEL GAS
PULVERIZER MILLS WITH DRYING (4-1/3 CAPACITY MACHINES)
DRY COAL SILOS
(500 TON EACH)
PNEUMATIC PUMPS
(8-1/8 CAPACITY PUMPS)
TO PROCESS - 8 SLURRY PREPARATION TANKS
(802.5 TONS/HR TOTAL)
H-COAL LIQUEFACTION PROCESS
UNIT 100
COAL DRYING AND GRINDING
SHEET 2 OF 2
NOTE: NUMBERS IN CIRCLES REFER TO EQUIPMENT LIST.
ENGR: E.V.P.
DESIGN
DATE 1-23-81
DRAWN F.R.
CHECKED
STONE & WEBSTER ENGINEERING CORPORATION
ELECTRIC POWER RESEARCH INSTITUTE
ILLINOIS NO. 6 COAL FEED
A
NO REVISION DESCRIPTION
BY DATE
CERT FOR FAB
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APPROVED
AREA
J.O. NO.
13461
DRAWING NO
75-B2
ISSUE
A

Table 5-2

EQUIPMENT LIST
UNIT 100 - COAL PREPARATION
CASE HE

Item No.	No. Req'd.	Description	Specification	Flowsheet Ref. No.
		Railroad Car Delivery		
-	1	Thaw Shed	Includes heaters and "soaking" area for three 100 ton railroad cars.	1
100W-103	1	Rotary Car Dumper	4-clamp rotary car dumper for coupled cars w/car haul for positioning cars in dumper, coal breaker, dust suppression system & controls.	2 & 3
100W-104	1	Receiving Hopper	400 ton capacity, with grating and steel hopper, concrete pit, with 4 feeder areas.	4
100W-105	4	Rack and Pinion Gates	48 inch, motor operated	5
100W-106	4	Vibrating Feeders	0 to 750 ton/hr feeders	6
100W-107	2	Belt Conveyor	1500 ton/hr capacity, 48 inch width, 500 ft/min, 35° idler.	7
100W-108	1	Intermediate Bin	Two ton capacity	8
100W-109	1	Belt Conveyor with Gallery	48 inch width, 35° idlers, 700 ft/min, 2000 ton/hr capacity.	9
100W-110	1	Belt Scale	Located in pit tunnel, mechanical or electronic.	10
100W-111	1	Tunnel	Underground to grade	11
100W-112	1	Transfer and Sample House	Includes sample system & flop gate.	12
100W-113	1	Stack Conveyor	48 inch width, 35° idlers, 700 ft/min to dead storage, 2000 ton/hr capacity.	13

Table 5-2 (cont'd)

Item No.	No. Req'd.	Description	Specification	Flowsheet Ref. No.
100W-114	1	Belt Conveyor	48 inch width, 35° idlers, 700 ft/min to live storage, 2000 ton/hr capacity.	14
100W-115	2	Magnetic Separators	Self-cleaning.	15
100W-116	1 + 1	Tripper Conveyor	54 inch width, 600 ft/min, 35° idlers, 2000 tons/hr capacity. Includes gallery and transfer house.	16
100W-117	1	Dead Storage Hopper	15 foot width x 30 foot length, two 15 foot cones each 50 ton capacity.	17
100W-118	2	Rack and Pinion Gates	48 inch, motor operated	18
100W-119	2	Vibrating Feeders	750 tons/hr capacity each.	19
100W-120A	1	Bulldozer		20A
100W-120B	1	R.R. Switch Engine		20B
100W-121	1	Belt Conveyor with Gallery	48 inch width, 500 ft/min, 1500 ton/hr capacity 35° idlers, to live storage.	21
		<u>Live Storage To Wet Storage</u>		
100W-122	4	Concrete Storage Silos	15,000 tons each, 70 foot diameter x 200 feet tall, concrete construction.	22
100W-124	4	Rotary Plow Feeders	750 tons/hr	24
100W-125	1 + 1	Belt Conveyor with Gallery	48 inch width, 35° idlers, 500 ft/min, 1500 ton/hr capacity.	25
100W-126	1 + 1	Magnetic Separator	Self-cleaning.	26
100W-127	1 + 1	Crusher Surge Bin	5 ton capacity.	27

Table 5-2 (cont'd)

Item No.	No. Req'd.	Description	Specification	Flowsheet Ref. No.
100W-128	1 + 1	Rack and Pinion Gate	24 inch, motor operated.	28
100W-129	2 + 1	Vibrating Feeder	With ½ inch hole grating, approximately 500 tons/hr.	29
100W-130	2 + 1	Coal Crusher	Approximately 500 tons/hr capacity, ½ inch end product, with chutes to belt conveyor.	30
100W-131	1 + 1	Belt Conveyor with Gallery	1500 tons/hr capacity, 35° idlers, 48 inch width, 500 ft/min.	31
100W-132	1 + 1	Tripper Conveyor with Transfer House	1500 tons/hr, 400+ ft/min, 35° idlers, 54 inch width.	32
		Wet Storage To Dry Storage		
100W-133	8	Wet Storage Silos	500 ton capacity, 24 foot diameter x 50 feet tall, located above mills, with cone bottom.	33
100W-134	8	Rack and Pinion Gates	48 inch, motor operated	34
100W-135	8	Flow Indicators	Flow/no flow indicators.	35
100W-136	8	Volumetric Feeders	150 tons/hr capacity 350 tons/hr, with compressor.	36
100W-137	4	Pulverizer Mills	350 tons/hr capacity, minus 20 mesh end product, with drying.	37
100W-138	4	Cyclone Separators	350 tons/hr capacity, with bag filters and exhaust fans, piping.	38
100W-139	3 + 1	Pneumatic Conveyor	To dry storage silos, approximately 350 tons/hr each, with compressors.	39

Table 5-2 (cont'd)

Item No.	No. Req'd.	Description	Specification	Flowsheet Ref. No.
		Dry Storage		
100W-140	8	Dry Storage Silos	500 tons capacity, 24 foot diameter x 50 foot, double cone hopper.	40
100W-141	8	Rack and Pinion Gates	48 inch, motor operated	41
100W-142	8	Flow Indicators	Flow/no flow indicators.	42
100W-143	8	Pneumatic Pumps	Fuller Kinyon pumps with compressors, 200 ton/hr capacity max, with piping.	43

Note: Fifteen percent 304L, cladding of carbon steel (ASTM 264) is used as the material of construction for hoppers, feeders, silos, bins, gates, etc.

Table 5-3

MATERIAL SUMMARY - UNIT 100
COAL PREPARATION - CASE HE

Input

Coal, Illinois No. 6 (as received)	lb/hr	1,824,243
- Moisture content, weight percent		12

Output

Coal (2% moisture)	lb/hr	1,638,095
Water vapor discharge	lb/hr	186,148

UNIT 200 - COAL LIQUEFACTION

Process Description - Case HE

General. The coal liquefaction plant design for the Illinois coal case is based on the H-Coal process developed by HRI. Unit 200 is composed of reaction, separation, hydrotreating, and naphtha reforming sections as follows:

Reaction and Separation Sections

Section 201 - Coal Slurrying and H-Coal Reaction

Section 202 - Effluent Separation

Section 203 - Fractionation

Section 204 - Amine Plant

Section 205 - Cryogenic Plant

Product Hydrotreating and Reforming Sections

Section 206 - Naphtha Hydrotreating

Section 207 - Turbine Fuel Hydrotreating

Section 208 - Naphtha Reforming

Sections 201, 202, and 203 are described below. Following these descriptions are the process flow diagrams for the Reaction and Separation Sections, drawings 75-D5 and 75-D6, and a schematic diagram of the catalyst addition and withdrawal system, drawing 75-A1. Equipment lists and process equipment specifications on major items of equipment are presented in Tables 5-4 and 5-5. A block flow diagram for Sections 201 through 205, drawing 75-B8, is followed by the material balance on Table 5-6.

Descriptions of the Amine and Cryogenic Sections (204 and 205) and the Hydrotreating and Reforming Sections (206, 207, and 208) follow separately.

SECTION 201 - COAL SLURRYING AND H-COAL REACTION

Coal Slurrying. Pneumatic pumps in the Coal Preparation Unit (100) transport pulverized and dried Illinois No. 6 coal to eight equal capacity parallel operating trains of the coal slurrying area. The coal divides evenly to each train and enters slurry preparation tanks.

The coal mixes in the tanks with recycle slurry oil from the fractionator bottoms of the Fractionation Section (203) to form a recycle oil slurry containing 50 weight percent total coal-solids. This slurry stream then mixes with recycled hot solids, contained in a hydroclone liquid overflow stream, from the Effluent Separation Section (202). The combined slurry stream then enters slurry holding tanks. Additional recycle slurry oil is used to maintain the slurry at the proper composition in the holding tanks. The slurry holding tanks are at a sufficient pressure to prevent vaporization of the oil.

Internal agitators in the slurry preparation and holding tanks, assisted by continuous recirculation of a portion of the slurry to the tanks, maintain a uniform slurry composition. Inert gas blanketing of the tanks prevents air leakage into the system.

Slurry from the holding tanks joins a portion of the total hydrogen feed stream to improve the thermal conductivity and flow properties of the slurry through the slurry feed heaters. The slurry feed heaters are process furnace type heaters which preheat the slurry and hydrogen mixture to reactor feed temperature.

Hydrogen heaters, which are also process furnace type heaters, preheat the balance of the total recycled hydrogen feed stream to reactor feed temperature. A portion of the plant high pressure (1500 psig) steam is generated in the convection section of the hydrogen heaters. High pressure steam flows to a high pressure steam header for distribution to the plant as process steam for the Texaco gasifiers in Section 401, or as steam for power generation.

The coal slurrying area has a standby ninth equipment train, identical to one operating train.

<u>H-Coal Reaction.</u> The preheated slurry-hydrogen mixture and remaining recycle hydrogen streams enter at the bottom of an H-coal reactor and flow upward through an ebullating bed of catalyst.

The H-coal reaction is the catalytic hydrogenation of the coal-oil slurry under conditions of relatively high temperature (850°F) and high pressure (3000 psig). The reaction liquefies the coal and produces light hydrocarbon vapors and non-hydrocarbon gases, coal liquids consisting of a broad range of volatilities, and a heavy residual oil stream containing ash and unconverted coal. The reactors operate in a near-isothermal state.

The H-coal reactors are vertical, cylindrical vessels containing catalyst. The upflowing reaction gases and liquids fluidize the bed. External reactor ebullating pumps recirculate slurry from the top to the bottom of each reactor to maintain the bed in an ebullated state.

The reaction products, unreacted coal and ash particles, finer than the catalyst, exit from the top of the reactors and separate into vapor and liquid slurry fractions in reactor effluent separators. The solids disengage from the vapor and remain in the slurry.

The coal slurrying area and the H-Coal reaction area each have a standby ninth equipment train, identical to one operating train.

<u>H-Coal Reactor Catalyst Addition and Withdrawal System.</u> Catalyst activity in the H-Coal reactor system is kept substantially constant by the daily batchwise addition of a small amount of fresh catalyst and the withdrawal of a corresponding amount of spent catalyst during normal operation.

There are nine equal-capacity parallel trains of equipment in the Catalyst Addition and Withdrawal System, each associated with nine installed H-Coal reactors.

A lock-hopper type system is used for the addition and withdrawal of catalyst. During catalyst addition operation, fresh catalyst, charged to catalyst fill hoppers, drains by gravity flow into catalyst addition drums, initially at atmospheric pressure. Make-up hydrogen pressurizes the drums to a pressure slightly above reactor operating pressure, and the catalyst transfers to the H-Coal reactors by gravity flow. After catalyst loading, the drums are depressurized and purged with inert gas to prepare for the next batch. During catalyst withdrawal operation, inert gas purges air from catalyst withdrawal drums and catalyst liquid separators. Make-up hydrogen next pressurizes the vessels to reactor operating pressure. Hot recycle slurry oil is then circulated through the vessels to minimize thermal shock when very high temperature material from the reactors is introduced. Withdrawn catalyst and slurry flow to the catalyst withdrawal drums where the heavier catalyst settles from the slurry. The slurry overflows to the catalyst liquid separation drums, which separate dissolved gases from the liquid slurry. The gases and slurry flow separately to high pressure letdown drums. The effective catalyst withdrawal rate from the reactors is controlled by adjustment of the gas vent pressure which regulates the pressure in the separation drums. Reduction of the drum pressure establishes a differential pressure between the reactors and the drums which causes catalyst to flow from the reactors to the withdrawal system. When the desired amount of catalyst has been removed, flushing oil is used to backflush the withdrawal system to clean and partially cool the system. The withdrawal system vessels are depressurized and further cooled with cold flushing oil. When the system is sufficiently cooled, flush oil circulation ceases, the vessels drain, spent catalyst is discharged to spent catalyst storage via bottom connections in the catalyst withdrawal drums, and inert gas purges the system to prepare for processing the next batch.

Provision is made in the withdrawal system for dumping the entire catalyst inventory from the reactors after a reactor shutdown. Operation is first switched from coal feed to a light oil feed to displace heavy coal liquids from the reactors. The reactors are then shut down. Continued light oil circulation transports catalyst from the reactors to catalyst dump tanks. Spent catalyst is discharged from the dump tanks to spent catalyst storage.

SECTION 202 - EFFLUENT SEPARATION

The Effluent Separation Section (202) separates the multi-phase effluent from the H-Coal reactors into several raw-product streams, which undergo further processing in other sections. Hydrogen and slurry oil streams, recycled as feeds to the Slurry Preparation and H-Coal Reaction Section (201), are also produced. Finally, the separations yield a sour water effluent stream requiring waste water treatment in the Effluent Control Unit (700).

The Effluent Separation Section utilizes an arrangement of three parallel levels of multi-stage flash separations at successively lower temperatures and pressures, with interstage process cooling and heat recovery.

The combined gaseous and slurry effluent from the reactor pass into the reactor effluent separator where a separation of vapor and slurry reactor products occurs.

The recovered vapor enters the first level of effluent separation and is cooled first by preheating recycle gas, and then by preheating fractionator feed. The condensate produced is separated from the vapor stream and sent to the second level of effluent separation. The vapor is further cooled by producing steam, preheating boiler feedwater, and by air cooling. Wash water is injected prior to the final cooling stages to assure that ammonium sulfide salts formed are dissolved and will not plug an exchanger or line. The final separation at level one produces vapor and hydrocarbon liquid phases, and an aqueous phase.

A portion of the hydrogen rich vapors is compressed and recycled to the reactor. The remaining vapors mix with vapors from the second level of effluent separation and are used as feed to the amine unit for removal of acid gases, followed by a cryogenic unit to provide an enriched hydrogen stream for recycle to the H-Coal reactor. The aqueous phase is sent to a water degassing drum and discharged to sour water stripping in Section 701.

Two-stage condensation of vapors is used throughout the coal hydrogenation unit wherever a wash water injection is required for the removal of ammonium sulfides. The first condensation is made at relatively high temperature to condense and separate the heavy hydrocarbon content of the vapor stream before the water is injected. This method avoids creation of emulsions in water which may be formed if the heavy hydrocarbon oils are allowed to condense along with the aqueous phase.

The bottoms liquid from the reactor effluent separator, consisting of a slurry of H-Coal liquids containing unreacted coal solids, flows to the second level of flash separation. Relatively higher volatility intermediate hydrocarbons and light H-Coal liquids are flashed off. These vapors flow overhead from a separator to join the intermediate volatility hydrocarbon condensate from the first level of flash separation and undergo further separation at the second level. The combined vapor-liquid stream is cooled and the vapor fraction partially condensed by exchanging waste heat with boiler feed water to generate low pressure steam. A portion of the bottoms liquid condensate from the separator is air-cooled and recycled to the second level of separation, where it joins the reactor effluent separator bottoms. The balance of the liquid joins the overhead vapors from the Low Pressure Slurry Letdown Drum for further separation at the third separation level. Uncondensed relatively lighter hydrocarbon vapors exit as the overhead stream. Wash water is injected into the vapor as before to prevent the formation of ammonium sulfide salts. The vapor-liquid stream is air-cooled and further partial condensation of vapor occurs. The multi-phase stream joins the final organic liquid separated from the first level of flash separation and flows to a final flash separator in the second level. Uncondensed light hydrocarbon vapor is separated from the liquid. The vapor joins a portion of the hydrogen rich vapors from the first level of separation and flows to the Amine Plant (204). The organic liquid is then sent to the final separator of the third separation level. An aqueous liquid phase enters a sour water collection vessel for ultimate flow to waste water treatment.

The bottoms liquid from the H.P. Slurry Letdown Drum in the second level, consisting of a slurry of the unreacted coal solids, the middle to heavy distillates, and residual oil, flows to the third level of flash separation. The mid-range distillates and traces of lighter components flash. These flash vapors, exiting overhead from the L.P. Slurry Letdown Drum, are the third level of separation. The vapors are cooled and partially condensed by heat exchange with the fractionator feed and then by exchanging waste heat with boiler feed water to generate low pressure steam. The condensate from the separator constitutes part of the fractionator feed. Uncondensed vapors of medium weight hydrocarbons and light to medium distillates are separated overhead. As before, wash water is injected into the vapor to prevent the formation of ammonium sulfide salts. The vapor-liquid stream is air-cooled and further partial condensation of vapor occurs. The multi-phase stream joins the final organic liquid separated from the second level of flash separation and flows to a final flash separator in the third level. Uncondensed hydrocarbon vapor is separated from the liquid and flows overhead to the LPG Recovery Plant (300) for recovery of propane and butane liquid products. An organic liquid phase, containing light to middle range distillates, is separated from the final multi-phase stream from the third level of separation. This stream constitutes part of the fractionator feed. An aqueous liquid phase, decanted from the final total liquid from the third separation level, joins the similar streams from the first two levels and sour water streams from the Fractionation Section (203). The total sour water enters a sour water collection vessel for ultimate flow to the Effluent Control Unit (700) for waste water treatment.

The heavy distillates and residual oil, containing the unreacted coal solids, exit as a slurry from the bottom of the first flash separator in the third level of separation. This material then flows to the hydroclones and is separated into a relatively low-solids oil stream for recycle to the slurry preparation area, and a heavy solids-containing residual oil which is sent to the Fractionation Section (203).

The Effluent Separation Section has eight equal capacity parallel operating trains at the first level of separation, and two 50 percent capacity parallel operating trains at the second and third levels of separation and in the hydroclones separation area.

SECTION 203 - FRACTIONATION

The Fractionation Section receives raw liquefied coal feeds from the Effluent Separation Section (202) and separates these feed streams into light hydrocarbon vapors and liquid products. The liquid products are naphtha, turbine fuel, distillate fuel oil, and vacuum bottoms residual oil. Also, a heavy oil stream is produced which is recycled to the coal slurrying area. The following processing operations are used:

- Steam stripping
- Vacuum distillation
- Fractionation
- Stabilization distillation
- Partial condensation

The hydroclones underflow from the Effluent Separation Section (202), consisting of concentrated slurry, enters a steam stripper. Medium pressure steam is used to strip low boiling hydrocarbons from the liquid.

The steam stripper overhead, consisting of steam and light hydrocarbon vapors, joins other hydrocarbon vapor streams from the Effluent Separation Section and is cooled and partially condensed. The resultant multi-phase mixture separates into a steam-hydrocarbon vapor stream which is flared, an organic liquid phase of condensed hydrocarbons which constitute the principal component of the fractionator feed, and an aqueous liquid phase containing sour water which is sent to waste water treatment.

The concentrated slurry from the bottom of the steam stripper flows to a vacuum tower. By vacuum distillation, the slurry feed is separated into an overhead stream as a distillate fuel-oil product, and a vacuum bottoms residual oil stream which flows to the hydrogen plant as feedstock to the Texaco Gasification Section (401).

A steam jet ejector, using medium pressure steam as the motive fluid, maintains a vacuum in the vacuum tower.

The distillate, recovered from the steam stripper overhead, joins hydrocarbon liquid streams from the Effluent Separation Section. The combined stream is heated and flows to the fractionator as the feed to the tower. The fractionator separates these heavy coal-derived liquids into naphtha, turbine oil and distillate fuel oil cuts. Medium pressure steam, fed to the bottom of the fractionator, strips residual light hydrocarbons from the heavy bottom material, which is of distillate fuel oil quality. The fractionator bottoms product splits to provide a small distillate fuel oil stream which joins with the net distillate fuel oil stream from the vacuum tower overhead and flows to storage. The bulk of the fractionator bottoms flows to the Slurry Preparation Section (201) as slurry oil.

Raw turbine oil, withdrawn as a liquid from the fractionator mid-section, enters a sidestream stripper, which uses medium pressure steam to strip the more volatile hydrocarbon components. This yields a stabilized bottoms turbine oil product which flows to the Oil Upgrading Section (207) for upgrading to turbine fuel quality. Steam and volatile hydrocarbons, exiting the sidestream stripper overhead, flow back to the fractionator at a point above the liquid withdrawal. The bulk of this vapor, after further fractionation, exits in the fractionator overhead vapor. The fractionator overhead is cooled to partially condense steam and hydrocarbon vapors. The resultant multi-phase mixture separates into a hydrocarbon vapor stream, an organic liquid phase and an aqueous liquid phase. The vapor joins other similar hydrocarbon vapor streams from the Effluent Separation Section (202) and the naphtha stabilizer. The combined stream is compressed and flows to the DGA Plant (301) for removal of residual acid gases and to the LPG Recovery Plant (302). The aqueous sour water phase joins other sour water streams, which are sent to waste water treatment.

The organic liquid phase, consisting of the higher volatility naphtha cut material orginally contained in the fractionator feed, flows to a naphtha stabilizer. The naphtha stabilizer is a tower which removes the high volatility components from the feed to yield a stabilized naphtha product. The naphtha stabilizer overhead vapor joins other streams flowing to the DGA and LPG recovery plants.

The tower bottoms, consisting of the stabilized naphtha, is cooled and sent to the Naphtha Hydrotreating Section (206), where it is hydrotreated before reforming in the Naphtha Reforming Section (208) to produce high octane gasoline.

The Fractionation Section has a single 100 percent operating train.

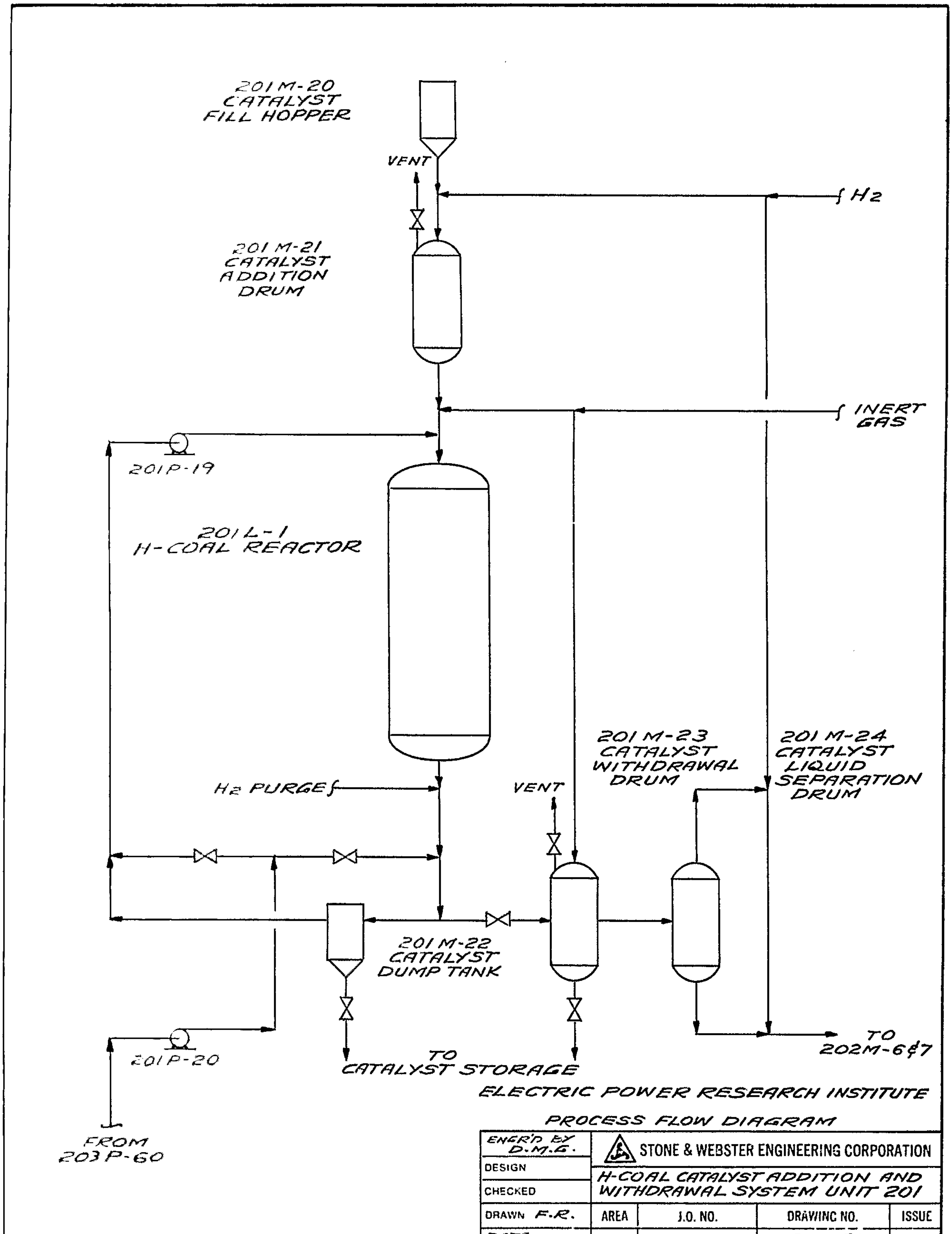

201M-20
CATALYST
FILL HOPPER
VENT
H2
201M-21
CATALYST
ADDITION
DRUM
INERT
GAS
201P-19
201L-1
H-COAL REACTOR
201M-23
CATALYST
WITHDRAWAL
DRUM
201M-24
CATALYST
LIQUID
SEPARATION
DRUM
H2 PURGE
VENT
201M-22
CATALYST
DUMP TANK
201P-20
TO
CATALYST STORAGE
TO
202M-6&7
FROM
203P-60
ELECTRIC POWER RESEARCH INSTITUTE
PROCESS FLOW DIAGRAM
ENGR'D BY D.M.G.
DESIGN
CHECKED
DRAWN F.R.
DATE 1-27-81
STONE & WEBSTER ENGINEERING CORPORATION
H-COAL CATALYST ADDITION AND
WITHDRAWAL SYSTEM UNIT 201
AREA
J.O. NO.
13461
DRAWING NO.
75-A1
ISSUE
A

Table 5-4

EQUIPMENT LIST
UNIT 200 - SECTIONS 201, 202, AND 203
CASE HE

Section 201 - Coal Slurrying & H-Coal Reaction

Item No.	No. Req'd	Description
201 F-1	8 + 1	Slurry Feed Heater
201 F-2	8 + 1	Hydrogen Heater
201 L-1	8 + 1	H-Coal Reactor
201 M-1	8 + 1	Slurry Preparation Tank
201 M-2	2	Condensate Collector
201 M-3	8 + 1	Slurry Holding Tank
201 M-4	2	High Pressure Steam Drum
201 M-5	8 + 1	Reactor Effluent Separator
201 M-20	8 + 1	Catalyst Fill Hopper
201 M-21	8 + 1	Catalyst Addition Drum
201 M-22	8 + 1	Catalyst Dump Tank
201 M-23	8 + 1	Catalyst Withdrawal Drum
201 M-24	8 + 1	Catalyst Liquid Separator
201 P-1	8 + 10	Slurry Prep Circulation Pump
201 P-2	2 + 2	Condensate Booster Pump
201 P-3	2 + 2	Slurry Oil Recycle Booster Pump
201 P-4	8 + 10	Slurry Tank Circulation Pump
201 P-5	16 + 6	Slurry Feed Pump
201 P-6	2 + 2	Water Circulation Pump
201 P-7	8 + 1	Reactor Ebullating Pump

Table 5-4 (cont'd)

Section 201 - Coal Slurrying & H-Coal Reaction (cont'd)

Item No.	No. Req'd	Description
201 P-19	8 + 1	Catalyst Unloading Pump
201 P-20	8 + 1	High Pressure Heavy Flush Oil Pump
201 R-3	8	Make-up Hydrogen Compressor
201 T-1	2	Vapor Condenser

Table 5-4 (cont'd)

Section 202 - Effluent Separation

Item No.	No. Req'd	Description
202 G-1	10	Hydroclone Assembly
202 M-6	2	High Pressure Slurry Letdown Drum
202 M-7	2	Low Pressure Slurry Letdown Drum
202 M-8	2	Low Pressure Condensate Receiver
202 M-9	2	Low Pressure Condensate Wash Water Separator
202 M-10	8	Reactor Effluent Vapor Separator
202 M-11	2	High Pressure Condensate Receiver
202 M-12	2	Low Pressure Steam Drum
202 M-13	8	Reactor Effluent Vapor Wash Water Separator
202 M-14	2	High Pressure Condensate Drum
202 M-15	2	Compressor Suction Knockout Drum
202 M-16	2	Recycle Slurry Oil Flash Drum
202 M-17	2	Hydroclone Overflow Surge Drum
202 M-18	2	Hydroclone Underflow Surge Drum
202 M-19	2	Water Degassing Drum
202 P-8	2 + 2	Slurry Recirculation Pump
202 P-9	2 + 2	Fractionator Pump
202 P-10	2 + 2	Fractionator Feed Pump
202 P-11	2 + 2	Quench Pump
202 P-12	2 + 2	Water Circulation Pump
202 P-13	4 + 2	Slurry Oil Recycle Pump
202 P-14	4 + 2	Hydroclone Overflow Circulation Pump

Table 5-4 (cont'd)

Section 202 - Effluent Separation (cont'd)

Item No.	No. Req'd	Description
202 P-15	2 + 2	Hydroclone Feed Pump
202 P-16	2 + 2	Hydroclone Underflow Circulation Pump
202 P-17	2 + 2	Sour Water Discharge Pump
202 P-18	2 + 2	Wet Oil Discharge Pump
202 R-1	2	Hydrogen Recycle Compressor
202 R-2	1	Light Ends Compressor
202 T-2	2	Vapor Cooler/Fractionator Heater
202 T-3	2	Vapor Final Cooler
202 T-4	2	LP Receiver Overhead Condenser
202 T-5	8	Vapor Cooler/Recycle Gas Heater
202 T-6	8	Vapor Cooler/Fractionator Feed Heater
202 T-7	2	Feed Cooler/Waste Heat Boiler
202 T-8	2	Quench Cooler
202 T-9	8	Vapor Cooler/Waste Heat Boiler
202 T-10	8	Feed Cooler/Boiler Feedwater Preheater
202 T-11	8	Feed Final Cooler
202 T-12	2	HP Receiver Overhead Condenser

Table 5-4 (cont'd)

Section 203 - Fractionation

Item No.	No. Req'd	Description
203 A-1	1	Fractionator
203 A-2	1	Sidestream Stripper
203 A-3	1	Steam Stripper
203 A-4	1	Vacuum Tower
203 A-5	1	Naphtha Stabilizer
203 F-51	1 + 1	Fractionator Feed Preheater
203 G-2	2 + 1	Ejector Assembly
203 M-53	1	Fractionator Overhead Drum
203 M-55	1	Low Pressure Wash Water Separator
203 M-59	1	Naphtha Stabilizer Overhead Drum
203 P-51	1 + 1	Fractionator Upper Pumparound Pump
203 P-52	1 + 1	Fractionator Lower Pumparound Pump
203 P-53	1 + 1	Naphtha Stabilizer Feed Pump
203 P-55	1 + 1	Fuel Oil Product Pump
203 P-56	1 + 1	Turbine Oil Product Pump
203 P-57	1 + 1	Steam Stripper Bottoms Pump
203 P-58	1 + 1	Fractionator Feed Pump
203 P-59	1 + 1	Sour Water Pump
203 P-60	1 + 1	Slurry Oil Recycle Pump
203 P-61	1 + 1	Vacuum Tower Pumparound Pump

Table 5-4 (cont'd)

Section 203 - Fractionation (cont'd)

Item No.	No. Req'd	Description
203 P-62	1 + 1	Vacuum Tower Bottoms Pump
203 P-63	1 + 1	Naphtha Stabilizer Reflux Pump
203 T-51	1	Fractionator Upper Pumparound Air Cooler
203 T-52	1	Fractionator Lower Pumparound Cooler
203 T-53	1	Fractionator Overhead Air Cooler
203 T-54	1	Fractionator Overhead Final Cooler
203 T-55	1	Fuel Oil Air Cooler
203 T-56	1	Turbine Oil Air Cooler
203 T-57	1	Feed Cooler/Fractionator Feed Heater
203 T-58	1	Feed Final Cooler
203 T-59	1	Vacuum Tower Pumparound Cooler
203 T-60	1	Naphtha Stabilizer Feed/Bottoms Exchanger
203 T-61	1	Naphtha Stabilizer Reboiler
203 T-62	1	Naphtha Stabilizer Overhead Condenser
203 T-63	1	Naphtha Product Cooler

Table 5-5

EQUIPMENT SPECIFICATIONS
UNIT 200 - CASE HE

Equipment Item No.	Quantity Oper.	Quantity Spare	Service	Number of Trays	Horiz. or Vert.	Size Diam.	Size T-T	Design P/T psi/°F	Materials/Remarks
TOWERS									
203 A-1	1	0	Fractionator	28	Vert.	21'0" and 18'0"	45'0" and 21'0"	75/660	SA516 with 12 Cr Cladding
203 A-2	1	0	Sidestream Stripper	9	Vert.	6'6"	27'0"	75/550	SA516
203 A-3	1	0	Steam Stripper	4	Vert.	7'6"	22'0"	50/775	SA515 Gr 70 with 410 SS Cladding Disc/Donut Trays
203 A-4	1	0	Vacuum Tower		Vert.	13'0" and 9'6"	28'0" and 7'0"	50/750	CS with 410 SS Cladding 5' high packed bed using 2" Al Pall rings, chimney tray
203 A-5	1	0	Naphtha Stabilizer.	9	Vert.	5'0"	28'0"	115/400	A516

Table 5-5 (cont'd)

Equipment Item No.	No. Quantity Oper.	No. Quantity Spare	Service	Fired Duty 10^6 Btu/hr (Each)	Design Press. Psig	Design Temp. °F	Materials
FIRED HEATERS							
201 F-1	8	1	Slurry Feed Heater	68.2	3,250	690	347 SS
201 F-2	8	1	Hydrogen Heater	21.4	3,250	1100	347 SS
203 F-51	1	1	Fractionator Feed Preheater	72.5	75	700	347 SS

Table 5-5 (cont'd)

Equipment Item No.	Quantity Oper.	Quantity Spare	Service	Horiz. or Vert.	Size Diam.	Size T-T	Design P/T psi/°F	Materials
REACTOR								
201 L-1	8	1	H-Coal Reactor	Vert.	13'0"	59'0"	3250/875	$2\frac{1}{4}$ Cr - 1 Mo with 347 Weld Overlay and 6" Kastolite or Equal Refractory (Hot Wall Design)
DRUMS								
201 M-1	8	1	Slurry Preparation Tank (15 HP Agitator)	Vert.	12'0"	29'0"	30/50	CS
201 M-2	2	0	Condensate Collector	Horiz.	4'6"	13'0"	30/280	CS
201 M-3	8	1	Slurry Holding Tank	Vert.	10'0"	21'0"	325/550	SA204 GR C with 410 SS Cladding
201 M-4	2	0	High Pressure Steam Drum	Horiz.	5'0"	10'0"		CS/1500 psig Steam
201 M-5	8	1	Reactor Effluent Separator	Vert.	9'0"	13'0"	3250/875	SA367 GR 22 C1 2 with 347 or 321 Cladding and 6" Kastolite or Equal Refractory
201 M-20	8	1	Catalyst Fill Hopper	Vert.	6'0"	7'6"	0/150	SA285 Gr C Hinged Cover Conical Bottom Section
201 M-21	8	1	Catalyst Addition Drum	Vert.	3'0"	9'0"	3250/400	SA204 Gr C
201 M-22	8	1	Catalyst Dump Tank	Vert.	4'6'	9'0"	0/450	SA285 Gr C Hinged Cover Conicle Bottom Section

Table 5-5 (cont'd)

Equipment Item No.	Quantity Oper.	Quantity Spare	Service	Horiz. or Vert.	Size Diam.	Size T-T	Design P/T psi/°F	Materials
DRUMS (cont'd)								
201 M-23	8	1	Catalyst Withdrawal Drum	Vert.	2'6"	9'0"	3250/875	SA387 Gr 22 Cl 2 with 347 or 321 SS Cladding
201 M-24	8	1	Catalyst Liquid Separator	Vert.	3'0"	9'0"	3250/875	SA 387 Gr 22 Cl 2 with 347 or 321 SS Cladding
202 M-6	2	0	High Pressure Slurry Letdown Drum	Vert.	7'6"	23'0"	1305/850	SA387 Gr 12 Cl 2 with 321 SS Cladding
202 M-7	2	0	Low Pressure Slurry Letdown Drum	Vert.	8'0"	24'0"	85/815	SA387 Gr 12 Cl 2 with 321 SS Cladding
202 M-8	2	0	Low Pressure Condensate Receiver	Horiz.	10'0"	21'0"	75/400	CS
202 M-9	2	0	Low Pressure Condensate Water Wash Separator	Horiz.	4'6"	21'0"	50/175	SA516 Gr 70
202 M-10	8	0	Reactor Effluent Vapor Separator	Horiz.	4'0"	12'0"	3250/550	$1\frac{1}{4}$ Cr - $\frac{1}{2}$ Mo with 321 SS Cladding
202 M-11	2	0	High Pressure Condensate Receiver	Horiz.	5'6"	18'0"	1295/475	CS with 304L Cladding
202 M-12	2	0	Low Pressure Steam Drum	Horiz.	5'6"	47'0"		CS/50 psig Steam
202 M-13	8	0	Reactor Effluent Vapor Wash Water Separator	Horiz.	4'0"	14'0"	3230/180	SA516 Gr 70

Table 5-5 (cont'd)

Equipment Item No.	Quantity Oper.	Spare	Service	Horiz. or Vert.	Size Diam.	T-T	Design P/T psi/°F	Materials
DRUMS (cont'd)								
202 M-14	2	0	High Pressure Condensate Drum	Horiz.	3'6"	14'0"	1285/175	SA516 Gr 70
202 M-15	2	0	Compressor Suction Knockout Drum	Vert.	2'6"	8'0"	3220/180	SA516 Gr 70
202 M-16	2	0	Recycle Slurry Oil Flash Drum	Vert.	5'0"	19'0"	30/795	SA515 Gr 70
202 M-17	2	0	Hydroclone Overflow Surge Drum	Vert.	6'6"	14'0"	85/815	SA515 Gr 70
202 M-18	2	0	Hydroclone Underflow Surge Drum	Vert.	5'0"	11'0"	85/815	SA515 Gr 70
202 M-19	2	0	Water Degassing Drum	Horiz.	11'0"	27'0"	30/180	SA516 Gr 70
203 M-53	1	0	Fractionator Overhead Drum	Horiz.	7'6"	21'0"	50/250	Killed CS
203 M-55	1	0	Low Pressure Water Wash Separator	Horiz.	11'0"	28'0"	50/250	SA516
203 M-59	1	0	Naphtha Stabilizer Overhead Drum	Horiz.	5'0"	14'0"	125/250	A516

Table 5-5 (cont'd)

Equipment Item No.	No. Required Oper.	No. Required Spare	Service	Design gpm (Each)	Design Disc/ Suct.	Oper. Temp. °F	Materials Casing	Materials Internals	Driver Type	Driver hp
PUMPS										
201 P-1	8	10	Slurry Prep Circulation	1001	320/10	340	CA-6NM[a]	CA-6NM	Motor	300
201 P-2	2	2	Condensate Booster	44	320/5	230	CS	CS	Motor	
201 P-3	2	2	Slurry Oil Recycle Booster	700	320/90	550	5 Cr	5 Cr	Motor	
201 P-4	8	10	Slurry Tank Circulation	1752	375/285	481	CA-6NM	CA-6NM	Motor	125
201 P-5	16	6	Slurry Feed[b]	637	3150/375	481	CA-6NM	CA-6NM	Motor	1250
201 P-6	2	2	Water Circulation	2400	645/595	489	12 Cr	12 Cr	Motor	
201 P-7	8	1	Reactor Ebullating	9048	[c]	[c]	316 SS	Trim: Tungsten Carbide	Motor	300
201 P-19	8	1	Catalyst Unloading	200	100/0	120-550	12 Cr	12 Cr	Motor	25
201 P-20	8	1	High Pressure Heavy Flush Oil[b]	175	3250/0	550	CS	12 Cr	Motor	500
202 P-8	2	2	Slurry Recirculation	3693	80/65	765	5 Cr	5 Cr	Motor	
202 P-9	2	2	Fractionator	2689	160/55	350	CS	12 Cr	Motor	
202 P-10	2	2	Fractionator Feed	237	160/30	125	CS	12 Cr	Motor	
202 P-11	2	2	Quench Pump	328	1235/1170	425	12 Cr	12 Cr	Motor	

[a] Chrome Steel [b] Reciprocating Pump [c] HRI confidential information

Table 5-5 (cont'd)

Equipment Item No.	No. Required Oper.	No. Required Spare	Service	Design gpm (Each)	Design Disc/Suct.	Oper. Temp. °F	Materials Casing	Materials Internals	Driver Type	Driver hp
PUMPS (cont'd)										
202 P-12	2	2	Water Circulation	3933	95/55	308	12 Cr	12 Cr	Motor	
202 P-13	4	2	Slurry Oil Recycle	2180	365/10	745	CA-6NM	CA-6NM	Motor	
202 P-14	4	2	Hydroclone Overflow Circulation	2563	90/65	765	CA-6NM	CA-6NM	Motor	
202 P-15	2	2	Hydroclone Feed	1605	160/80	765	CA-6NM	CA-6NM	Motor	
202 P-16	2	2	Hydroclone Under-flow Circulation	1131	90/65	765	CA-6NM	CA-6NM	Motor	
202 P-17	2	2	Sour Water Discharge	1384	90/10	130	316 SS	316 SS	Motor	
202 P-18	2	2	Wet Oil Discharge	13	90/10	130	CS	CS	Motor	
203 P-51	1	1	Fractionator Upper Pumparound	6101	65/40	366	CS	CS	Motor	
203 P-52	1	1	Fractionator Lower Pumparound	1427	70/45	507	CS	CS	Motor	
203 P-53	1	1	Naphtha Stabilizer Feed Pump	472	140/30	110	CS	CS	Motor	
203 P-55	1	1	Fuel Oil Product	480	100/40	558	CS	12 Cr	Motor	
203 P-56	1	1	Turbine Oil Product	845	100/35	463	CS	CS	Motor	
203 P-57	1	1	Steam Stripper Bottoms	1667	25/10	727	CA-6NM	CA-6NM	Motor	

Table 5-5 (cont'd)

Equipment Item No.	No. Required Oper.	No. Required Spare	Service	Design gpm (Each)	Design Disc/Suct.	Oper. Temp. °F	Materials Casing	Materials Internals	Driver Type	Driver hp
PUMPS (cont'd)										
203 P-58	1	1	Fractionator Feed	837	160/5	200	CS	12 Cr	Motor	
203 P-59	1	1	Sour Water	21	25/5	200	316 SS	316 SS	Motor	
203 P-60	1	1	Slurry Oil Recycle	5632	90/40	550	5 Cr	5 Cr	Motor	
203 P-61	1	1	Vacuum Tower Pumparound	1552	40/-15	411	5 Cr	5 Cr	Motor	
203 P-62	1	1	Vacuum Tower Bottoms	1400	75/-15	699	CA-6NM	CA-6NM	Motor	
203 P-63	1	1	Naphtha Stabilizer Reflux	84	130/100	106	CS	CS	Motor	

Table 5-5 (cont'd)

Equipment Item No.	No. Required Oper.	Spare	Service	Rated Capacity ICFM (Each)	Pressure psig Suct.	Disch.	Mol Wt.	Description	Driver Type	(Each) hp
COMPRESSORS										
201 R-3	8	0	Make-up Hydrogen Compressor	728	700	3150	2.79	Reciprocating	Motor	5000
202 R-1	2	0	Hydrogen Recycle Compressor	311	2925	3150	6.95	Reciprocating	Motor	300
202 R-2	1	0	Light Ends Compressor	6933	35	400	25.76	Centrifugal	Motor	6000

Table 5-5 (cont'd)

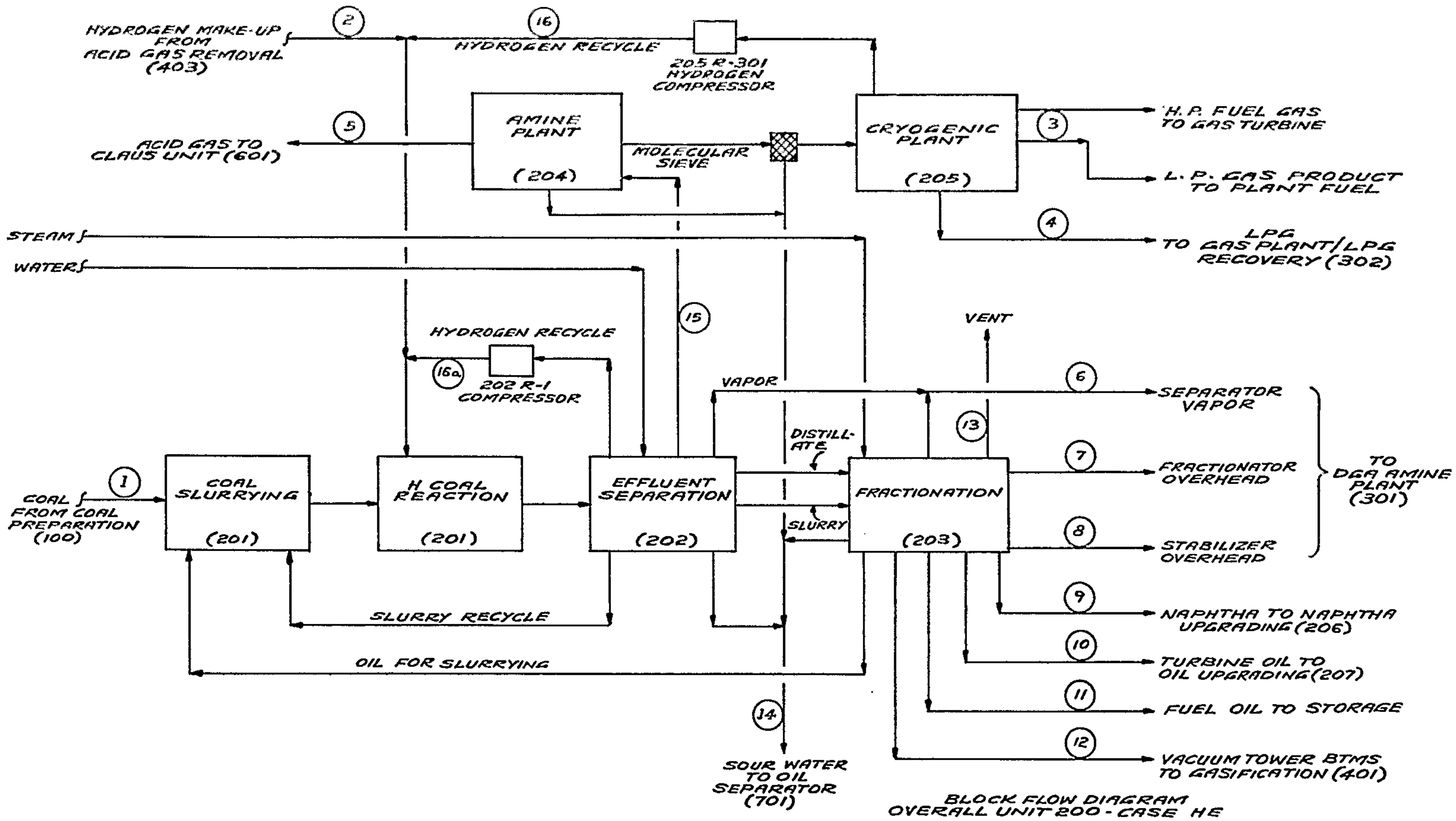
Equipment Item No.	No. Required Oper.	No. Required Spare	Service	Duty 10^6 Btu/hr (Each)	Surface Area Bare (Each)	Design Press. psig	Design Temp. °F	Materials
AIR COOLERS								
201 T-1	2	0	Vapor Condenser	16.0	1743	75	390	CS
202 T-4	2	0	LP Receiver Overhead Condenser	17.7	2391	75	400	304 SS Tubes CS Headers
202 T-8	2	0	Quench Cooler	17.3	2571	1360	475	CS
202 T-11	8	0	Feed Final Cooler	13.2	2300	3235	550	304 SS Tubes CS Headers
202 T-12	2	0	HP Receiver Overhead Condenser	12.8	1267	1295	475	304 SS Tubes CS Headers
203 T-51	1	0	Fractionator Upper Pumparound	183.2	30267	80	415	CS
203 T-53	1	0	Fractionator Overhead Air Cooler	114.9	17453	75	325	CS
203 T-55	1	0	Fuel Oil Air Cooler	25.3	1600	115	610	CS
203 T-56	1	0	Turbine Oil Air Cooler	26.1	1715	115	515	CS
203 T-58	1	0	Feed Final Cooler	37.6	4845	75	795	CS

Table 5-5 (cont'd)

Equipment Item No.	No. Required Oper.	No. Required Spare	Service	Duty 10^6 Btu/hr (Each)	Surface Area ft^2 (Each)	Design Press. psig/Temp.°F Shell	Design Press. psig/Temp.°F Tube	Materials Shell	Materials Tube
SHELL AND TUBE EXCHANGERS									
202 T-2	2	0	Vapor Cooler/ Fractionator Heater	59.9	4763	85/815	95/645	KCS with 321 SS	304L SS
202 T-3	2	0	Vapor Final Cooler	109.3	12617	80/815	75/360	CS	304 SS
202 T-5	8	0	Vapor Cooler/Recycle Gas Heater	53.7	5858	3300/900	3300/850	3 Cr-1 Mo with 321 SS Clad	3 Cr-1 Mo
202 T-6	8	0	Vapor Cooler/ Fractionator Feed Heater	37.4	3807	3270/900	100/570	2-1/4 Cr-1 Mo with 321 SS Clad	304L SS
202 T-7	2	0	Feed Cooler/Waste Heat Boiler	45.9	2616	1305/550	75/360	CS with 304L Clad	304 SS
202 T-9	8	0	Vapor Cooler/Waste Heat Boiler	18.2	1673	3260/550	75/360	1-1/4 Cr-1/2 Mo with 321 SS Clad	321 SS
202 T-10	8	0	Feed Cooler/Boiler Feedwater Preheater	17.1	1176	3245/550	75/250	CS with 304L Clad	304 SS
203 T-52	1	0	Fractionator Lower Pumparound Cooler	40.0	2555	85/560	80/350	CS	CS
203 T-54	1	0	Fractionator Over-head Final Cooler	3.2	1765	75/250	100/125	CS	CS
203 T-57	1	0	Feed Cooler/ Fractionator Feed Heater	117.6	6880	75/795	75/360	CS with 321 SS Clad	321 SS

Table 5-5 (cont'd)

Equipment Item No.	No. Required Oper.	No. Required Spare	Service	Duty 10^6 Btu/hr (Each)	Surface Area ft^2 (Each)	Design Press. psig/Temp. °F Shell	Design Press. psig/Temp. °F Tube	Materials Shell	Materials Tube
SHELL AND TUBE EXCHANGERS (cont'd)									
203 T-59	1	0	Vacuum Tower Pump-around Cooler	22.7	6880	75(vac)/465	80/350	CS	CS
203 T-60	1	0	Naphtha Stabilizer Feed/Bottoms Exchanger	11.1	909	125/295	115/410	CS	CS
203 T-61	1	0	Naphtha Stabilizer Reboiler	14.5	1076	115/410	660/540	CS	CS
203 T-62	1	0	Naphtha Stabilizer Overhead Condenser	3.6	899	115/250	100/125	CS	CS
203 T-63	1	0	Naphtha Product Cooler	10.7	1768	110/285	100/125 CS	CS	CS



BLOCK FLOW DIAGRAM
OVERALL UNIT 200 - CASE HE

REF. TABLES 5-6 & 5-7

A		E.V.P.	11-5-81	ENGR: E.V.P.	STONE & WEBSTER ENGINEERING CORPORATION
NO	REVISION DESCRIPTION	BY	DATE	DESIGN	ELECTRIC POWER RESEARCH INSTITUTE ILLINOIS NO. 6 COAL FEED
CERT FOR FAB	CERT FOR CONST	APPROVED		CHECKED	
				DRAWN F.R.	AREA: — / J.O. NO: 13461 / DRAWING NO: 75-B8 / ISSUE: A
				CHECKED	

Table 5-6

OVERALL MATERIAL BALANCE
UNIT 200 - CASE HE

Stream Number	1		2/52			3/17	4/18	5/19
Description	Coal from (100)	H-Coal Reactor Yield	Hydrogen Make-up From (403)	Process Water & Steam	Total Input To Unit 200	Combined H.P & L.P Fuel Gas	LPG To (302)	Acid Gas To (601)
Component Flowrate, lb/h								
H2		-79,895	82,561		2,666	457		
N2			5,828		5,828	4,135		
CO		-12,169	24,725		12,556	10,153		
H2S		42,381			42,381			9,950
NH3		17,337			17,337			354
H20	32,761	141,049		1,003,307	1,144,356			749
CO2		15,644	5,579		21,223			14,445
C1_		64,291	3,005		67,296	60,176		
C2‾		2,408			2,408	2,042		
C2_		54,421			54,421	45,350	171	
C3‾		963			963	194	542	
C3		53,457			53,457	175	40,997	
C4		38,849			38,849	11	20,769	
IBP-100 F		27,724			27,724		9,106	
100-200 F		51,932			51,932		8,528	
200-300 F		71,068			71,068		2,037	
300-400 F		110,624			110,624		358	
400-500 F		150,516			150,516		46	
500-600 F		143,164			143,164		7	
600-700 F		75,579			75,579		1	
700-800 F		25,140			25,140			
800-900 F		30,196			30,196			
900-975 F		30,839			30,839			
Residuum		305,014			305,014			
Subtotal, lb/h	32,761	1,360,532	121,698	1,003,307	2,485,537	122,693	82,562	25,498
Coal	1,420,559	92,788			92,788			
Ash	184,775	184,775			184,775			
Total, lb/h	1,638,095	1,638,095	121,698	1,003,307	2,763,100	122,693	82,562	25,498
Temperature, F	200		220		100	100	110	110
Pressure, psig			3150				200	15

Ref. Dwg. 75-B8

Table 5-6 (cont'd)

OVERALL MATERIAL BALANCE
UNIT 200 - CASE HE

Stream Number	6	7	8	9	10/21	11	12	13	14
Description	Separator Vapor To (301)	Fractionator Overhead To (301)	Stabilizer Overhead To (301)	Naphtha To (206)	Turbine Oil To (207)	Distillate Fuel Oil To Storage	Vacuum Tower Bottoms To (401)	Vent Gas From Wash Water Separator	Sour Water To (701)
Component Flowrate, lb/h									
H2	2,162	17	1					29	
N2	1,612	24	2					55	
CO	2,295	28	2					78	
H2S	3,760	321	487					88	27,775
NH3								19	16,964
H20	2,691	69	21					184	1,140,642
CO2	6,483	194	101						
C1_	6,888	127	27					78	
C2	338	12	8					8	
C2_	8,218	295	253					134	
C3_	199	7	19					2	
C3	10,764	388	1,025	19				89	
C4	13,057	496	3,186	1,239				91	
IBP-100 F	8,441	314	3,921	5,905				37	
100-200 F	9,602	401	3,400	29,955				46	
200-300 F	2,036	118		66,147	704	5		21	
300-400 F	254	13		49,005	60,942	43		9	
400-500 F	22				150,182	259	4	3	
500-600 F	2				125,421	17,206	527	1	
600-700 F					29,356	43,830	2,392		
700-800 F					97	20,792	4,251		
800-900 F						16,671	13,525		
900-975 F						8,774	22,065		
Residuum						1	305,013		
Subtotal, lb/h	78,824	2,824	12,453	152,270	366,702	107,581	347,777	972	1,185,381
Coal							92,788		
Ash							184,775		
Total, lb/h	78,824	2,824	12,453	152,270	366,702	107,581	625,340	972	1,185,381
Temperature, F	125	110	106	100	300	300	701	200	120
Pressure, psig	35	25	90	100	100	100	50	5	50

Ref. Dwg. 75-B8

SECTIONS 204 AND 205 - AMINE AND CRYOGENIC PLANTS

Process Description - Case HE

General. The Amine Plant (204) and Cryogenic Plant (205) are shown schematically on block flow diagram Figure 5-1 followed by an overall material balance, Table 5-7, for these sections. An equipment list for Sections 204 and 205 is given in Table 5-8.

SECTION 204 - AMINE PLANT

The Amine Plant (204) removes the acid gas constituents, H_2S and CO_2, contained in the hydrogen and light hydrocarbon vapors from the Effluent Separation Section (202). This gas treatment process is required to produce an environmentally acceptable low sulfur content in the fuel gas, and to prevent a build-up of acid gases in the hydrogen stream. CO_2 removal is required to prevent it from solidifying at the extremely low temperatures in the Cryogenic Plant (205).

The Amine Plant is a conventional system incorporating a commercially proven gas treatment process which utilizes an aqueous diethanolamine (DEA) solution to absorb the acid gas components from the bulk gas stream. The acid gases are removed in an absorber. Cleaned gas, exiting overhead, flows to molecular sieve dryers which dry the gas. Removal of essentially all the moisture from the gas is required to prevent the water vapor from solidifying at the extremely low temperatures in the Cryogenic Plant. The cleaned dry gas from the dryers flows to the Cryogenic Plant.

The Amine Plant also contains a complete system for regeneration of the rich aqueous DEA solution containing the absorbed acid gases. Regeneration of the DEA solution takes place in a system of stripping towers. The collected acid gases from the regeneration process join other acid gas streams from the plant and flow to the Claus Plant (601) for recovery of elemental sulfur contained in the H_2S. Aqueous condensate collected during regeneration of the beds flows to the Effluent Control System (700) for waste water treatment.

The Amine Plant has two 50 percent capacity equipment trains in both the processing and regeneration areas.

SECTION 205 - CRYOGENIC PLANT

The Cryogenic Plant (205) separates the treated gas from the Amine Plant (204) to recover a relatively pure hydrogen stream for recompression and recycle to the H-Coal reactors in Section 201. This Section also produces light hydrocarbon gas streams for use as fuel, and an LPG hydrocarbon liquid stream from which additional fuel gas, light hydrocarbon product gases and a light naphtha product are subsequently recovered in the LPG Recovery Plant (302).

The Cryogenic Plant consists of a refrigeration system incorporating:

- Several stages of low temperature condensation in core type heat exchangers, supplemented by an external cascaded propane-ethylene refrigeration unit, with each condensing stage followed by inter-stage vapor-liquid separation and liquid re-flash at reduced pressure to lower the temperature (Joule-Thompson expansion).

- Additional stages of liquid flash at reduced pressure to further lower the temperature (Joule-Thompson expansion) and effect a final separation of the hydrocarbons and hydrogen.

Cleaned, cooled and dried gas, containing hydrogen and light hydrocarbon vapors, flows from the molecular sieve dryers in the Amine Plant (204) to the Cryogenic Plant (205). The feed stream passes through several stages of core type exchangers and externally refrigerated auxiliary exchangers which fractionally separate the feed gas by condensing light hydrocarbons at low temperatures to produce a hydrogen-rich stream. The core exchangers cool and partially condense the feed streams by heat exchange with colder hydrocarbon and hydrogen-rich vapor process streams, resulting from subsequent interstage Joule-Thompson expansion. Part of the refrigeration is supplied by a propane-ethylene cascaded refrigeration system. At temperatures below that of the external refrigerants, Joule-Thompson expansion alone is utilized to attain lower temperatures. In the final stage, expanders are utilized to effect the final separation producing a purified hydrogen stream.

Hydrocarbon condensate collected at each interstage separation is de-ethanized to produce crude LPG. The crude LPG flows to the LPG Recovery Plant (302) for further processing to light hydrocarbon product streams, chiefly propane and butane, and a light naphtha product.

The Cryogenic Plant has two 50 percent capacity parallel equipment trains. Refrigerated equipment in each train is enclosed in a well-insulated cold box to minimize external heat absorption.

FIGURE 5-1

BLOCK FLOW DIAGRAM
AMINE AND CRYOGENIC PLANTS

SECTIONS 204, 205 - CASE H E

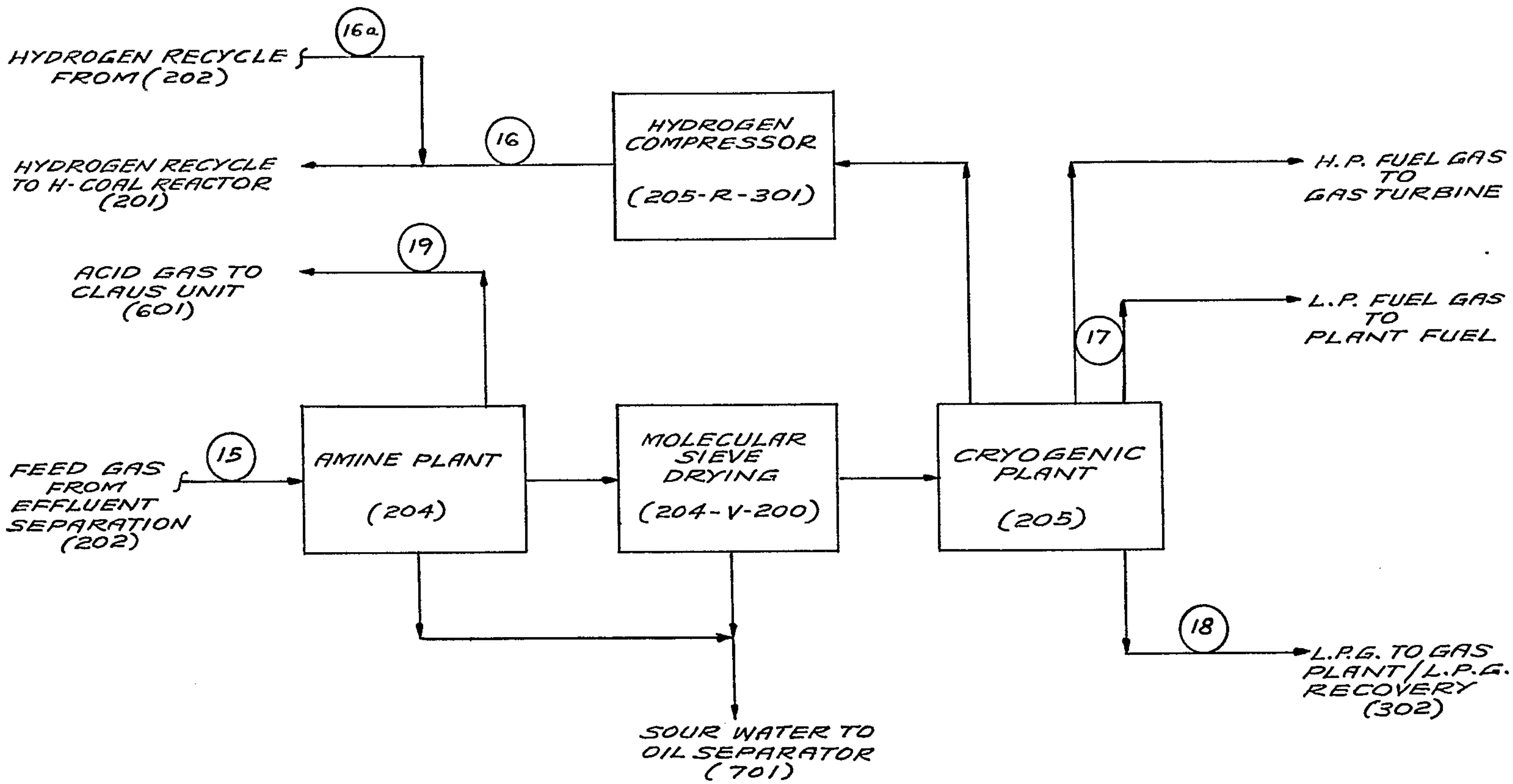


Table 5-7

MATERIAL BALANCE
AMINE AND CRYOGENIC PLANTS
SECTIONS 204, 205 - CASE HE

Stream Number	15	16	16a	3/17	4/18	5/19
Description	Feed To (204)	Hydrogen Recycle To (201) From (205)	Hydrogen Recycle To (201) From (202)	Combined H.P. & L.P. Fuel Gas	LPG To (302)	Acid Gas To (601)
Component Flowrate, lb/h						
H2	82,618	82,161	6,880	457		
N2	25,840	21,705	2,097	4,135		
CO	36,262	26,109	2,936	10,153		
H2S	9,950		767			9,950
NH3	354					354
H2O	749		58			749
CO2	14,445		1,116			14,445
C1-C4	190,916	20,489	15,374	107,948	62,479	
C5+	20,083		1,616		20,083	
Total, lb/h	381,217	150,464	30,844	122,693	82,562	25,498
Temperature, F	126	258	145	100	100	110
Pressure, psig	1160	3150	3150	380/35	200	15

Ref. Fig. 5-1

Table 5-8

EQUIPMENT LIST
UNIT 200 - AMINE AND CRYOGENIC PLANTS
SECTIONS 204, 205 - CASE HE

Section 204 - Amine Plant

Item No.	No. Req'd	Description
204 A-200	2	Absorber
204 A-201	2	Stripper
204 A-202	2	Pre-Stripper
204 M-200	2	Hydrocarbon Flash Drum
204 M-201	2	Reflux Drum
204 M-202	2	DEA Surge Tank
204 P-200	2 + 1	Stripper Reflux Pump
204 P-201	2 + 1	Lean Amine Circulation Pump
204 P-202	2	Hydraulic Turbine Pump
204 Q-200	1	Amine Storage Tank
204 T-200	2	Stripper Reboiler
204 T-201	2	Stripper Condenser
204 T-202	2	Amine Preheater
204 T-203	2	Amine Cooler
204 V-200	2 + 2	Filters

Table 5-8 (cont'd)

Section 205 - Cryogenic Plant

Item No.	No. Req'd	Description
205 A-300	2	Deethanizer
205 G-300	2	Cold Box
205 M-300	2	Reflux Drum
205 M-301	2	Separator Drum No. 1
205 M-302	2	Separator Drum No. 2
205 M-303	2	Separator Drum No. 3
205 M-304	2	Separator Drum No. 4
205 M-305	2	Expander Outlet Drum
205 M-306	2	Expansion Drum No. 1
205 M-307	2	Expansion Drum No. 2
205 M-308	2	Expansion Drum No. 3
205 P-300	2 + 2	Reflux Pump
205 P-301	2 + 2	LPG Pump
205 R-300	2	Expander
205 R-301	8	Hydrogen Compressor
205 T-300	2	Feed Water Cooler
205 T-301	2	Core Exchanger No. 1
205 T-302	2	Core Exchanger No. 2
205 T-303	2	Core Exchanger No. 3
205 T-304	2	Core Exchanger No. 4
205 T-305	2	Bypass Cooler No. 1
205 T-306	2	Bypass Cooler No. 2

Table 5-8 (cont'd)

Section 205 - Cryogenic Plant (cont'd)

Item No.	No. Req'd	Description
205 T-307	2	Bypass Cooler No. 3-1
205 T-308	2	Deethanizer Reboiler
205 T-309	2	Reflux Condenser
205 T-310	2	Bypass Cooler No. 3-2
205 T-311	2	Bypass Cooler No. 3-3

SECTIONS 206, 207, AND 208 - PRODUCT HYDROTREATING AND REFORMING

Process Description - Case HE

General. Hydrotreating of the H-Coal naphtha and turbine fuel distillates recovered in the Fractionation Section (203) is required to produce fuels with acceptably low levels of sulfur, nitrogen and oxygen content. The maximum allowable values in the turbine fuel proposed by EPRI are: 0.30 weight percent sulfur and 0.25 weight percent nitrogen. Oxygen is substantially reduced by hydrotreating, but the need to set a maximum oxygen level remains under study. The minimum hydrogen level proposed for turbine fuel is 10.0 percent by weight.

In the present study, the naphtha fraction is processed to produce a reformate for motor gasoline blending. It is necessary to reduce sulfur and nitrogen levels in the naphtha to about 1 ppm by hydrotreating before reforming. The naphtha reformate is blended with light sweet naphtha to yield motor gasoline. By-product hydrogen, produced in the reformer, is used in the naphtha and turbine oil hydrotreaters.

The Product Hydrotreating and Reforming Sections (206, 207, 208) are shown schematically on block flow diagram Figure 5-2. An overall material balance for these three sections is shown in Table 5-9.

SECTION 206 - NAPHTHA HYDROTREATING

Coal derived naphthas are high in sulfur, nitrogen, and oxygen content. These elements, chemically bound in heterocyclic compounds, are removed by hydrogen treatment. The applicability of the hydrotreating and reforming processes to naphthas derived from the H-Coal process has been evaluated by UOP and others. The following values were selected from the UOP report (1) for use in this study:

	Naphtha	
	Feed	Hydrotreated
Hydrogen, wt-%	12.80	13.59
Sulfur, wt-ppm	1289	0.39
Nitrogen, wt-ppm	1930	0.63
Oxygen, wt-ppm	5944	34

The feed streams to the Naphtha Hydrotreating Section consist of naphtha from the Fractionation Section (203) and naphtha from the LPG Recovery Section (302). These two streams enter a naphtha splitter where light naphtha, as splitter overhead, is separated from the heavier naphtha components. Odoriferous compounds in the splitter overhead are neutralized by a sweetening process. The sweetened light naphtha is then blended with naphtha reformate to yield motor gasoline. The bottom fraction from the naphtha splitter is sent to the hydrotreater. The naphtha hydrotreater receives hydrogen produced in the naphtha reformer. Unreacted hydrogen from the hydrotreater, still of sufficient quantity for turbine oil hydrotreating, contains hydrogen sulfide and C1 - C3 fractions produced in the hydrotreater.

Hydrogen sulfide is removed by amine absorption in two units:

- A high pressure amine wash tower is used to scrub hydrogen sulfide from the recycle gas in the hydrotreater.
- A low pressure amine wash tower is used to scrub hydrogen sulfide from a low pressure stripper overhead fuel gas stream.

The hydrogen sulfide from an amine regenerator joins a similar stream from the Turbine Fuel Hydrotreating Section and flows to the Claus Plant (601) for sulfur recovery. The fuel gas is discharged to the fuel gas header.

An ammoniated sour water by-product stream is also produced and is sent to effluent treatment.

The total recovery of naphtha is about 99.8 weight percent of the feed. This includes 24.2 percent as splitter overhead and 75.6 percent as hydrotreated naphtha to the Naphtha Reforming Section (208).

SECTION 207 - TURBINE FUEL HYDROTREATING

Elemental analysis data used in the design of turbine fuel hydrotreating were obtained from an EPRI report prepared by Mobil Research and Development Corporation (2). The data are shown below.

	Turbine Fuel	
	Feed	Hydrotreated
Hydrogen, wt-%	10.10	10.70
Sulfur, wt-%	0.11	0.01
Nitrogen, wt-%	0.38	0.10
Oxygen, wt-%	1.20	0.39

The critical elements are nitrogen and hydrogen. In most cases, when fuel-bound nitrogen has been reduced to an acceptable level, the sulfur level is also very low.

The turbine fuel hydrotreater receives the excess hydrogen from the naphtha hydrotreater. Hydrogen sulfide, fuel gas, and sour water are the by-products of the hydrotreating process which contains treatment and separation facilities similar to those in the naphtha hydrotreating process. The hydrotreated turbine fuel, yielding about 99.4 weight percent of the feed is sent to product storage.

SECTION 208 - NAPHTHA REFORMING

This unit produces a gasoline blending stock by catalytic reforming of hydrotreated naphtha. The primary reaction is naphthene dehydrogenation, which causes an increase in aromatic content and a corresponding increase in octane rating.

The reformate analysis used for reference in this study is based on data taken from the same UOP study referred to for naphtha hydrotreating, and is summarized below:

Reforming Hydrotreated H-Coal Naphtha (3)

Product Yields		
Hydrogen	wt-%	3.0
C1 - C3	wt-%	0.3
nC4	wt-%	0.4
C5 +	wt-%	96.3
	Total	100.0
RON, clear		98

By-products from the Reforming Section include fuel gas, propane-butane (LPG), and hydrogen for hydrotreating.

The reformate has a calculated gravity of 37.3 °API and an estimated RON, clear, of 98. When blended with light naphtha from the splitter overhead, the gravity increases to 47.0 °API and the octane number drops to an estimated 91 RON.

REFERENCES

1. G. Tan and A.J. deRossett. Upgrading Coal Liquids - Hydrotreating and Reforming H-Coal Process Derived Naphthas. UOP Inc., Des Plaines, Ill., Interim Report FE-2566-12 (DOE), March 1978, Table 2.

2. Economic Screening Evaluation of Upgrading Coal Liquids to Turbine Fuels. EPRI AF-710, Mobil Research and Development Corporation, March 1978, Table 4-2.

3. Upgrading Coal Liquids. Interim Report FE-2566-12 (DOE), March 1978, Table 11, Period No. 5.

FIGURE 5-2

BLOCK FLOW DIAGRAM

PRODUCT UPGRADING

SECTIONS 206, 207, 208 - CASE HE

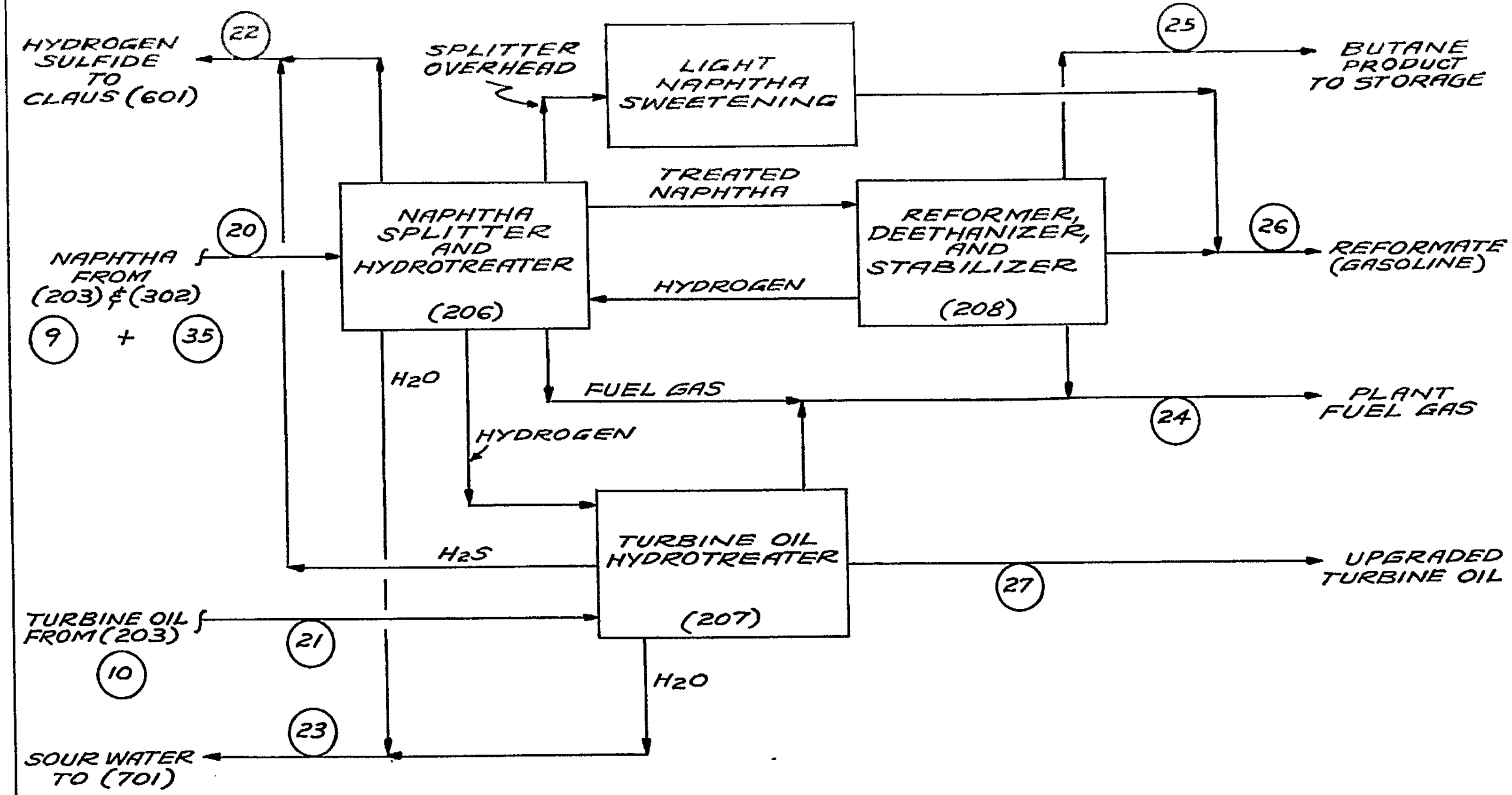


Table 5-9

MATERIAL BALANCE - PRODUCT UPGRADING
SECTIONS 206, 207, 208 - CASE HE

Stream Number	20	10/21	22	23	24	25	26	27
Description	Naphtha From (203) & (302)	Turbine Oil From (203)	H2S To Claus (601)	Sour Water To (701)	Fuel Gas To Plant Header	Butane To Product Storage	Gasoline To Product Storage	Turbine Oil To Product Storage
Component Flowrate, lb/h								
H2			a		329			
H2S			604					
NH3			a	1,594				
H2O			a	4,032				
C1			a		310			
C2					324			
C3	19				130	89	19	60
C4	1,239				8	392	1,414	369
C5+								363,971
C5-350 F	188,953	61,646					183,346	
350-650 F	78	305,056						
Total, lb/h	190,289	366,702	604	5,626	1,101	481	184,779	364,400
Temperature, F	100	300	110	120	100	100	100	130
Pressure, psig	100	100	15	50	35	190	15	15

Ref. Fig. 5-2

a Quantities not determined.

UNIT 300 - LIGHT ENDS PROCESSING

Process Description - Case HE

General. The Light Ends Processing Unit (300) includes Section 301 - Diglycolamine (DGA) Plant and Section 302 - Liquefied Petroleum Gas (LPG) Recovery Plant.

The DGA Plant and LPG Recovery Plant are shown schematically on block flow diagram Figure 5-3 followed by an overall material balance, Table 5-10, for these sections. A list of equipment for Sections 301 and 302 is given in Table 5-11.

SECTION 301 - DGA PLANT

The DGA Plant (301) removes the acid gases contained in the light hydrocarbon vapor streams, which are produced in the H-Coal Reaction Section (201) and recovered in the Effluent Separation Section (202) and Fractionation Section (203). The light hydrocarbon streams contain principally H_2S and CO_2, which must be removed before separation of the hydrocarbons into fuel gas, light hydrocarbon product, and light naphtha product streams in the LPG Recovery Plant (302). The DGA Plant is a conventional system incorporating a commercially proven gas treatment process which utilizes an aqueous diglycolamine (DGA) solution to absorb the acid gas components from the bulk gas stream. Cleaned gas from the absorber joins the LPG stream from the Cryogenic Plant (205) and flows to the LPG Recovery Plant.

The DGA Plant also contains a complete system for regeneration of the rich aqueous DGA solution containing the absorbed acid gases. Regeneration of the DGA solution takes place in a system of stripping towers. The collected acid gases from the regeneration process join other acid gas streams and flow to the Claus Plant (601) of the Emission Control System (600) for recovery of elemental sulfur. An aqueous condensate by-product stream flows to the Oil Separation Section (701) of the Effluent Control Unit (700) for ultimate waste water treatment.

The DGA Plant has a single 100 percent capacity equipment train in both the processing and regeneration areas.

SECTION 302 - LPG RECOVERY PLANT

The LPG Recovery Plant (302) separates the cleaned light-hydrocarbon containing gas stream from the DGA Plant and the LPG stream from the Cryogenic Plant (205) into a hydrogen and light hydrocarbon containing fuel gas stream, propane and butane product streams and a light naphtha liquid product.

The LPG Recovery Plant utilizes a system of three conventional trayed towers, one as an absorber and two as distillation towers, to:

- Absorb propane and heavier hydrocarbons, contained in the feed gas from the DGA Unit, into a lean naphtha solvent to produce a rich solvent stream and an ethane and lighter fuel gas stream.

- Fractionate the rich solvent stream and feed gas from the Cryogenic Unit into a butane and lighter overhead and a light naphtha bottoms product. Part of the bottoms is used as the lean solvent to the absorber.

- Fractionate the butane and lighter overhead to propane and butane LPG product.

The three towers in the recovery scheme are integrated for maximum energy efficiency. The LPG Recovery Plant has a single 100 percent capacity processing train.

FIGURE 5-3

BLOCK FLOW DIAGRAM

DGA AMINE AND L.P.G. RECOVERY PLANTS

SECTIONS 301, 302 - CASE HE

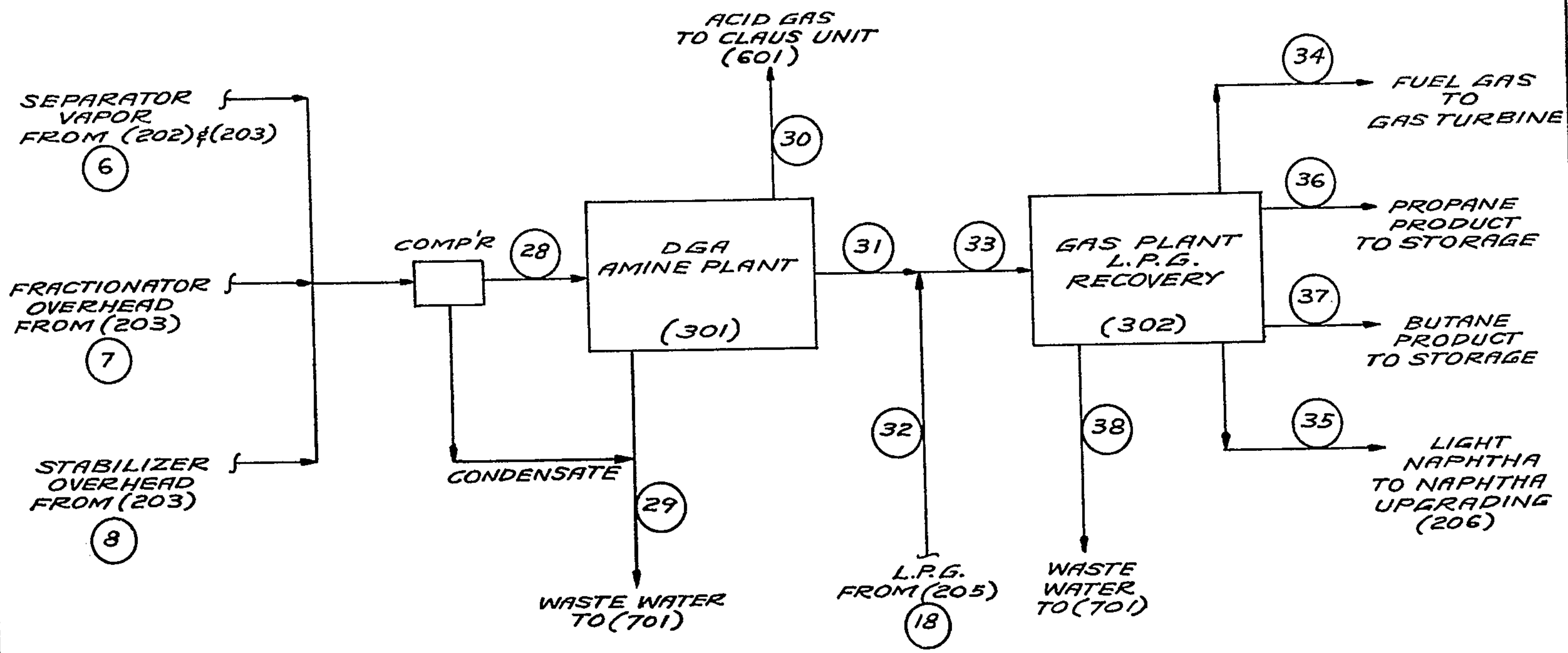


Table 5-10

MATERIAL BALANCE
DGA AMINE AND LPG RECOVERY PLANTS
SECTIONS 301, 302 - CASE HE

Stream Number	28	29	30	31	32/18/4	33
Description	Feed To DGA Amine Plant (301)	Waste Water To (701)	Acid Gas To (601)	Hydrocarbon Vapor To (302)	LPG From (205)	Total Feed to Gas Plant/ LPG Recovery (302)
Component Flowrate, lb/h						
H2	2,180			2,180		2,180
N2	1,638			1,638		1,638
CO	2,325			2,325		2,325
H2S	4,568		4,568			
H2O	2,781	2,291	377	113		113
CO2	6,778		6,775	3		3
C1_	7,042			7,042		7,042
C2	358			358		358
C2_	8,766			8,766	171	8,937
C3	225			225	542	767
C3	12,177			12,177	40,997	53,174
C4	16,739			16,739	20,769	37,508
IBP-100 F	12,676			12,676	9,106	21,782
100-200 F	13,403			13,403	8,528	21,931
200-300 F	2,154			2,154	2,037	4,191
300 + F	291			291	412	703
Total, lb/h	94,101	2,291	11,720	80,090	82,562	162,652
Temperature, F	115	120	120	120	100	120
Pressure, psig	400	50	10	380	200	375

Ref. Fig. 5-3

Table 5-10 (cont'd)

MATERIAL BALANCE
DGA AMINE AND LPG RECOVERY PLANTS
SECTIONS 301, 302 - CASE HE

Stream Number	34	35	36	37	38
Description	Fuel Gas To Gas Turbine	Light Naphtha To (206)	Propane To Storage	Butane To Storage	Waste Water To (701)
Component Flowrate, lb/h					
H2	2,180				
N2	1,638				
CO	2,325				
H2S					60
H20	53				
CO2	3				
C1_	7,042				
C2	358				
C2_	8,498		439		
C3	60		706	1	
C3	1,519		51,430	225	
C4	920		282	36,306	
IBP-100 F	5088	13,774		2,920	
100-200 F	2480	19,447		4	
200-300 F	89	4,102			
300 + F	7	696			
Total, lb/h	32,260	38,019	52,857	39,456	60
Temperature, F	110	100	103	110	110
Pressure, psig	335	100	190	190	50

Ref. Fig. 5-3.

Table 5-11

EQUIPMENT LIST
UNIT 300 - DGA AMINE AND LPG RECOVERY PLANTS
SECTIONS 301, 302 - CASE HE

Section 301 - DGA Amine Plant

Item No.	No. Req'd	Description
301 A-1	1	Absorber
301 A-2	1	Stripper
301 A-3	1	Pre-Stripper
301 M-1	1	Hydrocarbon Flash Drum
301 M-2	1	Reflux Drum
301 M-3	1	DGA Surge Tank
301 P-1	1 + 1	Stripper Reflux Pump
301 P-2	1 + 1	Lean Amine Circulation Pump
301 Q-1	1	Diglycolamine Storage Tank
301 T-1	1	Stripper Reboiler
301 T-2	1	Stripper Condenser
301 T-3	1	Amine Preheater
301 T-4	1	Amine Cooler
301 T-5	1	Reclaimer
301 V-1	1 + 1	Filters

Table 5-11 (cont'd)

Section 302 - LPG Recovery Plant

Item No.	No. Req'd	Description
302 A-100	1	Lean Oil Absorber
302 A-101	1	Debutanizer
302 A-102	1	Depropanizer
302 M-100	1	Debutanizer Reflux Drum
302 M-101	1	Depropanizer Reflux Drum
302 P-100	1 + 1	Debutanizer Reflux Pumps
302 P-101	1 + 1	Lean Oil Transfer Pumps
302 P-102	1 + 1	Depropanizer Reflux Pumps
302 P-103	1 + 1	Depropanizer Feed Pumps
302 T-100	1	Lean Oil Absorber Reboiler
302 T-101	1	Debutanizer Condenser
302 T-102	1	Debutanizer Reboiler
302 T-103	1	Depropanizer Condenser
302 T-104	1	Depropanizer Reboiler No. 1
302 T-105	1	Lean Oil Air Cooler
302 T-106	1	Lean Oil Trim Cooler
302 T-107	1	Depropanizer Feed Exchanger
302 T-108	1	Depropanizer Reboiler No. 2

UNIT 400 - HYDROGEN PLANT

Process Description - Case HE

General. The Hydrogen Plant (400) has three plant sections, one of which contains four sub-systems, as follows:

Section 401 - Gasification (Texaco)

Water Recovery
Scrubbing
Waste Water Treating

Section 402 - CO Shift

Section 403 - Acid Gas Removal (Selexol)

Figure 5-4 shows the overall block flow diagram for Sections 401 through 403, which is followed by material balances in Tables 5-12 through 5-14. Table 5-15 shows the equipment list for the three sections. The equipment list for Section 401 is abbreviated and shows general systems only, because of the proprietary nature of the Texaco process.

SECTION 401 - GASIFICATION

Hydrogen flow to the H-Coal liquefaction reactors is made up of unreacted hydrogen recycled from the Effluent Separation Section (202) and the Cryogenic Plant (205), and combined with make-up hydrogen from the hydrogen plant. The make-up hydrogen is supplied by partial oxidation of the heavy vacuum tower bottoms stream separated in the Fractionation Section (203). This vacuum bottoms residue has an initial boiling point of 975°F and contains unreacted coal and ash. Partial oxidation of this material by the Texaco gasification process produces a mixed gas stream consisting primarily of H_2, CO, CO_2 and H_2O, with lesser amounts of CH_4, NH_3, H_2S, COS, and N_2, and a small amount of unreacted carbon and soot.

The vacuum tower bottoms stream from the Fractionation Section (203) mixes with steam and the residuum-steam mixture and oxygen from the Oxygen Plant (500) then enter a specially designed burner where partial oxidation of the hydrocarbon feedstock occurs. The gasifiers, which are refractory lined vertical cylindrical vessels, operate at a pressure of 800 psig and a temperature in the range of 2000 to 2800°F. Under these conditions, the hydrocarbon feed is partially oxidized to yield a two-phase stream consisting of gaseous products, unreacted carbon, soot and molten ash.

Effluent from the gasifier flows downward into a quench section, where it is quenched by direct contact with water. The process effluent stream is cooled to cause the molten ash to solidify. The solidified ash, as slag, is separated from the effluent and collected in a lock hopper for periodic disposal.

The quenched raw gas stream, containing unreacted carbon, flows to a gas scrubber and is countercurrently contacted with heated water. This operation removes most of the fine soot particles from the gas and cools the gas by vaporization of some of the water. The temperature and vaporization are monitored to bring the overall water content of the gas to the appropriate level for the subsequent CO shift conversion.

Wash water from the gas scrubber is sent to a settling tank for removal of soot. A portion of the water from the settling tank is sent to the Texaco waste water treatment system. The balance of the water is recycled to the scrubbing system. The cleaned gas exits overhead from the scrubbing tower and flows to CO Shift (402).

SECTION 402 - CO SHIFT

The CO Shift Section (402) utilizes the water gas reaction to catalytically shift carbon monoxide in the scrubbed Texaco gasifier effluent to produce hydrogen and carbon dioxide. A cobalt-molybdate catalyst, resistant to poisoning by the H_2S in the gas stream, is used. Two stages of shift are required to reduce the CO content to 1.25 percent. The shift reaction is highly exothermic. Waste heat is extracted from the hot first stage effluent gas, thereby reducing its temperature to generate high pressure steam. The shifted gas stream, exiting the second stage reactor, is partially condensed and cooled to ambient temperature in an integrated heat recovery scheme which preheats boiler feed water and generates low pressure steam. Hot aqueous process condensate is collected and used as quench water in the Gasification Section (401). Cold aqueous process condensate, which contains a small quantity of ammonia, is collected after the final stage of syngas cooling. A portion of this water is used as make-up water in the H-Coal Liquefaction Unit (200). The balance is sent to the Sour Water Stripping Section (702) and ultimately to the Phosam Unit in the Ammonia Recovery Section (703) for removal of the ammonia.

The cooled, shifted syngas stream, rich in hydrogen and carbon dioxide, flows to the Acid Gas Removal Section (403) for removal of H_2S and CO_2.

The CO Shift Section has five parallel operating shift converters in each stage because of capacity and distribution limitations in the packed bed vessels. Certain items have five corresponding parallel units. Other pieces of equipment in the section have single 100 percent or twin 50 percent operational units, depending on individual size limitations.

SECTION 403 - ACID GAS REMOVAL

The Selexol* process was chosen for this study for removing acid gases from the shifted syngas stream. This process uses a solvent to selectively absorb acid gas components, principally H_2S and CO_2, from the gas stream. The absorption is a physical process performed in an integrated, two-stage operation. The system also includes facilities for regenerating the solvent.

In the first stage, H_2S is absorbed through countercurrent contact with a high pressure CO_2-rich Selexol solvent stream. The absorption is highly selective to H_2S, with only an insignificant amount of CO_2 absorption occurring to saturate the solvent.

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* Selexol is the trade name of the proprietary physical solvent acid gas absorption process developed by Allied Corporation and licensed by Norton Company.

The solvent, now rich in H_2S as well as CO_2, is flashed to remove traces of hydrocarbons coabsorbed with the H_2S. The solvent is stripped of H_2S and CO_2 by the combined action of pressure letdown and thermal regeneration. The H_2S stream is sent to the Claus Plant (601) for recovery of elemental sulfur. The lean Selexol solvent, leaving the bottom of the H_2S stripper, flows to the CO_2 absorber.

The H_2S-free syngas stream passes to the second stage for bulk CO_2 removal. As with the H_2S removal, CO_2 absorption occurs by scrubbing the syngas stream with Selexol solvent. The CO_2 absorber overhead is the make-up hydrogen rich gas stream and the bottoms is the CO_2-rich Selexol solvent. Part of the bottoms is recycled to the H_2S absorber with the balance going to the CO_2 stripper.

The rich solvent is stripped of CO_2 by pressure letdown and by countercurrent stripping with dry nitrogen produced as a by-product waste gas stream in the Oxygen Plant (500). The CO_2 stream is vented to the atmosphere.

The final cleaned hydrogen rich gas stream is compressed and recycled to the H-Coal reactors in the H-Coal reaction area of Section 201 as a make-up hydrogen stream.

The Acid Gas Removal Section has a single 100 percent capacity operating train of equipment for the first stage H_2S absorption and Selexol regeneration process and two 50 percent operating trains in the second stage CO_2 absorption and Selexol regeneration process.

FIGURE 5-4

BLOCK FLOW DIAGRAM
HYDROGEN PLANT
SECTIONS 401, 402, 403-CASE HE

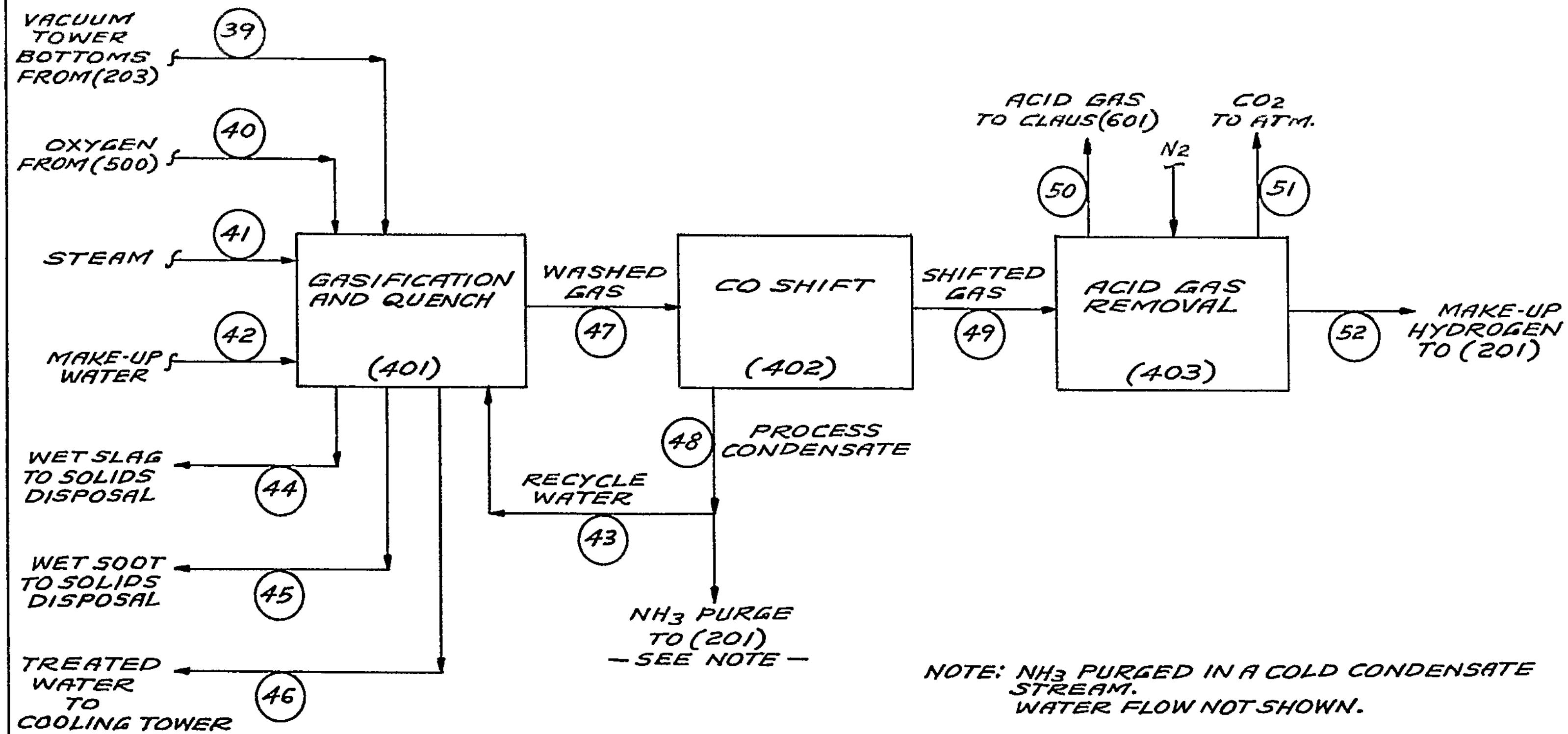


Table 5-12

FEED STREAM ANALYSES
HYDROGEN PLANT - SECTION 401
CASE HE

Vacuum Tower Bottoms

Cut	Wt %	Ultimate Analysis	Wt %
400-500°F	Trace	C	57.45
500-600°F	0.08	H	3.90
600-700°F	0.38	N	1.00
700-800°F	0.68	S	2.40
800-900°F	2.16	O	5.70
900-975°F	3.53	Ash	29.55
Residuum	48.78		100.00
Coal (ash free)	14.84		
Ash	29.55		
	100.00		

Oxygen

Ultimate Analysis	Wt %	Vol %
O2	99.91	99.90
N2 + Ar	0.09	0.10
	100.00	100.00

Table 5-13

MATERIAL BALANCE
GASIFICATION - SECTION 401
CASE HE

Stream No.	Input	Flowrate, lb/h
39	Vacuum Tower Bottoms	625,340
40	Oxygen	410,234
41	Steam	312,670
42	Make-up Water	481,858
43	Recycle Water	1,072,691
	Total	2,902,793

Stream No.	Output	Flowrate, lb/h
44	Wet Slag - Solids	139,287
	- Water	34,820
45	Wet Soot - Solids	48,469
	- Water	48,209
46	Treated Water	165,600
47	Raw Gas	2,466,408
	Total	2,902,793

Ref. Fig. 5-4

Table 5-14

MATERIAL BALANCE - HYDROGEN PLANT
CO SHIFT AND ACID GAS REMOVAL
SECTIONS 402 and 403 - CASE HE

Stream No.	47	48	49	50	51	52/2
Description	Washed Gas From (401)	Process Condensate	Shifted Gas From (402)	Acid Gas To Claus (601)	CO2 To Atmos.	Make-up H2 To (201)
Component Flowrate, lb/h						
H2	36,871		83,342		781	82,561
N2	5,828		5,828			5,828
CO	670,879		25,209		484	24,725
H2S	14,946		15,921	15,914	7	
NH3	1,016	1,016[b]				
H2O	1,490,320	1,072,691	1,820	1,820		
CO2	241,658		1,257,409	166,296	1,085,534	5,579
CH4	3,118		3,118		113	3,005
COS	1,772		54	54		
Total, lb/h	2,466,408	1,073,707	1,392,701	184,084	1,086,919	121,698
Temperature, °F	466	313/150[a]	103	120	120	45
Pressure, psig	770	700/0[a]	720	8	Atm.	700

Ref. Fig. 5-4

[a] Temperatures and pressures of hot and cold condensate streams.

[b] NH3 purged to section 202 in a cold condensate stream.

Table 5-15

EQUIPMENT LIST
UNIT 400 - HYDROGEN PLANT
SECTIONS 401, 402, 403 - CASE HE

Section 401 - Gasification - Texaco

Item No.	Description
401 G-1	Charge Section
401 G-2	Gasification and Quench Section
401 G-3	Gas Scrubbing Section
401 G-4	Water Recovery and Solids Handling Section
401 G-5	Waste Water Treating Section

Table 5-15 (cont'd)

Section 402 - CO Shift

Item No.	No. Req'd	Description
402 L-100	5	High-Temp. Shift Converter
402 L-101	5	Low-Temp. Shift Converter
402 M-100	5	H.P. Steam Drum
402 M-101	1	Condensate Separator No. 1
402 M-102	1	Condensate Separator No. 2
402 M-103	1	Condensate Separator No. 3
402 M-104	1	Condensate Separator No. 4
402 M-105	2	M.P. Steam Drum
402 M-106	1	Hot Condensate Drum
402 M-107	1	Cold Condensate Drum
402 P-100	1 + 1	Hot Condensate Pump
402 P-101	1 + 1	Cold Condensate Pump
402 T-100	5	Shift-Preheater
402 T-101	5	Syn Gas Cooler/H.P. Steam Generator
402 T-102	1	Syn Gas Cooler/BFW Heater
402 T-103	1	Phosam Regenerator Reboiler
402 T-104	5	Shift Startup Heater
402 T-105	1	Gray Water Heater
402 T-106	1	Syn Gas Cooler/Condensate Heater
402 T-107	2	Syn Gas Cooler/L.P. Steam Generator
402 T-108	1	Syn Gas Air Cooler
402 T-109	1	Syn Gas Final Cooler

Table 5-15 (cont'd)

Section 403 - Acid Gas Removal - Selexol

Item No.	No. Req'd	Description
403 A-50	1	H_2S Absorber
403 A-51	1	H_2S Stripper
403 A-52	2	CO_2 Absorber
403 A-53	2	CO_2 Stripper
403 M-50	1	Feed Gas Inlet Separator
403 M-51	2	H_2S Rich Selexol Flash Drum
403 M-52	1	H_2S Stripper Reflux Drum
403 M-53	2	CO_2 Rich Selexol Flash Drum
403 P-50	1	Hydraulic Turbine No. 1
403 P-51	2	Hydraulic Turbine No. 2
403 P-52	1 + 1	Lean Selexol Transfer Pump
403 P-53	2 + 1	CO_2 Pre-Saturated Selexol Pump
403 P-54	2 + 1	CO_2 Stripper Bottoms Pump
403 Q-50	1	Selexol Storage Tank
403 R-50	1	H_2S Recycle Compressor
403 R-51	2	CO_2 Recycle Compressor
403 T-50	1	Feed Gas Cooler
403 T-51	1	H_2S Stripper Reboiler
403 T-52	1	H_2S Stripper Feed Heater
403 T-53	1	Selexol Cooler
403 T-54	1	H_2S Stripper Condenser

Table 5-15 (cont'd)

Section 403 - Acid Gas Removal - Selexol (cont'd)

Item No.	No. Req'd	Description
403 T-55	2	CO_2 Stripper Feed Exchanger
403 T-56	2	Lean Selexol Cooler
403 T-57	1	Water Trim Cooler
403 V-50	1 + 1	Side Stream Filter

UNIT 500 - OXYGEN PLANT

Process Description - Case HE

General. Figure 5-5 shows an overall block flow diagram of the principal process areas of the oxygen plant and its auxiliaries. Table 5-16, the equipment list for the oxygen plant, shows the plant as a package containing all the inside battery limits equipment generally provided by the licensor-supplier. Table 5-17 shows the material balance for the oxygen plant.

Description. The Oxygen Plant (500) is a conventional commercial design of the type available as a turnkey package from air separation plant suppliers.

The Oxygen Plant utilizes a process based on the cryogenic separation of air to produce high purity oxygen for use in the gasification of the vacuum bottoms heavy residuum in the Texaco Gasification Section (401). Nitrogen, for use as stripping gas in the Acid Gas Removal Section (403), and inert gas, for use in vessel blanketing, is produced as by-products.

Atmospheric air is filtered and compressed to 90 psig by electric motor driven centrifugal compressors in the air compression area. Total air intake is 29,241 st/sd. The power requirement for the air compressors is 55,130 kW.

Carbon dioxide and water vapor are removed from the compressed air in a reversing heat exchanger system using cold products for freezing and warm waste nitrogen for evaporation and removal of solidified contaminants. At cryogenic temperatures, CO_2 and water vapor solidify and deposit on the exchanger surface. Periodically, switching valves alternate the air stream with the waste nitrogen stream. The solid deposits vaporize into the waste nitrogen stream which is purged to the atmosphere.

The purified air is cooled within a few degrees of its liquefaction temperature by heat exchange with the cold oxygen and waste nitrogen products. The low temperature air is separated into cold saturated oxygen vapor and waste nitrogen products in the cryogenic distillation area. An integrated double-column distillation system is generally used to recover the maximum practicable amount of oxygen from the feed air stream, thus minimizing both the total air required and the energy consumed by air compression.

The product oxygen stream, leaving the cryogenic distillation area at slightly above atmospheric pressure, enters the oxygen compressors. Reciprocating compressors boost the oxygen pressure to 1000 psig requiring an energy consumption of 30,450 kW. The compressed oxygen flows to the Texaco gasifiers to supply the oxygen requirements for the partial oxidation of the vacuum tower residuum stream.

Nitrogen gas, separated in the cryogenic distillation area, is utilized as stripping nitrogen to regenerate the Selexol solvent in the Acid Gas Removal Section (403) and as plant inert gas for purging.

Two parallel operating trains each with a nominal capacity of 2500 st/sd oxygen product are provided to meet the total oxygen requirements. Oxygen product is stored in a liquefied state in a 69 foot diameter sphere which provides storage capacity for two days' production of one train. Nitrogen product is stored in the gaseous state. A total nitrogen storage capacity of 3,000,000 scf at 200 psig is provided. Normal product consumption rates in the plant are 4918 st/sd oxygen for the gasifiers in Section 401, and 147 st/sd stripping nitrogen for solvent regeneration for acid gas removal in Section 403.

FIGURE 5-5

BLOCK FLOW DIAGRAM
OXYGEN PLANT - SECTION 500 - CASE HE

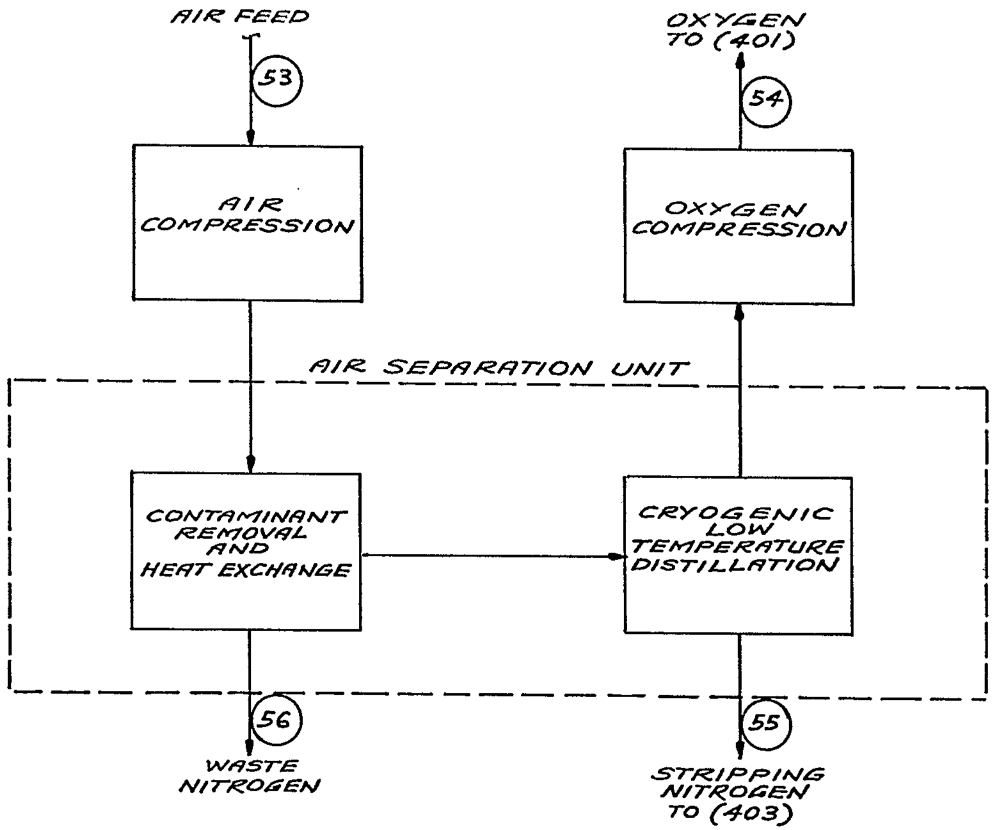


Table 5-16

EQUIPMENT LIST
UNIT 500 - OXYGEN PLANT
CASE HE

Item No.	No. Req'd	Description
500 G-1	2	Oxygen Plant
500 R-1	2	Air Compressor
500 R-2	2	Oxygen Compressor

Table 5-17

MATERIAL BALANCE
OXYGEN PLANT - UNIT 500
CASE HE

Stream No.	53	54	55	56
Description	Air Feed	Oxygen	Stripping Nitrogen	Waste Nitrogen
Component Flowrate, lb/hr				
O_2	458,018	409,825	14	48,179
N_2[a]	1,520,727	409	122,460	1,397,858
Total, lb/hr	1,978,745	410,234	122,474	1,446,037
Temperature °F	88	200	95	95
Pressure, psig	0	1000	70	0

Ref. Fig. 5-5

[a]As nitrogen plus argon.

UNIT 600 - EMISSION CONTROL

Process Description - Case HE

General. The plant complex is shown schematically in block flow diagram Figure 5-6. This emission control system consists of the following three processing sections:

Section 601 - Sulfur Recovery (Claus Process)

Section 602 - Tail Gas Treating (SCOT Process)

Section 603 - Sulfur Flaking

Table 5-18 shows the overall material balance for the three sections.

Table 5-19 is an abbreviated equipment list for the three sections. The Claus and SCOT units are shown only as process packages, including all battery limits equipment. These units are proprietary and are generally furnished by the licensor-supplier on a turnkey-package basis.

The sulfur flaking area is similarly shown as a battery limits equipment package. Only equipment needed to integrate this unit with the sulfur product disposal system is shown separately.

SECTION 601 - SULFUR RECOVERY (CLAUS PROCESS)

Acid gases, removed from the principal process streams in the Amine Plant (204), Naphtha Hydrotreating Section (206), Turbine Fuel Hydrotreating Section (207), and the DGA Plant (301), and recovered from the ammonia by-product stream in the Ammonia Recovery Section (703), are collected and sent to the Sulfur Recovery Section (Claus Plant) (601) for conversion of H_2S to elemental sulfur. Initially, a stream containing one-third of the total acid gas is diverted to a fired process heater in which the H_2S is oxidized to SO_2. The combustion products recombine with the balance of the acid gas stream and enter reaction vessels. Two moles of H_2S react with every mole of SO_2 to form 1½ moles of diatomic elemental sulfur and two moles of water. Variation in the 2:1 H_2S to SO_2 ratio of the feed affects the tail gas composition. The sulfur formation reaction is catalytically promoted by passing the gaseous reactants over a bed of activated alumina or bauxite. Control of the reactor inlet temperature is maintained by utilizing waste heat from the H_2S oxidation reaction to generate steam in a boiler. Molten elemental sulfur produced in the catalytic reaction flows from the reactor vessels to the Sulfur Flaking Section (603). The effluent gases flow to the Tail Gas Treating Section (602).

There are three equal-capacity Claus Unit packages in the Sulfur Recovery Section (601).

SECTION 602 - TAIL GAS TREATING (SCOT PROCESS)

Effluent tail gas from the Sulfur Recovery Section (601), containing unreacted H_2S and other acid gases, is reduced to environmentally safe levels in the Tail Gas Treating Section (602). The SCOT Process is employed to achieve low levels of residual sulfur.

The tail gas enters reactor vessels which catalytically hydrogenate all species of sulfur to H_2S over a cobalt/molybdenum catalyst supported on alumina. The reactor effluent is quenched and cooled before H_2S removal in an absorber.

The reactor effluent is stripped of H_2S and a small quantity of CO_2 by countercurrent contact with an aqueous diisopropanol amine (DIPA) solution. The aqueous DIPA solution is used as the absorbent because of its high selectivity for H_2S at atmospheric pressure. Cleaned tail gas from the absorber overhead is sent to an incinerator which oxidizes remaining hydrocarbons to CO_2. The combustion products are vented to the atmosphere.

Facilities are provided for regenerating the DIPA solution by reboiling the rich solution with steam.

Acid gases, principally H_2S exiting overhead from the regeneration column, are recycled back to the Claus Plant for additional recovery of sulfur. Regenerated DIPA solution from the column bottoms returns to the absorber.

There are two equal-capacity SCOT Unit packages, including reactors, absorbers, and regeneration facilities in the Tail Gas Treating Section (602).

SECTION 603 - SULFUR FLAKING

Molten sulfur from each unit of the Claus Plant in the Sulfur Recovery Section (601) flows to a corresponding unit in the Sulfur Flaking Section (603). The three parallel operating units of the Sulfur Flaking Section utilize a cooled belt system to convert the molten sulfur to fine flakes. A total of 664 st/sd of sulfur product is produced by the three units.

FIGURE 5-6

BLOCK FLOW DIAGRAM

EMISSION CONTROL
SECTIONS 601,602,603-CASE HE

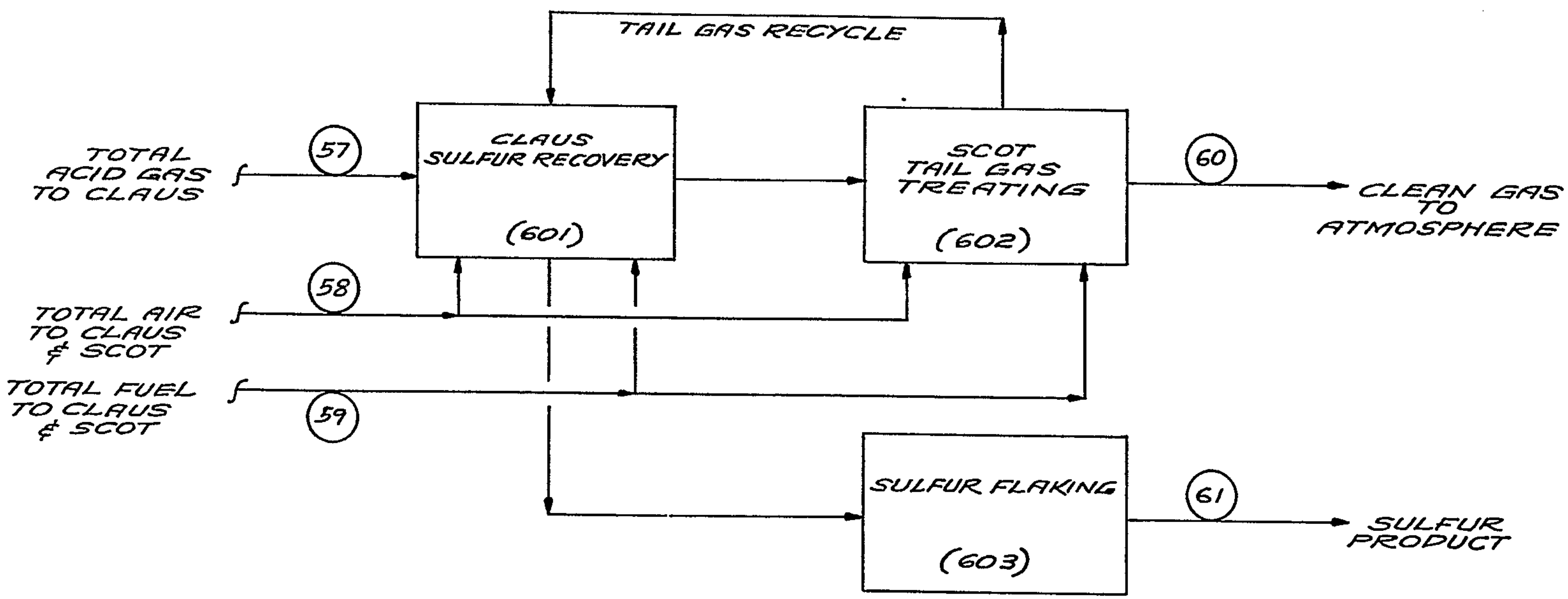


Table 5-18

MATERIAL BALANCE
EMISSION CONTROL
CLAUS, SCOT AND SULFUR FLAKING PLANTS
SECTIONS 601, 602, 603 - CASE HE

Stream No.	57	58	59	60	61
Description	Total Acid Gas To Claus	Air	Fuel Gas	Clean Gas To Atmosphere	Sulfur To Storage
Component Flowrate, lb/h					
H2			38		
N2		140,053	58	140,402	
CO			451		
H2S	58,799				
NH3	354				
H2O	5,356			44,369	
CO2	193,443			203,039	
COS	54				
CH4			2,698		
O2		42,184	488	826	
S					55,340
SO2, ppmv				(200)	
Total, lb/h	258,006	182,237	3,733	388,636	55,340

Ref. Fig 5-6

Table 5-19

EQUIPMENT LIST
UNIT 600 - CLAUS AND SCOT PLANTS AND SULFUR FLAKING
SECTIONS 601, 602, 603 - CASE HE

Section 601 - Sulfur Recovery
Section 602 - Tail Gas Treating
Section 603 - Sulfur Flaking

Item No.	No. Req'd	Description
Sulfur Recovery - Claus		
601 G-1	3	Sulfur Recovery Plant (Claus)
Tail Gas Treating		
602 G-50	2	Tail Gas Treating Plant (SCOT)
Sulfur Flaking		
603 W-100	3	Sulfur Flaking Plant with Belt Cooler
603 W-101	1	Flaked Sulfur Recovery Belt
603 W-102	1	Sulfur Stacker
603 W-103	1	Loading Conveyor
603 W-104	1	Weigh Feeder System

UNIT 700 - EFFLUENT CONTROL

Process Description - Case HE

General. This unit includes three processing sections which treat the sour water effluent produced in the plant. These sections recover oil and contaminant chemicals from the water prior to final biological treatment of the water in another section. After final treatment, the water is recycled to the process or used as cooling water makeup. The Effluent Control Unit is divided into three sections as follows:

Section 701 - Oil Separation and Phenol Recovery

Section 702 - Sour Water Stripping

Section 703 - Ammonia Recovery

These sections are shown schematically in block flow diagram Figure 5-7. An overall material balance for the three sections is given in Table 5-20. An equipment list for Sections 701 through 703 is given in Table 5-21. Certain equipment is represented by an overall package designation where the process involved is proprietary and/or where the licensor-supplier typically provides all the required battery limits equipment for the process as a turnkey package.

SECTION 701 - OIL SEPARATION AND PHENOL RECOVERY

The total sour water produced in the plant comes from the following sources:

- Effluent Separation Section (202)
- Fractionation Section (203)
- Molecular Sieve Dryers in the Amine Plant (204)
- Naphtha Hydrotreating Section (206)
- Turbine Fuel Hydrotreating Section (207)
- DGA Plant (301)
- LPG Recovery Plant (302)
- Sulfur Recovery Section (Claus Plant) (601)
- Tail Gas Treating Section (SCOT Plant) (602)

The total sour water contains a number of contaminants in the form of oil, phenols, ammonia, dissolved acid gases principally H_2S, and traces of hydrocarbons.

The total combined plant sour water stream collected from these sources flows to the oil separation area in Section 701. The sour water enters a rectangular, multichannel API oil separator which utilizes density difference and the mutual insolubility of oil and water to effect a separation of the two liquid phases. The oil phase is decanted and sent to disposal. The aqueous phase flows to the phenol recovery area in Section 701. The phenol recovery area, a licensor-supplier provided package, removes phenols from the sour water stream. The package utilizes a commercial proprietary dephenolization process developed by the Jones and Laughlin Steel Company and licensed by Chem-Pro Equipment Corporation. The process uses an extraction step with a proprietary solvent and a distillation step to effect removal of the phenols from the water. The recovered mixture of phenols, at rate of 60 st/sd, is sent to by-product storage. The dephenolized effluent sour water stream flows to the Sour Water Stripping Section (702).

Both the oil separation area and phenol recovery area utilize a single 100 percent capacity processing train.

SECTION 702 - SOUR WATER STRIPPING

The sour water stream from the phenol recovery area in Section 701 flows to the Sour Water Stripping Section (702) for removal of ammonia and dissolved H_2S. Over 99 percent of the ammonia and H_2S are removed from the water by steam stripping in a stripping column. The sour gas stream exiting overhead from the stripper flows to the Ammonia Recovery Section (703). The cleaned water stream flows to the biological treatment area of the Water Management Section (1300) before being recycled as process water or cooling tower makeup.

The Sour Water Stripping Section (702) includes two 50 percent capacity operating trains of equipment.

SECTION 703 - AMMONIA RECOVERY

The ammonia and H_2S sour gas stream from the Sour Water Stripping Section (702) flows to the Ammonia Recovery Section (703) for separation and recovery of the components. The Ammonia Recovery Section utilizes the Phosam-W* process to effect the separation of the gas. The process employs an aqueous ammonium phosphate solution to selectively absorb the ammonia from the gas stream. The absorption occurs as a reversible chemical reaction between the ammonia and the solvent. The ammonia-H_2S gas stream enters an absorber where it is countercurrently contacted with lean ammonium phosphate solution. The rich ammonia-containing ammonium phosphate solution, exiting the bottom of the absorber, flows to a stripping column. The absorber overhead gas, containing the H_2S, flows to the Sulfur Recovery Section (Claus Plant) (601) where it joins other plant acid gas streams for recovery of elemental sulfur.

In the stripping column, ammonia is steam stripped from the rich phosphate solution. Lean phosphate solution, exiting from the bottom of the stripper, is recycled to the absorber. An ammonia-steam vapor stream, exiting overhead from the stripper, is cooled and condensed. The liquid ammonia-water mixture flows to a distillation column where it is fractionally distilled to produce a 99.99 percent pure anhydrous liquid ammonia product. Liquid ammonia distillate, at a rate of 222 st/sd, is sent to by-product storage. Water, from the column bottoms, flows to the biological treatment area of the Water Management Section (1300).

The Ammonia Recovery Section (703) has a 100 percent capacity operating Phosam-W package with single trains of equipment for both the absorption and stripping operations.

---

* Phosam-W is the trade name of the commercial proprietary physical solvent ammonia absorption process developed and licensed by United States Steel Corporation.

FIGURE 5-7

BLOCK FLOW DIAGRAM

EFFLUENT CONTROL

SECTIONS 701, 702, 703-CASE HE

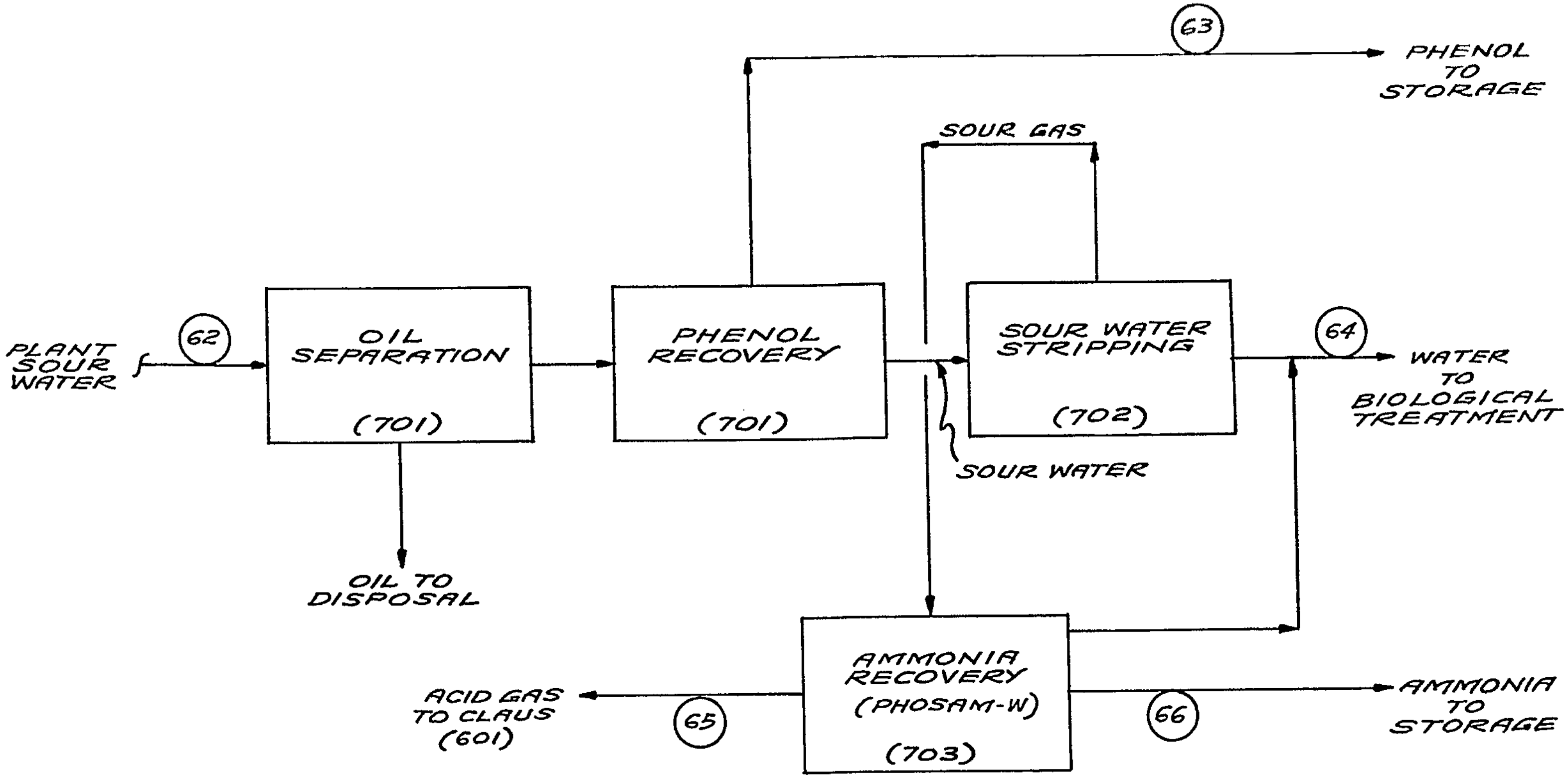


Table 5-20

MATERIAL BALANCE
EFFLUENT CONTROL
SECTIONS 701, 702, 703 - CASE HE

Stream No.	62	63	64	65	66
Description	Plant Sour Water[a]	Phenol To Storage	Water to Biological Treatment	Acid Gas to Claus (601)	Ammonia to Storage
Component Flowrate, lb/h					
H_2S	27,775		12	27,763	
NH_3	18,558		60		18,498
CO_2	5,927			5,927	
H_2O	1,227,410		1,225,000	2,410	
Phenol	4,333	4,206	127		
Total,lb/h	1,284,003	4,206	1,225,199	36,100	18,498

Ref. Fig. 5-7

[a] Water and phenol quantities estimated.

Table 5-21

EQUIPMENT LIST
UNIT 700 - EFFLUENT CONTROL
SECTIONS 701, 702, 703 - CASE HE

Section 701 - Phenol Recovery
Section 702 - Sour Water Stripping
Section 703 - Ammonia Recovery

Item No.	No. Req'd	Description
Phenol Recovery		
701 G-1	1	API Oil Separator
701 G-2	1	Phenol Package
Sour Water Stripping		
702 A-1	2	Stripper
702 A-3	2	Condenser Drum
702 P-1	2 + 1	Stripper Feed Pump
702 P-2	2 + 1	Condenser Pump
702 P-3	2 + 1	Stripped Water Pump
702 Q-1	1	Feed Surge Tank
702 T-1	2	Stripper Reboiler
702 T-2	2	Stripper Feed Exchanger
702 T-3	2	Stripper Condenser
Ammonia Recovery		
703 G-50	1	Phosam Package

UNIT 800 - TANK STORAGE

Process Description - Case HE

Plant storage facilities are shown in the equipment list Table 5-22.

The Storage Unit (800) includes storage facilities for all chemical feedstocks, intermediate and final plant products, and by-products. Coal storage facilities are included in the Coal Preparation Unit (100).

Storage capacity equivalent to approximately three weeks' production is provided for all liquid products except naphtha, for which a 29-day storage capacity is provided. Liquid oxygen storage capacity equivalent to 2 days' normal consumption is provided.

The storage volumes of principal products and by-products are summarized below:

	BBLS
Naphtha	360,000
Turbine Oil	612,000
Distillate Fuel Oil	150,000
Butane	90,000
Propane	73,400
Ammonia	37,000
Phenols	7,200

Floating roof tanks are provided for naphtha storage. Fixed roof tanks are provided for turbine fuel, distillate fuel oil and phenols. Refrigerated tanks are utilized for storage of ammonia, oxygen, propane and butane. Vapor recovery systems are provided on all liquid storage facilities in conformance with safety and environmental requirements. Facilities for shipment of products by rail or truck are also included.

Table 5-22

EQUIPMENT LIST
UNIT 800 - TANK STORAGE
CASE HE

Item No.	No. Req'd	Description
800 G-1	2	C_3 LPG Tank Refrigerant Unit
800 G-2	2	C_4 LPG Tank Refrigerant Unit
800 G-3	2	Ammonia Tank Refrigerant Unit
800 G-4	2	Light Oil Storage Tank Refrigerant Unit
800 P-1	1 + 1	C_3 LPG Storage Pump
800 P-2	2	C_3 LPG Off Spec. Storage Pump
800 P-3	1 + 1	C_4 LPG Storage Pump
800 P-4	2	C_4 LPG Off Spec. Storage Pump
800 P-5	2	Naphtha Storage Pump
800 P-6	3	Turbine Oil Storage Pump
800 P-7	1 + 1	Distillate Fuel Oil Storage Pump
800 P-8	1 + 1	Phenol Storage Pump
800 P-9	1 + 1	Ammonia Storage Pump
800 P-10	2	Sour Water Storage Pump
800 P-11	1 + 1	Phenol Treatment Pump
800 P-12	1 + 1	Light Emergency Storage Pump
800 P-13	1 + 1	Cold Rerun Storage Pump
800 P-14	1 + 1	Hot Rerun Storage Pump
800 P-15	1 + 1	Oxygen Storage Pump
800 P-16	1 + 1	Caustic Storage Pump
800 P-17	1 + 1	Flushing Oil Storage Pump
800 P-18	1 + 1	Residual Oil Storage Pump

Table 5-22 (cont'd)

Item No.	No. Req'd	Description
800 Q-1	1	Atmospheric C_3 Storage Tank
800 Q-2	2	Pressurized C_3 Storage Tank
800 Q-3	1	Atmospheric C_4 Storage Tank
800 Q-4	2	Pressurized C_4 Storage Tank
800 Q-5	2	Naphtha Storage Tank
800 Q-6	3	Turbine Oil Storage Tank
800 Q-7	1	Distillate Fuel Oil Storage Tank
800 Q-8	1	Phenol Storage Tank
800 Q-9	1	Ammonia Storage Tank
800 Q-10	2	Sour Water Storage Tank
800 Q-11	1	Isopropyl Ether Storage Tank
800 Q-12	1	Light Emergency Oil Storage Tank
800 Q-13	1	Cold Rerun Storage Tank
800 Q-14	1	Hot Rerun Storage Tank
800 Q-15	1	Oxygen Storage Tank
800 Q-16	1	Caustic Storage Tank
800 Q-17	1	Flushing Oil Storage Tank
800 Q-18	1	Nitrogen Storage Tank
800 Q-19	1	Residual Oil Storage Tank

UNIT 900 - REFRIGERATION PLANT

Process Description - Case HE

The equipment list for the auxiliary refrigeration plant is shown in Table 5-23.

The auxiliary Refrigeration Plant (900) includes a two-train cascaded refrigeration system utilizing propane and ethylene refrigerants. The system provides 3630 tons of refrigeration to the Cryogenic Plant (205) and 1250 tons of refrigeration to the Acid Gas Removal Section (404).

The Refrigeration Plant has a power consumption of 7285 kilowatts and a cooling water requirement of 13,040 gpm.

Table 5-23

EQUIPMENT LIST
UNIT 900 - REFRIGERATION
CASE HE

Item No.	No. Req'd	Description
901 M-1	2	Ethylene 1st Stage Suction Drum
901 M-2	2	Ethylene 2nd Stage Suction Drum
901 M-3	2	Ethylene 3rd Stage Suction Drum
901 M-4	2	Ethylene Refrigerant Drum
901 M-5	2	Propane 1st Stage Suction Drum
901 M-6	2	Propane 2nd Stage Suction Drum
901 M-7	2	Propane 3rd Stage Suction Drum
901 M-8	2	Propane 4th Stage Suction Drum
901 M-9	2	Propane Refrigerant Drum
901 R-1	2	Ethylene Refrigerant Compressor
901 R-2	2	Propane Refrigerant Compressor
901 T-1	2	Propane Cooled Ethylene Exchanger No. 1
901 T-2	2	Propane Cooled Ethylene Exchanger No. 2
902 T-3	2	Propane Cooled Ethylene Exchanger No. 3
901 T-4	2	Propane Aftercooler

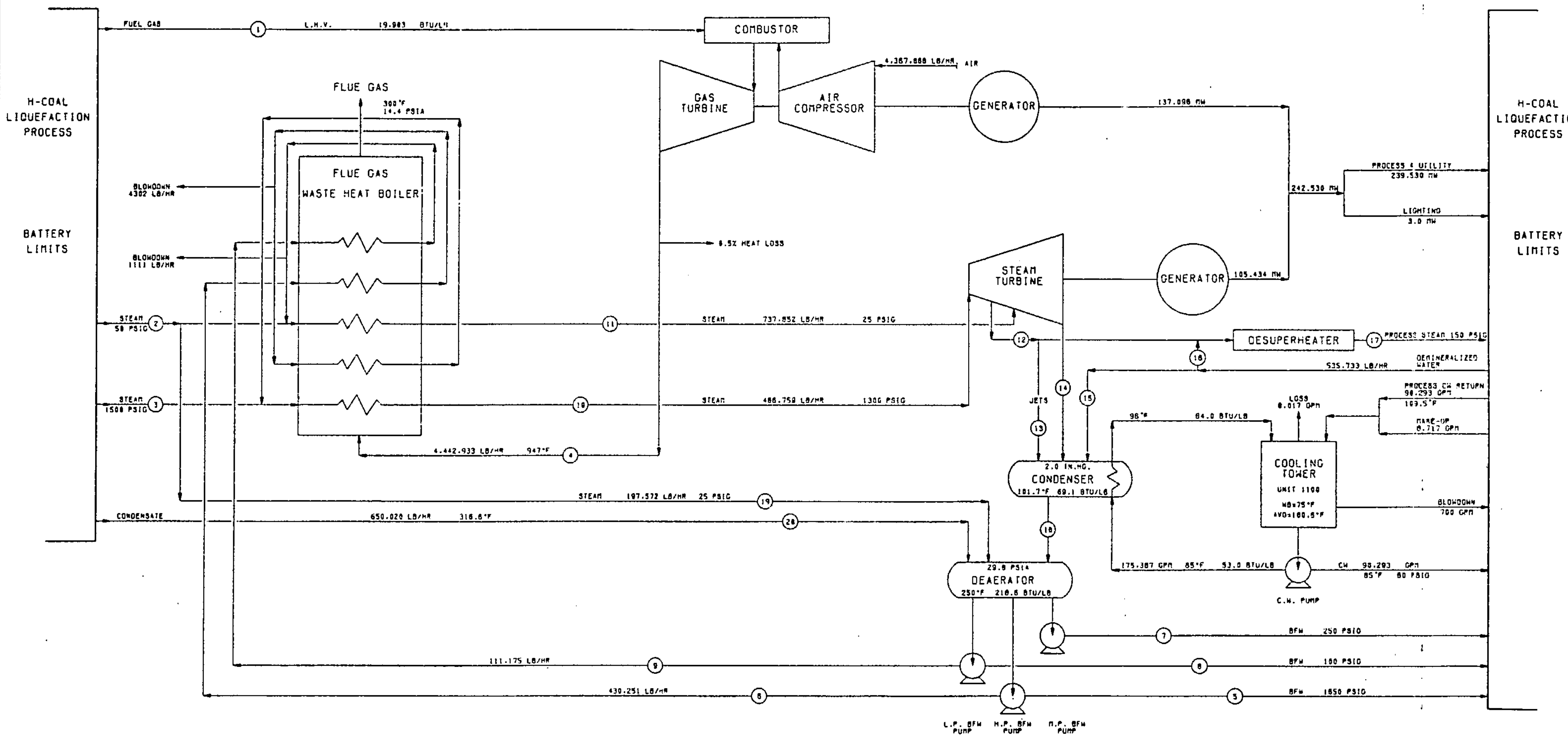
UNIT 1000 - POWER GENERATION

Process Description - Case HE

The power generation system is shown schematically in process flow diagram Drawing 75-D15. This drawing also includes associated facilities for generating steam for the steam turbine and for condensate recovery and cooling. The drawing shows the integration of the power generation, steam generation and condensate recovery, and cooling facilities with the inside battery limits process units.

The power generation system is designed on the following basis: (1) all rotating equipment in the plant is driven by electric motor, (2) excess clean, light hydrocarbon gases recovered in the process units are utilized as fuel for the gas turbines, and (3) surplus steam generated within the process units is utilized in the steam turbine generator to supplement steam generated by the hot turbine exhaust gases in the waste heat boiler.

Power is generated by one 135 MVA steam turbine and three 55 MVA gas turbines in a combined cycle system designed to product 300 megawatts of electricity. Under normal plant operating conditions, 242.5 megawatts are produced and consumed by the plant. There is no export of power.



SERVICE	FUEL GAS TO TURBINE	PROCESS L.P. STEAM	PROCESS H.P. STEAM	TURBINE EXHAUST GAS	H.P. BFW	H.P. BFW	M.P. BFW	L.P. BFW	L.P. BFW	SUPER-HEATED STEAM	SUPER-HEATED STEAM	150 PSIG STEAM	STEAM JET RETURN	CONDENSING STEAM	DEMIN-ERALIZED WATER	DEMIN-ERALIZED WATER	150 PSIG STEAM	CONDEN-SATE	25 PSIG STEAM	CONDENSATE
STREAM NO.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20
FLOW LB/HR	75.085	825.380	60.810	4.442.933	393.150	430.251	67.970	1.355.948	111.175	486.759	737.852	213.748	1.500	1.018.863	520.531	7202	219.458	1.548.894	197.572	650.020
TEMP F	113.8	297.8	597.5	947.1	250	250	250	250	250	900	578.9	432.1	120		70	70	366.0	101.7	266.8	318.6
PRESSURE PSIG	165.3	50	1500	0.8	1650	1650	250	100	100	1300	25	150					150		25	
ENTHALPY BTU/LB	19.903	1179.1	1169.3		224.6	224.6	218.5	218.5	218.5	1436.5	1323.3	1234.8	87.9	1037.1	38.1	38.1	1195.5	69.1	1169.8	286.9

NOTE: STEAM ENTHALPY BASIS-1967 ASME STEAM TABLES

STONE & WEBSTER ENGINEERING CORPORATION

CLIENT: ELECTRIC POWER RESEARCH INSTITUTE

TITLE: PROCESS FLOW DIAGRAM
POWER GENERATION
H-COAL ILLINOIS CASE HE
UNIT 1000

ISSUE	DATE	DESCRIPTION OF ISSUE	BY	CHK	APPVD
0	5-1-82				EVP

DRAWN: D. ANDERSON

JOB NUMBER	DRAWING NUMBER	ISSUE
13461	75-015	0

UNIT 1100 - COOLING WATER SYSTEM

Process Description - Case HE

This unit provides cooling water for process heat rejection, condensation of steam from turbines and cooling of mechanical equipment.

The cooling tower is designed for a wet bulb temperature of 75°F and a dry bulb temperature of 88°F. The tower is an induced draft, cross-flow unit with a design capacity to handle the plant normal cooling water circulation rate of 265,680 gpm plus an additional 10 percent flow.

The total normal circulation rate includes 90,293 gpm from the process unit users, at a return temperature at 109.5°F and 175,387 gpm from the combined cycle power plant at a return temperature of 103.0°F. The average return temperature for the total water circulation is 105.2°F. Cooling water from the cooling tower is available at 85°F.

Make-up to the cooling tower includes filtered and softened river water and biologically treated process water. Cooling tower blowdown is sent to a waste water reclamation unit (1300) for water recovery and return to the process.

UNIT 1200 - UTILITY AND STEAM SUMMARY

Process Description - Case HE

The plant steam availability and user grid is shown on Drawing 75-D11. An overall plant utility summary showing the production and consumption of the various types of utilities for each individual plant unit is shown in Table 5-24.

The plant utilities include electrical power, fuel gas, steam and water.

Steam is distributed through the plant at three levels: high pressure (1500 psig), medium pressure (150 psig) and low pressure (50 psig).

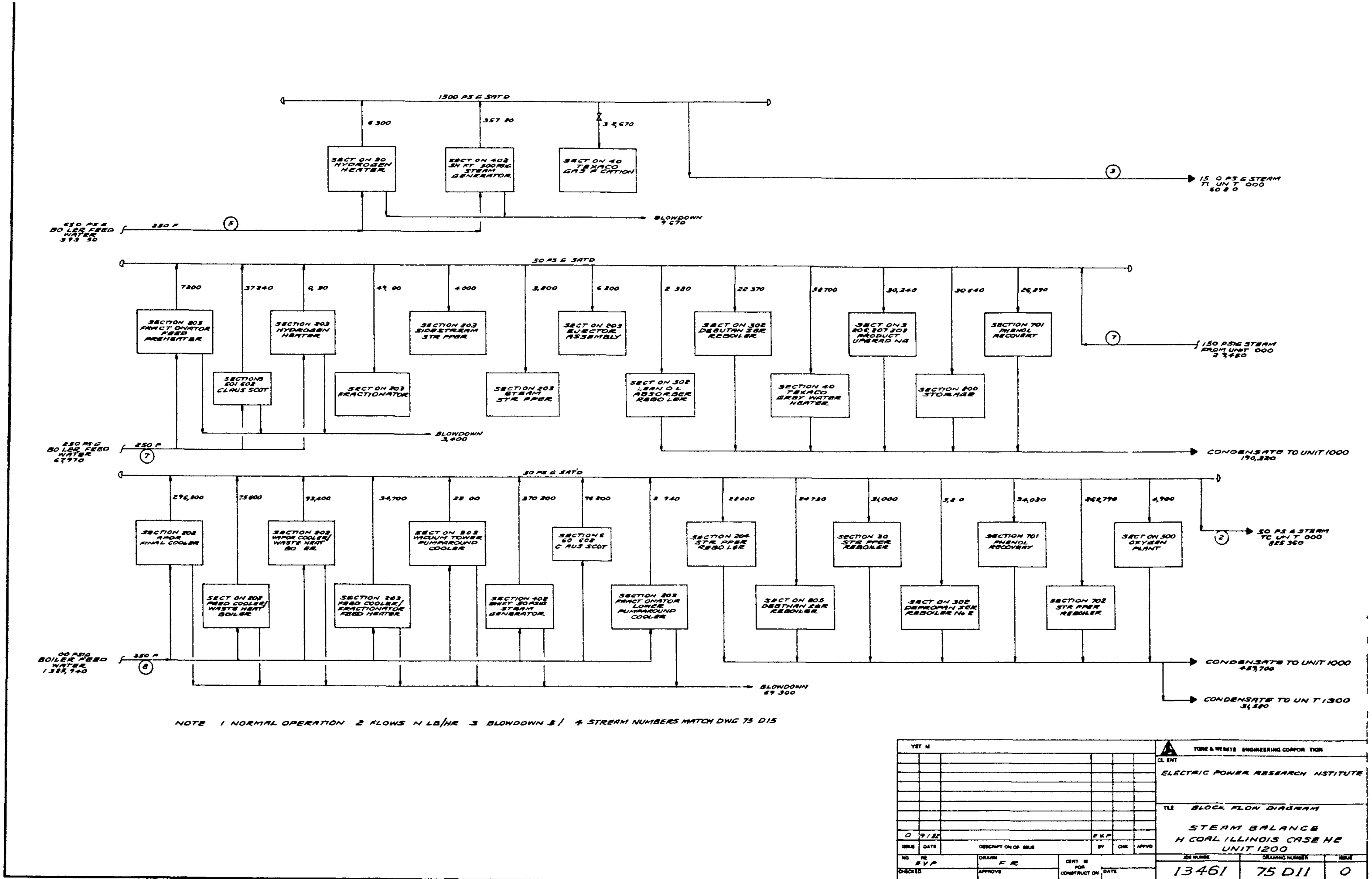
Automatic pressure letdown valves and steam desuperheaters are provided at the high and medium pressure headers. Interconnecting bypass lines between headers at adjacent levels allow steam to be transferred from higher to lower pressure levels. An excess-steam condenser is provided to avoid venting 50 psig steam during startup. Condensate is collected from steam users in a header at each level and sent to the deaerator.

All boiler feed water used in the plant to generate steam at the three levels is chemically pre-treated to inhibit corrosion in the steam generation equipment and to protect the equipment against solids deposition and sludge formation.

Table 5-24

OVERALL UTILITY SUMMARY - CASE HE

Unit Description	Coal Preparation	H-Coal Plant	Light Ends Processing	Hydrogen Plant	Oxygen Plant	Emission Control	Effluent Control	Product Storage	Refrigeration	Power & Steam Generation	Utilities & Off-sites	Total
Unit Number	100	200	300	400	500	600	700	800	900	1,000	1,100 to 1,600	
Electrical Power, KW												
Produced										242,530		242,530
Consumed	17,132	89,234	309	20,760	86,049	353	2,488	620	7,285	12,500	5,800	242,530
Cooling Water, gpm												
Produced											265,680	265,680
Consumed		25,670	7,535	9,475	18,300	9,426	6,750	97	13,040	175,387		265,680
Fuel Gas, 10 btu/hr												
Produced		2,366	649									3,015
Consumed	350	1,085		16		70				1,494		3,015
Raw Water, gpm												
Produced												
Consumed											9,196	9,196
Steam, 1500 psig, lb/hr												
Produced		16,300		357,180						425,949		799,429
Consumed				312,670						486,759		799,429
Steam, 150 psig, lb/hr												
Produced		27,330				37,240				219,450		284,020
Consumed		124,040	43,750	58,700			26,890					284,020
Steam, 50 psig, lb/hr												
Produced		650,240		570,200		96,200				110,064		1,426,704
Consumed		152,750	36,810		4,900		296,820			935,424		1,426,704
BFW, lb/hr												
Produced										2,388,486		2,388,486
Consumed		730,390		976,200		140,470				541,426		2,388,486
Condensate, lb/hr												
Produced		183,090	80,560	58,700	4,900		323,710	30,640		1,540,894		2,222,494
Consumed										2,190,914	31,580	2,222,494
Demin. Water, lb/hr												
Produced											535,733	535,733
Consumed										535,733		535,733


1500 PSIG SAT'D
SECTION 20 HYDROGEN HEATER
SECTION 402 SHIFT 300PSIG STEAM GENERATOR
SECTION 40 TEXACO GASIFICATION
BLOWDOWN
15 0 PSIG STEAM TO UNIT 000
BOILER FEED WATER
250 F
50 PSIG SAT'D
SECTION 203 FRACTIONATOR FEED PREHEATER
SECTIONS 601 602 CLAUS SCOT
SECTION 203 HYDROGEN HEATER
SECTION 203 FRACTIONATOR
SECTION 203 SIDESTREAM STRIPPER
SECTION 203 STEAM STRIPPER
SECTION 203 EJECTOR ASSEMBLY
SECTION 302 LEAN OIL ABSORBER REBOILER
SECTION 302 DEBUTANIZER REBOILER
SECTION 40 TEXACO GREY WATER HEATER
SECTIONS 206, 207 208 PRODUCT UPGRADING
SECTION 800 STORAGE
SECTION 701 PHENOL RECOVERY
BLOWDOWN 3,400
150 PSIG STEAM FROM UNIT 000
CONDENSATE TO UNIT 1000 170,320
SECTION 202 VAPOR FINAL COOLER
SECTION 202 FEED COOLER/ WASTE HEAT BOILER
SECTION 202 VAPOR COOLER/ WASTE HEAT BOILER
SECTION 203 FEED COOLER/ FRACTIONATOR FEED HEATER
SECTION 203 VACUUM TOWER PUMPAROUND COOLER
SECTION 402 SHIFT 50PSIG STEAM GENERATOR
SECTIONS 601 602 CLAUS SCOT
SECTION 203 FRACTIONATOR LOWER PUMPAROUND COOLER
SECTION 204 STRIPPER REBOILER
SECTION 805 DEETHANIZER REBOILER
SECTION 30 STRIPPER REBOILER
SECTION 302 DEPROPANIZER REBOILER No 2
SECTION 701 PHENOL RECOVERY
SECTION 702 STRIPPER REBOILER
SECTION 500 OXYGEN PLANT
50 PSIG STEAM TO UNIT 000 825,360
CONDENSATE TO UNIT 1000 423,700
CONDENSATE TO UNIT 1300 31,520
BOILER FEED WATER 1,383,940
BLOWDOWN 69 300
NOTE 1 NORMAL OPERATION 2 FLOWS IN LB/HR 3 BLOWDOWN 5% 4 STREAM NUMBERS MATCH DWG 75 D15
ELECTRIC POWER RESEARCH INSTITUTE
BLOCK FLOW DIAGRAM
STEAM BALANCE
H COAL ILLINOIS CASE HE
UNIT 1200
13461
75 D11
0

UNIT 1300 - WATER MANAGEMENT

Process Description - Case HE

The complete plant water management system is shown in block flow diagrams Drawing 75-D13. The diagram shows an integration of all the plant water facilities, and includes several plant process sections (202, 401, 403), the Effluent Control Unit (700), and the cooling tower (1100). The block flow diagram shows estimated normal and design (in parentheses) flow quantities.

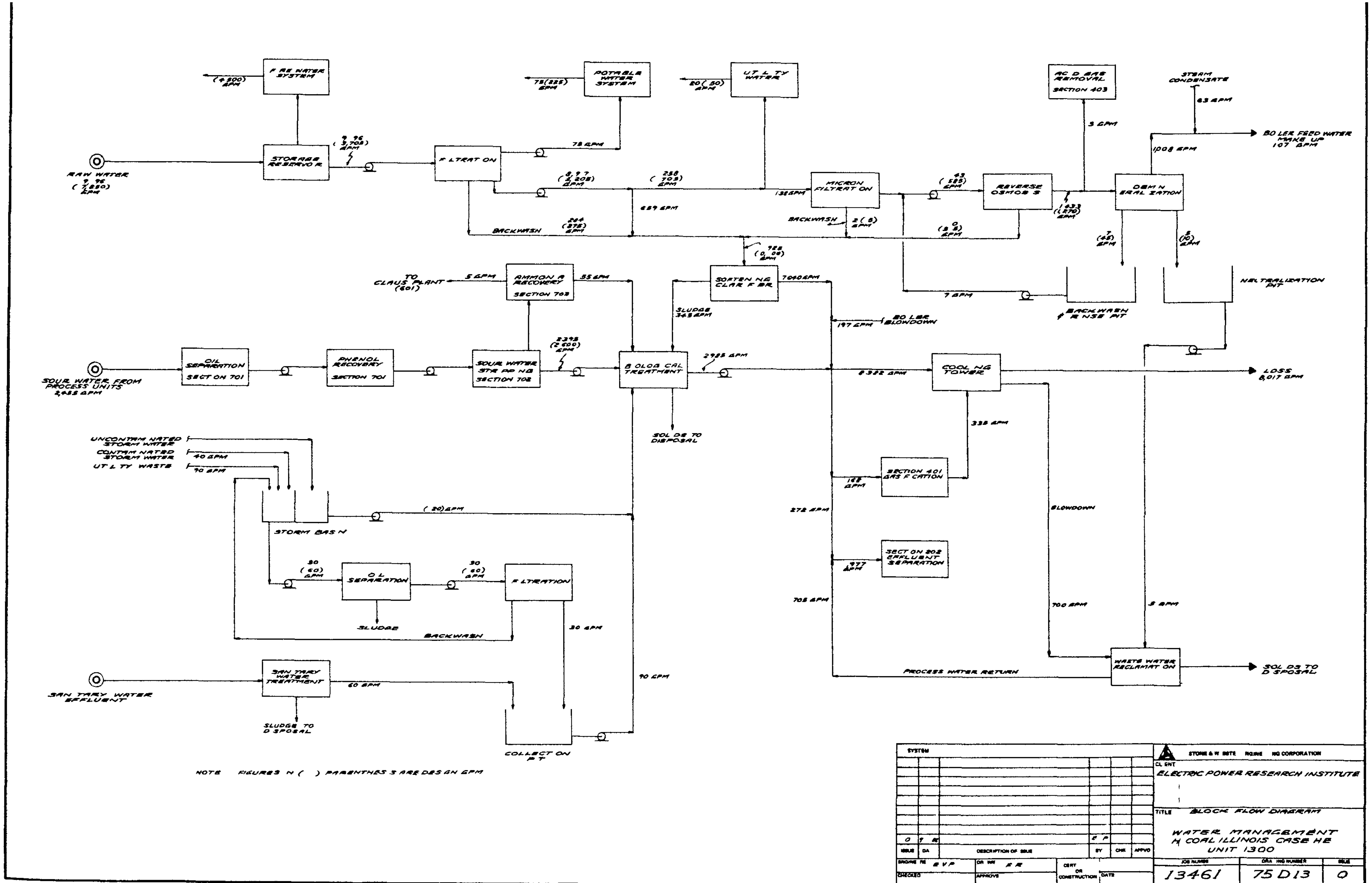
The water management system includes the following additional water handling, distribution and treatment operations:

- Raw water storage and filtration.
- Fire, utility and potable water distribution.
- Micron filtration, reverse osmosis, and demineralization for boiler feed-water make-up.
- Water softening, clarification and biological treatment for cooling tower and process water make-up.
- Waste water reclamation for removal of solids and return of water to process.
- Storm water, utility waste, and sanitary water treatment.

The following summarizes the normal plant water flow requirements:

	Water Make-Up GPM		Water Consumption GPM
Raw Water	9,196	Potable	75
Condensate	63	Utility	120
Sanitary	60	BFW	1,071
Storm	130	CT Losses	8,017
Boiler BD	197	Process	2,813
Sour Water	2,455	Claus Unit	5
Total	12,101	Total	12,101

Facilities are provided in the waste water reclamation unit for the maximum reuse of water to accomplish zero discharge of liquid waste. These facilities include waste volume reduction by reverse osmosis followed by evaporation and condensation of the vapors for reuse. Using a cooling tower blowdown feed of 700 gpm, each pass through a reverse osmosis system produces about 450 gpm of good quality water suitable for cooling tower makeup or slurrying. The concentrate (reject), which contains 80-90 percent of the original dissolved solids, can now be processed by evaporation or, if feasible, processed through another reverse osmosis unit before evaporation. The solids are discarded to landfill.


F RE WATER SYSTEM
(4 500) GPM
POTABLE WATER SYSTEM
75 (225) GPM
UT L TY WATER
20 (50) GPM
AC D GAS REMOVAL SECTION 403
STEAM CONDENSATE
63 GPM
BO LER FEED WATER MAKE UP 107 GPM
1008 GPM
3 GPM
STORAGE RESERVO R
RAW WATER 9,96 (7,850) GPM
F LTRAT ON
75 GPM
BACKWASH
MICRON FILTRAT ON
REVERSE OSMOS S
DEM N ERAL ZATION
689 GPM
TO CLAUS PLANT (601)
5 GPM
AMMON A RECOVERY SECTION 703
55 GPM
SOFTEN NG CLAR F ER
7040 GPM
SLUDGE 345 GPM
BO LER BLOWDOWN
197 GPM
7 GPM
BACKWASH & R NSE P T
NEUTRALIZATION P T
SOUR WATER FROM PROCESS UNITS 2,435 GPM
OIL SEPARATION SECT ON 701
PHENOL RECOVERY SECTION 701
SOUR WATER STR PP NG SECTION 702
B OLOG CAL TREATMENT
2985 GPM
COOL NG TOWER
LOSS 8,017 GPM
SOL DS TO DISPOSAL
UNCONTAM NATED STORM WATER
CONTAM NATED STORM WATER
UT L TY WASTE
40 GPM
90 GPM
STORM BAS N
(30) GPM
335 GPM
SECTION 401 GAS F CATION
SECT ON 202 EFFLUENT SEPARATION
272 GPM
705 GPM
BLOWDOWN
700 GPM
5 GPM
O L SEPARATION
F LTRATION
SLUDGE
BACKWASH
30 GPM
90 GPM
WASTE WATER RECLAMAT ON
PROCESS WATER RETURN
SOL DS TO D SPOSAL
SAN TARY WATER TREATMENT
SAN TARY WATER EFFLUENT
60 GPM
SLUDGE TO D SPOSAL
COLLECT ON P T
NOTE FIGURES N ( ) PARENTHES S ARE DES GN GPM
STONE & W BSTE NG NE NG CORPORATION
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TITLE BLOCK FLOW DIAGRAM
WATER MANAGEMENT H COAL ILLINOIS CASE HE UNIT 1300
13461
75 D13
0

UNIT 1400 - FLARE SYSTEM

Process Description - Case HE

The Flare System (1400) includes the flare header system and disposal facilities for flammable and noxious gases vented during normal and emergency plant operations. It is assumed that a dual relief system is provided for this plant. One system is provided for high pressure relief and one system for low pressure relief. One flare stack is provided for each system. The process equipment is protected from damage and the possibility of explosion due to over-pressure by a pressure relief system designed to vent the vessels via relief lines to the flare header.

Similarly, in the event a vessel pressure falls below normal, causing flashing of the liquid contents with resulting excessive vapor load, the low pressure system is activated to release the excess vapor to the flare header.

Individual vessel relief lines feed the flare header which conveys released gases from the processing area to the elevated flare stacks where combustion of the released material takes place. Separator drums are provided at the base of each stack to separate entrained liquid which is pumped to slops storage.

The flare stacks are provided with molecular seals which selectively allow vented gases to enter the flare for ignition, but prevent air intrusion into the relief system via the flare during inactive periods when combustion isn't occurring.

UNIT 1500 - BUILDINGS

Process Description - Case HE

The following buildings are provided:

Building	Approximate Size
Administration Building	2-story, 12,000 sq ft
Auxiliary Building	9,000 sq ft
Change House	Accommodation for 200 people, 9,000 sq ft
Chemical Storage Building	2,800 sq ft w/truck unloading facilities
Control Building	7,500 sq ft w/office space
Fire Station/First Aid Building	2,000 sq ft w/truck and ambulance bays
Guard House	480 sq ft
Laboratory	5,000 sq ft
Maintenance Shop	17,600 sq ft w/bridge crane
Maintenance Building	28,800 sq ft w/10 offices
Raw Water Treatment	15,000 sq ft
Utility Building	4,800 sq ft
Warehouse	13,200 sq ft w/truck unloading facilities

Buildings are equipped with facilities consistent with the services rendered, including offices, reception and conference rooms, library, lavatories, heating and air conditioning, stock rooms, and storage areas.

UNIT 1600 - COMMON FACILITIES

Process Description - Case HE

The plant complex includes various facilities common to all units, as summarized below:

Facility	Description
Interconnecting Piping	All major process and utility lines carried on overhead pipe racks.
Electrical Distribution System	138 kV switchyard with lines to transformers, substations, and motor control centers. Motors rated for 13.2 kV, 4000 V, 460 V or 120 V.
Site Preparation	Clear and graded site, 8,000 ft by 5,500 ft (1000 acres).
Roads and Parking Areas	Constructed with 3" asphaltic concrete and 6" cement treated base.
Curb, Ditch and Gutters	100,000 lineal ft allowed.
Culverts	2,000 lineal ft, average 36" diameter.
Railroad Siding	40,000 lineal ft including ballast, wood ties, turnouts and switches.
Site Fence	27,000 lineal ft, 8 ft high.
Fire Protection Equipment	Fire equipment vehicles, fire truck, ancillary facilities.

In addition to the above, a cost allowance is included for other facilities common to the plant, which include:

- Mobile equipment (other than fire trucks)
- Spare parts
- Landfill
- Steam and condensate system
- Instrument and plant air distribution
- Inert gas distribution
- Fire water distribution.