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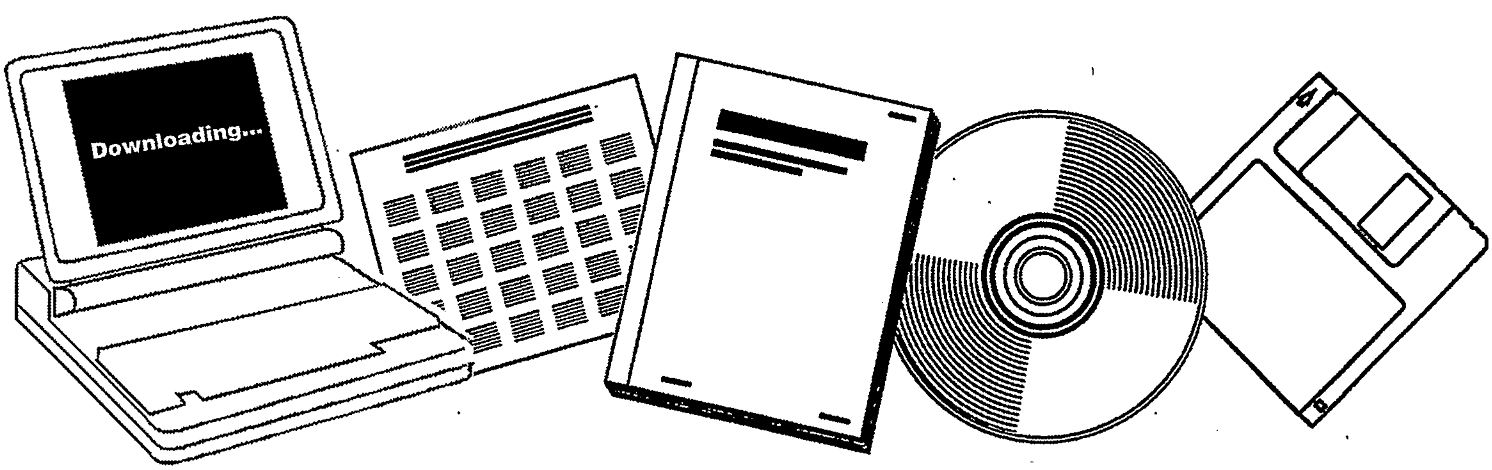
COMMERCIAL COMPLEX CONCEPTUAL DESIGN/ECONOMIC ANALYSIS. OIL AND POWER BY COED BASED COAL CONVERSION. R AND D REPORT NO. 114. INTERIM REPORT NO. 1

PARSONS (RALPH M.) CO., PASADENA, CALIF

SEP 1975



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COMMERCIAL COMPLEX CONCEPTUAL DESIGN/ECONOMIC ANALYSIS

OIL AND POWER BY COED BASED COAL CONVERSION

R & D REPORT NO. 114 - INTERIM REPORT NO. 1

September 1975

FOR THE UNITED STATES
ENERGY RESEARCH AND DEVELOPMENT ADMINISTRATION
WASHINGTON, D. C. 20545
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The Ralph M. Parsons Company
Pasadena, California 91124

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ABBREVIATIONS

av	average
bbl	barrels
bp	boiling point
BPD	barrels per day
Btu	British thermal unit
Btu/hr	Btu per hour
CH	channel
CI	cast iron
CS	carbon steel
DTPH	dry tons per hour
eff	efficiency
gpm	gallons per minute
Hdr	header
HHV	higher heating value
hp	horsepower
kV	kilovolt (1,000 volts)
lb/hr	pounds per hour
M	thousand
MAF	moisture and ash free (coal)
MF	moisture free (coal)
MM	million
MW	megawatts
MWe	megawatt electricity
ppm	parts per million
psia	pounds per square inch absolute
psig	pounds per square inch gauge

ROM	run of mine (coal)
scf	standard cubic feet
scfd	standard cubic feet per day
scfh	standard cubic feet per hour
sh	shell
sp gr and S.G.	specific gravity
SS	stainless steel
T	tubes
TDH	tons per day
TPH	tons per hour
TPY	tons per year
wt	weight

SECTION 1

INTRODUCTION

This report presents the results of a preliminary design and economic evaluation for a commercial complex to mine high-sulfur coal and produce low-sulfur synthetic crude oil (syncrude), electrical energy, and sulfur using COED-based pyrolysis technology for the coal conversion portion of the complex.

This work was performed for the Energy Research and Development Administration (ERDA) - Fossil Energy, whose support and guidance in these activities are gratefully acknowledged. From the experience gained during pilot plant operation, the design basis was developed in cooperation with representatives of ERDA and the process development contractor, FMC Corporation.

1.1 OBJECTIVES

The objectives of the work described in this report were to:

(1) Review the experience obtained during the successful operation of the ERDA-supported COED pilot plant operated by FMC Corporation at Princeton, New Jersey, over the period 1970 through 1974.

(2) Develop a conceptual design for a commercial COED-based industrial complex including all operations required to mine coal, prepare it by cleaning and washing it, convert it to ecologically clean liquid and gaseous fuels, and convert the gaseous fuels to electrical energy for sale.

(3) Estimate the economics for the facility to serve as a guide in making decisions regarding future commercial applications of this technology.

(4) Provide recommendations regarding additional development effort to foster commercial exploitation of the technology.

(5) Define probable project and financial parameters for design, engineering, procurement, construction, and startup of the complex.

1.2 REPORT ORGANIZATION

A summary of the material contained in this report is presented in Section 2 to aid the reader in rapid assimilation of its contents.

Sections 3 and 4 provide an introduction and orientation for the detailed design information which follows in later sections. The design parameters and design bases used are summarized in Section 3. Section 4 describes the scope and major units included in the complex. An overview of the method of assembling the principal process units and material flows, presented in the form of a block flow diagram, is also included in Section 4, together with an artist's rendition of the complex. Section 5 contains detailed descriptions of the design, and process flow diagrams are presented in Section 6. The overall materials and energy efficiencies are summarized in Sections 7 through 9.

Section 10 summarizes the major equipment items required; this provides a basis for the fixed capital investment and operating cost estimates which follow. Environmental factors that must be considered are detailed in Section 11. The estimated economics for this type of complex is developed in Section 12. Here the fixed capital investment, other capital requirements, operating requirements and operating cost, and projected profitability are presented. Sensitivity factors are also given.

Opinions regarding projected performance of this facility are presented in Section 13 and, finally, recommendations for future design improvements are given in Section 14. These latter two sections summarize the results of an after-the-fact evaluation of probable performance and suggestions for further design work.

SECTION 2

SUMMARY

A conceptual design and economic evaluation for a project to design, engineer, procure, construct, and start up an industrial complex which will mine high-sulfur coal and convert it to low-sulfur syncrude plus electrical energy has been completed. The results are summarized in this report.

This work was done with the support and guidance of the Energy Research and Development Administration - Fossil Energy. The design basis was developed in cooperation with representatives of ERDA and FMC Corporation, the process developer. The design basis utilized data and experience gained during the pilot plant operation.

The scope of the industrial complex consists of a large captive coal mine supplying the feed material to a coal preparation plant, which in turn supplies approximately 25,000 TPD of clean, washed coal to a COED-based pyrolysis coal conversion plant. In the COED facility, the feed coal is converted to 25°API, 0.1% sulfur syncrude plus low-sulfur fuel gases, as well as byproduct sulfur. The fuel gases are fed to a close-coupled electrical power generation plant which produces electricity for export; it also produces steam for captive use in the complex. The complex is a grass roots facility and is conceived to be located in the Eastern Region of the Interior Coal Province. The mine-mouth processing facility meets desired location criteria consisting of significant resource of high-sulfur coal with a large utility/industrial market nearby, with ecological restrictions for direct consumption of the indigenous high-sulfur coal.

This design provides the equipment and operating flexibility to process feed coal with a range of analyses which might be expected over the course of a 20-year operating life, using coal typically mined in the Eastern Region of the U.S. Interior Coal Province. This distinguishes the design from other designs which have been based on a single typical coal analysis and which might be called single feed source or "point" designs. The use of a fixed coal feed rate and variable coal characteristics requires higher fixed capital investment to provide the necessary flexibility; it also results in variable product rates.

The process flowsheets and accompanying heat and material balances which are presented are based on a typical coal analysis which is intermediate between the extreme analyses that might be encountered during the project life. All equipment was sized to handle the range of feed analyses and resulting operating condition adjustments to permit operation at capacity approximately 95% of the onstream time.

For the typical design case, approximately 36,000 TPD of run-of-mine (ROM) coal is mined and processed through a coal preparation plant to produce approximately 27,500 TPD of clean, washed coal feed to the COED pyrolysis plant. Products from the process plant include 28,000 bbl/day of 25°API syncrude with a maximum sulfur content of 0.1% by weight plus about 830 MW of electrical power for sale. About 750 long tons of sulfur is produced as by-product.

Considerable attention was given to methods of scale-up; the scale-up factor from pilot plant to the conceptual design reported here was of the order of 700. Methods of scale-up were selected to provide efficiency, operability, and process controls.

To develop the conceptual design it was necessary to use extrapolation procedures in certain cases. For these cases, the basic chemical engineering phenomena were examined in detail with the objective of developing a sound basis for the extrapolation and scale-up. An example is that the conceptual design encompasses gasification of pyrolysis-produced char to consume a total of approximately 98% of the carbon contained in the feed coal. This represents an example of extrapolation; in a typical pilot plant run approximately 30% of the carbon was converted in the pyrolysis section. About 6% of the carbon in the resulting pyrolysis-produced char was gasified by reaction with steam and oxygen. This compares with 66% steam-oxygen gasification required in the conceptual plant design described here.

The design represents an assessment of a proposed configuration and potential economics for this type of technology. To accomplish this objective required the use of engineering judgement for the scale-up and the selection of the equipment required to achieve the stated objectives. It also represents an exposition of factors required to integrate the coal conversion plant with a closely coupled electrical power generation facility and a large coal mine. The development of the interfaces between the coal mine, process plant, and power plant has defined a number of the design and operational options which exist for maximizing efficiencies and profitabilities.

Approximately 500 acres should be allocated for the complex site exclusive of the coal mine. Over a 20-year project life, about 42 square miles would be mined. An artist's conceptual drawing of the complex is presented.

The estimated fixed capital investment for the complex is $1 billion; all estimates are in first-quarter 1974 dollars. The total capital investment is estimated to be $1.125 billion; this includes the cost of initial raw materials, catalysts and chemicals, allowance for startup and land acquisition and initial working capital.

The population of the complex is estimated to be about 1700. Operating costs are projected to be about $127 million per year. The required plant revenue for a 10% discounted cash flow rate of return (DCF) with 65% debt at 9% interest is $300 million per year. Typical required selling prices for the mixed product slate at 10% DCF, after by-product sulfur credit, are as follows:

Syncrude, $/bbl	Electricity, mils/kW-hr
10	32
15	25
18	20
26	10

Other cases and sensitivities of required selling prices and profitability to key economic parameters are presented.

A representative project schedule for the design, engineering, construction, and startup is given; a 57-month schedule to mechanical completion is projected, and a probable fund drawdown schedule is presented.

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

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

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

Phase I: Thermogravimetric Study.

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

The results of the IGT study indicated:

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

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

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

A number of potential design improvements are presented. These improvements would be expected to improve the economics when successfully reduced to practice.

SECTION 3

DESIGN PARAMETERS

This section describes the raw materials utilized, the products produced, and the basic design parameters/criteria used.

3.1 GENERAL CHARACTERISTICS

A most important characteristic of the design is that it provides the equipment and operating flexibility to process feed coal with a range of analyses which might be expected over the course of a 20-year operating life, using coal typically mined in the Eastern Region of the U.S. Interior Coal Province. This distinguishes the design from other designs which have been based on a single typical coal analysis and which might be called single feed source or point designs. The use of variable feedstock characteristics requires higher fixed capital investment to provide the necessary flexibility and variable product rates. These factors will be referred to during the course of subsequent discussion of characteristics and economics summarized in this report.

In order to characterize the design results, the process flowsheets and accompanying heat and material balances have been based on a "typical" coal analysis which is intermediate between the extreme analyses that might be encountered during the project life. All equipment was sized to handle the range of feed analyses and resulting operating condition adjustments to permit operation at capacity approximately 95% of the onstream time.

3.2 DESIGN BASIS

A detailed summary of the Design Basis developed in the early stage of the work is included as Appendix A. The Design Basis was intended to state the philosophy and data base to be used for the development of the conceptual commercial plant design. The primary objective was a preliminary design in sufficient detail for a budget-type cost estimate for the facility described hereafter.

A number of the key design parameters are summarized in the following paragraphs of this section.

3.3 PLANT LOCATION

The plant was considered to be located in the Eastern Region of the U.S. Interior Coal Province which includes portions of the states of Illinois, Indiana, and Kentucky. The site conditions used for equipment design are summarized in the Basic Design Criteria document presented as Appendix B of this report. The plant complex was to be close to the coal mines and a river.

3.4 SCOPE

The coal conversion complex is a grass roots facility with captive coal mines to supply the necessary feed coal. The electrical power generated is considered supplied to a power grid.

3.5 RAW MATERIALS

The raw materials will consist of the following:

(1) Coal - Run of mine (ROM) coal will be produced in captive mines. The range of characteristics of washed, ground coal fed to the process plants is given in the following proximate analysis:

Item	Range
Moisture	9.5 to 11.5 wt %, wet basis
Ash	10.45 to 13.95 wt %, dry basis
Volatile Matter	44.15 to 48.65 wt %, MAF basis
Fixed Carbon	55.85 to 51.35 wt %, MAF basis
Heating Value	12,121 to 12,809 Btu/lb, dry basis

Ultimate analysis (weight percent, MAF basis) is as follows:

Item	Range
Carbon	77.35 to 79.85
Hydrogen	5.20 to 5.60
Nitrogen	1.35 to 1.65
Sulfur	2.80 to 5.80
Oxygen	9.20 to 11.20

The above ranges of coal characteristics were considered to include 95% of the coal to be produced in the conceptual coal mine area.

The design is based on a constant coal feed rate of 21,500 tons of moisture- and ash-free (MAF) coal per stream day to the pyrolysis plant. For the typical case, this corresponds to approximately 27,400 TPD of coal as fed.

(2) Oxygen - 99.5% purity; produced captively by air separation.

(3) Water

- Process water from the river.

- Potable water from wells.

3.6 PRODUCTS

The principal products from the complex consist of syncrude, electrical power, and sulfur. They are presented for three cases in the following table, including maximum, minimum, and an intermediate oil production case corresponding to that described in the process flow diagrams presented later.

		Production Rate		
Product	Characteristics	Max. Oil	Min. Oil	Typical Oil
Syncrude	Approx. 25 API S < 0.1% wt	32,750 BPD	24,000 BPD	28,000 BPD
Electrical	138 kV	270 MW	1,150 MW	830 MW
Sulfur	99.9% pure	750 TPD	800 TPD	765 TPD

Note: Sulfur is expressed in long tons

3.7 PRIMARY PROCESS UNITS

The coal conversion complex will consist of the following units:

(1) A unit to crush and wash the coal to minus 1/8-in. size.

(2) Facilities to dry the coal with hot process gas.

(3) A unit to pyrolyze the coal in a series of fixed fluidized beds using heat liberated in gasifying the residual char. Part of this heat is extracted from the hot gasifier gas, and the remainder is transported from the gasifiers to the pyrolyzers by means of a recirculating stream of char.

(4) A unit to condense oil from the pyrolysis vapors by cooling in direct contact with cooled raw condensate.

(5) Facilities to remove fine solids from the intermediate pyrolysis oil; filtration is used in this design.

(6) A unit to hydrotreat the recovered oil to reduce the sulfur, nitrogen, and oxygen contents; the hydrotreating also saturates unsaturated hydrocarbons and reduces the viscosity.

(7) A unit to desulfurize pyrolysis gas to produce a clean fuel and recover elemental sulfur.

(8) A unit to generate low-Btu fuel gas by gasifying the residual char with steam and oxygen.

(9) A unit to desulfurize the low-Btu fuel gas to produce a clean fuel and recover elemental sulfur.

(10) An oxygen plant.

(11) A hydrogen plant.

(12) A power plant to produce electric power from the pyrolysis gas and low-Btu fuel gas.

3.8 EFFLUENT TREATMENT AND NOISE CONTROL

All effluent streams will be treated so as to meet environmental standards. Disposal of solid waste will be integrated with coal mining to provide haul-away and proper disposal. Equipment will be designed to meet OSHA noise level requirements.

3.9 RAW MATERIAL AND PRODUCT STORAGE

Facilities for a 30-day inventory of coal and products are provided.

SECTION 4

SUMMARY FACILITY DESCRIPTION

This section briefly describes general characteristics of the coal conversion complex; an overall block flow diagram is shown in Figure 4-1. This will provide background for the sections on design and economics.

The complex includes captive coal mines with capacity to produce up to approximately 13 million TPY for 20 years. Units are included which will clean, wash, crush, and size the coal and feed it to the process units.

All necessary facilities for production of oxygen, hydrogen, and all required utilities are included in the design as well as treatment and disposal of solid, liquid, and gas waste streams. The design is based on a site location capable of providing 45,000 acre-feet of water per year for process requirements and utilities makeup. Well water is used for potable and sanitary water.

The land area required for the life of the project for mining required coal is estimated to be about 42 square miles; approximately 500 acres would be allotted to the initial plant complex.

An artist's conceptual drawing of the complex is shown in Figure 4-2. A model of the complex has been constructed; a photograph of this model is presented in Figure 4-3.

4.1 THE PYROLYSIS UNIT

The heart of the coal conversion plant is a multiple-stage pyrolysis unit. The vapors generated in the pyrolysis unit are treated to recover the oil and separate the gas. The oil is filtered to remove solids and then hydrotreated to reduce heteroatom content and viscosity. The resulting product is a low-sulfur synthetic crude oil (syncrude). Pyrolysis gases are treated to remove the acid gases, hydrogen sulfide and carbon dioxide, and then used in the power generation unit. Elemental sulfur is produced as a by-product of the gas cleaning operations.

The pyrolysis section produces a significant amount of char which is, in turn, essentially completely gasified using steam and oxygen. Recycled char and effluent gases from the gasifier supply energy to the pyrolysis section. The gasifier gaseous effluent is then purified and the environmentally acceptable fuel gases are fed to the power plant where electrical energy and steam are produced.

The following legend applies to Figure 4-3, the conceptual model of a COED plant design:

Color	Unit
Black	Coal Preparation
White	Oxygen Production
Orange	Pyrolysis and Gasification
Blue	Hydrogen Production
Green	Oil Treating
Yellow	Gas Treating and Sulfur Recovery
Red	Offsites
Brown	Power Plant

4.2 PLANT CAPACITY

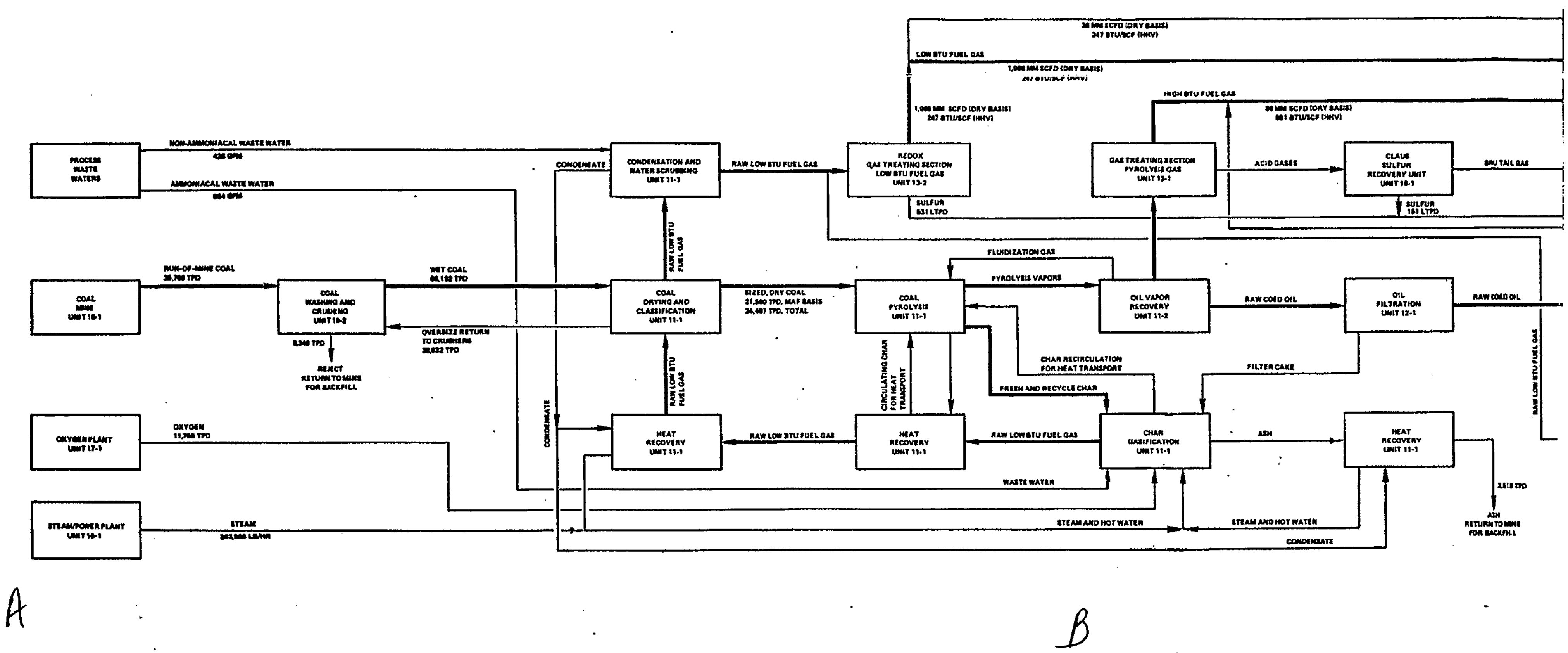
The typical throughput of coal is based on 21,500 TPD of MAF coal; this corresponds to about 24,500 TPD of MF coal and 27,400 TPD of as-is feed coal containing ash and moisture. This throughput will produce the following approximate output rates:

Synthetic Crude Oil	28,000 bbl/day
Electric Power	830 MW
Sulfur	760 LTPD

Because of the varying content of volatile matter, moisture, and ash in the feed coal, the rate of product output will also vary. Oil output is expected to vary from 24,000 to 32,000 bbl/day. Electric power maximum exportable output is about 1,150 MW when volatile matter, moisture, and ash are lowest. Electrical power output will be lowest under conditions of highest expected content of volatile matter, moisture, and ash in the feed coal, at which point steam demand is high. See Section 3 for expected ranges of power production. Efficiency of fuel utilization for electrical generation declines significantly at levels below 825 MW.

4.3 ENERGY BALANCE FACTORS

Gas, which serves as fuel for the power and steam generation unit, is composed of a mix of high-Btu gas (about 890 Btu/scf) from pyrolysis, and low-Btu gas (250 Btu/scf) from char burning. The total heat content of the combined streams is typically 14,200 million Btu/hr. In addition to the electric


PROCESS WASTE WATERS
NON-AMMONIACAL WASTE WATER
426 GPM
AMMONIACAL WASTE WATER
664 GPM
COAL MINE UNIT 18-1
RUN-OF-MINE COAL
35,700 TPD
OXYGEN PLANT UNIT 17-1
OXYGEN
11,768 TPD
STEAM/POWER PLANT UNIT 16-1
STEAM
LB/HR
COAL WASHING AND CRUSHING UNIT 19-2
TPD
REJECT RETURN TO MINE FOR BACKFILL
WET COAL
TPD
OVERSIZE RETURN TO CRUSHERS
TPD
CONDENSATION AND WATER SCRUBBING UNIT 11-1
COAL DRYING AND CLASSIFICATION UNIT 11-1
HEAT RECOVERY UNIT 11-1
CONDENSATE
RAW LOW BTU FUEL GAS
SIZED, DRY COAL
TPD, MAF BASIS
TPD, TOTAL
REDOX GAS TREATING SECTION LOW BTU FUEL GAS UNIT 13-2
SULFUR
LTPD
LOW BTU FUEL GAS
SCFD (DRY BASIS)
247 BTU/SCF (HHV)
COAL PYROLYSIS UNIT 11-1
CIRCULATING CHAR FOR HEAT TRANSPORT
FLUIDIZATION GAS
PYROLYSIS VAPORS
CHAR RECIRCULATION FOR HEAT TRANSPORT
FRESH AND RECYCLE CHAR
OIL VAPOR RECOVERY UNIT 11-2
GAS TREATING SECTION PYROLYSIS GAS UNIT 13-1
HIGH BTU FUEL GAS
ACID GASES
CLAUS SULFUR RECOVERY UNIT UNIT 16-1
SRU TAIL GAS
RAW COED OIL
OIL FILTRATION UNIT 12-1
FILTER CAKE
CHAR GASIFICATION UNIT 11-1
ASH
WASTE WATER
STEAM AND HOT WATER
ASH RETURN TO MINE FOR BACKFILL
A
B

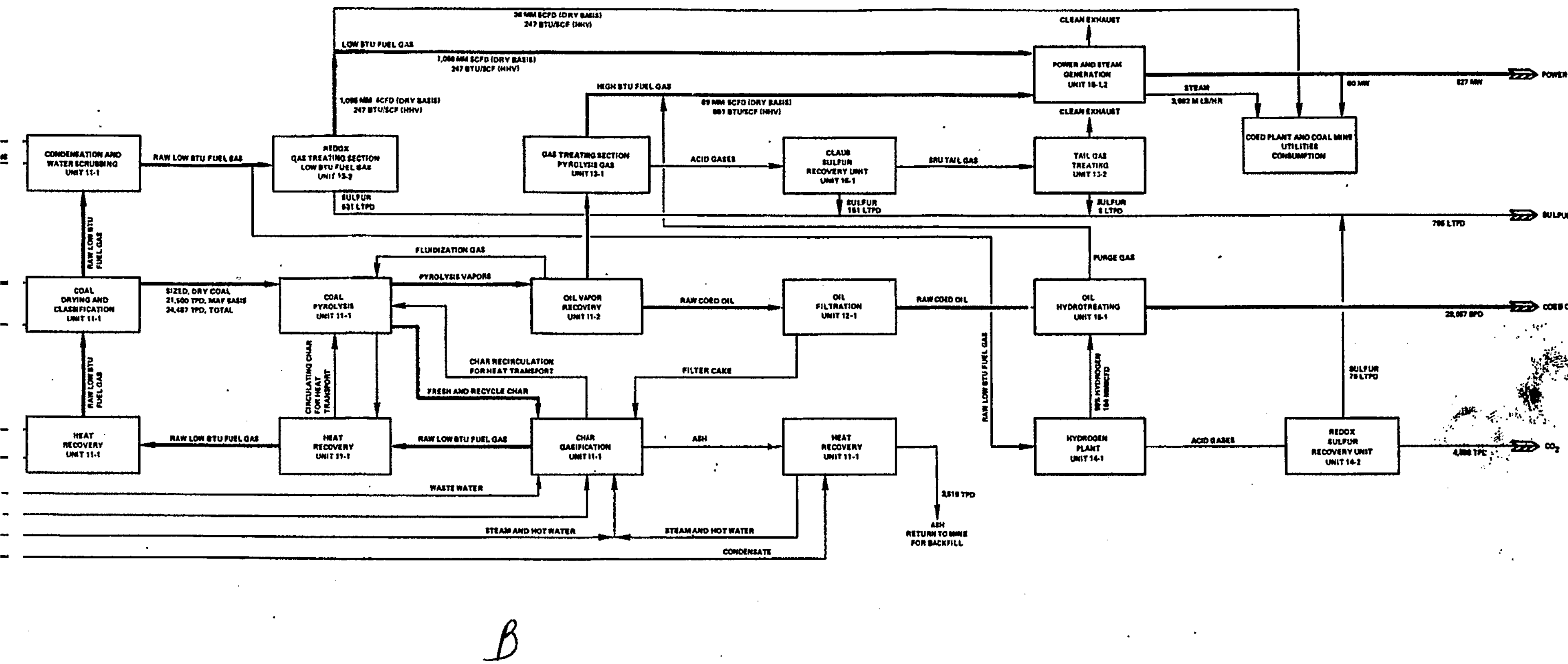


Figure 4-1 - Block Flow Diagram - Conceptual Commercial COED Plant Design

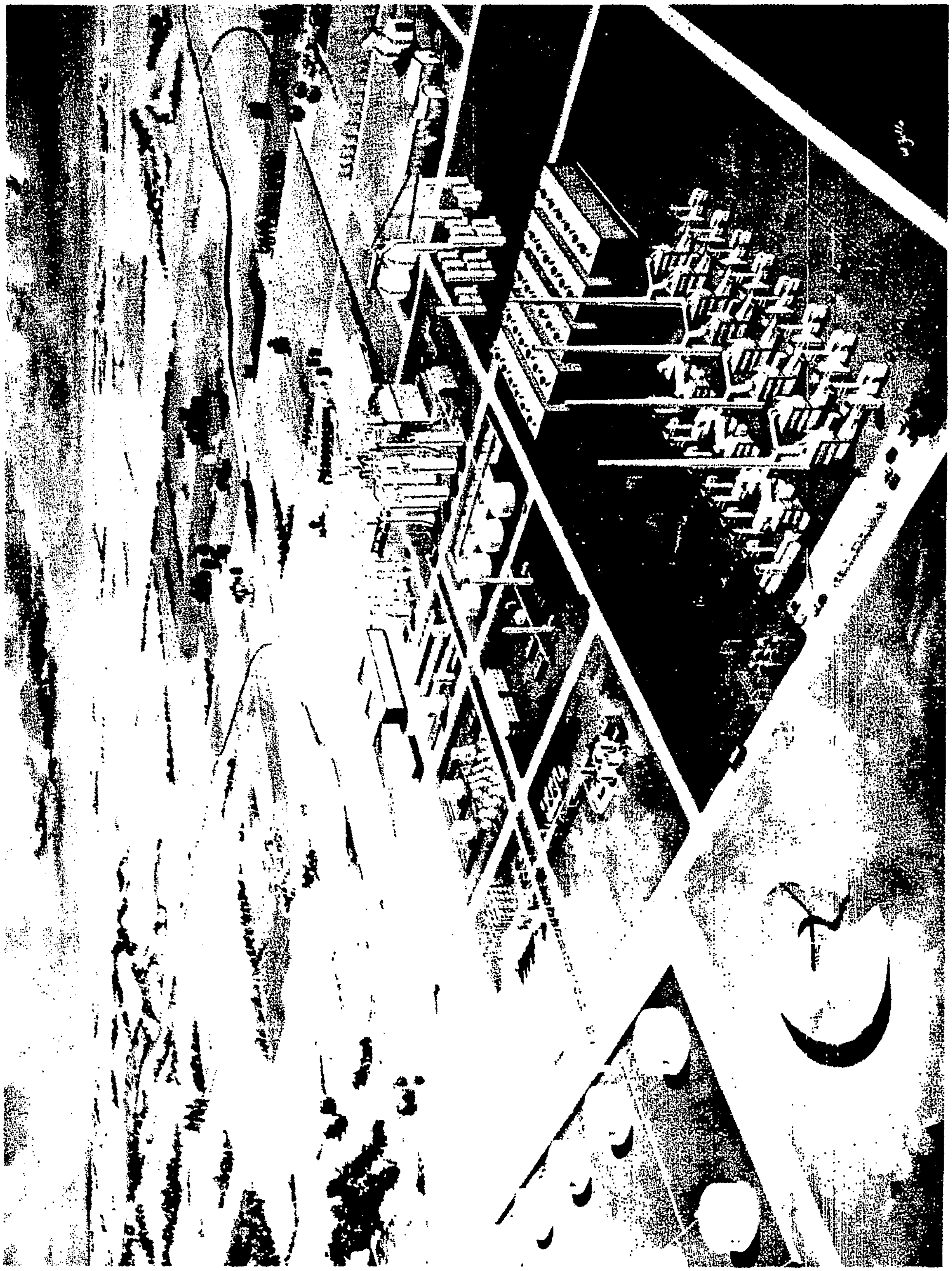


Figure 4-2 - Artist's Concept of Conceptual

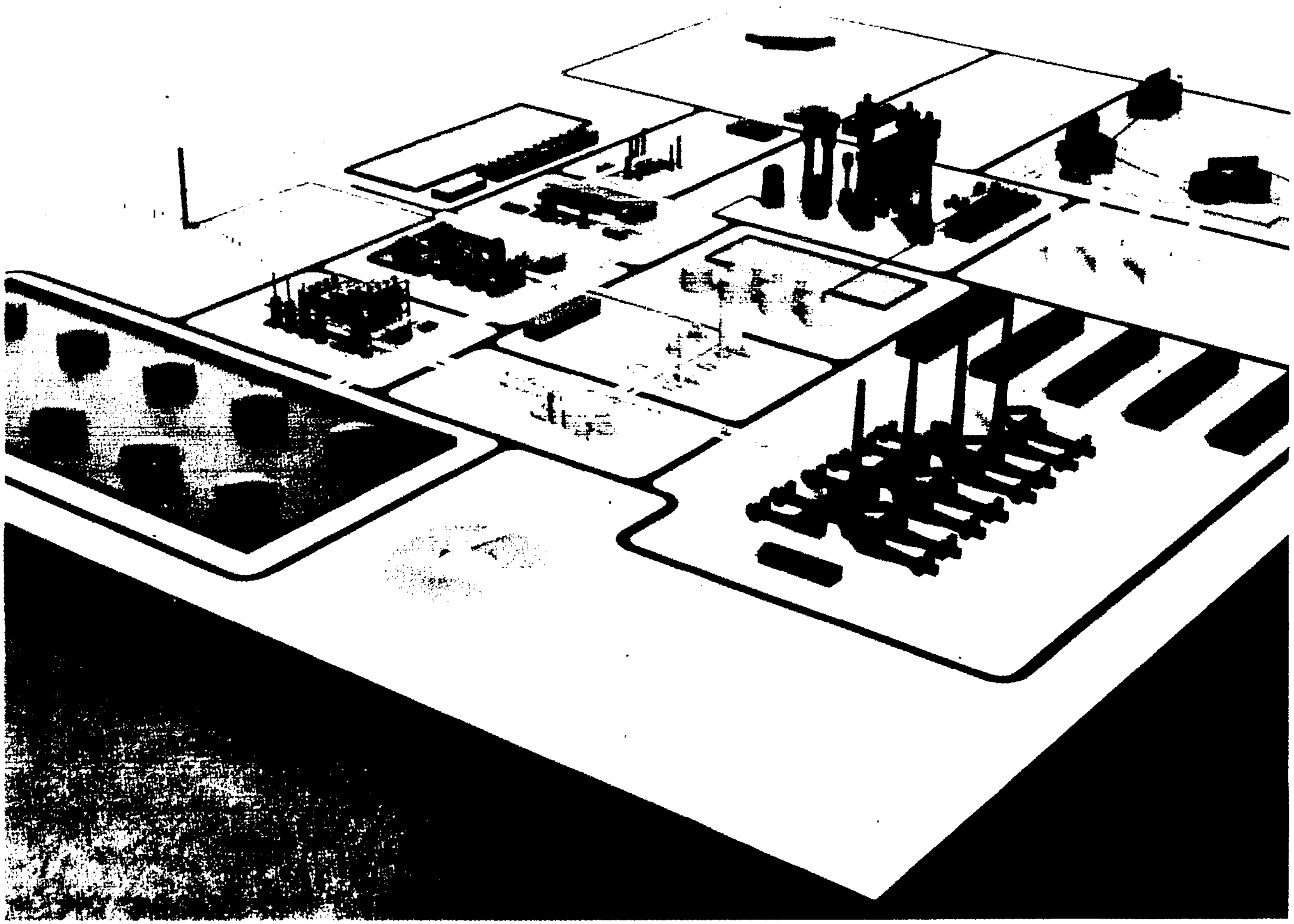


Figure 4-3 - Model of Conceptual
COED Plant Design
(for color legend, see page 4-2)

power produced with a typical coal composition, this fuel must also produce 5.2 million lb/hr of steam for captive use in the complex. Approximately 3.7 million lb/hr is required in the process units for mechanical drivers and process use to supplement steam which is produced in these units. In addition, 1.5 million lb/hr is required for power plant fuel gas compressor drives. The heating value of fuel gas required to produce this 5.2 million lb/hr of steam, plus the amount required to produce about 80 MW of power required for captive use in the complex, leaves a net quantity of 7,600 million Btu/hr (HHV) for production of electrical power for export.

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SECTION 5

PLANT UNIT DESCRIPTIONS

Descriptions of the separate units which are a part of the COED Conceptual Commercial Plant Design are presented in this section.

The following units are described:

Unit No.	Description	Flowsheet No.	Paragraph No.
10-1	Coal Mine	--	5.1
10-2	Coal Preparation	5054-3-AE-10-2	5.2
11-1	Pyrolysis and Gasification	5054-3-AE-11-1	5.3
11-2	Oil-Vapor Recovery	5054-3-AE-11-2	5.4
12-1	Oil Filtration	5054-3-AE-12-1	5.5
13-1	Pyrolysis Gas Treating	5054-3-AE-13-1	5.6
13-2	Low-Btu Gas Treating	5054-3-AE-13-2	5.7
14-1	Hydrogen Plant	5054-3-AE-14-1	5.8
14-2	Hydrogen Plant Tailgas Desulfurizer	5054-3-AE-14-2	5.9
15-1	Oil Hydrotreating	5054-3-AE-15-1	5.10
16-1	Sulfur Recovery Unit - Pyrolysis Gas	5054-3-AE-16-1	5.11
16-2	Tailgas Treating Unit, from Unit 16-1	5054-3-AE-16-2	5.12
17-1	Oxygen Plant	--	5.13
18-1	Power/Steam Generating Plant	5054-3-AE-18-1	5.14
19-1	Plant Air and Instrument Nitrogen	--	5.15

Unit No.	Description	Flowsheet No.	Paragraph No.
19-2	Cooling Water System	--	5.16
19-3	Industrial Water System	5054-3-AE-19-3	5:17
19-4	Potable and Sanitary Water System	--	5.18
19-5	Fire Water System	--	5.19
19-6	Waste Water Treatment	--	5.20
20	Buildings and General Facilities		

The flowsheets are contained in Section 6. Utilities for each unit are summarized in Section 8, while equipment lists for the separate sections are given in Section 10.

5.1 COAL MINE (UNIT 10-1)

The COED Conceptual Commercial Plant Design includes an integrated strip mine in the Eastern Region Interior (Coal) Province of the United States. Basic criteria established include an average seam thickness of 5 feet, an average thickness of overburden of 60 feet, and a deposit sufficient for a 20-year mine life. The ROM high volatile C bituminous coal (average as mined) is projected to have the following properties:

Item	Wt%
Fixed Carbon	36 ± 10.0
Volatile Matter	13 ± 5.5
Moisture	9 ± 6.5
Ash	24 ± 10.0

Ultimate analysis on a wt%, MAF Basis, is as follows:

Item	Range
Carbon	77.35 - 79.85
Hydrogen	5.20 - 5.60
Nitrogen	1.35 - 1.65
Sulfur	2.80 - 5.80
Oxygen	9.20 - 11.20

A mining plan was formulated, equipment was sized for the mine, and capital and operating costs were estimated. These cost estimates exclude land acquisition, relocation of railroads, highways, pipelines, buildings, and related items. Cost figures appear in Section 12.

Raw coal production is to average approximately 11,900 MTPY over the 20-year period; this would make the operation among the largest coal mines in the country.

Of particular interest is the method conceived for continuous land reclamation, with topsoil placed back on the surface of the mined-out area, closely following the mining face.

5.1.1 PRODUCTION REQUIREMENTS

Mine production capability required is 35,700 TPD, ROM, 365 day/year operating basis, or 13 MMTYP. Planned production is equal to 330 days equivalent to produce approximately 11,900 MTPY.

Coal density is 1,800 tons per acre-foot.

Assume coal seam is 5 feet thick, not including thin seamlets of shale. The rejects consist of these seamlets and diluting material (mostly shale) from above and below the seam. The seam then produces 9,000 tons/acre; about 4 acres per day would be mined.

Since the mine will be separated into three completely independent units, the unit production will require about 1.33 acres per day or approximately 58,000 square feet per day.

With a stripping width of 180 feet, each unit would then work about 325 lineal feet per day.

5.1.2 MINING PLAN

At the scheduled rate of production, and with an annual average equivalent to 330 days of production, an average of 1,320 acres of coal per year must be mined. Over the assumed 20-year life of the mine, 26,400 acres, or nearly 42 square miles, will be mined out.

Because of the large stripping ratio (12:1 on a volume basis, and 21:1 on a weight basis), and because of present limitations on size of mining equipment, the mine will be divided into three completely separate mining units. Each unit will consist of the following:

(1) Upper overburden stripping system which will return this material to the top of the spoil piles for reclamation purposes.

(2) Large stripping shovel able to cast or spoil the lower overburden to allow the mining of the coal seam.

(3) Rotary drills to facilitate blasting of the lower overburden.

(4) Loading and hauling equipment for coal removal.

(5) Auxiliary equipment, such as dozers, loaders, and graders, for supporting each operation.

The three mining units will be supported by a centralized shop and other equipment which will be available where required.

The mine will be rectangular in shape with the washing plant located approximately on the line bisecting the long dimension, and on the surface as close as possible to the pit edge. The primary crusher will be located in the pit with belt conveyors transporting the coal to the washing plant. See Figure 5-1.

The overall mine is laid out such that the long dimension is approximately twice the width. This scheme minimizes haulage distances. The three mining areas are thus separated sufficiently to avoid congestion, but near enough for close supervision.

The actual total mine width is controlled by the width which the stripping shovel will clean - 180 feet. A total of 135 strips equals 4.6 miles; based on the total of 42 square miles of area, the length is then 9.2 miles.

To obtain a balanced coal hauling pattern, the mining areas will be located as shown in the sequence sketches, Figure 5-2. When Area 3 needs the most trucks, Areas 1 and 2 need the least, and vice versa.

5.1.3 MINING SEQUENCE

A. Upper Stripping

The top 20 feet of overburden consists of unconsolidated gravels, sands, and soil. Since it is required that the disturbed or mined-out area be reclaimed to approximately the original surface contour, and that plantings be made on the reclaimed ground, this top overburden and topsoil must be placed on top of the spoiled lower overburden. The topsoils thus replaced will facilitate the growth of the plantings.

Since 43,000 bank (in situ) cubic yards per day of upper overburden must be moved from each mining area, and a linear advance of 325 feet is also required, a highly mobile and productive system is indicated. Of the various systems investigated (including shovel-truck, front-end loader - truck, and bucket-wheel excavator) the most practical and economical is considered to be a Holland loader in combination with a belt-conveyor system.

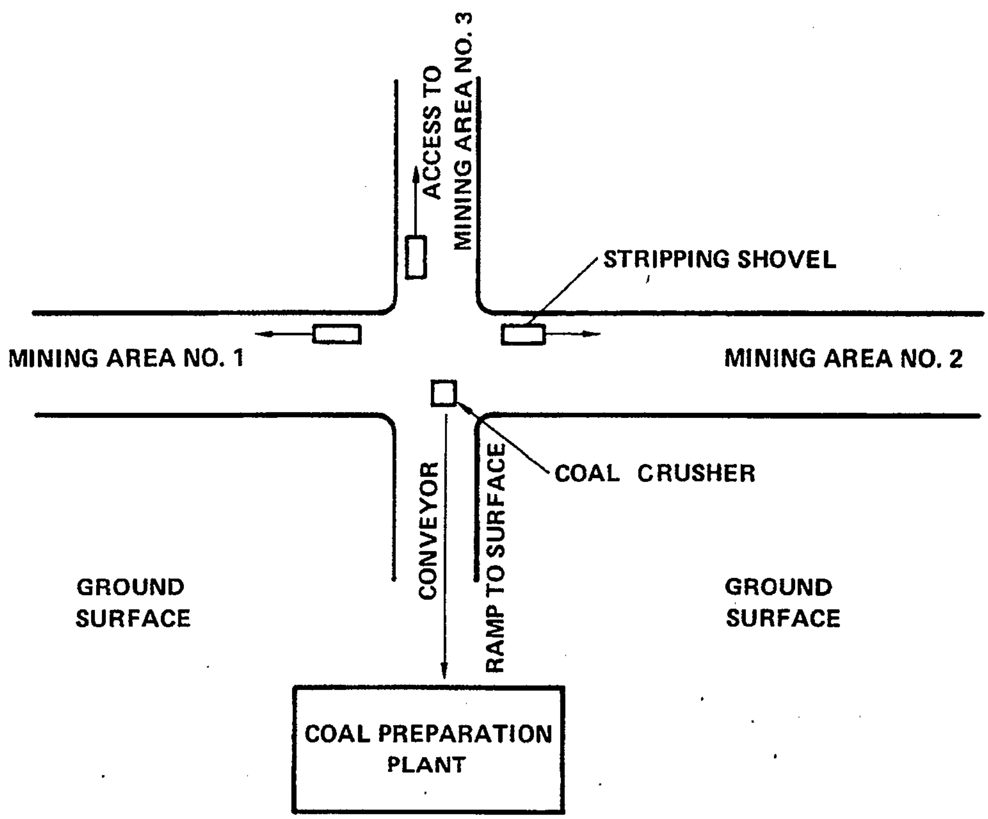

Figure 5-1 - Sketch of Mine Plant

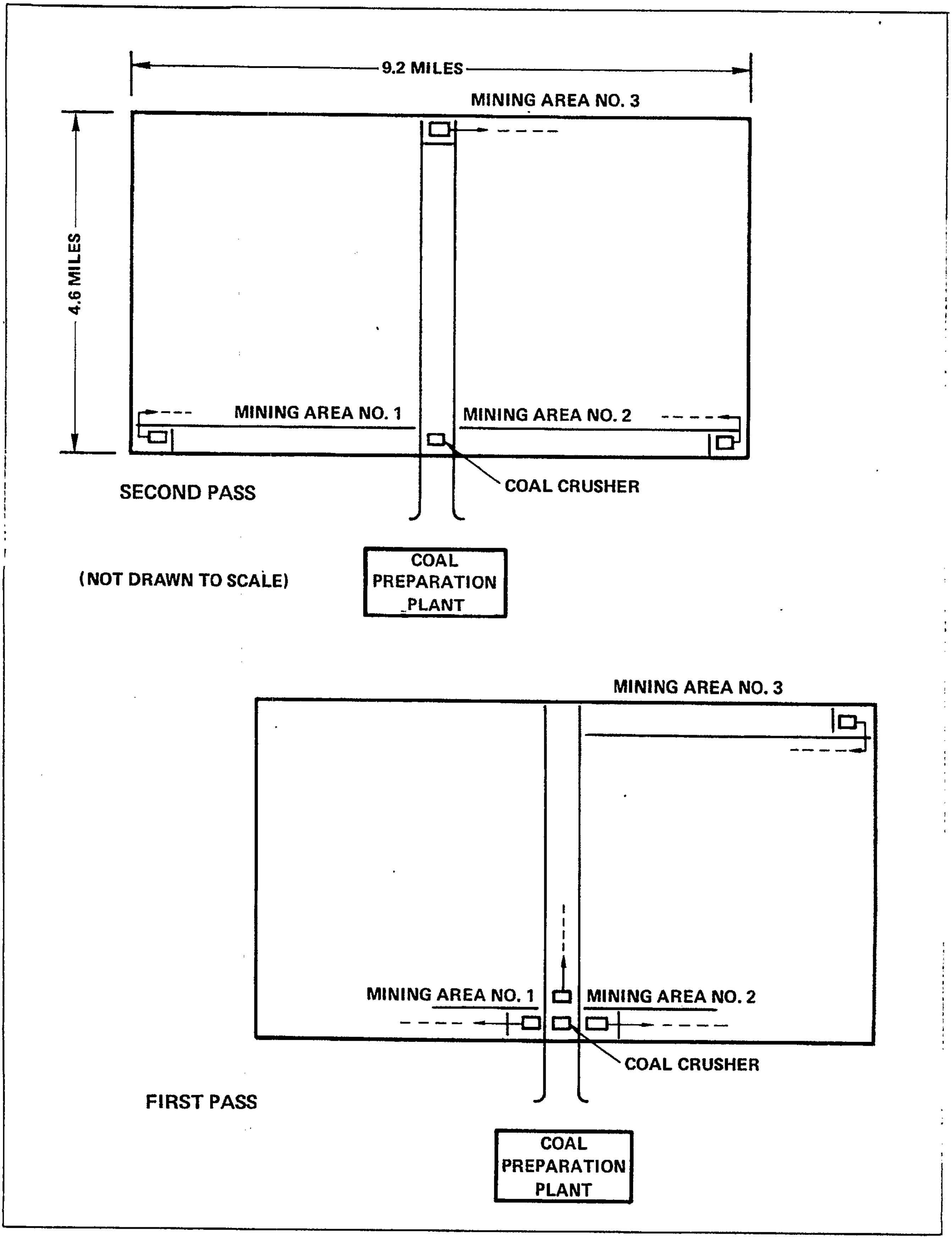

Figure 5-2 - Illustration of Mine Working Plan

B. Lower Stripping

To allow for time to drill and blast the limestones and shales, the upper stripping will be kept several days in advance of the lower stripping operation. Since four drills will be required for each mining unit, diesel-powered machines have been selected because of their mobility.

Each mining area is provided with a 140-cubic-yard shovel because of its high productivity and long reach. Since all material must be blasted, draglines would not be practical. The shovel will spoil the material in the adjoining mined-out strip.

C. Coal Mining

Twelve-cubic-yard electric shovels are provided for loading coal into 120-ton bottom dump trucks. The top of the coal bed will first be cleaned by using dozers and front-end loaders, and then the coal will be ripped to facilitate loading with the shovel. A 2-day uncovered reserve of coal will be maintained to allow for cleaning and ripping. Each mining unit is provided with a 10-cubic-yard front-end loader, which can be used for coal loading in addition to cleanup work.

D. Waste Disposal

The stripping shovel removes overburden from the coal and dumps it on the spoil pile in the previously mined-out strip. Dozers are operated on top of the dump area to spread and level off the spoil. After the lower overburden has been levelled, stripped material from the upper overburden, which has been transported by a belt conveyor system, is placed on top and likewise is levelled. Later suitable grasses, plants, and trees will be grown to bring the area back essentially to its original form. Solid waste material from the plant is mixed in with the lower stripping spoil rocks.

E. Preproduction Stripping

In general, starting at a predetermined point near the washing plant, a ramp is developed to the bottom of the coal bed. This ramp will not only serve as access to the mining faces, but will also be used for the belt conveyor installation which will transport the coal from the in-pit crusher to the plant. From the bottom of the ramp, small equipment will be used to develop the required mining faces and to provide adequate area for assembling the large stripping shovels.

The crusher and belt conveyor installations will be installed and completely tested before plant startup.

5.2 COAL PREPARATION (UNIT 10-2)

This unit receives ROM coal and conditions it to be suitable as feed to the pyrolyzing unit. Conditioning consists of grinding and washing to produce 27,400 TPD of cleaned coal of -6 mesh and including about 5.0% free moisture, 5.5% inherent moisture and 10.9% ash. See Drawing 5054-3-AE-10-2.

The general arrangement of the preparation equipment will locate the hopper receiving coal from the mine trucks and the coal breaker at the lower mine level in an area readily available to all mining units. A conveyor will then transport the coal up to ground level and to the raw coal silos located in the preparation plant. Equipment is included to provide a stockpile of 3-inch x 0 unwashed coal to supply 30 days plant operation. Coal can flow either continuously to the stockpile and be reclaimed therefrom, or once the stockpile is established it can be bypassed. Waste material will be returned to the mine in trucks for burial in the mined-out areas. An emergency dump will be located nearby at the mine level in case the preparation plant suffers a shutdown.

Drawing 5054-3-AE-10-2 shows in detail the flow of coal from the mine through the preparation steps to its delivery to the pyrolysis unit. The preparation plant is designed to receive approximately 36 M TPD of wet ROM coal containing an average of 11.7% free moisture from the mine trucks, which dump into a 300-ton ROM hopper 10-2651. Vibrating feeders place the coal on belt conveyor 10-2052, having belt scale and tramp iron magnet, which delivers to a scalping screen 10-2751. Here material over 3-inch size goes to rotary coal breaker 10-2251 which rejects oversize to waste. Three-inch and under coal from both the scalping screen and coal breaker is deposited on belt conveyor 10-2053 which transports the coal from the lower mine level to either of two 10,000-ton raw coal silos 10-2652. Selection of which silo is made by use of reversible conveyor 10-2054. Each silo is equipped with six vibrating feeders, each of which places the coal on one of two belt conveyors 10-2056 equipped with belt scale, tramp iron detector, and automatic belt sampler, from which the coal is delivered to the washing section.

In the washing section, the 3-inch and under coal is fed in two trains first to a Baum-type coal jig 10-2253, where water is added for washing. Screens 10-2752, 10-2753, and 10-2754 receive the effluent and separate the washed coal from water and waste. The 3-inch to 1/4-inch clean coal is carried by conveyors 10-2059 and 10-2060 to two silos 10-2653, having a capacity of 10,000 tons each. The -1/4-inch coal is slurried and pumped by pumps 10-1552 to the cyclone separator section. Two 2-stage, 4-roll crushers 10-2151 reduce the middlings out of the jigs to 3/4-inch x 0.

Coarse waste material is rejected by screen 10-2754 and is conveyed back to the mine for burial by conveyors 10-2066 and 11-2009 (see Drawing 5054-3-AE-11-1).

The minus 3-inch plus 1/4-inch product is conveyed by belt conveyors 10-2059 and 10-2060 to two clean coal silos 10-2653, having a capacity of 10,000 tons each. Coal is withdrawn from these silos by vibrating feeders 10-2061 from which conveyors 10-2062 and 10-2063 carry it over a weigh scale to the clean coal crusher feed bin 10-2654 with a capacity of 1,500 tons. Belt feeders 10-2064 withdraw the coal from the bin and feed one or more of the six Cage Pactor crushers 10-2152 which reduce the particle size to -1/2 inch with approximately 41% below 6 mesh. This material is joined by the 1/4 inch x 0 coal from the cyclone section, and transported by belt conveyor 10-2065 to the drying section of the pyrolysis unit 11-1. Size classification is performed by the dryers in unit 11-1 and oversize material 1/2-inch x 6 mesh is transported back to the clean coal crusher feed bin by conveyors 11-2007 and 10-2856 (see Drawing 5054-3-AE-11-1), from which it is again ground in the crushers along with the normal flow described above.

The cyclone separation section receives a slurry of 1/4-inch x 0 coal from pump 10-1552 in the washing section and entering first sixteen cyclones 10-2755. Then a series of screens, cyclone separators, and centrifuges produces the dewatered stream of minus 1/4-inch which joins the product flow at the clean coal crusher feed bin as noted previously. The fines and separated water proceed to a 75-foot-diameter thickener 10-2254 from which the fines are pumped to a tailings dam and separated water is pumped to head tank 10-1952 for reuse.

5.3 PYROLYSIS AND CHAR GASIFICATION (UNIT 11-1)

The techniques of pyrolysis and gasification of the residual char are those developed in bench scale and pilot plant operations. The commercial plant has been designed to accommodate the range of coal properties to be expected at various times during the life of the mine. When moisture, ash, and volatile matter contents are high, the amount of heat required for processing is high and the amount of fuel gas produced from the char is low. Each piece of equipment has been sized so that variations in feed coal properties will not cause plant throughput to operate at less than design capacity for more than 5% of the time.

For this design two coal compositions, Cases A and B, have been selected to represent the 95% probable limits of volatile matter, moisture, and ash contents. These are within the limits stated in the Design Basis and are consistent with the conceptual combination of coal field characteristics, mining pattern, and coal preparation plant. An intermediate composition, referred to as a typical case, has been chosen as a basis for the example heat and material balance shown on the Process Flow Diagrams. Yields of oil, gas, and char for these coal compositions are based on data observed in process development unit and pilot plant operations. These compositions of prepared coal are:

Proximate		Case A	Case B	"Typical" Case C
Moisture	wt% wet basis	9.5	11.5	10.5
Ash	wt% dry basis	10.45	13.95	12.2
Volatile Matter	wt% MAF basis	44.15	48.65	46.4
Fixed Carbon	wt% MAF basis	55.85	51.35	53.6
Ultimate				
Carbon	wt% MAF basis	79.8	77.4	78.6
Hydrogen	wt% MAF basis	5.2	5.6	5.4
Nitrogen	wt% MAF basis	1.5*	1.5*	1.5*
Sulfur	wt% MAF basis	4.3**	4.3**	4.3**
Oxygen	wt% MAF basis	9.2	11.2	10.2
		100.00	100.00	100.00

*Variation in nitrogen content from 1.35 to 1.65 was not dealt with because no item of equipment is dependent upon this variable.

**A separate variability in sulfur content, from 2.8 to 5.8%, is considered applicable to all three above compositions.

5.3.1 PROCESS DESCRIPTION

A description of the operations is best obtained by following the steps on Process Flow Diagram 5054-3-AE-11-1.

Coal received from the cleaning and crushing plant, Unit 10-2, is dried in two stages in dryers 11-2811 and 11-2812 by hot low-Btu gas from the char gasifiers. Gas stream 32 first contributes heat to the hottest pyrolyzer, then to successively lower temperature services until it gives up its last useful heat in drying the fresh coal. Oversized coal is returned to the crushers. Dried coal is passed through three fluidized-bed pyrolysis vessels, 11-1201, 11-1202, and 11-1203, operating at successively higher temperatures. Gas and oil vapor released in pyrolysis are passed to the Oil Vapor Recovery Section, Drawing 5054-3-AE-11-2. The residual char is then gasified by contact with steam and oxygen in three fluidized bed char gasifiers, 11-1204, 11-1205, and 11-1206, to produce a low-Btu fuel gas. Conditions are such that gasification produces all heat needed to dry and pyrolyze the coal.

For the conditions desired in the pyrolyzers, it is necessary to have the coal crushed to a size range of -6 to +325 mesh. The type of crusher most suitable to the required capacity and size range will not reduce all of the feed to -6 mesh in once-through operation without producing a large amount of material finer than 325 mesh. Therefore, the reduction per pass is limited, and the oversize material is separated from the acceptable material and returned to the crushers. An entrained-flow type dryer system serves to separate the oversize particles as well as to warm and dry the acceptable sizes.

Two entrained-flow drying stages are used, with the gas and coal in counterflow between stages. Part of the raw low-Btu fuel gas, which has been cooled in other services to a temperature where its heat content is just sufficient to dry the coal, is used in the second stage dryer (Item 11-2812) for final heating, drying, and classification. Here the last of the coarse coal is dropped out for return to the crushers. Two separation stages are provided to remove the entrained coal from the gas; first an enlarged hopper to disengage the larger particles, then a cyclone to recover particles down to the 325-mesh range.

The gas leaving the second-stage dryer is combined with the rest of the raw low-Btu fuel gas and used in the first stage dryer (11-2811) for initial heating, drying, and classification. Here the largest of the coarse particles are dropped out for return to the crushers. Since the quantity of raw low-Btu fuel gas will vary as the coal composition varies, the first-stage dryer is designed to entrain all of the 6-mesh particles at the velocity provided by the lowest anticipated gas flow rate. Most of the time the first-stage dryer gas will be entraining particles larger than 6 mesh. Therefore, the gas flow rate through the second-stage dryer is regulated so that those particles larger than 6 mesh are dropped out. Equal sized lift pipes have been specified for the two stages so that a large part, but never all, of the gas will be passed through the second stage.

Three stages are used to separate the entrained coal from the gas leaving the first-stage dryer. First is an enlarged hopper to disengage the large particles, secondly a roughing cyclone to recover particles down to the 325-mesh range and combine them with the large particles from second-stage drying, and finally a second-stage cyclone to recover the 325-mesh and finer, down to 10-micron particles. The 10-micron to 325-mesh material is conducted separately to the third-stage pyrolyzer (11-1203) in order to minimize the quantity of fine material passing through the first and second stages of pyrolysis. The finest dust, which escapes the second-stage cyclone, will be collected by wet scrubbing in the raw low-Btu gas scrubber, 11-1101. The resulting slurry is pumped to the gasifiers; this point is described in more detail later.

Moist, crushed coal is delivered to the first-stage dryer by screw conveyors which provide the seal between atmospheric pressure in the feed surge hopper and the pressure in the dryer, up to about 5 psig. Oversize coal which drops to a hopper at the bottom of the dryer is removed by screw conveyors, weighed, and returned by belt to the crushers. Coal is moved forward to the second-stage dryer in a low-velocity, dense-phase fluidized condition by the differential head produced in two legs of a U-tube trap seal. This differential head is produced by a combination of different heights and different densities of the fluidized solids in the two legs. This transport technique is used frequently in this design. The transport U-tubes have been given equipment numbers, listed under Pressure Balance Lines, to distinguish them from ordinary piping connections and have been dimensioned to give proper flow velocities and differential heads. Differential heads in the several seals can range from +13.5 to -20 psi. The short legs vary from 45 to 92 feet in length and the long legs are from 80 to 195 feet long.

Pyrolysis is accomplished in three fluidized beds operating at successively higher temperatures, but at essentially identical pressures. More than three pyrolyzers may be desirable or required for other types of coal, but experimental work indicates that three is an adequate number for the design coal. The typical operating temperatures shown on the Process Flow Diagram are 575°F, 815°F, and 1,050°F for the first, second, and third pyrolyzers, respectively. Mechanical Design temperatures for the vessels are 857°F, 975°F, and 1,100°F to permit use of higher operating temperatures when coal properties would make it desirable.

Heat for the pyrolysis is obtained from the heat released in the gasifiers by the partial oxidation of the char remaining after pyrolysis. A portion of this heat is obtained from the sensible heat of the raw low-Btu fuel gas which is produced in the char gasification step, and part by transporting heat from the char gasifiers to the pyrolyzers by means of a circulating stream of partially reacted char. In the illustrative operation, 1,112 MM Btu/hr is obtained from the gas and 428 MM Btu/hr is obtained from the char circulation. The heat transport by char requires the circulation of 2,094,000 lb/hr of char, which is 1.63 times the fresh char production rate of 1,281,000 lb/hr.

The description of the operation of one pyrolyzer applies to all. Coal from the dryer, or partially pyrolyzed coal from a previous pyrolyzer, is fed to the fluidized bed where it is immediately dispersed throughout the bed. A stream of bed contents is withdrawn, contacted with hot raw low-Btu fuel gas (in lift pipe 11-2816 for example), and returned to the bed to supply the major portion of the heat required. The rest of the heat required is supplied by bringing in hot char from a char gasifier (line 22 for example) at such a rate that the evolution of gas and oil vapor is maintained at a relatively constant rate so that proper fluidization of the bed is maintained.* Longer term variation of gas and oil vapor evolution, due to variation in coal composition, is accommodated by adjusting the size distribution of feed coal. This is done by adjusting the crusher speed and the gas flow rate in the second-stage dryer.

Much of the fluidizing gas is generated within each bed, but to assure adequate fluidization at the very bottom of the bed, some gaseous product of pyrolysis (after removal of pyrolysis oil and water) is recycled to the pyrolyzers. In order to feed the proper amount of recycle gas to each pyrolyzer without the usual waste of power by control valves, three separate compressors are provided, under speed control so that only the useful amount of power is drawn from the motive steam line; see oil vapor recovery unit 11-2, paragraph 5.4. Each stream of recycle pyrolysis gas is preheated by contacting with recycle hot char, as in lift pipe No. 11-2813, to increase its entrance velocity. Cyclones and hoppers are used to separate the char from the recycled gas stream. Recycle char which has been used for this purpose and thereby cooled below 1,050°F is then introduced into the first-stage pyrolyzer to counteract any agglomerating tendency of the feed coal.

The char remaining from the pyrolysis is gasified, as in the pilot plant, by reaction with a mixture of oxygen and steam. The function of the first of three fluidized bed gasifiers (char burner 11-1204-1206) is equivalent to the single gasifier (fourth-stage pyrolyzer) of the pilot plant. The second and third beds continue the gasification at the same conditions until the Design Basis level of carbon content is reached. That level was set at 2% of the original carbon in the coal fed to the plant, considered to be a tolerable amount to leave in the ash. At this design point, the concentration of carbon in the ash is about 10%.

Gasification conditions in the char burners are maintained such that: (1) there is always an excess of carbon in the beds, (2) the product gas contains high concentrations of CO and H_2, and (3) the overall reaction is sufficiently exothermic to satisfy the pyrolysis heat requirement. All products leave at reaction temperature, and the beds have negligible heat loss, so the heat of reaction must be balanced by the heat required to bring the reactants up to the reaction temperature. The amount of heat generated in each gasifier bed depends on the amounts of H_2O and O_2 reacted, and these quantities are controlled so that about 55% of the total char gasification takes place in the first gasifier, 30% in the second, and 15% in the third.

*Note that no hot char is needed for the No. 1 pyrolyzer at the conditions used in the typical operation.

In the second and third gasifiers, the char feed comes from a prior gasification stage, already at reaction temperature, and the oxygen temperature is relatively constant, though not controlled. Therefore the desired extent of gasification and the temperature must be controlled by regulating the amounts of steam and water used. It would be possible to balance the heat generated with the heat required to heat the H_2O even if the H_2O were all in the form of steam, but it is preferable to introduce part of the H_2O as water. There is a minimum amount of steam required to dilute the oxygen to avoid hot spots in the bed, and there is a minimum amount of water required to transport the very fine coal dust which escapes the coal dryer cyclones and is caught in the low-Btu fuel gas scrubber. Between these limits, the amounts of steam and water are controllable. The No. 3 gasifier will need approximately the same proportions of oxygen, steam, and water that the No. 2 gasifier requires.

Water and steam supplied to the char gasifiers is primarily the purge water slurry from the raw low-Btu gas scrubber which has been heated in the low-Btu gas trim cooler. In addition, sour waters from the hydrotreater, gas plant, and oil recovery column overhead separator are fed to the char gasifier bed. The use of these waters eliminates the need to purify them; they are therefore not discarded as waste.

The first gasifier differs from the second and third in that it receives feed char at pyrolysis temperature, several hundred degrees below the gasifier temperature. The sensible heat absorbed by this stream is approximately equivalent to the latent heat of the water used to control the temperature in the other gasifiers. This gasifier may not need to have any of its H_2O in the form of liquid but it can take any excess water which the other two gasifiers cannot handle.

The gas produced in the char gasifiers is rich in hydrogen and carbon monoxide but it must be cooled and desulfurized before it can be burned as fuel. Much of its heat content is utilized for drying and pyrolyzing the coal, and some of the excess, 500 MM Btu/hr in the illustrative operation, is used to generate low-pressure steam. After cooling, but before desulfurization, approximately 1/8 of the stream is split off and used as the feedstock for the manufacture of hydrogen for the hydrotreater. After desulfurization, the remaining 7/8 of the gas is used, along with the desulfurized pyrolysis gas, to generate electric power and steam.

The ash from the gasifiers is cooled, moistened, and returned to the mine for backfill. A rotary drum, 11-2401, containing steam generating tubes, is shown as the primary cooler. This choice makes possible the generation of about 7% of the steam required for char gasification. The final cooling is accomplished by spraying the partially cooled ash with enough water (cooling tower blowdown) to moisten it sufficiently to prevent escape of dust during transport back to the mine. The heat in the partially cooled ash is enough to evaporate nearly all of this water, so this design provides for condensing the evaporated water (in scrubber 11-1103) and spraying it as a recycle stream on the now cooled ash to provide the moisture required.

5.4 OIL VAPOR RECOVERY (UNIT 11-2)

The major operations in this portion of the plant are depicted in Drawing 5054-3-AE-11-2.

Raw COED oil is generated as a vapor in the pyrolyzers along with gaseous products. The mixture leaves the pyrolyzers through cyclone separators which remove entrained dust down to a particle size of about 10 microns. The gas and oil vapor from the three pyrolyzers are collected into a manifold (line 31, Drawing 5054-3-AE-11-1, and line 1, Drawing 5054-3-AE-11-2) and conducted to the Oil Recovery Tower, 11-1151.

In the bottom section of the oil recovery tower, the heaviest of the oil is condensed at about 600°F by direct contact cooling of the 900°F pyrolysis vapor with a circulating stream of condensed oil which is cooled externally to about 400°F. The heat removed is used to generate approximately 30% of the steam required for char gasification.

In the upper section of the tower, another 20% of the oil is condensed at about 375°F, partly by contact with a circulating stream of the intermediate condensate which is cooled externally to about 200°F, and further by contact with overhead condensate at 130°F. In cooling the overhead vapors from about 270°F to 130°F, the lightest 5% of the oil is condensed, along with half the water. All of the heat removed in condensing the intermediate and light oil fractions is rejected to the atmosphere by way of a closed water loop. Design and operation are such to prevent excessive concentration of high melting components in any one fraction.

Net production of uncondensed pyrolysis products is compressed and delivered to the Pyrolysis Gas Treating Section, Drawing 5054-3-AE-13-1.

Also, a small amount of this gas, after compression, is used to make up solution losses of filter pressurization gas in the oil filtration unit (paragraph 5.5). Three streams of pyrolysis gas, large in relation to the size of the net production stream, are used as recycle gas for fluidization of the pyrolysis beds; see Pyrolysis, paragraph 5.3, and Drawing 5054-3-AE-11-1.

The condensed pyrolysis water, containing soluble portions of the light COED oil, H_2S, and other pyrolysis products, is combined with other process waste waters, and utilized in the char gasification step as described in paragraph 5.3.

5.5 OIL FILTRATION (UNIT 12-1)

The light oil does not need to be filtered, and its passage through the filters would aggravate evaporation problems, so it is sent directly to the hydrotreater section (Drawing 5054-3-AE-15-1). The intermediate and heavy oil fractions are combined and sent to the oil filtration section which is depicted in Drawing 5054-3-AE-12-1.

Filter feed is taken from a pair of 8,000-bbl surge tanks. Each filter is fed by its own pump taking oil from the top of a horizontal header between the two tanks. Either tank can be isolated from the system for cleaning.

Each filter is designed to operate 40 hours out of a 48-hour cycle. Approximately 5 inches of precoat are removed during the cycle; the removal rate is 0.002 inch per minute. At the end of the cycle, the feed to the filter is shut off and the precoat rebuilt by feeding precoat slurry which is continuously prepared in precoat tanks 12-1203. Approximatley every 20 cycles, the residual precoat and the base coat are removed from the drum and a new base coat applied by adding slurry from base coat tank 12-1204.

The filter cake composed of precoat, base coat, insoluble particles, and containing approximately 50% by weight of product oil is fed to the third stage char gasifier where the oil and residual coal particles are gasified. The resultant ash joins the main ash stream for disposal.

Pyrolysis gas, predominantly methane, is used to pressurize the filters. In sweeping oil through the filter coats, this gas evaporates the more volatile components of the oil. They are condensed when the gas is cooled for recycle compression. The condensate is mixed with filter feed so that its evaporation during the filtration operation does not significantly change the composition of the oil. The gas is cooled just enough so that recompression raises its temperature to or slightly above the filter temperature.

5.6 PYROLYSIS GAS TREATING SECTION (UNIT 13-1)

Refer to Drawing 5054-3-AE-13-1. Raw gas from the oil vapor recovery section (unit 11-2) is first passed through a gas filter/separator, and then to the contactor where the gas is countercurrently washed with DGA (diethylene glycol amine) solution for removal of hydrogen sulfide and carbon dioxide. The overhead gas from the contactor is routed to the knockout section for separation of entrained liquid prior to exporting to the fuel system.

The rich DGA solution from the bottom of the contactor is released to the flash drum for separation of hydrocarbons, vapor, and liquid, and then pumped to the regenerator through the rich/lean exchanger.

The top section of the regenerator column is a cooler designed to cool the acid gas stream rejected from the regeneration section by countercurrent contact with the externally cooled water. The overhead acid gas stream is then passed on to the sulfur recovery unit 16-1 (see paragraph 5.11).

A direct-fired heater is employed for reboiling service for the regenerator. The lean DGA solution from the base of the regenerator column is passed through the rich/lean exchanger, the solution air cooler, and then a level control valve prior to entering the suction of the lean solution pump. The lean solution is further cooled by water circulation in the solution cooler, and then divided into two streams with flow control in each. One stream discharges into the contactor and the other into the wash column of the flash drum.

The solution filter and the reclaimer are provided for solution conditioning. The solution tank provides service for normal operation surge as well as for solution storage. The solution sump is used for collecting drains and drips and for solution makeup. Equipment for injection of corrosion inhibitor and antifoam agent is also provided.

5.7 LOW-BTU GAS TREATING (UNIT 13-2)

The gas treating unit 13-2, depicted on Drawing 5054-3-AE-13-2, is designed to reduce hydrogen sulfide to an odorless level of approximately 1 ppm. The raw low-Btu fuel gas produced in Unit 11-1 is fed to a redox solution contacting device wherein the hydrogen sulfide is absorbed by the redox liquor. After a suitable time, the hydrogen sulfide is oxidized to elemental sulfur and water by the following reaction:

$$H_2S + 1/2\ O_2 \longrightarrow S + H_2O$$

The H_2S free low-Btu gas is transferred to the power plant for utilization as fuel.

The reduced redox solution is transferred to an air blowing tank wherein the contained sulfur is removed as a sulfur froth. The reoxidized redox solution is subsequently recirculated to the redox solution contacting device. The sulfur froth is pumped to a sulfur melter, where the sulfur is melted, separated from the redox solution, and pressured to sulfur product storage. The decanted redox solution from the melter is returned to the system. The sulfur product is 99.9% pure.

5.8 HYDROGEN PLANT (UNIT 14-1)

5.8.1 HYDROGEN PRODUCTION

Flow Diagram 5054-3-AE-14-1 shows the flow sequence for the production of hydrogen. Since the feed gas contains essentially no methane but is high in carbon monoxide only shift conversion is employed without the need for reforming. The feed gas is compressed to 600 psia and preheated to 700°F before entering the first bed of sulfided shift catalyst. A second bed of shift catalyst is used after heat is removed from the effluent stream from the first reactor, to take advantage of the more favorable equilibrium conditions at the lower temperatures. Following the second reactor the gas is cooled to condense the steam before absorption of the acid gases in a catalyzed hot carbonate system. Methanation of residual carbon oxides is used as a method of final purification before product hydrogen is compressed for delivery to the hydrotreater, Unit 15-1 (see paragraph 5.10).

The quality of the product hydrogen to be produced and the quality of the feed gas determines the amount of steam required in the process. End of run conditions are shown on the flowsheet so when operating with fresh catalyst, less steam would be required.

If operating experience indicates that the total sulfur cannot be removed to a tolerable level for methanation by the catalyzed hot carbonate system referred to above and described in the next paragraph, then a bed of zinc oxide would be added for additional protection.

5.8.2 CATALYZED HOT CARBONATE ACID GAS REMOVAL

This section receives the shift effluent gas as the feed stream. The gas first gives up heat to the hot carbonate reboiler. After separation of steam condensate downsteam of the reboiler, the gas is fed to the hot carbonate absorber. The gas is then countercurrently contacted with the hot carbonate solution in the absorber, thereby removing carbon dioxide and hydrogen sulfide from the gas. The treated gas proceeds to the methanation step.

Rich hot carbonate solution, which contains carbon dioxide and hydrogen sulfide absorbed from the gas stream, is routed from the base of the absorber through the hydraulic turbine for horsepower recovery. The solution is then pressured to the hot carbonate regenerator. The reboiler receives heat from the shift effluent as required for stripping carbon dioxide and hydrogen sulfide from the hot carbonate solution. The cooled overhead acid gas stream, containing mostly carbon dioxide and hydrogen sulfide from the regenerator, is routed to sulfur recovery, Unit 14-2 (see paragraph 5.9). The regenerated lean hot carbonate solution from the base of the regenerator is pumped to the top section of the absorber after being cooled, while the semilean solution is pumped to the midsection of the absorber without further cooling.

The other auxiliary items of equipment in this section include a storage tank, filters for removal of particulate matters and degradation materials, and a sump for collecting drains and drips.

5.9 HYDROGEN PLANT TAILGAS DESULFURIZER (UNIT 14-2)

The hydrogen plant tailgas desulfurizer as depicted on Drawing 5054-AE-14-2 is designed to reduce hydrogen sulfide in the effluent to an odorless level (approximately 1 ppm). The tailgas from Unit 14-1 is fed to a redox solution contacting device wherein the hydrogen sulfide is absorbed by the redox liquor. After a suitable time, the hydrogen sulfide is oxidized to elemental sulfur and water in the reaction tank by the following overall reaction:

$$H_2S + 1/2\ O_2 \longrightarrow S + H_2O$$

The H_2S-free tailgas, consisting primarily of CO_2, is vented to the atmosphere.

The reduced redox solution is transferred to an air blowing tank wherein the contained sulfur is removed as sulfur froth. The reoxidized redox solution is subsequently recirculated to a contacting device. The sulfur froth is pumped to a sulfur melter, where the sulfur is melted, separated from the redox solution, and pressured to sulfur product storage. The decanted redox solution from the melter is returned to the system. The sulfur is 99.9% pure.

5.10 OIL HYDROTREATING (UNIT 15-1)

Filtered oil, plus the light 5% of the oil which bypasses the filters, is hydrotreated in a process which is somewhat similar to petroleum hydrotreating. Process Flow Diagram 5054-3-AE-15-1 depicts the process.

The conditions used in this design were found to be effective in COED pilot plant work. Sulfur content is reduced approximately 98%, nitrogen 94% and oxygen 90%. At the same time, the API gravity of the oil is raised from about -5° to about +25°. Reaction temperature is 650° to 750°F, pressure is 2,335 to 2,420 psig, weight hourly space velocity is 0.3 lb/hr/lb, and hydrogen to oil ratio is 10,400 scf H_2/bbl. Makeup hydrogen purity supplied to the hydrotreating unit is 94 to 96%.

Fresh oil, line 3, is diluted with recycle oil, line 17, as an aid to temperature control. The combined oil, mixed with part of the hydrogen, is heated to 650°F for entrance to the first reactor. Effluent from the first reactor is cooled by addition of the rest of the hydrogen, and cooled further by heat exchange, generating steam, to 650°F for entrance to the second reactor. Cooling of second and third-stage effluents is by heat exchange, generating steam for power generation. Cooling of fourth-stage effluent is by heat exchange with feed streams, low-pressure steam generation, and cooling water. Hydrotreated product oil is flashed in stages down to 100 psig at which pressure it is stabilized (volatility) for storage and shipment.

The nitrogen content of the pyrolysis oil from the design coal is sufficiently high that the H_2S released in hydrotreating is tied up as NH_4SH, and is dissolved in injected water and removed from the hydrotreater condensing train. The hydrotreater offgas is sufficiently low in sulfur to be used as fuel gas and is mixed with the desulfurized pyrolysis gas in line 2, steam and power generating plant, Drawing 5054-3-AE-18-1. The ammoniacal, sulfidic water is used for temperature control of the char gasifiers, as described in Unit 11-1.

5.11 SULFUR RECOVERY - PYROLYSIS GAS (UNIT 16-1)

A typical Claus type three-stage sulfur recovery unit is shown on Process Flow Diagram 5054-3-AE-16-1. The acid gas from pyrolysis gas treating, Unit 13-1, is fed to a knockout drum for removal of any entrained liquids before entering the external combustion chamber of the reaction furnace.

The chemistry of the process can be described as follows:

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

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

(3) $3H_2S + 3/2\ O_2 \longrightarrow 3S + 3H_2O$

(4) $\text{Hydrocarbons} + O_2 \longrightarrow CO_2 + H_2O$

The acid gas is one-third oxidized by reaction with air in the combustion chamber: the heat generated from the exothermic reaction produces 150-psig steam in the boiler section of the furnace and 50-psig steam in sulfur condensers No. 1 through No. 4. Sulfur is condensed and drained through a liquid sulfur seal to the sulfur tank.

The cooled gas is reheated and passed to the first stage of the catalytic converter to produce elemental sulfur. The exothermic reaction causes a temperature rise across the converter No. 1 catalyst bed. The hot gas is cooled in sulfur condenser No. 2 by generating low pressure steam and the condensed sulfur flows to the sulfur tank. Entrained sulfur in the gas is removed by a coalescer.

Similarly, for the second and third stages, the cooled gas is reheated in the auxiliary burner, additional sulfur is produced in the converter and the gas is cooled by producing low pressure steam. The condensed sulfur flows to the sulfur tank from each condenser.

Liquid sulfur is pumped from the sulfur tank to sulfur product storage where it is piled in popcorn form until removed for shipment. Tailgas flows to Unit 16-2 for treatment before discharge to the atmosphere.

5.12 TAILGAS TREATING (UNIT 16-2)

In the Sulfur Removal Unit, depicted on Drawing 5054-3-AE-16-2, sulfur recovery unit tailgas may be treated by one of several commercially available processes for reducing the sulfur content of the treated tailgas to an environmentally acceptable level. A sulfur content of less than 100 ppm is achievable by one such process (the Beavon Sulfur Removal Process) and this was used as the basis for the estimates of this study. In the process taken for example, hydrogenation and hydrolysis are used to convert essentially all sulfur compounds to hydrogen sulfide. The gas is then cooled and passed into a contactor, where the hydrogen sulfide is absorbed by the redox liquor and oxidized to elemental sulfur. The purified tailgas is vented to the atmosphere. The reduced redox liquor is reoxidized by contact with air and subsequently recirculated to the absorber. Elemental sulfur is removed in the air-blowing step as a froth. The froth is pumped to a sulfur melter, where the sulfur is melted under pressure, separated from the redox solution, and transferred to sulfur product storage. The decanted redox solution is returned to the system.

The chemical reactions are:

Hydrogenation

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

(2) $S + H_2 \longrightarrow H_2S$

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

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

Hydrogen Sulfide Extraction

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

The purified tailgas is odorless and contains typically less than one ppm of H_2S and less than 50 ppm of total sulfur compounds, mainly COS. The sulfur product is yellow and better than 99.9% pure.

5.13 OXYGEN PLANT (UNIT 17-1)

This is a conventional plant which is available from commercial air separation plant suppliers.

The oxygen production facility will consist of six package plants of about 2,200 TPD capacity each, totaling approximately 13,000 TPD. Each plant will include the cold box, distillation columns, heat exchange equipment, air and oxygen compressors, and auxiliary equipment.

Product will be gaseous oxygen of 99.5% purity delivered at 30 psig and approximately ambient temperature.

5.14 POWER AND STEAM GENERATING PLANT (UNIT 18-1)

5.14.1 DESCRIPTION

The steam and electric generation power plant consists of multiple large gas turbine-generator-boiler packages which supply the steam and electric power requirements for the COED process and also produce net electric power for export. The design is shown in Drawing 5054-3-AE-18-1.

The fuel gas streams supplied to the power plant consist of a high-Btu gas stream and a low-Btu gas stream. The high-Btu gas stream arrives at the power plant at 55 psia and 115°F. It is compressed by a steam-turbine-driven two-stage compressor to 265 psia. This is the gas pressure required for gas turbine utilization. The low-Btu fuel gas stream arrives at the power plant at 14.7 psia and 100°F and is compressed in three parallel compressor trains to 265 psia. The high- and low-Btu fuel gas streams are then combined and the resulting fuel gas is fed to the gas turbine power units.

A total of 13 of these gas turbine units are utilized in the power plant. The gas turbine used is a large, simple cycle, single shaft machine that is directly connected to an electrical generator and operates at 3,600 rpm. The functions of the gas turbine are: (1) to produce electric power through its connected generator, and (2) to supply hot gas through its exhaust system to the heat recovery boiler which is fitted to the exhaust of each gas turbine. These boilers are expressly designed for use with a large volume of gas and incorporate extended fin-tube construction. Additionally, duct burners are utilized to increase the energy level of the exhaust gases by the firing of additional fuel in the exhaust gas stream prior to entry into the boiler.

Analysis of the power plant and the possible variations in the quantity of fuel gas supplied indicate that under certain conditions only 10 of the 13 gas turbine units may be operating. At any given time the total steam generated in the heat recovery boiler is used for the steam turbine drives on the power plant fuel gas compressors and for the motive and heating requirements in the various process sections.

A portion of the total power plant electrical generation is tapped for use in the process plant and in the coal mine. The remainder is for export and sale. For this design, the power plant generation can vary from a low of 345 MW to a high of 1,227 MW. This variation results from variations in feed coal composition over the range described in the Design Parameters (Section 3), plus variations in operations of the process plant. The exact power output at any time depends on the quantity and heating value of the high- and low-Btu fuel gas supplied to the power plant and also on the steam requirements of the power plant and process units.

The quantity of fuel gas available to the power plant is a function of the coal composition, with the greatest quantity of gas available when the volatile matter, moisture, and ash in the coal are lowest. When these constituents are highest, the fuel gas available is at its lowest and it may be expedient to supplement with some other fuel during these periods to maintain the electrical output at a more constant level. The output shown on Drawing 5054-3-AE-18-1 is 907 MW which corresponds to the typical case illustrated on all flowsheets (827 MW are available for export).

5.14.2 DESIGN APPROACH

The COED power plant design philosophy was to investigate state-of-the-art and advanced electrical generation systems. The goal was to achieve a power plant design with a high degree of flexibility of operation to accommodate variations of up to 32% in the quantity of fuel energy from the COED process sections, and to utilize the available fuel in as economical a manner as practical.

The analysis of the power plant involves investigation of several power cycle variations and combinations of electrical generation equipment. The two end-point bounding design cases were: (1) the all-simple-steam cycle and (2) the all-gas turbine case. Between these two configurations are several cases involving various combinations of conventional boilers with steam turbine-driven generators and gas turbine/combined cycle units.

Various power plant cycle configurations were analyzed to determine the net electric power available for export and sale after the COED in-house steam and power requirements are satisfied. On this basis, and for operational flexibility, the all-gas turbine generator configuration was chosen as the most desirable power plant configuration for the COED conceptual design.

The all-gas turbine power plant contains only large simple cycle gas turbines, each fitted with waste heat recovery boilers. No combined cycle units are utilized due to the large steam requirements of the process units and related auxiliary units. The large in-plant steam consumption leaves no net steam for steam turbine-driven generators. In fact, under some conditions, part-load gas turbine operation is required in order to provide sufficient fuel for supplementary firing of the waste heat boilers to satisfy these steam requirements.

The process sections require large quantities of motive and process steam as shown on the Utility Summary in Section 8 of this report. These requirements vary as much as 15% and are highest when fuel supply is lowest. These steam requirements are largely supplied by the power plant. Fuel gas, in excess of in-plant steam generation requirements, is used for electric power generation. An average of about 80 MW of the electrical generation is used within the COED plant and coal mine. The remainder is available for export and sale to neighboring utilities.

5.15 PLANT AIR AND INSTRUMENT NITROGEN (UNIT 19-1)

One motor-driven air compressor with a turbine-driven full capacity spare is provided to furnish 16,000 acfm of 125 psig air for general plant utility use. An air receiver and instrumentation together with distribution system complete the plant air facility.

Nitrogen at 100 psig and dry to minus 40°F dew point is available in ample quantity from the oxygen plant to provide for the pneumatic instrument system. The multiple units in the oxygen plant will assure a reliable supply of nitrogen.

5.16 COOLING WATER SYSTEM (UNIT 19-2)

This system includes six induced draft cooling towers and twelve motor driven pumps to provide 650,000 gpm of 86°F cooling water. The cooling towers have a total capability of about 10 billion Btu/hr at 77°F wet bulb ambient condition. Included are all necessary equipment and facilities for water treatment to inhibit corrosion and the growth of algae.

5.17 INDUSTRIAL WATER SYSTEM (UNIT 19-3)

Water in the amount of some 28,000 gpm (45,000 acre-ft/yr) will be pumped from a river. This design is based on the river being about two miles from the plant site. Following screening, for trash removal, water flows by gravity to a concrete sedimentation basin at the riverbank of about 7 acres, 16 feet deep, which provides about 20 hours residence for settling. The pumps will be mounted in the clear well of this basin.

The entire stream will receive further clarification in two mechanical sludge blanket tanks aided by coagulants and clarifying chemicals.

Makeup for the cooling water system, which constitutes about 87% of the water usage requirement, receives additionally conventional chemical treatment for corrosion inhibition and algae control.

Makeup water for the boilers in the power plant and other areas, about 10% of the total, is filtered and demineralized before joining sour condensate and flowing to the deaerator and thence along with clean condensate to the boilers. The balance of about 3% needed for various process makeup requirements requires no treatment beyond the clarification step.

5.18 POTABLE AND SANITARY WATER SYSTEM (UNIT 19-4)

This water is obtained from a well. A 50-gpm pump and a full capacity standby pump are included to assure reliable supply. A water treatment system to sterilize and otherwise make the water suitable for drinking or other sanitary use is also included. The piping system for this water is galvanized.

5.19 FIREWATER SYSTEM (UNIT 19-5)

The water for this system is supplied by pumps taking suction from the same sedimentation basin at the river as was described in paragraph 5.17 for the industrial water system. The water is delivered to a firewater loop at 100 psig. One electric motor-driven and one steam turbine-driven pump, each with a capacity of 3,000 gpm, provide the 6,000 gpm required. One diesel engine-driven pump of 3,000 gpm provides standby. A steam-driven jockey pump will maintain pressure on the system during periods when there is no demand. Hydrants and monitors connected to the loop are located strategically in all units. Oil product storage tanks are protected by both hydrants and by a foam system.

5.20 WASTE WATER - TREATMENT AND DISPOSITION (UNIT 19-6)

Waste water from process units in the amount of approximately 2,100 gpm will be treated in a manner to render it suitable for discharge back to the river. The sources of the waste water are principally cooling tower blowdown in the amount of about 1,500 gpm, boiler blowdown about 380 gpm, demineralizing system blowdown 200 gpm, and sanitary sewage of 50 gpm. Other waste streams of sour water containing H_2S and COS are being incinerated in the char gasifiers from which the evolved gases are treated for removal of sulfur.

Waste water from coal washing is directed to a tailings pond where the harmless solids settle out, and the clarified water either evaporates or is recycled for dust abatement.

The blowdown from cooling water and boiler systems should require no chemical treatment or filtration before discharge to a lagoon of about 18 acre-feet for evaporation and settling. Waste water from the demineralizer will discharge to this lagoon after acids or caustics have been neutralized. The suspended solids will settle in the lagoon and will be removed for land fill. Decant from the lagoon then flows to a large surge pond of about 130 acre-feet where it is joined by effluent from the sanitary sewage treatment plant and by oily surface runoff water from curbed process areas after passing through a surge pond of about 14 acre-feet, and an API separator for removal of most of the oily material. Storm drainage from nonprocess areas also flows into the large surge pond. Overflow from the surge pond after oil skimming finally discharges to the river during storm water runoff. The estimated 10 ppm BOD in the waste waters is below the level that would require biological treatment. It is therefore judged to be acceptable for discharge to the environment.

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SECTION 6

PROCESS FLOW DIAGRAMS

The flow diagrams for the units described in Section 5 are shown on the drawings contained in this section. A list of these drawings appears on pages 5-1 and 5-2 in Section 5.

These drawings show the process flow, material balances, and characteristics of the major process equipment. Also shown are the control instruments critical for the process.

The flow diagrams for proprietary processes are shown in a simplified form and contain only the material balances in and out of the units.

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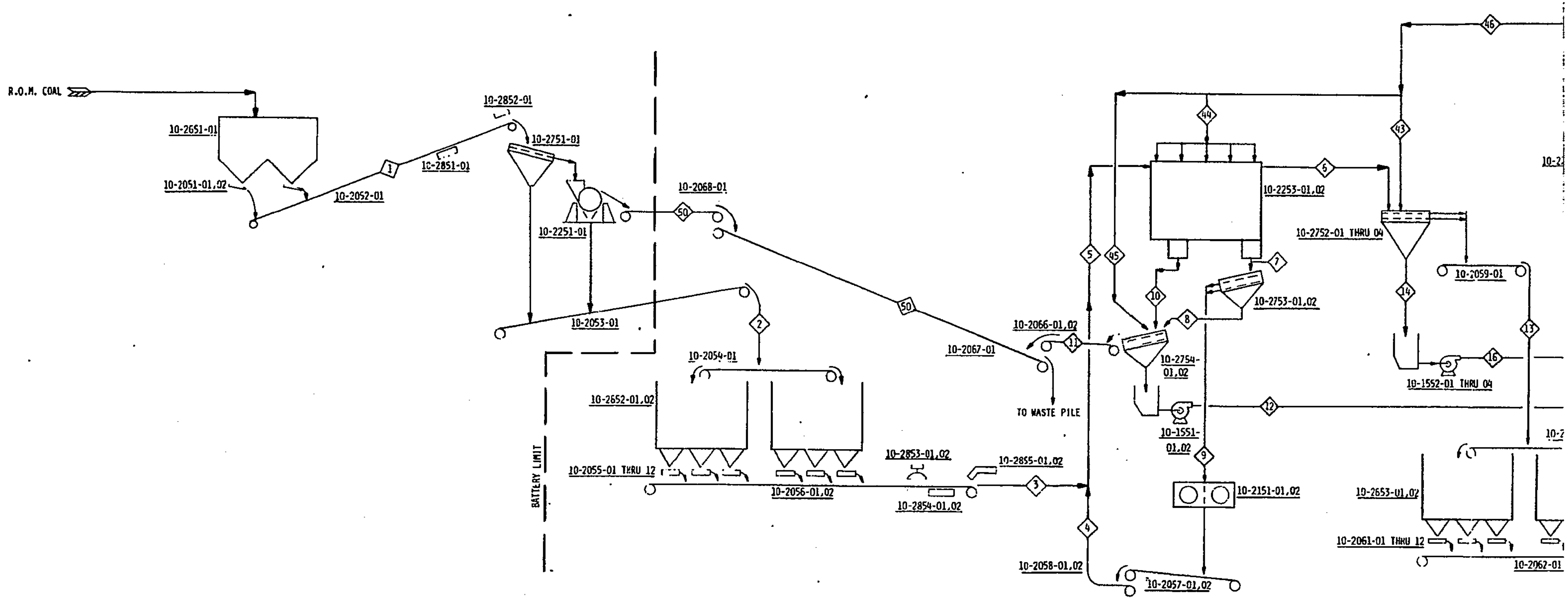
10-2651-01 D.M. HOPPER 300 TONS | 10-2051-01,02 VIBRATING FEEDERS 12"x0 COAL | 10-2052-01 54" R.O.M. COAL CONVEYOR | 10-2853-01 BELT SCALE 0-2000 TPH | 10-2852-01 TRAMP IRON MAGNET | 10-2751-01 8'x16' SCALPING SCREEN 3" SQ. OP'NG. | 10-2251-01 10'x20' ROTARY COAL BREAKER 3-1/2" SQ. OP'NG. | 10-2068-01 WASTE CONVEYOR | 10-2067-01 WASTE CONVEYOR | 10-2066-01,02 WASTE CONVEYORS | 10-2754-01,02 WASTE DEWATERING SCREENS 3/4" & 1mm SCREENS | 10-1551-01,02 WASTE DEWATERING SCREEN UNDER SIZE PUMPS 1 STANDBY | 10-2753-01,02 4'x6' D.D. MIDDLING SCREENS 1-1/2" & 3/4" SCREENS | 10-2253-01,02 BAUM TYPE COAL JIGS 180FT² EA | 10-2752-01 THRU 04 8'x16' D.D. CLEAN COAL SCREENS 7/8" & 1/4" SCREENS | 10-2059-01 CLEAN COAL CONVEYOR NO. 1



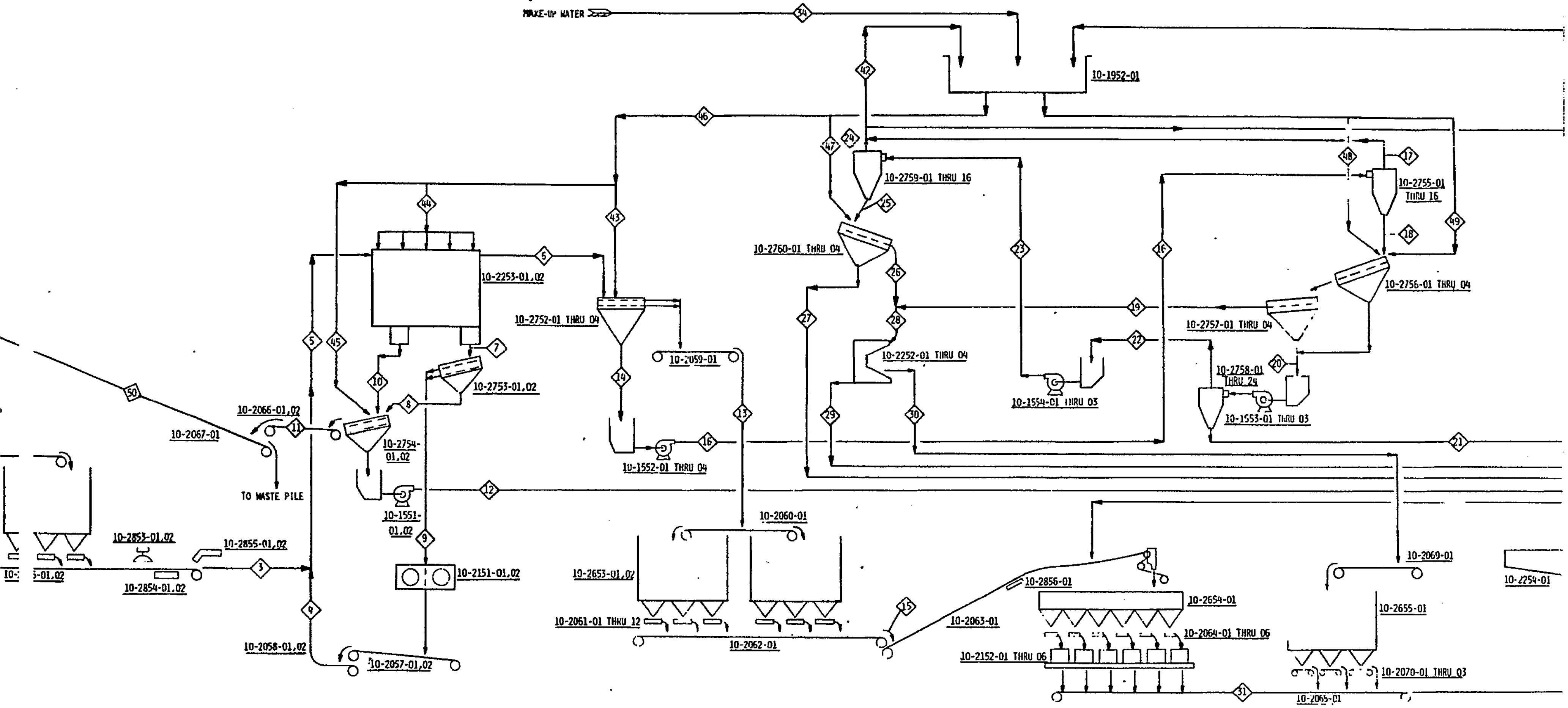
10-2053-01 54" COAL CONVEYOR 3"x0 COAL | 10-2652-01,02 100' DIAM. RAW COAL SILOS 10,000 TONS EA. | 10-2055-01 THRU 12 VIBRATING FEEDERS | 10-2054-01 54" REVERSING CONVEYOR | 10-2056-01,02 36" JIG FEED CONVEYORS | 10-2853-01,02 TRAMP METAL DETECTORS | 10-2854-01,02 BELT SCALES 0-750 TPH | 10-2855-01,02 AUTOMATIC BELT SAMPLERS 3"x0 COAL | 10-2058-01,02 MIDDLING RECYCLE CONVEYORS | 10-2057-01,02 MIDDLING RECYCLE CONVEYORS | 10-2151-01,02 2-STAGE, 4 ROLL CRUSHERS | 10-2061-01 THRU 12 VIBRATING FEEDERS | 10-2653-01,02 100' DIAM. CLEAN COAL SILOS 10,000 TONS EA. | 10-1552-01 THRU 04 CLEAN COAL FINES PUMPS | 10-2062-01 CLEAN COAL COLLECTING CONVEYOR | CLEA

	1	2	3	4	5	6	7	8	9	10	11	12	13
SOLIDS DTPH	1,500	1,350	1,135	13.4	1,148.4	1,042	22.0	8.6	13.4	84.4	87.8	5.2	713
SOLIDS S.G.	1.40	1.40	1.40	1.70	1.40	1.35	1.93	2.5	1.70	2.5	2.5	2.5	1.35
FREE WATER TPH	176	162	136	0.5	136.5	3,200	13.4	12.9	0.5	21.1	15.5	323.5	26.6
PERCENT SOLIDS	-	-	89.3	96.4	89.4	24.6	62.1	40.0	96.4	80.0	85.0	4.0	96.4
SLURRY GPM	-	-	-	-	-	15,950	99.1	65.6	-	219.4	-	502.3	-
SLURRY S. G.	-	-	-	-	-	1.07	1.43	1.31	-	1.92	-	1.02	-
SOLIDS SIZE	12"x0	3"x0	3"x0	3/4"x0	3"x0	3"x0	3"x0	3/4"x0	3"x3/4"	3"x0"	3"x1mm	1mmx0	3"x1/4"
INH. WATER TPH	-	-	65.2	-	-	-	-	-	-	-	-	-	45.6
TOTAL WATER TPH	-	-	201.2	-	-	-	-	-	-	-	-	-	72.2

	14	15	16	17	18	19	20	21	22	23	24	25	
SOLIDS DTPH	329	715	329	12.0	317.0	297.5	19.5	7.1	12.4	12.4	1.0	11.4	
SOLIDS S.G.	1.35	1.35	1.35	1.35	1.35	1.35	1.35	1.44	1.30	1.30	1.30	1.30	
FREE WATER TPH	3,383.4	26.6	3,383.4	2,907.9	475.5	127.5	1,058	7.1	1,050.9	1,050.9	1,033.8	17.1	
PERCENT SOLIDS	8.9	96.4	8.9	1/2%	40	70	1.8	50	1.2	1.2	1/2%	40	
SLURRY GPM	14,508.6	-	14,508.6	11,667.3	2,841.3	1,391.5	4,289.8	48.1	4,241.7	4,241.7	4,138.2	103.5	
SLURRY S. G.	1.02	-	1.02	1.00	1.12	1.22	1.01	1.18	1.01	1.00	1.00	1.10	
SOLIDS SIZE	1/4"x0	3"x1/4"	1/4"x0"	1/4mmx0	1/4 x1/4mm	1/4"x1/4mm	1/2mmx0	1/2mmx0	1/2mmx0	1/2mmx0	-	1/2mmx0	1/2
INH. WATER TPH	-	45.6	-	-	-	-	-	-	-	-	-	-	
TOTAL WATER TPH	-	72.2	-	-		-	-	-	-	-	-	-	

A 6-2 B 6-2 C

-01 CONVEYC | 10-2066-01,02 WASTE CONVEYORS | 10-2754-01,02 WASTE DEWATERING SCREENS 3/4" & 1mm SCREENS | 10-1551-01,02 WASTE DEWATERING SCREEN UNDER SIZE PUMPS 1 STANDBY | 10-2753-01,02 4'x6' D.D. MIDDLING SCREENS 1-1/2" & 3/4" SCREENS | 10-2253-01,02 BAUM TYPE COAL JIGS 180FT² EA | 10-2752-01 THRU 04 8'x16' D.D. CLEAN COAL SCREENS 7/8" & 1/4" SCREENS | 10-2059-01 CLEAN COAL CONVEYOR NO. 1 | 10-2760-01 THRU 04 3' STATIONARY CROSS-FLOW SCREENS 1/2mm SCREEN | 10-2759-01 THRU 16 14" DIAM. CYCLONES 2 SET-8 EA. | 10-2252-01 THRU 04 CENTRIFUGES 1 STANDBY | 10-1554-01 THRU 03 CYCLONE FEED PUMPS 1 STANDBY | 10-1952-01 HEAD TANK 100,000 GALS. | 10-2757-01 THRU 04 7'x 16' SINGLE DECK SCREENS 1/2 mm SCREEN | 10-2758-01 THRU 24 12" DIAM. CYCLONES 2 SET-12 EA. | 10-1553-01 THRU 03 CYCLONE FEED PUMPS 1 STANDBY | 10-20



10- ... -01,02 ... C BELT ... ERS ... COAL | 10-2058-01,02 MIDDLING RECYCLE CONVEYORS | 10-2057-01,02 MIDDLING RECYCLE CONVEYORS | 10-2151-01,02 2-STAGE, 4 ROLL CRUSHERS | 10-2061-01 THRU 12 VIBRATING FEEDERS | 10-2653-01,02 100' DIAM. CLEAN COAL SILOS 10,000 TONS EA. | 10-1552-01 THRU 04 CLEAN COAL FINES PUMPS | 10-2062-01 CLEAN COAL COLLECTING CONVEYOR | 10-2060-01 CLEAN COAL CONVEYOR NO. 2 | 10-2063-01 CLEAN COAL TRIPPER CONVEYOR | 10-2152-01 THRU 06 COAL CRUSHERS, CAGE PAKTORS 3 STANDBY | 10-2856-01 WEIGH SCALE 0-1000 TPH | 10-2654-01 CLEAN COAL CRUSHER FEED BIN 1,500 TONS | 10-2064-01 THRU 06 BELT FEEDERS | 10-2065-01 DRYING & CLASSIFICATION FEED BELT CONVEYOR 1/2"x 0 COAL | 10-2069-01 CENTRIFUGE CAKE CONVEYOR | CEN

11	12	13	14	15	16	17	18	19	20	21	22	23	24	25	26	27
87.8	5.2	713	329	713	329	12.0	317.0	297.5	19.5	7.1	12.4	12.4	1.0	11.4	10.4	1.0
2.5	2.5	1.35	1.35	1.35	1.35	1.35	1.35	1.35	1.35	1.44	1.30	1.30	1.30	1.30	1.30	1.3
15.5	123.5	26.6	3,383.4	26.6	3,383.4	2,907.9	475.5	127.5	1,058	7.1	1,050.9	1,050.9	1,033.8	17.1	9.2	25.9
85.0	4.0	96.4	8.9	96.4	8.9	1/2%	40	70	1.8	50	1.2	1.2	1/2%	40	53	3.7
-	502.3	-	14,508.6	-	14,508.6	11,667.3	2,841.3	1,391.5	4,289.8	48.1	4,241.7	4,241.7	4,138.2	103.5	68.8	106.7
-	1.02	-	1.02	-	1.02	1.00	1.12	1.22	1.01	1.18	1.01	1.00	1.00	1.10	1.14	1.01
"x1mm	1mmx0	3"x1/4"	1/4"x0	3"x1/4"	1/4"x0"	1/4mmx0	1/4"x1/4mm	1/4"x1/4mm	1/2mmx0	1/2mmx0	1/2mmx0	1/2mmx0	-	1/2mmx0	1/2mmx0	1/2mmx0
-	-	45.6	-	45.6	-	-	-	-	-	-	-	-	-	-	-	-
-	-	72.2	-	72.2	-	-	-	-	-	-	-	-	-	-	-	-

28	29	30	31	32	33*	34*	35	36	37	38	39	40
307.9	0.9	307	2,181	2,488	-	-	1,468	13.0	27.2	27.2	-	-
1.35	1.35	1.35	1.35	1.35	-	-		1.35	1.59	-	-	-
136.7	108.5	28.2	87.8	116.0	-	-	61.2	996.7	1,251.7	55.7	1,234.5	38.5
69.3	0.8	91.6	96.1	95.5	-	-	96.0	1.3	2.1	50	-	-
1,460.3	436.7	-	-	-	25	500	-	4,025.5	5,046.8	252.8	4,938.0	154
1.22	1.00	-	-	-	-	-	-	1.00	1.01	1.20	-	-
1/4"x0	-	1/4"x0	1/2"x0	1/2"x0	-	-	1/2x6Mesh	-	1mmx0	1mmx0	-	-
-	-	19.6	-	154	-	-	54	-	-	-	-	-
-	-	47.8	-	270	-	-	150	-	-	-	-	-

6-2

C

6-2

D

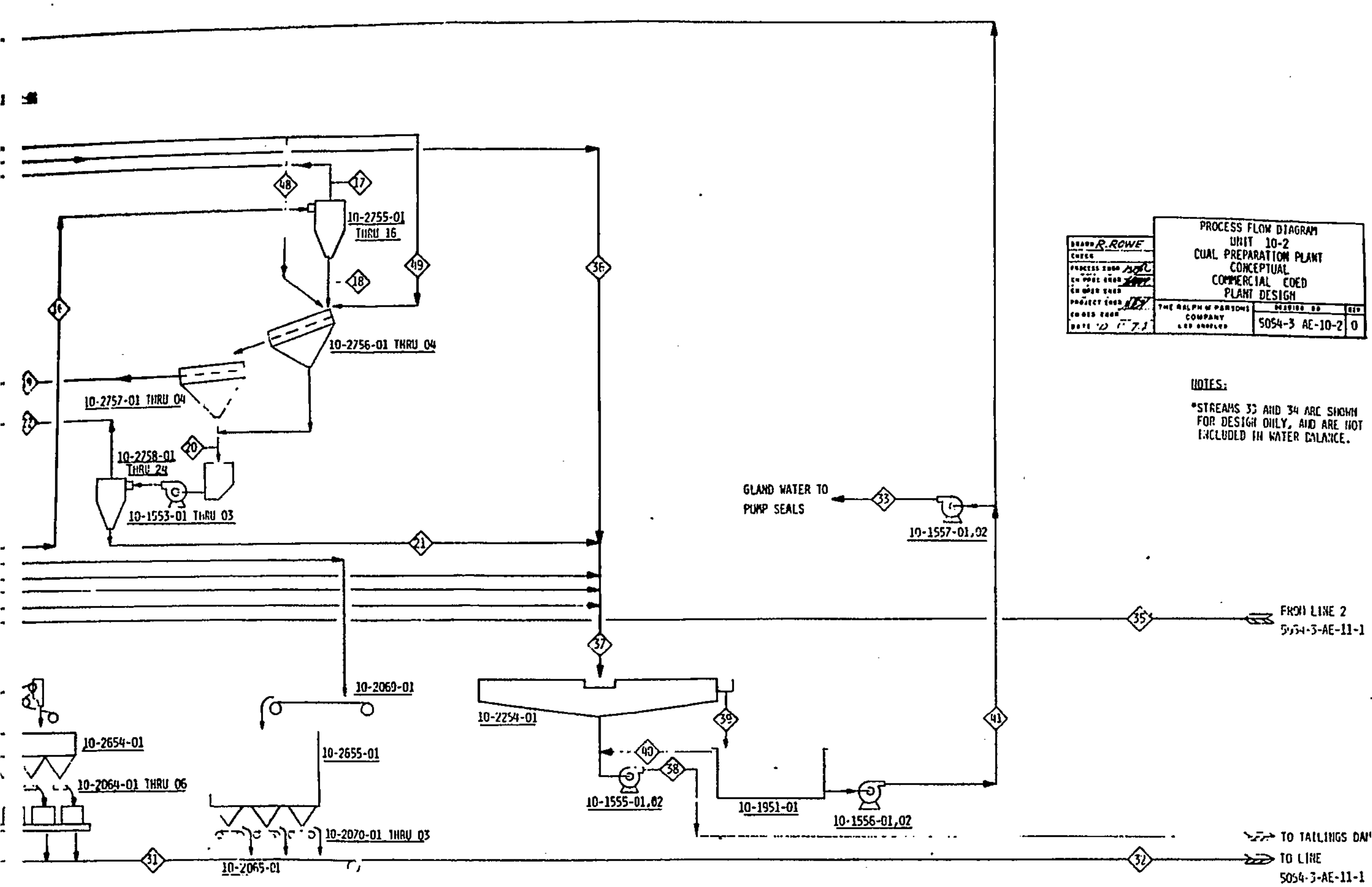
10-2757-01 THRU 04 6'x 16' SINGLE DECK SCREENS 1/2 mm SCREEN

10-2758-01 THRU 24 12" DIAM. CYCLONES 2 SET-12 EA.

10-1553-01 THRU 03 CYCLONE FEED PUMPS 1 STANDBY

10-2755-01 THRU 16 20" DIAM. CYCLONES 2 SET-8 EA.

10-2756-01 THRU 04 6' STATIONARY CROSS-FLOW SCREENS 1/2mm SCREEN



DRAWN	R. ROWE
PROCESS FLOW DIAGRAM UNIT 10-2 COAL PREPARATION PLANT CONCEPTUAL COMMERCIAL COED PLANT DESIGN	
THE RALPH M. PARSONS COMPANY LOS ANGELES	5054-3 AE-10-2 / 0

NOTES:

*STREAMS 33 AND 34 ARE SHOWN FOR DESIGN ONLY, AND ARE NOT INCLUDED IN WATER BALANCE.

10-2654-01 LEAN COAL CRUSHER FEED BIN 1,500 TONS

10-2064-01 THRU 06 BELT FEEDERS

10-2065-01 DRYING & CLASSIFICATION FEED BELT CONVEYOR 1/2"x 0 COAL

10-2069-01 CENTRIFUGE CAKE CONVEYOR

10-2655-01 CENTRIFUGE CAKE SURGE BIN 10,000 TONS

10-2070-01 THRU 03 BELT FEEDERS

10-2254-01 75' DIAM. THICKENER

10-1555-01,02 TAILINGS PUMPS 1 STANDBY

10-1951-01 RECYCLE WATER TANK 200,000 GALS.

10-1556-01,02 RECYCLE WATER PUMPS 1 STANDBY

10-1557-01,02 GLAND WATER PUMPS 1 STANDBY

	33*	34*	35	36	37	38	39	40
SOLIDS DTPH	-	-	1,468	13.0	27.2	27.2	-	-
SOLIDS S.G.	-	-		1.35	1.59	-	-	-
FREE WATER TPH	-	-	61.2	996.7	1,261.7	55.7	1,234.5	38.5
PERCENT SOLIDS	-	-	96.0	1.3	2.1	50	-	-
SLURRY GPM	25	500	-	4,025.5	5,046.8	252.8	4,938.0	154
SLURRY S.G.	-	-	-	1.00	1.01	1.20	-	-
SOLIDS SIZE	-	-	1/2x6Mesh	-	1mmx0	1mmx0	-	-
THRU. WATER TPH	-	-	54	-	-	-	-	-
TOTAL WATER TPH	-	-	150	-	-	-	-	-

	41	42	43	44	45	46	47	48	49	50
SOLIDS DTPH	-	-	-	-	-	-	-	-	-	150
SOLIDS S.G.	-	-	-	-	-	-	-	-	-	-
FREE WATER TPH	1,190	2,905	210	3,098	105	3,413	13	210	500	10
PERCENT SOLIDS	-	-	-	-	-	-	-	-	-	-
SLURRY GPM	4,784	11,760	840	12,392	420	13,652	72	840	2,000	-
SLURRY S.G.	-	-	-	-	-	-	-	-	-	-
SOLIDS SIZE	-	-	-	-	-	-	-	-	-	12"x3"
THRU. WATER TPH	-	-	-	-	-	-	-	-	-	-
TOTAL WATER TPH	-	-	-	-	-	-	-	-	-	-

D

E

6-2

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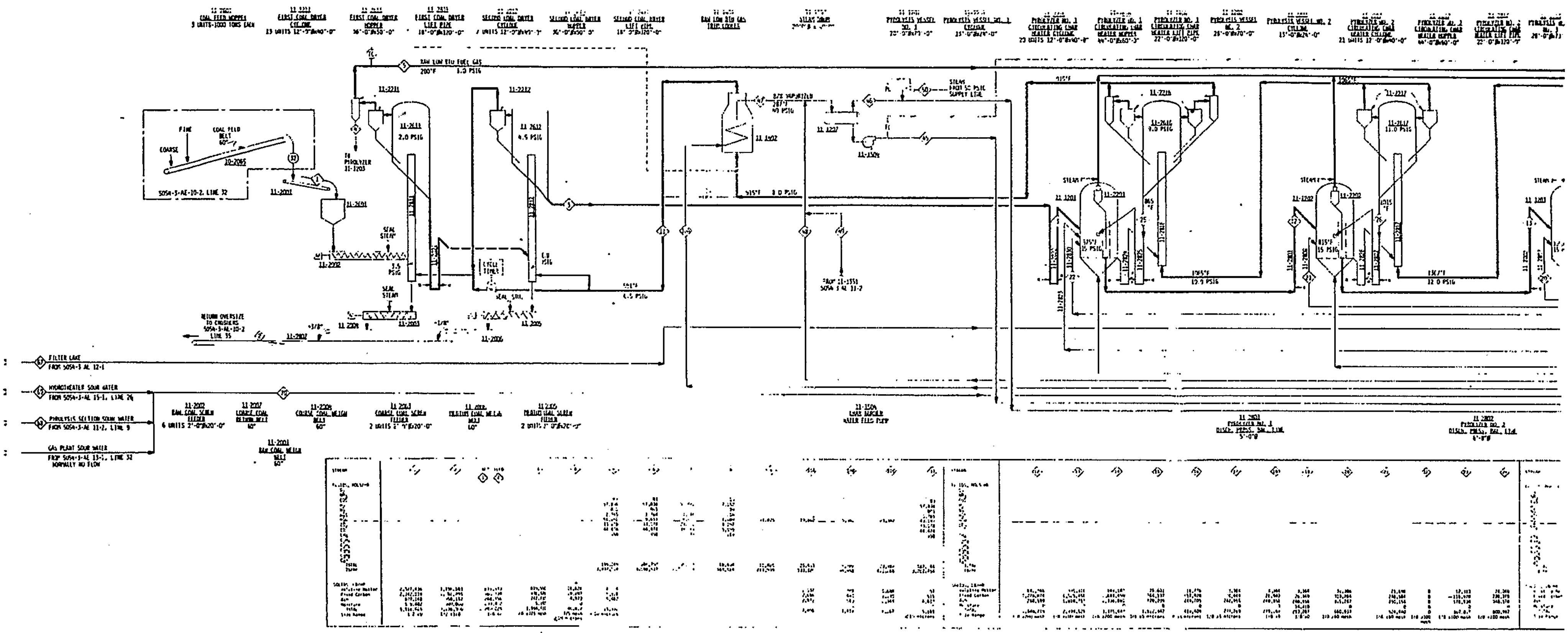
FINE
COARSE
COAL FEED BELT
RAW LOW BTU FUEL GAS
SEAL STEAM
FILTER CAKE
HYDROTREATER SOUR WATER
PYROLYSIS SECTION SOUR WATER
GAS PLANT SOUR WATER
NORMALLY NO FLOW

A

6-3

B

6-3

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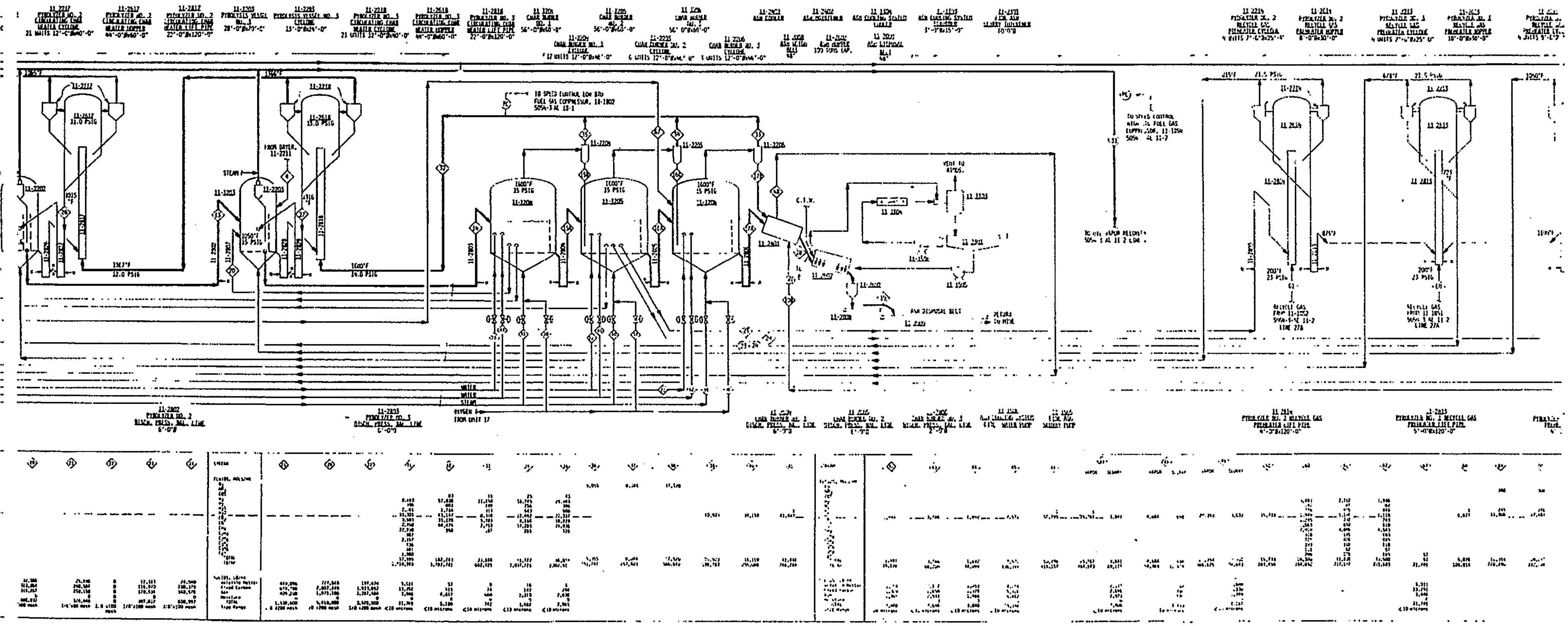

10 SPEED CONTROL LOW BTU FUEL GAS COMPRESSOR, 11-1802
FROM DRYER, 11-2211
STEAM
WATER
WATER
STEAM
OXYGEN FROM UNIT 17
ASH DISPOSAL BELT
RETURN TO MINE
VENT TO ATMOS.
C.T.W.
RECYCLE GAS

C

6-3

D

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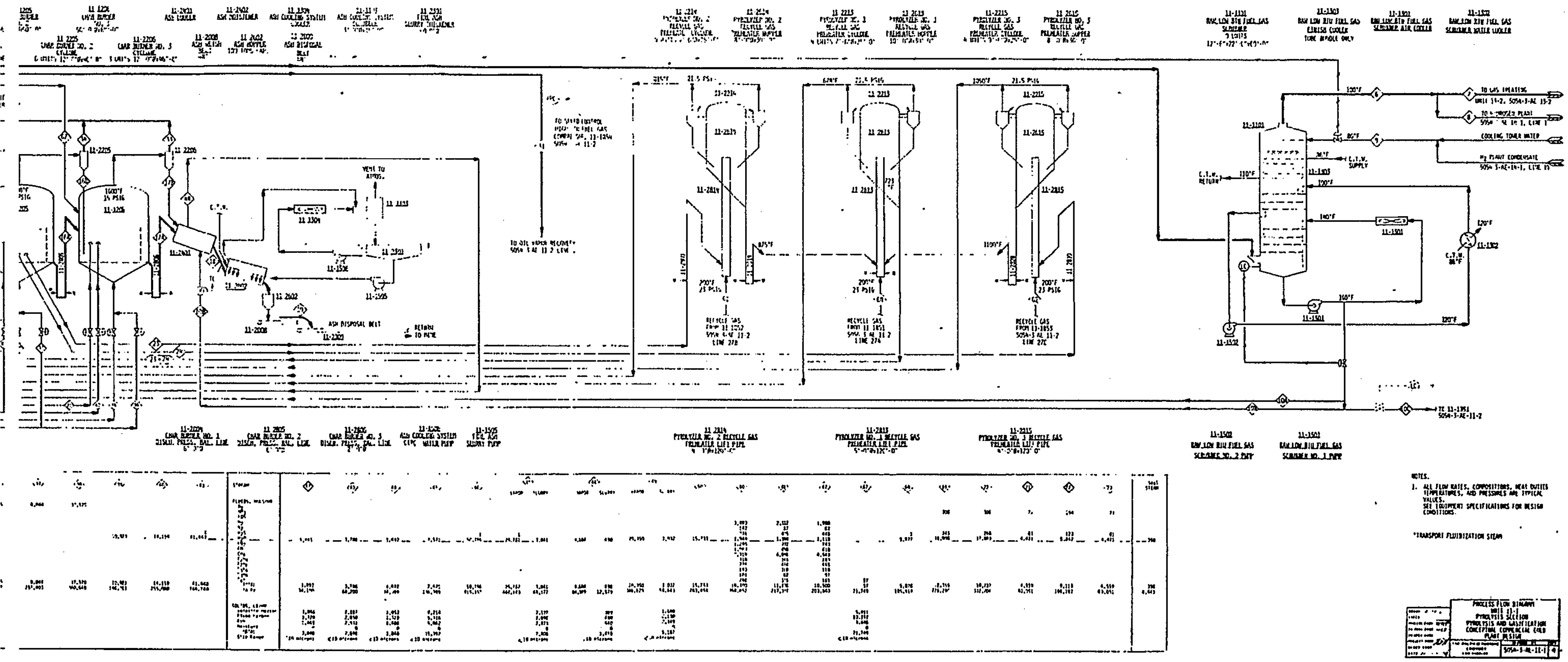

NOTES.

1. ALL FLOW RATES, COMPOSITIONS, HEAT DUTIES TEMPERATURES, AND PRESSURES ARE TYPICAL VALUES.
SEE EQUIPMENT SPECIFICATIONS FOR DESIGN CONDITIONS.

*TRANSPORT FLUIDIZATION STEAM

PROCESS FLOW DIAGRAM
UNIT 11-1
PYROLYSIS SECTION
PYROLYSIS AND GASIFICATION
CONCEPTUAL COMMERCIAL (4E) PLANT DESIGN

505A-3-AE-11-1

6-3

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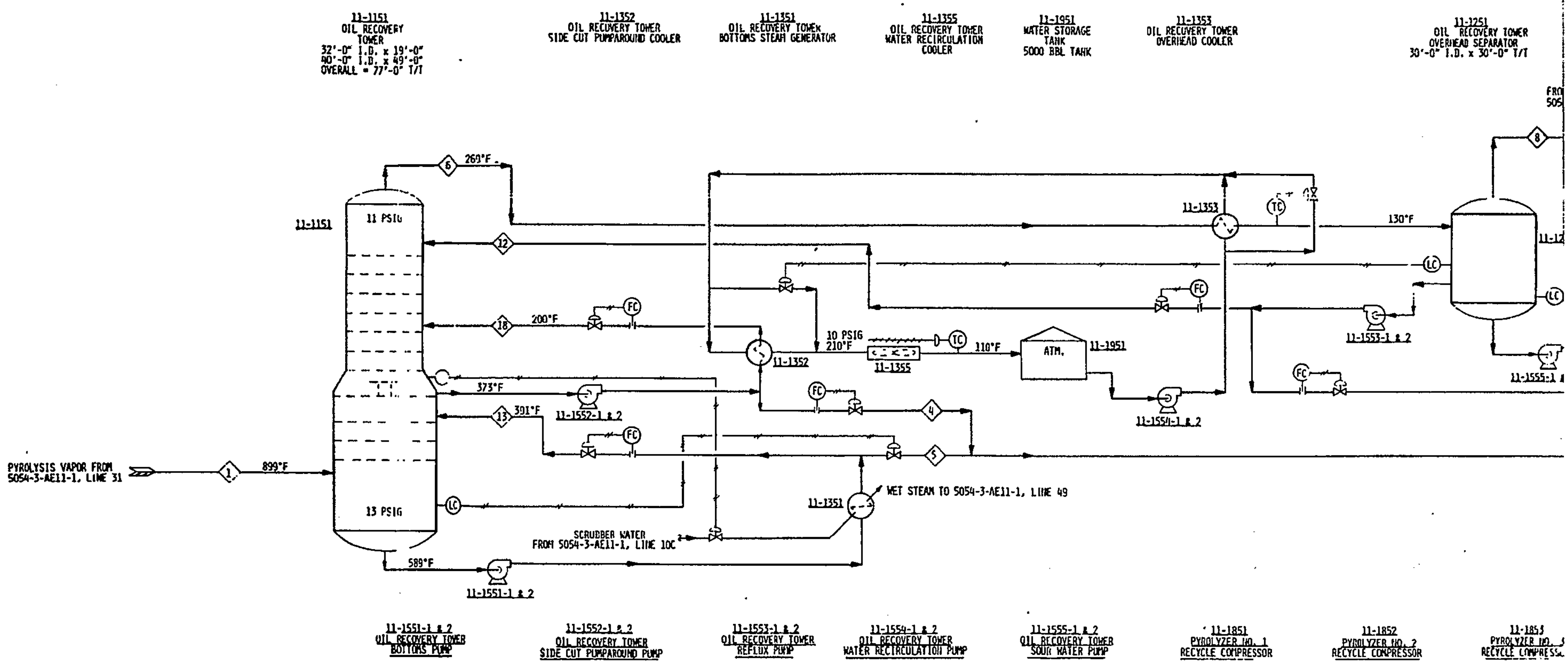


STREAM NO.	1*	4	5*	6	8	9 #	11	12	13	18	27	28	29
	FEED TOTAL	SIDE PRODUCT	TOWER BOTTOMS	OVERHEAD VAPOR	OVERHEAD VAPOR PRODUCT	OVERHEAD WATER	OVERHEAD LIQUID PRODUCT	REFLUX	BOTTOM PUMPAROUND EXCHANGER OUTLET	SIDE PUMPAROUND EXCHANGER OUTLET	RECYCLE GAS	GAS TO TREATING	COOLER WATER
H_2	9693.25	.11	.35	9693.03	9692.77	0.00	.07	.24	4.25	1.09	7613.07	2079.71	0.00
N_2	396.30	.01	.02	396.29	396.27	0.00	.00	.02	.24	.09	311.25	85.01	0.00
H_2S	2160.63	.12	.18	2162.53	2160.19	0.00	.14	2.20	2.20	1.39	1696.70	463.50	0.00
H_2O	11304.86	.53	.44	11346.69	5424.45	5876.80	2.64	42.80	5.34	5.42	4260.57	1163.88	168743.65
CO_2	3603.36	.15	.30	3604.65	3602.80	0.00	.11	1.74	3.66	1.53	2829.77	773.03	0.00
CO	2957.62	.07	.15	2957.57	2957.38	0.00	.01	.18	1.83	.72	2322.84	634.54	0.00
C_1	22037.53	.59	1.06	22039.36	22035.67	0.00	.21	3.48	12.73	5.99	17307.64	4728.03	0.00
$C_2=$	886.94	.05	.10	887.25	886.76	0.00	.03	.46	1.26	.48	696.50	190.27	0.00
C_2	2157.01	.13	.25	2158.03	2156.55	0.00	.09	1.39	3.04	1.28	1693.84	462.72	0.00
$C_3=$	536.32	.05	.08	537.12	536.13	0.00	.06	.93	.99	.54	421.10	115.03	0.00
C_3	280.78	.03	.05	281.24	280.67	0.00	.03	.53	.55	.30	220.45	60.22	0.00
nC_4	437.43	.08	.11	439.85	437.08	0.00	.16	2.61	1.28	.87	343.30	93.78	0.00
IBP-400	403.26	2.15	.76	1326.87	342.88	0.00	57.20	926.59	9.17	22.06	289.31	73.57	0.00
400-500	108.91	21.80	.80	1218.15	17.38	0.00	69.83	1131.19	9.62	273.31	13.65	3.73	0.00
500-600	96.93	92.27	2.94	28.58	.05	0.00	1.66	26.87	35.38	945.26	.04	.01	0.00
600-750	195.88	147.37	48.66	.05	.00	0.00	.00	.05	545.55	1509.70	.00	.00	0.00
750-950	250.22	32.99	216.82	.00	.00	0.00	.00	.00	2618.83	337.92	.00	.00	0.00
950 Plus	487.31	.56	484.93	.00	.00	0.00	.00	.00	5858.88	5.76	.00	.00	0.00
TOTAL	57994.54	299.04	760.92	59077.26	50927.05	5876.80	132.19	2141.29	9144.80	3063.52	40000.00	10927.05	168743.65
LB/HR	1514592.76	70281.81	332436.64	1411959.80	987579.52	105876.35	18520.36	300000.00	4000000.00	720000.00	775681.77	211897.76	3040085.57
BBLS/DAY		4742.79	19653.21			7264.50	1353.46	21923.86	236474.66	48587.51			208589.50
MSCFD	528214.25			538075.69	463843.53						364320.00	99523.53	
MOL WT	26.12	235.02	437.41	23.90	19.39	18.02	140.10	140.10	437.41	235.02	19.39	19.38	18.02
API		7.67	-9.56			10.00	19.20	19.20	-9.56	7.67			10.00

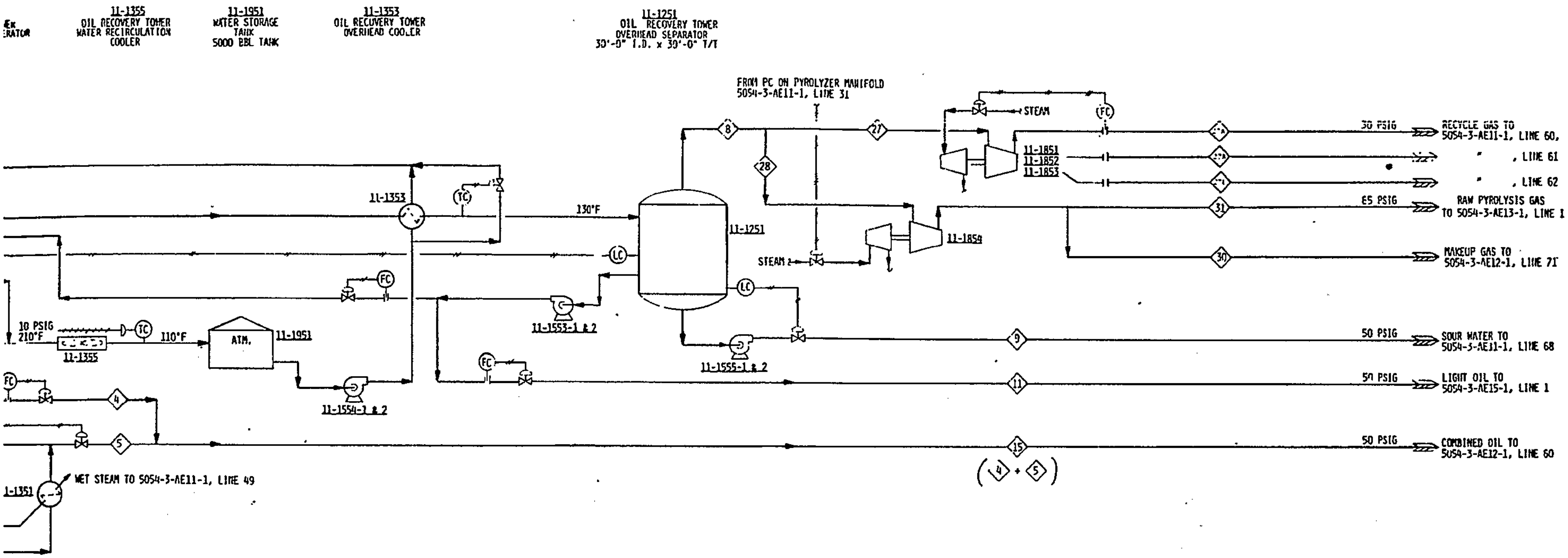
* Both streams 1 and 5 contain 21,749 lb/hr of dust

Sour water in stream 9 contains 106 ppm of H_2S

A

6-4. [illegible]

B



	11-1554-1 & 2 OIL RECOVERY TOWER WATER RECIRCULATION PUMP	11-1555-1 & 2 OIL RECOVERY TOWER SOUR WATER PUMP		11-1851 PYROLYZER NO. 1 RECYCLE COMPRESSOR		11-1852 PYROLYZER NO. 2 RECYCLE COMPRESSOR		11-1853 PYROLYZER NO. 3 RECYCLE COMPRESSOR		11-1854 RAW HIGH BTU FUEL GAS COMPRESSOR
8 OVERHEAD VAPOR PRODUCT	9 # OVERHEAD WATER	11 OVERHEAD LIQUID PRODUCT	12 REFLUX	13 BOTTOM PUMPAROUND EXCHANGER OUTLET	18 SIDE PUMPAROUND EXCHANGER OUTLET	27 RECYCLE GAS	28 GAS TO TREATING	29 COOLER WATER	30 MAKEUP GAS	31 FUEL GAS
9692.77	0.00	.02	.24	4.25	1.09	7613.07	2079.71	0.00	.49	2079.22
396.27	0.00	.00	.02	.24	.09	311.25	85.03	0.00	.02	85.01
2160.19	0.00	.14	2.20	2.20	1.19	1696.70	463.50	0.00	.11	463.39
5424.45	5876.80	2.64	42.80	5.34	5.42	4260.57	1163.88	168743.65	.28	1163.60
3602.80	0.00	.11	1.74	3.66	1.53	2829.77	773.03	0.00	.18	772.85
2957.38	0.00	.01	.18	1.83	.72	2372.84	634.54	0.00	.15	634.39
22035.67	0.00	.21	3.48	12.73	5.99	17307.64	4728.03	0.00	1.12	4726.91
886.76	0.00	.03	.46	1.26	.48	696.50	190.27	0.00	.05	190.22
2156.55	0.00	.09	1.39	3.04	1.28	1693.84	462.72	0.00	.11	462.61
536.13	0.00	.06	.93	.99	.54	421.10	115.03	0.00	.03	115.00
280.67	0.00	.03	.53	.55	.30	220.45	60.22	0.00	.01	60.21
437.08	0.00	.16	2.61	1.28	.87	343.30	93.78	0.00	.02	93.76
342.88	0.00	57.20	926.59	9.17	22.06	289.33	73.57	0.00	.02	77.78
17.38	0.00	69.83	1131.19	9.62	223.31	13.65	3.73	0.00	0.00	.01
.05	0.00	1.66	26.87	35.38	945.26	.04	.01	0.00	0.00	0.00
.00	0.00	.00	.05	345.55	1509.70	.00	.00	0.00	0.00	0.00
.00	0.00	.00	.00	2648.83	337.92	.00	.00	0.00	0.00	0.00
.00	0.00	.00	.00	5858.88	5.76	.00	.00	0.00	0.00	0.00
50927.05	5876.80	132.19	2141.29	9144.80	3063.52	40000.00	10927.05	168743.65	2.59	10924.46
987579.52	105876.35	18520.36	300000.00	4000000.00	720000.00	775681.77	211897.76	3040085.57	49.99	210871.71
	7264.50	1353.46	21923.86	236474.66	48587.51			208589.50		
463843.53						364320.00	99523.53		23.59	99499.98
19.39	18.02	140.10	140.10	437.41	235.02	19.39	19.39	18.02	19.30	19.30
	10.00	19.20	19.20	-9.56	7.67			10.00		

NOTES:
(1) ALL FLOW RATES, HEAT DUTIES, COMPOSITIONS, TEMPERATURES AND PRESSURES ARE TYPICAL VALUES. SEE EQUIPMENT SPECIFICATIONS FOR DESIGN CONDITIONS.

6-4

B

C

PROCESS FLOW DIAGRAM
UNIT 11-2
PYROLYSIS SECTION
OIL VAPOR RECOVERY
CONCEPTUAL COMMERCIAL COED
PLANT

DRAWN R. ROWE
THE RALPH M. PARSONS COMPANY LOS ANGELES
DATE 10-10-76
5054-3-AE11-2 0

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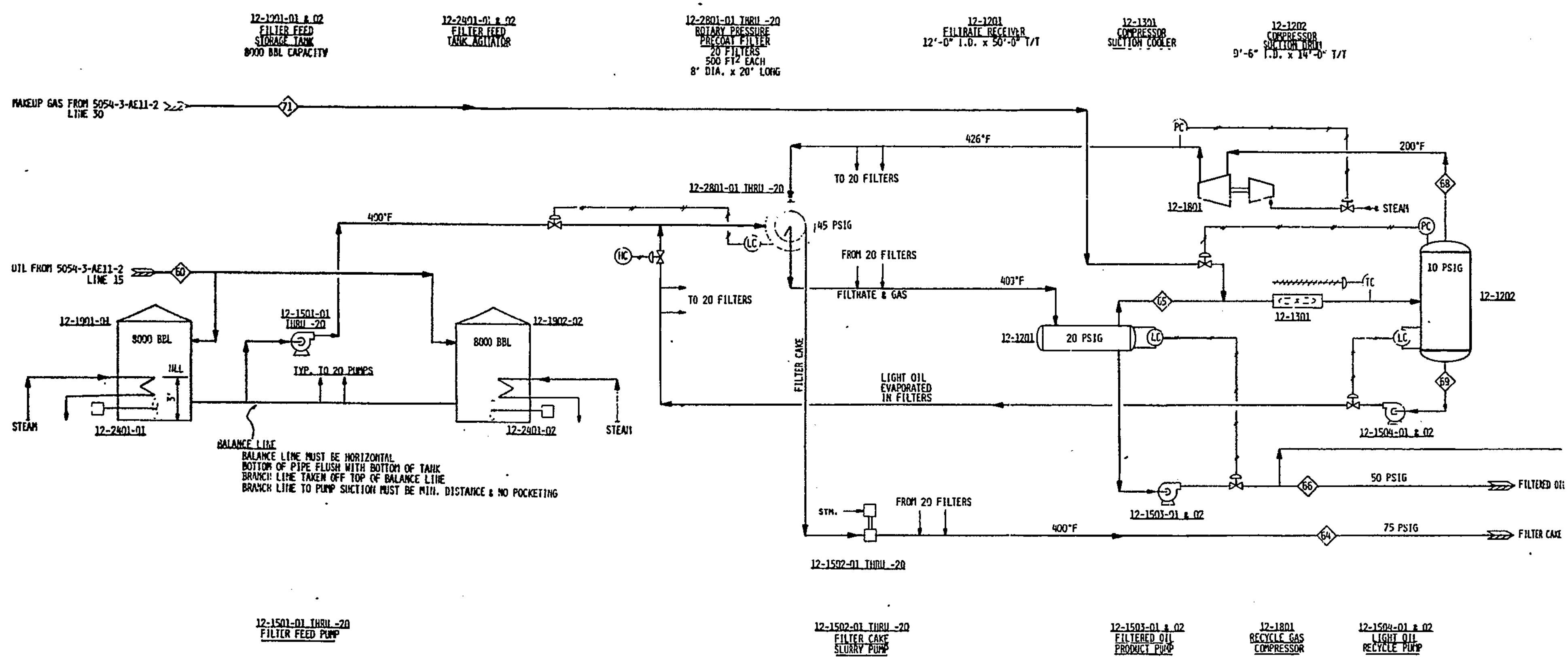

STREAM NO.	60 *	64 **	65	66	68	69	71
	OIL FEED	OIL IN CAKE	RECEIVER VAPOR	OIL PRODUCT	COMPRESSOR INLET	RECYCLE OIL	MAKEUP GAS
H_2	.46	.02	1278.86	.93	1279.34	.01	.49
N_2	.03	.00	33.83	.05	[illegible]3.85	.00	.02
H_2S	.30	.02	126.37	.39	12[illegible].46	.02	.11
H_2O	.97	.05	401.92	1.20	401.[illegible]	.24	.28
CO_2	.45	.02	248.03	.61	248.19	.03	.38
CO	.22	.01	229.51	.36	229.66	.01	.15
C_1	1.64	.09	1614.80	2.67	1615.84	.07	1.12
C_2=	.15	.01	59.66	.19	59.70	.01	.05
C_2	.38	.02	138.13	.47	138.22	.02	.11
C_3=	.14	.01	28.16	.16	28.18	.01	.03
C_3	.08	.00	14.59	.09	14.60	.01	.01
nC_4	.19	.01	19.58	.20	19.58	.02	.02
IBP-300	.69	.04	[illegible].84	.66	5.63	.22	.01
300-400	2.23	.12	5.89	2.11	4.72	1.18	.01
400-500	22.60	1.22	16.44	21.38	5.48	10.96	.00
500-550	49.27	2.66	12.33	46.61	1.04	11.29	0.00
550-600	45.94	2.48	[illegible].37	43.45	.15	5.22	0.00
600-650	59.50	3.21	3.13	56.28	.0[illegible]	3.11	0.00
650-750	136.53	7.37	1.99	129.16	.00	1.99	0.00
750-850	132.43	7.15	.28	125.28	.00	.28	0.00
850-950	117.37	6.34	.03	111.03	.00	.03	0.00
950-1050	106.74	5.76	.00	100.98	.00	.00	0.00
1050-1150	98.71	5.33	.00	93.38	.00	.00	0.00
1150-1250	92.53	5.00	.00	87.53	.00	.00	0.00
1250-1350	77.97	4.21	.00	73.76	.00	.00	0.00
1350 Plus	111.53	6.02	.00	105.51	.00	.00	0.00
TOTAL	1059.06	57.19	4244.74	1004.44	4212.61	34.72	2.59
LB/HR	402717.82	21749.00	7586[illegible].43	381018.26	69409.90	6508.82	50.29
BBLS/DAY	24395.98	1317.52		23086.71		454.93	
MSCFD			3866..12		38368.47		23.62
MOL WT	380.26	380.26	17.87	379.33	16.48	187.44	19.39
API	-6.55	-6.55		-6.52		12.64	

*Feed oil contains 5% solids
**Filter cake contains 50% solids
Not included in stream totals

A

B

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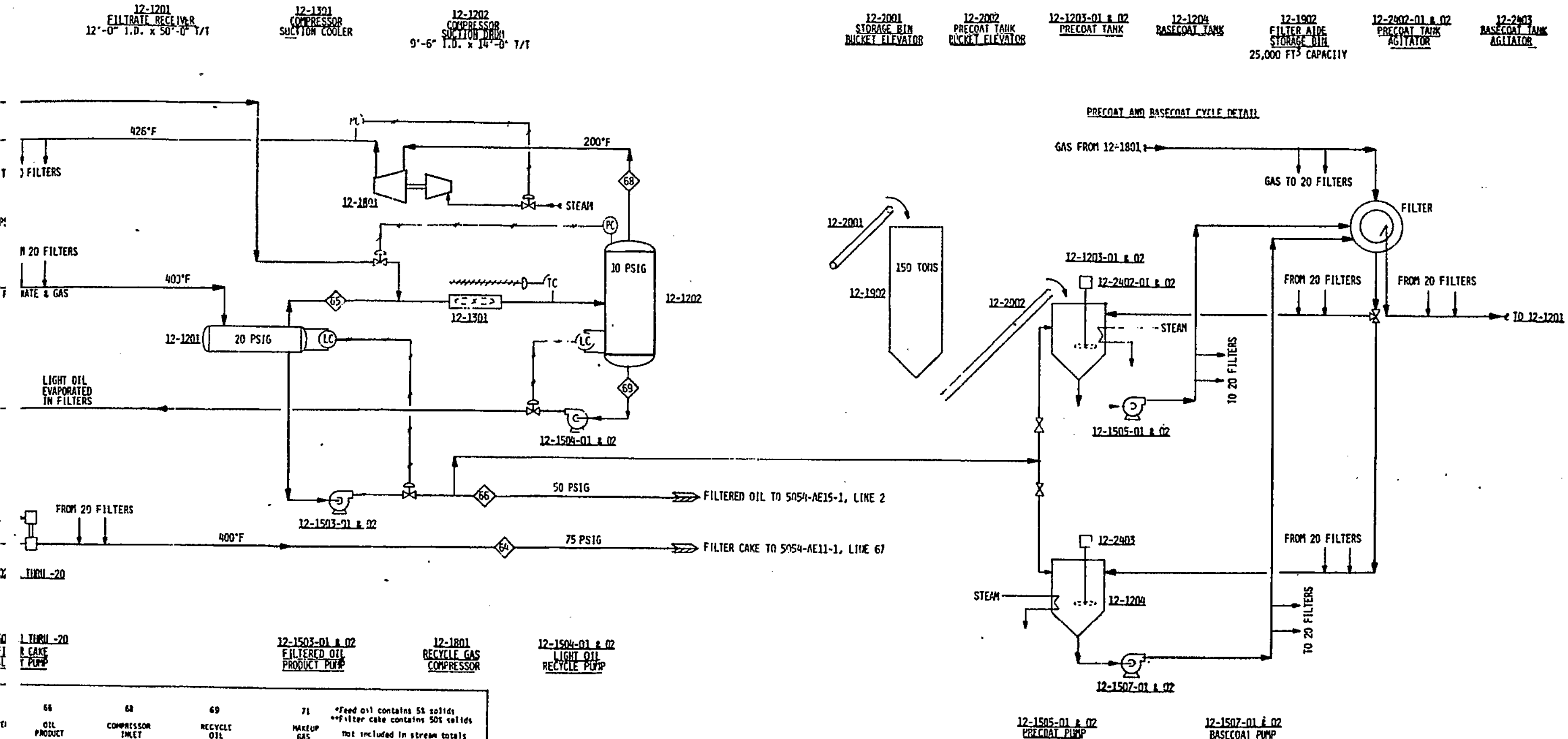

66 OIL PRODUCT	68 COMPRESSOR INLET	69 RECYCLE OIL	71 MAKEUP GAS
.93	1279.34	.01	.49
.05	71.85	.00	.02
.39	12[illegible].46	.02	.11
1.20	401.[illegible]	.24	.28
.61	248.19	.03	.18
.36	229.66	.01	.15
2.67	1615.84	.07	1.12
.19	59.70	.01	.05
.47	138.22	.02	.11
.16	28.18	.01	.03
.09	14.60	.01	.01
.20	19.58	.02	.02
.66	5.63	.22	.01
2.11	4.72	1.18	.01
21.38	5.48	10.96	.00
40.81	1.04	11.29	0.00
43.45	.15	5.22	0.00
56.78	.03	3.11	0.00
129.16	.00	1.99	0.00
125.28	.00	.28	0.00
111.03	.00	.03	0.00
100.90	.00	.00	0.00
93.38	.00	.00	0.00
87.53	.00	.00	0.00
73.76	.00	.00	0.00
105.51	.00	.00	0.00
1004.44	4212.61	34.72	2.59
381018.26	69409.90	6508.82	50.29
23086.71		454.93	
	38368.47		23.62
379.33	16.48	187.44	19.39
-6.52		12.64	

*Feed oil contains 5% solids
**Filter cake contains 50% solids
Not included in stream totals

NOTES:
(1) ALL FLOW RATES, HEAT DUTIES, COMPOSITIONS, TEMPERATURES & PRESSURES ARE TYPICAL VALUES. SEE EQUIPMENT SPECIFICATIONS FOR DESIGN CONDITIONS.

6-5

PROCESS FLOW DIAGRAM
UNIT 12-1
OIL FILTRATION SECTION
CONCEPTUAL COMMERCIAL COED PLANT DESIGN
THE RALPH M. PARSONS COMPANY
LOS ANGELES
5054-3-AE12-1 | 0
DATE 10-10-74

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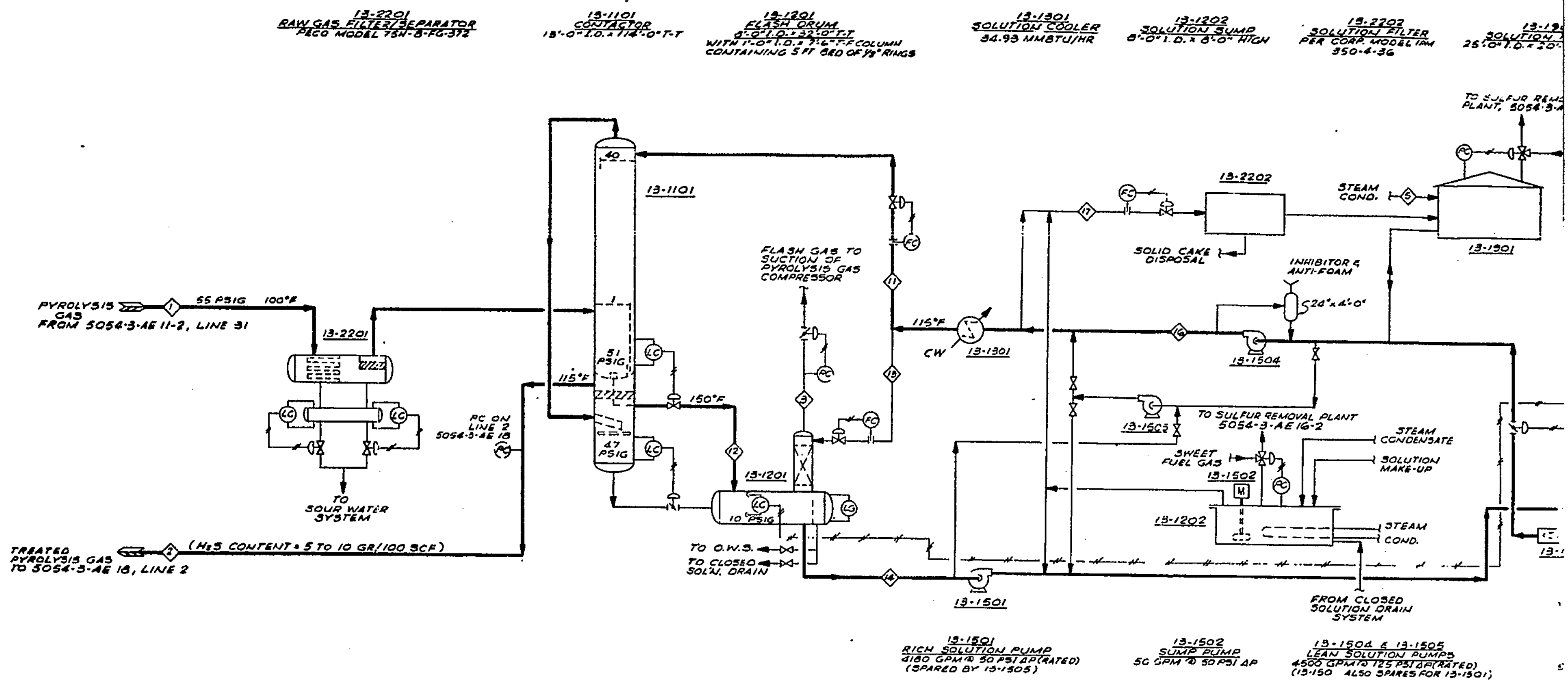

STREAM NO.	1	2	3	4	5
STREAM NAME	FEED GAS	TREATED GAS TO BURNER FUEL SYSTEM	FLASH GAS TO PYROLYSIS GAS COMPRESSOR	ACID GAS TO SULFUR PLANT	WATER MAKEUP
COMPONENT, MPH					
H_2S	463.39	-	-	463.39	-
CO_2	772.85	-	-	772.85	-
CO	634.39	634.15	0.22	0.02	-
C_1	4,726.91	4,724.30	1.66	0.95	-
C_2=	190.22	190.22	-	-	-
C_2	462.61	462.61	-	-	-
C_3=	115.00	115.00	-	-	-
C_3	60.21	60.21	-	-	-
C_4's	171.05	171.05	-	-	-
H_2	2,079.22	2,078.12	0.69	0.41	-
N_2	85.01	85.01	-	-	-
Dry	9,760.86	8,520.67	2.57	1,237.62	-
H_2O	134.88	207.96	0.32	54.08	127.48
Total	9,895.74	8,728.63	2.89	1,291.70	127.48
Lean 40% DGA, GPM @ 60°F	-	-	-	-	-
Lean 40% DGA, Lb/Hr	-	-	-	-	-
DGA Content, MPH	-	-	-	-	-
COMPONENTS NOT INCLUDING LEAN DGA SOL'N					
Lbs/Hr, Dry	186,659	136,802	34	49,823	-
MMSCFD, Dry	88.90	77.61	0.02	11.27	
Mol. Wt., Dry	19.12	16.06	13.30	40.28	-
TOTAL INCLUDING DGA SOL'N					
Lbs/Hr, Wet	189,089	140,549	40	50,797	2,297
MMSCFD, Wet	90.13	79.50	0.03	11.76	-
Mol. Wt., Wet	19.11	16.10	13.82	39.33	18.02
GPM @ T	-	-	-	-	5

STREAM NO.	11	12	13	14	15	16	17
STREAM NAME	LEAN SOLUTION TO CONTACTOR	RICH SOLUTION OFF CONTACTOR	LEAN SOLUTION TO FLASH TANK	RICH. SOLUTION OFF FLASH TANK	LEAN SOLUTION OFF REGEN.	LEAN SOL'N OFF PUMP	LEAN SOLUTION TO FILTER
COMPONENT, MPH							
H_2S	-	463.39	-	463.39	-	-	-
CO_2	-	772.85	-	772.85	-	-	-
CO	-	0.24	-	0.02	-	-	-
C_1	-	2.61	-	0.95	-	-	-
C_2=	-	-	-	-	-	-	-
C_2	-	-	-	-	-	-	-
C_3=	-	-	-	-	-	-	-
C_3	-	-	-	-	-	-	-
C_4's	-	-	-	-	-	-	-
H_2	-	1.10	-	0.41	-	-	-
N_2	-	-	-	-	-	-	-
Dry	-	1,240.19	-	1,237.62	-	-	-
H_2O	127.41	54.33	.02	54.08	-	140.23	12.75
Total	127.41	1,294.52	.02	1,291.70	-	140.23	12.75
Lean 40% DGA, GPM @ 60°F	3,380	3,320	2	3,382	3,382	3,720	338
Lean 40% DGA, Lb/Hr	1,762,749	1,762,749	[illegible]	1,763,749	1,763,749	1,940,124	176,375
DGA Content, MPH	6,706	6,706	4	6,710	6,710	7,381	671
COMPONENTS NOT INCLUDING LEAN DGA SOL'N							
Lbs/Hr, Dry	-	49,017	-	49,823	-	-	-
MMSCFD, Dry	-	-	-	-	-	-	-
Mol. Wt., Dry	-	-	-	-	-	-	-
TOTAL INCLUDING DGA SOL'N							
Lbs/Hr, Wet	1,765,044	1,813,585	1,001	1,814,546	1,763,749	1,942,650	176,605
MMSCFD, Wet	-	-	-	-	-	-	-
Mol. Wt., Wet	-	-	-	-	-	-	-
GPM @ T	3,444	3,564	2	3,586	3,637	3,847	348

STREAM NO.
STREAM NAME
COMPONENT, MPH
H_2S
CO_2
CO
C_1
C_2=
C_2
C_3=
C_3
C_4's
H_2
N_2
Dry
H_2O
Total
Lean 40% DGA, GPM @ 60°F
Lean 40% DGA, Lb/Hr
DGA Content, MPH
COMPONENTS NOT INCLUDING LEAN DGA SOL'N
Lbs/Hr, Dry
MMSCFD, Dry
Mol. Wt., Dry
TOTAL INCLUDING DGA SOL'N
Lbs/Hr, Wet
MMSCFD, Wet
Mol. Wt., Wet
GPM @ T

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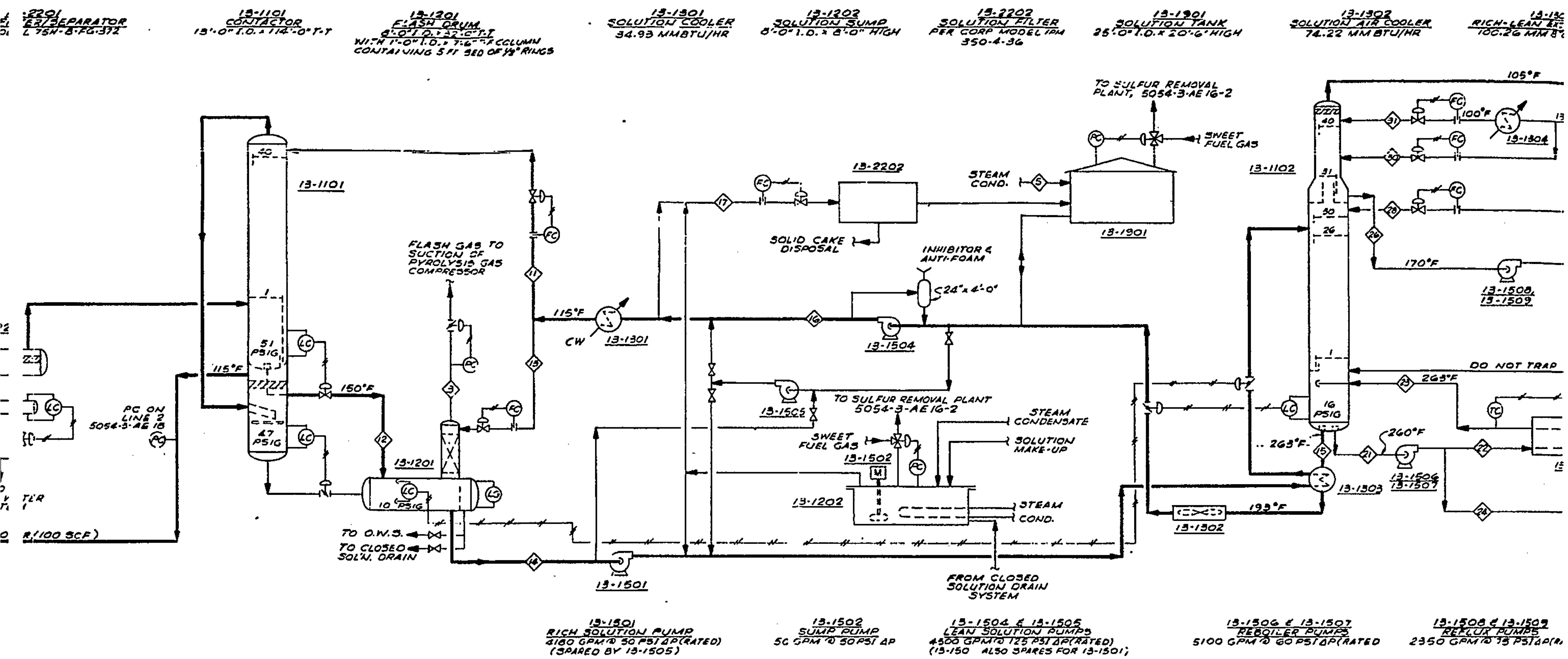

STREAM NO.	1	2	3	4	5
STREAM NAME	FEED GAS	TREATED GAS TO BURNER FUEL SYSTEM	FLASH GAS TO PYROLYSIS GAS COMPRESSOR	ACID GAS TO SULFUR PLANT	WATER MAKEUP
COMPONENT, MPH					
H_2S	463.39	-	-	463.39	-
CO_2	772.85	-	-	772.85	-
CO	634.39	634.15	0.22	0.02	-
C_1	4,726.91	4,724.30	1.66	0.95	-
C_2=	190.22	190.22	-	-	-
C_2	462.61	462.61	-	-	-
C_3=	115.00	115.00	-	-	-
C_3	60.21	60.21	-	-	-
C_4's	171.05	171.05	-	-	-
H_2	2,079.22	2,078.12	0.69	0.41	-
N_2	85.01	85.01	-	-	-
Dry	9,760.86	8,520.67	2.57	1,237.62	-
H_2O	134.88	207.96	0.32	54.08	127.48
Total	9,895.74	8,728.63	2.89	1,291.70	127.48
Lean 40% DGA, GPM @ 60°F	-	-	-	-	-
Lean 40% DGA, Lb/Hr	-	-	-	-	-
DGA Content, MPH	-	-	-	-	-
COMPONENTS NOT INCLUDING LEAN DGA SOL'N					
Lbs/Hr. Dry	186,659	136,802	34	49,823	-
MMSCFD, Dry	88.90	77.61	0.02	11.27	
Mol. Wt. Dry	19.12	16.06	13.30	40.26	-
TOTAL INCLUDING DGA SOL'N					
Lbs/Hr. Wet	189,089	140,549	40	50,797	2,297
MMSCFD, Wet	90.13	79.50	0.03	11.76	-
Mol. Wt. Wet	19.11	16.10	13.82	39.33	18.02
GPM @ T	-	-	-	-	5

STREAM NO.	11	12	13	14	15	16	17
STREAM NAME	LEAN SOLUTION TO CONTACTOR	RICH SOLUTION OFF CONTACTOR	LEAN SOLUTION TO FLASH TANK	RICH SOLUTION OFF FLASH TANK	LEAN SOLUTION OFF REGEN.	LEAN SOL'N OFF PUMP	LEAN SOLUTION TO FILTER
COMPONENT, MPH							
H_2S	-	463.39	-	463.39	-	-	-
CO_2	-	772.85	-	772.85	-	-	-
CO	-	0.24	-	0.02	-	-	-
C_1	-	2.61	-	0.95	-	-	-
C_2=	-	-	-	-	-	-	-
C_2	-	-	-	-	-	-	-
C_3=	-	-	-	-	-	-	-
C_3	-	-	-	-	-	-	-
C_4's	-	-	-	-	-	-	-
H_2	-	1.10	-	0.41	-	-	-
N_2	-	-	-	-	-	-	-
Dry	-	1,240.19	-	1,237.62	-	-	-
H_2O	127.41	54.33	0.07	54.08	-	140.23	12.75
Total	127.41	1,294.52	0.07	1,291.70	-	140.23	12.75
Lean 40% DGA, GPM @ 60°F	3,380	3,380	2	3,382	3,382	3,720	338
Lean 40% DGA, Lb/Hr	1,762,749	1,762,749	1,000	1,763,749	1,763,749	1,940,124	176,375
DGA Content, MPH	6,706	6,706	4	6,710	6,710	7,381	671
COMPONENTS NOT INCLUDING LEAN DGA SOL'N							
Lbs/Hr. Dry	-	49,857	-	49,823	-	-	-
MMSCFD, Dry	-	-	-	-	-	-	-
Mol. Wt. Dry	-	-	-	-	-	-	-
TOTAL INCLUDING DGA SOL'N							
Lbs/Hr. Wet	1,765,044	1,813,585	1,001	1,814,546	1,763,749	1,942,650	176,605
MMSCFD, Wet	-	-	-	-	-	-	-
Mol. Wt. Wet	-	-	-	-	-	-	-
GPM @ T	3,444	3,584	2	3,586	3,637	3,847	348

STREAM NO.	21	22	23	24	25	26	27
STREAM NAME	SOLUTION TO REBOILER PUMP	SOLUTION TO REBOILER HEATER	OUTLET FROM REBOILER HEATER	SOLUTION TO RECLAIMER	VAPOR OFF RECLAIMER	LIQUID TO REFLUX PUMP	WATE[illegible] TO RECLA[illegible]
COMPONENT, MPH							
H_2S	-	-	-	-	-	-	-
CO_2	-	-	-	-	-	-	-
CO	-	-	-	-	-	-	-
C_1	-	-	-	-	-	-	-
C_2=	-	-	-	-	-	-	-
C_2	-	-	-	-	-	-	-
C_3=	-	-	-	-	-	-	-
C_3	-	-	-	-	-	-	-
C_4's	-	-	-	-	-	-	-
H_2	-	-	-	-	-	-	-
N_2	-	-	-	-	-	-	-
Dry	-	-	-	-	-	-	-
H_2O	7,461.65	7,341.42	7,341.42	120.23	1,496.22	50,603.91	413.[illegible]
Total	7,461.65	7,341.42	7,341.42	120.23	1,496.22	50,603.91	413.[illegible]
Lean 40 DGA, GPM @ 60°F	3,437	3,382	3,382	55	-	-	-
Lean 40% DGA, Lb/Hr	1,792,642	1,763,749	1,763,749	28,893	-	-	-
DGA Content, MPH	6,820	6,710	6,710	110	110	-	-
COMPONENTS NOT INCLUDING LEAN DGA SOL'N							
Lbs/Hr. Dry	-	-	-	-	-	-	-
MMSCFD, Dry	-	-	-	-	-	-	-
Mol. Wt. Dry	-	-	-	-	-	-	-
TOTAL INCLUDING DGA SOL'N							
Lbs/Hr. Wet	1,927,071	1,896,012	1,896,012	31,059	38,513	911,680	7,45[illegible]
MMSCFD, Wet	-	-	66.87	-	14.63	-	-
Mol. Wt. Wet	-	-	-	-	23.98	18.02	18.[illegible]
GPM @ T	3,973	3,909	3,637	64	-	1,872	[illegible]

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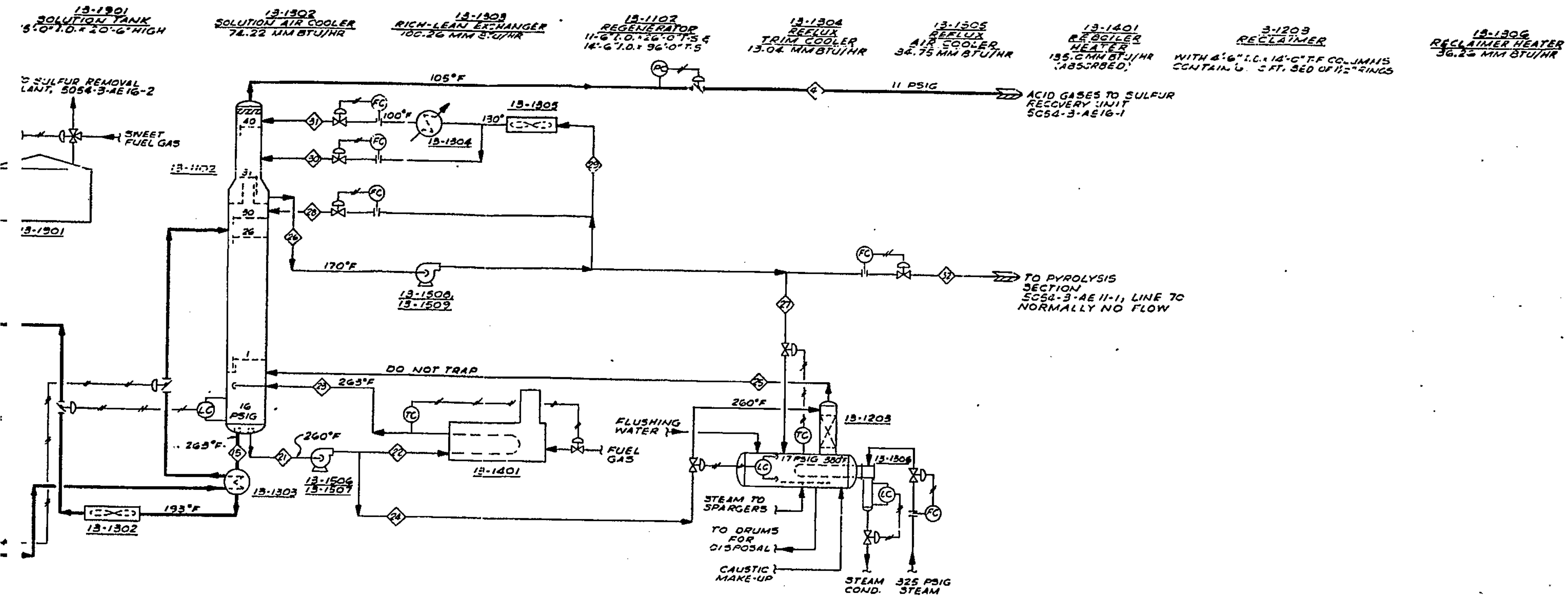

13-1506 & 13-1507
REBOILER PUMPS
5100 GPM @ 60 PSI ΔP (RATED

13-1508 & 13-1509
REFLUX PUMPS
2350 GPM @ 78 PSI ΔP (RATED)

NO.	21	22	23	24	25	26	27	28	29	30	31
NAME	SOLUTION TO REBOILER PUMP	SOLUTION TO REBOILER HEATER	OUTLET FROM REBOILER HEATER	SOLUTION TO RECLAIMER	VAPOR OFF RECLAIMER	LIQUID TO REFLUX PUMP	WATER TO RECLAIMER	REFLUX TO REGEN.	WATER TO REFLUX AIR COOLER	WARM WATER TO CONTACT CONDENSER	COOL WATER TO CONTACT CONDENSER
WT, MPH											
	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-
	-	-	-	-	-	-	-	-	-	-	-
	7,461.65	7,341.42	7,341.42	120.23	1,496.22	50,603.91	413.7[illegible]	1,970.80	48,219.36	24,109.68	24,109.68
1	7,461.65	7,341.42	7,341.42	120.23	1,496.22	50,603.91	413.7[illegible]	1,970.80	48,219.36	24,109.68	24,109.68
40 DGA, GPM @ 60°F	3,437	3,382	3,382	55	-	-	-	-	-	-	-
40% DGA, Lb/Hr	1,792,642	1,763,749	1,763,749	28,893	-	-	-	-	-	-	-
Content, MPH	6,820	6,710	6,710	119	110	-	-	-	-	-	-
TS NOT INCLUDING SOL'N											
r, Dry	-	-	-	-	-	-	-	-	-	-	-
D, Dry	-	-	-	-	-	-	-	-	-	-	-
Wt. Dry	-	-	-	-	-	-	-	-	-	-	-
CLUDING DGA SOL'N											
r, Wet	1,927,071	1,896,012	1,896,012	31,059	38,513	911,680	7,45[illegible]	35,506	868,720	434,360	434,360
D, Wet	-	-	66.87	-	14.63	-	-	-	-	-	-
Wt. Wet	-	-	-	-	23.98	18.02	18.02	18.02	18.02	18.02	10.02
T	3,973	3,909	3,637	64	-	1,872	15	73	1,783	881	874

6-6

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PROCESS FLOW DIAGRAM
UNIT 13-1
GAS TREATING SECT., PYROLYSIS GAS
CONCEPTUAL COMMERCIAL COED
PLANT DESIGN

THE RALPH M. PARSONS COMPANY
LOS ANGELES

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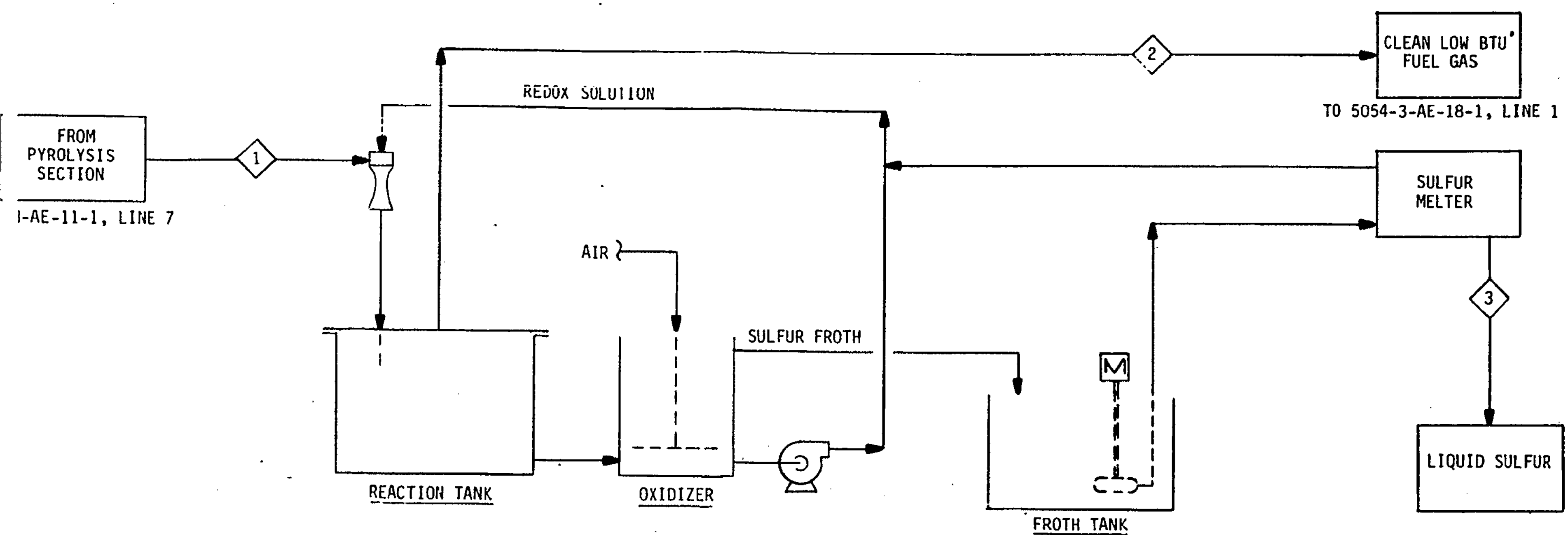

STREAM	1	2	3
Fluids, Mols/Hr.			
COS	73	73	-
H_2	50681	50681	-
N_2	702	702	-
H_2S	1546	(1 ppm)	-
H_2O	8422	8316	-
CO_2	29071	29071	-
CO	38969	38969	-
CH_4	839	839	
Total	130303	129312	
Lb/Hr.	2715023	2661400	
Solids, Lb/HR.			
Sulfur			49570

UNIT CAPACITY 823 Lt/D

NOTE: THIS PROCESS ILLUSTRATED IS ONE OF SEVERAL PROPRIETARY PROCESSES AVAILABLE FOR THE PURPOSE INTENDED.

6-7

DRAWN	PROCESS FLOW DIAGRAM UNIT 13-2 GAS TREATING SECTION LOW BTU GAS TREATMENT CONCEPTUAL COMMERCIAL COED PLANT DESIGN
CHECK	
PROCESS ENGR	
CH PROC ENGR	
CH OPER ENGR.	
PROJECT ENGR.	THE RALPH M PARSONS COMPANY LOS ANGELES — DRAWING NO. 5054-3-AE-13-2 — REV 0
CH DES ENGR.	
DATE	

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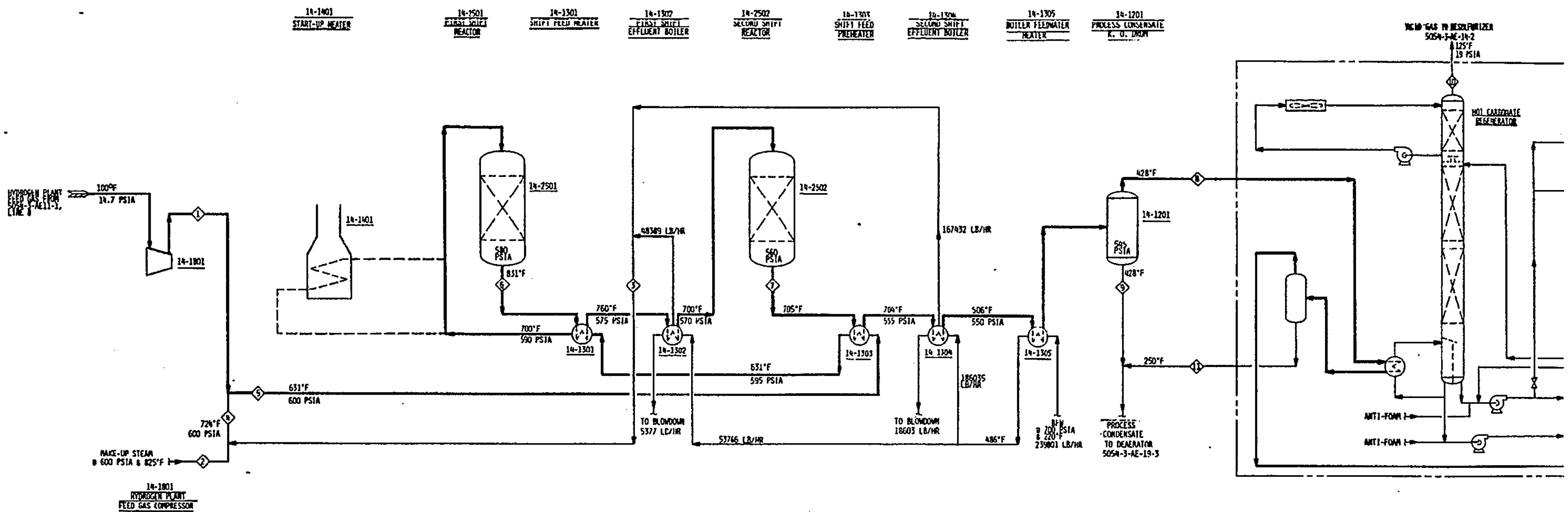

STREAM	1	2	3	4	5	6	7	8	9	10	11
PHASE	VAPOR	VAPOR	VAPOR	VAPOR	VAPOR	VAPOR	VAPOR	VAPOR	LIQUID	VAPOR	LIQUID
MOLES/HR											
H_2	7040.20	-	-	-	7040.20	12,026.04	12,219.55	12,219.5[illegible]	-	-	-
CH_4	117.06	-	-	-	117.06	117.06	117.06	117.[illegible]	-	-	-
CO	5415.16	-	-	-	5415.16	429.41	235.80	235.[illegible]	-	-	-
CO_2	4039.97	-	-	-	4039.97	9,035.19	9,228.89	9,228.[illegible]	-	9,203.50	-
N_2	97.38	-	-	-	97.38	97.38	97.38	97.[illegible]	-	-	-
H_2S	214.44	-	-	-	214.44	223.81	224.00	224.[illegible]	-	224.14	-
COS	9.84	-	-	-	9.84	.47	.28	[illegible]	-	-	-
H_2O	80.07	34,453.34	11,979.41	46,432.75	46,512.82	41,517.61	41,323.91	40,417.5[illegible]	906.32	1,027.10	39,111.47
TOTAL MOL/HR	17,014.12	34,453.34	11,979.41	46,432.75	63,446.87	63,446.87	63,446.87	62,540.[illegible]	906.32	10,454.74	39,111.47
TOTAL LBS/HR	357,619	620,711	215,821	836,532	1,194,152	1,194,152	1,194,152	1,177,[illegible]	16,328	431,211	704,632
MOLECULAR WT	21.02	18.016	18.016	18.016	18.82	18.82	18.82	18.[illegible]	18.016	41.25	18.0[illegible]
MSCFD	154,964	313,801	109,109	422,910	577,874	577,874	577,874	569,[illegible]	-		

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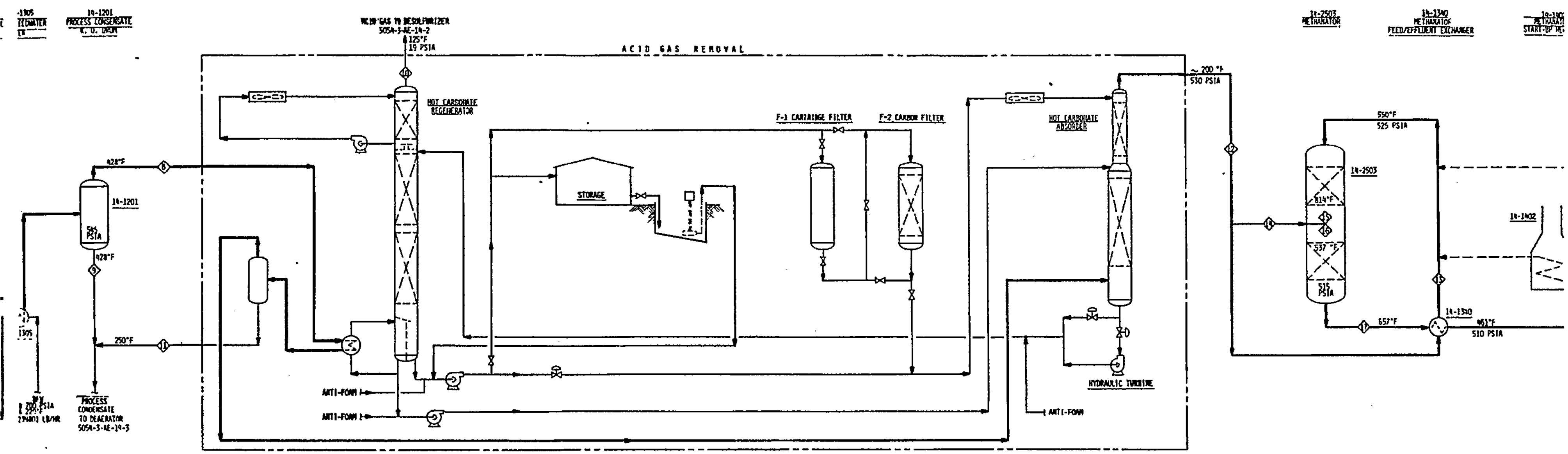

11.47	
11.47	
.632	
.016	

STREAM	12	13	14	15	16	17
PHASE	VAPOR	VAPOR	VAPOR	VAPOR	VAPOR	VAPOR
MOLES/HR						
H_2	12,219.55	6,720.75	5,498.80	6,276.05	11,274.85	11,411.00
CH_4	117.06	64.38	52.68	207.97	260.65	378.13
CO	235.80	129.69	106.11	.03	[illegible]	.06
CO_2	25.39	13.96	11.43	.03	11.96	.06
N_2	97.38	53.56	43.82	97.38	97.38	97.38
H_2S	TRACE	TRACE	TRACE	TRACE	-	-
COS	-	-	-	-	-	-
H_2O	279.02	153.46	125.56	310.99	436.55	565.43
TOTAL MOLES/HR	12,974.21	7,135.82	5,838.39	[illegible]	12,687.03	12,452.06
TOTAL LBS/HR	41,980	23,095	18,895	23,095	41,990	41,990
MOLECULAR WT	3.29	3.24	3.29	3.37	3.31	3.37
MSCFD	118,169	64,993	53,176	62,377	115,553	113,415

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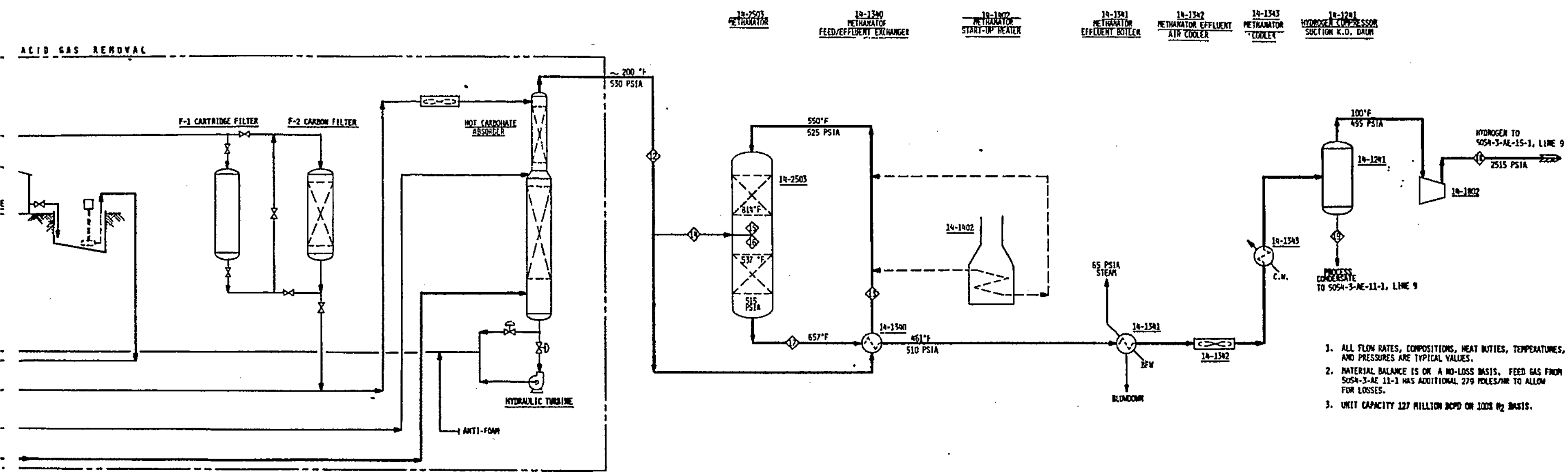

1. ALL FLOW RATES, COMPOSITIONS, HEAT DUTIES, TEMPERATURES, AND PRESSURES ARE TYPICAL VALUES.
2. MATERIAL BALANCE IS ON A NO-LOSS BASIS. FEED GAS FROM 5054-3-AE 11-1 HAS ADDITIONAL 279 MOLES/HR TO ALLOW FOR LOSSES.
3. UNIT CAPACITY 127 MILLION SCFD ON 100% H_2 BASIS.

STREAM	12	13	14	15	16	17	18	19
PHASE	VAPOR	VAPOR	VAPOR	VAPOR	VAPOR	VAPOR	VAPOR	LIQUID
MOLES/HR								
H_2	12,219.55	6,720.75	5,498.80	6,276.05	11,774.85	11,411.00	11,411.00	-
CH_4	117.06	64.38	52.68	207.97	260.65	378.13	378.13	-
CO	235.80	129.69	106.11	.03	106.14	.06	.06	-
CO_2	25.39	13.96	11.43	.03	11.46	.06	.06	-
N_2	97.38	53.56	43.82	97.38	97.38	97.38	97.38	-
H_2S	TRACE	TRACE	TRACE	TRACE	-	-	-	-
COS	-	-	-	-	-	-	-	-
H_2O	279.02	153.46	125.56	310.99	436.55	565.43	22.83	542.60
TOTAL MOLES/HR	12,974.21	7,135.82	5,838.39	6,8[illegible]	12,687.03	12,452.06	11,909.96	542.60
TOTAL LBS/HR	41,980	23,095	18,895	23,095	41,990	41,990	32,215	9,775
MOLECULAR WT	3.24	3.24	3.24	3.37	3.31	3.37	2.70	18.016
MSCFD	118,169	64,993	53,176	62,377	115,553	113,413	108,470	-

6-8

NOTE: THE ACID GAS REMOVAL INDICATED IS ONE OF SEVERAL PROPRIETARY PROCESSES AVAILABLE FOR THIS PURPOSE INTENDED.

PROCESS FLOW DIAGRAM UNIT 14-1 HYDROGEN PLANT CONCEPTUAL COMMERCIAL COED PLANT DESIGN	
THE RALPH M. PARSONS COMPANY LOS ANGELES	5054-3-AE 14-1 / 0

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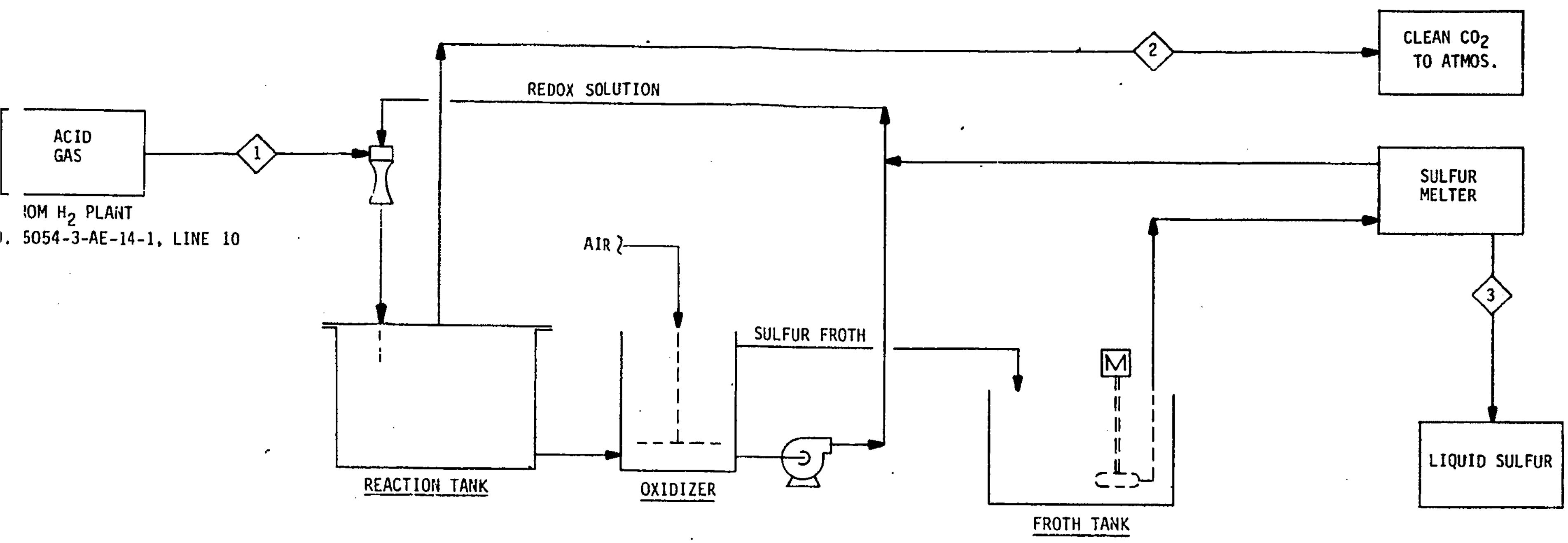

TREAM	1	2	3
luids, Mols/Hr.			
CO_2	9204	9204	-
H_2S	224	(1 ppm)	-
H_2O	1027	637	
Total	10455	9842	
Lb/Hr.	431211	416580	
olids, Lb/Hr.			
Sulfur			7180

UNIT CAPACITY 135 Lt/D

NOTE: THIS PROCESS ILLUSTRATED IS ONE OF SEVERAL PROPRIETARY PROCESSES AVAILABLE FOR THE PURPOSE INTENDED.

6-9

DRAWN	PROCESS FLOW DIAGRAM UNIT 14-2 HYDROGEN PLANT TAILGAS DESULFURIZER CONCEPTUAL COMMERCIAL COED PLANT DESIGN
CHECK	
PROCESS ENGR	
CH PROC ENGR	
CH OPER ENGR.	
PROJECT ENGR.	THE RALPH M PARSONS COMPANY LOS ANGELES — DRAWING NO. 5054-3-AE-14-2 — REV 0
CH DES ENGR.	
DATE	

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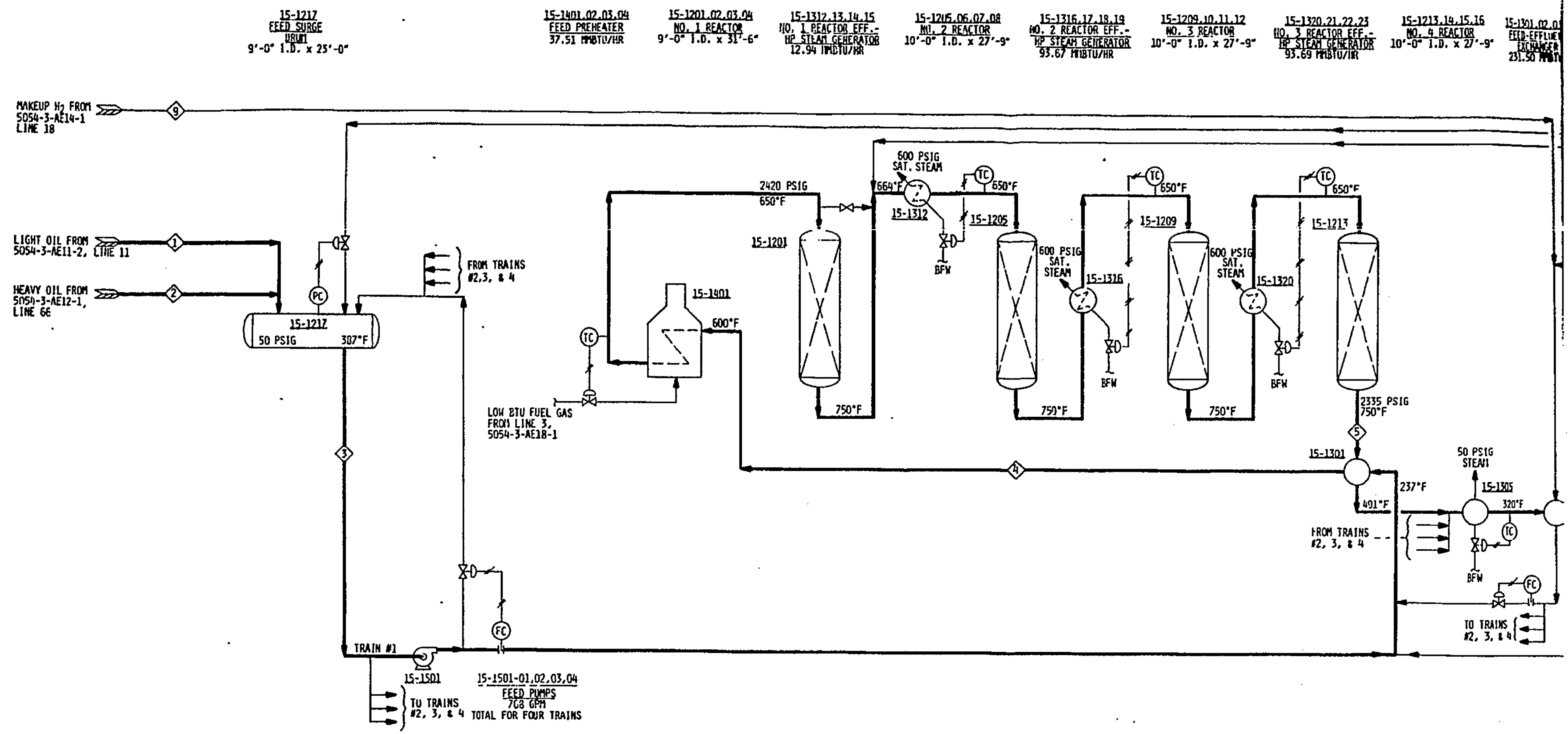

STREAM NO.	1 LIGHT OIL FEED	2 HEAVY OIL FEED	3 TOTAL FEED	4 TOTAL TO FURNACE 4 TRAINS	5 TOTAL REACTOR EFFLUENT TOTAL 4 TRAINS	6 WASH WATER	7 TOTAL EFFLUENT TO HP SEPARATOR	8 QUENCH GAS TOTAL 4 TRAINS	9 MAKEUP HYDROGEN
H_2	.02	.93	.94	18666.04	17263.22	0.00	17263.22	9401.90	11410.41
N_2	.00	.05	.05	1194.82	2568.52	0.00	2568.52	1373.70	118.90
NH_3	0.00	0.00	0.00	0.00	307.85	0.00	307.85	0.00	0.00
H_2S	.14	.39	.53	.53	244.59	0.00	244.59	0.00	0.00
H_2O	2.64	1.20	3.84	50.04	1900.70	10000.00	11900.70	17.79	0.00
CO_2	.11	.61	.72	31.73	71.18	0.00	71.18	31.37	0.00
CO	.01	.36	.37	25.27	59.43	0.00	59.43	31.45	0.00
C_1	.21	2.67	2.89	3045.11	6358.47	0.00	6358.47	3216.12	356.58
C_2=	.03	.19	.22	12.82	28.91	0.00	28.91	12.82	0.00
C_2	.09	.47	.55	113.21	255.85	0.00	255.85	108.45	0.00
C_3=	.06	.16	.21	17.61	37.36	0.00	37.36	11.70	0.00
C_3	.03	.09	.12	70.45	150.28	0.00	150.28	45.74	0.00
nC_4	.16	.20	.36	61.19	122.46	0.00	122.46	22.28	0.00
IBP-200P	0.00	0.00	0.00	331.55	628.86	0.00	628.86	31.43	0.00
200-300P	0.00	0.00	0.00	363.29	675.87	0.00	675.87	3.57	0.00
300-430P	0.00	0.00	0.00	603.30	1120.15	0.00	1120.15	.68	0.00
430-550P	0.00	0.00	0.00	476.47	884.46	0.00	884.46	.03	0.00
550-650P	0.00	0.00	0.00	341.32	633.58	0.00	633.58	.00	0.00
650 Plus	0.00	0.00	0.00	357.37	664.48	0.00	664.48	.00	0.00
IBP-400F	57.20	2.78	59.98	59.98	0.00	0.00	0.00	0.00	0.00
400-500F	69.83	21.38	91.21	91.21	0.00	0.00	0.00	0.00	0.00
500-600F	1.66	90.07	91.73	91.73	0.00	0.00	0.00	0.00	0.00
600-750F	.00	185.44	185.45	185.45	0.00	0.00	0.00	0.00	0.00
750-950F	0.00	236.31	236.31	236.31	0.00	0.00	0.00	0.00	0.00
950 Plus	0.00	461.16	461.16	461.16	0.00	0.00	0.00	0.00	0.00
TOTAL	132.19	1004.44	1136.63	26888.57	33976.23	10000.00	43976.23	14309.00	11885.88
LB/HR	18570.32	381018.32	399538.63	964206.72	1085948.94	180160.00	1266108.94	121742.22	32054.57
BBLS/DAY	1353.46	23086.71	24440.17			12361.32			
MSCFD								130326.37	108256.59
MOL WT	140.10	379.33	351.51	35.86	31.96	18.02	28.79	8.51	2.70
API	19.20	-6.52	-5.33			10.00			

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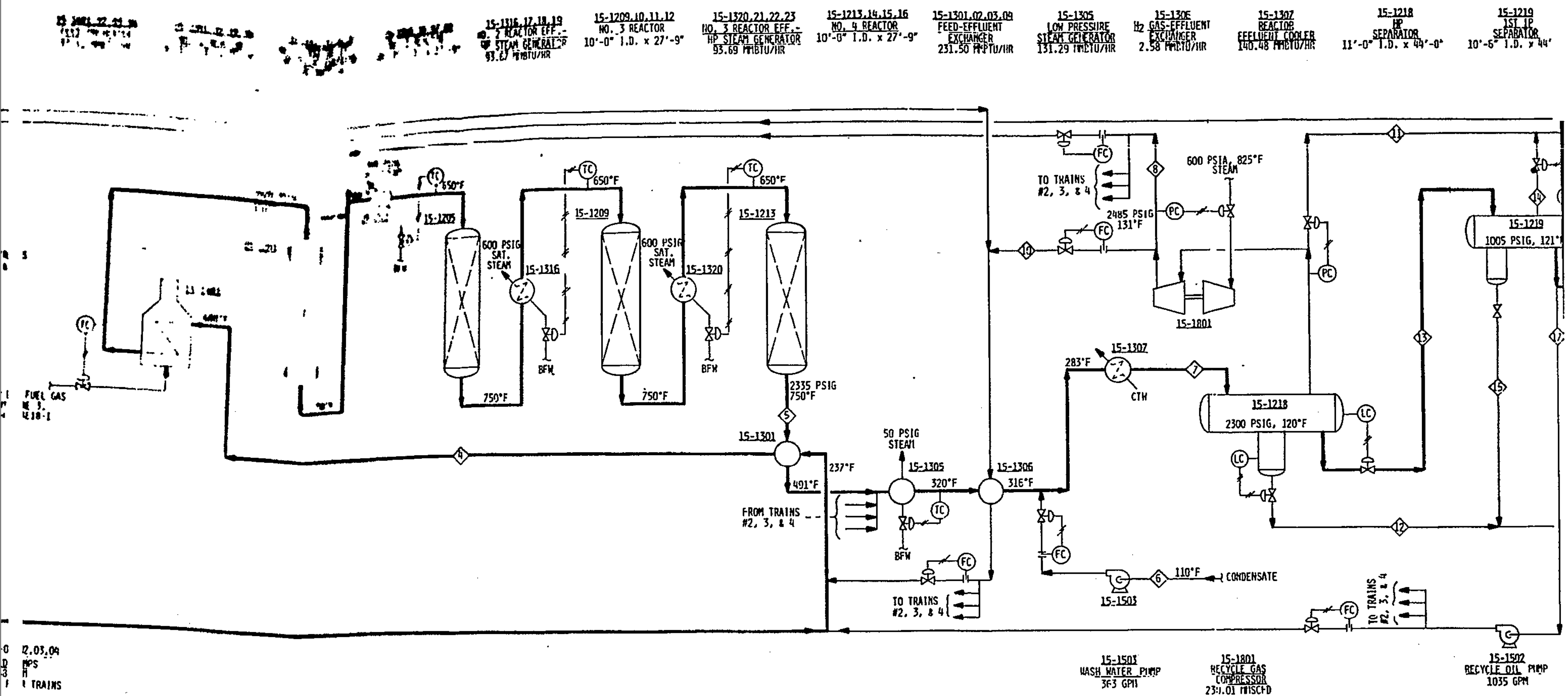

STREAM NO.	1 LIGHT OIL FEED	2 HEAVY OIL FEED	3 TOTAL FEED	4 TOTAL TO FURNACE 4 TRAINS	5 TOTAL REACTOR EFFLUENT TOTAL 4 TRAINS	6 WASH WATER	7 TOTAL EFFLUENT TO HP SEPARATOR	8 QUENCH GAS TOTAL 4 TRAINS	9 MAKEUP HYDROGEN	10 RECYCLE GAS TO FEED
H_2	[illegible]	.91	.94	10666.04	17263.22	0.00	17263.22	9401.90	13410.41	7191.54
N_2	[illegible]	.05	.05	1194.82	2568.52	0.00	2568.52	1373.70	118.30	1050.74
NH_3	[illegible]	0.00	0.00	0.00	307.85	0.00	307.85	0.00	0.00	0.00
H_2S	[illegible]	.19	.53	.53	244.59	0.00	244.59	0.00	0.00	0.00
H_2O	[illegible]	1.20	3.84	50.04	1900.70	10000.00	11900.70	17.79	0.00	13.60
CO_2	[illegible]	.61	.72	31.73	71.18	0.00	71.18	31.37	0.00	23.99
CO	[illegible]	.36	.37	25.27	59.43	0.00	59.43	31.45	0.00	24.06
C_1	[illegible]	2.67	2.89	3045.11	6358.47	0.00	6358.47	3216.12	356.58	2460.02
C_2=	[illegible]	.19	.22	12.82	28.91	0.00	28.91	12.82	0.00	9.80
C_2	[illegible]	.47	.55	113.21	255.95	0.00	255.85	108.45	0.00	82.95
C_3=	.0[illegible]	.16	.21	17.61	37.36	0.00	37.36	11.70	0.00	8.95
C_3	.03	.09	.12	70.45	150.28	0.00	150.28	45.74	0.00	34.98
nC_4	.16	.20	.36	61.19	122.46	0.00	122.46	22.28	0.00	17.04
IBP-200P	0.00	0.00	0.00	331.55	628.86	0.00	628.86	31.43	0.00	24.04
200-300P	0.[illegible]	0.00	0.00	363.29	675.87	0.00	675.87	3.57	0.00	2.73
300-430P	0.00	0.00	0.00	603.30	1120.15	0.00	1120.15	.68	0.00	.52
430-550P	0.00	0.00	0.00	476.47	884.46	0.00	884.46	.03	0.00	.02
550-650P	0.00	0.00	0.00	341.32	633.58	0.00	633.58	.00	0.00	.00
650 Plus	0.00	0.00	0.00	357.97	664.48	0.00	664.48	.00	0.00	.00
IBP-400F	57.20	2.78	59.98	59.98	0.00	0.00	0.00	0.00	0.00	0.00
400-500F	69.83	21.38	91.21	91.21	0.00	0.00	0.00	0.00	0.00	0.00
500-600F	1.44	90.07	91.73	91.73	0.00	0.00	0.00	0.00	0.00	0.00
600-750F	.00	185.44	185.45	185.45	0.00	0.00	0.00	0.00	0.00	0.00
750-950F	0.00	236.31	236.31	236.31	0.00	0.00	0.00	0.00	0.00	0.00
950 Plus	0.00	461.16	461.16	461.16	0.00	0.00	0.00	0.00	0.00	0.00
TOTAL	132.19	1004.44	1136.63	26888.57	33976.23	10000.00	43976.23	14309.00	11885.88	10945.00
LB/HR	18520.32	381018.32	399538.63	964206.72	1085948.94	180160.00	1766108.94	121742.22	32054.57	93121.02
BBLS/DAY	1353.46	23086.71	24440.17			12361.32				
MSCFD								130326.37	108256.59	99687.06
MOL WT	140.10	379.33	351.51	35.86	31.96	18.02	28.79	8.51	2.70	8.51
API	19.20	-6.52	-5.33			10.00				

STREAM NO.	11 HP PURGE GAS	12 HP SEPARATOR SOUR WATER	13 HP SEPARATOR TOTAL HC LIQUID	14 1ST IP SEPARATOR VAPOR	15 1ST IP SEP/ SOUR WA'
H_2	322.20	0.00	347.58	230.36	0.00
N_2	47.08	0.00	97.00	50.34	0.00
NH_3	0.00	307.85	0.00	0.00	0.00
H_2S	0.00	244.59	0.00	0.00	0.00
H_2O	.61	11806.23	62.46	1.05	.91
CO_2	1.07	0.00	14.74	1.71	0.00
CO	1.08	0.00	2.85	1.28	0.00
C_1	110.21	0.00	572.12	153.32	0.00
C_2=	.44	0.00	5.85	.66	0.00
C_2	3.72	0.00	60.73	5.60	0.00
C_3=	.40	0.00	16.31	.62	0.00
C_3	1.57	0.00	67.99	2.38	0.00
nC_4	.76	0.00	82.38	1.10	0.00
IBP-200P	1.08	0.00	572.31	1.50	0.00
200-300P	.12	0.00	669.45	.16	0.00
300-430P	.02	0.00	1118.93	.03	0.00
430-550P	.00	0.00	884.41	.00	0.00
550-650P	.00	0.00	633.58	.00	0.00
650 Plus	.00	0.00	664.48	.00	0.00
IBP-400F	0.00	0.00	0.00	0.00	0.00
400-500F	0.00	0.00	0.00	0.00	0.00
500-600F	0.00	0.00	0.00	0.00	0.00
600-750F	0.00	0.00	0.00	0.00	0.00
750-950F	0.00	0.00	0.00	0.00	0.00
950 Plus	0.00	0.00	0.00	0.00	0.00
TOTAL	490.36	12358.67	5873.19	450.11	.91
LB/HR	4172.01	226280.61	820793.08	4973.62	16.44
BBLS/DAY		15910.20	65055.87		1.13
MSCFD	4466.18			4099.58	
MOL WT	8.51	18.32	139.75	11.05	18.02
API		13.50	31.93		10.00

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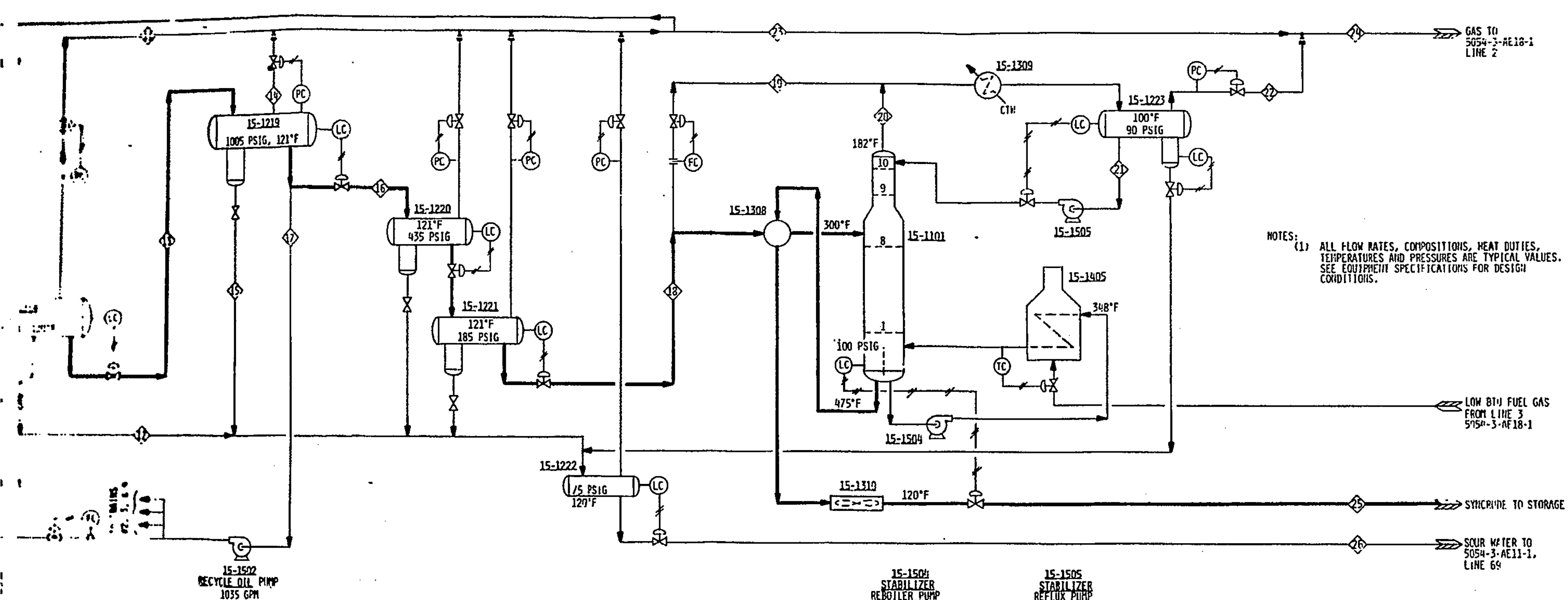
15-1218	15-1219	15-1220	15-1221	15-1222	15-1308	15-1309	15-1101	15-1310	15-1405	15-1223
[illegible]	1ST IP SEPARATOR 10'-6" I.D. x 44'-0"	2ND IP SEPARATOR 8'-0" I.D. x 32' 0"	LP SEPARATOR 8'-0" I.D. x 32'-0"	SOUR WATER DRUM 4'-6" I.D. x 16'-0"	STABILIZER FEED-BOTTOMS EXCHANGER 75.92 MMBTU/HR	STABILIZER OVERHEAD CONDENSER 2.45 MMBTU/HR	STABILIZER TOP 3'-6" I.D. x 6'-0" BOTTOM 7'-0" I.D. x 28'-0"	STABILIZER BOTTOMS COOLER 43.07 MMBTU/HR	STABILIZER REBOILER 47.80 MMBTU/HR	STABILIZER OVERHEAD ACCUMULATOR 5'-0" I.D. x 24'-0"



NOTES:
(1) ALL FLOW RATES, COMPOSITIONS, HEAT DUTIES, TEMPERATURES AND PRESSURES ARE TYPICAL VALUES. SEE EQUIPMENT SPECIFICATIONS FOR DESIGN CONDITIONS.

15-1504
STABILIZER
REBOILER PUMP
1252 GPM

15-1505
STABILIZER
REFLUX PUMP
243 GPM

[illegible]	13 HP SEPARATOR TOTAL HC LIQUID	14 1ST IP SEPARATOR VAPOR	15 1ST IP SEPARATOR SOUR WATER	16 1ST IP SEPARATOR HC LIQUID	17 RECYCLE OIL	18 LP SEPARATOR HC LIQUID	19 COLD FEED
[illegible]	[illegible]	230.36	0.00	54.07	63.15	2.84	.71
[illegible]	[illegible]	50.34	0.00	21.52	25.14	2.61	.65
[illegible]	[illegible]	0.00	0.00	0.00	0.00	0.00	0.00
[illegible]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
[illegible]	[illegible]	1.05	.91	27.91	32.60	26.61	6.65
[illegible]	[illegible]	1.71	0.00	6.01	7.02	4.21	1.05
[illegible]	[illegible]	1.28	0.00	.73	.85	.13	.03
[illegible]	[illegible]	153.32	0.00	193.19	225.62	77.85	19.46
[illegible]	[illegible]	.66	0.00	2.40	2.80	1.72	.43
[illegible]	[illegible]	5.60	0.00	25.43	29.70	19.47	4.87
[illegible]	[illegible]	.62	0.00	7.24	8.45	6.52	1.63
[illegible]	[illegible]	2.38	0.00	30.27	35.35	27.54	6.89
[illegible]	[illegible]	1.10	0.00	37.49	43.79	36.31	9.08
[illegible]	[illegible]	1.50	0.00	263.30	307.51	261.73	65.43
[illegible]	[illegible]	.16	0.00	308.73	360.56	308.56	77.14
[illegible]	[illegible]	.03	0.00	516.17	602.78	516.10	129.02
[illegible]	[illegible]	.00	0.00	407.96	476.45	407.96	101.99
[illegible]	[illegible]	.00	0.00	292.25	341.32	292.25	73.06
[illegible]	[illegible]	.00	0.00	306.51	357.97	306.51	76.63
[illegible]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
[illegible]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
[illegible]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
[illegible]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
[illegible]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
[illegible]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
[illegible]	[illegible]	450.11	.91	2501.12	2921.06	2290.92	574.73
[illegible]	[illegible]	4973.62	16.44	376310.85	439492.50	373157.66	93289.41
[illegible]	[illegible]		1.13	29423.03	34363.12	28755.17	7188.79
[illegible]	[illegible]	6099.50	18.02	160.46	150.46	162.32	162.32
[illegible]	[illegible]	11.05	10.00	29.72	29.72	27.39	27.39

[illegible]	20 TOWER OVERHEAD	21 REFLUX	22 OVERHEAD VAPOR	23 H_2 TREATING PURGE GAS	24 TOTAL PURGE GAS	25 STRIPPER BOTTOMS	26 TOTAL SOUR WATER
[illegible]	2.16	.03	2.84	603.79	606.63	.00	0.00
[illegible]	2.48	.53	2.61	116.34	118.94	.00	0.00
[illegible]	0.00	0.00	0.00	0.00	0.00	0.00	307.85
[illegible]	0.00	0.00	0.00	0.00	0.00	0.00	244.59
[illegible]	20.58	2.59	5.64	2.96	8.60	1.97	11826.15
[illegible]	5.25	2.09	4.20	4.59	8.79	.00	0.00
[illegible]	.12	.03	.13	2.95	3.08	.00	0.00
[illegible]	74.89	36.50	77.85	378.87	456.72	.00	0.00
[illegible]	2.23	.94	1.72	1.77	3.49	.00	0.00
[illegible]	27.94	33.38	19.43	35.28	34.71	.04	0.00
[illegible]	16.69	32.27	6.05	1.74	7.79	.47	0.00
[illegible]	73.17	55.61	24.44	6.67	31.11	3.10	0.00
[illegible]	31.92	36.94	6.06	3.04	9.10	30.26	0.00
[illegible]	20.09	83.00	7.52	4.14	6.67	259.21	0.00
[illegible]	1.84	78.82	.16	.45	.61	308.40	0.00
[illegible]	.36	129.36	.02	.08	.10	516.08	0.00
[illegible]	.02	102.01	.00	.00	.00	407.96	0.00
[illegible]	.00	73.06	.00	.00	.00	292.25	0.00
[illegible]	.00	76.63	.00	.00	.00	306.51	0.00
[illegible]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
[illegible]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
[illegible]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
[illegible]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
[illegible]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
[illegible]	0.00	0.00	0.00	0.00	0.00	0.00	0.00
[illegible]	281.73	683.80	153.66	1142.67	1296.34	2126.25	12378.59
[illegible]	10348.84	99164.92	4131.03	12299.43	16429.46	368684.32	226639.36
[illegible]		7894.45				28056.65	15934.81
[illegible]	2566.03	145.02	1399.57	10407.46	11807.03	173.40	18.31
[illegible]	36.73	32.65	26.88	10.76	12.67	25.42	13.49

6-10

DRAWN A.M.L.	PROCESS FLOW DIAGRAM UNIT 15-1 OIL HYDROTREATING CONCEPTUAL COMMERCIAL COED PLANT DESIGN	
CHECK		
PROCESS ENGR R.T.N.		
CH PROC ENGR N.E.T.		
CH OPER ENGR		
PROJECT ENGR	THE RALPH M. PARSONS COMPANY LOS ANGELES	5054 3 AE15 1
CHIEF ENGR.		REV 0
DATE 10-10-74		

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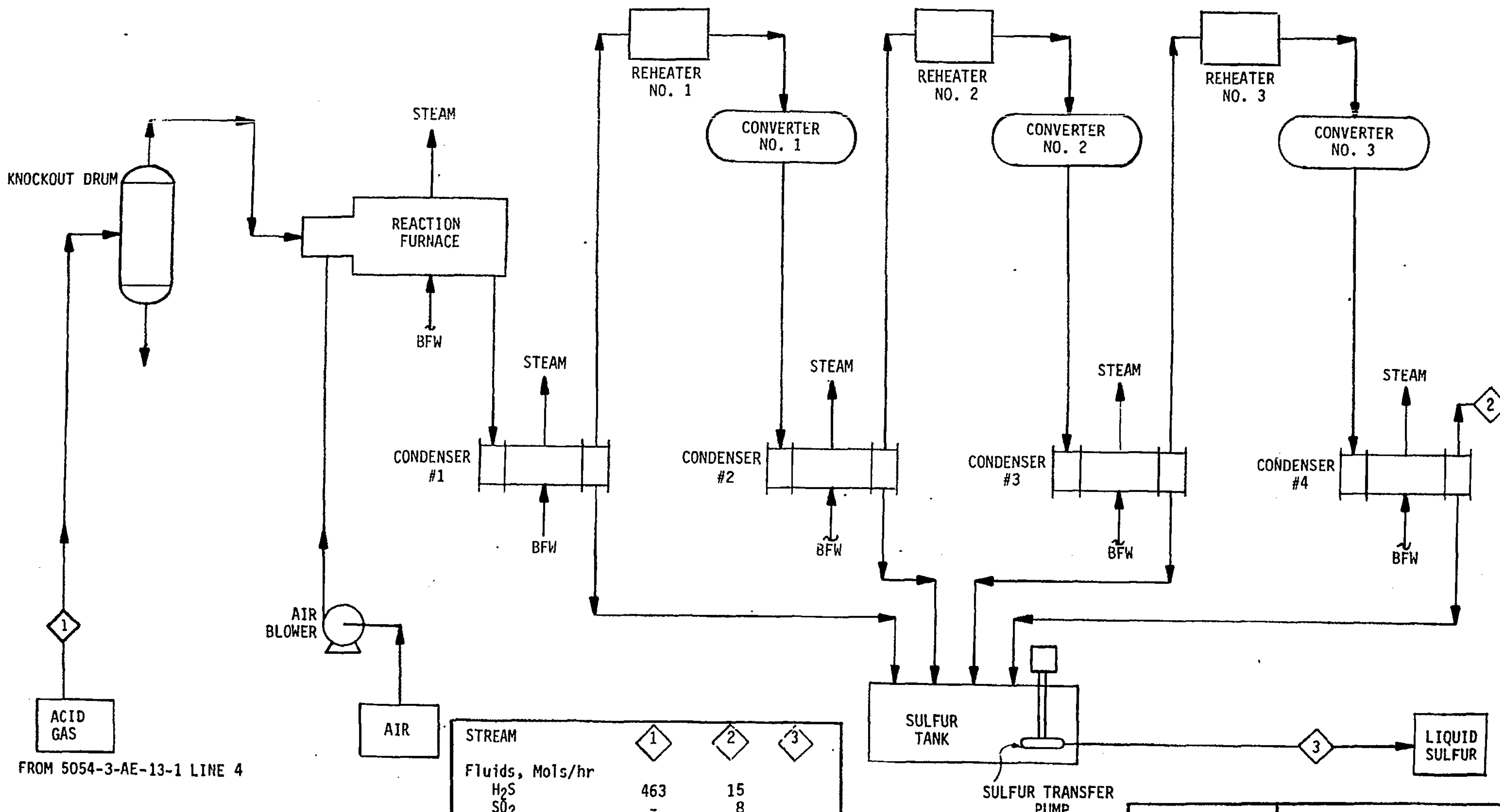

STREAM	1	2	3
Fluids, Mols/hr			
H_2S	463	15	
SO_2	-	8	
CO_2	773	774	
CH_4	1	-	
N_2	-	877	
H_2O	54	508	
Total	1291	2182	
LB/HR	50797	68780	
Solids, LB/HR			
Sulfur			14100

UNIT CAPACITY 418 LT/D

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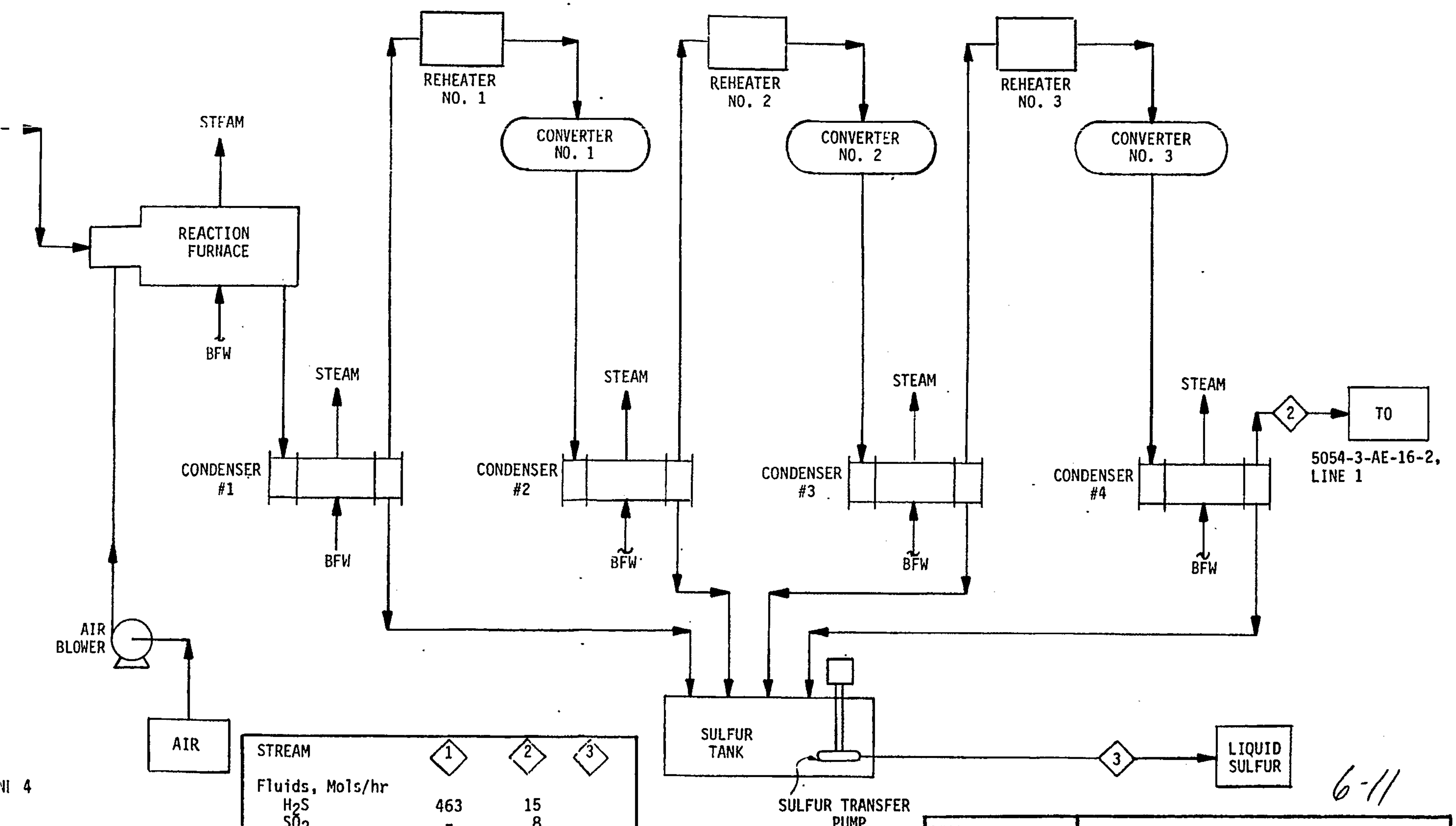
DRAWN	
CHECK	
PROCESS ENGR.	CLB
CH. PROC. ENGR.	NEJ
CH. OPER. ENGR.	
PROJECT ENGR.	[illegible]
CH. DES. ENGR.	
DATE	10-10-74

PROCESS FLOW DIA
UNIT 16-1
SULFUR RECOVERY
CONCEPTUAL COMMER
COED PLANT DESI

THE RALPH M PARSONS COMPANY
LOS ANGELES

DRAW
5054-3-



STREAM	1	2	3
Fluids, Mols/hr			
H_2S	463	15	
SO_2	-	8	
CO_2	773	774	
CH_4	1	-	
N_2	-	877	
H_2O	54	508	
Total	1291	2182	
LB/HR	50797	68780	
Solids, LB/HR			
Sulfur			14100

UNIT CAPACITY 418 LT/D .

6-11

DRAWN	
CHECK	
PROCESS ENGR.	CLB
CH. PROC. ENGR.	N&J
CH. OPER. ENGR.	
PROJECT ENGR.	[illegible]
CH. DES. ENGR.	
DATE	10-10-74

PROCESS FLOW DIAGRAM
UNIT 16-1
SULFUR RECOVERY UNIT
CONCEPTUAL COMMERCIAL
COED PLANT DESIGN

THE RALPH M PARSONS COMPANY
LOS ANGELES

DRAWING NO. 5054-3-AE-16-1
REV. 0

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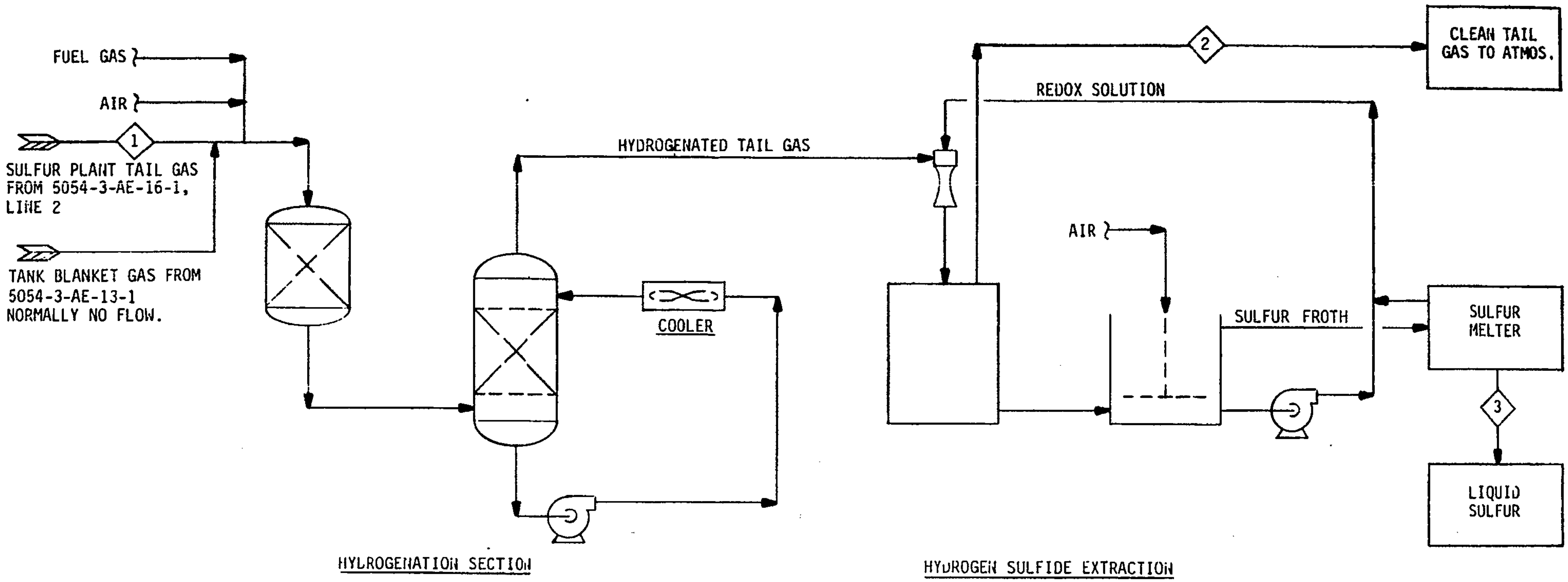

STREAM	1	2	3
Fluids, Mols/Hr.			
H_2S	15	(1 ppm.	-
SO_2	8	-	-
CO_2	774	774	-
N_2	877	877	-
H_2O	508	106	
Total	2182	1757	
Lb/Hr.	68783	60520	
Solids, Lb/Hr.			
Sulfur			740

UNIT CAPACITY 18-1/2 LT/D

A

6-12

NOTE: THIS PROCESS ILLUSTRATED IS ONE OF SEVERAL PROPRIETARY PROCESSES AVAILABLE FOR THE FURPOSE INTENDED.

DRAWN	PROCESS FLOW DIAGRAM UNIT 16-2 TAIL GAS SULFUR REMOVAL CONCEPTUAL COMMERCIAL COED PLANT DESI
CHECK	
PROCESS ENGR	
CH PROC ENGR	
CH OPER ENGR.	
PROJECT ENGR	THE RALPH M PARSONS COMPANY LOS ANGELES
CH DES ENGR.	DRAWING NO 5054-3-AE-16-2
DATE	

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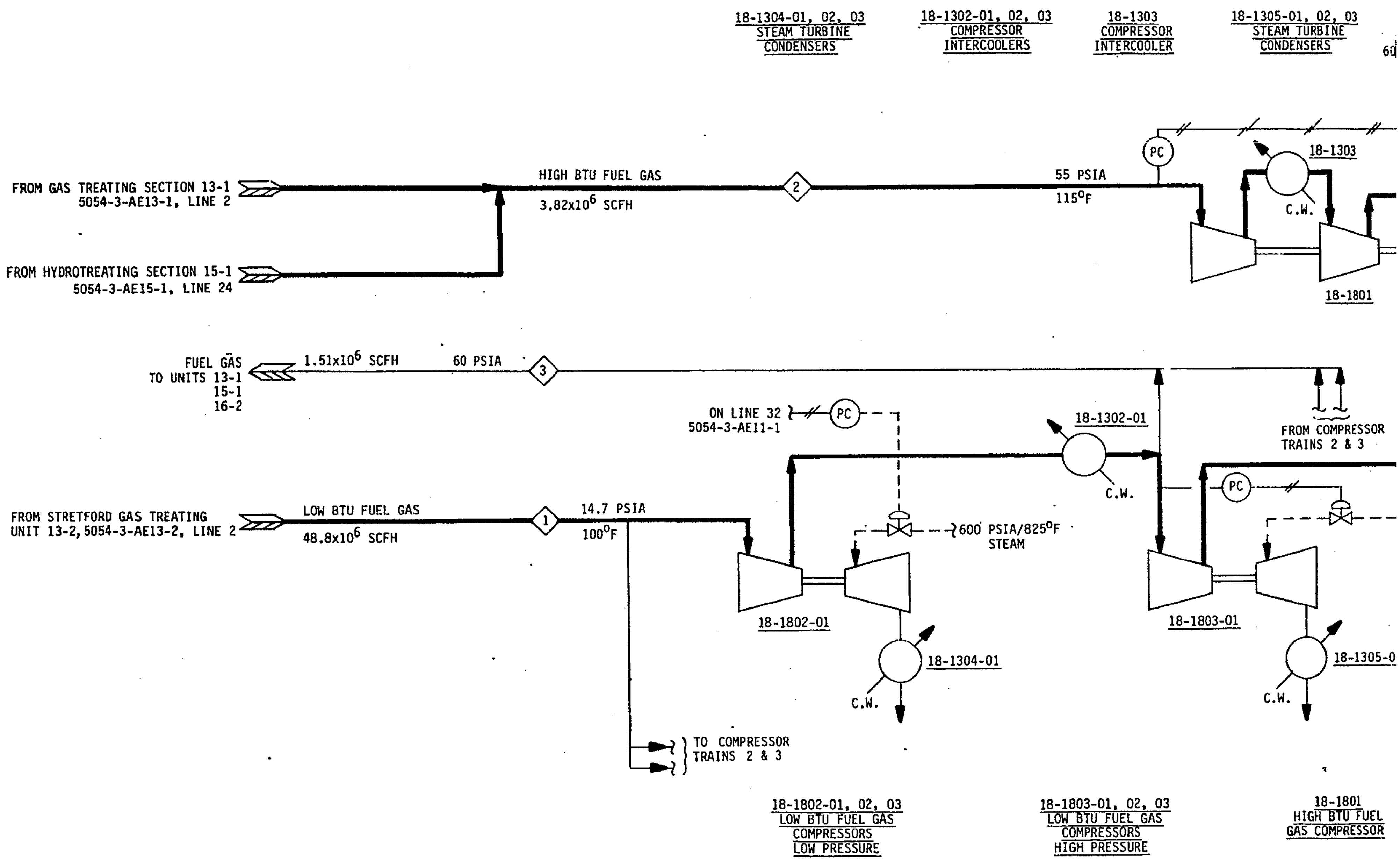

18-1304-01, 02, 03
STEAM TURBINE
CONDENSERS
18-1302-01, 02, 03
COMPRESSOR
INTERCOOLERS
18-1303
COMPRESSOR
INTERCOOLER
18-1305-01, 02, 03
STEAM TURBINE
CONDENSERS
FROM GAS TREATING SECTION 13-1
5054-3-AE13-1, LINE 2
FROM HYDROTREATING SECTION 15-1
5054-3-AE15-1, LINE 24
HIGH BTU FUEL GAS
3.82x10^6 SCFH
2
55 PSIA
115°F
PC
18-1303
C.W.
18-1801
FUEL GAS
TO UNITS 13-1
15-1
16-2
1.51x10^6 SCFH
60 PSIA
3
ON LINE 32
5054-3-AE11-1
PC
18-1302-01
C.W.
FROM COMPRESSOR
TRAINS 2 & 3
PC
FROM STRETFORD GAS TREATING
UNIT 13-2, 5054-3-AE13-2, LINE 2
LOW BTU FUEL GAS
48.8x10^6 SCFH
1
14.7 PSIA
100°F
600 PSIA/825°F
STEAM
18-1802-01
18-1803-01
18-1304-01
C.W.
18-1305-0
C.W.
TO COMPRESSOR
TRAINS 2 & 3
18-1802-01, 02, 03
LOW BTU FUEL GAS
COMPRESSORS
LOW PRESSURE
18-1803-01, 02, 03
LOW BTU FUEL GAS
COMPRESSORS
HIGH PRESSURE
18-1801
HIGH BTU FUEL
GAS COMPRESSOR

60
A
B

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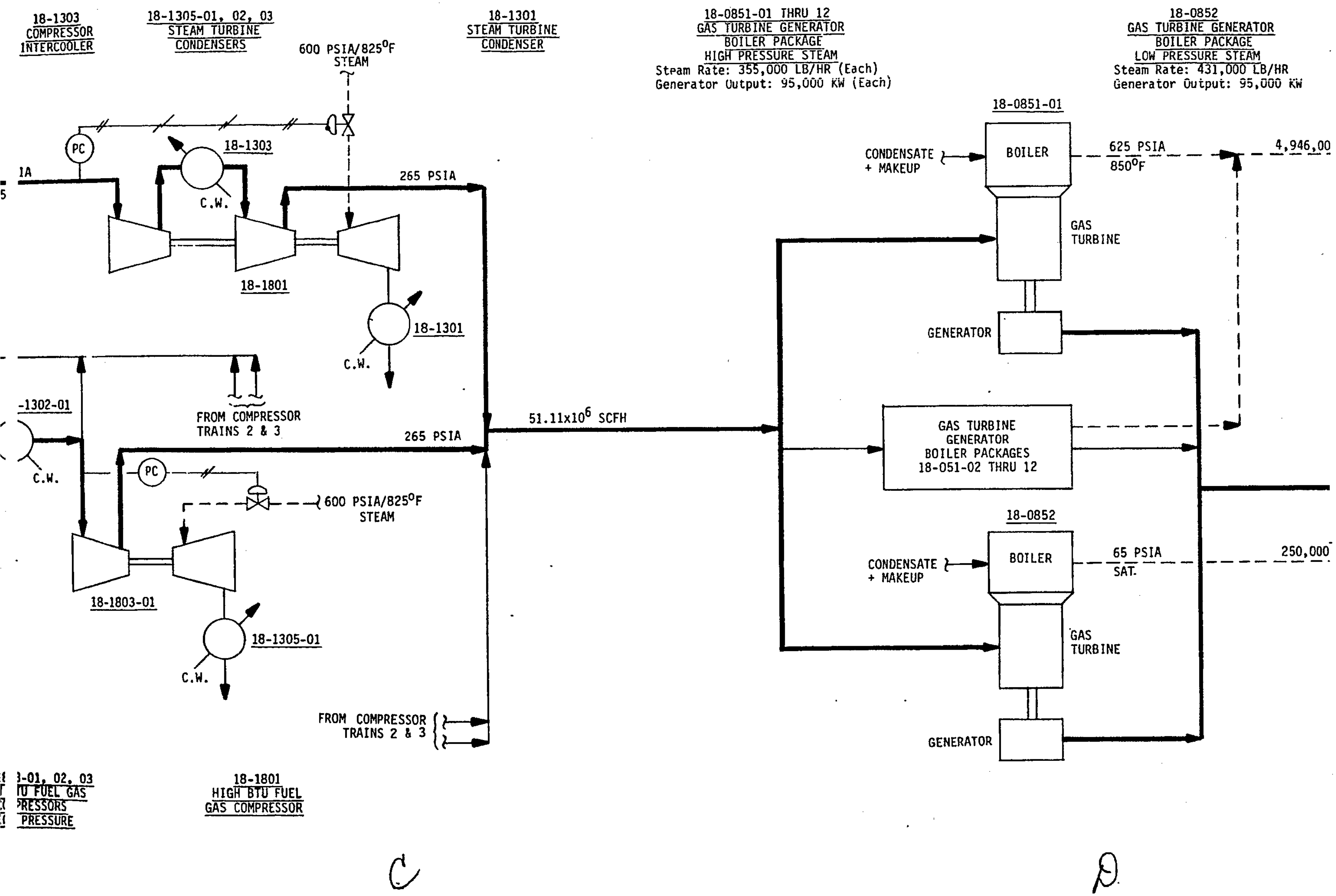

18-1303
COMPRESSOR
INTERCOOLER
18-1305-01, 02, 03
STEAM TURBINE
CONDENSERS
600 PSIA/825°F
STEAM
18-1301
STEAM TURBINE
CONDENSER
18-0851-01 THRU 12
GAS TURBINE GENERATOR
BOILER PACKAGE
HIGH PRESSURE STEAM
Steam Rate: 355,000 LB/HR (Each)
Generator Output: 95,000 KW (Each)
18-0852
GAS TURBINE GENERATOR
BOILER PACKAGE
LOW PRESSURE STEAM
Steam Rate: 431,000 LB/HR
Generator Output: 95,000 KW
PC
18-1303
1A
265 PSIA
C.W.
18-1801
18-1301
C.W.
-1302-01
FROM COMPRESSOR
TRAINS 2 & 3
265 PSIA
C.W.
PC
600 PSIA/825°F
STEAM
18-1803-01
18-1305-01
C.W.
FROM COMPRESSOR
TRAINS 2 & 3
51.11x10^6 SCFH
18-0851-01
CONDENSATE
+ MAKEUP
BOILER
625 PSIA
850°F
4,946,00
GAS
TURBINE
GENERATOR
GAS TURBINE
GENERATOR
BOILER PACKAGES
18-051-02 THRU 12
18-0852
CONDENSATE
+ MAKEUP
BOILER
65 PSIA
SAT.
250,000
GAS
TURBINE
GENERATOR
-01, 02, 03
U FUEL GAS
RESSORS
PRESSURE
18-1801
HIGH BTU FUEL
GAS COMPRESSOR
C
D

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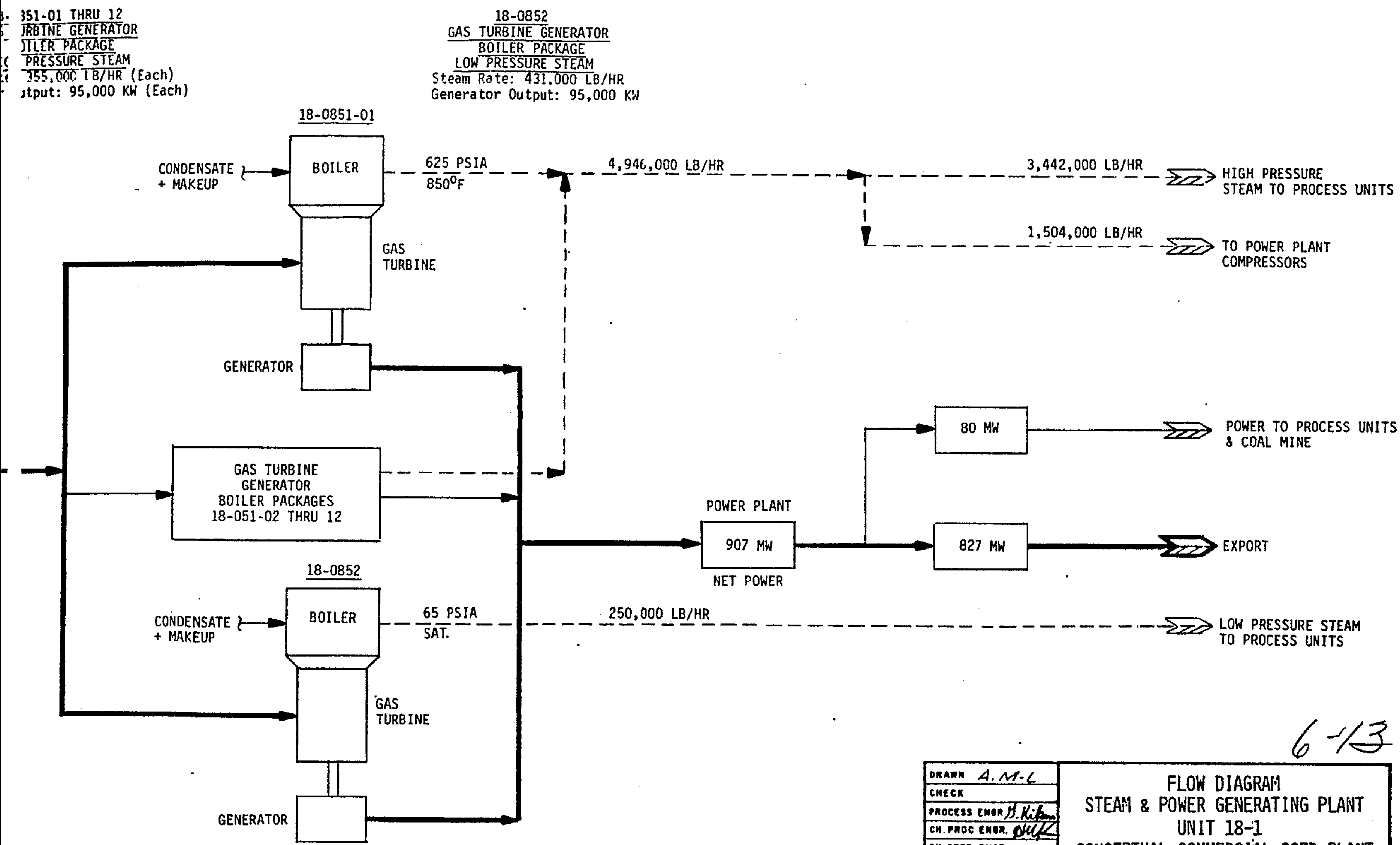

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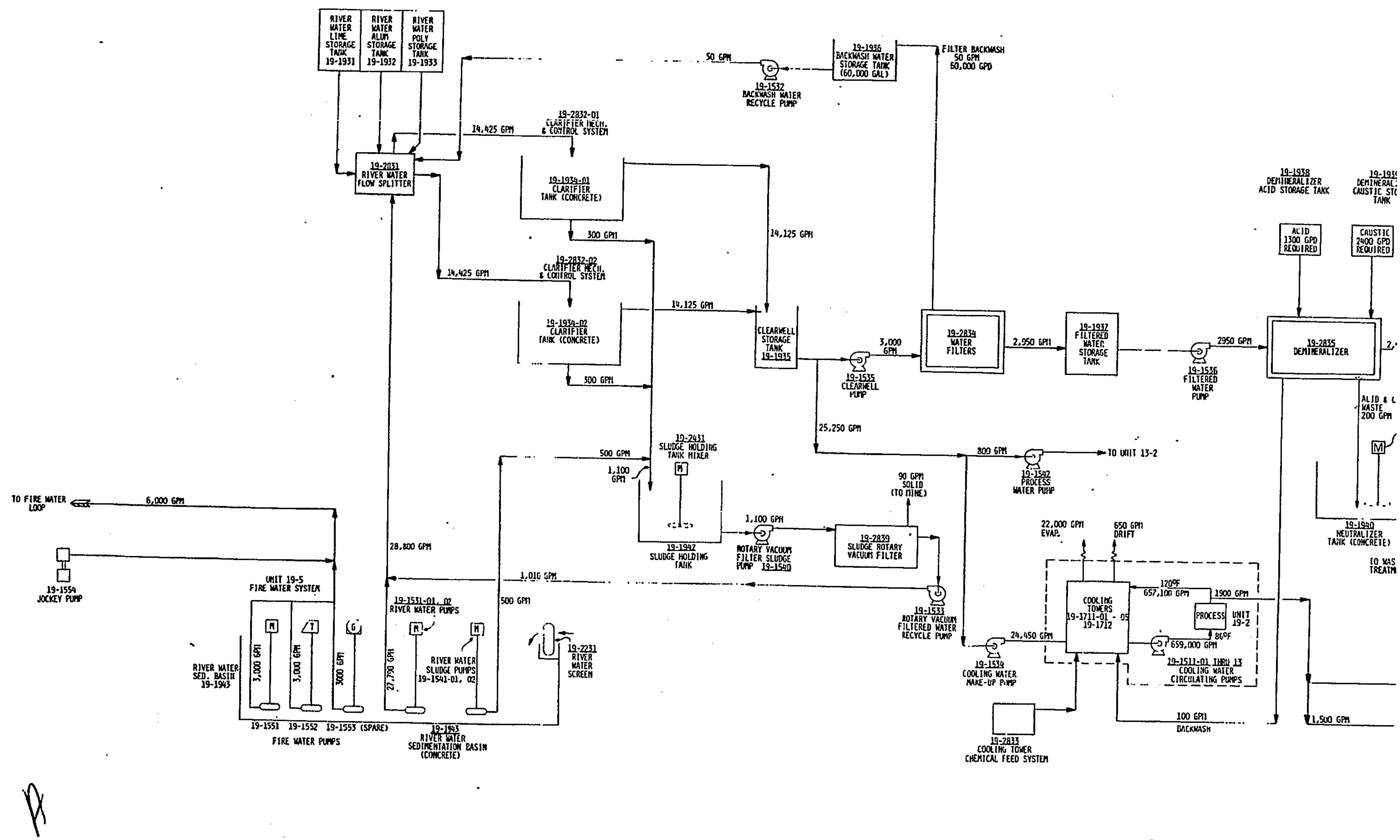
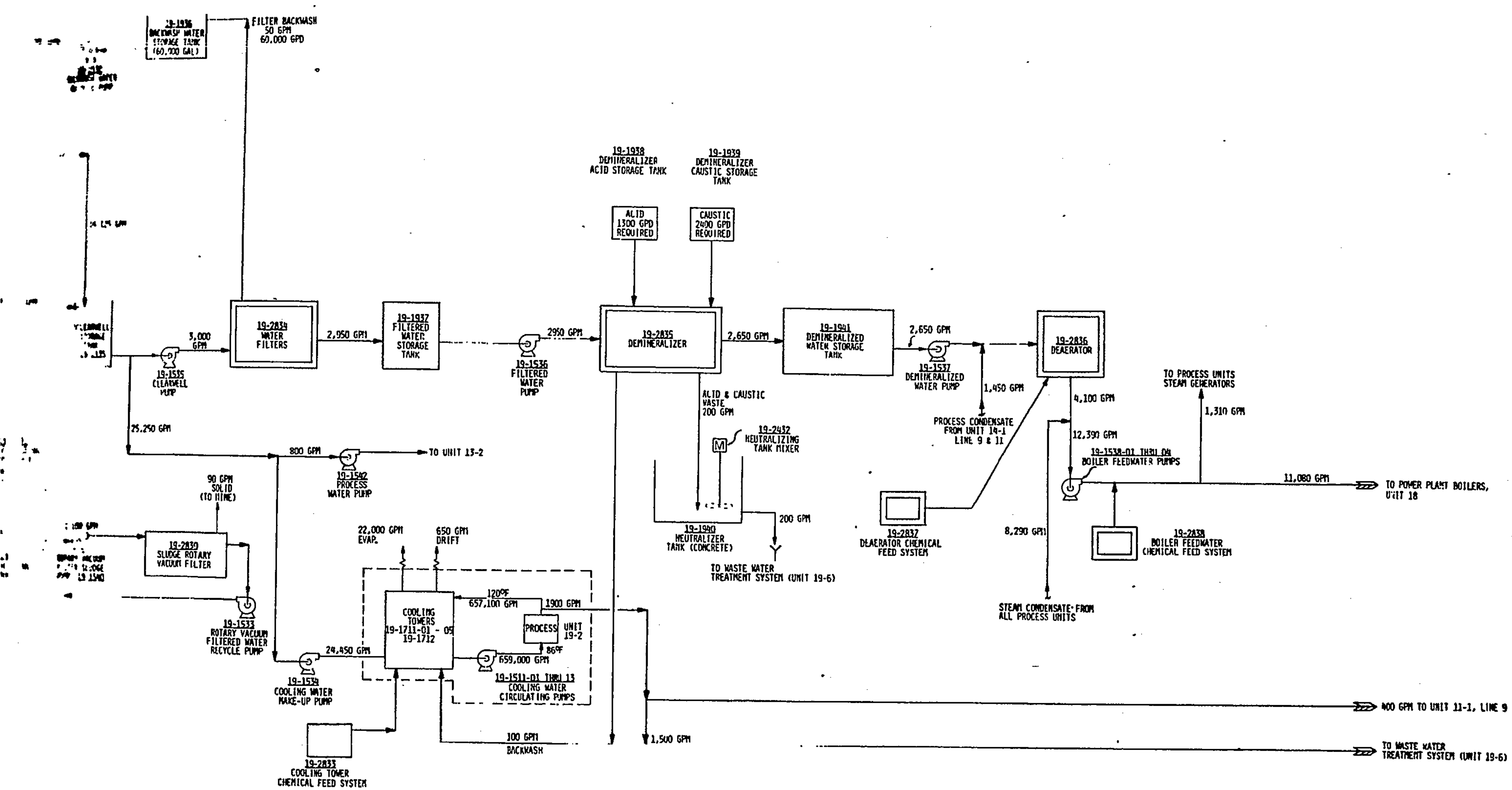
DRAWN A.M-L	FLOW DIAGRAM STEAM & POWER GENERATING PLANT UNIT 18-1 CONCEPTUAL COMMERCIAL COED PLANT	
CHECK		
PROCESS ENGR B. Kibm		
CH. PROC ENGR.		
CH OPER ENGR.		
PROJECT ENGR.	THE RALPH M PARSONS COMPANY LOS ANGELES	DRAWING NO. 5054-3-AE-18-1 / REV. 0
CH DES ENGR.		
DATE 10-10-74		

D

E


RIVER WATER LIME STORAGE TANK 19-1931
RIVER WATER ALUM STORAGE TANK 19-1932
RIVER WATER POLY STORAGE TANK 19-1933
19-2831 RIVER WATER FLOW SPLITTER
14,425 GPM
19-2832-01 CLARIFIER MECH. & CONTROL SYSTEM
19-1934-01 CLARIFIER TANK (CONCRETE)
300 GPM
14,425 GPM
19-2832-02 CLARIFIER MECH. & CONTROL SYSTEM
19-1934-02 CLARIFIER TANK (CONCRETE)
300 GPM
14,125 GPM
14,125 GPM
50 GPM
19-1532 BACKWASH WATER RECYCLE PUMP
19-1936 BACKWASH WATER STORAGE TANK (60,000 GAL)
FILTER BACKWASH 50 GPM 60,000 GPD
CLEARWELL STORAGE TANK 19-1935
3,000 GPM
19-1535 CLEARWELL PUMP
19-2834 WATER FILTERS
2,950 GPM
19-1937 FILTERED WATER STORAGE TANK
2950 GPM
19-1536 FILTERED WATER PUMP
19-2835 DEMINERALIZER
19-1938 DEMINERALIZER ACID STORAGE TANK
ACID 1300 GPD REQUIRED
19-1939 DEMINERALIZER CAUSTIC STORAGE TANK
CAUSTIC 2400 GPD REQUIRED
ACID & CAUSTIC WASTE 200 GPM
19-1940 NEUTRALIZER TANK (CONCRETE)
TO WASTE TREATMENT
25,250 GPM
800 GPM
19-1592 PROCESS WATER PUMP
TO UNIT 13-2
500 GPM
1,100 GPM
19-2431 SLUDGE HOLDING TANK MIXER
19-1942 SLUDGE HOLDING TANK
1,100 GPM
ROTARY VACUUM FILTER SLUDGE PUMP 19-1540
19-2839 SLUDGE ROTARY VACUUM FILTER
90 GPM SOLID (TO MINE)
19-1533 ROTARY VACUUM FILTERED WATER RECYCLE PUMP
1,016 GPM
TO FIRE WATER LOOP
6,000 GPM
19-1554 JOCKEY PUMP
UNIT 19-5 FIRE WATER SYSTEM
3,000 GPM
3,000 GPM
3000 GPM
19-1551 19-1552 19-1553 (SPARE)
FIRE WATER PUMPS
RIVER WATER SED. BASIN 19-1943
28,800 GPM
27,790 GPM
19-1531-01, 02 RIVER WATER PUMPS
RIVER WATER SLUDGE PUMPS 19-1541-01, 02
500 GPM
19-1943 RIVER WATER SEDIMENTATION BASIN (CONCRETE)
19-2231 RIVER WATER SCREEN
22,000 GPM EVAP.
650 GPM DRIFT
COOLING TOWERS 19-1711-01 - 05 19-1712
120°F 657,100 GPM
1900 GPM
PROCESS
UNIT 19-2
80°F
659,000 GPM
19-1511-01 THRU 13 COOLING WATER CIRCULATING PUMPS
24,450 GPM
19-1534 COOLING WATER MAKE-UP PUMP
19-2833 COOLING TOWER CHEMICAL FEED SYSTEM
100 GPM BACKWASH
1,500 GPM
A
B



DRAWN R. ROWE	INDUSTRIAL WATER SYSTEM SCHEMATIC UNIT 19-3 CONCEPTUAL COMMERCIAL COED PLANT DESIGN
	THE RALPH M. PARSONS COMPANY LOS ANGELES
	5054-3-AE19-3 2

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SECTION 7

MATERIAL BALANCE

The overall material balance for the process sections of the complex is depicted in Figure 7-1. The balance is for a typical feed coal composition.

The Figure 7-1 balance reflects the portion of the complex which converts 24,487 TPD of moisture-free coal to a product slate consisting of:

(1) High-Btu gas ($\approx 890 \frac{Btu}{scf}$ HHV)

(2) Low-Btu gas ($\approx 250 \frac{Btu}{scf}$ HHV)

(3) Syncrude

(4) Sulfur

(5) CO_2 + ventgas

(6) Ash

The total weight of these products for the typical case is 45,080 TPD.

The revenue-producers are syncrude, electricity, and sulfur. The high- and low-Btu gases from the process sections are used to produce the export electricity as well as the steam and electricity required to operate the COED-based complex.

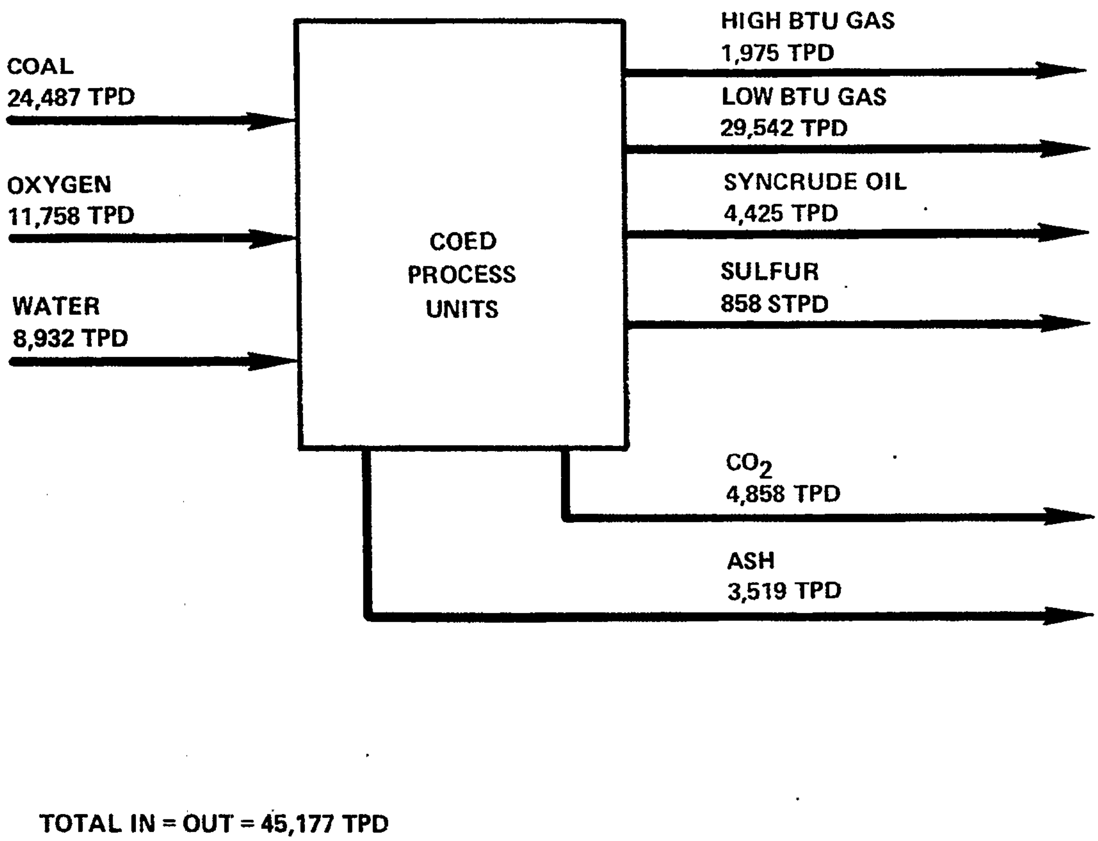

Figure 7-1 - Overall Material Balance - Typical Operation for Process Sections

SECTION 8

UTILITIES

All utilities needed for operation of the COED Conceptual Complex will be produced onsite utilizing a portion of the energy contained in the feed coal. In addition utilities require a significant amount of water for consumption.

The utilities required for all operations in the complex include three types of steam which have the following characteristics: (1) 600 psi/825°F, (2) 165 psia/saturated, and (3) 65 psia/saturated. The electrical requirements include power delivery at 13.8, 4.16 kV, 440 and 120/240 volts, 60 hertz. The cooling water supply is to be at 86°F. Boiler feedwater is also required.

The Utility Summary presented in Table 8-1 tabulates the various utility requirements based on typical feed-coal composition.

In some of the units, condensate is produced during normal operation; this results from condensation of turbine exhaust or heating steam. In other units, steam is generated at one of the pressure-temperature conditions in the course of process stream cooling. These generated quantities are shown in Table 8-1. Approximately 95% of the total steam required will be produced in the power plant. Gas turbines burning gas produced onsite from the coal exhaust through heat recovery boilers which generate steam at 600 psia/825°F and 65 psia saturated. The relatively lesser quantity of 165 psia steam required will be produced by letting down some of the 600 psia steam produced in the oil hydrotreating unit. The balance of this 600 psia saturated steam is superheated in the power plant and added to the 600 psia/825°F system.

Makeup for cooling water, boiler feedwater, and process water is derived from river water and suitably treated onsite as described under Unit 19-3 in Section 5.

Electrical power is generated in the power plant utilizing the gas produced in the process units for fuel (refer to Steam and Power Generating Plant, Unit 18-1 in Section 5).

Table 8-1 - Utility Summary

Unit Number	Unit Description	600-psia Steam at 825°F (lb/hr)	165-psia Steam at Saturation[c] (lb/hr)	65-psia Steam at Saturation (lb/hr)	15-psig Steam at Saturation (lb/hr)	Condensate (lb/hr)	Boiler Feedwater (lb/hr)	Cooling Water (gpm)	Electrical Power (MW)	Fuel Gas (MM Btu/hr)	Water Makeup (gpm)	Type of Water Makeup
Unit 10-1	Coal Mine								16.6			
Unit 10-2	Coal Preparation								2.6			
Unit 11-1	Pyrolysis and Gasification	89,000		343,000		(89,000)		71,900 500[f]	3.0		500	Cooling Water Blowdown to Process
Unit 11-2	Oil-Vapor Recovery	310,000	6,000			(310,000)		28,000	1.4			
Unit 12-1	Oil Filtration	33,000	1,000	2,000		(33,000)		3,000	0.6			
Unit 13-1	Pyrolysis Gas Treating	44,000		5,000		(44,000)		4,000	1.2	178		
Unit 13-2	Low Btu Gas Treating		77,000						16.1		300	Process Water
Unit 14-1	Hydrogen Plant	997,000	5,500	(20,000)		(376,000)	263,000	27,000	7.8		525	Boiler Feedwater
Unit 14-2	H_2 Plant Tail Gas		12,000			(720,960)[d]						
Unit 15-1	Oil Hydro-Treating	13,000 (200,000)[a,b]	500	(133,000)		180,000 (13,000)	344,000	10,000	2.0	128	690	Boiler Feedwater
Unit 16-1	S_2 Recovery Pyrolysis Gas		(22,000)	10,000	(3,000)		27,000		0.4		55	Boiler Feedwater
Unit 16-2	Tail Gas Treating of 16-1		(11,000)	10,700			12,000		1.0	20	25 15	Boiler Feedwater Process Water
Unit 17-1	Oxygen Plant	1,960,000	35,000	32,000		(1,960,000)		258,000				
Unit 18-1	Power Plant	1,500,000				(1,500,000)	1,000,000	207,000			2,000	Boiler Feedwater
Cooling Tower Pumps									15.0			
Utilities & Offsites							280,000[e]	24,000[g]	12.3		24,000 560 200	Cooling Water Boiler Blowdown Water Treating
Total Consumed		4,946,000	137,000	402,700		180,000	1,926,000	24,500	80.0	326	28,800	
Total Generated		200,000[a]	33,000	153,000	3,000	4,325,000						
Total Net Required		4,946,000	104,000	249,700			1,926,000	24,500	80.0	326	28,800	
Total Net Generated					3,000	4,145,000						
Total Circulated								609,000				

[a]At saturation (not included in total).
[b]Numbers in parentheses indicate "generated".
[c]Taken from 600-psia saturation (see footnote a).
[d]Process condensate requiring deaeration only (not included in total).
[e]Boiler blowdown makeup.
[f]Consumed.
[g]Cooling tower makeup.

SECTION 9

ENERGY BALANCE

The overall energy balance is illustrated in Figure 9-1. All values are based on a typical coal feed and will vary as the characteristics of the coal vary.

Figure 9-1 indicates that of the 25,433 MM Btu/hr energy input from the coal, 15,329 Btu/hr or approximately 60% is consumed within the complex. Energy value of the products for export are also indicated; these total 10,104 MM Btu/hr or approximately 40% of the total energy input. The contributors are:

Product	Energy Content (MM Btu/hr)	% Feed Coal	% Product
COED Syncrude Oil	7,005	28	69
Electrical Power	2,823	11	28
Sulfur	276	1	3
Total	10,104	40	100

Note that the production of electrical power represents about 28% of the exported energy. The energy efficiency for the process of converting fuel gas to electricity for this case is approximately 35%.

Figure 9-2 depicts the estimated thermal efficiency for the process section. The results indicate a thermal efficiency of approximately 58% for the conversion of feed coal to syncrude, fuel gas, and sulfur.

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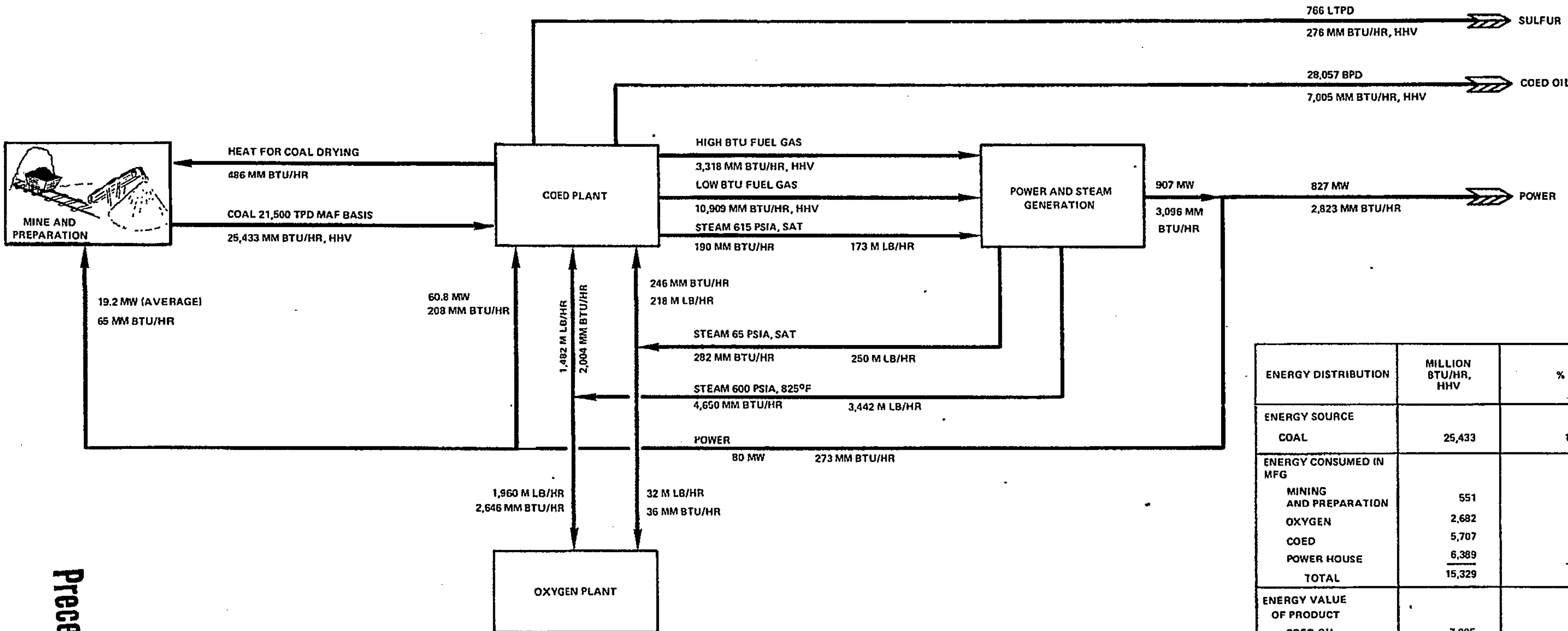

ENERGY DISTRIBUTION	MILLION BTU/HR, HHV	%
ENERGY SOURCE		
COAL	25,433	100.0
ENERGY CONSUMED IN MFG		
MINING AND PREPARATION	551	2.2
OXYGEN	2,682	10.6
COED	5,707	22.4
POWER HOUSE	6,389	25.1
TOTAL	15,329	60.3
ENERGY VALUE OF PRODUCT		
COED OIL	7,005	27.5
EXPORT POWER	2,823	11.1
SULFUR	276	1.1
TOTAL	10,104	39.7

Figure 9-1 - Energy Balance - Conceptual Commercial COED Plant Design

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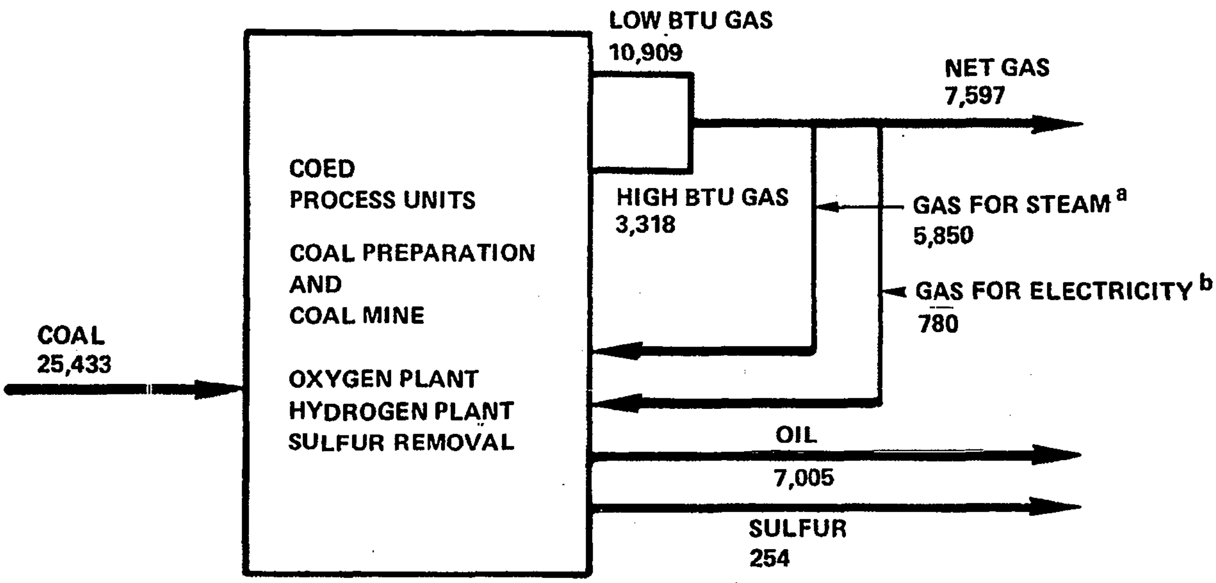

ALL FIGURES ARE MM BTU/HR, HHV

$$\text{THERMAL EFFICIENCY} = \frac{7{,}597 + 7{,}005 + 254}{25{,}433} = 58.4\%$$

a) GAS FOR IN-HOUSE STEAM REQUIRED: $\frac{4{,}970}{0.85\ \text{EFF}} = 5{,}850$

b) GAS FOR IN-HOUSE ELECTRIC POWER REQUIRED: $\frac{80\ \text{MW} \times 3{,}413}{0.35_{\text{EFF}}} = 780$

Figure 9-2 - Thermal Efficiency
Based on Export of Fuel Gas

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