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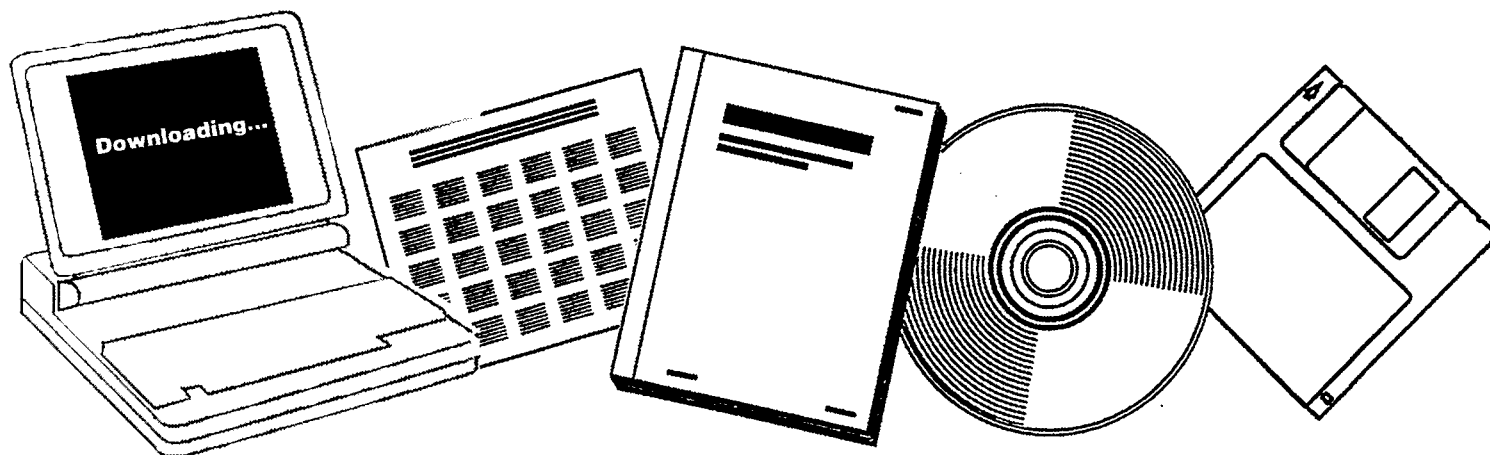
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**MULTI-PROCESS DEMONSTRATION PLANT
PRELIMINARY DESIGN/ECONOMIC EVALUATION. R
AND D REPORT NO. 114, INTERIM REPORT NO. 7**

PARSONS (RALPH M.) CO.
PASADENA, CA

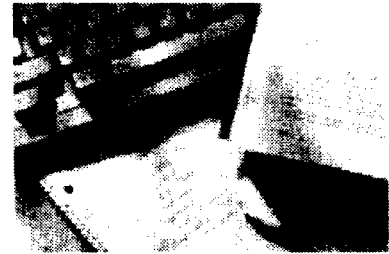
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MULTI-PROCESS DEMONSTRATION PLANT
PRELIMINARY DESIGN/ECONOMIC EVALUATION

R&D REPORT NO. 114, INTERIM REPORT NO. 7

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CONTENTS (Contd)

TABLES

4-1	Products, Projected Quantities, Heating Values, and Process Thermal Efficiencies	4-5
4-2	Plant 3 Fischer-Tropsch Plant Products and Thermal Efficiencies	4-7
5.2-1	Estimated Gasifier Effluent Compositions	5.2-7
6-1	Utilities Summary	6-2
7-1	Combined Gaseous Effluents	7-4
7-2	Comparison of Gaseous Emmissions with Federal, New Mexico, and West Virginia Source Emission Standards . . .	7-6
7-3	Sulfur Balance (lb/hour)	7-7
7-4	New Source Performance Standards for the Petroleum Refining Industry	7-10
7-5	Water Quality Parameters, State of West Virginia	7-11
7-6	Suggested Exposure Guidelines for Metal Carbonyls	7-13
7-7	Mean Analytical Values for 82 Coals from the Illinois Basin	7-14
8-1	Major Equipment Summary Unit 110 - Coal Storage and Handling	8-2
8-2	Major Equipment Summary Unit 111 - Coal Grinding	8-3
8-3	Major Equipment Summary Unit 112 - Low Btu Gasifier . . .	8-4
8-4	Major Equipment Summary Unit 113 - Steam Gencreation . . .	8-6
8-5	Major Equipment Summary Unit 210 - Coal Storage and Handling	8-11
8-6	Major Equipment Summary Unit 211 - Coal Grinding	8-12
8-7	Major Equipment Summary Unit 212 - Medium Pressure Gasifier	8-13
8-8	Major Equipment Summary Unit 213 - Medium Pressure Gasifier Heat Recovery	8-17
8-9	Major Equipment Summary Unit 217 - Process Water Reclamation	8-21
8-10	Major Equipment Summary Unit 241 - Power Plant	8-26
8-11	Major Equipment Summary Unit 311 - Coal Grinding	8-29
8-12	Major Equipment Summary Unit 335 - Intermediate Storage	8-30
8-13	Major Equipment Summary Unit 336 - Product Storage and Shipping Facilities	8-32
9-1	Plants 1, 2 and 3 - Estimated Fixed Capital Investment	9-13
9-2	Total Initial Capital Requirement	9-14
9-5	Plant 1 Catalyst and Chemicals Requirement	9-14
	Plant 2 Catalyst and Chemicals Requirement	9-15
	Plant 3 Catalyst and Chemicals Requirement	9-16

CONTENTS

SECTION 1	INTRODUCTION	1-1
SECTION 2	SUMMARY	2-1
SECTION 3	DESIGN PARAMETERS	3-1
SECTION 4	FACILITIES DESCRIPTION SUMMARY	4-1
SECTION 5	UNIT DESCRIPTIONS (with Flow Sheets, Material Balances and Product Descriptions).	5-1
	5.1 Plant 1	5.1-1
	5.2 Plant 2	5.2-1
	5.3 Plant 3	5.3-1
SECTION 6	UTILITIES	6-1
SECTION 7	ENVIRONMENTAL FACTORS	7-1
SECTION 8	MAJOR EQUIPMENT SUMMARY	8-1
SECTION 9	ECONOMICS	9-1
SECTION 10	ADVANCED DESIGN ASPECTS	10-1
SECTION 11	LITERATURE CITED	11-1
APPENDIX		
A	Site Conditions	A-1
FIGURES		
4-1	Plot Plan	4-2
4-2	Artist's Conceptual Drawing	4-3
5.1-1	Low-Btu Gasifier Conceptual Sketch	5.1-8
5.2-1	Intermediate Btu Gasifier	5.2-3
5.2-2	Agglomerating Ash Fluid-Bed Gasifier	5.2-6
5.3-1	Synthesis Reactor	5.3-3
7-1	Block Flow Diagram, Air Pollution Abatement	7-2
7-2	Block Flow Diagram, Water Treatment and Supply	7-9
9-1	Construction and Operating Schedule	9-7
9-2	Project Fund Drawdown	9-9
9-3	Cumulative Project Expenditures	9-10
9-4	Cumulative Project Expenditures with Credits	9-12

CONTENTS (Contd)

TABLES

9-4	Annual Operating Cost Summary	9-17
9-5	Basis of Economics	9-18
9-6	Manpower Summary	9-19
9-7	Project Fund Requirement Schedule	9-20
9-8	Possible Product Selling Prices	9-21
9-9	Possible Net Cash Flow	9-22

FLOW DIAGRAMS

R-01-FS-1	Block Flow Diagram - Plants 1, 2, & 3	4-9
R-110/111/ 210/211/ 310/311- FS-1	Coal Storage & Preparation Units 110, 111, 210, 211, 310	5.1-9
R-112/113- FS-1	Low Pressure Gasifier Units 112, 113	5.1-10
R-114- FS-1	Acid Gas Sulfur Removal - Unit 114	5-1-11
R-130/131- FS-1	Industrial Water Treatment System - Unit 130, Cooling Tower - Unit 131	5-1-12
R-212/213- FS-1	Process Gasification Unit - 212, Heat Recovery and Gas Cleaning Unit - 213	5.2-15
R-215/215- FS-1	Sulfur Plant/Tail Gas Plant - Units 215/216	5.2-16
R-217-FS-1	Water Reclamation Unit - 217	5.2-17
R-241-FS-1	Heat Balance - Plant 2, Power Plant - Unit 241	5.2-18
R-241-FS-2	Heat Balance - Plant 3, Power Plant - Unit 241	5.2-19
R-319-FS-1	Fischer-Tropsch Synthesis - Unit 319	5.3-17
R-320-FS-1	Liquid Product Recovery Unit - 320	5.3-18
R-321-FS-1	Methanation Unit - 321	5.3-19
R-322-FS-1	Chemical Recovery Unit - 322	5.3-20

ABBREVIATIONS

av	average
bb1	barrel
BCR	Bituminous Coal Research
bp	boiling point
BFW	boiler feed water
BPD	barrels per day
BPCD	barrels per calendar day
Btu	British thermal unit
Btu/hr	Btu per hour
CA	corrosion allowance
cfm	cubic feet per minute
CI	cast iron
cu ft	cubic foot
CS	carbon steel
CS	centistokes
DB	dry basis
DCF	discounted cash flow
dp	differential pressure
eff	efficiency
FEL	front end loader
FOE	fuel oil equivalent (6,300,000 Btu/bbl)
FSC	flame sprayed catalyst
F-T	Fischer-Tropsch
ft	foot
gpm	gallons per minute

SECTION 1

INTRODUCTION

This report presents the results of a preliminary design and economic evaluation for a multi-process demonstration plant (MPDP). The design includes demonstration scale units for a number of coal conversion process steps. The design was begun under sponsorship of the Energy Research and Development Administration (ERDA) and completed under the Department of Energy (DOE) - Division of Coal Conversion.

Current trends and forecasts indicate that domestic production of oil and natural gas will supply a decreasing portion of future U.S. energy needs. Alternatives to acceptance of increased national security risks, coupled with decreased economic growth and standards of living because of this oil/gas shortfall, include continued expansion of imports, accelerated exploration for new oil and gas, increased use of coal combustion and nuclear energy for production of electricity, steam, and heat, and production of liquid and gaseous fuels from coal or shale.

The use of coal has the advantage that the U.S. has vast indigenous resources; we know where it is and how to mine it. Production of gas and oil from it has been practiced industrially - it can be done. What is not known is the cost, using U.S. coals and current technology. Recent extensive conceptual designs/economic evaluations prepared under contract to DOE/ERDA indicate that with proper development and use of large captive coal mines, coal conversion could produce synfuel at prices that deserve consideration. However, the true costs will be known only after near-commercial or commercial size facilities have been designed, constructed, and operated. This design presents a candidate configuration for a demonstration scale multi-process test facility.

1.1 SELECTION OF MPDP

Analysis of alternative routes to test candidate technologies on a near-commercial scale shows that the multi-process demonstration plant facility has many advantages:

- Time and money could be saved if many common facilities and process units could be located in a central coal gasification and liquefaction test facility.
- All processes that convert coal to gaseous and liquid fuels require a gasification unit.
- The facility will permit testing coal (or lignite) from any source in a number of candidate gasifier units. The gases produced can be converted to high-Btu (pipeline) gas and can also be used in development of high potential coal liquefaction technologies.

- Test and evaluation work would be performed and reported on a uniform basis for all processes.
- Sufficient product would be made available for use in functional product testing by potential customers.
- Operating efficiency would be increased. When a given process unit is removed from operation for maintenance, revision, or having achieved its objective, an alternate process unit can be brought into operation. This procedure improves usage efficiency of personnel and supporting facilities. Since the demonstration plant is expected to employ upwards of 500 people, progress will be speeded and costs per achievement decreased.
- The demonstrated performance of large proven components should diminish the degree of risk, and therefore encourage the private sector to invest in commercial plants.

To explain the common facilities cited in the first advantage point listed above, all coal conversion plants require:

- Coal storage
- Coal grinding and preparation, which may vary from process to process
- Product recovery and refining
- Waste treatment facilities
- Utilities, such as steam, water, electricity, compressed air, and cooling water
- Administrative offices, first aid, and safety facilities
- Maintenance and warehouse facilities
- Computer and other planning/performance analysis facilities
- Laboratories and engineering development facilities
- Plant and personnel support facilities
- Transportation

These facilities can represent 25-35% of the total test facility investment; they can commonly serve multiple test units.

In addition to offsites and primary coal conversion units, processes that convert coal to gaseous and liquid fuels also require:

- Oxygen plants
- Gas purification (solids removal)
- Gas composition adjustment (shift conversion)
- Acid gas removal (largely hydrogen sulfide and carbon dioxide)
- Sulfur plants (to convert contaminant hydrogen sulfide to salable sulfur)
- Product storage

These facilities can represent 15-20% of the total plant cost. Therefore, the savings accruing from use of common units in an MPDP facility can be significant and may be of the order of 40-55% of the alternative costs of building a separate facility to test each unit at a separate location. The exact savings can be more accurately predicted once the final configuration of the test facility is defined.

The value of obtaining test and performance results and evaluating these results on a uniform basis at a single location deserves emphasis. The key to success here is an objective, highly qualified management, operating, maintenance, development, and analysis team supported by advanced equipment and good communications with DOE leadership.

A total MPDP plan should also include, as one of its elements, the development of target plant designs to further define the preferred configuration of the commercial plants, identify trade-off options, establish optimum plant parameters, and define the experimental tests to be completed to confirm the optimization.

An MPDP program should use the experience gained throughout the total coal conversion development program to date; this includes pilot plant design, construction, and operation, as well as preliminary (conceptual) designs of commercial plants and the predicted sensitivities of economics to key design and operating parameters.

1.2 PROJECT OBJECTIVES

The key MPDP objective is to provide a sound basis for decisions by industry to design, construct, and operate coal conversion plants at the earliest possible date. To accomplish this, the program objectives include:

- Develop a broad technological, engineering, environmental, safety, and economics base.
- Demonstrate the reliability and safety of the performance of the plant(s) and the types of equipment that perform best to achieve the program objectives.

- Demonstrate that gaseous and liquid products can be produced which will perform satisfactorily in the marketplace. Large quantities of products should be produced to permit testing in commercial scale equipment. The probability exists that future commercial use of these fuels will require some mutual accommodation of fuel characteristics and the design and mode of operation of users' equipment.
- Demonstrate that the production plants can be operated in an environmentally acceptable manner.
- Develop the breadth and depth of the technological and engineering base for subsequent use in the commercialization programs.
- Provide a reliable basis for predicting the economics of the commercial plants.

The design described here is intended to achieve these objectives.

1.5 REPORT ORGANIZATION

A summary of key elements of the design and economic evaluation, a summary of design parameters, and a facility description, including a block flow diagram, are presented in Sections 2, 3, and 4.

Section 5 contains descriptions of the three plants. Product descriptions and process flow diagrams for each plant are also included in this section.

Section 6 summarizes utility usage and production for all three plants. A utility summary, by unit, for each plant is included.

Important environmental factors are summarized in Section 7. Facilities included to ensure that effluent streams are properly treated to meet environmental standards are described here.

Lists of major equipment, sizes, and materials of construction are presented in Section 8. These lists provide the basis for a major portion of the fixed capital investment estimate. Section 9 is a detailed presentation of the financial and economic aspects of this demonstration plant project.

The remainder of the report presents supporting data and pertinent discussions relative to design choices.

SECTION 2

SUMMARY

A preliminary design and economic evaluation have been completed for a multi-process demonstration plant (MPDP); the results are summarized here.

The work was begun under the auspices of the Major Facilities Project Management Division of the Energy Research and Development Administration - Fossil Energy and completed under the Department of Energy, Office of Assistant Secretary for Energy Technology, Division of Coal Conversion. Their support and guidance are gratefully acknowledged.

The objectives for the MPDP are to:

- Develop a broad technological, engineering, environmental, safety, and economics base for coal conversion processing.
- Demonstrate the reliability and safety of the MPDP performance and the types of equipment that perform best to achieve the program objectives.
- Demonstrate that gaseous and liquid products can be produced which will perform satisfactorily in the marketplace. Large enough quantities of products should be produced to permit testing in commercial scale equipment. The probability exists that future commercial use of these fuels will require some mutual accommodation of fuel characteristics and the design and mode of operation of users' equipment.
- Demonstrate that the production plants can be operated in an environmentally acceptable manner.
- Develop the breadth and depth of the technological and engineering base for subsequent use in the commercialization programs.
- Provide a reliable basis for predicting the economics of the commercial plants.

The design described here was developed to achieve these objectives.

2.1 MPDP DESIGN

The MPDP design consists of the following: three principal process plants; coal receiving storage and handling facilities; and the necessary ancillaries to service the plants and a plant population of approximately 550 people. The key elements of the three plants are:

Plant 1 is a low pressure coal gasifier, which can be operated either in the air-blown or oxygen-blown mode, with attendant heat and sulfur recovery auxiliaries. The products generated are, initially, low-Btu fuel gas, steam, and byproduct sulfur.

Plant 2 consists of two oxygen-blown intermediate pressure gasifiers, entrained and fluid-bed types with oxygen plant, heat and sulfur recovery equipment, and a combined-cycle power plant. The design provides for one of the two gasifier types to be operated at any given time.

The combined-cycle power plant will provide facilities for demonstrating the performance of closely coupled generation of environmentally acceptable intermediate-Btu fuel gases from coal followed by conversion to electricity in a high efficiency mode.

In addition to supplying fuel gas to the combined-cycle power plant, the gasifiers will produce synthesis gas (syngas) for use in a Fischer-Tropsch indirect liquefaction plant. This syngas can later be used as feed to other indirect liquefaction facilities such as methanol, or it can be used as a source of reducing gases for tests on hydroliquefaction or donor solvent coal liquefaction plants. The information obtained from this syngas production unit could complement that obtained from other pilot plant and demonstration plant programs.

Salable byproduct sulfur is also produced.

Plant 3 is a Fischer-Tropsch plant complete with a carbon dioxide removal system and methanation and product recovery equipment. Products include salable substitute natural gas (SNG), Fischer-Tropsch liquid fuels (LPG, naphthas, diesel fuel, and heavy fuel oil) and alcohol mixtures.

The design incorporates the use of flame-sprayed catalyst fin tube reactors; this technology appears to have promise, based on the results of an earlier published conceptual commercial plant design and a development program underway at the Department of Energy's Pittsburgh Energy Research Center (DOE's PERC).

The three plants will have the capability for demonstrating a number of basic coal conversion operations:

- Low pressure coal gasification to produce a clean, low-sulfur fuel gas and steam.

- Intermediate-pressure coal gasification to produce synthesis gas from two basic types of advanced-design gasifiers.
- Electric power generation, in the combined-cycle mode, integrated with intermediate-Btu gasification and sulfur removal.
- Advanced Fischer-Tropsch synthesis and methanation to produce high quality, high value fuel products and steam byproduct.
- Creditable overall thermal efficiencies for the plants achieved through heat recoveries producing usable steam.

Estimated time needed to design, procure for, and construct the three-plant facility is 36 months for Plants 1 and 2, followed 12 months later by completion and startup of Plant 3.

2.2 PROJECT FINANCING

The fixed capital investment, including a 10% contingency, is approximately 500 million mid-1977 dollars. All economics here are expressed in mid-1977 dollars. The expected accuracy of this estimate is -5, +20%. The contingency is included to allow for undeveloped design factors, possible expansion of operating flexibility provisions (to be defined during a detailed design program), and possible additional ancillary facilities.

The total capital investment required is estimated to be approximately \$560 million. In addition to fixed capital requirements, this total includes the cost of initial raw materials, catalysts and chemicals, working capital, allowance for startup costs, and allowance for land acquisition.

Annual operating costs for the MPDP are projected to be approximately \$90 million. Employee population is approximately 530 people. Possible annual income credits from sale and transfer of products total \$60 million; these would be based on all plants operating at nameplate capacity and the products being sold at market values comparable to similar products derived from crude oil or natural gas.

Realistically, the project financing should not depend on full revenues from the products that might be produced. Since it is a demonstration plant, its prime objectives would be to demonstrate the performance of the facility and not to serve primarily as a production unit. Also, since the products may differ somewhat from similar items of commerce, their market values could differ from current petroleum based products. Potential product customers can be expected to test the performance of relatively large quantities of the products before deciding to purchase; product values could therefore be discounted during the test periods.

A total program period of 10 years is envisioned to design, procure, construct, start up, and operate the facility. The objectives at the end of this period are to have enough information to design commercial plants, to determine the products' marketability, and to be able to accurately predict the economics of commercial plants. The total cash outflow, during this 10-year period, is projected to be approximately \$1.15 billion; this assumes the plant has zero scrap value at the end of the program. Optimistically, if the plants produced at 50% of nameplate capacity for the initial 1.5 years of operation and at nameplate capacity for the remainder of their operating life, with the products sold at market value, the negative cash flow would be reduced to approximately \$0.8 billion. If, in addition, the plant were also 100% funded with private capital such that the tax losses from this project could be used to offset other corporate profits, and it could be depreciated in the 7-year operating life, the total project net costs could be as low as \$0.35 billion.

The processes utilize proven equipment items coupled with certain items of advanced technology. The two types of intermediate-pressure gasifiers are based on pilot plant units. Entrained-bed gasifiers are being piloted by DOE at Homer City, Pennsylvania and at Windsor, Connecticut. A fluidized-bed gasifier and ash agglomeration unit have been piloted by DOE, with the Institute of Gas Technology (IGT) as the developer, at Chicago, Illinois. The Fischer-Tropsch reactor design is being piloted by the DOE's PERC at Bruceton, Pennsylvania, following successful prior bench-scale experiments. This type of unit is projected to provide efficient recovery of reaction heat in the form of 1250-psig steam.

The Fischer-Tropsch products, having nil sulfur, nitrogen and particulate matter, represent premium grade fuels from an environmental standpoint. They also have characteristics which make them attractive as petrochemical feedstocks.

2.3 EXPECTED ACCOMPLISHMENTS

The key result expected is that the MPDP should provide a major basis for industry decisions regarding investment in the coal conversion technologies tested.

To accomplish its objectives, the facility should be conservatively designed, using experience from all sources to reduce technical risks to an acceptable level and assure reliable, safe, and environmentally acceptable operation. The design effort should continue to be supported by an active research and development program. In parallel with the design, procurement, construction, and startup of the MPDP, components should be tested and improved; this includes cooperative programs with equipment, process development, and instrumentation firms.

The construction and operation of an MPDP would provide hands-on experience with the performance of essential plant components. It would provide data and experience on operation of large scale coal conversion

plant units and the interaction of the plant units with their associated supporting facilities and environment. An improved understanding would be developed for the range of costs and other factors pertinent to development of this energy option. The construction and operation experience would also contribute to development of the necessary technical and engineering expertise in safety, reliability, economics, and environmental factors for later use in commercial projects. It would also provide a core of experienced personnel in the design, construction, and operation of this type of synfuels plant; the personnel should be available for contributions on later projects.

Specific results to be expected include:

- Successful development and testing of large components should lead to improvements in commercial plant planning, scheduling, and cost prediction.
- The availability of large components whose performance has been proven should reduce the risks in design of commercial-scale plants and, therefore, should encourage industry to invest in the larger plants.
- Acceptance of the performance of the fuel products in consumer applications and agreement that they can be sold at competitive prices.

Importantly, the MPDP described here should provide the operational experience and records needed to evaluate the commercial viability of commercial scale coal conversion plants using the technologies tested.

Details of the design, operating efficiencies, and economic considerations are presented in this report.

SECTION 3
DESIGN PARAMETERS

This section describes the raw material utilization, products, and the basic design criteria used.

3.1 GENERAL CHARACTERISTIC AND DESIGN BASIS

The plant will:

- Demonstrate the performance of key coal-conversion process equipment.
- Demonstrate the production of valuable energy products.
- Produce significant quantities of coal-derived energy products for functional performance testing.
- Demonstrate the capability of utilizing a variety of coal and other types of fuel feed.
- Demonstrate operability while meeting environmental standards.
- Provide a firmer basis for predicting the economics of commercial scale coal conversion complexes.

3.2 SITE CONDITIONS

The site conditions used for the design are included as Appendix A.

3.3 RAW MATERIALS

The plant is designed to operate on purchased coal and can be adapted to use other suitable solid fuels such as lignite or peat. In order to illustrate its projected performance, the flow sheets with material and heat balances are presented in this report based on use of a single-feed coal analysis which is typical of coal mined in the Eastern Region of the U.S. Interior Coal Province. Details concerning the raw materials are as follows:

(1) Coal:

- (a) Clean washed coal is purchased
- (b) The proximate and ultimate analysis of coal feed to the process are outlined as follows:

Table 3-1. Coal Feed Composition

Proximate Analysis (Composition Wt%)		Ultimate Analysis (Composition Wt%)	
Item	Wt%	Item	Wt%
Moisture	2.7	Carbon	67.2
Ash	11.8	Hydrogen	4.6
Volatile matter	59.7	Nitrogen	1.3
Fixed carbon	45.8	Sulfur	3.7
		Oxygen	8.7
		Ash	11.8
		Moisture	2.7
Total	100.0	Total	100.0

The design can be adjusted for use of alternate fuels having major differences in analyses. The effect of other eastern U.S. area coals is expected to be minimal, resulting in minor shifts of product quantities.

- (2) Oxygen - 98% purity, produced captively by air separation.
- (3) Water - process water from a nearby river and potable water from wells.

3.4 PRODUCTS

The products to be obtained are:

Table 3-2. Product Characteristics

Product	Characteristics	Approximate Stream Day Production Rate
<u>Plant 1:</u>		
Fuel gas	Air-blown: 135 Btu/scf HHV DB or oxygen-blown: 290 Btu/scf HHV DB	250,000,000 scf/d 260,000,000 scf/d
Steam	1,250-psig, superheated to 950°F	2,250,000 lb/day
Sulfur	99.9% sulfur	65 ton/d
<u>Plant 2:</u>		
Electric power	13,600 V, 192 MW	4,600,000 kW-h
Sulfur	99.9% sulfur	80 ton/d

Table 3-2. Product Characteristics (Contd)

Product	Characteristics	Approximate Stream Day Production Rate
<u>Plant 3:</u>		
Additional electric power	13,600 V, 11 MW	260,000 kW-h
Additional sulfur	99.9% sulfur	30 ton/d
SNG	1025 Btu/scf HHV	5,700,000 scf/d
Butane/Butylene	37-psig vapor pressure @ 100°F	80 BPD
Light naphtha	Nil sulfur, 12.3 K*, 85.5°API 185°F ASTM end point	235 BPD
Heavy naphtha	Nil sulfur, 12.3 K*, 71.3°API 300°F ASTM end point	210 BPD
Diesel fuel	Nil sulfur, 60-plus cetane.	360 BPD
Fuel oil	Nil sulfur, low viscosity, 41°API	110 BPD
Oxygenates	Mixed alcohols: ethanol 67%; propanol 18%; methanol 6%	70 BPD
*UOP characterization factor (highly paraffinic)		

The Fischer-Tropsch process was selected for Plant 3 because of its potential to produce a number of quality products and because of its flexibility in varying the product slate by controlled changes of synthesis reactor operating conditions and catalyst composition.

3.5 EQUIPMENT SPARES

This design uses spares only for critical rotating equipment. A critical piece of equipment was defined as one that would shut down a process unit in case of failure; exceptions occur when its cost is excessive and it has a sufficiently reliable performance history. All spares are shown as such in the equipment lists and on the flow diagrams.

For example, all process pumps whose failure would shut down a unit have spares. In cases in which two pumps are required to meet the service duty, one additional pump is provided as spare. Major compressors and blowers are not spared, following the philosophy used successfully in oil refineries, ammonia plants, and similar plants for many years. Slurry pressure-reducing valves are provided with bypasses and spares to allow maintenance of these devices.

Feed to the gasifiers is arranged at multiple points around their periphery to provide satisfactory feed distribution. They are sized to permit full throughput with one feeder out of operation for maintenance.

The power plant consists of two gas turbines with heat recovery units allowing operation of the plant at a reduced rate. Normal preventive maintenance will be carried out on these units when the process plant is shut down for similar purposes.

3.6 EFFLUENT TREATMENT AND NOISE CONTROL

All effluent streams will be treated to meet environmental standards. Equipment will be designed to meet OSHA noise level requirements.

3.7 RAW MATERIAL AND PRODUCT STORAGE

Facilities are provided for storage of a 15-day feed coal inventory, a 15-day liquid fuel products inventory, and a 30-day sulfur product inventory.

3.8 ANCILLARY FACILITIES

Adequate facilities are provided to service this approximately 100-acre industrial area and its personnel population of approximately 550. These include, among other facilities, change houses, cafeteria, office, and parking facilities.

SECTION 4

FACILITIES DESCRIPTION SUMMARY

A block flow diagram, Drawing R-01-FS-1, shows the MPDP plants and their interrelationships. Figure 4-1 is a plot plan of the plants and units involved. An artist's conceptual drawing of the complex is shown in Figure 4-2.

The plant is conceived to be located in the Eastern Region of the Interior Coal Province.

The total land area requirement of the project is 100 acres; this should be made available as a single parcel at the beginning for the three plants (and also a fourth plant, should it be later desired). The demonstration plants will require approximately 17,000 acre-ft/yr of water for process requirements and utility makeup.

Purchased coal will be delivered by rail and trucks, received, and stored in open piles. Coal receiving, unloading, handling, storage, and grinding take place at a central location which serves all three plant modules.

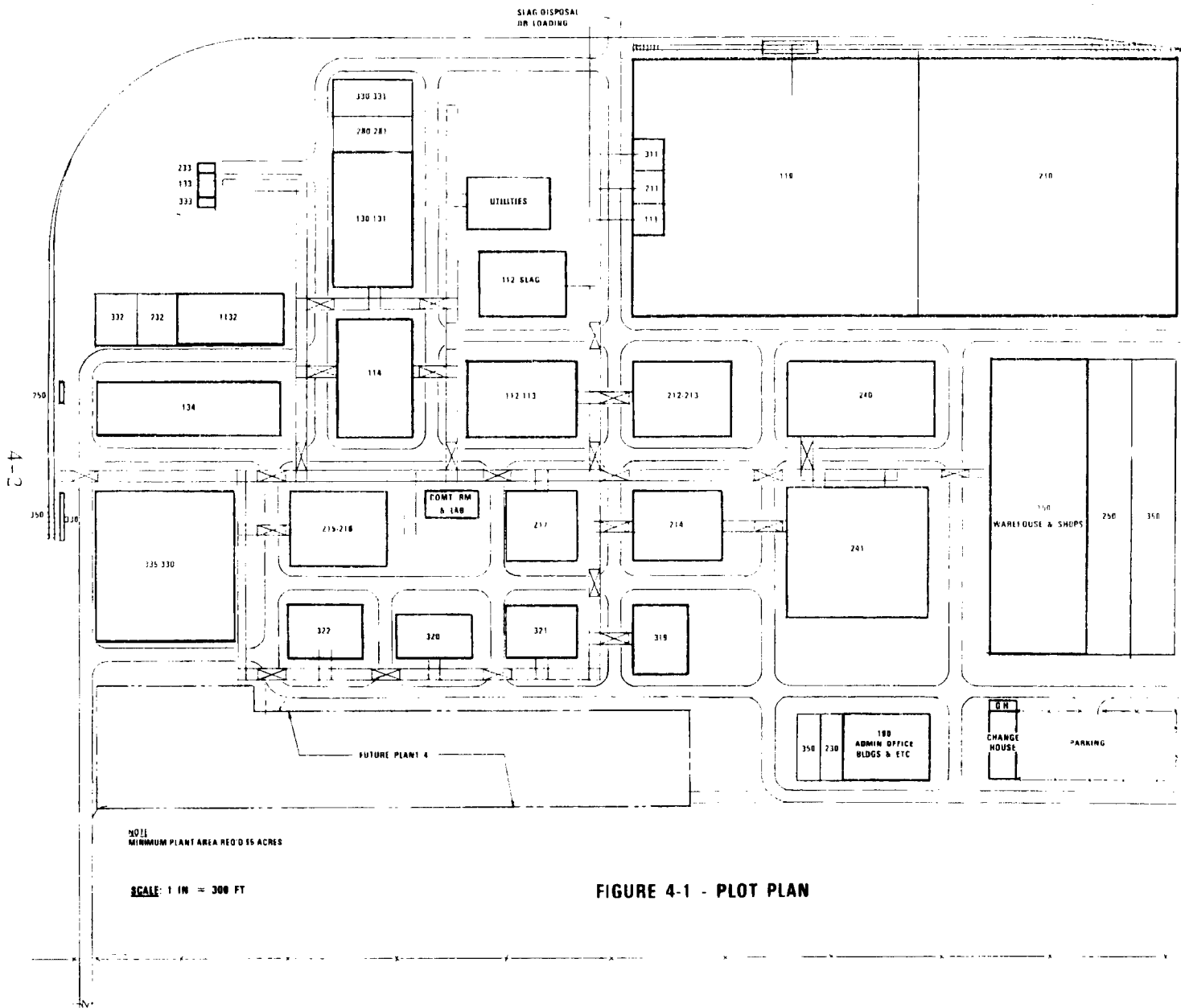
4.1 PLANT CAPACITY

Coal feed rates are shown on the block flow diagram for the three plants. To provide flexibility and the ability to expand the scope of the program in the future, the Plant 2 gasifiers and sulfur plants are sized to supply synthesis gas to a potential future fourth plant. To illustrate, when supplying gas for Plant 2 operation only, the gasifier will be operating at approximately 60% of capacity. While supplying gas for Plant 2 and Plant 3 simultaneous operation, the gasifier will operate at 80% of capacity. Coal feed rates are as follows:

<u>Plant</u>	<u>Plants in Operation</u>	<u>Coal Feed Rates (ton/d)</u>
1	1	1800
2	2	2250
2	2 and 3	3000
2	2, 3, and 4	3750

4.2 OPERATING SEQUENCE AND LIMITS

The following outlines the operating relationships and the interdependence of the plants.



PLANT AND UNIT NO	UNIT
PLANT 1	LOW-PRESSURE FUEL GAS GASIFICATION
110	COAL STORAGE
111	COAL GRINDING
112	LOW-PRESSURE GASIFIER
113	LOW BTU GAS HEAT RECOVERY
114	LOW BTU ACID GAS SULFUR REMOVAL
130	WATER TREATMENT
131	COOLING WATER SYSTEM
132	EFFLUENT TREATMENT
133	FLARE
134	SULFUR STORAGE
150	BUILDINGS RAILROAD ROADS GENERAL FACILITIES
PLANT 2	INTERMEDIATE PRESSURE GASIFICATION AND POWER GENERATION
210	ADDED COAL STORAGE
211	ADDED COAL GRINDING
212	MEDIUM PRESSURE GASIFIERS
213	MEDIUM BTU GAS HEAT RECOVERY
214	MEDIUM BTU ACID GAS REMOVAL
215	SULFUR PLANT
216	TAR GAS TREATMENT
217	PROCESS WATER RECYCLATION
218	ADDED WATER TREATMENT
219	ADDED COOLING WATER SYSTEM
222	ADDED EFFLUENT TREATMENT
233	ADDED FLARE SYSTEM
240	OXYGEN PLANT
241	POWER PLANT
250	ADDED BUILDINGS, RAILROAD ROADS GENERAL FACILITIES
PLANT 3	INTERMEDIATE PRESSURE GASIFICATION, POWER GENERATION AND FISCHER TROPSCH SYNTHESIS
311	ADDED COAL GRINDING
310	FISCHER TROPSCH ACID GAS REMOVAL
319	FISCHER TROPSCH SYNTHESIS
320	FISCHER TROPSCH LIQUID PRODUCT RECOVERY
321	FISCHER TROPSCH GAS METHANATION
322	FISCHER TROPSCH ALCOHOLS MIXTURE RECOVERY
330	ADDED WATER TREATMENT
331	ADDED COOLING WATER SYSTEM
332	ADDED EFFLUENT TREATMENT
335	INTERMEDIATE STORAGE
336	PRODUCT STORAGE AND SHIPPING FACILITIES
350	ADDED BUILDINGS, RAILROAD ROADS GENERAL FACILITIES

NOTE: MINIMUM PLANT AREA REQUIRED IS ACRES

SCALE: 1 IN = 300 FT

FIGURE 4-1 - PLOT PLAN

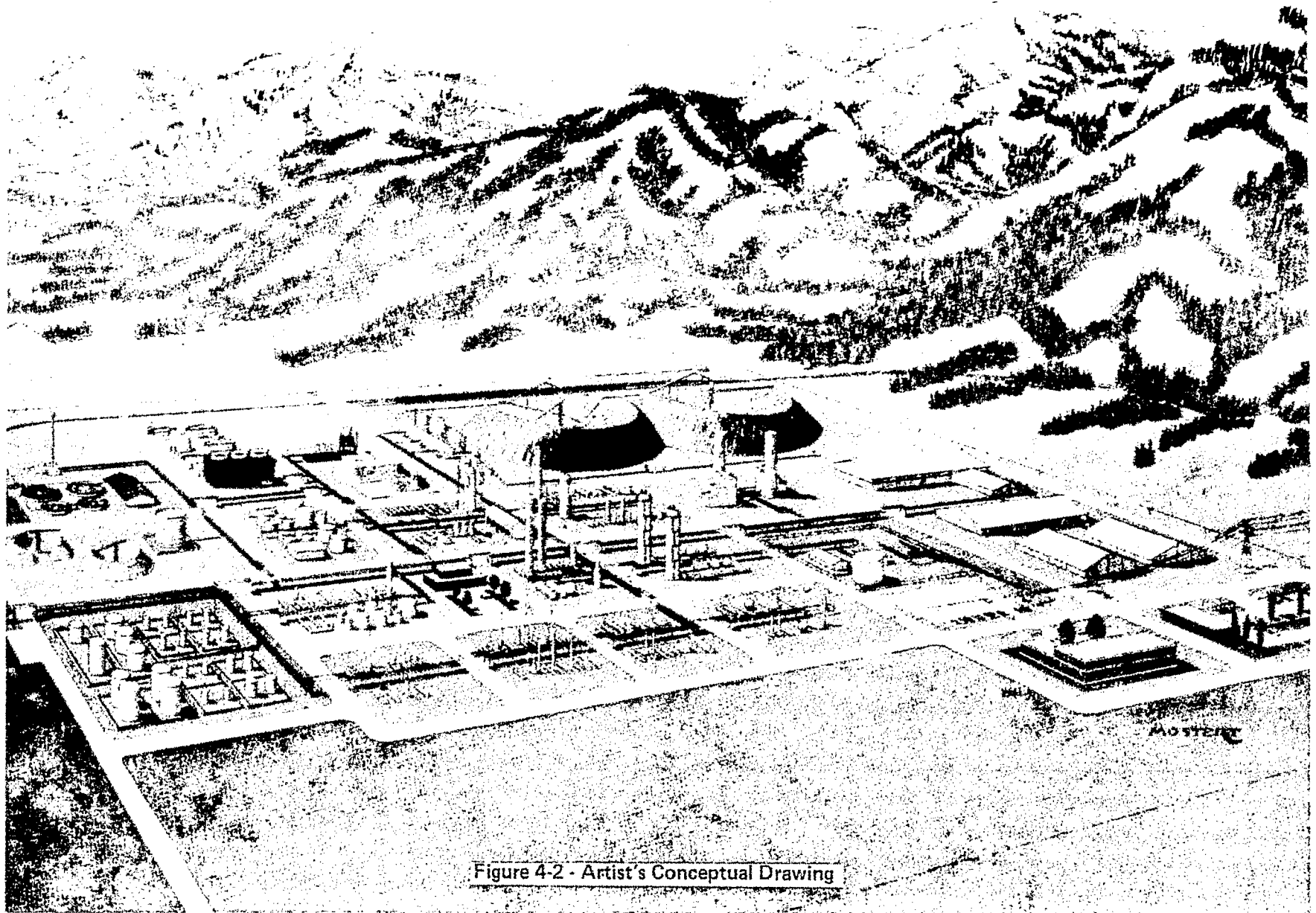


Figure 4-2 - Artist's Conceptual Drawing

Plant 1:

- (1) Operates alone.
- (2) Can be shut down independently of Plants 2 and 3 except for coal receiving and coal grinding.

Plant 2:

- (1) Can operate along with Plant 1.
- (2) Can be operated independently of Plant 1 except for coal receiving and coal grinding.
- (3) Operates at 60% of its oxygen and gasification capacity when operating alone.
- (4) Operates at 80% of its oxygen and gasification capacity when Plant 3 is also in operation.
- (5) Operates at 100% of its oxygen and gasification capacity when Plant 3 and the possible future plant 4 are also in operation.

Plant 3 cannot operate by itself; Plant 2 must supply the syngas feed.

Plant 4: (future)

- (1) Cannot operate by itself; Plant 2 must supply the syngas feed.
- (2) Can operate while Plant 3 is down.

The Fischer-Tropsch demonstration plant, designated as Plant 3, will provide data for design of a commercial scale plant. It will convert approximately 44 million scf/d of syngas to SNG plus liquid products. It will use the processing procedures defined in a published Fischer-Tropsch conceptual design/economic evaluation.¹

Table 4-1 summarizes feed and product quantities for each plant as well as heating values for the separate streams. Overall thermal efficiencies, based on coal feed, of approximately 81%, 63%, and 59% are indicated for Plants 1, 2, and 3, respectively.

Table 4-2 presents the overall thermal efficiencies for the Fischer-Tropsch plant only, based on the incremental coal feed to produce the syngas for the F-T operations and also based on the synthesis gas feed alone. These projected efficiencies are approximately 61% and 85%, respectively.

The efficiencies for Plant 2 and Plant 3 operations, based on coal, reflect the efficiency loss attributable to the use of water-slurried coal feed. The evaporation of the slurry water results in the consumption of additional fuel and oxygen relative to operation with dry coal feed as used in Plant 1. The slurry feed method for Plants 2 and 3 operation was selected because of expected reliability of performance based on experience with similar operations.

Table 4-1 - Products, Projected Quantities, Heating Values,
and Process Thermal Efficiencies

Feed and Product	Stream Quantity		Unit HHV	Total Heating Value (million Btu/d)	%
	Quantity per Stream Day	Tons per Stream Day			
<u>Plant 1 (Plant 2 in operation)</u>					
Coal Feed		1800	12,125 Btu/lb	43,650	
Electric power (fuel basis)	5.27 MMscf/d		291.7 Btu/scf	<u>1,537</u>	
Energy in				<u>45,187</u>	
Fuel gas	253 MMscf/d		130 Btu/scf	32,890	
Steam	94,000 lb/hr		1,400 Btu/lb	3,158	
Sulfur		66.0	3,990 Btu/lb	527	
Total products' heating value				<u>36,575</u>	
Thermal efficiency					80.9
<u>Plant 2</u>					
Coal Feed		2246	12,125 Btu/lb	<u>54,466</u>	
Fuel gas to power plant less fuel gas equivalent of electric power used	161 MMscf/d		270 Btu/scf	43,511	
	<u>-36 MMscf/d</u>		270 Btu/scf	9,769	
	125 MMscf/d		270 Btu/scf	33,742	
Sulfur		82.4	3,990 Btu/lb	658	
Total products' heating value				<u>34,400</u>	
Thermal efficiency					63.2

Table 4-1 (Contd)

Feed and Product	Stream Quantity		Unit HHV	Total Heating Value (million Btu/d)	%
	Quantity per Stream Day	Tons per Stream Day			
<u>Plant 3 (Including Plant 2)</u>					
Coal feed		2996	12,125 Btu/lb	<u>72,653</u>	
Fuel gas (net)	114 MMscf/d		270 Btu/scf	30,791	
Oxygenates	72 BPD	9.97	12,505 Btu/lb	249	
SNG	5.69 MMscf/d		1,025 Btu/scf	5,832	
LPG, C ₄ 's	78 BPD		21,035 Btu/lb	318	
Light naphtha	234 BPD	26.778	20,815 Btu/lb	1,115	
Heavy naphtha	211 BPD	25.773	20,430 Btu/lb	1,053	
Diesel Oil	356 BPD	46.618	20,255 Btu/lb	1,888	
Heavy fuel oil	112 BPD	16.095	19,855 Btu/lb	640	
Sulfur		109.9	3,990 Btu/lb	877	
Total products' heating value				<u>42,763</u>	
Thermal efficiency					58.9

Table 4-2-- Plant 3 Fischer-Tropsch Plant Products
and Thermal Efficiencies

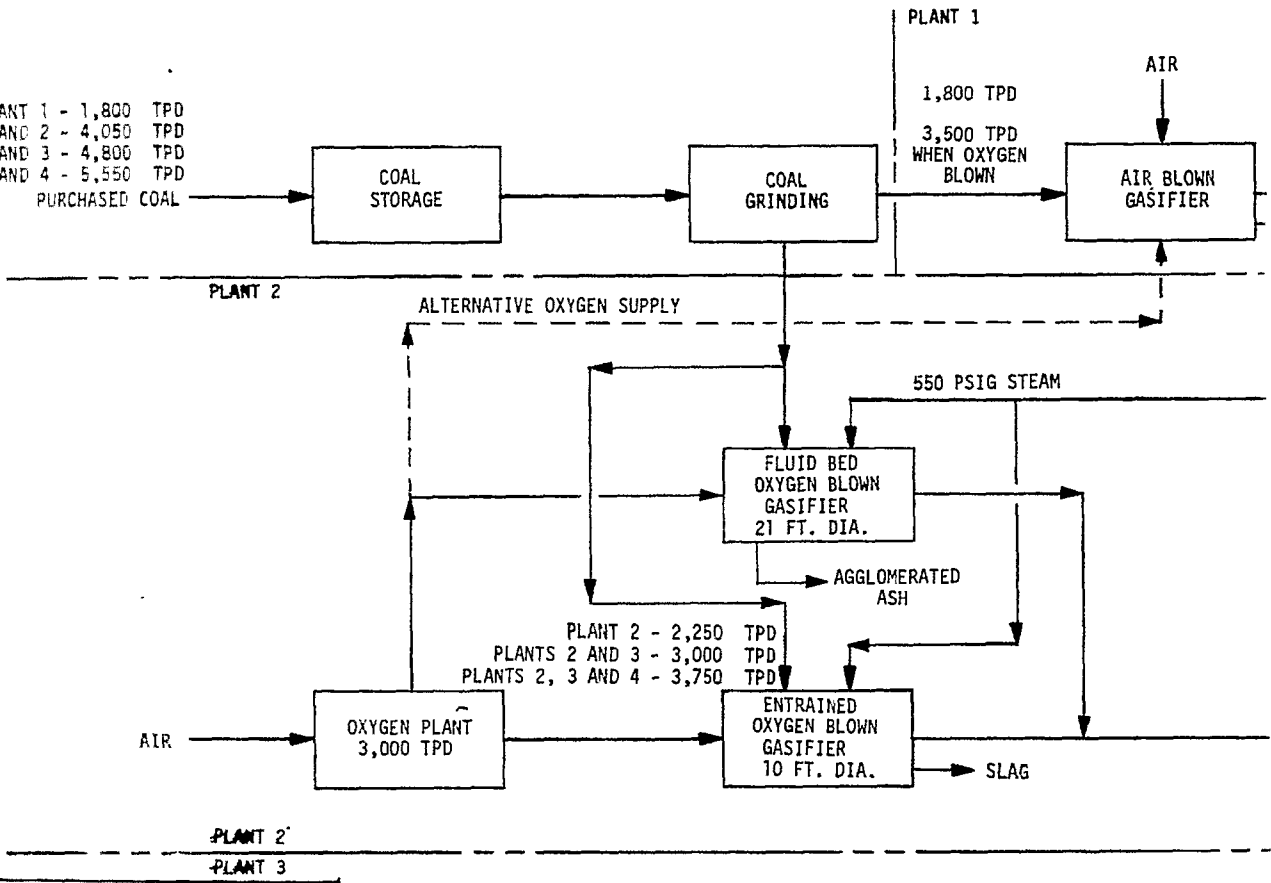
Feed and Product	Stream Quantity		Unit HHV	Total Heating Value (million Btu/d)	%
	Quantity per Stream Day	Tons per Stream Day			
Based on Incremental Coal Feed					
<u>Feeds</u>					
Coal feed		750	12,125 Btu/lb	18,188	
Add: fuel gas equivalent for electric power consumed	17,500 kW-h		*7,606 Btu/kW-h Heat Rate	<u>3,195</u>	
Total energy in				<u>21,383</u>	
<u>Products</u>					
Oxygenates	72 BPD	9.97	12,505 Btu/lb	249	
SNG	5.69 MMscf/d		1,025 Btu/scf	5,832	
LPG C ₄ 's	78 BPD		21,035 Btu/lb	318	
Light naphtha	234 BPD	26.778	20,815 Btu/lb	1,115	
Heavy naphtha	211 BPD	25.773	20,430 Btu/lb	1,053	
Diesel oil	356 BPD	46.618	20,255 Btu/lb	1,888	
Heavy fuel oil	112 BPD	16.095	19,855 Btu/lb	640	
Sulfur		27.5	3,990 Btu/lb	219	
Excess steam produced	124,00 lb/hr		(avg) 620 Btu/lb	<u>1,850</u>	
Total products' heating value				<u>13,164</u>	
Thermal efficiency					61
Based on Synthesis Gas Feed to F-T Reactor					
<u>Feeds</u>					
Syngas feed	44.00 MMscf/d		330 Btu/scf	14,529	
Add: fuel gas equivalent for electric power consumed	3,417 kW-h		*7,606 Btu/kW-h Heat Rate	<u>624</u>	
Total energy in				<u>15,153</u>	

Table 4-2 (Contd)

Feed and Product	Stream Quantity		Unit HHV	Total Heating Value (million Btu/d)	%
	Quantity per Stream Day	Tons per Stream Day			
<u>PRODUCTS</u>					
Oxygenates	72 BPD	9.97	12,505 Btu/lb	249	
SNG	5.69 MMscf/d		1,025 Btu/scf	5,832	
LPG C ₄ 's	78 BPD		21,035 Btu/lb	318	
Light naphtha	234 BPD	26.778	20,815 Btu/lb	1,115	
Heavy naphtha	211 BPD	25.773	20,430 Btu/lb	1,053	
Diesel oil	356 BPD	46.618	20,255 Btu/lb	1,888	
Heavy fuel oil	112 BPD	16.095	19,855 Btu/lb	640	
Excess steam produced	124,300 lb/hr		(avg) 620 Btu/lb	1,850	
Total products' heating value				<u>12,945</u>	
Thermal efficiency					85
*See flow diagram R-241-FS-2 in Section 5.2.					

PLANT 1 - 1,800 TPD
 PLANTS 1 AND 2 - 4,050 TPD
 PLANTS 1, 2 AND 3 - 4,800 TPD
 PLANTS 1, 2, 3 AND 4 - 5,550 TPD
 PURCHASED COAL

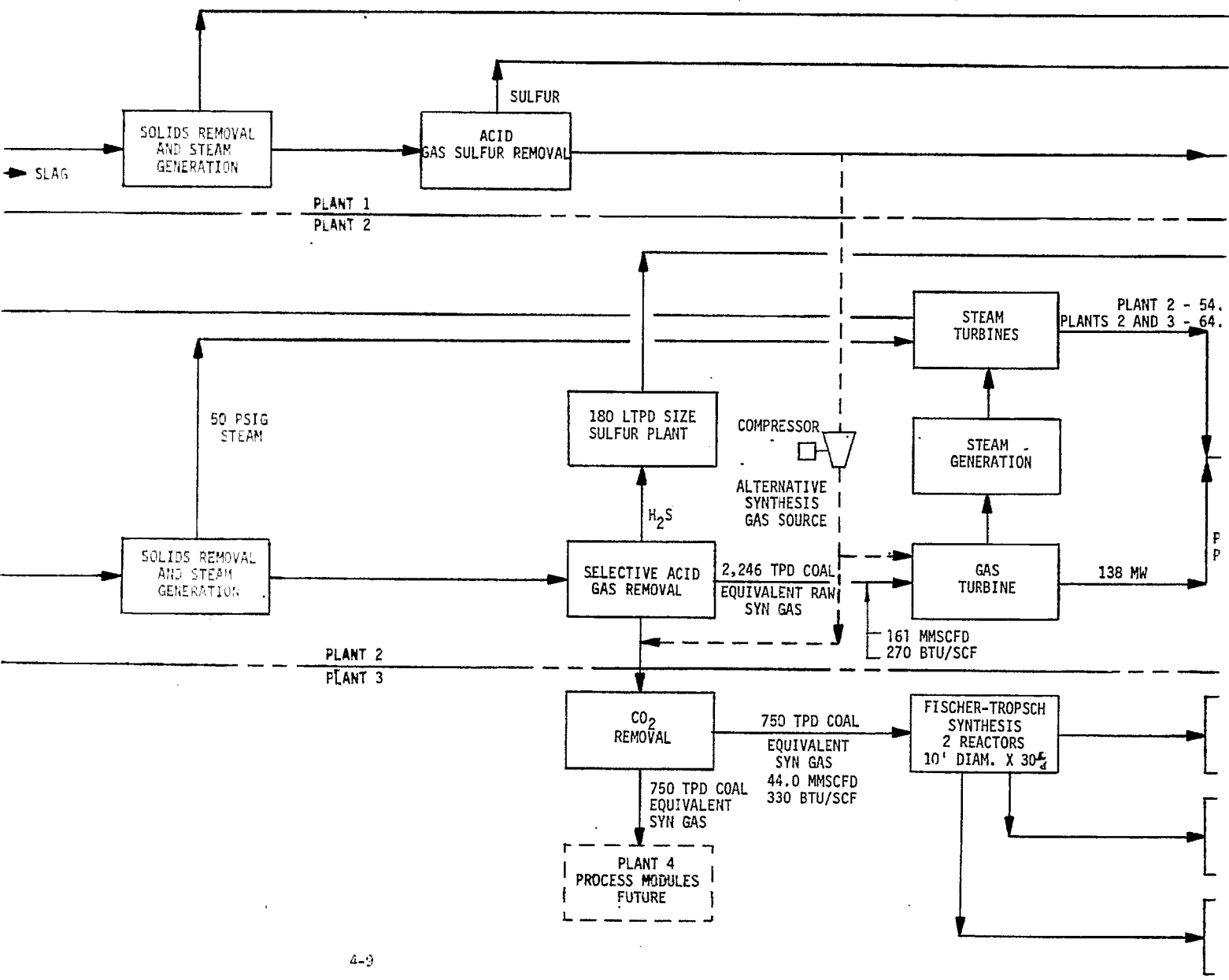
PLANT 1
 1,800 TPD
 3,500 TPD
 WHEN OXYGEN
 BLOWN



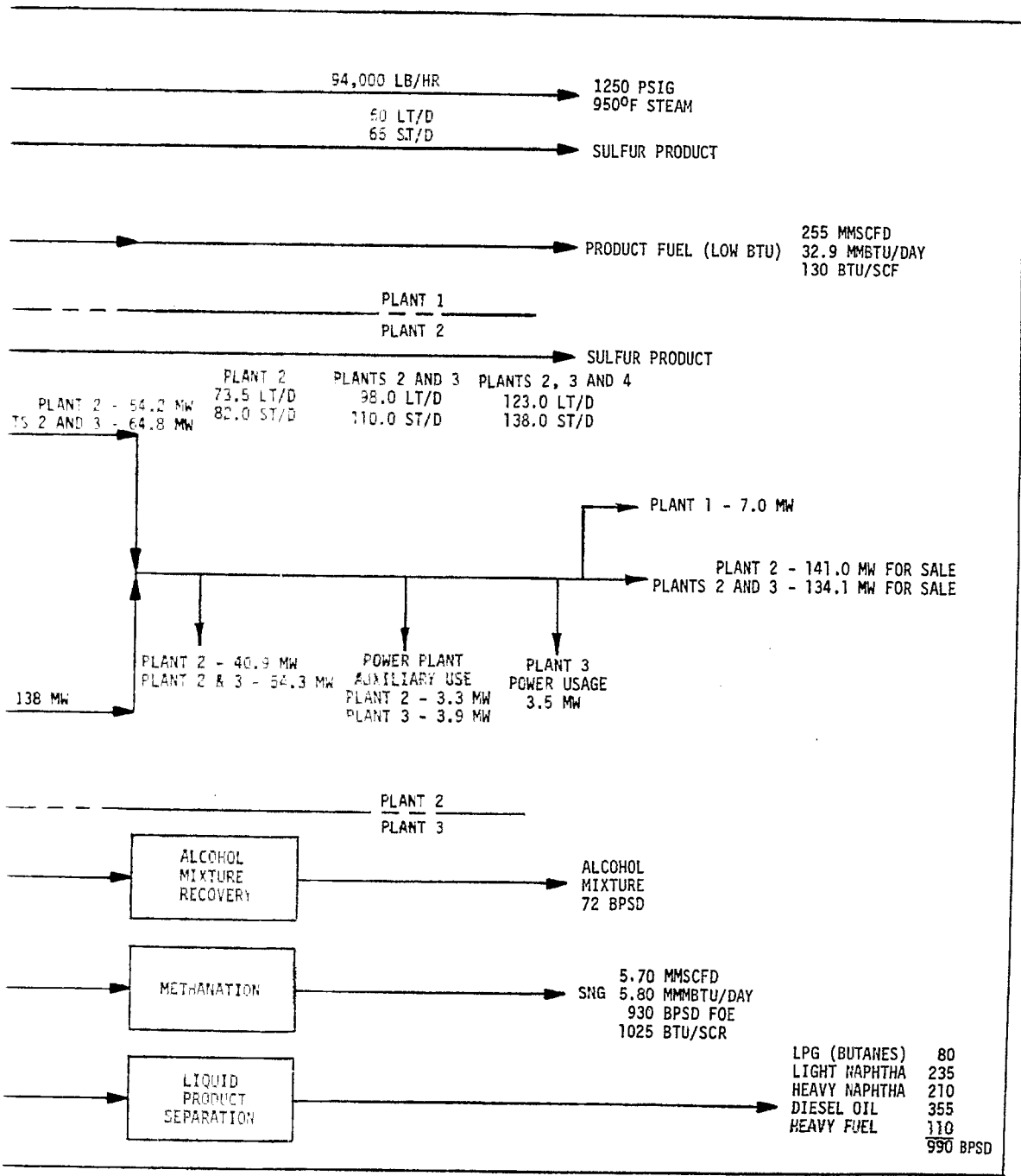
PLANT 2 - 2,250 TPD
 PLANTS 2 AND 3 - 3,000 TPD
 PLANTS 2, 3 AND 4 - 3,750 TPD

1		ISSUED FOR REPORT	LD	PMS	WED						
0		ISSUED FOR REPORT	LD	PMS	WED						
REV	DATE	DESCRIPTION	BY	CHKD	CHKD	CHKD	CHKD	CHKD	CHKD	CHKD	CHKD
DEPARTMENT OF ENERGY-DIVISION OF COAL CONVERSION MULTI-PROCESS DEMONSTRATION PLANT BLOCK FLOW DIAGRAM PLANTS 1, 2, & 3											
THE RALPH M PARSONS COMPANY PASADENA, CALIFORNIA		JOB NO. 5435-5	DWG NO. R-01-FS-1	REV. 1							

A



B



C

SECTION 5

UNIT DESCRIPTIONS

Descriptions of the separate operating units included in each plant of the MPDP preliminary design are presented in this section. Process flow sheets, material balances, and product summaries are also included to augment the written descriptions.

The flow diagrams are preliminary in nature; refinements characteristic of a final design have not been made. Material balance values for economic analysis have been taken from the overall block flow diagram, Figure 4-1, contained in Section 4.

The following units are described:

<u>Plant and Unit No.</u>	<u>Unit</u>	<u>Flow Sheet No.</u>	<u>Paragraph Number</u>
Plant 1	Low Pressure Fuel Gas Gasification		5.1
110	Coal Storage	R-110/111, 210/211, 310/311-FS-1	5.1.1
111	Coal Grinding	R-110/111, 210/211, 310/311-FS-1	5.1.2
112	Low Pressure Gasifier	R-112/113-FS-1	5.1.3
113	Low Btu Gas Heat Recovery	R-112/113-FS-1	5.1.4
114	Low Btu Acid Gas Sulfur Removal	R-114-FS-1	5.1.5
130	Water Treatment	R-130/131-FS-1	5.1.6
131	Cooling Water System	R-130/131-FS-1	5.1.7
132	Effluent Treatment	- - - - -	5.1.8
133	Flare	- - - - -	5.1.9
134	Sulfur Storage	- - - - -	5.1.10
150	Buildings, Railroad, Roads, General Facilities	- - - - -	5.1.11
Plant 2	Intermediate Pressure Gasification & Power Generation		5.2

<u>Plant and Unit No.</u>	<u>Unit</u>	<u>Flow Sheet No.</u>	<u>Paragraph Number</u>
210	Added Coal Storage	R-110/111, 210/211, 310/311-FS-1	5.2.1
211	Added Coal Grinding	R-110/111, 210/211, 310/311-FS-1	5.2.2
212	Medium Pressure Gasifiers	R-212/213-FS-1	5.2.3
213	Medium Btu Gas Heat Recovery	R-212/213-FS-1	5.2.4
214	Medium Btu Acid Gas Removal	- - - - -	5.2.5
215	Sulfur Plant	R-215/216-FS-1	5.2.6
216	Tail Gas Treatment	R-215/216-FS-1	5.2.7
217	Process Water Reclamation	R-217-FS-1	5.2.8
230	Added Water Treatment	- - - - -	5.2.9
231	Added Cooling Water System	- - - - -	5.2.10
232	Added Effluent Treatment	- - - - -	5.2.11
233	Added Flare System	- - - - -	5.2.12
240	Oxygen Plant	- - - - -	5.2.13
241	Power Plant	R-241-FS-1, -2	5.2.14
250	Added Buildings, Railroad Roads, General Facilities	- - - - -	5.2.15
Plant 3	Fischer-Tropsch Synthesis		5.3
311	Added Coal Grinding	R-110/111, 210/211, 310/311-FS-1	5.3.1
318	Fischer-Tropsch Acid Gas Removal	- - - - -	5.3.2
319	Fischer-Tropsch Synthesis	R-319-FS-1	5.3.3
320	Fischer-Tropsch Liquid Product Recovery	R-320-FS-1	5.3.4
321	Fischer-Tropsch Gas Methanation	R-321-FS-1	5.3.5

<u>Plant and Unit No.</u>	<u>Unit</u>	<u>Flow Sheet No.</u>	<u>Paragraph Number</u>
322	Fischer-Tropsch Alcohols Mixture Recovery	R-322-FS-1	5.3.6
330	Added Water Treatment	- - - - -	5.3.7
331	Added Cooling Water System	- - - - -	5.3.8
332	Added Effluent Treatment	- - - - -	5.3.9
335	Intermediate Storage	- - - - -	5.3.10
336	Product Storage and Shipping Facilities	- - - - -	5.3.11
350	Added Buildings, Railroad, Roads, General Facilities	- - - - -	5.3.12

5.1 PLANT 1 - LOW PRESSURE GASIFICATION

5.1.1 UNIT 110: COAL STORAGE

The receiving storage and reclaiming facilities are diagrammed on Drawing R-110/111/210/211/310/311-FS-1. Specification coal, sized to 3 x 0 in. and smaller, is delivered by rail and trucks. A train shed is provided, along with dust control car dump bag house collector 110-2201 and car spotter 110-3602, capable of moving a maximum of 55 bottom-dump hopper cars of 120-ton capacity each. The train shed permits thawing frozen coal in cars. Under-track car dump hopper 110-2601 is 110 ft in length with full length feeder 110-0501, which allow continuous dumping at a maximum rate of five cars per hour with one operator. Truck deliveries can be scheduled for off-shifts, unloading directly into the car dump hopper.

Coal is continuously stockpiled under the supervision of the operator. The undertrack feeder discharges into the intermediate No. 1 conveyor 110-2001, which feeds 36-in. x 150-ft radial stacker 110-2004. At the working radius of 150 ft and a discharge height of 47 ft, and traveling through an arc of 150 deg, the radial stacker will build a stockpile 131.5 ft wide with a capacity of 28,275 tons of coal, constituting more than 15 days' requirement for the fuel gas gasifier operation at 1,800 ton/d. A motorized hoist winch on the stacker will minimize the drop height of coal and provide dust control when stacking.

No. 2 conveyors 110-2002 will allow coal to be sent directly to process without stockpiling or rehandling. Reclaiming of stockpiled coal is accomplished with 4.5-cu yd front end loader (FEL) 110-3501 discharging into self-propelled hopper 110-3603, working along the length of plant belt conveyor 110-2003. The 15-day stockpile capacity can be increased by using the FEL to spread the coal outside of the working radius of the stacker.

5.1.2 UNIT 111: COAL GRINDING

Coal conveyed directly from the car dump via No. 2 conveyors 110-2002 and/or coal reclaimed from the stockpile on No. 3 conveyors 110-2003 will be discharged into 200-ton capacity storage hopper bin 111-2602. No intermediate coal storage is provided. The entire conveyor system, including the car dump hopper, will furnish a minimum additional 200-ton storage. The entire system will be fully interlocked and controlled by pulverizer feeder 111-0502, according to the pulverizer 111-2101 loading set point. The pulverizer is a table and roller type, and the desired size classification of 70% minus-200-mesh coal will be controlled by an integral air classifier.

According to manufacturers who produce both ball mill coal pulverizing and table and roller mill pulverizing systems, the latter are more efficient and can pulverize higher moisture content coal than is possible with ball mills.

When coal is stored, or otherwise exposed to rainfall, and pulverizer feed would exceed 10% (or greater) moisture content, the pulverizer can be swept with heated inert gas.

Drawing R-110/111/210/211/310/311-FS-1 also shows a stockpile and equipment for subsequent Plant 2 and Plant 3 operations.

5.1.3 UNIT 112 - LOW PRESSURE GASIFIER

Figure 5.1-1 is a sketch of the gasifier.

Coal is gasified at 40 psig with steam and air to produce a low-Btu gas which, after cleanup, is useful for boiler fuel or limited power generation. High pressure steam is also produced from the heat recovery. The process is shown on Flow Diagram R-112/113-FS-1.

In Plant 2 of the project, an oxygen plant will be available, and oxygen may be substituted for air in the gasifier. The use of oxygen would approximately double the gasifier capacity, produce higher Btu gas, and result in additional steam make. This alternate mode of operation is included to provide for the possibility of the plant's two gasifiers being unavailable to supply fuel gas to the combined cycle power plant or syngas to the Fischer-Tropsch plant. A compressor is also included to compress the gasifier product to 500 psig for use in Plant 2 and/or 3 operations.

Coal is fed into the gasifier second stage by screw feeders 112-2001 together with superheated process steam. Hot gases rising from the first stage combustion zone heat and pyrolyze the coal. The steam reacts with the coal to form hydrogen and carbon monoxide. The resulting gas and char mix is carried overhead to char cyclone 112-2201. Cyclone overhead gas flows to the heat recovery unit. Char underflow flows into the gasifier first stage where it reacts with preheated air (or oxygen) to form molten ash or slag and additional gas.

Molten slag is tapped from the gasifier into the quench water pit which is kept cool by circulating water through quench water cooler 112-1301. The slag solidifies to a frit of sand-like consistency. A conveyor lifts the slag from the water, and the slag sludge is transported for burial as land fill.

During air blown operation, the gasifier produces a gas which, after water condensation and H₂S removal, is 15 vol % hydrogen, 26 vol % carbon monoxide, and 55 vol % nitrogen, dry basis. The higher heating value is estimated to be approximately 135 Btu/scf, dry basis, or 130 Btu/scf, as-is basis. When operating using oxygen, the gasifier product gas is estimated to contain 40 and 48 vol % H₂ and CO, respectively, and to have a higher heating value of approximately 290 Btu/scf dry basis.

Temperature control in the gasifier will be maintained by a controller with sensor located in the gas outlet line. The controller will reset the speed control on the air compressor turbine, so that rising gasifier temperature will cause a reduction in air flow. During oxygen-blown operations, the controller will reset a valve in the oxygen inlet line.

Process steam flow will be maintained or adjusted by means of a flow control element in the steam generator outlet.

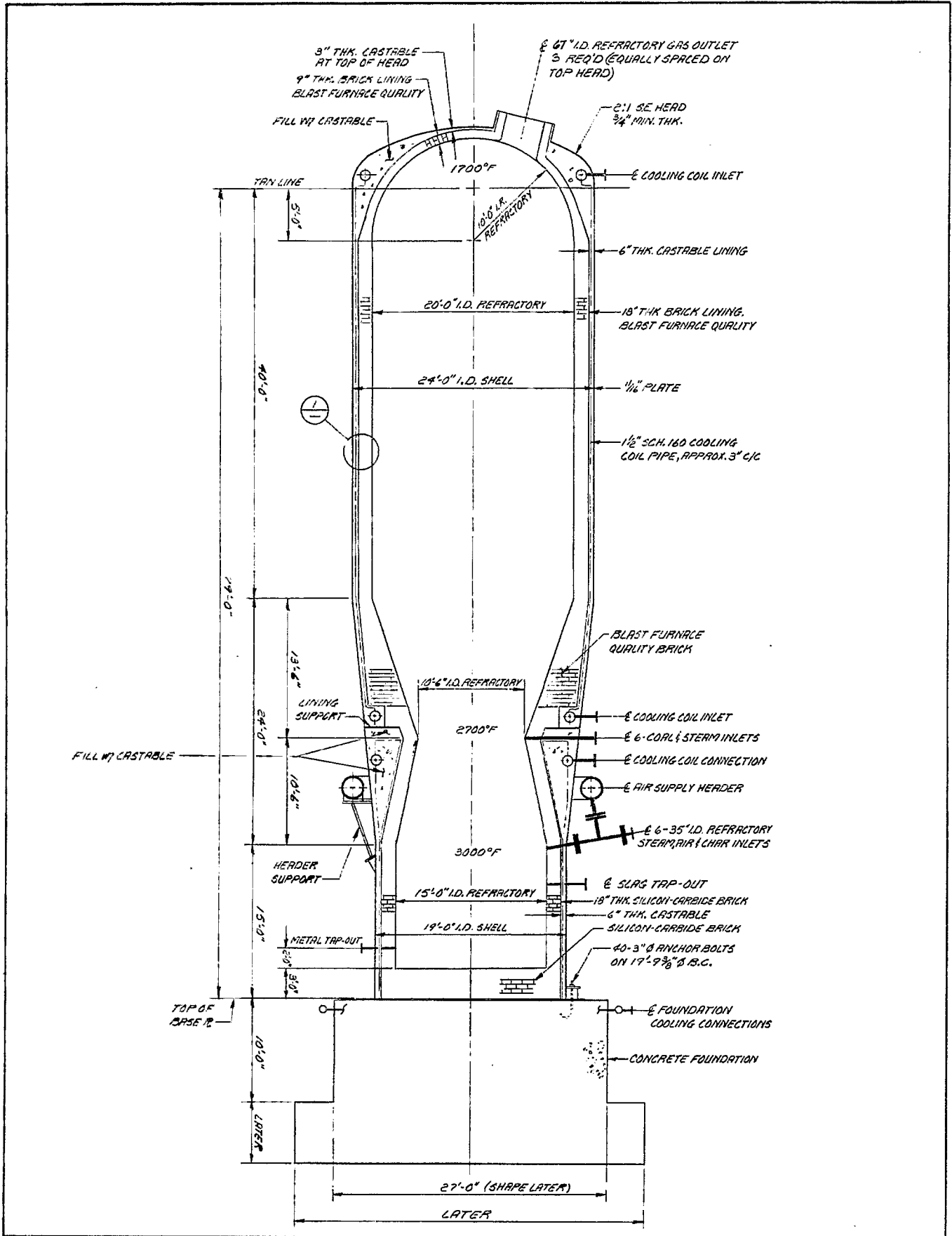


Figure 5.1-1 - Low-Btu Gasifier Conceptual Sketch

The stage 1 gasifier is equipped with a boiling-water cooled refractory chamber. The temperature in stage 1 can be maintained by controlling the quantity of raw coal introduced to this stage by a second set of screw feeders, 112-2002.

5.1.4 UNIT 113: LOW-Btu GAS HEAT RECOVERY

The process is shown on Flow Diagram R-112/113-FS-1. In summary, gasifier overhead gas is cooled from 1800°F to approximately 180°F, the heat being recovered in three steam systems:

- (1) Low pressure (50-psig) process steam. A quantity sufficient for feed to the gasifier is generated and superheated to 1100°F. A portion of the makeup water will be filtered condensate recovered from the gasifier; therefore, the water will be of low quality, and the system will contain H₂S.
- (2) Medium pressure (150-psig) steam. This steam is generated without superheat for use in the turbine-driven high pressure feedwater pumps, 113-1501 and 1502 and also for use in acid gas removal unit 114. A portion of this steam is condensed for use in Unit 114 and, when necessary, to supply high quality makeup water to the high pressure steam system.
- (3) High pressure (1500-psig) steam. Heat not used for generation of low and medium pressure steam is recovered as superheated (950°F) high pressure steam. The steam is used to preheat air in air heater 112-1501 and to operate turbine driven air compressor 113-1801. The remainder is product available to a consumer.

During operation on oxygen, there will be insufficient process steam make, so a portion of the 1500-psig steam will be reduced in pressure to 50 psig for use in the gasifier.

The recovery of heat from the gasifier effluent gas is described in the following paragraphs.

Gasifier overhead gas at 1800°F from char cyclone 112-2201 is cooled in two parallel steam superheaters, process steam superheater 113-1307, and higher pressure steam superheater 113-1308. The parallel streams then combine and the effluent is further cooled in high pressure steam generator 113-1309. Discharge temperature from the high pressure generator is about 1050°F.

The gas then passes through hot electrostatic precipitator 113-2202 for further removal of suspended char fines. The gas then flows through three sets of heat recovery systems in series, each set consisting of three parallel heat exchangers. Discharge from each set is combined in a manifold line. The three systems are listed below:

- (1) Medium pressure steam generator 113-1311, high pressure feedwater heater 113-1310, and process steam superheater 113-1323

- (2) Medium pressure feedwater heater 113-1321, high pressure feedwater heater 113-1320, and process steam generator 113-1312, followed in series by process water heater 113-1313
- (3) Medium pressure feedwater preheater 113-1319, high pressure feedwater preheater 113-1314, and process feedwater preheater 113-1322

The combined discharge from the last set of exchangers flows through effluent air cooler 113-1316 into condensate return surge drum 113-1205. Product gas from this drum then flows to the acid gas removal unit.

Condensate from the surge drum is filtered and returned to the process steam system. Makeup water is added downstream of the filters.

During operation on oxygen, the air compressor is shut down, and oxygen is preheated in one of the two air heater shells 112-1201.

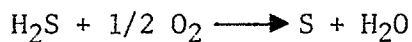
5.1.5 UNIT 114: LOW-Btu ACID GAS SULFUR REMOVAL

The cleaned cooled fuel gas is processed in two parallel proprietary redox solution units to remove hydrogen sulfide and oxidize it to elemental sulfur. The process is depicted in Drawing R-114-FS-1.

The hydrogen sulfide present in the fuel gas is absorbed in the reactor by treatment with the proprietary redox solution and oxidized to commercial sulfur. The reduced redox solution is reoxidized by contact with air and subsequently recirculated to the reactor.

Elemental sulfur is removed in the air-blowing step as a froth. The froth is pumped to the sulfur separator and melter system where the sulfur is melted under pressure, separated from the redox solution, and transferred to sulfur product storage. The separated redox solution is returned to the system.

The following simplified basic reaction is involved:



The sweetened fuel gas is suitable for combustion containing typically less than 25 ppm of H₂S and less than 50 ppm of total sulfur compounds, mainly carbonyl sulfide (COS).

The sulfur product is yellow and has a purity of 99.9% - plus. A slip stream of the redox solution is treated so that the effluent will satisfy environmental requirements.

5.1.6 UNIT 130: WATER TREATMENT SYSTEM

The process is shown in Flow Diagram R-130/131-FS-1.

Water will be pumped from the river through screens for trash removal into river water sedimentation basin 130-1911 where settling of larger

solid particles occurs. River water pumps 130-1501, 1502, and 1503, mounted in the clear well of this basin, then pump the water to the mechanical clarifier tanks.

Water for the cooling tower and noncritical process use, which requires only settling, is pumped to clarifier tank 130-1905. The water then goes to intermediate storage. Sludge from the clarifier tank is returned to the river.

Water which will become 50-psig BFW or evaporator feed is pumped to treated water clarifier tank 130-1904 through chemicals addition unit 130-0802, where it is treated with sodium carbonate, lime, and coagulants. Water from the clarifier is filtered through filter 130-0801 and stored in treated water tank 130-1908.

Sludge from the treated water clarifier tank is filtered in sludge rotary vacuum filter 130-2204. Solids are used as land fill, and the filtered water is recycled to the clarifier tanks.

5.1.7 UNIT 131: COOLING WATER SYSTEM

Cooling tower water receives additional conventional chemical treatment to inhibit corrosion and to control algae. The cooling water system is portrayed on Drawing R-130/131-FS-1. The cooling towers are the mechanical-draft cross-flow type.

5.1.8 UNIT 132: EFFLUENT TREATMENT

Provisions for effluent treatment include a skimmer pit for separation of oil from wash downs and contaminated waters followed by a settling pond for removal of particulates before discharging to the storm drain.

A sewage treatment plant is included for treating sanitary sewage. Effluent will be discharged to the storm drain.

5.1.9 UNIT 133: FLARE

A plant flare provides for combustion of vented gas on operation of pressured relief valves or manual venting. A knockout drum is provided to accumulate and return condensed liquid to the process system or water to effluent treatment.

5.1.10 UNIT 134: SULFUR STORAGE

Facilities are included to solidify molten recovered sulfur by chill spraying and stockpiling in an open area as the need arises. This unit will also serve to handle excess molten sulfur from subsequent phase installations.

5.1.11 UNIT 150: BUILDINGS AND GENERAL FACILITIES

The buildings consist of office facilities, maintenance shops, and laboratory.

The laboratory area is also equipped with space and facilities for bench-scale process investigation and troubleshooting activities. These facilities, and similar facilities to be installed to support Plants 2 and 3 operations, will permit independent small scale investigation of problem areas defined during operation of the larger demonstration plant units. They will also provide facilities for process improvement studies.

5.1.12 PLANT 1 PRODUCTS

Products from Plant 1 are as follows:

A. Low-Btu Fuel Gas

Quantity - 255 MMscf/d

This is a gaseous mixture of hydrogen, carbon monoxide, carbon dioxide, and nitrogen when produced by air-blown gasification. With full oxygen-blown gasification, nitrogen content would be near nil, and the heating value would be higher.

Composition (vol %)

	<u>Air-Blown Gasification</u>	<u>Oxygen-Blown Gasification</u>
Hydrogen	14.1	39.1
Carbon Monoxide	25.5	46.5
Carbon Dioxide	4.0	10.5
Nitrogen	53.5	1.0
Water	2.9	2.9
Hydrogen Sulfide <25 ppm		<25ppm
Total	<u>100.0</u>	<u>100.0</u>

Properties

Molecular weight	24.8	19.4
Higher heating value, Btu/scf, dry basis	134	289
Btu/scf, as-is basis	130	280
Specific gravity, air = 1, @60°F	0.86	0.67
Delivered pressure (psig)	22	22
Delivered temperature (°F)	110	110

B. Steam

Quantity for sale or transfer (lb/hr) - 94,000.

Properties

Pressure (psig)	1,250
Temperature (°F)	950

C. Sulfur

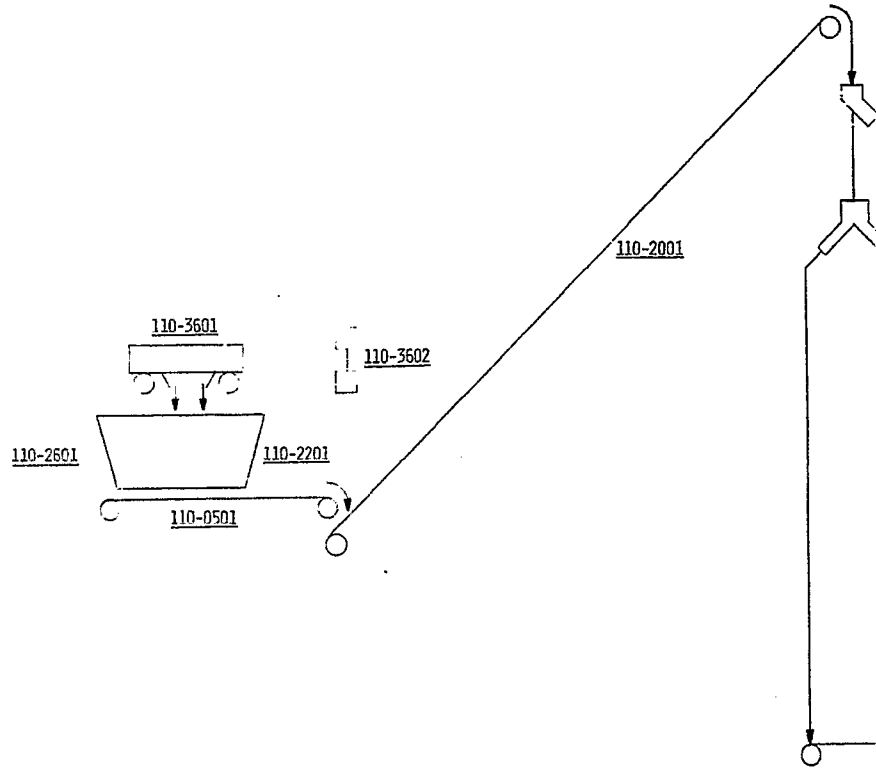
Quantity (ton/d)	65.0
Purity (% sulfur)	99.9
Color	Yellow

110-2601
CAR DUMP HOPPER
12' WIDE X 100' LONG
200 TON CAPACITY

110-3601
CAR THAWER
2 CAR CAPACITY
2000 KW

110-3602
CAR SPOTTER
55 CAR CAPACITY
100 HP

110-2201
CAR DUMP
BAG HOUSE DUST COLLECTOR
35,000 CFM @ 15" Wg
100 HP



110-0501
HOPPER BELT FEEDER
48" WIDE X 100'
150 HP DRIVE

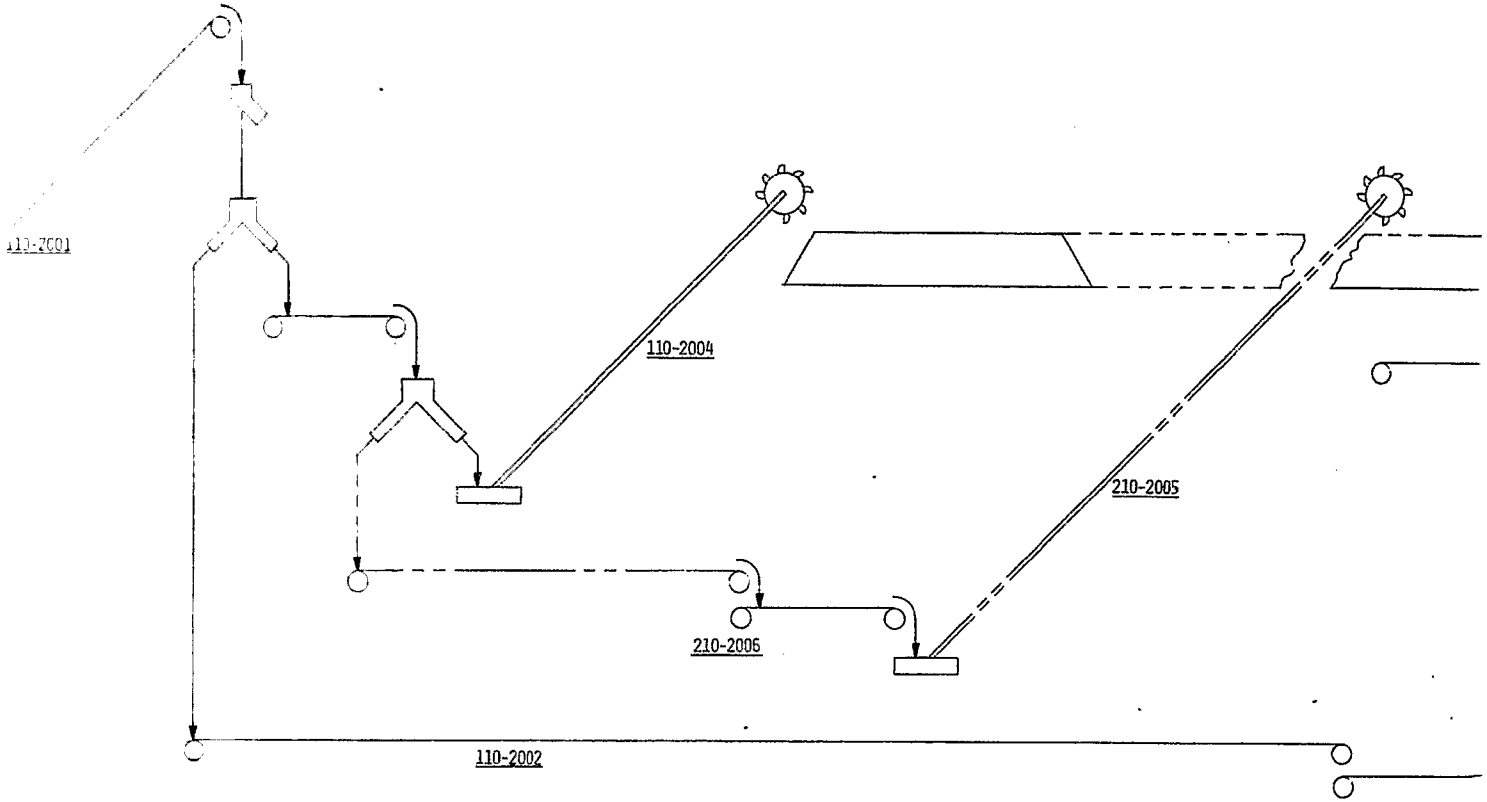
110-2001
BELT CONVEYOR NO. 1
36" WIDE X 120'
20 HP DRIVE

A

110-2201
 CAR DUMP
 BAG HOUSE DUST COLLECTOR
 35,000 CFM @ 15" Wg
 100 HP

110/210-3501,3502
 FRONT END LOADER
 RUBBER TIRED, DIESEL
 ENGINE POWERED

111/211/311-2602,26
 STORAGE BIN
 200 TON CAPACI



110-2001
 CONVEYOR NO. 1
 36" WIDE X 120'
 HP DRIVE

110-2002
 BELT CONVEYOR NO. 2
 36" WIDE X 540'
 50 HP DRIVE

110-2004
 RADIAL STACKER NO. 1
 36" WIDE X 150'
 65 HP DRIVE

210-2005
 BELT CONVEYOR NO. 4
 36" WIDE X 405'
 50 HP DRIVE

210-2005
 RADIAL STACKER NO. 2
 36" WIDE X 150'
 65 HP DRIVE

111/211/311-2101, 2102, 2103
 COAL PULVERIZER
 75 TPH

111

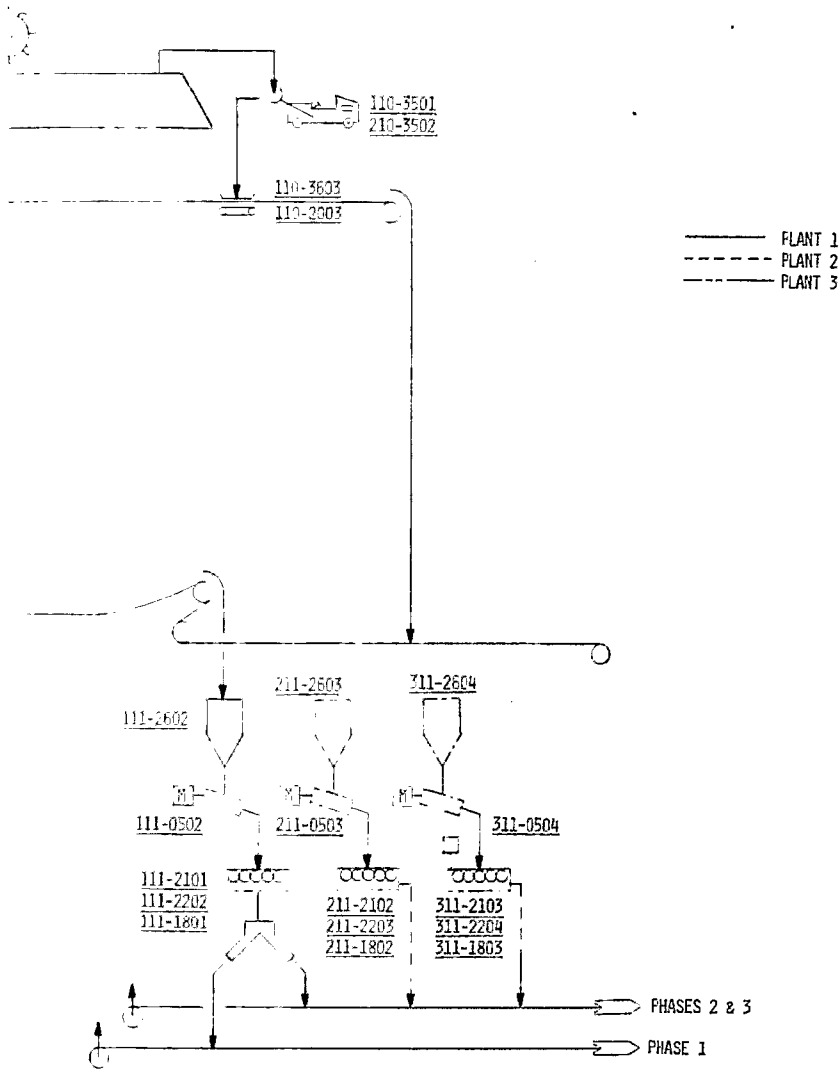
5.1-9

B

111-2101, 2603, 2604
STORAGE BIN
10 TON CAPACITY

111/211/311-0502, 0503, 0504
PULVERIZER FEEDER
24" WIDE X 50'
20 HP DRIVE

111/211/311-2202, 2203, 2204
BAG HOUSE DUST COLLECTOR
100,000 CFM @ 25" Wg



111/211/311-1801, 1802, 1803
BAG HOUSE BLOWER
100,000 CFM @ 55" Wg
900 HP DRIVE

110-3603
SELF PROPELLED HOPPER
10 TON CAPACITY
5 HP DRIVE

110-2003
BELT CONVEYOR NO. 3
36" WIDE X 1,080'
75 HP DRIVE

REV. NO.	CUST. APPR.	DATE	REVISION	BY	PROG. CHECK	CHIEF PROC. ENGR.	CHIEF OPER. ENGR.	PRVC. ENGR.
0			ISSUED FOR REPORT					
DEPARTMENT OF ENERGY - DIVISION OF COAL CONVERSION MULTIPROCESS DEMONSTRATION PLANT PROCESS FLOW DIAGRAM COAL STORAGE & PREPARATION UNITS 110/111/210/211/310/311								
THE RALPH M. PARSONS COMPANY PASADENA, CALIFORNIA				JOB NO. 5435-5	Dwg. NO. R-110/111/210/211/ 310/311-FS-1			REV. 0

e

112-2501
LOW PRESSURE
GASIFIER

112-2201
CHAR CYCLONE

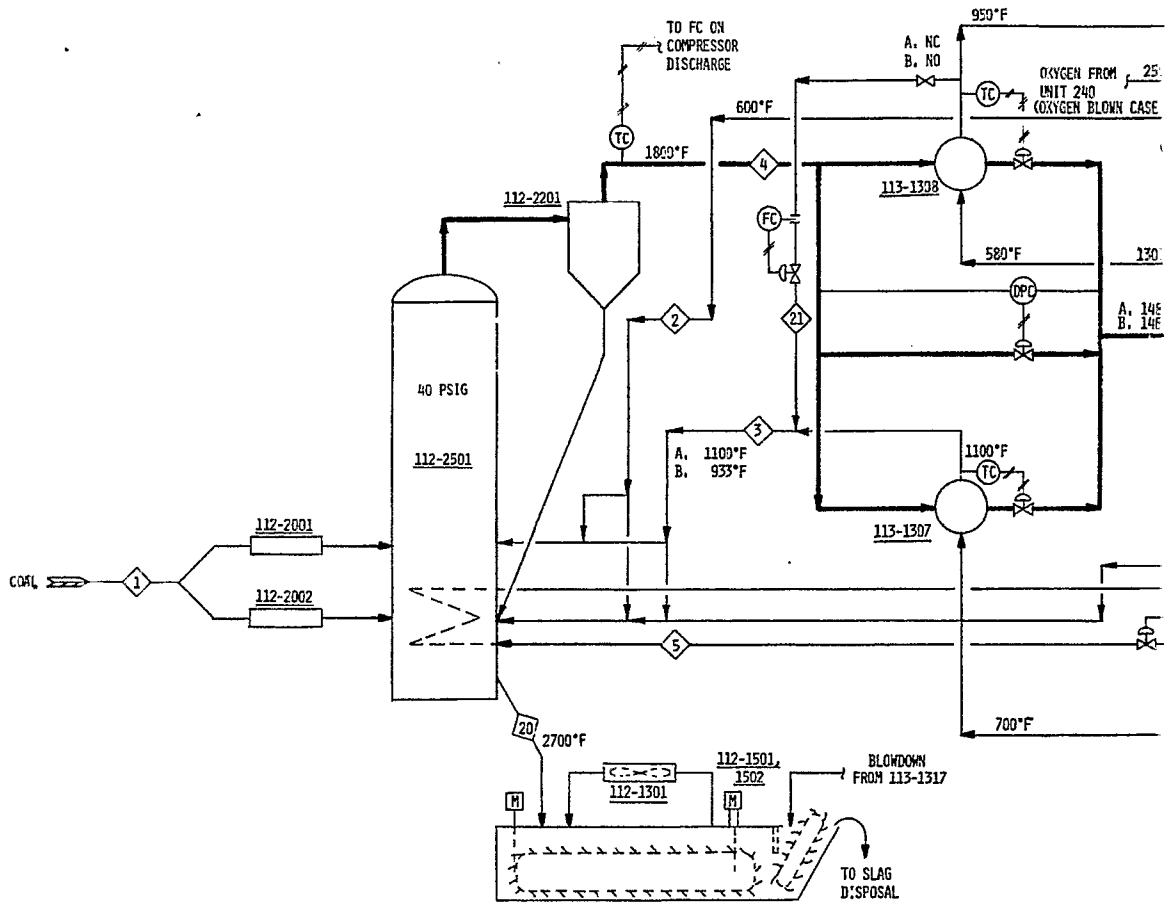
112-1501
QUENCH WATER
AIR COOLER

113-1307, 1323
PROCESS STEAM
SUPERHEATERS
A. 5.4 MMBTU/HR. EACH
B. 7.8 MMBTU/HR. EACH

113-1308
HIGH PRESSURE
STEAM SUPERHEATER
A. 73.3 MMBTU/HR.
B. 83.7 MMBTU/HR.

112-1302
AIR HEATER
A. 40.2 MMBTU/HR.
B. 16.8 MMBTU/HR.

112-1303
HIGH PRESSURE
STEAM
A. 97.5
B. 91.2



112-2001
GASIFICATION ZONE
COAL FEEDER

112-2002
SLAGGING ZONE
COAL FEEDER

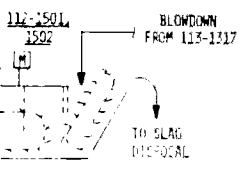
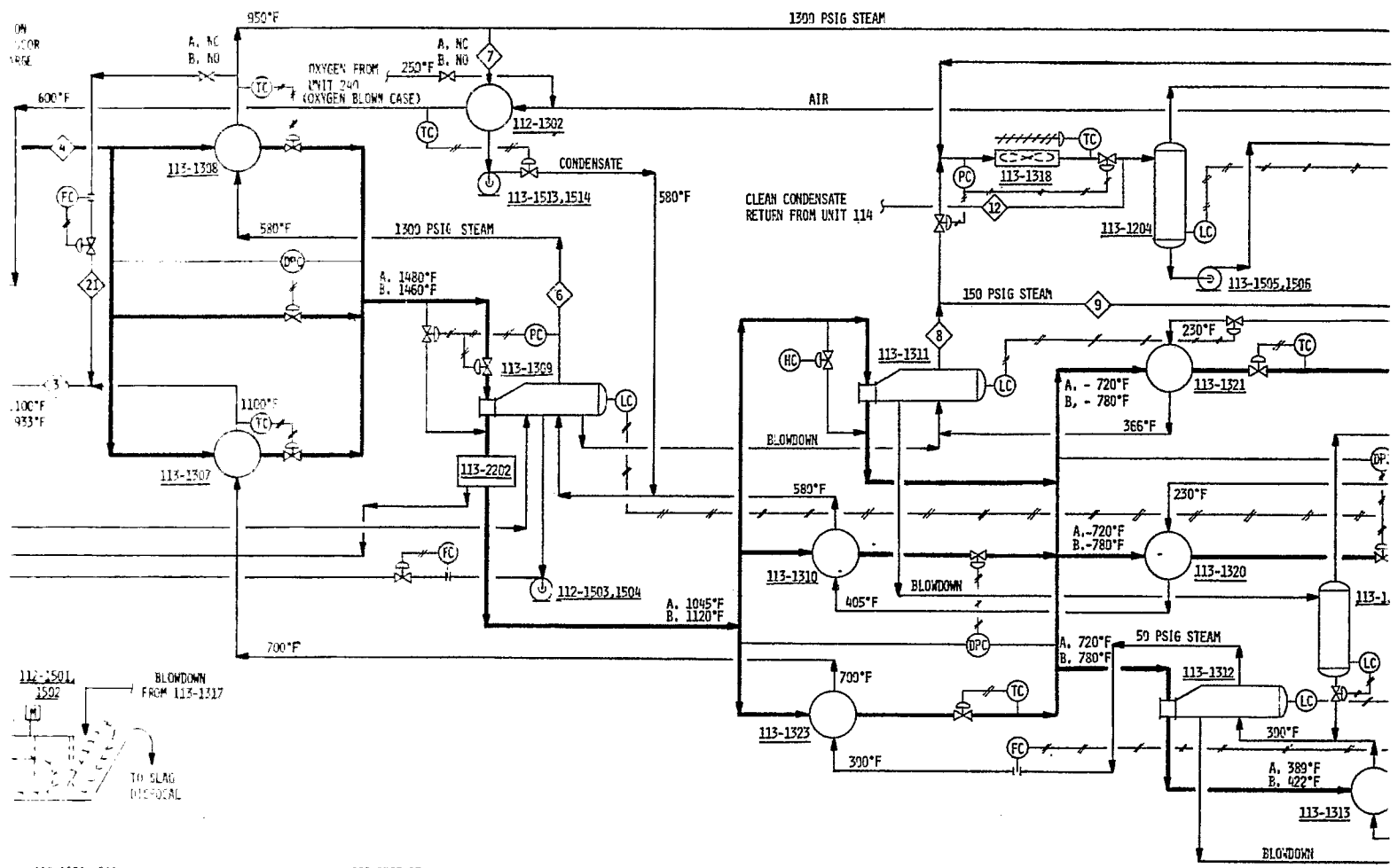
112-1501, 1502
SLAG QUENCH
CIRCULATING PUMPS

112-1302, 1303
HIGH PRESSURE
STEAM
CIRCULATING

AIR BLOWN CASE

STREAM NO.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
DESCRIPTION	COAL FEED	AIR TO GASIFIER	STEAM TO GASIFIER	GASIFIER GAS	COOLING WATER	1300 PSIG STEAM	STEAM TO AIR HEATER	150 PSIG STEAM	STEAM TO TURBINE	50 PSIG STEAM TO UNIT 114	CONDENSATE TO UNIT 114	CONDENSATE FROM UNIT 114	TREATED MAKEUP WATER	STEAM TO COMPRESSOR	1300 PSIG PRODUCT STEAM
FLOW, MPH	-	-	-	3.515	-	-	-	-	-	-	-	-	-	-	-
CO ₂	-	-	-	2,095	-	-	-	-	-	-	-	-	-	-	-
H ₂	-	-	-	1,131	-	-	-	-	-	-	-	-	-	-	-
CH ₄	-	-	-	113	-	-	-	-	-	-	-	-	-	-	-
N ₂	-	80,800	-	14,670	-	-	-	-	-	-	-	-	-	-	-
O ₂	-	3,996	-	-	-	-	-	-	-	-	-	-	-	-	-
H ₂ O	225	-	1,482	1,034	4,536	14,099	2,538	1,665	994	910	638	133	994	6,342	5,219
SLAG - SOL. LEAD	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
COND. LP/HP	14,952	-	-	-	-	-	-	-	-	-	-	-	-	-	-
COND. LB/HR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FLOW TOTAL, MPH	-	18,734	1,482	28,219	4,936	14,099	2,538	1,665	994	910	638	133	994	6,342	5,219
FLOW TOTAL, LB/HR	100,000	540,517	26,700	637,515	88,923	254,000	45,729	30,000	17,920	16,400	11,500	2,400	17,800	114,260	94,000
MPH	-	28.6	18.0	24.7	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0	18.0
TEMPERATURE, °F	100	170.4	13.5	257.0	-	128.4	23.1	15.2	9.0	8.3	228	293	100	80	47.5
TEMPERATURE, °C	-	60	110	125	-	53	8	6	5	5	90	37	38	27	11
PRESSURE, PSIG	-	50	50	40	1300	1300	1300	150	1300	50	50	20	20	1300	1300

113-1304 HIGH PRESSURE STEAM REHEATER A. 73.3 MMBTU/HR. B. 83.7 MMBTU/HR.	112-1502 AIR HEATER A. 40.2 MMBTU/HR. B. 16.8 MMBTU/HR.	113-1309 HIGH PRESSURE STEAM GENERATOR A. 97.5 MMBTU/HR. B. 91.2 MMBTU/HR.	113-1310, 1320 HIGH PRESSURE FEEDWATER HEATERS A. 42.1 MMBTU/HR. EACH B. 54.5 MMBTU/HR. EACH	113-1311 MEDIUM PRESSURE GENERATOR A. 25.7 MMBTU/HR. B. 25.7 MMBTU/HR.	113-1318 EXCESS STEAM CONDENSER	113-1204 CLEAN CONDENSATE RECEIVER	113-1321 MEDIUM PRESSURE FEEDWATER HEATER A. 4.3 MMBTU/HR. B. 4.3 MMBTU/HR.	113-1312 PROCESS STEAM GENERATOR A. 24.3 MMBTU/HR. B. 35.2 MMBTU/HR.	11 BLOWDOWN
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113-1301, 1302
SLAG PIT
CIRCULATING PUMP

112-1502, 1504
HIGH PRESSURE
CIRCULATING PUMPS

113-1505, 1506
DEAERATOR FEED PUMPS

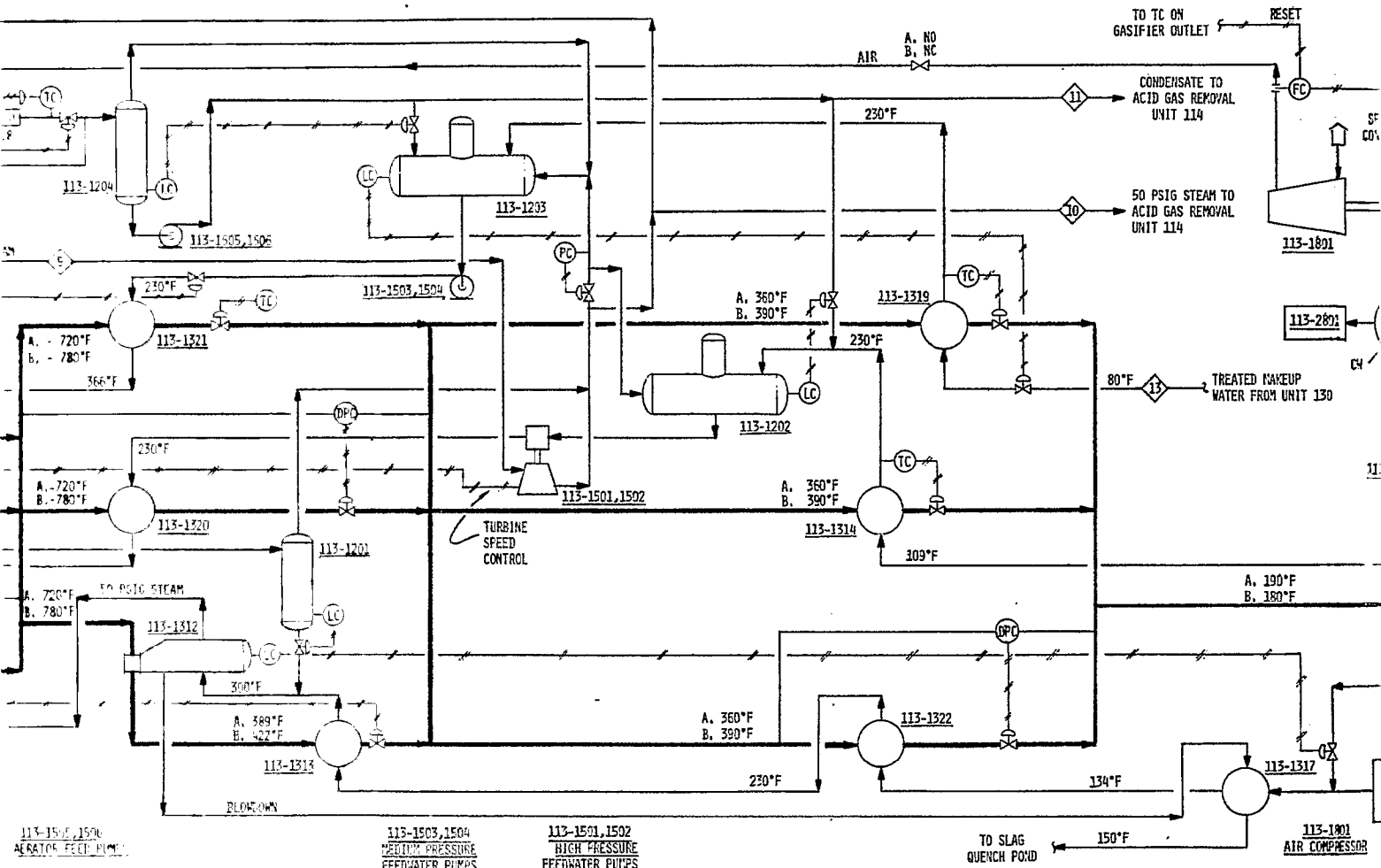
17	18	19	20	21	STREAM NO.	17	18	19	20	21
CONDENSATE TO UNIT 114	TREATED MAKUP WATER	STEAM TO OWNER'S USE	1300 PSIG PROD. BY STEAM	1300 PSIG CONDENSATE	DESCRIPTION	PROCESS CONDENSATE	MAKEUP WATER	GAS TO UNIT 114	SLAG	PROCESS STEAM FROM HP SYSTEM
-	-	-	-	-	FLOW, MPH	-	-	3,916	-	-
-	-	-	-	-	H ₂	-	-	7,095	-	-
-	-	-	-	-	CO	-	-	1,131	-	-
-	-	-	-	-	CO ₂	-	-	173	-	-
-	-	-	-	-	H ₂ S	-	-	14,870	-	-
-	-	-	-	-	N ₂	-	-	-	-	-
-	-	-	-	-	O ₂	-	-	-	-	-
-	-	-	-	-	H ₂ O	235	1,395	799	-	-
-	-	-	-	-	SOLIDS: ASH, LB/HR	-	-	-	17,700	-
-	-	-	-	-	COAL, LB/HR	-	-	-	-	-
-	-	-	-	-	CRAB, LB/HR	-	-	-	2,016	-
-	-	-	-	-	FLOW TOTAL, MPH	235	1,395	27,994	-	-
-	-	-	-	-	FLOW TOTAL, LB/HR	4,234	25,136	693,261	19,716	-
-	-	-	-	-	MW	18.0	18.0	24.8	-	-
-	-	-	-	-	MCCFD	-	-	254.9	-	-
-	-	-	-	-	TEMPERATURE, °F	110	80	110	2700	-
-	-	-	-	-	PRESSURE, PSIG	25	65	22	40	-

1	STREAM NO.	COAL FEED
-	DESCRIPTION	-
-	FLOW, MPH	-
-	H ₂	-
-	CO	-
-	CO ₂	-
-	H ₂ S	-
-	N ₂	-
-	O ₂	-
-	H ₂ O	437
-	SOLIDS: ASH, LB/HR	-
-	COAL, LB/HR	233,720
-	CRAB, LB/HR	-
-	FLOW TOTAL, MPH	-
-	FLOW TOTAL, LB/HR	291,620
-	MW	-
-	MCCFD	-
-	TEMPERATURE, °F	100
-	PRESSURE, PSIG	-

B

113-1204 MEDIUM PRESSURE FEEDWATER HEATER A. 4.3 MMBTU/HR. B. 4.3 MMBTU/HR.	113-1312 PROCESS STEAM GENERATOR A. 24.3 MMBTU/HR. B. 35.2 MMBTU/HR.	113-1201 BLOWDOWN RECEIVER	113-1313 PROCESS WATER HEATER A. 2.1 MMBTU/HR. B. 3.1 MMBTU/HR.	113-1203 MEDIUM PRESSURE FEEDWATER DEAERATOR	113-1202 HIGH PRESSURE FEEDWATER DEAERATOR	113-1314 HIGH PRESSURE FEEDWATER PREHEATER A. 26.2 MMBTU/HR. B. 33.9 MMBTU/HR.	113-1319 MEDIUM PRESSURE FEEDWATER PREHEATER A. 4.6 MMBTU/HR. B. 4.6 MMBTU/HR.	113-1322 PROCESS FEEDWATER PREHEATER A. 4.4 MMBTU/HR. B. 6.4 MMBTU/HR.	113-1317 BLOWDOWN/ FEEDWATER EXCHANGER 0.75 MMBTU/HR.
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1300 PSIG STEAM



113-1503, 1504
AERATOR FEED PUMPS

113-1503, 1504
MEDIUM PRESSURE
FEEDWATER PUMPS

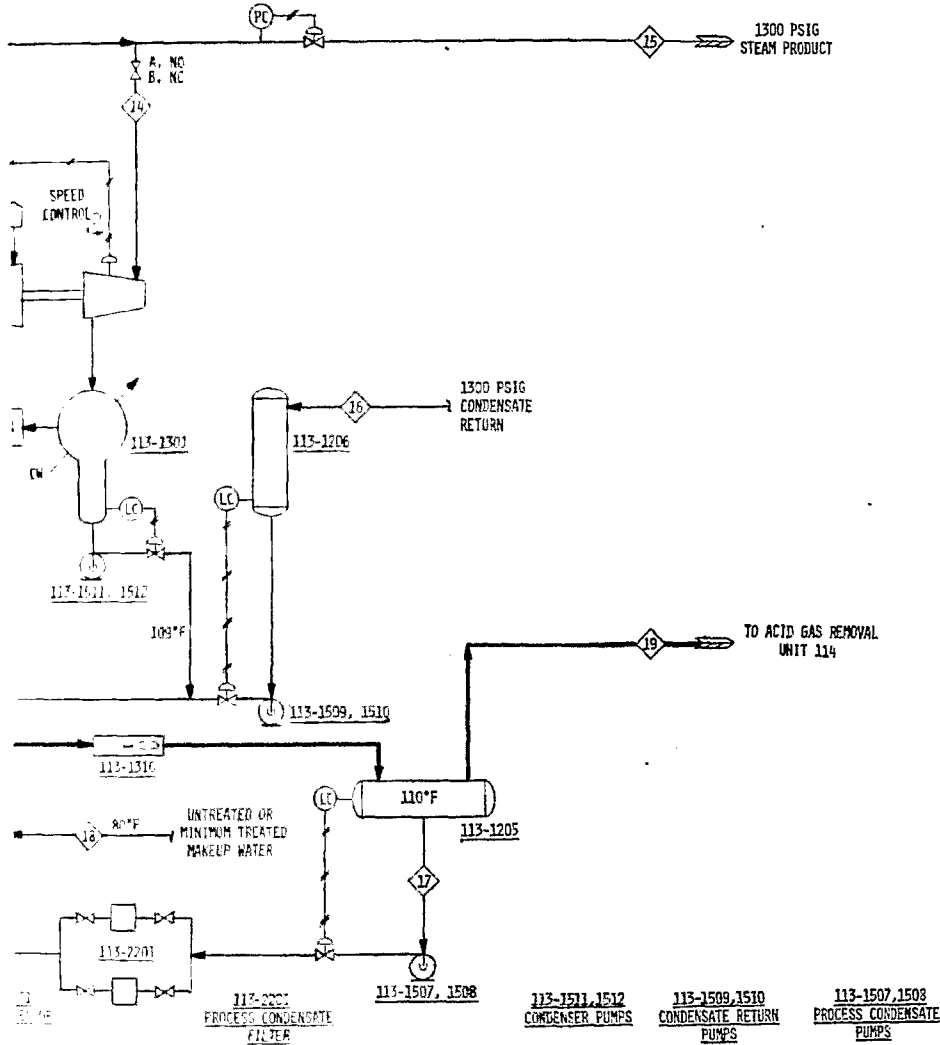
113-1501, 1502
HIGH PRESSURE
FEEDWATER PUMPS

O₂ BLOWN CASE

STREAM NO.	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15
DESCRIPTION	COOL WATER	O ₂ TO GASIFIER	STEAM TO GASIFIER	GASIFIER GAS	COOLING WATER	1300 PSIG STEAM	STEAM TO O ₂ HEATER	150 PSIG STEAM	STEAM TO TURBINE	50 PSIG STEAM TO UNIT 114	CONDENSATE TO UNIT 114	CONDENSATE FROM UNIT 114	TREATED MAKEUP WATER	STEAM TO COMPRESSOR	1300 PROX.
FLOW, M ³ /HR	-	-	-	10,557	-	-	-	-	-	-	-	-	-	-	-
WATER	-	-	-	19,042	-	-	-	-	-	-	-	-	-	-	-
STEAM	-	-	-	2,549	-	-	-	-	-	-	-	-	-	-	-
CONDENSATE	-	-	-	236	-	-	-	-	-	-	-	-	-	-	-
WATER	-	-	-	255	-	-	-	-	-	-	-	-	-	-	-
WATER	4.07	4,551	0,319	4,104	7,521	16,097	1,061	1,665	1,287	910	633	133	994	-	8.
SOLIDS: ASH, LB/HR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CO ₂ , LB/HR	287,720	-	-	-	-	-	-	-	-	-	-	-	-	-	-
CH ₄ , LB/HR	-	-	-	-	-	-	-	-	-	-	-	-	-	-	-
FLOW TOTAL, M ³ /HR	281,600	6,483	8,319	31,654	7,521	16,097	1,061	1,665	1,287	910	633	133	994	-	8.
FLOW TOTAL, LB/HR	281,600	206,848	149,872	610,023	135,501	280,000	19,112	30,000	23,182	16,400	11,500	2,400	17,500	-	159.
M ³ /HR	-	31.9	18.0	15.3	18.0	38.0	18.0	18.0	19.0	18.0	18.0	18.0	18.0	-	-
MPCOH	-	59.0	75.0	255.3	-	146.6	9.7	15.2	11.7	8.3	-	-	-	-	-
TEMPERATURE, °F	100	600	930	1000	580	800	950	302	950	298	298	100	80	-	-
PRESSURE, PSIG	-	50	50	40	1300	1300	1300	150	1300	50	50	20	20	-	-

e

7	113-2801	113-1201	113-1316	113-1206	113-1205	113-2202
V	VACUUM	SURFACE	EFFLUENT ATR	CONDENSATE RETURN	PRODUCT	ELECTROSTATIC
ER	SYSTEM	CONDENSER	COOLER	SURGE DRUM	CONDENSATE	PRECIPITATOR
EF		131.6 MMBTU/HR.	A. 22.0 MMBTU/HR.		RECEIVER	
J/HR.			B. 65.0 MMBTU/HR.			



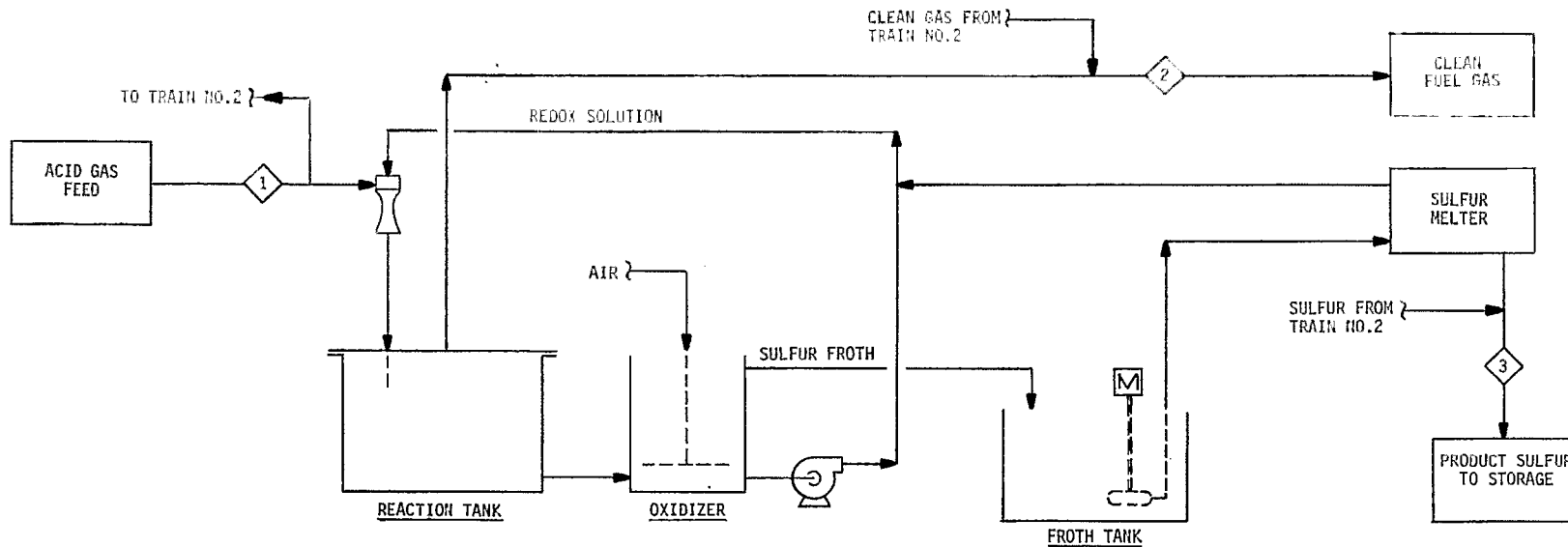
- NOTES:
- CASE A - AIR BLOWN GASIFIER. HEAT AND MATERIAL BALANCE SHOWN ON THIS PROCESS FLOW DIAGRAM IS AN AVERAGE OPERATING CASE ASSUMING 52 MMBTU/HR HEAT DUTY IN THE GASIFIER STEAM COIL. (FOR EQUIPMENT DESIGN, THE MAXIMUM DUTY IN THE GASIFIER COIL IS 80 MMBTU/HR AND THE MINIMUM 25 MMBTU/HR.
CASE B - OXYGEN BLOWN GASIFIER. HEAT AND MATERIAL BALANCE ASSUMES MAXIMUM (80 MMBTU/HR) DUTY IN GASIFIER COIL.
 - NO - INDICATES NORMALLY OPEN
NC - INDICATES NORMALLY CLOSED

15	16	STREAM NO.	17	18	19	20	21
1300 PSIG STEAM	1300 PSIG CONDENSATE	DESCRIPTION	PROCESS CONDENSATE	MAKEUP WATER	GAS TO UNIT 114	SLAG	PROCESS STEAM FROM HP SYSTEM
-	-	FLOW, MPH	-	-	10,957	-	-
-	-	H ₂	-	-	13,642	-	-
-	-	CO	-	-	2,949	-	-
-	-	CO ₂	-	-	325	-	-
-	-	H ₂ O	-	-	266	-	-
-	-	N ₂	-	-	-	-	-
-	-	O ₂	-	-	-	-	-
-	-	SO ₂	-	-	-	-	-
6,864	6,864		3,294	6,857	810	-	6,372
-	-	SOLIDS - ASH, LB/DG	-	-	-	36,409	-
-	-	LOAM, LB/DG	-	-	-	-	-
-	-	CLAY, LB/DG	-	-	-	3,919	-
6,864	6,864	FLOW TOTAL, MPH	3,294	6,857	28,760	-	6,172
131,767	131,686	FLOW TOTAL, LN/HR	59,344	105,528	550,679	38,328	111,203
18.0	18.0	MPH	18.0	18.0	19.4	-	18.0
109	109	TEMPERATURE, °F	110	80	258.3	-	55.2
1500	20	PRESSURE, PSIG	25	65	110	2700	50

ISSUED FOR REPORT		BY	DATE	REVISED	BY	DATE
0	5/25/78	WJ	5/25/78			
REV NO	DATE	BY	DATE	REVISED	BY	DATE
0	5/25/78	WJ	5/25/78			
DEPARTMENT OF ENERGY - DIVISION OF COAL CONVERSION MULTI-PROCESS DEMONSTRATION PLANT PROCESS FLOW DIAGRAM LOW PRESSURE GASIFIER UNITS 112/113						
THE RALPH M. PARSONS COMPANY PASADENA, CALIFORNIA		JOB NO. 5435-5	DWG. NO. R-112/113-FS-1	REV 9		

D

5.1-11



STREAM	1	2	3
GASES, MOLES/HR			
H ₂	5,296.65	5,296.65	-
N ₂	12,739.70	12,739.70	-
H ₂ S	173.08	0.67	-
H ₂ O	569.82	570.45	-
CO ₂	1,372.25	1,372.25	-
CO	6,854.23	6,854.23	-
TOTAL, MOLES/HR	27,005.73	26,833.95	-
TOTAL, LB/HR	-	-	-
LIQUID SULFUR, LB/HR	-	-	5,529

SULFUR REMOVAL UNIT CONSISTS OF TWO PARALLEL TRAINS EACH SIZED TO TREAT 50 PERCENT OF ACID GAS FEED. STREAM DATA SHOWN IS TOTAL FOR BOTH TRAINS.

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

0	1/24/77	ISSUED FOR REPORT							
REV NO	CUST APPR	DATE	REVISION	BY	PROG ENGR	CHECK	CHIEF ENGR	CHIEF OPER ENGR	PROG DIR

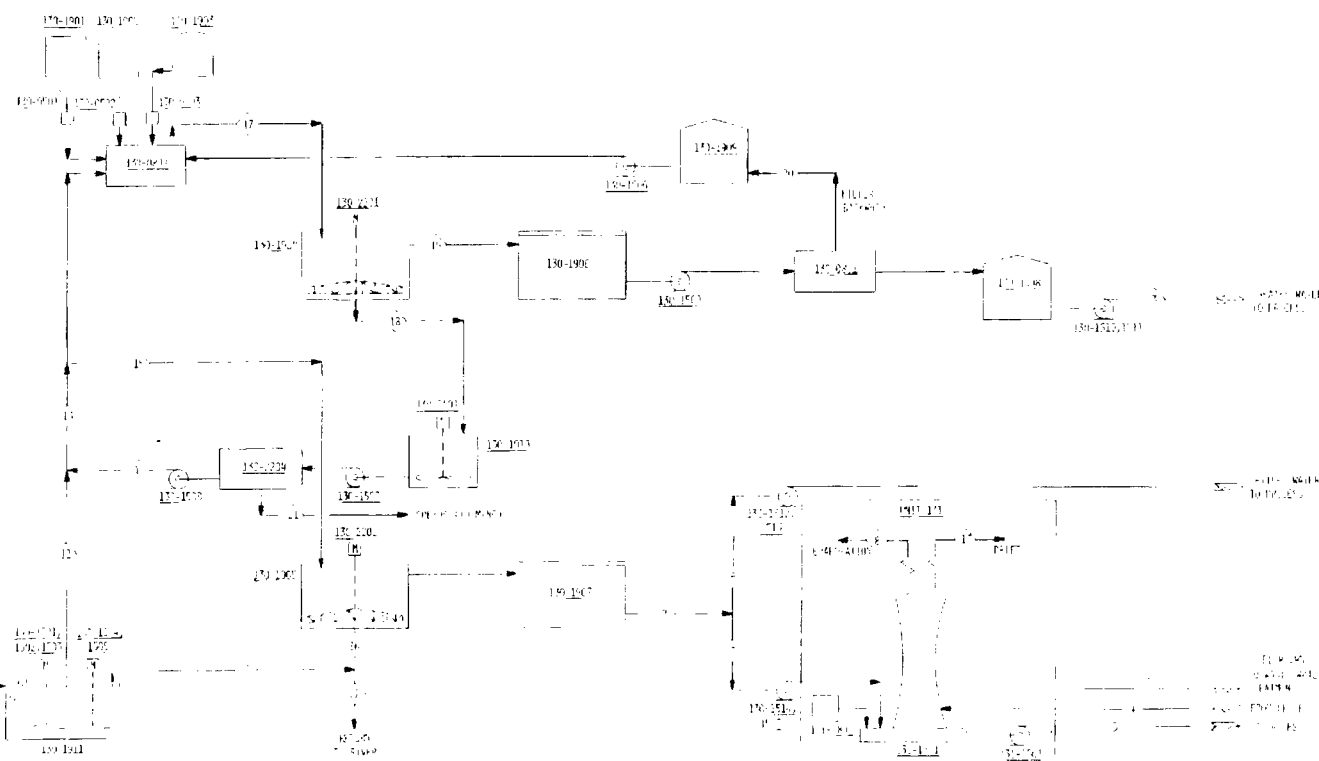
ENERGY RESEARCH & DEVELOPMENT ADMINISTRATION
(ERDA-FE)
MULTI-PROCESS DEMONSTRATION PLANT - PHASE I
PROCESS FLOW DIAGRAM
ACID GAS SULFUR REMOVAL - UNIT 114

THE RALPH M. PARSONS COMPANY PASADENA, CALIFORNIA	JOB NO 5435-5	DWG NO R-114-FS-1	REV 0
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DC-

DT-

17-121 17-122 17-123 17-124 17-125 17-126 17-127 17-128 17-129 17-130 17-131 17-132 17-133
 17-134 17-135 17-136 17-137 17-138 17-139 17-140 17-141 17-142 17-143 17-144 17-145 17-146
 17-147 17-148 17-149 17-150 17-151 17-152 17-153 17-154 17-155 17-156 17-157 17-158 17-159 17-160



17-161 17-162 17-163 17-164 17-165 17-166 17-167 17-168 17-169 17-170 17-171 17-172 17-173
 17-174 17-175 17-176 17-177 17-178 17-179 17-180 17-181 17-182 17-183 17-184 17-185 17-186
 17-187 17-188 17-189 17-190 17-191 17-192 17-193 17-194 17-195 17-196 17-197 17-198 17-199 17-200

LINE NO. 1-11											LINE NO. 12-22											TOTAL		
1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	Sum	Max	
1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	1000	22000	1000

5.1-12

B

DATE		SCALE		SHEET NO.		TOTAL SHEETS	
PARTIAL SCHEDULE OF MATERIALS FOR THE PROJECT OF THE							
THE RALPH W. PARSONS COMPANY PASADENA, CALIFORNIA				JOB NO. 		SHEET NO. 	

5.2 PLANT 2 - INTERMEDIATE PRESSURE GASIFICATION AND POWER GENERATION

This plant operates concurrently with Plant 1. It utilizes a number of facilities common to the operation of both plants. In most cases an addition to the Plant 1 facilities is required. Common facilities, which require additions, include:

- (1) Coal receiving, unloading, and storage area
- (2) Coal grinding area
- (3) Water treatment
- (4) Cooling water system
- (5) Effluent treatment
- (6) Flare system
- (7) General facilities

5.2.1 UNIT 210: ADDED COAL STORAGE

To provide the total feed coal requirement of 4,050 ton/d for Plants 1 and 2, a second 150-ft radial stacker conveyor 210-2005 with intermediate feeder conveyor 210-2006, and a second 4.5-cu-yd rubber tired tractor FEL 210-3502 are required. These are shown on Drawing R-110/111/210/211/310/311-FS-1.

The additional Unit 210, Plant 2 coal train unloading, stockpiling, and/or conveyor system operations will be accomplished with one operator, as in Unit 110, Plant 1.

Stockpile capacity will be increased by using the full 210-degree radial travel on radial stacker No. 1, which increases that stockpile area to approximately 40,000-ton capacity, plus 20,500-ton stockpile capacity obtained from radial stacker No. 2 travelling over an arc of approximately 100 deg. The 60,500-ton stockpile will furnish a 15-day supply for the combined Plant 1 and Plant 2 operation.

5.2.2 UNIT 211: ADDED COAL GRINDING

Unit 211 contains 200-ton capacity coal storage hopper bin 211-2603, into which No. 3 plant feed conveyor 110-2003 and/or bypass conveyor No. 2 110-2002 will discharge. Pulverizer feeder 211-0503 extends from the hopper bin to Plant 2 coal pulverizer 211-2102. The additional second pulverizer will furnish the required additional 2,250 ton/d coal at 70% minus-200 mesh.

Drawing R-110/111/210/211/310/311-FS-1 also shows the additional equipment for Unit 211.

5.2.5 UNIT 212: PROCESS GASIFICATION

Two medium pressure oxygen-blown gasifiers are provided — one is an entrained slagging type, and the other is the fluidized-bed type with a combined pretreater. They are of equal capacity and are installed in parallel. Operation would be alternately. Thus, two foremost types of advanced design gasifiers can be demonstrated on a production scale, fed by a variety of coal types and in typical production circuits.

A. Entrained Slagging Type Gasifier

Coal is gasified in Unit 212-2501 at 485 psig by steam and oxygen. The process is shown on Flow Diagram R-212/213-FS-1.

The gasifier is a two-stage entrainment slagging type. It represents a modification of the Bi-Gas design which is being developed under DOE contract. The gasifier dimensions are approximately 12 ft OD x 130 ft high. A sketch of the gasifier is shown in Figure 5.2-1.

Powdered coal is mixed with an equal weight of water in slurry feed tank 212-1203 located in the vicinity of the pulverizer. The slurry is then pumped through an exchanger train where it is preheated to water bubble point (470°F) with gasifier effluent gas.

The preheated slurry is mixed directly with hot effluent gas (1270°F) in flash dryer 213-1201. The water is vaporized and the resulting steam, gas, and coal mix at about 600°F is carried overhead to coal cyclone 212-1201.

Steam and gas flow overhead from the cyclone through the electrostatic precipitator 213-2202 unit. The coal discharges into an injection nozzle where it is mixed with process steam superheated to 910°F. The coal and steam enter the bottom area of the upper stage, Stage 2, of gasifier 212-2501.

The coal is pyrolyzed and reduced to char by hot gas rising from the 3000°F lower, Stage 1, gasifier section. The resulting char/gas mixture is carried overhead at a nominal 1800°F outlet temperature to char cyclone 212-2202.

Cyclone overhead gas flows through 550-psig steam superheater 213-1305 and steam generator 213-1304 to the flash dryer. Cyclone char underflow discharges into a second steam injector. Char is mixed with an additional quantity of superheated process steam and injected into the gasifier, Stage 1. Preheated oxygen (600°F) is simultaneously injected into Stage 1 and the resulting combustion reaction forms ash and additional gas. Stage 1 combustion zone temperature is approximately 3000°F.

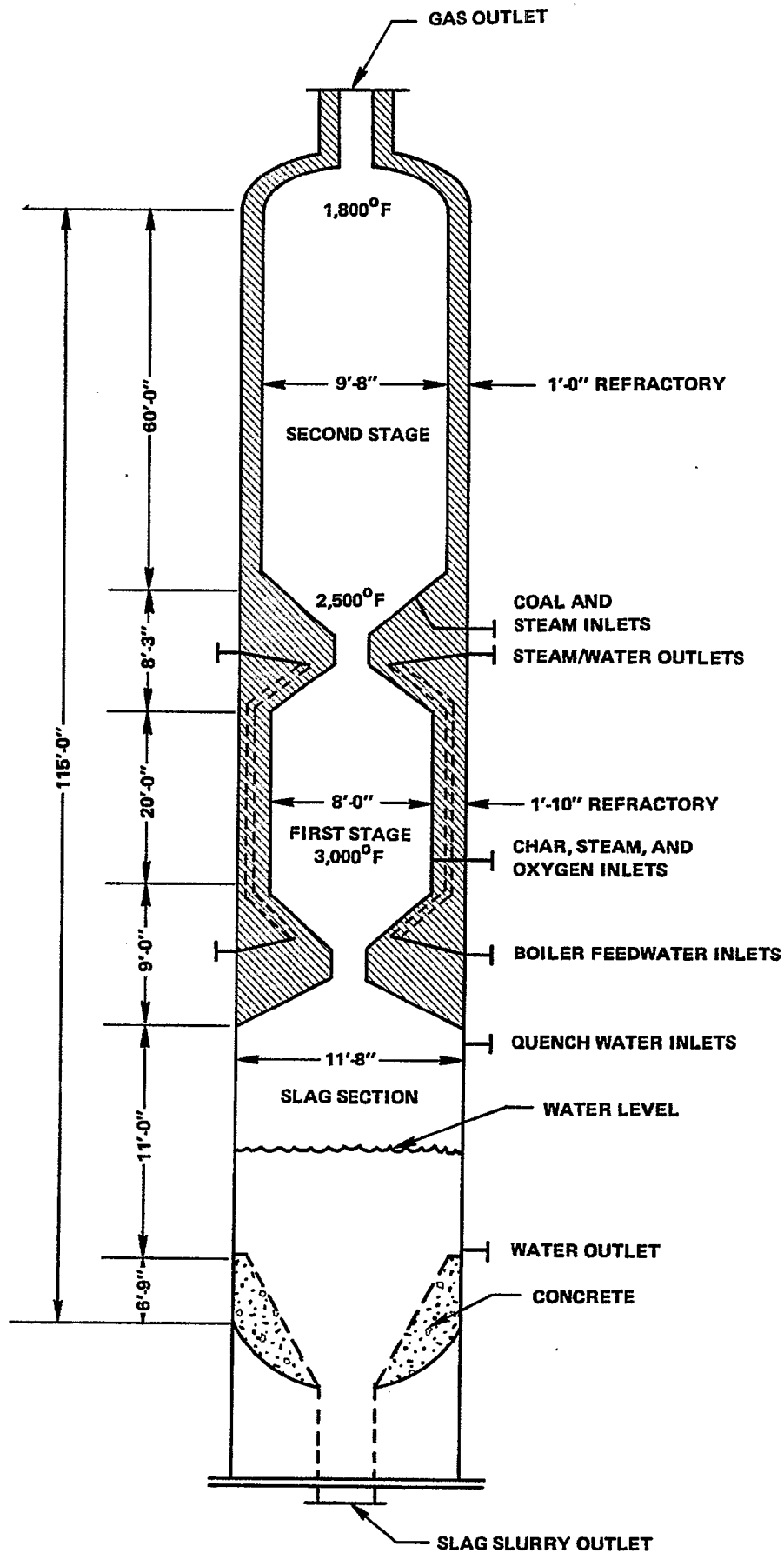


Figure 5.2-1 - Intermediate Btu Gasifier

Ash, depending on the composition of the coal being fired, is molten at 2000 to 2500°F and flows down the sides in Stage 1 and through the bottom opening into the lower section of the gasifier where it is quenched with water at 140°F. (The quench water may be at its bubble point, 467°F; this alternative operation is described later in this section.)

The slag/water slurry flows out the bottom of the gasifier through slag crusher 212-2101 to break up any clinkers. The divided and solidified slag generally has the consistency of coarse sand.

The slurry is pumped into slag slurry cyclone 212-2203. Most of the water is separated in the cyclone as overflow and is recycled through slag slurry cooler 212-1302 back to the gasifier quench zone. Makeup water is added as needed. Cyclone underflow is a thick, pumpable slurry that flows to atmospheric-pressure slag slurry degasser 212-1201 through a pressure device.

The depressured slag/water slurry is pumped to the settling pond. Overhead from the degasser is cooled in steam condenser 212-1305 and flows via a suction pot to vent compressor 212-1801. The compressor transfers the gas back to the gasifier.

An alternative operation is to maintain the quench water temperature close to its bubble point, 467°F. Hot slag vaporizes some of the water which then flows up through the gasifier and becomes a portion of the process steam. The air cooler will be bypassed during this operation and the temperature of the rundown to the settling pond will be approximately 212°F.

The operating conditions selected for the gasifier result in a raw gas composition, moisture and H₂S excluded, containing 75 vol % carbon monoxide and hydrogen plus 1.4% methane. The hydrogen to carbon monoxide ratio is 1.46:1.

Temperature control in the gasifier will be maintained by a controller with its thermocouple located in the vapor outlet line. Rising temperatures cause opening of the process steam superheater bypass which reduces the temperature of the steam to the gasifier. The resultant higher temperature of gasifier gas to the steam generator increases steam make, which further cools the gasifier. Further temperature increase reduces oxygen flow.

The gasifier is equipped with a boiling-water cooled refractory chamber for the lower, Stage 1. Temperatures can be maintained in Stage 1 by allowing a portion of the raw coal (from the coal cyclone) to bypass Stage 2 feeding directly into Stage 1.

B. Agglomerating Ash Fluid Bed Gasifier

Coal may be pretreated (as may be necessary, depending on coal type) and gasified in the fluidized-bed mode at 485 psig by steam and oxygen. This gasifier would be positioned in parallel with the entrained gasifier in Plant 2.

Gasifier 212-2502 (see Section 8, Table 8-7), is a single-stage agglomerating ash fluidized-bed type. It is similar to the agglomerating ash unit tested by IGT. For proper operation, this type of gasifier requires a noncaking coal feed. Caking coal can be processed if properly pretreated by mildly oxidizing the coal particles with a small quantity of oxygen at a moderate temperature of about 700 to 800°F.

The gasifier is shown in Figure 5.2-2. The vessel 212-2502 includes the lower fluidized pretreater bed, as well as the upper gasifier bed. This is considered to be patentable and an invention disclosure entitled Fluidized Bed Gasifier with Integral Pretreating Facilities has been filed with the Department of Energy (DOE) on February 22, 1978.

To describe the operation, coarse ground coal, approximately 4 to 6 mesh x 0, slurried in water, is dried in flash dryer 213-1201 by hot effluent gas. The resulting steam, gas, and coal mixture at approximately 600°F is carried overhead to coal cyclone 212-2201.

Steam and gas flow overhead from the cyclone to the heat recovery unit. The coal flows down a standpipe, through a flow regulating valve, and is mixed with process steam and pretreat oxygen. The fluidized mixture enters the bottom of the pretreater and remains for an average retention time of up to 5 min.

Pretreatment is accomplished in two stages.

The first stage treatment takes place when the coal is gas lifted to the pretreater bed using oxygen and sufficient steam to maintain pretreater temperature. Pretreatment is completed in the few minutes' residence time in the bed.

Pretreater off-gas, as in the IGT U-Gas pretreater³, flows through the gasifier bed. Unlike the U-Gas design, the off-gas contains most of the steam for gasification. To cause the ash particles to agglomerate, sufficient oxygen is sent to the central cone to produce a hot zone. The rest of the oxygen and gasifier steam enter the gasifier bed with the pretreater off-gas.

The pretreated coal is lifted continually from the pretreat zone via the lift pipe by a portion of the reaction steam into the gasifier gasification zone.

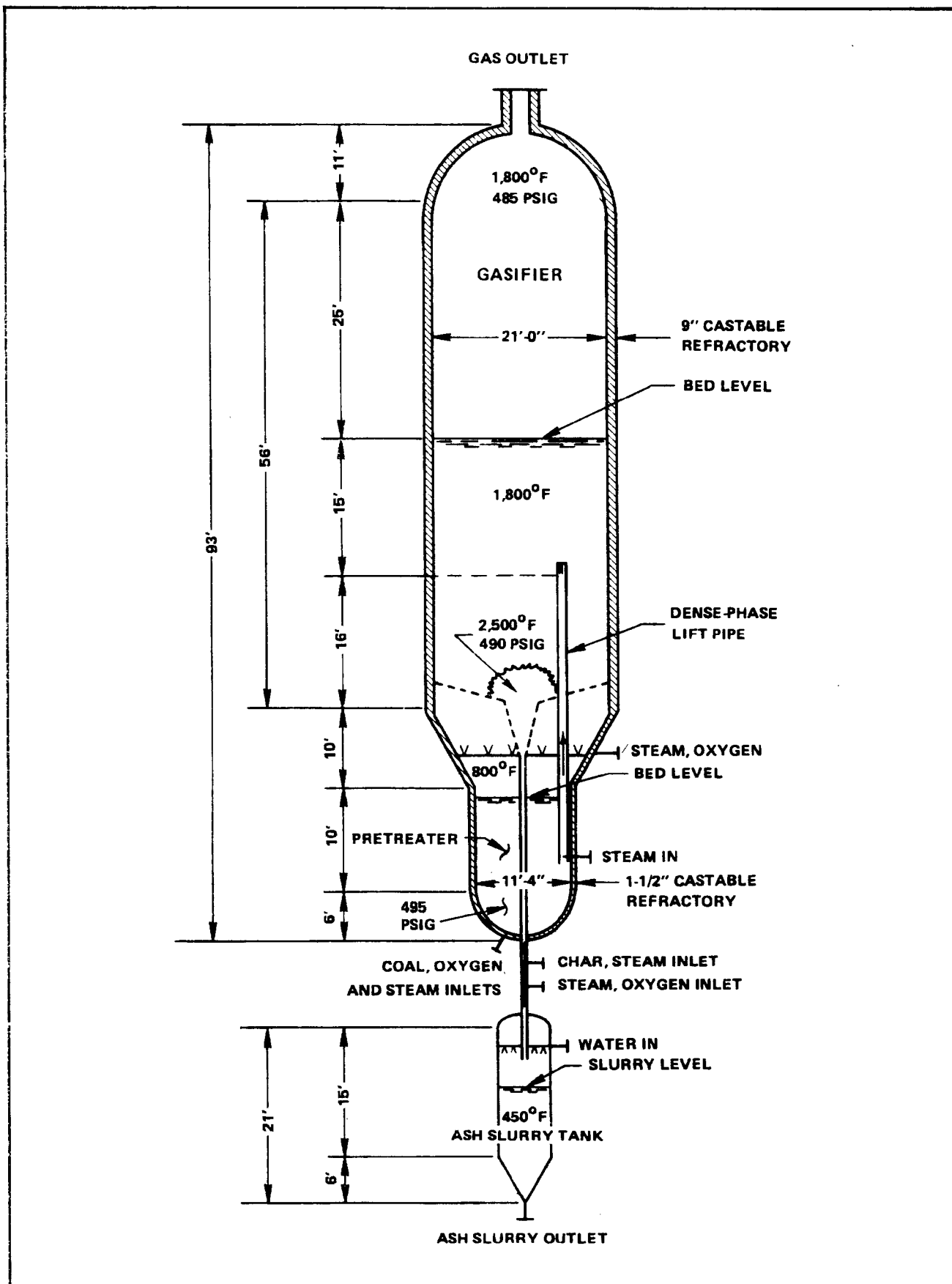


Figure 5.2-2 - Agglomerating Ash Fluid-Bed Gasifier

The localized high temperature zone softens the ash and allows particles to agglomerate. As size and weight increase, the agglomerated ash particles settle downward in the collecting cone or cones. They then fall through the incoming oxygen and steam flow into the ash slurry tank. There they are mixed with water to cool and form a slurry. The ash slurry is discharged via the slag slurry disposal system as described in subsection 5.2.3 A.

The product gas leaving the top of the gasifier flows to char cyclone 212-2202 where most of the entrained char particles are removed and recycled to the agglomerating cone of the gasifier.

The overhead raw gas from the cyclone flows to the coal flash dryer, 213-1201. From the coal cyclone 212-1201, the gas continues on to Unit 213 for heat recovery and gas cleanup.

Quantity, pressure, and temperature of the raw gas leaving the fluidized-bed gasifier are similar to those of the raw gas from the entrainment-type gasifier, but the composition will differ. Table 5.2-1 tabulates the comparative compositions.

Table 5.2-1 - Estimated Gasified Effluent Compositions

Component	Entrained Slagging (mol/hr)	Fluidized Agglomerating
H ₂	13,763	13,179
CO	9,451	8,933
CO ₂	6,870	7,515
CH ₄	447	320
H ₂ S	360	360
NH ₃	20	13
N ₂	273	292
H ₂ O	16,573	16,365
Total (mol/hr)	47,757	46,977
Total (lb/hr)	920,844 (lb/hr)	928,154 (lb/hr)
Molecular weight	19.3	19.8
MMscf/d	435	428

Features of the IGT U-Gas and Synthane pretreatment processes, mainly gas velocity and series flow of gas into the gasifier fluidized-bed zone, were incorporated in the design.

Normally, the pretreater is a separate vessel located externally and above the gasifier with valved feed ducts to the gasifier fluid bed zone. For this project an advantageous simplification has been made by incorporating the pretreater as a lower appendage to the gasifier. Solids flow from the pretreater zone to the gasification zone is by means of a lift pipe, motive power being furnished by a portion of the gasification reaction feed steam. External ducts and valves are thus eliminated.

Reaction oxygen and the remaining required reaction steam are introduced into the ash discharge duct where they flow up into the gasifier bed. The hottest combustion zone temperature occurs at the area of oxygen and steam entry into the fluidized coal bed. The high temperature causes an agglomeration of solid ash particles by a partial melting and softening of the particles initially contacted. As size and weight increase the agglomerated ash particles settle downward in the collecting cones and fall through the incoming oxygen-steam flow.

The ash particulates are collected in ash slurry tank 212-1204 where they are mixed with water to form a slurry. The ash slurry is discarded via the slag slurry disposal system as described in subsection 5.2.5 A.

The product gas leaving the top of the gasifier flows to char cyclone 212-2202 where a portion of the entrained char particulates is removed and recycled to the gasifier gasification zone. The overhead raw gas from the cyclone top outlet flows on to Unit 213 (heat recovery and gas cleaning).

5.2.4 UNIT 213: HEAT RECOVERY AND GAS CLEANING

The process is shown on Flow Diagram R-212/213-FS-1.

Gasifier gas at 1800°F from char cyclone 212-2202 overhead outlet is cooled to 1270°F before mixing with the feed coal slurry in the flash dryer. Heat recovered makes process steam in 550-psig steam superheater 213-1305 and steam generator 213-1304. Saturated steam makeup, as required, is brought in from the power plant entering between the steam generator and superheater. Steam from the superheater flows to the coal and char injectors mentioned previously and enters the gasifier.

Gasifier gas flows through the flash dryer picking up the steam from the vaporized coal slurry water, further reducing its temperature to 600°F.

The gas and steam effluent flows overhead from coal cyclone 212-2201, passes through electrostatic precipitator 213-2202 for additional char removal, and is then cooled to 395°F (dewpoint); the heat is recovered in parallel exchangers effluent/hot 550-psig BFW exchanger 213-1306 and hot slurry/effluent exchanger 213-1303.

The effluent then flows through three parallel heat exchanger systems, cooling it to 270°F. These exchangers are effluent/warm 550-psig exchanger 213-1307, warm slurry/effluent exchanger 213-1302, and, in series, 50-psig steam generator 213-1308 and sour water stripper reboiler 217-1302.

The gas is contacted with water in venturi scrubber 213-2201 to remove any remaining dust and then flows into hot separator 213-1202, in which condensate drops out. The gas is cooled to 268°F in the hot separator by the returning liquid from cold separator 213-1203 through heat exchanger 213-1313.

Gas from the hot separator flows through three parallel exchangers, cooling it to 228°F. These exchangers are cold slurry/effluent exchanger 213-1301, effluent/cold 550-psig BFW exchanger 213-1309, and effluent/cold 50-psig BFW exchanger 213-1310. The gas is further cooled to 157°F in an additional set of three parallel exchangers; effluent/evaporator reboiler 217-1312; effluent/makeup 550-psig BFW exchanger 213-1314; and effluent/makeup 50-psig BFW exchanger 213-1315. The gas is then cooled to 134°F in effluent/cold makeup 50-psig BFW exchanger 213-1316. It is finally cooled to 110°F in effluent air cooler 213-1311 and flows into cold separator 213-1203 where additional condensate is removed.

The cooled gas is fed to acid gas removal unit 214 for hydrogen sulfide removal and carbon dioxide reduction.

Condensate from the cold separator is reheated in exchange with hot separator condensate and put back into the hot separator to provide additional degasification. Hot separator condensate flows to the water reclamation unit 217 in two parallel streams; one stream is cooled to 190°F with cold separator liquid; the second stream bypasses the exchanger, flowing directly to water reclamation at 268°F. A portion of the hot separator liquid (at 268°F) is recirculated to the venturi scrubber to provide the contact water.

5.2.5 UNIT 214: MEDIUM BTU ACID GAS REMOVAL

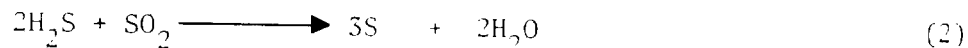
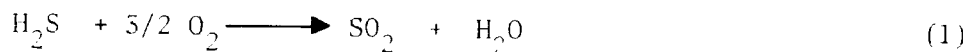
A selective acid gas removal unit employing a proprietary physical solvent is used to produce a clean product gas, a hydrogen sulfide-rich gas, and a vent gas stream. The Rectisol process was used as a representative process. The clean gas is used as feed stream for the power plant, Unit 241. The hydrogen sulfide-rich stream is fed to the sulfur plant, Unit 215. The remaining vent gas consists primarily of carbon dioxide with traces of hydrogen, methane, and carbon monoxide (approximately 250 ppm). It is vented through the plant main stack to the atmosphere (see Section 7, "Environmental Factors").

5.2.6 UNIT 215/216: SULFUR PLANT/TAIL GAS PLANT

Drawing R-215/216-FS-1 shows diagrammatically the major components of the sulfur plant required to produce an ecologically acceptable tail gas. This is achieved using a Claus-type sulfur recovery unit followed by a tail gas treating unit with a common redox solution unit.

A. Sulfur Recovery Unit

A typical Claus-type, three-stage sulfur recovery unit is shown diagrammatically on Drawing R-215/216-FS-1. The acid gas from Unit 214 is fed to a knockout drum for removal of any entrained liquids before entering the combustion chamber of the reaction furnace. The chemistry of the process involves burning part of the H_2S with air to form SO_2 , which combines with the remaining H_2S in the acid gas to form elemental sulfur according to the following equations:



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

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

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

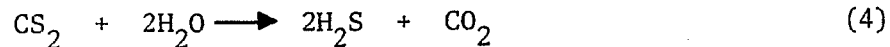
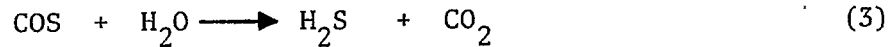
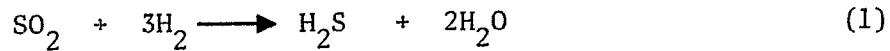
B. Tail Gas Treating Unit

The tail gas sulfur removal unit is included on Drawing R-215/216-FS-1. Several commercial processes are available for reducing the sulfur content of the sulfur recovery unit tail gas to an environmentally acceptable level. A sulfur content of less than 125 ppm is achievable by one of these processes (the Beavon sulfur removal process), and this was used as the basis for the estimates of this study.

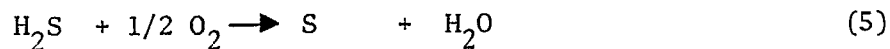
In the process used, for example, hydrogenation and hydrolysis are used to convert essentially all sulfur compounds to hydrogen sulfide. The gas is then cooled and passed into a contactor where the hydrogen sulfide is absorbed by the redox solution and oxidized to commercial sulfur. The purified tail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

The chemical reactions are:

Hydrogenation and Hydrolysis



Hydrogen Sulfide Extraction



The purified tail gas is odorless and contains typically less than 1 ppm of H₂S and less than 125 ppm of total sulfur compounds, mainly COS.

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

5.2.7 UNIT 217: WATER RECLAMATION

About 1300 gpm of sour water from the gasifier heat recovery units will be treated to make it suitable for reuse as boiler feedwater. Process Flow Diagram R-217-FS-1 shows the unit.

Sour water feed consists of two parallel streams at 268°F and 190°F. The hotter stream is cooled in sour water feed/evaporator reboiler 217-1301 to 190°F, and the two streams are combined. The total flow is further cooled in sour water stripper feed cooler 217-1307 to 120°F. This is sour water stripper 217-1101 feed.

For Plant 3 operation sour water extractor 317-1101 may be used to contact sour water stripper feed with fuel oil to remove tar and oil which may be in the water.

The sour water stripper removes most of the ammonia and hydrogen sulfide which are sent overhead to sulfur plant unit 215. Approximately one half of the stripped water is sent to the feed system to slurry coal after being cooled to between 180 and 212°F in slurry water/BFW exchanger 217-1313 and slurry water cooler 217-1308. The remainder of the stripped water is further treated with oxygen in oxidizer 217-2501.

In the oxidation process, stripped water is mixed with oxygen and heated in oxidizer feed/effluent exchanger 217-1303 and with superheated steam to a temperature at which the reaction between the oxidizable material and oxygen will proceed autogenously at a reasonable rate. Additionally, the oxidizer is run at high pressure, 1500 psig. Temperature in the oxidizer increases due to heat of reaction, the heat being recovered in exchanger 217-1303. Oxidizer overhead gas is returned to the gasifier.

Oxidizer water effluent containing solids, chlorides, carbonates, and dissolved gases (including SO₂) is mixed with neutralizing chemicals and fed to BFW settler 217-2201, operating at 6 psig. The flashed BFW settler vapor is cooled in BFW settler overhead/evaporator reboiler 217-1306 and BFW settler overhead cooler 217-1305, and the condensed steam is refluxed back to the settler. Noncondensables are returned to the gasifier by vent recovery compressor 217-1802. BFW settler bottoms containing the settled solids are mixed into the water for slurring coal.

Settled product water containing neutralized chlorides and carbonates is suitable for use as 50-psig boiler feedwater. This water is filtered and pumped to the gasifier 50-psig steam system and to evaporator 217-1203 via BFW deaerator 213-1204.

Evaporator 217-1203 is provided to make higher quality boiler feedwater needed for the 500-psig and higher steam systems, and to utilize some of the relatively low temperature heat available in this unit and the heat recovery unit. Evaporator feed is a portion of the water from deaerator 213-1204. The feed is deaerated and boiled in the evaporator at 140°F and 2.9 psia. The evaporator is reboiled with heat from the incoming sour water feed, BFW settler overhead, and gasifier effluent 217-1301, 217-1306 and 217-1312. Evaporator blowdown goes into the coal slurry water.

Evaporator overhead is condensed and pumped to the 550-psig steam system. Vacuum for the evaporator will be provided by either a pump or steam ejector.

5.2.8 UNIT 230: ADDED WATER TREATMENT

Plant 2 operation requires an increased supply of industrial water. Raw water pumping from the river is increased from approximately 1,200 gpm for Plant 1 operation by an additional 7,000 gpm to total 8,200 gpm.

The unit includes additional pumps, clarifiers, chemical treating equipment, rotary vacuum filters, treated water clarifiers, and the additional distribution capacity. This represents an expansion of the water treatment system shown on Drawing R-130/131-FS-1.

5.2.9 UNIT 231: ADDED COOLING WATER SYSTEM

Plant 2 operation requires a cooling water circulation rate and a cooling tower capacity of 167,000 gpm; Plant 1 requires 25,000 gpm. The Plant 2 cooling tower will be located in the area adjacent to the Plant 1 cooling tower to provide a common cooling water supply. This will maximize servicing efficiency and cooling water usage flexibility.

5.2.10 UNIT 232: ADDED EFFLUENT TREATMENT

The Plant 2 operations will increase the effluents requiring treatment. This requires increasing sanitary sewage treatment, skimmer pit, and settling pond capacity approximately six-fold.

5.2.11 UNIT 233: ADDED FLARE SYSTEM

The Plant 2 system requires increased flare capacity. The flare system provided for Plant 1 will be utilized with an enlarged burner replacement and a liquid return pumping system.

5.2.12 UNIT 240: OXYGEN PLANT

A 3,000-ton/d single train oxygen plant is included. Oxygen purity will be 98%. This size oxygen facility is 15% greater than is required to operate the Phase 2 entrainment-type gasifier at full rate and will supply the Phase 2 fluidized-bed gasifier for full rate operation.

The oxygen facility is large enough to operate the Phase 1 fuel gas gasifier in the totally oxygen-blown mode during periods when Plant 2 and Plant 3 may be unavailable. When Plants 2 and 3 are operated (80% of gasifier capacity) there are 550 to 900 ton/d of oxygen available to operate Plant 1 on a combination air- and oxygen-blown basis. Otherwise, with the entrainment gasifier operating at full rate, about 400 ton/d of oxygen, along with air, can be fed to the Phase 1 low Btu gasifier.

The oxygen plant is equipped with air compressor capacity to supply its full air-feed requirements and oxygen compressors to supply oxygen at 500 psig to the medium-pressure gasifiers and at 50 psig to the low-pressure gasifier.

5.2.13 UNIT 241: POWER PLANT

The power generation area consists of two gas turbines, two heat recovery steam generators, and steam turbines in the combined cycle mode. Drawing R-241-FS-1 shows the combined cycle system for the generation of approximately 200 MW of electricity, gross. The power plant also contains a low Btu fuel gas compressor for demonstrating power plant operation on low Btu fuel gas.

Clean fuel gas from Unit 214 (medium Btu acid gas removal) at 400 psig is fed to two gas turbine generators, 241-0101 and 241-0102. The exhaust of each gas turbine generator is fed to heat recovery steam generators 241-1601 and 241-1602. These generators produce about 245,000 lb/hr of steam at 1,250 psig and 850°F. This steam is fed to steam turbine 241-0105 which operates generator 241-0106. This steam turbine is provided with an extraction point to furnish 550-psig steam to the process plant. An additional 266,000 lb of steam at 50 psig and 300°F is supplied to Unit 241 from the process area. This steam is fed to steam turbine generator 241-0107 for the generation of additional electrical power.

Condensate leaving the main condensers, together with plant makeup requirements, is sent to station deaerator 241-1303, where it is picked up by the boiler feed pumps for return to waste heat steam generators. Demineralized water and condensate are also returned to the process plant heat recovery boilers.

5.2.14 UNIT 250: ADDED BUILDINGS AND GENERAL FACILITIES

The support of Plant 2 operations will require buildings and space for administration, change houses, laboratory, shops, field offices, control rooms, cafeteria, security buildings, parking areas, and a road system.

5.2.15 PHASE 2 PLANT PRODUCTS

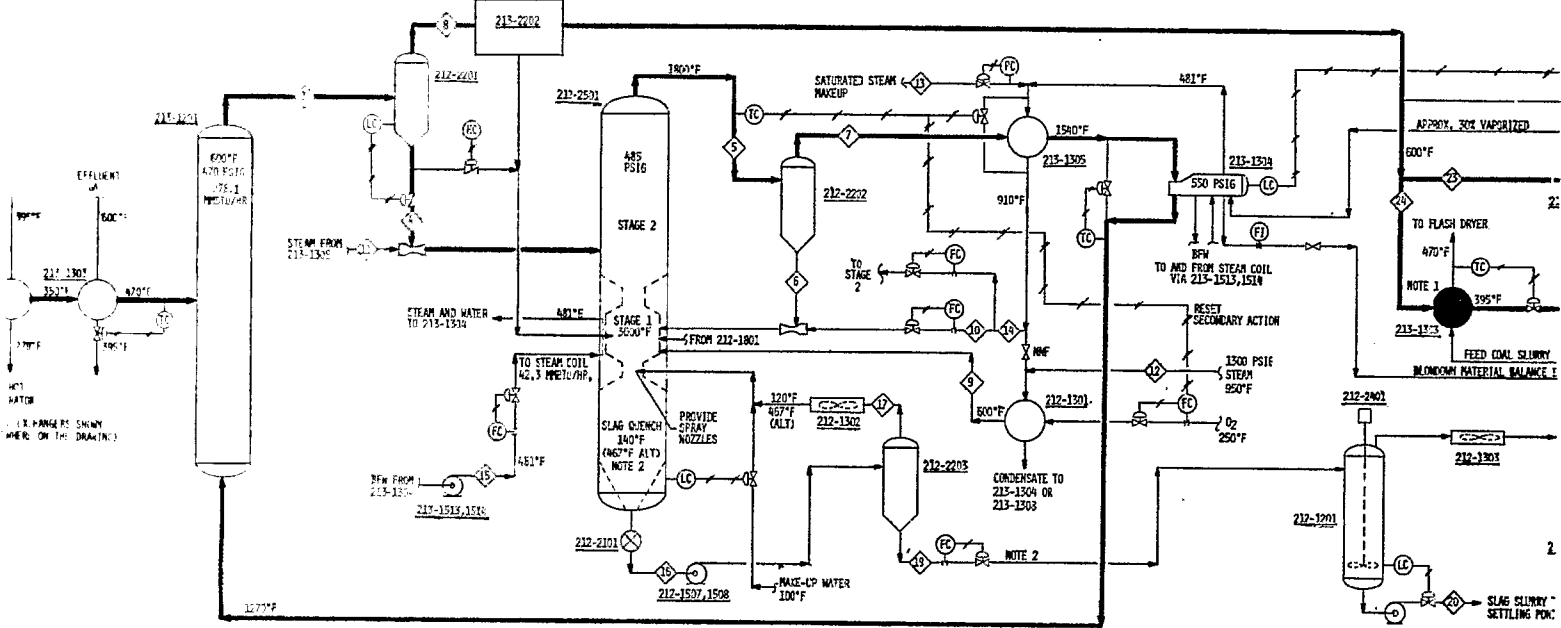
A. Electric Power

For sale, transfer, and process plant usage, 192.2 MW is required. This will be generated and transferred @ 13,600 V.

B. Sulfur

Quantity (ton/d)	82.4
Purity (% sulfur)	99.9
Color	Yellow

213-1301 HOT SLURRY FEED PUMP
 213-1302 ELECTRIC DRYER
 213-2201 COAL CRUSHER
 213-2202 ELECTROSTATIC PRECIPITATOR
 212-2501 GASTIFIER
 STAGE 1: 9'-8" I.D.
 STAGE 2: 8'-0" I.D.
 117' T/1
 212-2202 CRP CYCLONE
 212-1302 SLAG SLURRY COOLER
 212-2203 SLAG SLURRY EXCYLONE
 213-1305 550 PSIG STEAM SUPERHEATER
 219.7 MWBTU/HR.
 212-1301 OXYGEN HEATER
 19.7 MWBTU/HR.
 213-1304 550 PSIG STEAM GENERATOR
 120.3 MWBTU/HR.
 212-1303 SLAG SLURRY DEGASSER
 5'-0" I.D. X 10'-0" T/1
 212-1303 SLAG SLURRY DEGASSER
 5'-0" I.D. X 10'-0" T/1
 212-1303 STEAM CRYSTALLIZER
 24.8 MWBTU/HR.
 2'-6" I.D. X 5'-0" T/1
 212-2202 VERT. COPELASS
 SECTION END

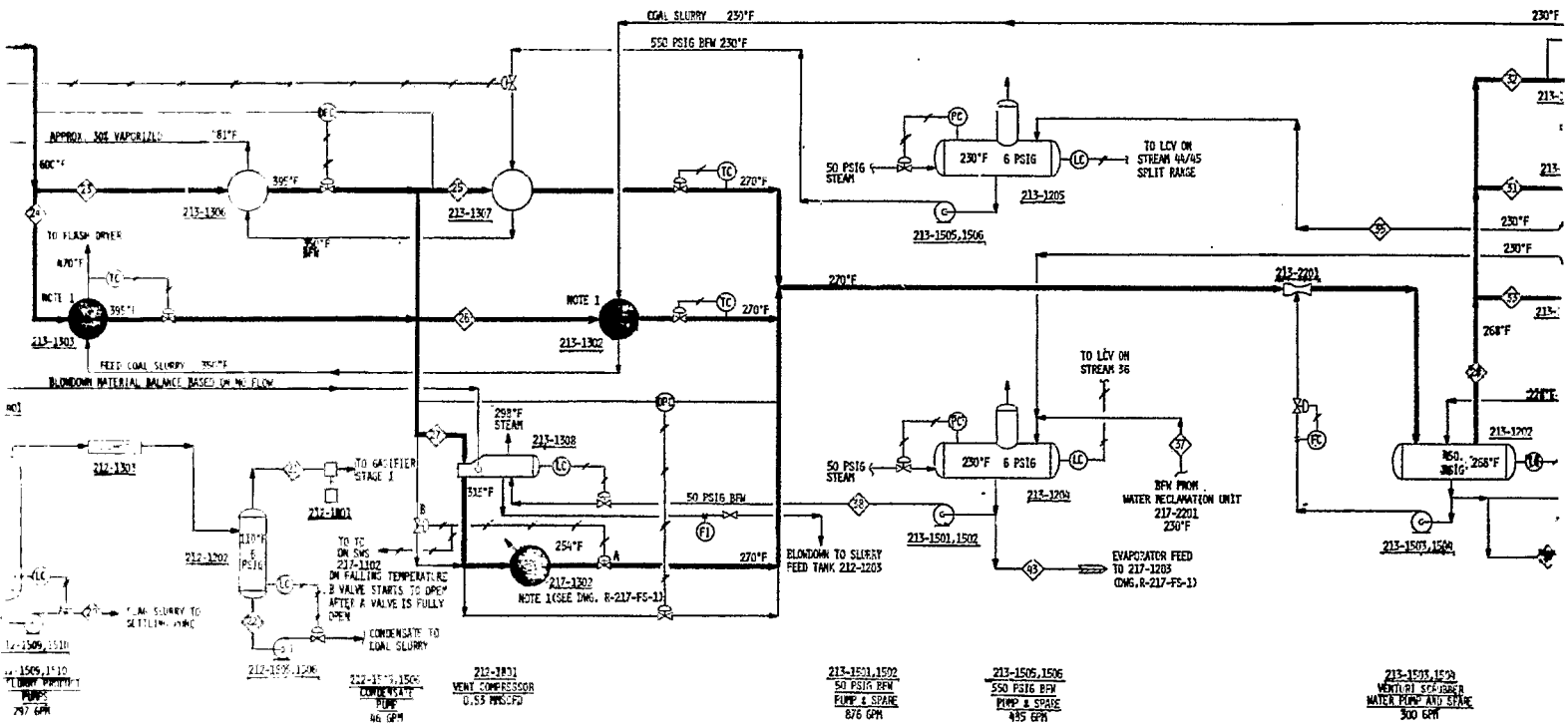


213-1513, 1514 COOKING WATER CIRCULATION PUMP & SPRAY
 301 GPM
 212-2101 SLAG CRUSHER
 212-1507, 1508 SLAG SLURRY CIRCULATION PUMP & SPRAY
 5251 GPM
 212-2101 SLAG SLURRY AGITATOR
 212-1509, 1510 SLAG SLURRY PRODUCT PUMP
 237 GPM

STREAM NO.	DESCRIPTION	QUENCHER SLAG	CIRCULATION WATER	MAKEUP WATER	SLAG SLURRY WITH WET GAS	SLAG SLURRY TO POND	VENT GAS	CONDENSATE	EFFLUENT TO 213-1304	EFFLUENT TO 213-1303	EFFLUENT TO 213-1307	EFFLUENT TO 213-1302	EFFLUENT TO 213-1309	NOT SEPARATOR BYHEAD
1	FLUX, MPH	45	43	-	2	-	2	-	7,013	6,753	533	1,368	11,392	33,343
2	H ₂ O	181	173	-	8	-	8	-	4,816	4,635	407	953	8,092	8,451
3	CO ₂	1,217	972	-	45	-	45	-	2,501	2,369	296	683	5,881	6,437
4	CO	-	-	-	-	-	-	-	225	177	19	45	363	447
5	H ₂	-	-	-	-	-	-	-	143	117	14	36	308	398
6	CH ₄	-	-	-	-	-	-	-	12	12	1	2	17	29
7	CP	-	-	-	-	-	-	-	159	154	12	28	254	273
8	SO ₂	337,570	289,543	5,029	6,025	5,018	4	3	17,274	16,425	1,440	3,421	29,620	3,813
9	SO ₃	36,825	-	-	36,825	36,835	-	-	-	-	-	-	-	-
10	SWH	8,291	-	-	8,291	8,291	-	-	-	-	-	-	-	-
11	FLUX TOTAL, MPH	129,733	129,733	5,021	59	-	59	3	33,165	31,920	2,804	6,566	55,715	34,153
12	COOKING WATER TOTAL, LFMW	2,141,222	2,003,222	90,453	137,265	135,430	2,291	128,297	624,710	63,116	124,290	1,651,503	674,725	
13	MP	-	16.0	16.0	-	-	16.0	16.0	16.0	16.0	16.0	16.0	16.0	
14	TEMPERATURE, °F	140	140	140	140	140	140	140	221	221	221	221	221	
15	PRESSURE, PSIG	480	485	300	20	20	40	40	628	628	395	395	395	
16									463	463	395	450	450	

B

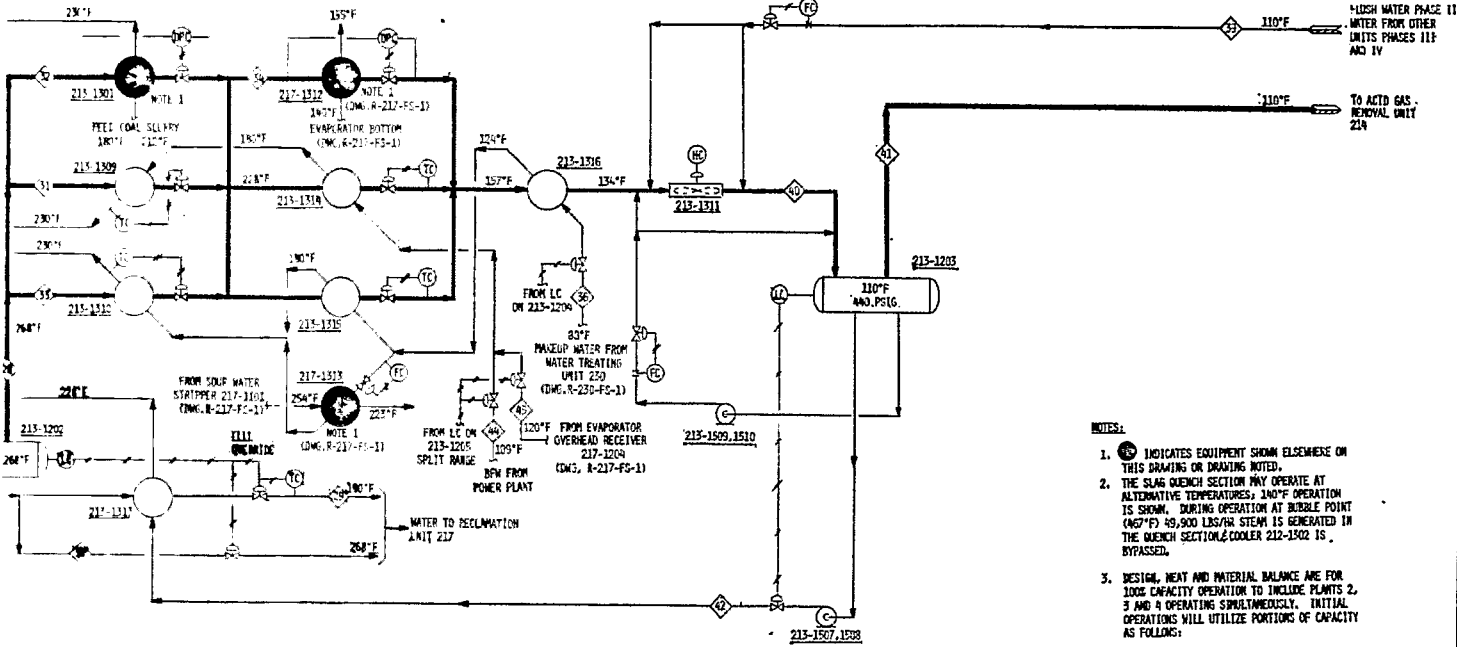
213-1306 STEAM 24.8 POUNDS/HR.	213-1307 VENT. COOL. W/56 SALTION 5.0 P/HR.	213-1308 EFFLUENT/W/56 EXCHANGER 56.0 POUNDS/HR.	213-1307 EFFLUENT/W/56 EXCHANGER 23.4 POUNDS/HR.	213-1308 50 PSIG STEAM GENERATOR 39.5 POUNDS/HR.	213-1309 50 PSIG WATER STRIPPED REHEATER 85.5 POUNDS/HR.	213-1204 50 PSIG BFW DEHEATER	213-1205 550 PSIG BFW DEHEATER	213-2201 VENTURI SCRUBBER	213-1202 HOT SEPARATOR 10'-0" X 23'-0" T/T	213-1309 EFFLUENT/COLD 550 PSIG BFW EXPANDER 9.7 POUNDS/HR.	213-1310 EFFLUENT/COLD 50 PSIG BFW EXCHANGER 10.8 POUNDS/HR.	213-1311 COLD SEPARATOR/W/ HOT SEPARATOR W/ EXCHANGER 9.0 POUNDS/HR.
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UNIT	INLET	OUTLET	STREAM NO.	UNIT	INLET	OUTLET	UNIT	INLET	OUTLET	UNIT	INLET	OUTLET	UNIT	INLET	OUTLET	UNIT	INLET	OUTLET	UNIT	INLET	OUTLET	UNIT	INLET	OUTLET	
213-1306	213-1307	213-1308	213-1309	213-1310	213-1311	213-1501	213-1502	213-1505	213-1506	213-1507	213-1508	213-1509	213-1306	213-1307	213-1308	213-1309	213-1310	213-1311	213-1501	213-1502	213-1505	213-1506	213-1507	213-1508	213-1509
11.76	13.81	13.81	13.81	13.81	13.81	13.81	13.81	13.81	13.81	13.81	13.81	13.81	11.76	13.81	13.81	13.81	13.81	13.81	11.76	13.81	13.81	13.81	13.81	13.81	13.81
1.99	2.37	2.37	2.37	2.37	2.37	2.37	2.37	2.37	2.37	2.37	2.37	2.37	1.99	2.37	2.37	2.37	2.37	1.99	2.37	2.37	2.37	2.37	2.37	2.37	
4.88	5.87	5.87	5.87	5.87	5.87	5.87	5.87	5.87	5.87	5.87	5.87	5.87	4.88	5.87	5.87	5.87	5.87	4.88	5.87	5.87	5.87	5.87	5.87	5.87	
5.81	6.97	6.97	6.97	6.97	6.97	6.97	6.97	6.97	6.97	6.97	6.97	6.97	5.81	6.97	6.97	6.97	6.97	5.81	6.97	6.97	6.97	6.97	6.97	6.97	
11	13	13	13	13	13	13	13	13	13	13	13	13	11	13	13	13	13	11	13	13	13	13	13	13	
2.74	3.27	3.27	3.27	3.27	3.27	3.27	3.27	3.27	3.27	3.27	3.27	3.27	2.74	3.27	3.27	3.27	3.27	2.74	3.27	3.27	3.27	3.27	3.27	3.27	
297.6	357.1	357.1	357.1	357.1	357.1	357.1	357.1	357.1	357.1	357.1	357.1	357.1	297.6	357.1	357.1	357.1	357.1	297.6	357.1	357.1	357.1	357.1	357.1	357.1	

P.

213-1311 COLD SEPARATOR/WATER NOT SEPARATOR WATER EXCHANGER 5.0 MBTU/HR
 213-1316 EFFLUENT/COLD MAKEUP EXCHANGER 50 PSIG BFW EXCHANGER 9.5 MBTU/HR
 213-1311 EFFLUENT AIR COOLER 8.7 MBTU/HR DES. 35.0 MBTU/HR
 213-1203 COLD SEPARATOR 7'-6" I.D. X 15'-0" T/T
 213-1312 EFFLUENT/EVAPORATOR REBOILER 29.9 MBTU/HR
 213-1315 EFFLUENT/MAKEUP EXCHANGER 2.6 MBTU/HR
 213-1313 SLURRY WATER/BFW EXCHANGER 9.6 MBTU/HR
 213-1316 EFFLUENT/COLD MAKEUP EXCHANGER 50 PSIG BFW EXCHANGER 9.5 MBTU/HR



- NOTES:
1. (Symbol) INDICATES EQUIPMENT SHOWN ELSEWHERE ON THIS DRAWING OR DRAWING NOTED.
 2. THE SLAG QUENCH SECTION MAY OPERATE AT ALTERNATIVE TEMPERATURES; 140°F OPERATION IS SHOWN. DURING OPERATION AT BUBBLE POINT (140°F) 49,900 LBS/HR STEAM IS GENERATED IN THE QUENCH SECTION & COOLER 213-1302 IS BYPASSED.
 3. DESIGN, HEAT AND MATERIAL BALANCE ARE FOR 100% CAPACITY OPERATION TO INCLUDE PLANTS 2, 3 AND 4 OPERATING SIMULTANEOUSLY. INITIAL OPERATIONS WILL UTILIZE PORTIONS OF CAPACITY AS FOLLOWS:

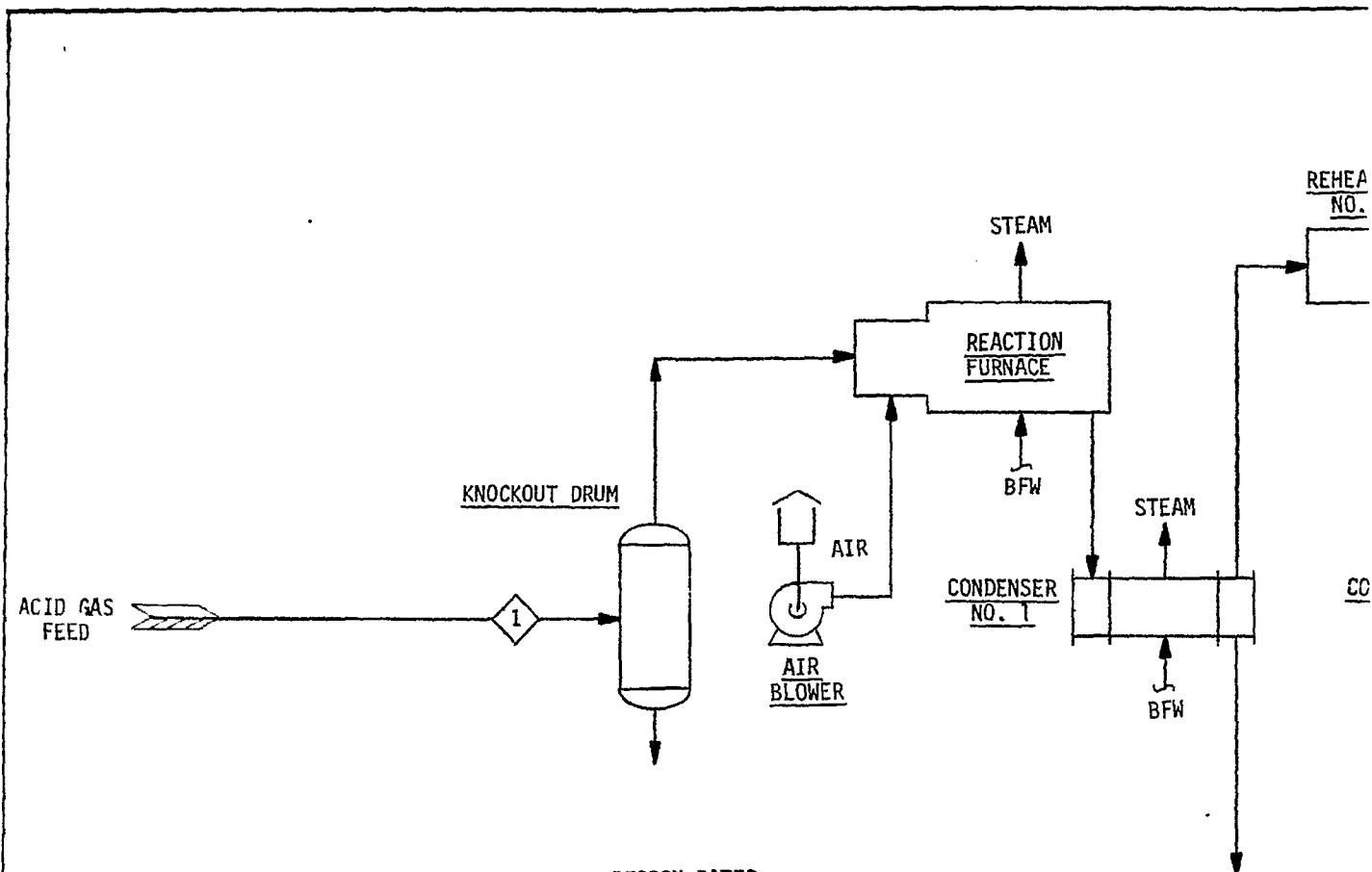
PLANT 2 60%
 PLANTS 2 AND 3 80%

213-1509, 1510 COLD SEPARATOR RECYCLE PUMP AND SPARE 200 GPM
 213-1507, 1508 COLD SEPARATOR WATER PUMP AND SPARE 200 GPM

PARAMETER	SEPARATOR 1	BFW FROM POWER PLANT	BFW FROM EVAPORATOR	DESCRIPTION
21				CONDENSATE
22				CONDENSATE
23				CONDENSATE
24				CONDENSATE
25				CONDENSATE
26				CONDENSATE
27				CONDENSATE
28				CONDENSATE
29				CONDENSATE
30				CONDENSATE
31				CONDENSATE
32				CONDENSATE
33				CONDENSATE
34				CONDENSATE
35				CONDENSATE
36				CONDENSATE
37				CONDENSATE
38				CONDENSATE
39				CONDENSATE
40				CONDENSATE
41				CONDENSATE
42				CONDENSATE
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94				CONDENSATE
95				CONDENSATE
96				CONDENSATE
97				CONDENSATE
98				CONDENSATE
99				CONDENSATE
100				CONDENSATE

ISSUE FOR REPORT		PREPARED BY	DATE
NO.	DATE	BY	DATE
DEPARTMENT OF ENERGY-DIVISION OF COAL CONVERSION MULTIPROCESS DEMONSTRATION PLANT PROCESS FLOW DIAGRAM PROCESS GASIFICATION UNIT-212 HEAT RECOVERY AND GAS CLEANING UNIT-213			
THE RALPH M. PARSONS COMPANY	PROJECT NO.	DRAWING NO.	SCALE
ALABAMA, CALIFORNIA	5435-S	R-212/213-FS-1	0

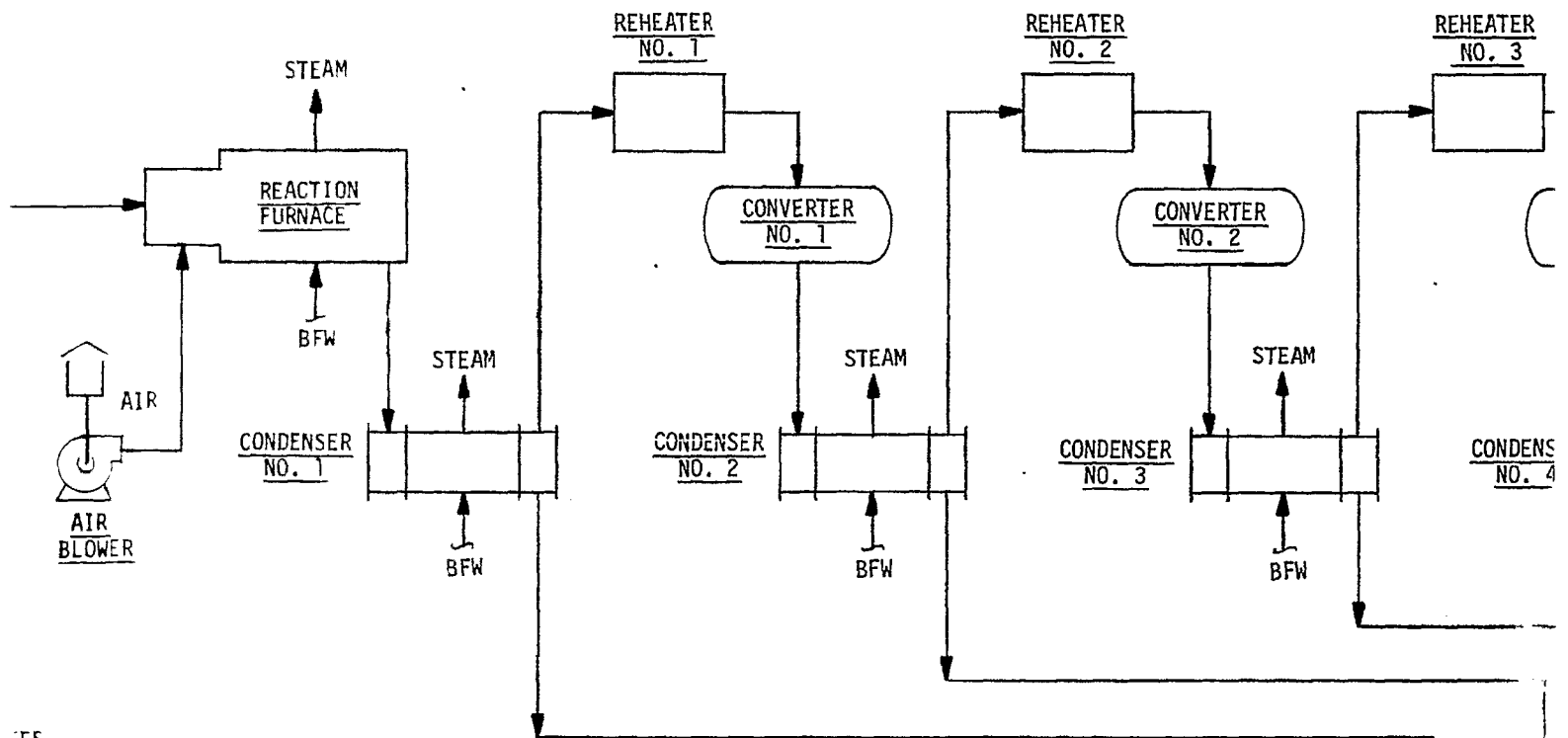
D



DESIGN RATES

STREAM NO.	1	2	3	4
NAME	ACID GAS FEED	CLEAN TAIL GAS	SOUR WATER (AVERAGE)	SULFUR PRODUCT
COMPOSITION, MPH				
H ₂ S	527.5	(1 PPM)	0.01	-
COS	TRACE	0.32	-	-
CO ₂	1,192.0	1,219.47	0.07	-
CO	-	2.99	-	-
N ₂	6.0	1,165.06	-	-
H ₂	-	30.06	-	-
NH ₃	14.0	-	-	-
CH ₄	TRACE	2.68	-	-
H ₂ O	47.1	142.21	499.37	-
S ₈	-	-	-	66.03
TOTAL	1,786.6	2,562.79	499.45	66.03
LB/HR	71,693	89,082	9,000	16,904

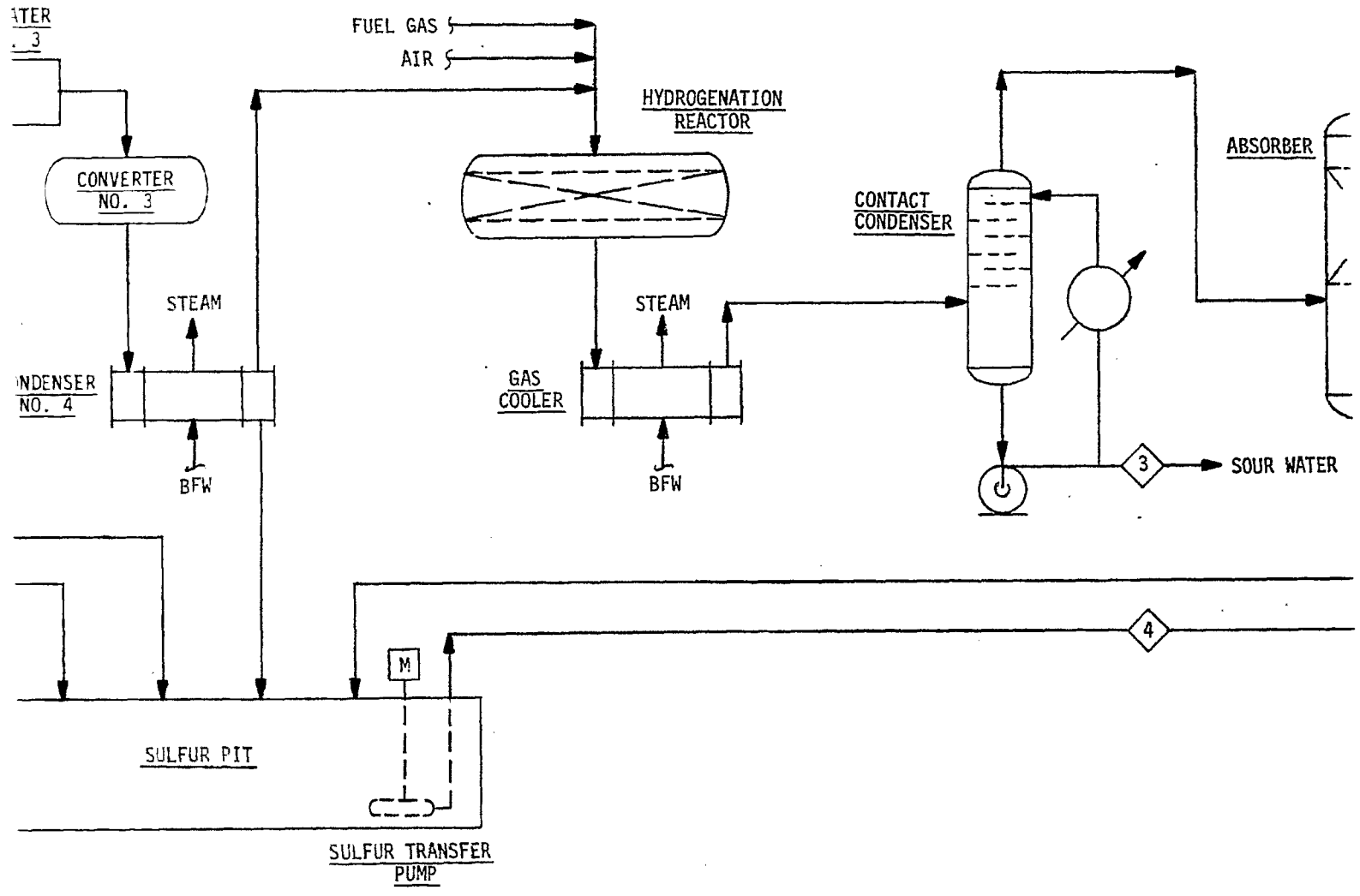
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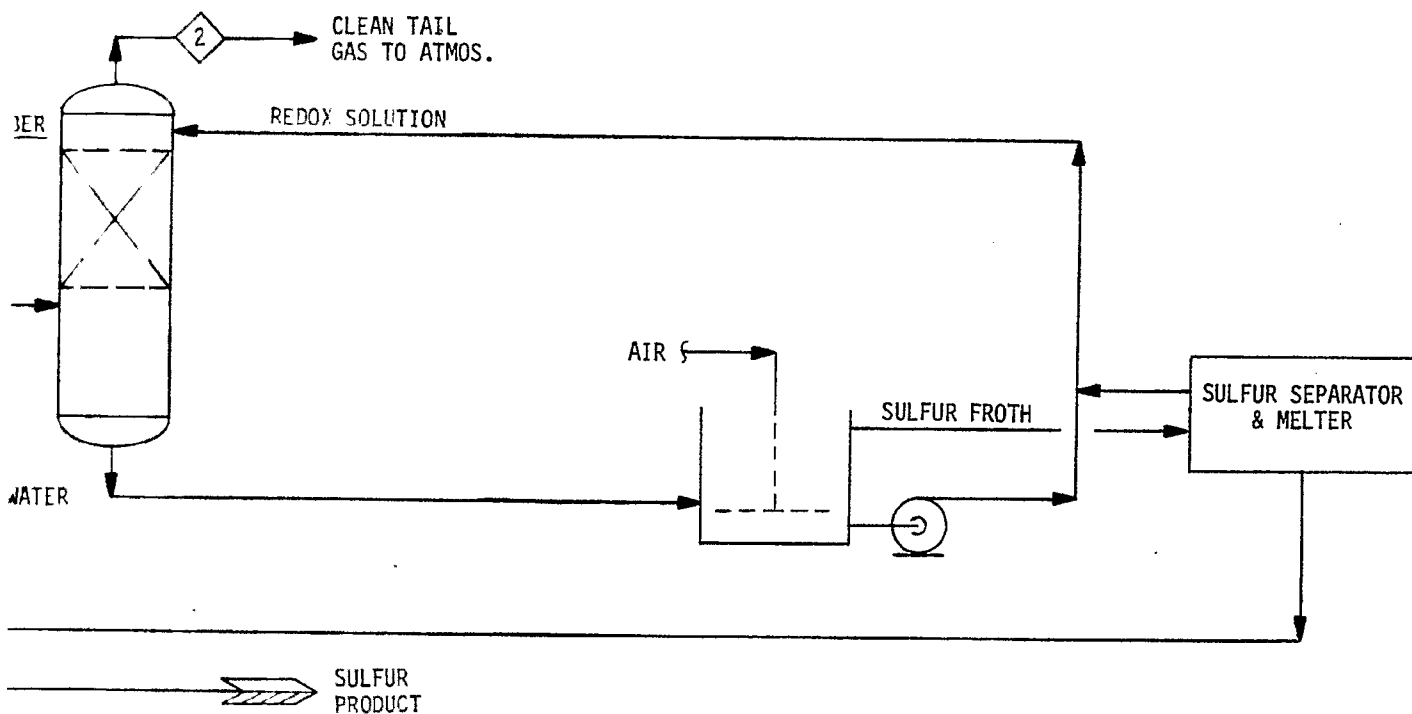
ES

2	3	4
CLEAN TAIL GAS	SOUR WATER (AVERAGE)	SULFUR PRODUCT
(1 PPM)	0.01	-
0.32	-	-
1,219.47	0.07	-
2.99	-	-
1,165.06	-	-
30.06	-	-
-	-	-
2.68	-	-
142.21	499.37	-
-	-	66.03
2,562.79	499.45	66.03
89,082	9,000	16,904

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P



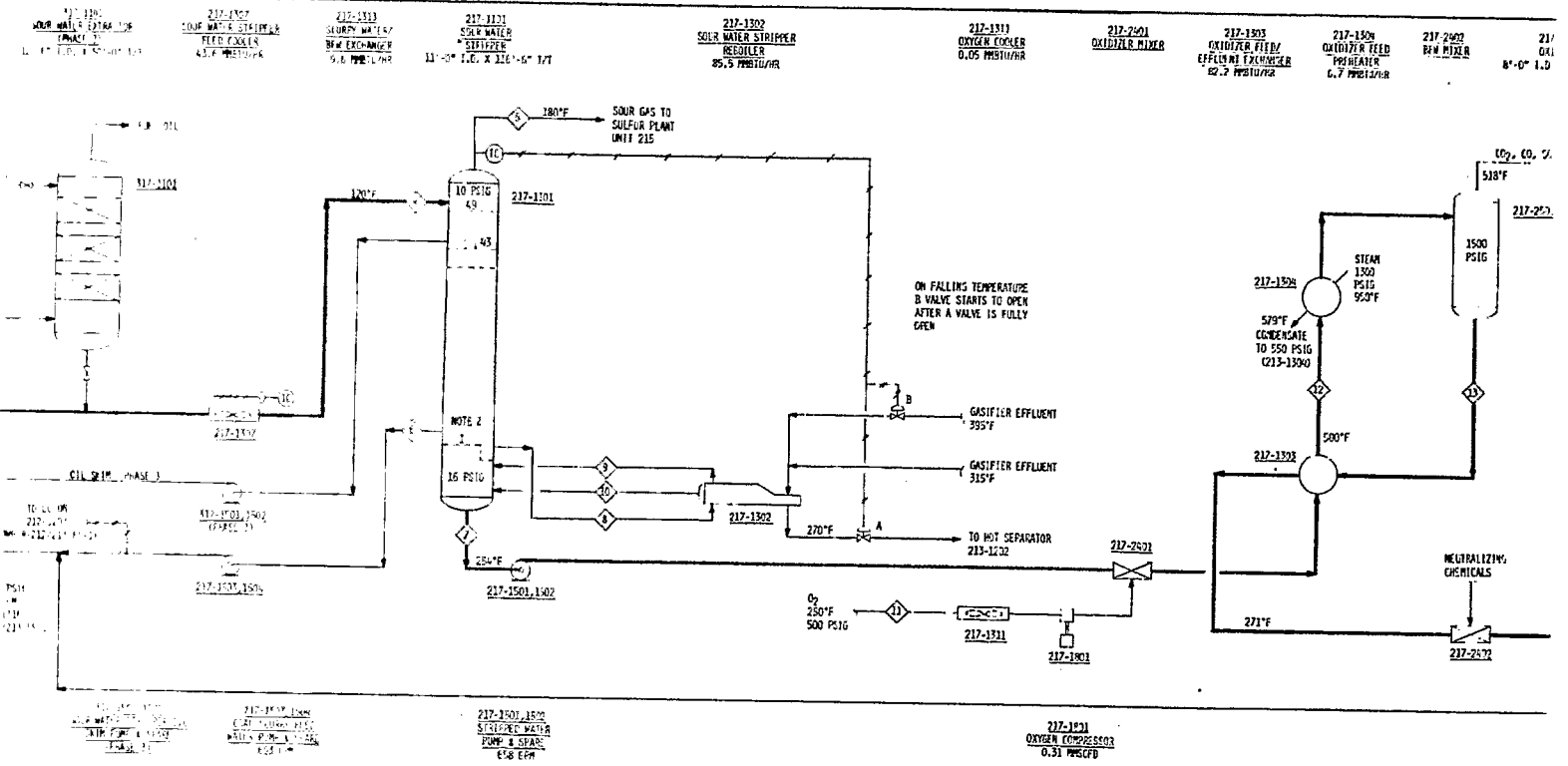
NOTE: THIS PROCESS ILLUSTRATED IS ONE OF SEVERAL PROPRIETARY PROCESSES AVAILABLE FOR THE PURPOSE INTENDED.

0	ISSUED FOR REPORT			LOS	RHC	EWB				
REV. NO.	CUST. APPR.	DATE	REVISION	BY	PROC. ENGR.	CHECK ENGR.	CHIEF PROC. ENGR.	CHIEF OPER. ENGR.	PROC. DIR.	
ENERGY RESEARCH & DEVELOPMENT ADMINISTRATION (ERDA-FE)										
MULTI-PROCESS DEMONSTRATION PLANT-PHASE II										
PROCESS FLOW DIAGRAM										
SULFUR PLANT/TAIL GAS PLANT-UNITS 215/216										
THE RALPH M. PARSONS COMPANY PASADENA, CALIFORNIA				JOB NO. 5435-5	DWG. NO. R-215/216-FS-1				REV. 0	

DC-

DT-

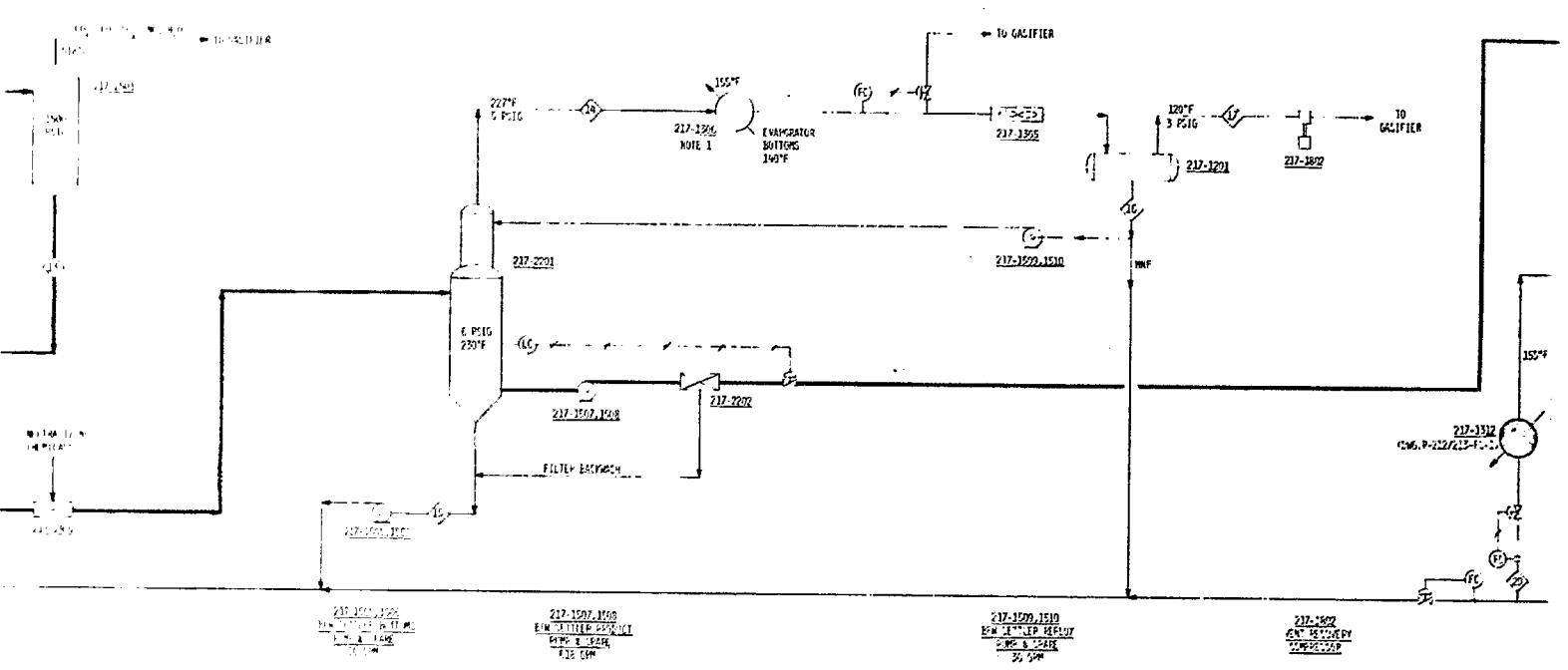
D



STREAM NO.	DESCRIPTION	FLOW RATE (GAL./HR)	TEMPERATURE (°F)	PHASE
1	TO GASifier	1000	250	LIQUID
2	FROM GASifier	1000	395	LIQUID
3	TO STRIPPER	1000	250	LIQUID
4	FROM STRIPPER	1000	180	LIQUID
5	TO SEPARATOR	1000	270	LIQUID
6	FROM SEPARATOR	1000	270	LIQUID
7	TO COMPRESSOR	1000	270	LIQUID
8	FROM COMPRESSOR	1000	538	LIQUID
9	TO NEUTRALIZING	1000	270	LIQUID
10	FROM NEUTRALIZING	1000	270	LIQUID

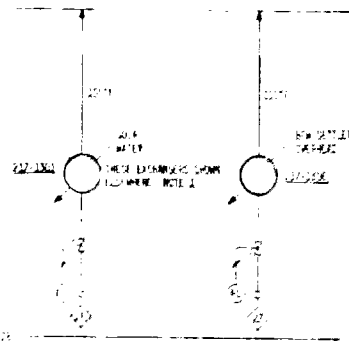
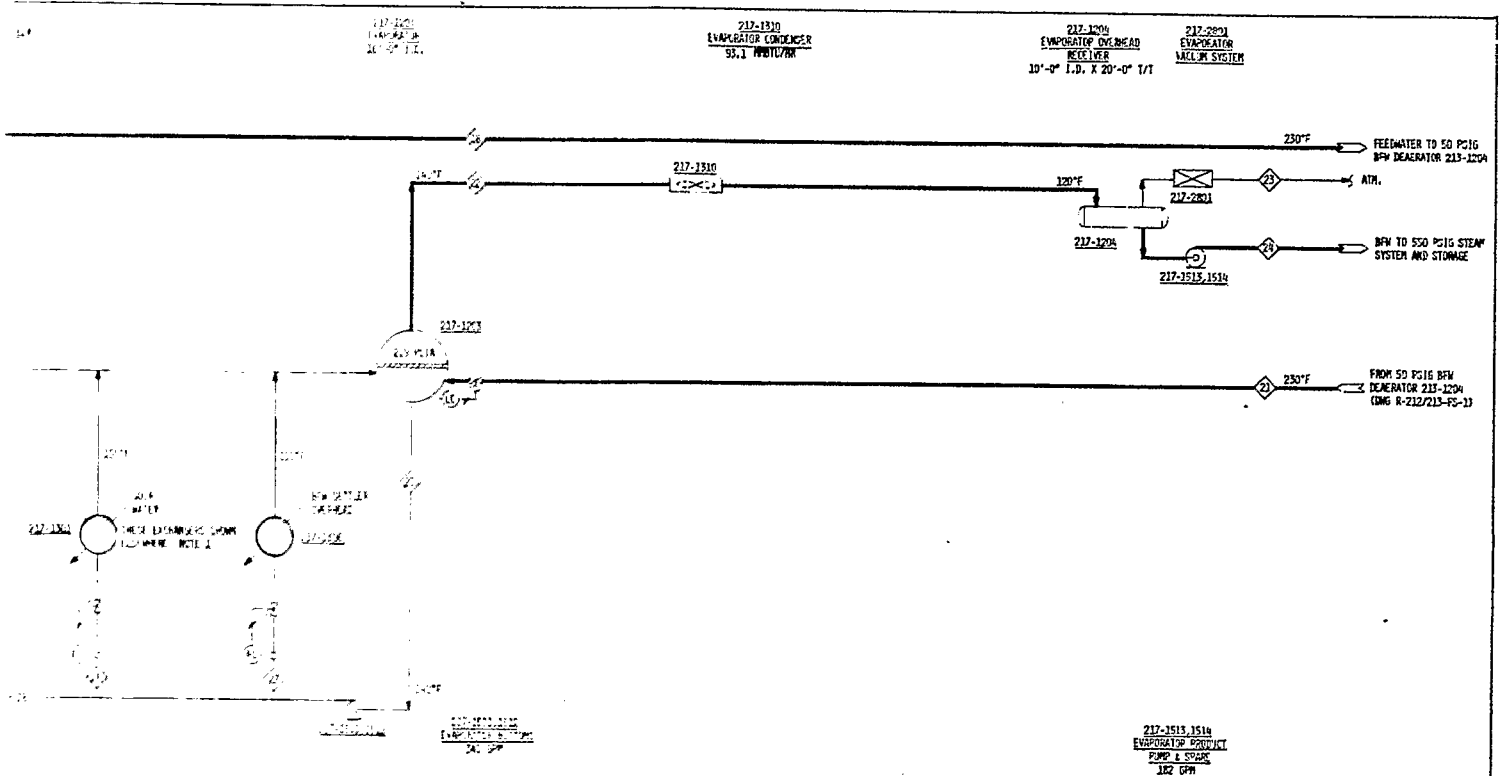
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217-200	217-201	217-202	217-203	217-204	217-205	217-206	217-207
2" L.D. X 10' 0" L	2" L.D. X 10' 0" L	2" L.D. X 10' 0" L	2" L.D. X 10' 0" L	2" L.D. X 10' 0" L	2" L.D. X 10' 0" L	2" L.D. X 10' 0" L	2" L.D. X 10' 0" L
217-208	217-209	217-210	217-211	217-212	217-213	217-214	217-215
2" L.D. X 10' 0" L	2" L.D. X 10' 0" L	2" L.D. X 10' 0" L	2" L.D. X 10' 0" L	2" L.D. X 10' 0" L	2" L.D. X 10' 0" L	2" L.D. X 10' 0" L	2" L.D. X 10' 0" L



NO.	DESCRIPTION	DATE	BY
1	ISSUED FOR CONSTRUCTION	10/1/78	J.M.
2	REVISION	10/1/78	J.M.
3	REVISION	10/1/78	J.M.
4	REVISION	10/1/78	J.M.
5	REVISION	10/1/78	J.M.
6	REVISION	10/1/78	J.M.
7	REVISION	10/1/78	J.M.
8	REVISION	10/1/78	J.M.
9	REVISION	10/1/78	J.M.
10	REVISION	10/1/78	J.M.

C



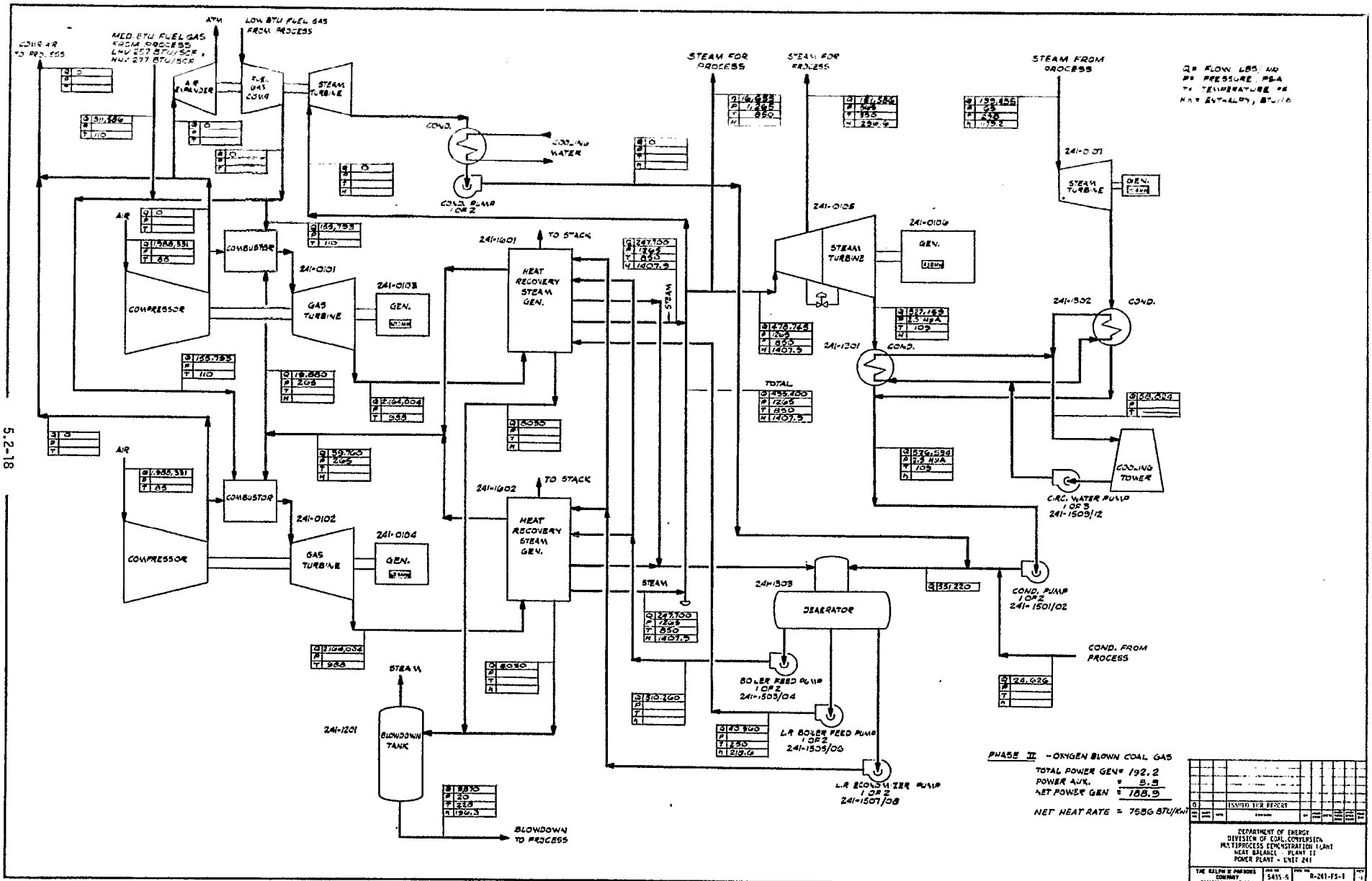
217-1204 FEEDWATER PUMP
217-1205 RAW WATER PUMP

217-1514 EVAPORATOR PRODUCT PUMP & STORAGE
122 GPM

- NOTES:
1. EXCHANGERS SHOWN ELSEWHERE ON THIS DRAWING OF DRAWING NOTED.
 2. S&C WATER DRAW TO BE DETERMINED DURING DETAILED DESIGN.

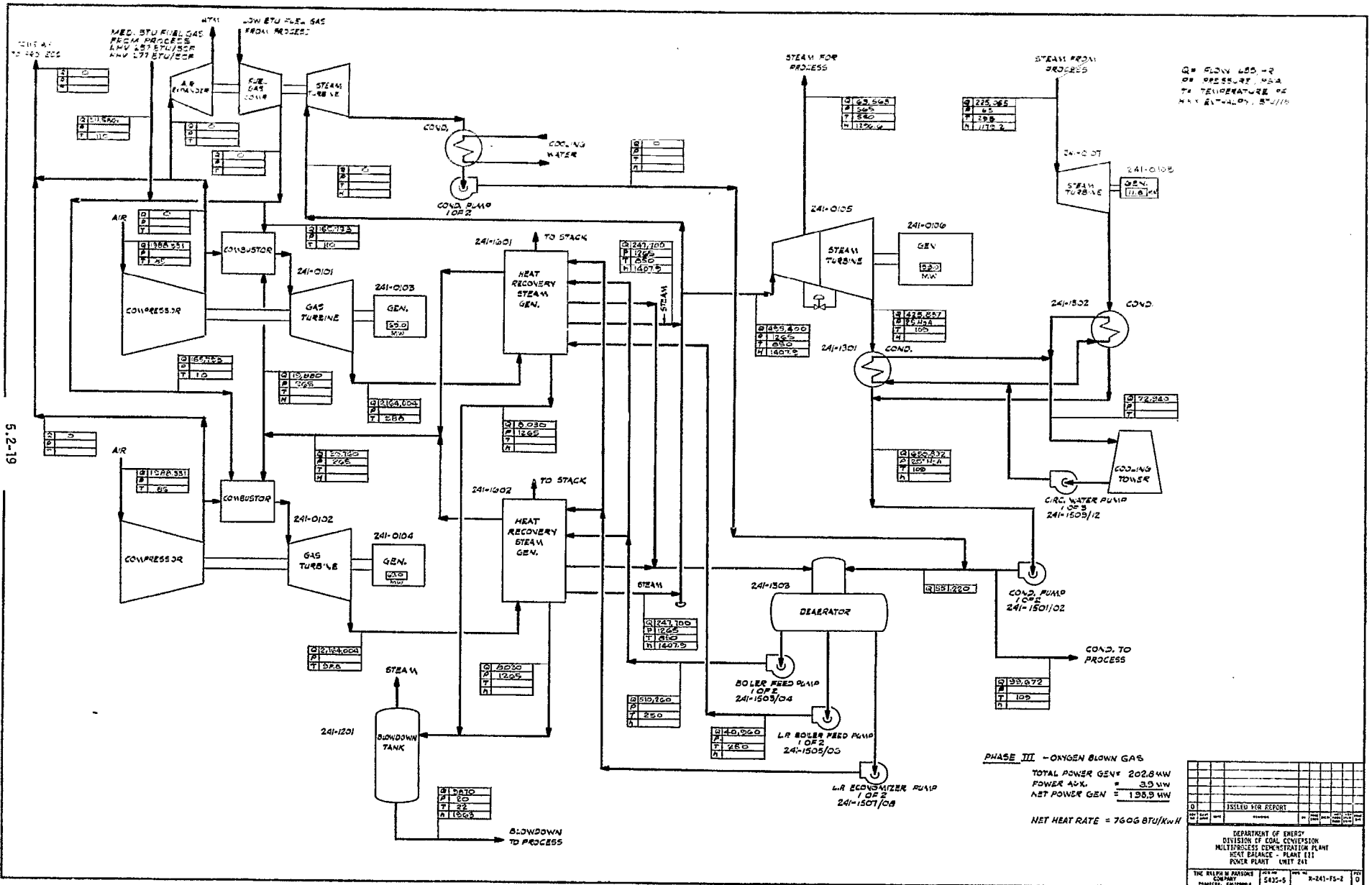
ISSUED FOR REPORT		PROJECT	DATE	BY	CHKD
DEPARTMENT OF ENERGY-DIVISION OF COAL CONVERSION MULTIPROCESS DEMONSTRATION PLANT PROCESS FLOW DIAGRAM WATER RECLAMATION UNIT-217					
THE WALPK & PARSONS COMPANY PARANAH, CALIFORNIA	5435-S	R-217-FS-1	D		

D



5.2-18

ISSUED FOR REPORT			
DEPARTMENT OF ENERGY DIVISION OF COAL CONVERSION MULTIPROCESS DEMONSTRATION PLANT HIGH BRIDGE - PLANT 11 POWER PLANT - LEVEL 241			
THE KALSH & PARSONS COMPANY	PROJECT NO. 5435-G	REV. NO.	8-241-FS-1



5.3 PLANT 3 - FISCHER-TROPSCH SYNTHESIS

The Unit 210 facilities earlier described in Section 5.2 provide the coal receiving, stockpiling, and reclaiming capability for Plant 3. The additional required stockpile capacity will be obtained by using the full 210-deg radial travel on the radial stacker No. 2. Resulting capacity on both radial stockpiles will be 40,000 tons each, and the balance of 1,000 tons plus will be acquired by using the FEL tractors to extend the stockpiles into the available general area to provide the required total of 81,000 tons. Use of the FEL's for stockpiling will allow significantly more storage than actual requirements on the 15-day process basis.

5.3.1 UNIT 311: ADDED COAL GRINDING

Plant 3 requirement for an additional 750 ton/d can be handled upon Unit 211, Plant 2 conveyor system. An additional bin, 311-2604, feeder 311-0503, and pulverizer 311-2103 will be provided for the additional Plant 3 pulverizing capacity. Duplication of mill sizes results in total excess capacity which is available for Plant 4 future operation.

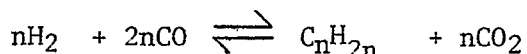
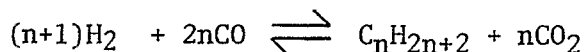
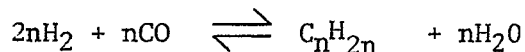
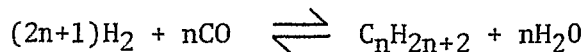
The additional equipment provided for Plant 3 operation is shown on Drawing R-110/111-FS-1.

5.3.2 UNIT 318: FISCHER-TROPSCH ACID GAS REMOVAL

The product gas of Plant 2 was treated in an acid gas removal system which removed the majority of the hydrogen sulfide and a portion of the carbon dioxide. Unit 318 consists of equipment integrated with Unit 214 based on use of the Rectisol process to process additional gas. Approximately 66,000 lb/hr of product gas is obtained from an additional 750 ton/d of coal fed to Plant 2. This would become a separate process if a system other than Rectisol is used for Unit 214. This operation removes the remainder of the carbon dioxide in order to obtain a suitable synthesis gas for the Fischer-Tropsch catalytic conversion.

5.3.3 UNIT 319: FISCHER-TROPSCH SYNTHESIS¹

The Fischer-Tropsch synthesis unit shown on Flow Diagram R-319-FS-1 is designed to produce liquid hydrocarbons from carbon monoxide and hydrogen (syngas). Representative chemical reactions are:



An iron catalyst is used. Straight chain paraffin and olefin hydrocarbons are the principal products. Trace quantities of cyclics and diolefins as well as small quantities of oxygenates are formed.

Clean nil-sulfur syngas from the acid gas removal, Unit 214, enters the Fischer-Tropsch synthesis unit at 406.5 psig design. It contains 39.0 mol % CO and 56.5 mol % H₂, plus small amounts of CH₄, CO₂, H₂O, and N₂. It is preheated in heat exchanger 319-1301-02 to 556°F and passes through one of two zinc oxide (ZnO) guard reactors, 319-2502, operated in parallel. The ZnO removes trace sulfur compounds such as hydrogen sulfide and carbonyl sulfide, prior to entering the synthesis loop. The zinc oxide beds are replaced periodically as they become depleted.

The syngas effluent from the ZnO guard chambers is mixed with recycle process gases and the combined stream preheated to the synthesis reactor inlet temperature of 571°F by the 1300-psig steam in Fischer-Tropsch reactor preheater 319-1302. The hot syngas then enters the F-T synthesis loop.

The heart of the synthesis loop is parallel synthesis reactors, 319-2501-01 and -02. They are designed to approach isothermal reaction conditions. The catalyst is applied by a flame-spray technique to extended external heat exchanger surface which contacts the syngas. Boiling water is inside the heat exchange tubes to remove the approximately 110 million Btu/hr of heat liberated in the two reactors by the highly exothermic synthesis reaction. The catalytic system used is based on the results of development work reported by DOE's Pittsburgh Energy Research Center (PERC). A sketch of a F-T synthesis reactor is shown in Figure 5.3-1.

Also included in the synthesis loop are associated reaction heat recovery equipment, a recycle compressor, reactor feed/product heat exchangers, and product recovery facilities.

The reactor effluent is cooled and partially condensed at 194°F and 394.5 psig by heat exchange against the fresh feed in heat exchanger 319-1301-02 and process gas recycle in exchanger 319-1301-01. A solution of caustic is sprayed into the partially condensed product immediately after the exchangers to neutralize organic acids. The condensed hydrocarbon and neutralized aqueous phases are then separated in F-T hot product separator 319-1202. The separated aqueous phase flows under level control to the alcohol stripper in the chemical recovery unit 322. The separated liquid hydrocarbon is cooled to 110°F in air cooler 319-1303 and pumped to the F-T liquid extractor, 319-1101, where it is contacted with process water to remove dissolved alcohols. These alcohols are subsequently recovered from the aqueous phase by the alcohol still in chemical recovery unit 322.

Uncondensed product gas exiting 319-1202 flows to carbon dioxide removal unit 319-2801, where the CO₂ content of the combined stream is reduced to 0.84%; CO₂ must be reduced in the recycle gas stream, since CO₂ and H₂O decrease the rate of synthesis in the Fischer-Tropsch reactor. A hot potassium carbonate system is used for CO₂ removal. Overhead condensate, stream 15, is

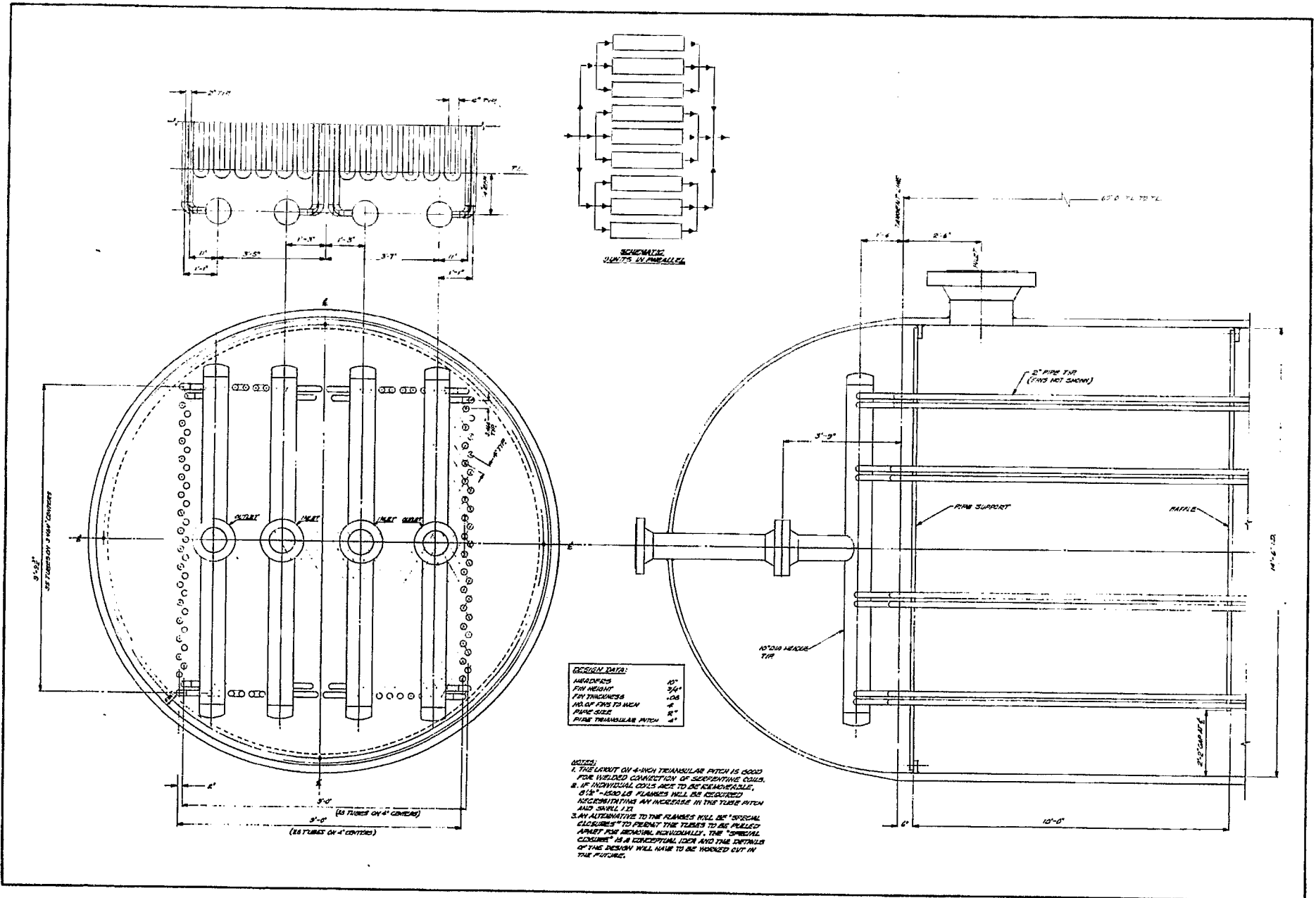


Figure 5.3-1 - Synthesis Reactor

pumped to the alcohol in chemical recovery unit 522 for alcohol recovery. Carbon dioxide vent gases from the system are scrubbed with process water in the F-T CO₂ scrubber to recover additional alcohols from the gas stream before discharge to the atmosphere. Water and recovered alcohols are pumped from the F-T CO₂ scrubber to extractor 319-1101.

Effluent gases from the CO₂ removal unit are cooled from 193 to 121°F by heat exchange in 319-1304 against boiler feed water, and then combined with liquid hydrocarbon product from F-T liquid scrubber 319-1101. The combined process stream is cooled and partially condensed at 110°F and 389 psig by air cooler 319-1306. Condensed water and liquid hydrocarbons are removed in F-T product separator 319-1203. Separated water is pumped to condensate receiver 213-1202 in gas cleaning unit 213. Separated hydrocarbon liquids flow by level control to F-T liquid product recovery unit 320.

Approximately 84% of the gas from F-T cold product separator 319-1203 is recycled by compressor 319-1801 to the F-T reactors. The balance of the F-T gas product is sent to liquid product recovery unit 320 for processing to produce SNG.

5.5.4 UNIT 320: FISCHER-TROPSCH LIQUID PRODUCTS RECOVERY

Liquid product recovery unit 320, depicted on Drawing R-320-FS-1, is designed to recover light hydrocarbon liquids from product Fischer-Tropsch gas, and to fractionate Fischer-Tropsch liquids into hydrocarbon products.

Sixty percent of the propylene/propane content of the Fischer-Tropsch gas is recovered. The balance is allowed to remain in the gas to increase its heating value. Ethylene and heavier hydrocarbons not recovered from the gas in lean oil absorber 320-1101 are hydrocracked to methane in downstream methanation unit 321. The hydrocarbons recovered from the gas stream and Fischer-Tropsch liquid are separated into C₄ LPG, light naphtha, heavy naphtha, diesel oil, and fuel oil. A light hydrocarbon stream containing C₂, C₃, and some C₄ is separated from the carbon monoxide in CO stripper 320-1104 and used to increase the calorific value of the SNG product.

Fischer-Tropsch gas from unit 319, entering the recovery unit at 110°F and 385 psig design, is dried by contact with 80 wt % solution of triethylene glycol. The dewpoint depression obtained is 80°F below an estimated 50°F gas hydrate temperature. The contacted gas and glycol stream is cooled by heat exchange in 320-1301, and refrigeration in 320-1302, to -20°F, and separated into gas, condensed hydrocarbons, and rich glycol streams in cold separator 320-1207. The gas stream next enters the bottom of lean oil absorber 320-1101, where propylene and heavier hydrocarbons are absorbed by a presaturated lean oil stream. Overhead gas from the absorber is contacted with a spray of lean oil and chilled to -20°F in presaturator chiller 320-1303, the oil thereby becoming saturated with light ends contained in the overhead gas stream. Vapor from the presaturator, now stripped Fischer-Tropsch gas, is used to cool the incoming rich Fischer-Tropsch gas and glycol by heat exchange in 320-1301.

Condensed hydrocarbons join with rich oil from the bottom of the absorber, and the combined rich stream is then warmed in heat exchanger 320-1304 by the hot lean oil stream returning to the presaturator from lean oil stripper 320-1103. The rich oil and hydrocarbons mixture flows to the upper feed tray of lean oil fractionator 320-1102.

Fischer-Tropsch liquid from Unit 320 enters the recovery unit at 110°F and 385 psig and is heated in heat exchanger 320-1319, -1320, and -1321 to 191°F and flows to the lower feed tray of lean oil fractionator 320-1102.

The lower section of the lean oil fractionator strips hexane and lighter components from the oil while heavier waxy components are refluxed to the bottom of the column. The lean oil from the upper side stream stripper, 320-1103, is wax free, while carbon monoxide, hexane, and lighter hydrocarbons go overhead.

The stripped lean oil is pumped to the presaturator after being cooled to -2.5°F by the rich oil stream. The lean oil stream pumped from 320-1103 is comprised of 2 mol % C₅, 51 mol % C₆, 43 mol % C₇, and 4 mol % C₈. Hydrocarbon products are collectively recovered by lean oil fractionator 320-1102. A 500-psig steam heated lean oil fractionator reboiler, 320-1306, supplies column stripping vapor. The top section of the fractionator is a rectifying section which prevents the loss of lean oil in the stripped vapors. The lean oil fractionator overhead is partially condensed at 110°F and 50 psig to provide reflux to the top section and a net overhead liquid product.

Uncondensed vapors from the lean oil fractionator are compressed to 400 psig by compressor 320-1801 and combined with the fractionator net overhead liquid product. The combined stream is cooled to 110°F and flows to the top tray of CO stripper 320-1104. The CO stripper is a refluxed stripper designed to remove CO and CO₂ from the lean oil fractionator net overhead product. The overhead is partially condensed at -20°F and 385 psig to provide stripper reflux. A refrigerated overhead condenser is used to minimize the loss of propylene and propane in the stripper overhead. The lean oil fractionator and CO stripper are water wet since full range Fischer-Tropsch liquid product is saturated and this dissolved water will enter both columns. Vapor from the top of the CO stripper is contacted with a spray of 80 Wt% triethylene glycol solution to prevent hydrate formation in the refrigerated overhead condenser. Reflux is preheated to 53°F in heat exchanger 320-1309 by column overhead vapor prior to entering the column. Vapors from the CO stripper overhead receiver are combined with the stripped Fischer-Tropsch gas and flow to methanator unit 321. CO stripper reboiler 320-1311 is heated with 50-psig steam.

Stripped product from the CO stripper is heated in depropanizer feed/bottoms exchanger 320-1312 to 249°F and enters depropanizer 320-1105. The depropanizer is a reboiled fractionator designed to produce an overhead liquid product of mixed light ends for blending into the SNG produced in methanator unit 321. Sufficient light ends are produced to increase the higher heating value of the SNG to 1035 Btu/scf. The depropanizer overhead is totally condensed at 120°F and 285 psig to produce reflux and a liquid distillate which is pumped to Unit 321. Depropanizer reboiler 320-1314 is heated by 135-psig steam.

Light naphtha from the bottom of the depropanizer is cooled from 318°F to 260°F in heat exchanger 320-1312 with the depropanizer feed and then flows to the naphtha stabilizer, 320-1106. The naphtha stabilizer is a reboiled fractionator designed to recover 98% of the butylene and butanes as a mixed LPG product. The stabilizer overhead is totally condensed at 120°F and 85 psig in 320-1315 to provide column reflux and a net liquid distillate which is pumped to product storage from depropanizer overhead receiver 320-1205. Stabilized light naphtha from the bottom of the stabilizer is cooled in heat exchanger 320-1319 with Fischer-Tropsch liquid and by air cooling in 320-1322 to 120°F before flowing to product storage. The naphtha stabilizer reboiler is heated by 135-psig steam.

The heavy oil from the bottom of lean oil fractionator 320-1102 flows through fuels fractionator charge heater 320-1317 where it is heated and vaporized by 500-psig steam prior to entering fuels fractionator 320-1107 flash zone. The fuels fractionator is a non-reboiled fractionating column operating under vacuum. Products from the fuels fractionator are heavy naphtha, diesel oil, and heavy fuel oil. Feed enters the column flash zone at 450°F and 320 mm Hg pressure. The diesel fraction is withdrawn through side stripper 320-1108, where it is steam stripped to obtain the specified diesel product flash point. Stripped diesel product pumped from the bottom of the side stripper is cooled to 120°F by heat exchange with Fischer-Tropsch liquid in 320-1320 and air cooler 320-1323 before flowing to product storage.

Heavy fuel oil condensed above the flash zone combined with flash zone liquid is steam stripped in the bottom section of the fuels fractionator column 320-1107, to improve product recoveries. Heavy fuel pumped from the bottom of the fractionator is cooled to 191°F in heat exchanger 320-1321 with Fischer-Tropsch liquid; it then flows to the water treating unit 217, where it is used to extract oil from waste water. The fuel oil returned from Unit 217 is cooled by air cooling to 140°F in 320-1324 and sent to the fuel oil rundown tankage. Stripping steam, vaporized reflux, and heavy naphtha product from the top of the fuels fractionator column are condensed at 100°F and 155 mm Hg in 320-1318. Reflux is pumped back to the top of the column and heavy naphtha is run down to product storage. Condensed stripping steam is separated in overhead receiver 320-1206 and pumped to Unit 213 scrubbers.

Uncondensed steam and oil, together with noncondensable gases, are withdrawn by package evacuation unit 320-2804. Steam and oil recovered by the evacuation unit are returned to the fuels fractionator overhead receiver.

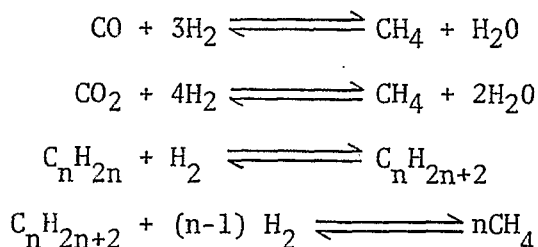
A package refrigeration unit, 320-2801, is provided to meet process refrigeration loads.

Water-rich triethylene glycol from cold separator 320-1207 and CO stripper overhead receiver 320-1203 is reconcentrated in package glycol regenerator unit 320-2805. A steam reboiled rectifying column is used for glycol reconcentration.

5.3.5 UNIT 321: FISCHER-TROPSCH GAS METHANATION

The methanation unit shown on Flow Diagram R-321-FS-1 is designed to produce a substitute natural gas (SNG) containing approximately 0.1 mol % CO and having a higher heating value (HHV) of 1025 Btu/scf from the stripped F-T gas stream flowing from liquid product recovery unit 320.

The stripped F-T gas stream contains 17 mol % CO, 0.8 mol % CO₂, 57 mol% H₂, and 18 mol % CH₄, and has an HHV of 484 Btu/scf. The methanation unit converts the low Btu gas to methane-rich high Btu gas by the following chemical reactions:



Sulfur-free stripped F-T gas enters the synthesis loop of methanator reactor 321-2501 at 90°F and 385 psig design. The synthesis loop is composed of one methanation reactor, together with the associated reaction heat recovery facilities, a recycle compressor, and reactor feed/product exchangers. The fresh feed is mixed with recirculated process gases, and the combined stream is raised to the methanation reactor inlet temperature of 571°F by heat exchange with reaction products in 321-1301 and by 1300-psig steam methanation reactor feed preheater 321-1302.

The methanation reactors are of a unique isothermal design similar to the F-T synthesis reactors with flame-sprayed catalyst on finned tubes. The catalyst used is a metallic nickel catalyst developed in experimental operations.

The methanation reactions are highly exothermic, and the resultant heat of reaction is removed by boiling Dowtherm contained inside the catalyst plate support tubes. The evaporated Dowtherm is used to generate 1300-psig steam in steam generators 321-1309 and to regenerate SNG dryer 321-3401.

Reactor operating conditions are selected so that CO₂ methanation is suppressed in order that sufficient hydrogen is available to achieve the desired degree of CO methanation.

Reaction products are cooled to 227°F by heat exchange to the reactor feed in 321-1301 and partially condensed at 120°F and 376 psig in air cooler 321-1303, then recycled through the product cooler. Condensed water is removed in recycle compressor suction receiver 321-1202 and flows under level control to the SNG pipeline compressor suction receiver 321-1203. Approximately 72% of the gas from receiver 321-1202 flows to recycle compressor 321-1801 for recirculation back to the methanation reactors.

Net product gas from separator 321-1202 is heated by heat exchange in 321-1307 to 520°F and flows to second stage one-pass reactor 321-2502 for methanation of the CO₂, and for final CO methanation should a breakthrough of CO occur from the methanation reactor. The final methanation reactor is an adiabatic fixed-bed radial-flow reactor employing pelleted, reduced-nickel type catalyst. Sufficient CO₂ is methanated to reduce the final SNG product CO₂ content below 1.5 mol %.

Product gas leaves the final methanator reactor at 550°F, and has an HHV of approximately 907 Btu/scf. The final methanator gas is combined with a mixed light hydrocarbon stream from liquid product recovery unit 320 so that the HHV of the final SNG product is equal to 1025 Btu/scf. The light hydrocarbon stream is vaporized into the methanator gas stream so that the combined stream enters the hydrotreater reactor at 500°F.

Hydrotreater reactor 321-2503 is an adiabatic fixed-bed radial-flow reactor employing pelleted cobalt-moly catalyst for the saturation of alkenes in the light hydrocarbons by residual hydrogen in the methanator gas.

Product gas leaves the hydrotreater at 550°F and is cooled to 210°F by heat exchange against the final methanator feed in 321-1306 and is partially condensed at 120°F and 360 psig by the SNG pipeline compressor suction air cooler, 321-1304. Condensed water is removed in SNG pipeline compressor suction receiver 321-1203 and, together with water from the recycle compressor suction, is pumped to medium Btu gas heat recovery unit 213.

The hydrotreated gas is compressed from 360 psig to 1010 psig by SNG pipeline compressor 321-1802 and, after cooling to 120°F and separation of condensed water, dried to a water dewpoint of 52°F at 1000 psig in 321-3401 prior to entering the gas transmission line.

A package gas glycol (TEG) contactor and regenerator is specified for SNG drying unit 321-3401. Glycol is regenerated using Dowtherm from the methanator waste heat recovery section.

5.3.6 UNIT 322: FISCHER-TROPSCH CHEMICALS RECOVERY

Flow Diagram R-322-FS-1 shows the flow sequence for the separation of chemicals, mainly oxygenates with a high alcohol content, from water. The source of oxygenate-water solution is Fischer-Tropsch synthesis unit 319.

Oxygenate solution feed from Fischer-Tropsch liquid scrubber 319-1101 is heated by exchange with alcohol still 322-1101 water bottoms before it is fed to the alcohol still. The overhead alcohol mix product is condensed in air cooler 322-1303 and sent to storage, while the noncondensables are recycled to Fischer-Tropsch CO₂ scrubber 319-1102 in unit 319. The alcohol still bottoms are cooled and used as process water in the Fischer-Tropsch CO₂ scrubber in Unit 319. Net product water bottoms goes to Unit 213 for scrubbing and re-use.

Alcohol-salt solution feed from Fischer-Tropsch hot receiver 519-1202 is heated by exchange with alcohol stripper 322-1102 salt solution effluent in heat exchanger 322-1306. The organic acid-salt solution results from neutralization of the acid formed in the Fischer-Tropsch synthesis. The overhead alcohol vapor mix from the alcohol stripper is recycled to alcohol still 322-1101, while the salt solution effluent is sent to the triple effect evaporator system 322-2301/2302/2303 for recovery.

The feed to the triple effect evaporator is mainly a combination of the salt solution from alcohol stripper 322-1102 and the blowdown from the various boilers in the plant. Other possible feed streams are the BFW settlers bottoms and the deionizer wash water from Unit 217. Evaporator feed amounts to approximately 20 gpm. The evaporator condensates are sent to boiler feed water storage while the concentrated salt solution may be used as spray water in the coal storage area with eventual recycle to the gasifier as means of final disposal.

5.3.7 UNIT 330: ADDED WATER TREATMENT

The addition of Plant 3 to Fischer-Tropsch operation requires nearly 25% additional water over that required for the simultaneous operation of the Phase 1 and Phase 2 plant modules. Raw water pumping will be increased by almost 2,040 gpm to a total of 10,240 gpm.

This unit includes additional pumping, clarification, and filtering equipment plus the additional distribution capacity. The expanded water treatment operation is shown in the material balance on Drawing R-130/131-FS-1.

5.3.8 UNIT 331: ADDED COOLING WATER SYSTEM

The Plant 3 Fischer-Tropsch operation requires additional cooling water circulation and cooling tower capacity of 32,000 gpm over the 192,000 gpm required for Plant 1 and Plant 2 operations.

The existing facilities would be further expanded by adding cooling tower sections, pumps, and distribution lines to supply the increased requirements. The quantities are shown on Drawing R-130/131-FS-1.

5.3.9 UNIT 332: ADDED EFFLUENT TREATMENT

The Fischer-Tropsch operation results in a further increase in effluents. Sanitary sewage treatment, skimmer pit, and settling pond capacity are expanded by approximately 25%.

5.3.10 UNIT 335: INTERMEDIATE STORAGE

This unit is comprised of 15 assorted tanks ranging from 3,000 gal to 15,000 gal capacity with required pumps. These serve as run tanks and for intermediate storage while awaiting laboratory tests before moving the liquid products into the main product storage tanks. These are listed in Section 8 of this report.

5.3.11 UNIT 356: PRODUCT STORAGE AND SHIPPING FACILITIES

This unit contains the storage tanks for the Fischer-Tropsch liquid products. Capacity for storage of 15 d of production of each product is provided. The nine storage tanks are from 40,000 to 225,000 gal capacity.

This unit also includes pumps and facilities for railroad tank car and tank truck loading and shipping.

5.3.12 UNIT 350: ADDED BUILDINGS AND GENERAL FACILITIES

Plant 3 Fischer-Tropsch operation will require minor additions and facilities to office, change houses, and shops. A major addition will be made to the laboratory, in both analytical and developmental areas.

The parking areas will be expanded and area road system built.

An additional railroad spur will be added to serve the liquid products shipping area.

5.3.13 PLANT 3 PRODUCTS

The products listed are from the operation of the Plant 2 gasifier at 80% of capacity. The products include those from Plant 2 operation.

ELECTRIC POWER

For sale, transfer, and process plant usage, 202.8 MW is required (generated and transferred @ 13,600 V).

SULFUR

Quantity (ton/d)	109.9
Purity (% sulfur)	99.9
Color	Yellow

SNG (SUBSTITUTE NATURAL GAS)

Quantity (MMscf/d)	5.69
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This is a gaseous mixture of methane, hydrogen, carbon monoxide, and carbon dioxide, together with sufficient quantity of light hydrocarbons to produce a nominal 1,025-Btu/cu ft gas.

Composition Volume Percent, Dry Basis

Methane	85.8
Ethane, propane, butane	6.9
Carbon monoxide	0.1

Hydrogen	1.0
Carbon dioxide	1.4
Nitrogen	6.8
	<u>100.00</u>

Product Characteristics

Higher heating value (dry)	1,035 Btu/scf	ASTM D900-55
Specific gravity (air = 1, at 60°F)	0.67	
Delivered pressure to pipeline	1,000 psig	
Dew point (hydrocarbon)	32°F at 800 psia	ASTM D1142-56
Dew point (water)	32°F at 1,000 psia	ASTM D1142-58
AGA interchangeability indexes:		preferable value
Lifting index*	1.091	1.06
Flash-back index	1.048	1.2
Yellow-tip index	0.942	0.8

BUTANES

Quantity (BPD) 78

This is a mixed liquid product containing butane and butylene with some associated lighter and heavier saturated and monounsaturated hydrocarbons.

<u>Composition</u>	<u>Wt %</u>	<u>Mol %</u>	<u>Liquid (Vol %)</u>
Butylene	16.2	16.7	15.8
Butane	82.1	81.8	82.6
Propane-propylene	0.1	0.1	0.1
Pentanes	1.7	1.4	1.6
Sulfur	nil		
Nitrogen	nil		

*Note: The lifting index can be adjusted to the preferred range by increasing the SNG hydrogen content.

<u>Product Characteristics</u>		<u>Tests</u>
Nominal specific gravity at 60°F, liquid	0.59	ASTM D1657 or D2598
Vapor pressure (psig at 100°F)	37	ASTM D1267
Temperature, 95% evaporation point (°F)	51	ASTM D1837
Sulfur content (grains/100 ft ³)	nil	ASTM D2784
Corrosion, copper strip	1	ASTM D1838
Nominal dryness (wt % water)	0.001	NGPA

NAPHTHA, LIGHTS AND HEAVY

Quantity (BPD) 234 and 211 respectively

These products are in the automotive gasoline distillation range and consist primarily of straight-chain monounsaturated and straight-chain saturated hydrocarbons boiling to 300°F ASTM end point range. These naphthas are free of sulfur and nitrogen and may be hydrogenated to produce turbine fuel or used as chemical feedstock.

<u>Product Characteristics</u>	<u>Light Naphtha</u>	<u>Heavy Naphtha</u>	<u>Tests</u>
Gravity (°API)	85.5	71.3	ASTM D287
ASTM Distillation:			ASTM D86
IBP	96°F	186°F	
10%	115°F	208°F	
30%	128°F	226°F	
50%	137°F	236°F	
70%	146°F	253°F	
90%	159°F	266°F	
EP	185°F	300°F	
Color (Saybolt)	plus 30	plus 30	ASTM D156
Viscosity at -30°F, CS	0.8	1.7	ASTM D445
Aniline point	140°F	160°F	ASTM D1012
Oxygen content (wt %)	0.2 max	0.2 max	

<u>Product Characteristics</u>	<u>Light Naphtha</u>	<u>Heavy Naphtha</u>	<u>Tests</u>
Sulfur (wt %)	nil	nil	ASTM D1323 or D1219
Hydrogen sulfide (wt %)	nil	nil	
Alcohol and oxygenates	less than 0.1%	less than 0.1%	
Doctor test	neg	neg	
Corrosion, copper strip			
(at 150°F)	1	1	
(at 210°F)	1	1	
Octane Number			
F-1 Clear	45.6		ASTM D2699
F-2 Clear	40.6		ASTM D2700
F-1 plus 3 ml TEL/US gal	67.0		
F-2 plus 3 ml TEL/US gal	68.5		
Reid vapor pressure (psia)	10	ASTM D323	
IP smoke point (mm)	over 30	over 30	(IP designation 57)
Yield nitrogen	nil	nil	
UOP "K"	12.3	12.3	

DIESEL FUEL

Quantity (BPD) 356

This product consists primarily of straight-chain hydrocarbons, free of sulfur and nitrogen; it meets specifications for commercial diesel fuel markets.

<u>Product Characteristics</u>		<u>Tests</u>
Grade	ASTM D975 No. 1-D	
Gravity (°API)	57	ASTM D287

Product Characteristics

Tests

ASTM distillation:

ASTM D86

IPB	301°F	
10%	327°F	
30%	351°F	
50%	372°F	
70%	421°F	
90%	539°F	
EP	637°F	
Percent recovered	98%	
Viscosity at 100°F, CS	1.4	ASTM D445
Flash point (°F, Pensky-Marten)	legal	ASTM D93
Pour point	plus 10°F	ASTM D97
Aniline point (°F)	175	ASTM D611
Oxygen content (wt %)	0.5 max	
Sulfur (wt %)	nil	ASTM D129
Mercaptan sulfur	nil	ASTM D1323 or D1219
Neutralization number (mg KCH/g)	0.1	ASTM D611
Corrosion, copper strip (at 150°F)	1	ASTM D130
(at 210°F)	1	
Ash (wt %)	less than 0.01	ASTM D482
IP smoke point (mm)	25	(IP designation 57)
Engine cetane number	60 plus	ASTM D613
Kieldahl nitrogen (ppm)	nil	ASTM D322

FUEL OIL

Quantity (BPD) 112

The fuel oil is a waxy, high-pour point, sulfur-free product.

Product Characteristics

Higher heating value, Btu/lb	19,855	ASTM D2382
Gravity (°API)	41	ASTM D287
ASTM distillation:		
IBP	572°F	ASTM D86
5%	642°F	ASTM D86
10%	665°F	ASTM D86
30%	715°F	ASTM D86
50%	759°F	ASTM D86
70%	811°F	ASTM D86
90%	873°F	ASTM D86
95%	886°F	ASTM D86
EP	885°F	ASTM D86
Viscosity at 100°F, SSU	40 to 100	ASTM D88
Flash point (°F, Pensky-Martens)	200	ASTM D93
Pour point (°F)	150	ASTM D97
Color (Saybolt)	dark	ASTM D1500
Oxygen (wt %)	0.2 max	
Sulfur	nil	ASTM D129

OXYGENATES

Quantity (BPD) 72

Oxygenates are a mixture of alcohols with a small amount of ketones.

<u>Composition</u>	<u>Vol % (dry basis)</u>
Acetone	3.2
Methyl ethyl ketone	0.7
Methanol	6.0
Ethanol	67.6
Propanol	18.0
Butanol	2.4

Amyl alcohol	1.1
Higher alcohols and other oxygenates	1.0
	<u>100.0</u>

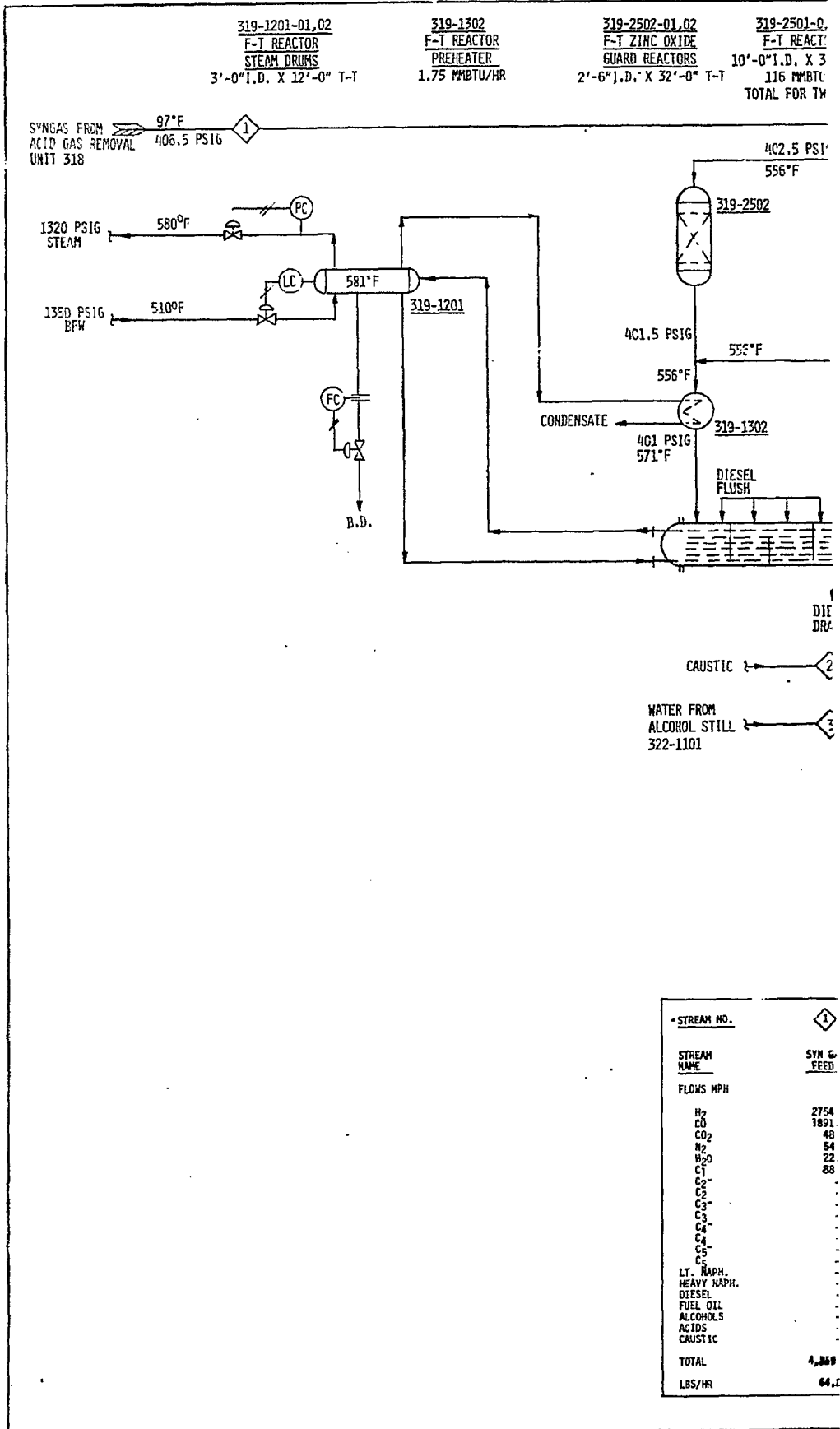
Product Characteristics

Higher heating value:

(dry)	13,160 Btu/lb average
(as is)	12,505 Btu/lb average

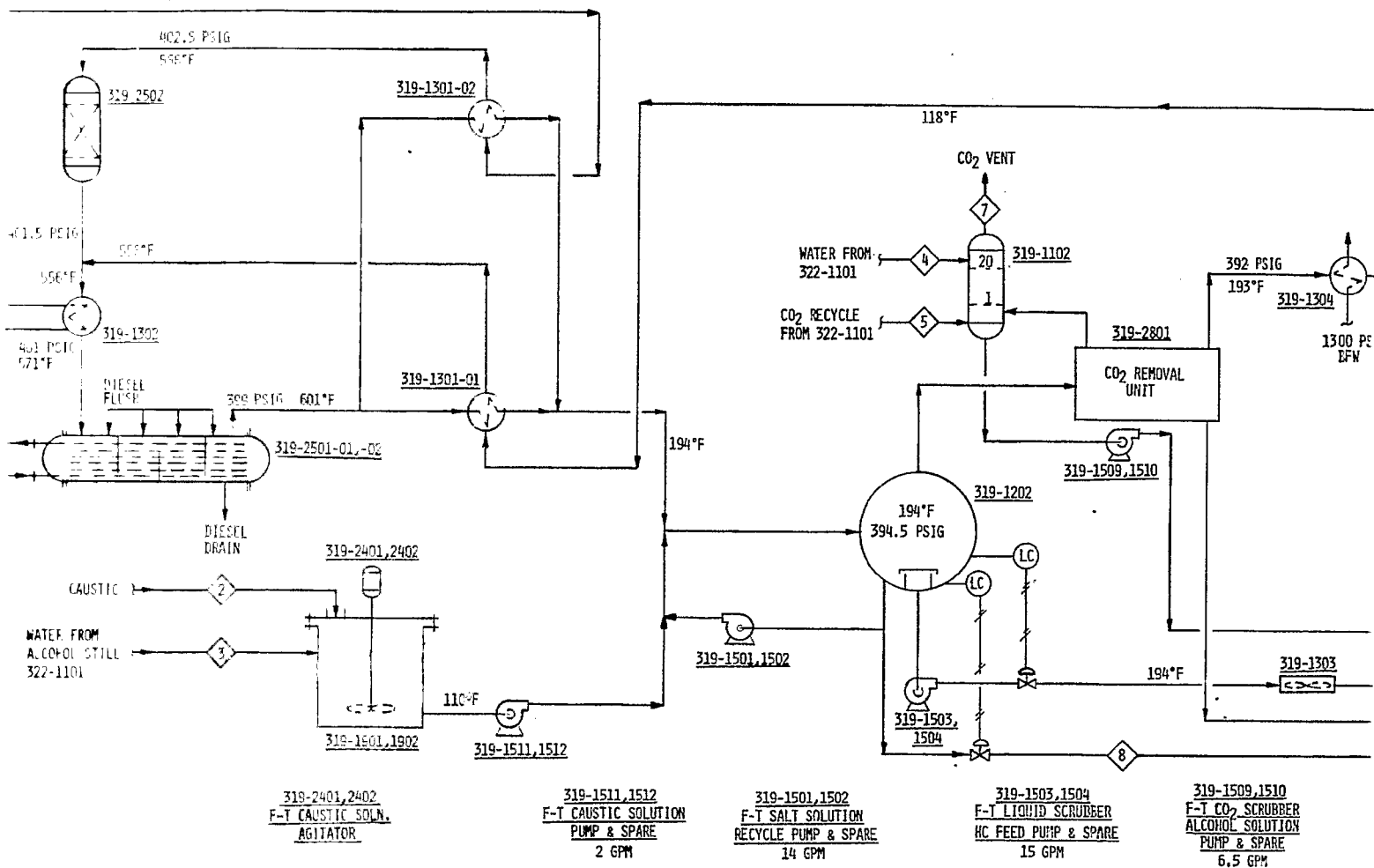
Specific gravity 0.79

Water content 5.0 wt % max



A

<u>319-2502-01,02</u> ZINC OXIDE F-D REACTORS 10' X 32'-0" T-T	<u>319-2501-01,02</u> F-T REACTORS 10'-0" I.D. X 30'-0" T-T 116 MMBTU/HR TOTAL FOR TWO UNITS	<u>319-1301-02</u> F-T REACTOR FEED/PRODUCT EXCHANGER 16.4 MMBTU/HR	<u>319-1901,1902</u> F-T CAUSTIC SOLUTION MIXING TANK 5'-0" I.D. X 5'-0" HIGH	<u>319-1301-01</u> F-T REACTOR RECYCLE/ PRODUCT EXCHANGER 27.7 MMBTU/HR	<u>319-1202</u> F-T HOT PRODUCT SEPARATOR 8'-0" I.D. SPHERE	<u>319-2801</u> CO ₂ REMOVAL UNIT	<u>319-1102</u> F-T CO ₂ SCRUBBER 8'-0" I.D. X 56'-0" T-T	<u>319-1304</u> F-T BFW HEATER 10.7 MMBTU/HR
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STREAM NO.	1	2	3	4	5	6	7	8	9	10	11	12	13
STREAM NAME	514 GPM FEED	CAUSTIC	WATER	WATER TO CO ₂ SCRUBBER	CO ₂ RECYCLE	WATER FROM ALCOHOL RECOVERY	CO ₂ VENT	HOT FLASH SALT SOL'N.	WATER ALCOHOL SOLUTION	F-T LIQ. PRODUCT	F-T WATER CONDENSATE	F-T GAS PRODUCT	CONDENSATE
FLOW: MFC													
H ₂	2754.06	-	-	-	-	-	-	-	-	1.01	-	738.77	-
O ₂	1891.23	-	-	-	-	-	-	-	-	.79	-	218.41	-
CO ₂	42.31	-	-	-	.35	-	603.12	.23	.12	.05	-	11.84	-
N ₂	54.66	-	-	-	-	-	-	-	-	.24	-	54.42	-
H ₂ O	22.98	-	27.67	104.88	-	78.79	39.34	374.11	187.70	-	163.69	4.73	-
C ₁	86.64	-	-	-	-	-	-	-	-	1.84	-	205.60	-
C ₂	-	-	-	-	-	-	-	-	-	.22	-	8.33	-
C ₃	-	-	-	-	-	-	-	-	-	1.09	-	31.06	-
C ₄	-	-	-	-	-	-	-	-	-	.30	-	3.57	-
C ₅	-	-	-	-	-	-	-	-	-	1.22	-	11.60	-
C ₆	-	-	-	-	-	-	-	-	-	1.87	-	6.78	-
C ₇	-	-	-	-	-	-	-	-	-	6.00	-	18.94	-
C ₈	-	-	-	-	-	-	-	-	-	1.04	-	5.17	-
C ₉	-	-	-	-	-	-	-	-	-	4.87	-	1.26	-
C ₁₀	-	-	-	-	-	-	-	-	-	11.34	-	4.00	-
LT NAP.	-	-	-	-	-	-	-	-	-	18.65	-	1.65	-
HEAVY NAP.	-	-	-	-	-	-	-	-	-	24.27	-	.17	-
DIESEL	-	-	-	-	-	-	-	-	-	2.80	-	-	-
FULL OIL	-	-	-	-	-	-	-	-	-	-	-	-	-
ALCOHOL	-	-	-	-	.04	-	-	3.96	12.41	-	-	-	-
ACIDS	-	-	-	-	-	-	-	1.41	-	-	-	-	-
CAUSTIC	-	1.41	-	-	-	-	-	1.41	-	-	-	-	-
TOTAL	4,869.00	1.41	27.67	104.88	.39	78.79	642.46	381.12	200.23	77.60	163.69	1,326.35	-
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B

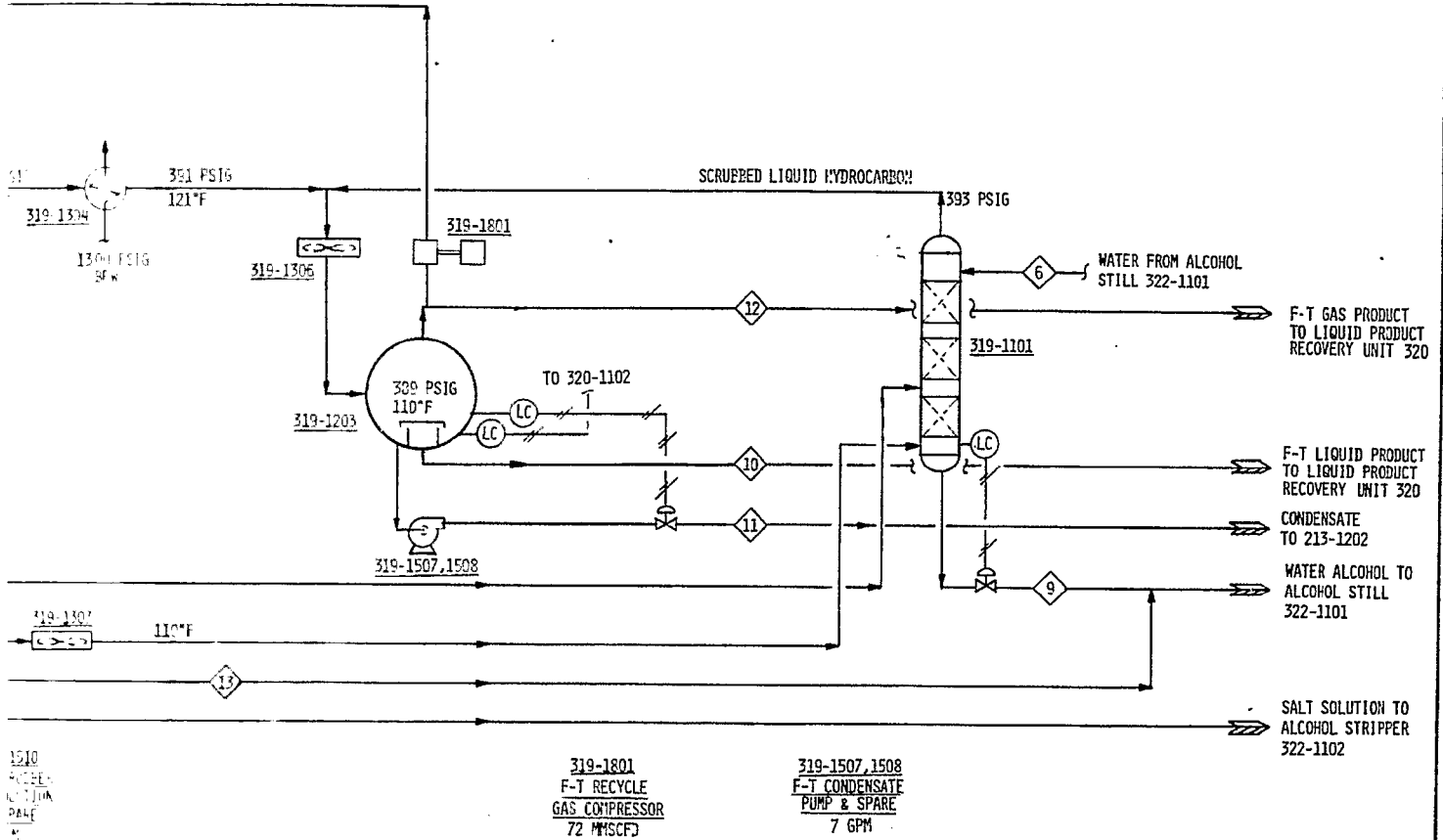
319-1304
F-T RECYCLE
HEATER
10.7 MBTU/HR

319-1303
F-T LIQUID
COOLER
200 MBTU/HR

319-1306
F-T GAS
AIR COOLER
5.8 MBTU/HR

319-1203
F-T COLD
PRODUCT
SEPARATOR
6'-6" I.D., SPHERE

319-1101
F-T LIQUID
SCRUBBER
2'-0" I.D., X
44'-0" T-T



1210
PCE
11/10
PAC

319-1801
F-T RECYCLE
GAS COMPRESSOR
72 MMSCFD

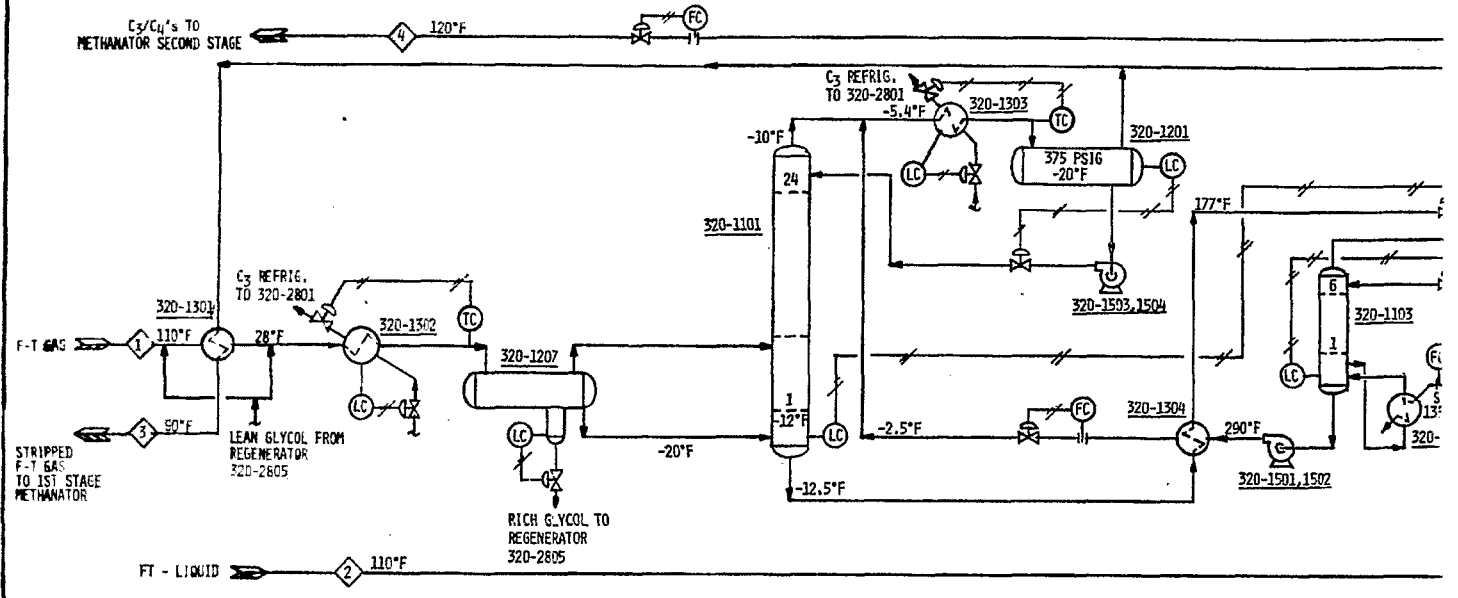
319-1507, 1508
F-T CONDENSATE
PUMP & SPARE
7 GPM

0	ISSUED FOR REPORT	RR	PH	PH	WEJ			
REV NO	CUST APPR	DATE	REVISION	BY	PROC ENGR	CHEM PROC ENGR	CHIEF OPER ENGR	PROC DIR
DEPARTMENT OF ENERGY-DIVISION OF COAL CONVERSION MULTIPROCESS DEMONSTRATION PLANT PROCESS FLOW DIAGRAM FISCHER-TROPSCH SYNTHESIS UNIT - 319								
THE RALPH M PARSONS COMPANY PASADENA, CALIFORNIA			JOB NO 5435-5	DWG NO R-319-FS-1	REV 0			

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C

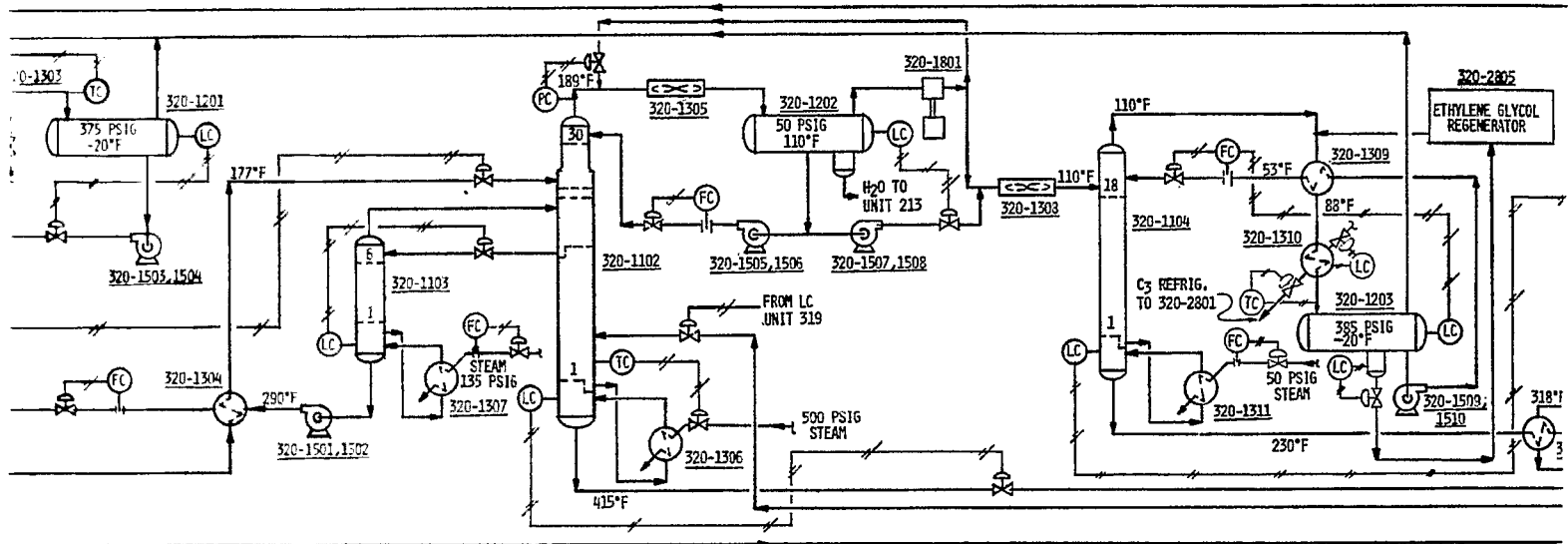
320-1301 F-T GAS/LEAN GAS EXCHANGER 1.1 MBTU/HR	320-1302 F-T GAS CHILLER 800 MBTU/HR	320-1207 COLD SEPARATOR 2'-6" I.D. X 12'-0" T-T	320-1101 LEAN OIL ABSORBER 2'-6" I.D. X 64'-0" T-T	320-1303 LEAN OIL PRESATURATOR 200 MBTU/HR	320-1201 PRESATURATOR SEPARATOR 2'-6" I.D. X 10'-0" T-T	320-1304 LEAN OIL/RICH OIL EXCHANGER 1.0 MBTU/HR	320-1103 LEAN OIL STRIPPER 1'-6" I.D. X 32'-0" T-T	320-1307 LEAN OIL STRIPPER REBOILER 200 MBTU/HR	320-1306 LEAN OIL FRACTIONATOR 3.0 MBTU/HR
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320-1503, 1504 PRESATURATOR LEAN OIL PUMP & SPARE 22 GPM	320-1501, 1502 LEAN OIL PUMP & SPARE 25 GPM
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A

320-1103 LEAN OIL STRIPPER 1'-6" I.D. X 32'-0" T-T	320-1307 LEAN OIL STRIPPER REBOILER 200 MBTU/HR	320-1306 LEAN OIL FRACTIONATOR 3.0 MBTU/HR	320-1102 LEAN OIL FRACTIONATOR 3'-0" I.D. X 83'-0" T-T	320-1305 LEAN OIL FRACTIONATOR CONDENSER 1.5 MBTU/HR	320-1202 LEAN OIL FRACTIONATOR OVERHEAD RECEIVER 2'-6" I.D. X 8'-0" T-T	320-1308 C ₅ PLUS SATURATOR 650 MBTU/HR	320-1104 CO STRIPPER 1'-6" I.D. X 55'-6" T-T	320-1310 CO STRIPPER OVERHEAD CONDENSER 60 MBTU/HR	320-1203 CO STRIPPER OVERHEAD RECEIVER 2'-0" I.D. X 8'-0" T-T	320-1309 CO STRIPPER OVERHEAD/REF. EXCHANGER 10 MBTU/HR
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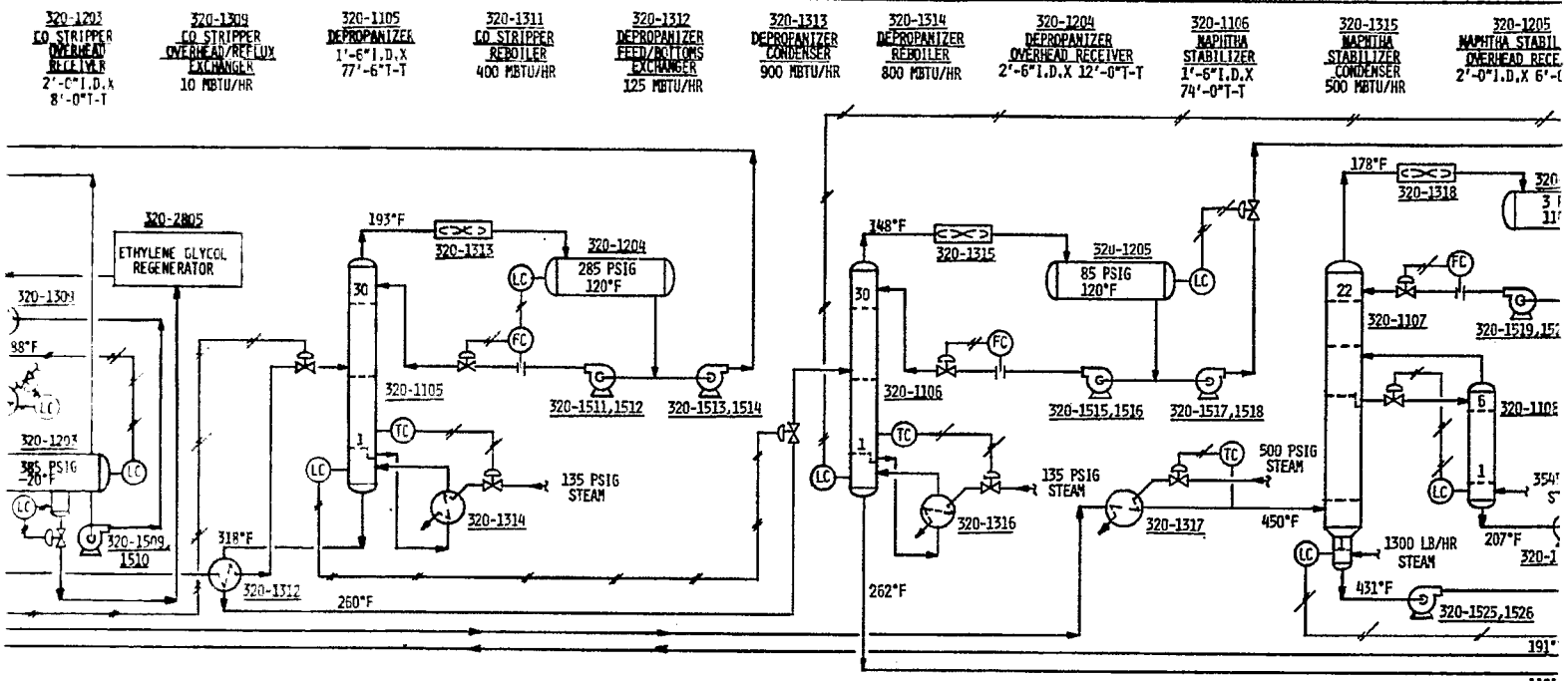


320-1503, 1504 PRESATURATOR LEAN OIL PUMP & SPARE 22 GPM	320-1501, 1502 LEAN OIL PUMP & SPARE 25 GPM	320-1505, 1506 LEAN OIL FRACTIONATOR REFLUX PUMP & SPARE 20 GPM	320-1507, 1508 LEAN OIL FRACTIONATOR OVERHEAD PUMP & SPARE 11 GPM	320-1801 LEAN OIL FRACTIONATOR OVERHEAD COMPRESSOR 500 MSCFD	320-1509, 1510 CO STRIPPER REFLUX PUMP & SPARE 2 GPM
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STREAM NO.	1	2	
STREAM NAME	F-T GAS	F-T LIQUID	S F
FLWS MPH			
H ₂	738.77	1.01	
CO	218.41	.78	
CO ₂	11.84	.05	
N ₂	54.42	.24	
H ₂ O ^a	4.73	-	
C ₁	205.60	1.84	
C ₂	8.35	.22	
C ₃	31.06	1.09	
C ₄	3.57	.30	
C ₅	11.60	1.22	
C ₆	6.73	1.57	
C ₇	18.94	6.00	
C ₈	1.26	1.04	
C ₉	5.17	4.87	
L ₂ NAPHTHA	4.00	11.38	
HEAVY NAPHTHA	1.65	18.65	
DIESEL	.17	24.27	
FUEL OIL		2.80	
TOTAL	1,326.35	77.60	1.
LB/HR	17,355	9,237	

^a WATER REMOVED BY GLYCOL REGENERATOR (85 LB.)

B

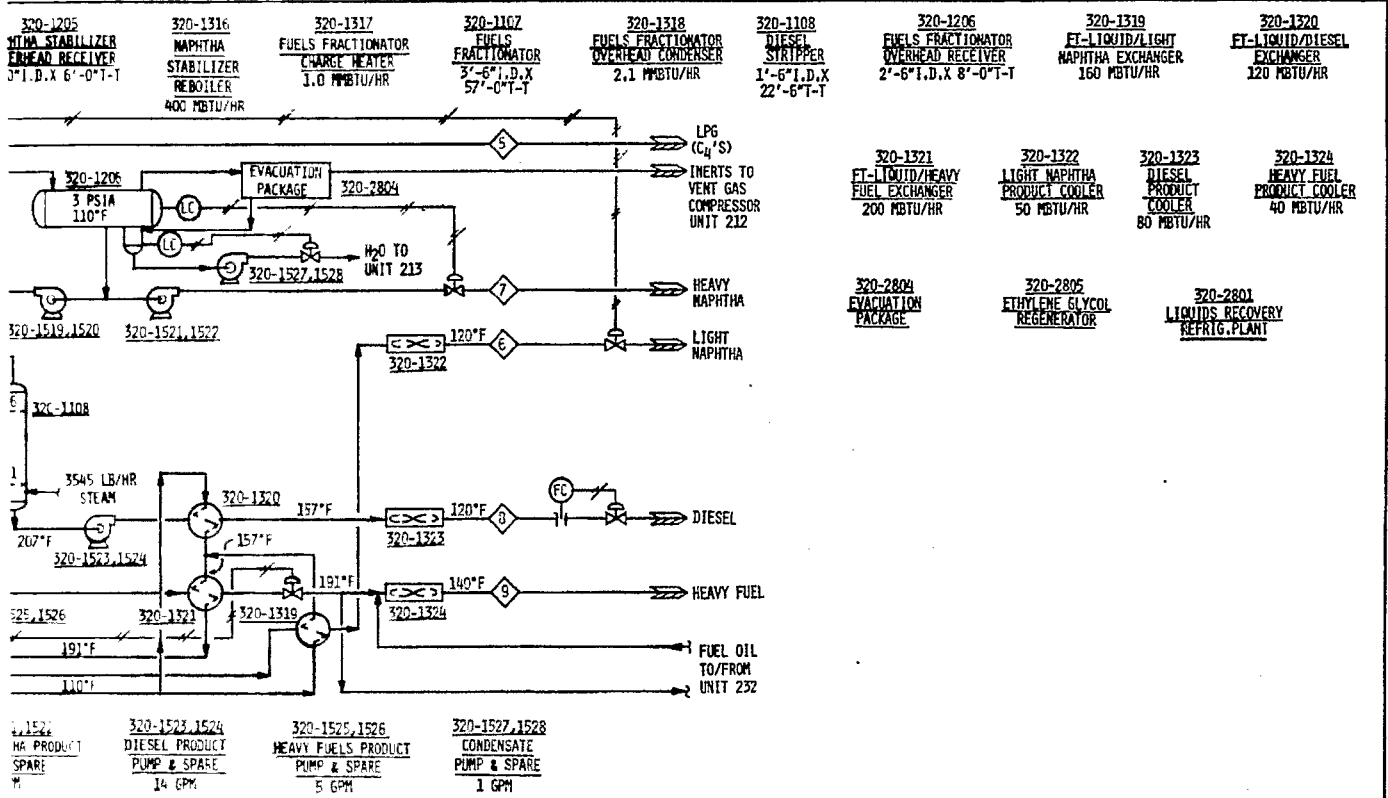


- 320-1509, 1510
CO STRIPPER
REFLUX PUMP & SPARE
2 GPM
- 320-1511, 1512
DEPROPANIZER
REFLUX PUMP & SPARE
11 GPM
- 320-1513, 1514
DEPROPANIZER OVERHEAD
PUMP & SPARE
9 GPM
- 320-1515, 1516
NAPHTHA STABILIZER
REFLUX PUMP & SPARE
10 GPM
- 320-1517, 1518
LPG PRODUCT
PUMP & SPARE
3.4 GPM
- 320-1519, 1520
FUELS FRACTIONATOR
REFLUX PUMP & SPARE
30 GPM
- 320-1521, 1522
HEAVY NAPHTHA PRODUCT
PUMP & SPARE
8 GPM

	1	2	3	4	5	6	7	8	9
	1-1 GAS	1-1 LIQUID	STRIPPER 1-1 GAS	TO METH- ANATION	LPG	LIGHT NAPHTHA PRODUCT	HEAVY NAPHTHA PRODUCT	DIESEL PRODUCT	HEAVY FUEL PRODUCT
	736.77	1.01	736.78						
	219.41	.79	219.20						
	11.84	.05	10.80	1.09					
	54.42	.24	54.66						
	4.73								
	20.80	1.84	20.53	.52					
	6.36	.22	7.27	.81					
	31.06	1.04	27.15	5.00					
	1.57	.30	1.85	2.22					
	11.80	1.52	4.30	2.81					
	9.78	1.07	.04	6.82	1.79				
	14.94	6.00	.04	15.73	8.95	.22			
	1.26	1.04		.05	.05	2.21			
	4.17	4.87		.09	.09	9.87			
	4.00	11.34	.08			14.66	.13		
	1.65	18.65	.09			.61	18.60	1.00	
	.17	24.27					1.18	22.78	.48
		2.80						.09	2.71
	1,376.35	77.60	1,272.52	41.56	10.88	27.77	19.91	23.87	3.19
	17.35	9,257	14,296	2,601	631	2,225	2,147	9,863	1,329

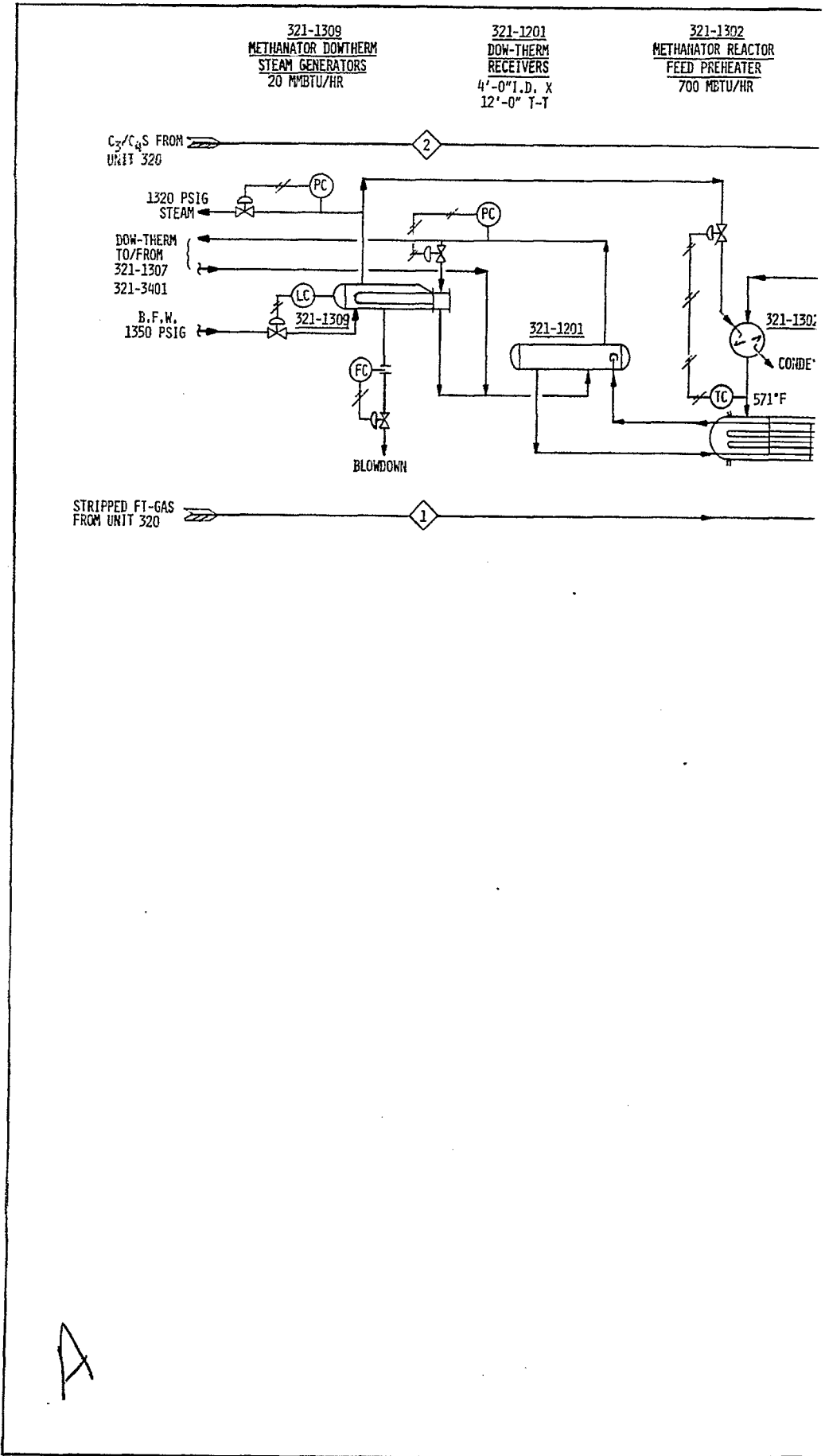
REMOVED BY GLYCOL REGENERATOR (RS LBS/HR)

C



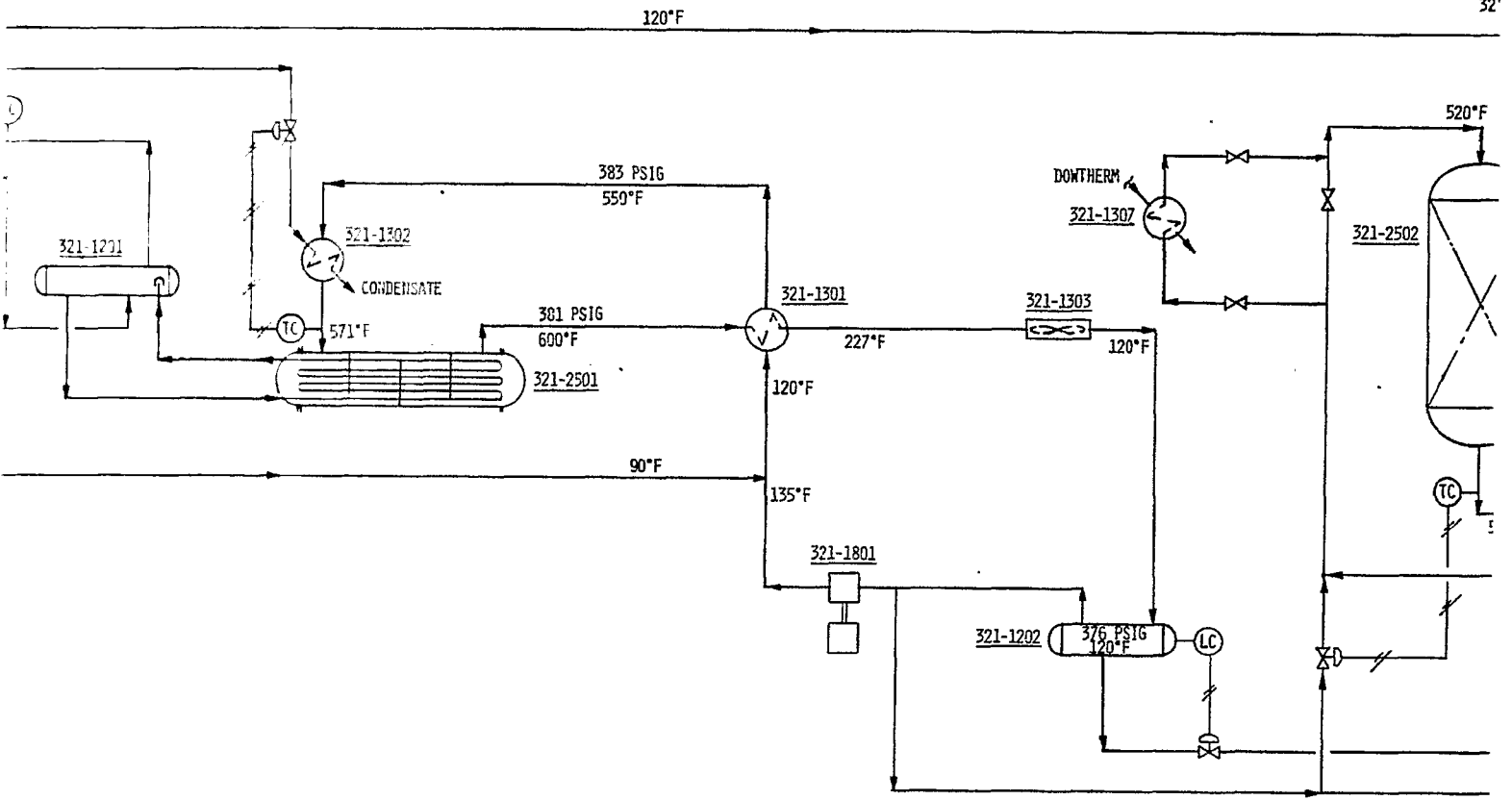
DEPARTMENT OF ENERGY-DIVISION OF COAL CONVERSION MULTIPROCESS DEMONSTRATION PLANT PROCESS FLOW DIAGRAM LIQUID PRODUCT RECOVERY UNIT-320											
THE RALPH M. PARSONS COMPANY PASADENA, CALIFORNIA				JOB NO. 5435-5		DWS. NO. R-320-FS-1				REV. 0	

D



A

321-1201 LOW-THERM RECEIVERS 3'-0" I.D. X 11'-0" T-T	321-1302 METHANATOR REACTOR FEED PRE-HEATER 700 MBTU/HR	321-2501 METHANATOR REACTOR 20 MMBTU/HR	321-1301 METHANATOR REACTOR FEED/ PRODUCT EXCHANGER 12 MMBTU/HR	321-1303 RECYCLE COMPRESSOR SUCTION COOLER 4 MMBTU/HR	321-1202 RECYCLE COMPRESSOR SUCTION RECEIVER 3'-0" I.D. X 8'-0" T-T	321-1310 C3/C4 EVAPORATOR 400 MBTU/HR	321-1311 MET R 2'- 32'
--	--	---	---	--	--	--	------------------------------------



321-1801
METHANATOR RECYCLE
COMPRESSOR
375 -390 PSIG
16.5 MMSCFD

STREAM
H2
CO
CO2
N2
H2O
C1
C2
C3
C4
C5
C6
LT. NAP
HEAVY N
TOTAL
LBS/HR

13

321-1201
LOW-THERM
RECEIVERS
3'-0" I.D. X
8'-0" T-T

321-1302
METHANATOR REACTOR
FEED PRE-HEATER
700 MBTU/HR

321-2501
METHANATOR REACTOR
20 MBTU/HR

321-1301
METHANATOR
REACTOR FEED/
PRODUCT EXCHANGER
12 MBTU/HR

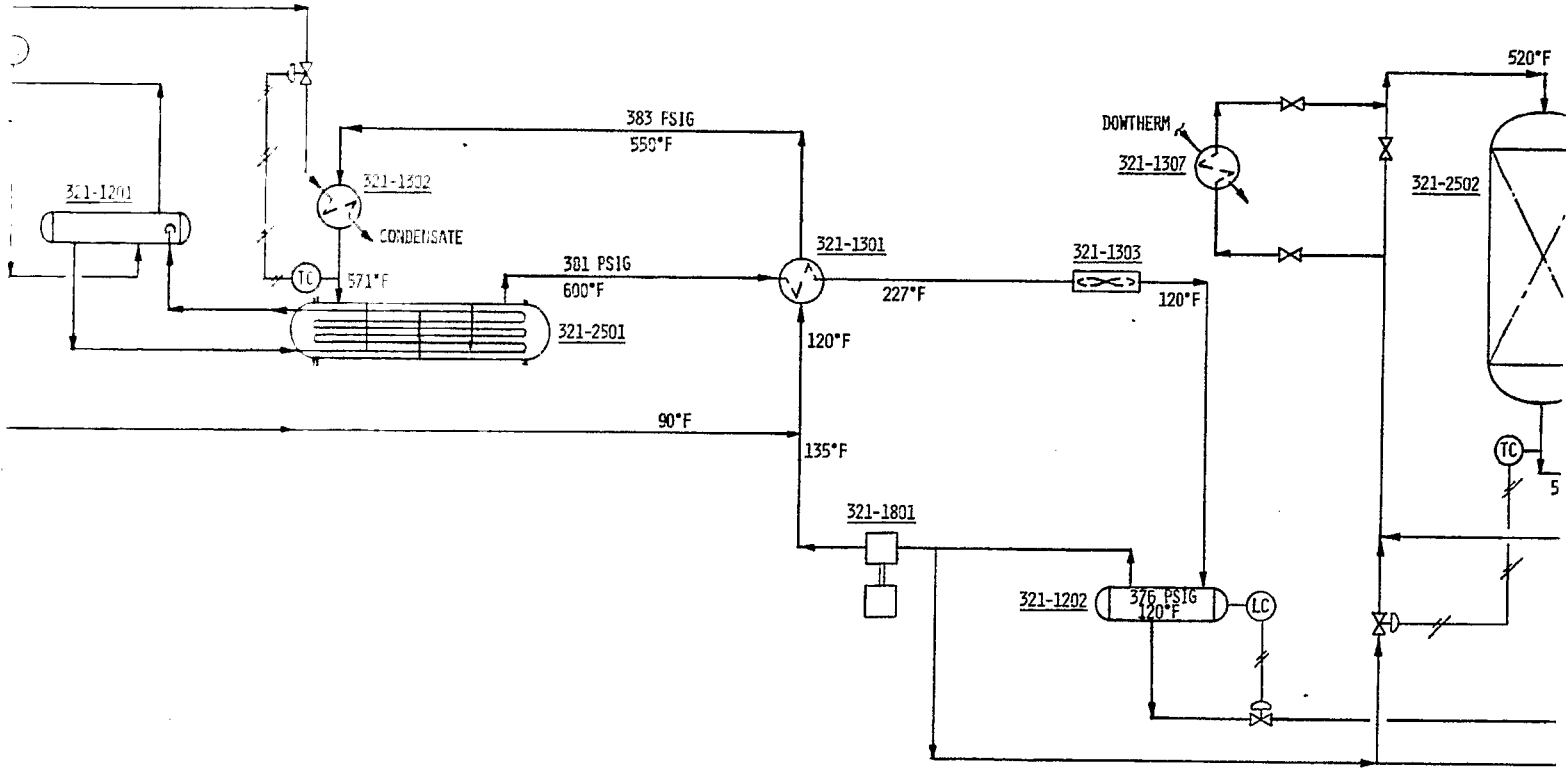
321-1303
RECYCLE COMPRESSOR
SUCTION COOLER
4 MBTU/HR

321-1202
RECYCLE COMPRESSOR
SUCTION RECEIVER
3'-0" I.D. X 8'-0" T-T

321-1310
C3/C4
EVAPORATOR
400 MBTU/HR

321-
F
MET-
RE
2'-
32'

120°F



321-1801
METHANATOR RECYCLE
COMPRESSOR
375 -390 PSIG
16.5 MMSCFD

STREAM A

STREAM A

FLOWS M

H2
CO
CO2
N2
H2O
C1
C2
C3
C4
C5
LT. NAP.
HEAVY N.
TOTAL
LBS/HR

B

321-1310
C3/C4
EVAPORATOR
400 MBTU/HR

321-2502
FINAL
METHANATION
REACTOR
2'-6" I.D. X
32'-0" T-T

321-1306
FINAL METHANATION
REACTOR FEED/SNG
EXCHANGER
3 MMBTU/HR

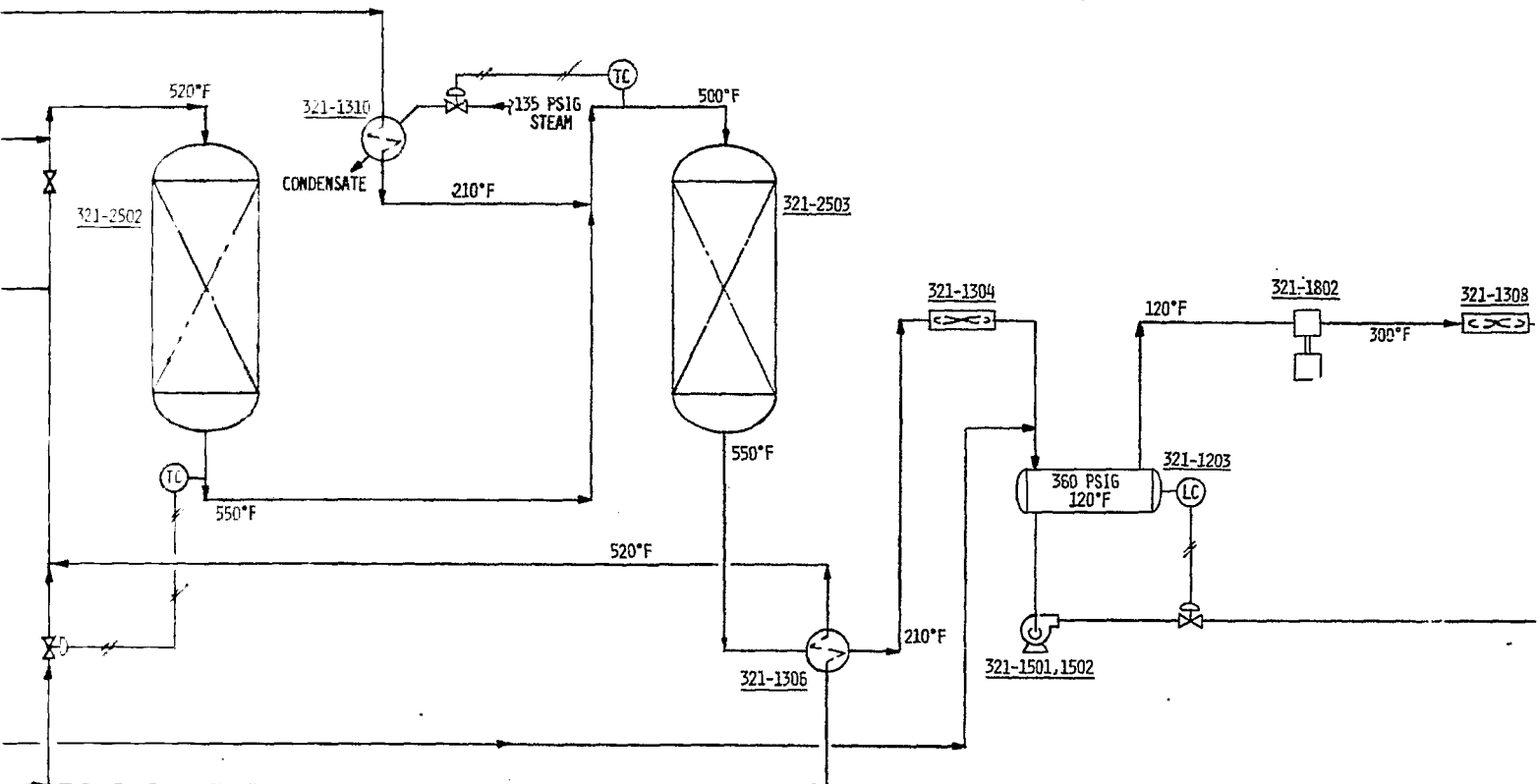
321-1307
FINAL METHANATION
START-UP HEATER
DESIGN: 1 MMBTU/HR

321-1304
SNG PIPELINE
COMPRESSOR
SUCTION COOLER
700 MBTU/HR

321-1203
SNG PIPELINE
COMPRESSOR SUCTION
RECEIVER
2'-0" I.D. X 6'-0" T-T

321-2503
HYDROTREATER
REACTOR
3'-0" I.D. X 35'-6" T-T

321-1308
SNG COOLER
1.5 MMBTU/HR



321-1501, 1502
CONDENSATE
PUMP & SPARE
11 GPH

321-1802
SNG PIPELINE
COMPRESSOR
360-1010 PSIG
6.6 MMSCFD

STREAM NO.	1	2	3	4
STREAM NAME	STRIPPED F-T GAS	C3/C4's	SNG	WATER
FLOWE MFP				
H ₂	719.78		3.66	
CO	219.20		.85	
CO ₂	10.60	1.09	11.88	
N ₂	54.66		54.66	
H ₂ O			*	217.00
C ₁	206.82	.92	510.14	
C ₂	7.77	.83		
C ₃	27.18	5.00	9.16	
C ₄	1.66	2.22		
C ₅	4.39	8.43	11.50	
C ₆	.04	6.82		
C ₇	.04	15.73	22.55	
C ₈		.04		
C ₉	.06		.54	
LT. NAPH.	.12			
HEAVY NAPH.	.09			
TOTAL	1,872.52	41.08	624.44	217.00
LBS/HR	14,258	2,001	12,365	3,909

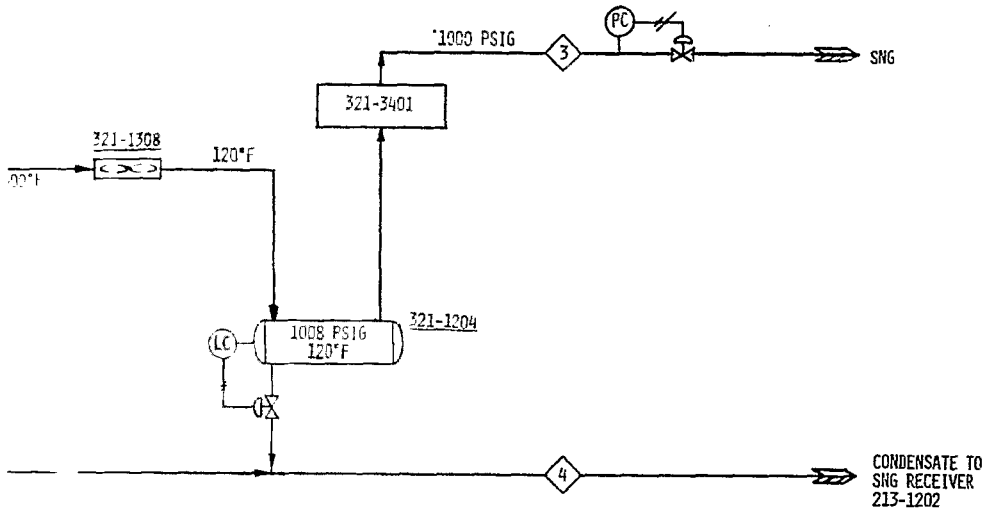
* 28 LBS/HR OF H₂O IS REMOVED BY THE SNG DRYER

P

321-1308
SNG COOLER
1.5 MMBTU/HR

321-1204
FINAL METHANATION
RECEIVER
2'-0" I.D. X 6'-0" T-T

321-3401
SNG DRYER



0	ISSUED FOR REPORT	PPK	PHI	WLSJ					
REV. NO.	CUST. APPR.	DATE	REVISION	BY	PRAC. ENGR.	CHEK. ENGR.	CONF. ENGR.	QA/EST. ENGR.	PROG. DIV.

DEPARTMENT OF ENERGY-DIVISION OF COAL CONVERSION
MULTIPROCESS DEMONSTRATION PLANT
PROCESS FLOW DIAGRAM
METHANATION UNIT-321

THE RALPH M. PARSONS COMPANY
PASADENA, CALIFORNIA

JOB NO. 5435-5
DWS. NO. R-321-FS-1
REV. D

D

322-1305
WATER RETURN
AIR COOLER
210 MBTU/HR

322-1301
ALCOHOL STILL
FEED/WATER RETURN
EXCHANGER
300 MBTU/HR

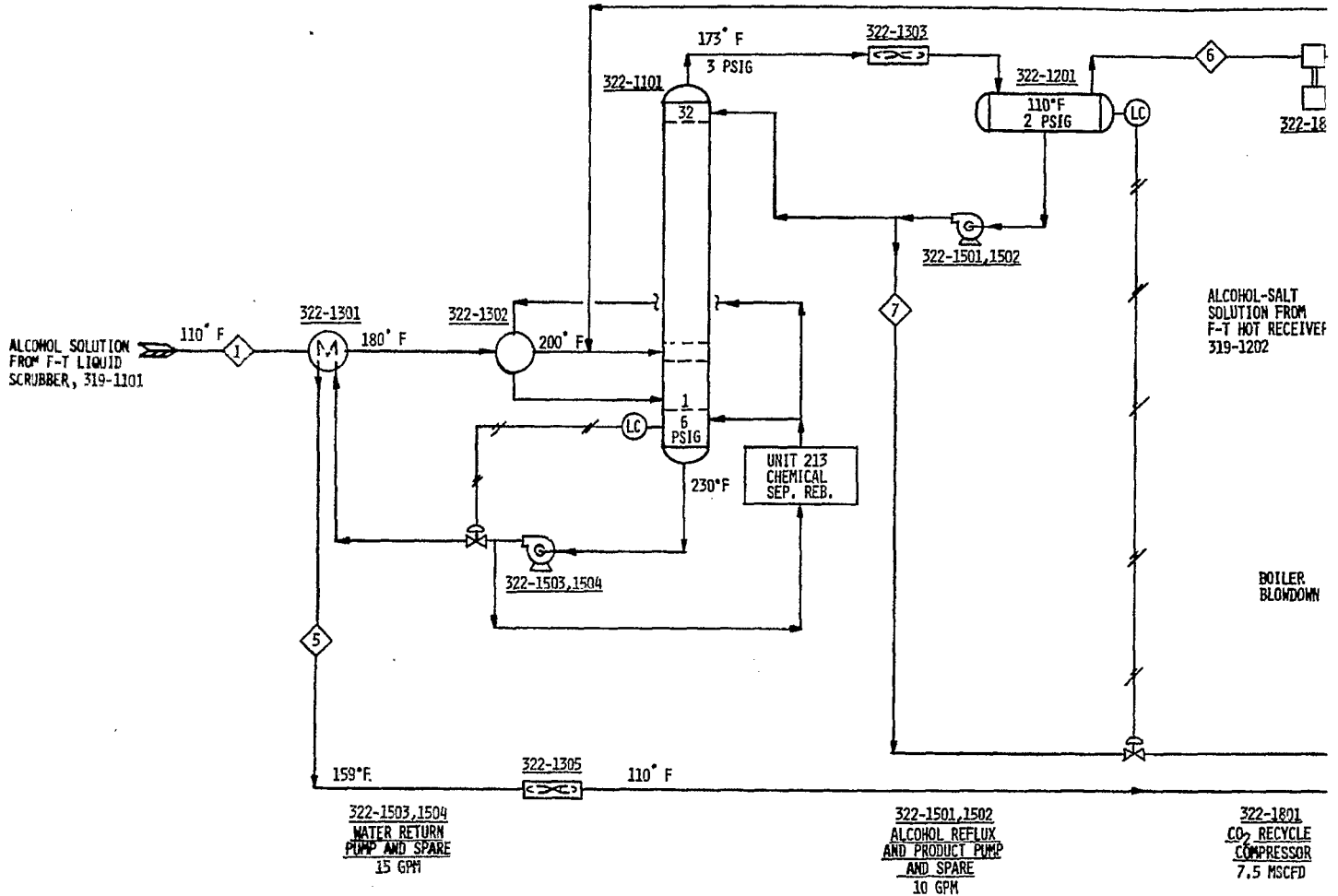
322-1302
ALCOHOL FEED
PREHEATER
90 MBTU/HR

322-1101
ALCOHOL
STILL
1'-6" I.D. X
54'-6" T-T

322-1303
ALCOHOL OVERHEAD
AIR CONDENSER
2 MBTU/HR

322-1201
ALCOHOL STILL
OVERHEAD RECEIVER
1'-6" I.D. X 6'-0" T-T

322-1306
ALCOHOL STRIPPER
FEED/BOTTOMS
EXCHANGER
40 MBTU/HR



5

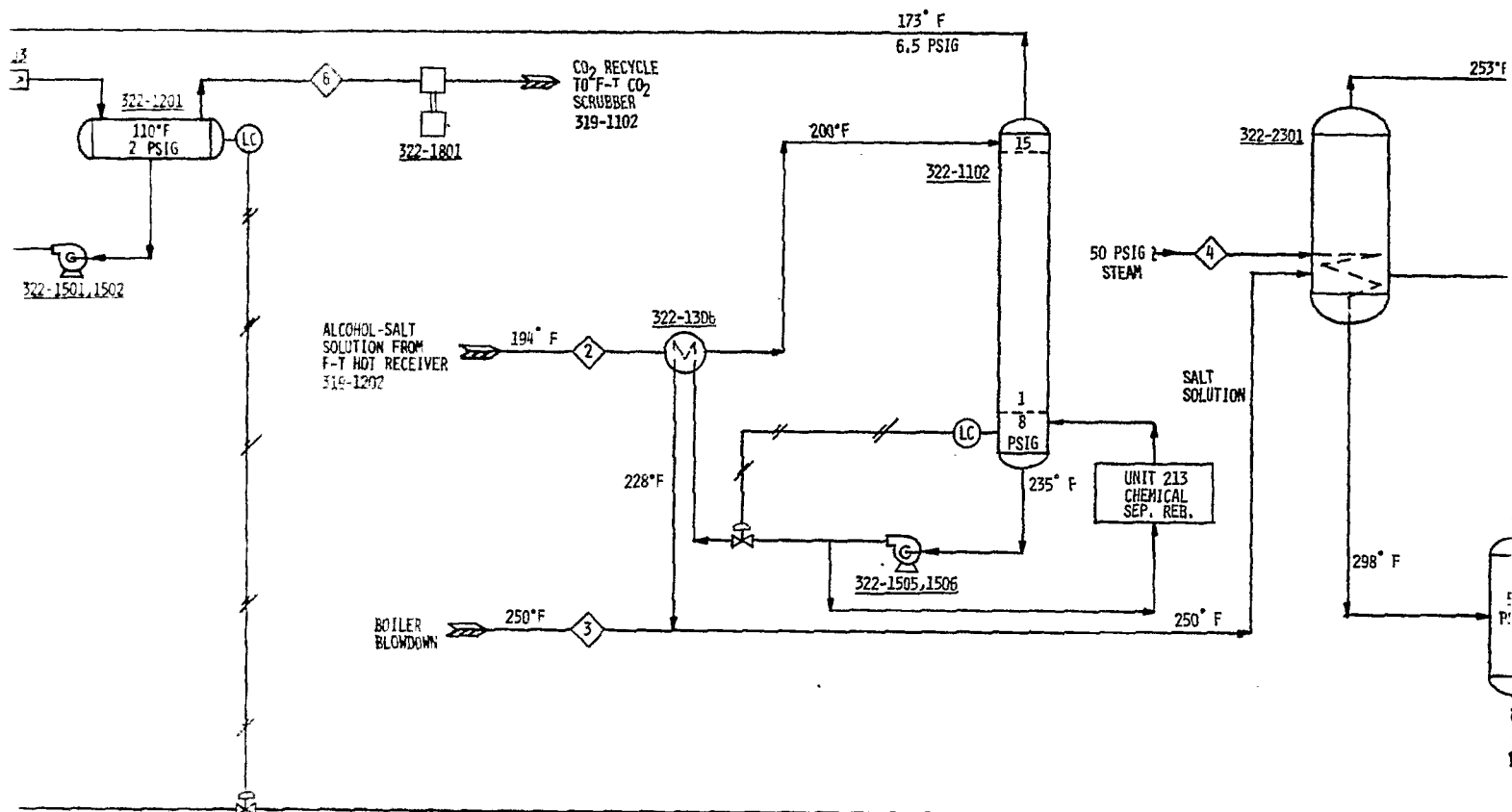
322-1201
ALCOHOL STILL
OVERHEAD RECEIVER
1'-6" I.D. X 6'-0" T-I

322-130E
ALCOHOL STRIPPER
FEED/BOTTOMS
EXCHANGER
40 MBTU/HR

322-1102
ALCOHOL
STRIPPER
1'-6" I.D. X
38'-0" T-I

322-2301
1ST EFFECT
EVAPORATOR
3.63 MBTU/HR

1'



322-1501, 1502
MOL REFLUX
PRODUCT PUMP
1 SPARE
1 GPM

322-1801
CO₂ RECYCLE
COMPRESSOR
7.5 MSCFD

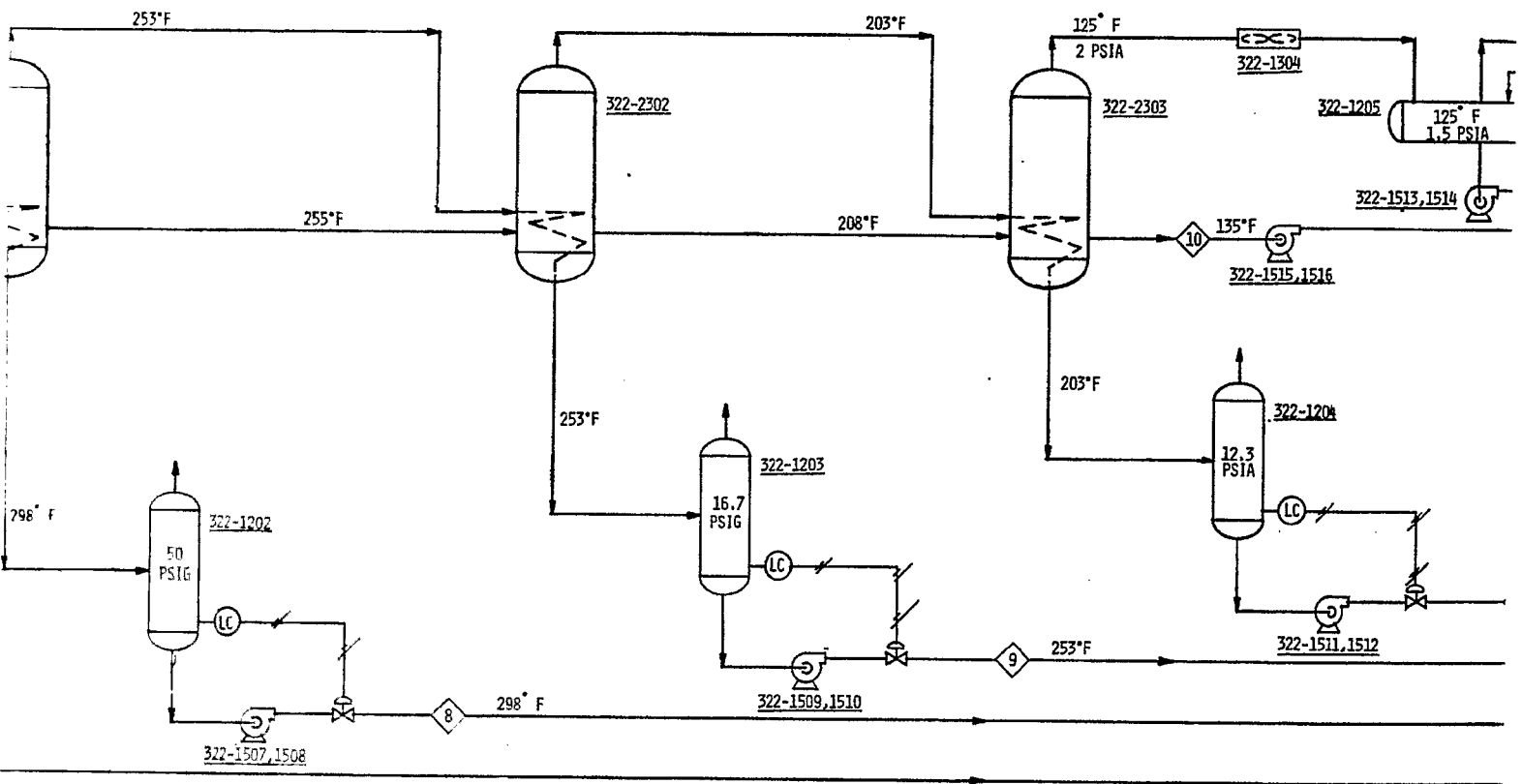
322-1505, 1506
SALT SOLUTION
PUMP & SPARE
15 GPM

STREAM NO.	1	2	3	4	5	6	7
STREAM NAME	ALCOHOL STILL FEED	ALCOHOL STRIP FEED	BOILER B.D.	1ST EFFECT STEAM FEED	ALCOHOL STILL WATER RETURN	ALCOHOL STILL GAS RECOVERY	ALCOHOL MIX PRODUCT
FLOWS MPH							
CO ₂	.12	.23	-	-	-	.35	-
Mixed Alcohols	12.41	3.96	-	-	.01	.04	16.30
Water	167.70	374.11	461.37	229.85	232.55	-	3.13
Acid Salts*	-	1.41	-	-	-	-	-
TOTAL	200.23	379.71	461.37	229.85	232.56	.39	19.43
LBS/HR	3971	7205	8312	4141	4190	17	824

* ACID SALTS HAS A MW EQUAL TO THE ACID'S + CAUSTIC'S

B

322-1202 1ST EFFECT CONDENSATE DRUM 1'-6" I.D. X 6'-0" T-T	322-2302 2ND EFFECT EVAPORATOR 3.63 MMBTU/HR	322-1203 2ND EFFECT CONDENSATE DRUM 1'-6" I.D. X 6'-0" T-T	322-2303 3RD EFFECT EVAPORATOR 3.63 MMBTU/HR	322-1204 3RD EFFECT CONDENSATE DRUM 1'-6" I.D. X 6'-0" T-T	322-1304 EVAPORATOR OVERHEAD AIR CONDENSER 4.4 MMBTU/HR	322-1205 EVAPORATOR OVERHEAD RECEIVE 2'-6" I.D. X 8'-0" T
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322-1507, 1508
1ST EFFECT
CONDENSATE
PUMP & SPARE
10 GPM

322-1509, 1510
2ND EFFECT
CONDENSATE
PUMP & SPARE
10 GPM

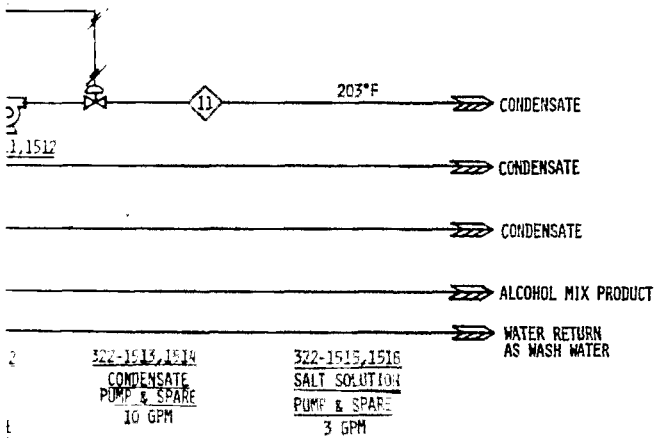
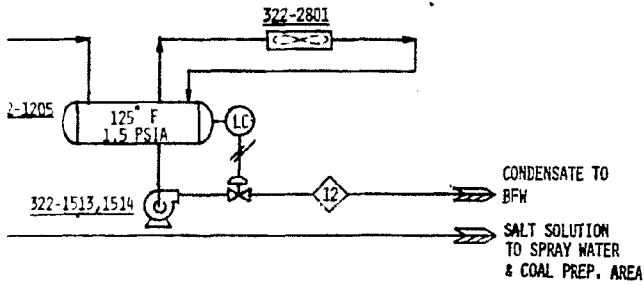
322-1511, 1512
3RD EFFECT
CONDENSATE
PUMP & SPARE
10 GPM

322-1513, 1514
CONDENSATE
PUMP & SPARE
10 GPM

STEP	6 ALCOHOL STILL GAS RECOVERY	7 ALCOHOL MIX PRODUCT	8 1ST EFFECT CONDENSATE	STREAM NO. STREAM NAME FLOWS MPH	9 2ND EFFECT CONDENSATE	10 3RD EFFECT SALT SOL'N.	11 3RD EFFECT CONDENSATE	12 3RD EFFECT OVHD. LIQUID WATER TO RECY
101	1.35	-	-	LG2	-	-	-	-
104	1.64	16.30	-	Mixed Alcohols	-	-	-	-
105	-	3.13	229.85	Water	220.54	73.77	237.82	256.37
106	-	19.43	229.85	Acid Sol'n	-	1.41	-	-
107	-	-	-	TOTAL	220.54	74.18	237.82	256.37
4190	17	824	4141	LES/HR	3,974	1,579	4,285	4,619

322-1205
EVAPORATOR
OVERHEAD RECEIVER
2'-6" I.D. X 8'-0" H-T

322-2801
EVAPORATOR
JET



REV. NO.	DATE	REVISION	BY	CHKD.	DATE	APP. NO.	REV. NO.
0		ISSUE FOR REPORT					
DEPARTMENT OF ENERGY-DIVISION OF COAL CONVERSION MULTIPROCESS DEMONSTRATION PLANT PROCESS FLOW DIAGRAM CHEMICAL RECOVERY UNIT-322							
THE RALPH M. PARSONS COMPANY PARADENA, CALIFORNIA			JOB NO. 5435-5	DWS. NO. R-322-FS-1		REV. 0	

