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September 29, 1992

U. S. Department of Energy
Pittsburgh Energy Technology Center
Mail Stop 922-H
P. O. Box 10940
Pittsburgh, PA 15236

Attention: Mr. Swenam Lee
Project Manager

Subject: D.O.E. Coal Liquefaction
Base Line Design and System Analysis
Contract No. DE-AC22 90PC89857
Bechtel Job No. 20952
Task III Volume I and II, Final Report
Letter No. BLD-112

Dear Mr. Lee:

The Task III Topical/Task report consists of three volumes and addresses the capital and operating costs (volumes I and II) as well as the economics (volume III) of the baseline design and options. This publication, however, consists of a set of two volumes, volumes I and II. The third volume of the Task will be published incorporating the economics of the improved baseline plus the best option and will represent the overall economics for the final report of this study.

Attached for your files are three copies of the subject report. As requested, one of these copies is bound in a loose leaf 3-ring binder for your desk use. Copies to other members of DOE, as required by the contract are transmitted separately and directly.

These two volumes incorporate DOE's comments which appeared on the "draft" issue dated May, 1992 and updated numbers on capital costs and operating requirements for various options.

The report does not contain any confidential information, which as agreed, would have been segregated in the appendix of this report.

Sincerely yours,

S K Poddar

Syamal K. Poddar
Project Manager

Attachment

cc: Martin Byrnes, DOE/PETC
Robert Hamilton, DOE/PETC
A. Schachtschneider, AMOCO
File
Gilbert V. McGurl, DOE/PETC
Joanne Wastek, DOE/PETC

Bechtel Corporation

U.S. DEPARTMENT OF ENERGY
PITTSBURGH ENERGY TECHNOLOGY CENTER

DIRECT COAL LIQUEFACTION
BASELINE DESIGN
AND
SYSTEM ANALYSIS

CONTRACT NO. DEAC22 90PC89857

TASK III TOPICAL REPORT:

COST ESTIMATES AND ECONOMICS OF THE BASELINE AND OPTIONS

VOL. I OF II

AMOCO

BECHTEL

SEPTEMBER 1992
PITTSBURGH, PENNSYLVANIA

The information and data contained in this report are the result of an ecomonic evaluation and a preliminary design effort and because of the nature of this work no guarantees or warranties of performance, workmanship, or otherwise are made, either expressed or by implication.

TASK III REPORT
Table Of Contents

VOLUME I, SECTIONS 1 THROUGH 23

TASK III REPORT
Table Of Contents

VOLUME II, SECTIONS 24 THROUGH 50

VOLUME II, SECTIONS 24 THROUGH 50 - continued

VOLUME II, SECTIONS 24 THROUGH 50 - continued

VOLUME II, SECTIONS 24 THROUGH 50 - continued

VOLUME II, SECTIONS 24 THROUGH 50 - continued

VOLUME I

LIST OF TABLES

VOLUME I - continued

LIST OF TABLES

VOLUME I - continued

LIST OF TABLES

VOLUME I

LIST OF FIGURES

INTRODUCTION

The U.S. Department of Energy (DOE) has established a program to "foster an adequate supply of energy at a reasonable cost," in accordance with the National Energy Policy Plan IV (NEPP IV). A cost effective direct coal liquefaction program sponsored by the pittsburgh Energy Technology Center (PETC) is an integral part of NEPP IV.

The overall goal of the coal liquefaction program is "to develop the scientific and engineering knowledge base with which industry can bring economically competitive and environmentally acceptable advanced technology for the manufacture of synthetic liquid fuels from coal.

The present assignment from PETC is undertaken by Bechtel (in collaboration with Amoco as the main subcontractor) to develop a computer model for a baseline direct coal liquefaction design based on two stage direct coupled catalytic reactors. Specifically, the scope of work calls for the development of:

1) a baseline design based on previous DOE/PETC results from Wilsonville pilot plant and other engineering evaluations,

2) a cost estimate and economic analysis, and

3) a computer model incorporating the above two steps over a wide range of capacities and select process alternatives.

In this study, the Topical Reports are also the Task reports. This Topical report (Task III) addresses the capital and operating costs (Volumes I and II) as well as the economics (Volume III) of the direct coal liquefaction study which is primarily based on Wilsonville Pilot Plant data with certain other processing alternates.

Note that Volume III covers the economics of the Improved Baseline plus the Best Option and will, in essence, represent the overall economics for the Final report of this study. For this reason, Volume III of this Task/Topical report has been completely decoupled from the other two volumes and it will be published after the completion of the unnumbered improved baseline economics task.

Therefore, at present this Task/Topical report is published as Volumes I and II of two volumes. The *Table of Contents*, *Introduction* (Section 1) and the *Executive Summary* (Section 2), of Volumes I and II are included in their entirety in both volumes for the reader's reference.

The overall number of topical/task reports for this study are given below as follows:

Task No.	Title
1	Management Plan - one volume
2	Baseline and Alternates Design Development - Volumes I, II and III
3*	Cost Estimate and Economics of the Baseline and Alternates - Volumes I, II and III
4	Development of Mathematical Algorithms and Models for Equipment Sizing, Scale-up, Costing and Train Duplication for Incorporation into the Aspen Simulation Program - one volume
5	Development of an Aspen Process Simulation Model of the Baseline Design and the Alternates - several volumes
6	Development of a Training Manual for the Simulation Model - one volume
(**)	Improved Baseline Design, Cost Estimate, and Modeling
7	Final Report - numerous volumes

* The Task/Topical report is published in two volumes as Volume I and II, the third volume will be published simultaneously with the Improved Baseline report.

** This report will contain the results of the improved baseline design, cost estimate and modeling and therefore will address Tasks 1 through 6.

2. EXECUTIVE SUMMARY

Introduction:

This study is an assignment of Bechtel from the U.S. Department of Energy (DOE)'s Pittsburgh Energy Technology Center (PETC) to develop a computer model for a baseline direct coal liquefaction design based on two stage direct coupled catalytic reactors.

Scope and Technical approach:

The scope of the study and the technical approach to accomplish the overall objective of the study include:

- a baseline design based on previous DOE/PETC results from Wilsonville pilot plant and other engineering evaluations,
- a cost estimate and economic analysis,
- a computer model incorporating the above two steps over a wide range of capabilities and selected process alternatives,
- a comprehensive training program for USDOE/PETC staff to understand and use the computer model,
- a thorough documentation of all underlying assumptions for baseline design and baseline economics, and
- a user manual and training material which will facilitate updating of the model for the future.

Execution Philosophy:

In order to carry out the study efficiently, the study has been divided into seven major tasks with each task having several identifiable subtasks. In Task I the study is defined. The baseline design is developed in Task II. The capital and operating requirements are developed in Task III. Mathematical models for computer simulation are developed in Task IV. Development and Validation of the model is conducted in Task V. Documentation of the process simulation and training program are conducted in Task VI. Whereas, the above mentioned six tasks are functional tasks, the remaining task, Task VII, is a level of effort task for project management, technical coordination and other miscellaneous support functions. Functional tasks are executed by a part time functional group while the project management and technical coordination (Task VII) are accomplished by a full time core management group.

Topical/Task III Report Contents:

The Task III report is divided into three volumes as follows:

Volumes I and II include capital and operating cost information while Volume III addresses the economics. Volume III of the report will be issued separately at a later date when the improved baseline economics case is developed.

The report starts by setting up the basis and methodology for capital cost estimating and by defining the first plant and Nth plant concepts. The first plant concept, as the name suggests, refers to the first commercial plant design which includes a degree of over-design to meet the name-plate capacity and product specifications. The Nth plant is defined as the commercial plant built N years after the first commercial plant for which the technology basis, plant design, and operation are well established.

In addition, the report describes the methodology used in determining the valuation of products utilizing Bechtel's Process Industry Modeling System (PIMS), a linear programming software. A detailed analysis of reliability and onstream factor for various inside battery limits (ISBL) plants in the complex is also included in the report.

The capital cost (both first plant and Nth plant) and operating requirements for plants 1 thru 25 (Chapters 6 through 23) are included in Volume I whereas similar information for Plants 30 through 42 (chapters 24 through 36) are included in Volume II of the report.

In addition, Volume II contains capital costs information for all seven options (both first plant and Nth plant scenarios). The definition of these options and methodology applied to select them were defined in Volume III of the Topical/Task II report, and are reiterated in Volume II of this report for the reader's convenience.

ECONOMIC CRITERIA AND CONSIDERATIONS

3.0 ESTIMATE BASIS

This is an estimate of the capital costs for a major direct coal liquefaction facility to be located in Perry County, Illinois. The plant capacity is a nominal 62,000 barrels per stream day of petroleum liquids, (C_5^+) utilizing Wilsonville's two stage liquefaction technology.

The estimate is based on a scope definition as appeared in the Statement of Work of contract number DEAC22 90PC89857, and subsequent contract modifications. It is further based on work done by Bechtel/Amoco in the Project Definition (Task I) and the Process Design (Task II).

This is a preliminary-type estimate with an associated accuracy of ±30%. Costs for major equipment have been developed for each individual item. From this information, the total installed cost was derived utilizing various curves, ratios and factors based on Bechtel's historical data for similar or related facilities.

The paragraphs that follow describe the methods and techniques used in completing each portion of the estimate.

<u>Major Equipment</u>

The major equipment was priced using curves and unit cost comparison for similar items from other recent Bechtel projects. The remaining equipment, especially unique or special items, was priced using vendor or technology licensor estimates.

The major equipment was considered on an item-by-item basis within each plant, unit or facility. General design parameters were extracted from equipment summary sheets, recognizing such features as size, capacity, metallurgy, wall thickness, etc. Typical design characteristics and units of measurement that were used to estimate costs for various classifications of equipment can be summarized as follows:

- Columns & Vessels
  - Based on tons of steel, metallurgy and plate thickness. Internals priced separately
- Tanks
  - Classified as to type and priced at barrels of capacity

- Heat Exchangers
  - Identified as air coolers or shell and tube type, priced on the basis of metallurgy and tube surface area
- Fired Heaters
  - Specified as to absorbed heat duty (MM Btu/hr) and priced utilizing vendor data and cost curves
- Pumps and Drivers
  - Case material, driver-type and brake horsepower were used
- Vacuum Equipment
  - Utilized vendor estimates
- Compressors and Drivers
  - Classified as reciprocal or centrifugal and priced on the basis of driver brake horsepower, using vendor estimates
- Special Equipment
  - Used vendor estimates for packaged or special equipment

<u>Subcontract Costs</u>

The estimate is based on a number of items being purchased and erected by subcontractors. Items such as tank construction, site preparation, boiler erection, etc., are typically supplied by someone other than the prime contractor, and these items have been shown as separate subcontract costs. These subcontracts include all material, labor, overhead and fees related to the work.

<u>Bulk Materials</u>

The costs of bulk materials were developed in two ways. First, in the process units all bulk materials and labor costs were derived from ratios and factors related to the major equipment costs. These factors were tailored to each process unit, based on Bechtel's in-house historical data for similar types of facilities. In certain cases, adjustments have been made to allow for special or unique characteristics of the unit.

The second method was used for estimating bulk materials involving the support and interconnecting plants. For these plants, it was necessary to develop quantity data based on preliminary plot plans and site plan arrangements, with assumptions made for routings, line sizes, pipeway configurations, etc. These preliminary quantities were priced on an itemized basis and compared to other large, complex projects as a cross check.

<u>Bulk Subcontract Costs</u>

Certain activities such as insulation, buildings, and painting have, in all cases, been based on subcontracts. For insulation and painting, the estimates are based on a percentage of major equipment costs. Buildings are estimated separately in Plant 41.

Direct Labor Manhours

For erection of major equipment, the direct labor manhours were calculated on the basis of unit rates and manhour standards for each individual item.

Because this preliminary level estimate does not contain detailed quantity data for bulk materials, the manhours required for these items have been applied as a percentage, or factor, of the bulk material cost which in turn was derived from factors related to the major equipment cost. These ratios have been tailored and adjusted at the plant level to conform to historical Bechtel experience for similar types of units, corrected to be site specific for the Perry County, Illinois job location.

Direct Labor Costs

The manhours derived above were priced using an overall, net average job wage rates in effect for this location based on Bechtel in-house wage rates for mid-1991 time frame.

Sales Tax

Sales tax is inapplicable here as this project is deemed exempt from sales tax.

Field Indirect Costs (Distributables)

Field indirect costs or distributable costs for this type of estimate are estimated as a percentage of direct labor cost taking into consideration the site location, job master schedule, project construction plan, subcontracting plan, etc. The indirect percentage is based on Bechtel's experience from other large, grassroots, refinery-type construction projects.

The overall distributable field costs have been estimated separately for each process or support plant in the complex.

The construction phase of the 5-year project schedule is scheduled for approximately four (4) years. As a result of construction duration the normally temporary-type construction offices and warehouses will be of a permanent nature. The sewage treatment facilities are handled similarly.

Items that are included in the indirect cost can be grouped into four functional areas, which are summarized below:

- Temporary Construction Services

    - Includes office buildings, warehouses, working areas and bays, temporary roads, walks, parking area and fences; railroad and barge unloading facilities; power, light and telephone facilities; minor temporary construction; general purpose scaffolding, cribbing and drainage; sanitary facilities

- Miscellaneous Construction Services
  - General and final cleanup, maintenance of tools and equipment; material handling, welder's supplies and testing, watchmen and guards and surveying

- Construction Equipment and Tools
  - Supplies and purchased utilities, fuels and lubricants. All types of construction equipment whether rented or purchased, and tools

- Field Office Cost
  - Nonmanual supervision, administration, warehousing and purchasing, first aid, safety and medical, nonmanual payroll adds and benefits, field office overhead, nonmanual travel and subsistence

<u>Home Office Manhour</u>

An evaluation of home office manhours has been included in the estimate. The estimate was produced first by an analysis of the engineering scope developed in the design and consisting of process descriptions, lists of equipment, estimated numbers of drawings, material requisitions, specifications, etc. The engineering manhours associated with this scope were estimated on overall project basis utilizing experience from similar types of projects.

Manhours for home office support services have also been included. These were added as a percentage of the engineering requirements for this plant. The percentage is based on historical data from other large, refinery-type projects and includes the following typical functions:

- Project Management
- Technical Services (Project Controls)
- Construction Management
- Procurement
- Commercial Services

Home Office Costs

The home office manhours, derived above, were priced using an overall average rate, based on Bechtel's current Houston office experience. The rate was developed by an analysis of salaries for various employment classifications and was distributed on a weighted basis for an organization of the size and complexity of this project.

In addition to the base salaries, the following items are included in the overall average rate:

- Bechtel standard payroll additives for taxes and insurance
- Engineering supplies
- General office supplies
- Communication costs
- Indirect cost allowances for facility and overhead items
- Fringe benefits
- Reproduction and printing
- Computer charges
- Travel expense (home office personnel)

Risk Analysis

A typical risk analysis was made using Bechtel's Risk Analysis - Contingency (RAC) program. This program helps to define the accuracy of the estimate, presents the most probable cost, assesses the risks and shows the probability of an overrun at various levels of contingency. The results of this program are normally used to aid in establishing the estimating contingency for the project.

Fee

For estimating purposes, the contractor's fee has been included in the single figure overall project estimate for Engineering, Home Office and Fee.

Estimate Exclusions

The capital cost estimate does not include cost for the items listed below.

- Land cost for site
- Socioeconomic considerations; community facilities, camp or other infrastructure
- Permits and bonds
- Cost of importing borrow fill material from offsite for site fill and compaction
- Gas pipeline

- Electric transmission line
- Cost of setting up remote preassembly yards and facilities
- Credit or debit for worldwide procurement
- Potable water wells
- Allowance for incentive to attract labor

3.1 Raw Material and Utility Pricing

The pricing of raw materials and utilities required for the baseline design and options are listed in Table 3.1 below.

Table 3.1

Raw Material and Utility Pricing

Item	Cost
Feed Coal	20.50 (1) $/s. ton
Raw Water	0.10 (2) $/Mgal
Natural Gas	2.00 (3) $/MMBTU

(1) Coal Week, March 9, 1992
(2) Typical price for raw water in Southern Illinois
(3) General consensus between Amoco, Bechtel and DOE/PETC

3.2 Product Valuation (PIMS)

The valuation of coal liquid products were carried out by utilizing Bechtel's linear programming modeling tool, PIMS (Process Industry Modeling Systems). Such valuations were calculated for various scenarios as case studies. Salient points for these scenarios are highlighted below and summarized in Table 3.2. The results are included in Table 3.3.

Primary input data utilized to run the model were:

Typical PAD II crude with fixed crude price
Coal liquid products rates and physical property
Constraints related to various options

Primary output results are:

Product valuation and syncrude premium[1].

Salient points for the various scenarios:

Case 1 is for a typical PAD 2 refinery handling only petroleum crude (no coal liquid) with a maximum processing capacity of 130 MBPD of average PAD 2 crude mix and 20 MBPD of Alaskan North Slope Crude. In this case the refinery product make is allowed to float up to the maximum market requirement level.

Case 1A is same as case 1 with the exception of floating the product slate as well as the feed composition.

The following cases are with various fractions of coal liquids available to the refinery. For this case study it is assumed that the naphtha fraction of the coal liquid (C5-350) is sent to the reforming unit, the light distillate fraction (350-450) is for blending (diesel and fuel oil), the heavy distillate fraction (450-650) is for diesel and fuel oil blending and also used as FCCU feed, and the vacuum gas oil (650-850) is used as fuel oil blending stock and FCCU feed.

Case 2A is for changing the feed to the typical PAD 2 refinery with 100% of coal liquids (61.94 MBPD) being available with corresponding amount of petroleum feed being backed out. There is not enough degrees of freedom in this case and consequently the case is infeasible. (Note: Case 7A resolves this infeasibility.)

Case 2B is same as Case 2A; however, the coal liquid is available at 50% of its

[1] Syncrude premium is defined as the ratio of the product value for any particular value for any particular case and petroleum crude price for the refinery.

production rate (having the same composition). This is a feasible case and the value per BBL of coal liquid mix (with the same product slate as the baseline coal liquefaction complex produces) is $19.04.

Case 2C is same as case 2B with coal liquid available at 25% production rate instead of 50%. The value per BBL of coal liquid mix is 19.06.

Case 2D simulates the case where the coal liquid addition to refinery is very small (1 MBPD), first drop to refinery. The value of coal liquid mix is $19.27 per BBL.

Cases 7A, 7B, 7C and 7D are similar to cases 2A, 2B, 2C and 2D respectively with the exception that the refining product slates for these cases have been floated. For these relaxed cases the values of the respective coal liquids have increased to $20.63, $22.45, $22.84 and $22.90 per BBL respectively.

Cases 3A, 4A, 5A and 6A for 100% naphtha (C5-350), 100% light distillate (350-450), 100% heavy distillate (450-650) and 100% gas oil (650-850) respectively entering the refinery with other conditions remaining same as in case 1. The values of the respective fractions of the coal liquids are $18.65, $12.80, $19.21 and $16.26. Note that the maximum value is achievable for heavy distillate.

Cases 3B, 4B, 5B and 6B are similar to Cases 3A, 4A, 5A and 6A respectively with the exception that in each of these cases the respective coal liquid addition to refinery was kept at a minimum level of 1 MBPD. The value of the fractions increased to $19.24, 18.78, $19.66 and $18.77 respectively.

The respective syncrude premium for various cases are included in Table 3.3.

Table 3.2
Salient Features of Various Cases

Case	Salient Feature
1	Refinery product make is floated up to the maximum market requirement
1A	Product slate as well as the feed composition are floated
2A	A portion of feed to the typical PAD 2 refinery is replaced with the total production of coal liquids (61.94 MBPD)
2B	Same as 2A, however, the replacement is for 50% of coal liquids (with same composition)
2C	Same as 2A, however, the replacement is for 25% of coal liquids (with same composition)
2D	Very small addition (first drop of coal liquid to refinery), 1 MBPD
3A	100% of vapor in a (C_5 - 350°F) is added to the refinery with other conditions remaining same as 1
3B	Same as 3A, but the addition of naphtha is only 1 MBPD
4A	100% of light distillate (350°F - 450°F) is added to the refinery with other conditions remaining same as 2
4B	Same as 4A, but the addition of light distillate is only 1 MBPD
5A	100% of heavy distillate (450°F - 650°F) is added to the refinery with other conditions remaining same as 2A
5B	Same as 5A, but the addition of heavy distillate is only 1 MBPD
6A	100% gas oil (650°F - 850°F) is added to the refinery with other conditions remaining same as 2A
6B	Same as 6A, but the addition of gas oil (650°F - 850°F) is only 1 MBPD
7A	Same as 2A, with refining product slate floated
7B	Same as 2B with refining product slates floated
7C	Same as 2C with refining product slates floated
7D	Same as 2D with refining product slates floated

TABLE 3.3
PRODUCT VALUATION FOR VARIOUS CASES

CASE NO.	1	1A	2A	2B	2C	2D
COAL LIQUIDS	ZERO	ZERO	100 % MIX	50% MIX	25% MIX	1 MBPD MIX
PRODUCT SLATE	MAX	FLOAT	MAX	MAX	MAX	MAX
OBJ FUNCTION, M$/DAY	623.46	708.95	N/A	1213.26	918.66	642.73
FEEDSTOCK PURCHASES						
==================	MBPD	MBPD	MBPD	MBPD	MBPD	MBPD
*PD2 AVG PAD2 CRUDE MIX	126.900	130.000		92.157	109.469	125.706
ANS ALASKAN NORTH SLOPE	1.239	20.000	I	1.239	1.239	1.239
NC4 NORMAL BUTANE	0.778	0.699	N	1.822	1.296	0.821
PGS H2 PLT FEED GAS, FOE	0.000	0.000	F	0.000	0.000	0.000
IC4 ISOBUTANE	2.041	2.041	E	2.041	2.041	2.041
MNC C5-350 COAL NAPHTHA	0.000	0.000	A	9.598	4.799	0.310
LDC 350-450 COAL LT DIST	0.000	0.000	S	3.902	1.951	0.126
HDC 450-650 COAL HV DIST	0.000	0.000	I	10.818	5.409	0.349
LVC 650-850 COAL LVGO	0.000	0.000	B	6.655	3.328	0.215
	-------	-------	L	-------	-------	-------
TOTAL FEEDSTOCKS	130.958	152.740	E	128.230	129.530	130.806
PRODUCT SALES						
============						
*LPG LPG	4.078	4.834		3.248	3.639	4.056
URG UNLEADED REGULAR	46.284	37.284		46.284	46.284	46.284
UPR UNLEADED PREMIUM	19.836	42.120		19.836	19.836	19.836
LRG LEADED REGULAR	6.614	0.000		6.614	6.614	6.614
JET KERO/JET	12.497	22.567		12.497	12.497	12.497
DSL DIESEL	29.133	24.149		29.133	29.133	29.133
LSF LOW SULFUR FUEL OIL	0.117	0.000		0.600	0.333	0.043
HSF HIGH SULFUR FUEL OIL	2.736	5.256		2.151	2.439	2.736
ASP ASPHALT	6.216	11.931		6.216	6.216	6.216
CKE COKE, TONS	0.649	0.762		0.450	0.549	0.643
SUL SULFUR, LTONS	0.059	0.067		0.037	0.048	0.058
FLR FUEL TO FLARE, FOEB	0.035	0.105		0.000	0.000	0.000
	-------	-------		-------	-------	-------
TOTAL PRODUCTION	127.512	148.141		126.578	126.991	127.415
LIQ RECOVERY, %	97.4	97.0		98.7	98.0	97.4

* The three character symbols in this column for feedstock purchases and product sales are used to identify streams in the PIMS model.

TABLE 3.2 – continued
PRODUCT VALUATION FOR VARIOUS CASES

CASE NO.	7A	7B	7C	7D	3A	4A
COAL LIQUIDS	100 % MIX	50% MIX	25% MIX	1 MBPD MIX	100% MNC NAPHTHA	100% LDC LT DIST
PRODUCT SLATE	FLOAT	FLOAT	FLOAT	FLOAT	MAX	MAX
OBJ FUNCTION, M$/DAY	1986.74	1404.24	1062.70	731.84	981.41	723.37
FEEDSTOCK PURCHASES						
===================	MBPD	MBPD	MBPD	MBPD	MBPD	MBPD
*PD2 AVG PAD2 CRUDE MIX	108.862	130.000	130.000	130.000	102.783	110.312
ANS ALASKAN NORTH SLOPE	1.239	20.000	20.000	20.000	4.395	1.239
NC4 NORMAL BUTANE	2.215	1.441	1.274	0.737	2.167	0.753
PGS H2 PLT FEED GAS, FOE	0.000	0.000	0.000	0.000	0.000	0.000
IC4 ISOBUTANE	2.041	2.041	2.041	2.041	1.260	2.041
MNC C5–350 COAL NAPHTHA	19.195	9.598	4.799	0.310	19.195	0.000
LDC 350–450 COAL LT DIST	7.803	3.902	1.951	0.126	0.000	7.803
HDC 450–650 COAL HV DIST	21.635	10.818	5.409	0.349	0.000	0.000
LVC 650–850 COAL LVGO	13.310	6.655	3.328	0.215	0.000	0.000
	-------	-------	-------	-------	-------	-------
TOTAL FEEDSTOCKS	176.301	184.454	168.801	153.778	129.800	122.148
PRODUCT SALES						
=============						
*LPG LPG	4.205	4.898	5.097	4.852	3.285	3.789
URG UNLEADED REGULAR	22.950	35.647	34.847	37.069	46.284	44.714
UPR UNLEADED PREMIUM	65.166	54.670	53.473	42.921	19.836	19.836
LRG LEADED REGULAR	0.000	0.000	0.000	0.000	6.614	0.000
JET KERO/JET	5.357	27.447	22.754	22.567	12.497	12.497
DSL DIESEL	61.801	34.597	27.911	24.392	29.133	29.133
LSF LOW SULFUR FUEL OIL	0.527	0.648	0.525	0.034	0.000	0.600
HSF HIGH SULFUR FUEL OIL	2.632	9.965	7.487	5.400	2.197	2.736
ASP ASPHALT	10.056	11.931	11.931	11.931	6.216	6.216
CKE COKE, TONS	0.528	0.762	0.762	0.762	0.532	0.558
SUL SULFUR, LTONS	0.042	0.059	0.063	0.066	0.051	0.050
FLR FUEL TO FLARE, FOEB	0.000	0.000	0.000	0.000	0.000	0.000
TOTAL PRODUCTION	-------	-------	-------	-------	-------	-------
LIQ RECOVERY, %	172.694	179.803	164.025	149.166	126.062	119.521
	98.0	97.5	97.2	97.0	97.1	97.8

* The three character symbols in this column for feedstock purchases and product sales are used to identify streams in the PIMS model.

TABLE 3.2 – continued
PRODUCT VALUATION FOR VARIOUS CASES

CASE NO.	5A	6A	3B	4B	5B	6B
COAL LIQUIDS	100%	100%	1 MBPD	1 MBPD	1 MBPD	1 MBPD
	HDC	LVC	MNC	LDC	HDC	LVC
	HV DIST	LT VGO	APHTHA	LT DIST	HV DIST	LT VGO
PRODUCT SLATE	MAX	MAX	MAX	MAX	MAX	MAX
OBJ FUNCTION, M$/DAY	1039.17	839.84	642.70	642.23	643.12	642.23
FEEDSTOCK PURCHASES						
==================	MBPD	MBPD	MBPD	MBPD	MBPD	MBPD
*PD2 AVG PAD2 CRUDE MIX	103.588	102.862	125.646	125.788	125.712	125.836
ANS ALASKAN NORTH SLOPE	1.239	1.239	1.239	1.239	1.239	1.239
NC4 NORMAL BUTANE	1.204	0.986	0.865	0.813	0.783	0.782
PGS H2 PLT FEED GAS, FOE	0.000	0.000	0.000	0.000	0.000	0.000
IC4 ISOBUTANE	1.542	2.041	2.041	2.041	2.041	2.041
MNC C5-350 COAL NAPHTHA	0.000	0.000	1.000	0.000	0.000	0.000
LDC 350-450 COAL LT DIST	0.000	0.000	0.000	1.000	0.000	0.000
HDC 450-650 COAL HV DIST	21.635	0.000	0.000	0.000	1.000	0.000
LVC 650-850 COAL LVGO	0.000	13.310	0.000	0.000	0.000	1.000
	-------	-------	-------	-------	-------	-------
TOTAL FEEDSTOCKS	129.208	120.438	130.791	130.881	130.775	130.899
PRODUCT SALES						
============						
*LPG LPG	3.772	3.191	4.046	4.072	4.057	4.020
URG UNLEADED REGULAR	46.284	46.284	46.284	46.284	46.284	46.284
UPR UNLEADED PREMIUM	19.836	19.836	19.836	19.836	19.836	19.836
LRG LEADED REGULAR	6.614	3.419	6.614	6.614	6.614	6.614
JET KERO/JET	12.497	12.497	12.497	12.497	12.497	12.497
DSL DIESEL	29.133	23.464	29.133	29.133	29.133	29.133
LSF LOW SULFUR FUEL OIL	0.600	0.600	0.000	0.082	0.058	0.184
HSF HIGH SULFUR FUEL OIL	2.306	2.736	2.736	2.736	2.736	2.736
ASP ASPHALT	6.216	6.216	6.216	6.216	6.216	6.216
CKE COKE, TONS	0.520	0.538	0.642	0.643	0.643	0.643
SUL SULFUR, LTONS	0.050	0.044	0.058	0.058	0.058	0.058
FLR FUEL TO FLARE, FOEB	0.000	0.000	0.000	0.000	0.000	0.000
	-------	-------	-------	-------	-------	-------
TOTAL PRODUCTION	127.258	118.243	127.362	127.470	127.432	127.520
LIQ RECOVERY, %	98.5	98.2	97.4	97.4	97.4	97.4

* The three character symbols in this column for feedstock purchases and product sales are used to identify streams in the PIMS model.

TABLE 3.2 – continued
PRODUCT VALUATION FOR VARIOUS CASES

CASE NO.	1	1A	2A	2B	2C	2D
INCREM REVENUE, M$/DAY	–	–	N/A	589.81	295.21	19.27
INCREM VOLUME, MBPD	–	–	N/A	30.97	15.49	1.00
VALUE OF COAL MIX, $/BBL	–	–	N/A	19.04	19.06	19.27
VALUE OF MNC NAPH, $/BBL	–	–				
VALUE OF LDC DIST, $/BBL	–	–				
VALUE OF HDC DIST, $/BBL	–	–				
VALUE OF LVC LVGO, $/BBL	–	–				
SYNCRUDE PREMIUM				1.057	1.059	1.069

==================================

CASE NO.	7A	7B	7C	7D	3A	4A
INCREM REVENUE, M$/DAY	1277.79	695.30	353.76	22.90	357.96	99.92
INCREM VOLUME, MBPD	–148.31	–148.31	–148.31	–148.31	–127.60	–127.60
VALUE OF COAL MIX, $/BBL	–8.62	–4.69	–2.39	–0.15		
VALUE OF MNC NAPH, $/BBL					–2.81	
VALUE OF LDC DIST, $/BBL						–0.78
VALUE OF HDC DIST, $/BBL						
VALUE OF LVC LVGO, $/BBL						
SYNCRUDE PREMIUM	1.146	1.247	1.269	1.272	1.036	0.711

==================================

CASE NO.	5A	6A	3B	4B	5B	6B
INCREM REVENUE, M$/DAY	415.71	216.38	19.24	18.78	19.66	18.77
INCREM VOLUME, MBPD	21.64	13.31	1.00	1.00	1.00	1.00
VALUE OF COAL MIX, $/BBL						
VALUE OF MNC NAPH, $/BBL			19.24			
VALUE OF LDC DIST, $/BBL				18.78		
VALUE OF HDC DIST, $/BBL	19.21				19.66	
VALUE OF LVC LVGO, $/BBL		16.26				18.77
SYNCRUDE PREMIUM	1.067	0.903	1.069	1.043	1.092	1.043

3.3 First & Nth Plant Concepts

For any developing technology where the first commercial plant has not been built, there is a period of time certain items are initially assumed and later revised downward as the techology's commercial history is established. Such items are:

1. Design Basis including scale-up considerations (from the plant capacity at which the technology was proven to the capacity of the commercial plant).

2. Assumed design overcapacity factors which take the form of sparing of whole production trains. These over capacity factors have a direct impact on the onstream factor.

3. Project Schedule

The First plant concept is thus self-explanatory. It refers to the first commercial plant with a degree of over design to meet the name plate capacities and product specifications.

The period of time between the first commercial plant and the plant at which the technology commercial maturity is normally designated as N years. Thus the Nth plant is that commercial plant built N years after the first commercial plant for which the technology basis, plant design and operation are well known.

The focus of this task (Task III) is to define and develop the Nth plant economics, as requested by DOE.

The Nth plant economics are defined as the economics of the Nth plant which has the following characteristics:

1. requires lowest reasonable plant cost contingency;

2. contains no spare trains;

3. incurs the lowest reasonable engineering cost;

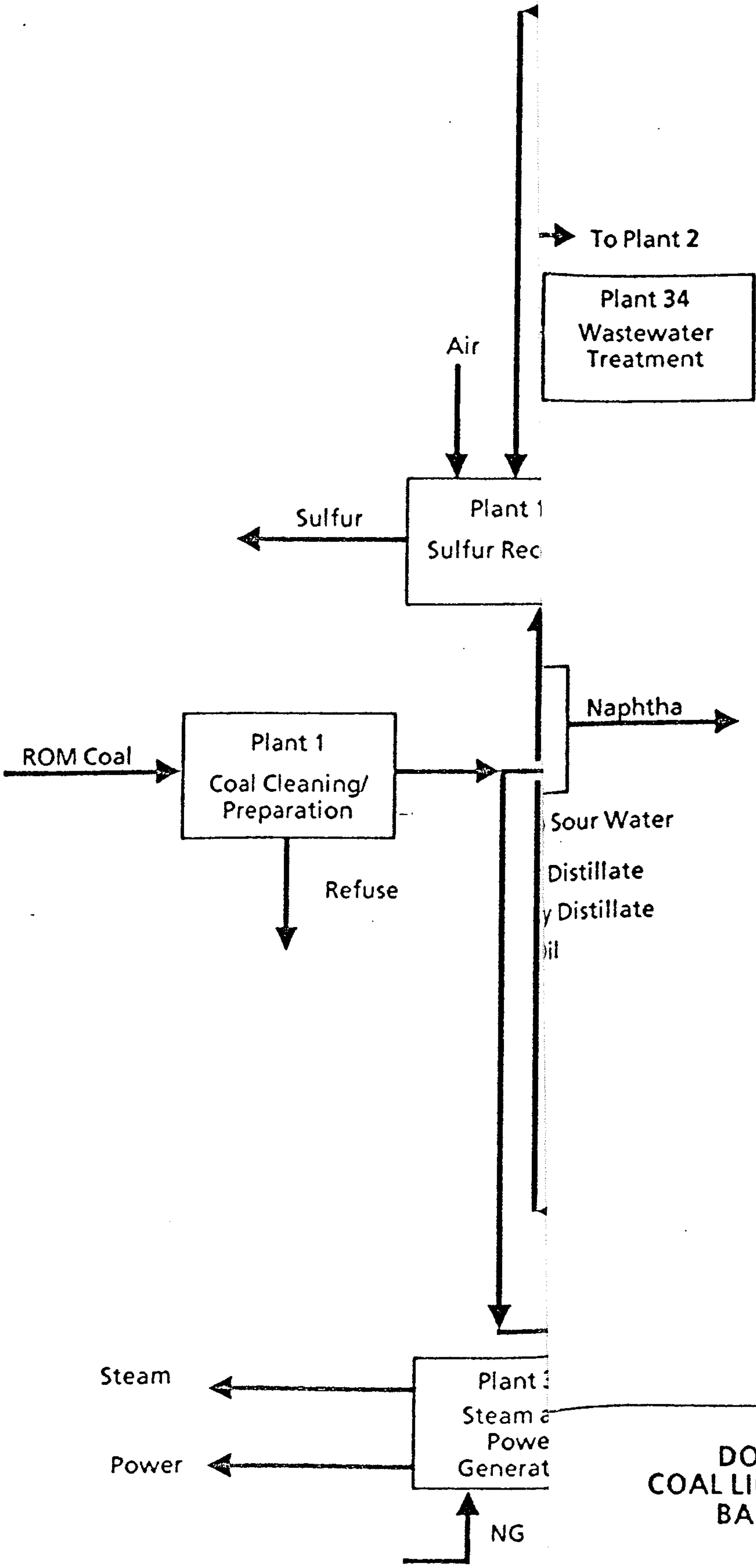
4. requires the lowest possible project schedule to construct and start-up;

5. technology has matured to the point that the Nth plant overall stream factor of the complex remains the same as that of the First plant.

4. Overall Plant Configuration

4.0 Configuration of the Complex

The overall plant configuration for the entire liquefaction complex is shown in Figure 4.1



DOE / PETC
COAL LIQUEFACTION
BASE CASE

OVERALL PLANT CONFIGURATION

Figure 4.1

Revised 08/01/91

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4.1 Number of Operating/Spare Trains (First & Nth Plants)

The number of operating and spare trains for each of the ISBL plants is shown in Table 4.1 below. This table includes the above information for the First plant as well as the Nth plant scenarios.

Table 4.1
Operating/Spare Trains for First & Nth Plants

Plant No.	No. of Oper. Train (1)	No. of Spare Train	
		First Plant	Nth Plant
1	5	0	0
1.4	10	2	0
2	5	1	0
3	1	0	0
4	1	0	0
5	1	0	0
6	1	0	0
8	1	0	0
9	5	1	0
10	5	0	0
11	4	0	0
38	1	0	0
39	1	0	0

(1) Number of operating trains remains the same for the First plant as well as the Nth plant scenarios.

4.2 Maximum Single Train Capacities

The maximum single train capacities for all the ISBL plants are shown in Table 4.2 below:

Table 4.2

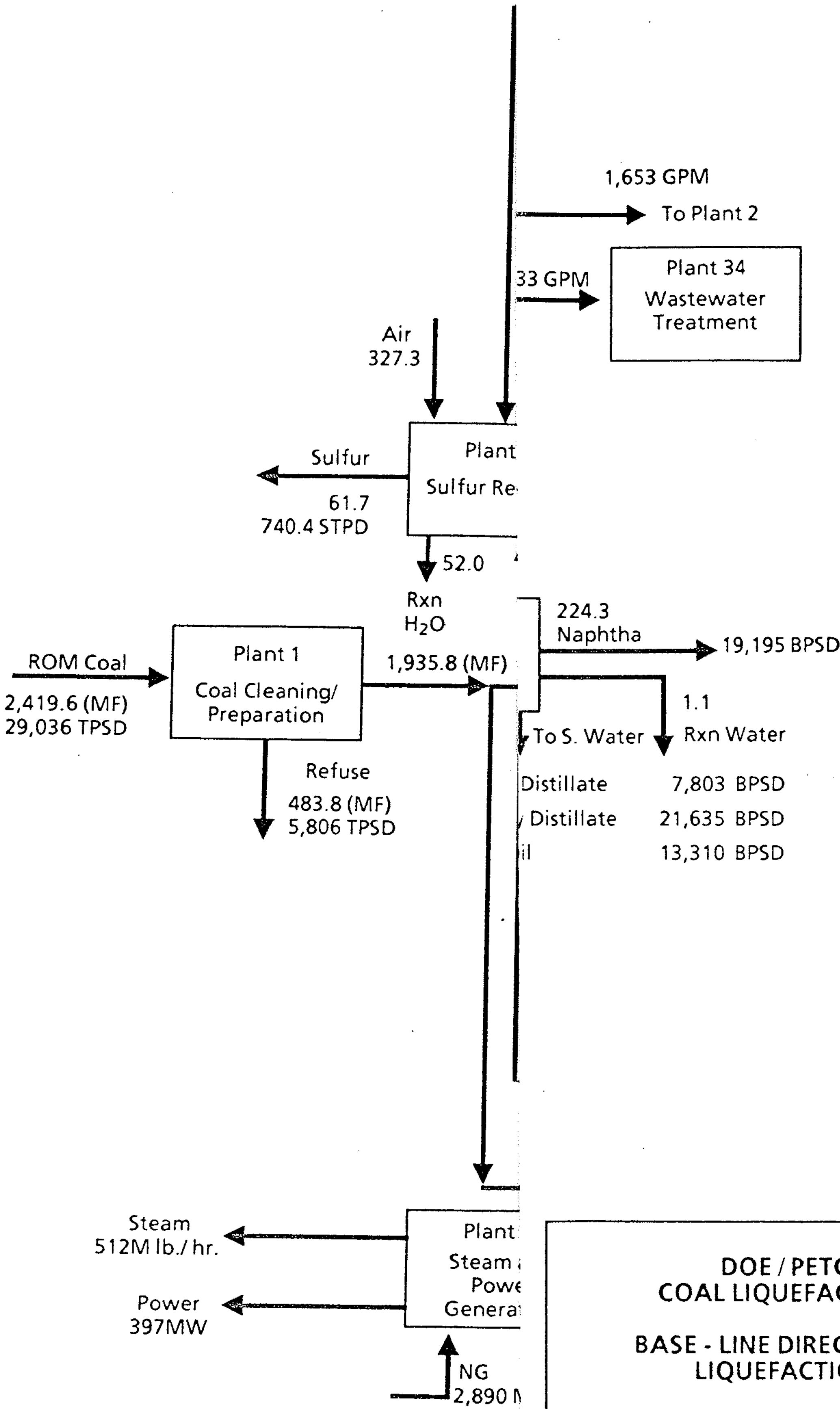
Maximum Capacity for Single Train

Plant No.	Feed Rate TPSD
1	6254
1.4	2323
2	3420
3	4111
4	2821
5	8267
6	2893
8	10889
9 (1)	1225
10	7689
11	1505
38	23360
39	16148

(1) Based on coal feed rate only

4.3 Overall Material Balance

The overall material balance for the entire complex showing input-output mass flow rates for each ISBL plant is shown in Figure 4.2. In addition, input-output mass flow rates for the waste water treatment plant (Plant 34) and the steam and power generation plant (Plant 31) are also included in this figure.



Revised 11/26/91

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Notes:

1.
2.
3.
4.

DOE / PETC
COAL LIQUEFACTION

BASE - LINE DIRECT COAL
LIQUEFACTION

OVERALL
MATERIAL BALANCE

Figure 4.2

5. Reliability and Onstream Factor Analysis

5.0 Methodology

The methodology used to determine the onstream factor for the entire coal liquefaction complex is highlighted below.

- Divide ISBL plants of the complex into groups of plants having the same number of trains and interrelated operations

- Carry out analysis to determine the following for each plant:

  - average failure rate
  - average repair time
  - average unscheduled outages

- Compute the probability of running (exclusive of turnarounds) for each group of plants

- Develop a turnaround schedule for each plant and calculate the duration of each turnaround pattern for each group of plants

- Calculate the probability of operation of each group of plants (considering unscheduled and scheduled turnarounds)

- Calculate the onstream factor on scheduled production for the entire complex

- Determine average scheduled shutdown for groups without spares

- Determine scheduled production days per year

- Calculate onstream factor for the entire complex (based on calendar days)

5.1 Calculation of Onstream Factor

Grouping of Plants

For computing this onstream factor, the ISBL plants of the coal liquefaction complex were grouped as shown in Table 5.1.

Table 5.1
Plant Grouping for Onstream Factor

		No. of Trains	
Group	**Plants**	**Operating**	**Spare**
A	2	5	1
B	8,38,39	1	0
C	3,6,4,5	1	0
D	9	5	1
E	11	4	0
F	1.4	10	2
G	10	5	0

Note: Plant 1 (Coal Cleaning and Handling plant) does not impact the overall plant availability because it is decoupled from the rest of the plant by adequate storage.

Unscheduled Downtime

Unscheduled downtime and the probability of running is summerized in Table 5.2.

Table 5.2
Operating Probabilities for Each Train of ISBL Plants

Group	Plants	Average Failure Rate per K Hrs	Average Repair Time per Failure, Hr	Unscheduled Outages Hrs/K Hrs	Probability of Running (1)
A	1	0.6948	120.6	83.8	0.9227
B	8, 38, 39	0.3417	50.3	17.5	0.9828
C	3, 4, 5, 6			10.1 (2)	0.9900
D	9	0.2935	79.0	23.2	0.9961
E	11	0.1653	59.3	9.8	0.9903
F	1.4	1.577	24.4	38.4	0.9630
G	10			10.1 (2)	0.9900 (2)

(1) Equal to mean on-stream factor for area grouping, exclusive of scheduled turnaround = 1000/(1000 + average unscheduled outages)

(2) Based on refinery experience

Turnaround Schedule

An average turnaround schedule is presented in Table 5.3

Table 5.3
Turnaround Schedule of ISBL Plants

Plant No.	Description	Turnaround Years Between	Turnaround Duration (weeks)	Plant Group
1	Coal Cleaning and Handling			*
1.4	Coal Grinding and Drying	2	2	F
2	Coal Liquefaction	1	4	A
3	Gas Plant	3	2	C
4	Naphtha Hydrotreater	2	4	C
5	Gas Oil Hydrotreater	2	4	C
6	Hydrogen Purification	3	2	C
8	Critical Solvent Deashing	3	2	B
9	Hydrogen Production by Coal Gasification	3	3	D
10	Air Separation	3	2	G
11	By-Product Sulfur Recovery	2	2	E
38	Ammonia Recovery	3	2	B
39	Phenol Recovery	3	2	B

* This plant does not impact the overall plant availability because it is decoupled from the rest of the plants by adequate storage.

Computation of Onstream Factor

The results of computation of onsteam factor are shown in Table 5.4 for the base case (First plant). Column (5), the operating probability at design rate for the group, is calculated for groups having spare (A, D and F) trains. A sample calculation is shown in Appendix 1. For groups of plants having no spare, Column (5) equals Column (4).

The onstream factor exclusive of turnarounds for groups B, C. E and G = the product of each item in Column (5) . . . . Item (6)

The average maximum scheduled shutdown for groups without spares B, C, and D is 3 weeks in 3 years, i.e., 1 week per year or 7 days . . . . Item (7)

Scheduled production days per year = 365 - Item (7) = 365-7 = 358 days ...... Item (8)

The operation days at plant design rate = Item (6) x Item (8) = 322.6 days ...... Item (9)

The onstream factor based on calendar days = Item (9) divided by 365 = 322.6 divided by 365 = 0.884 = 88.4% .... Item (10)

Table 5.4
Expected Onstream Factor Base Case (First Plant)

(1) Group and Plants	(2) Number of Trains	(3) Turnaround		(4) Probability of Running for each Train	(5) Operating Probability at Design Rate for the Group
		Years between	Duration Wks/Train		
A (2)	5 (1 spare)	1	4	0.9227	0.9415
B (8,38,39)	1	3	2	0.9828	0.9828
C (3,6,4,5)	1	2	4	0.9900	0.9900
D (9)	5 (1 spare)	3	3	0.9773	0.9961
E (11)	4	2	2	0.9903	0.9903
F (1.4)	10 (2 spare)	2	2	0.9630	0.9923
G (10)	5	3	2	0.9900	0.9900

(6) Onstream factor on scheduled production = 0.9010
(7) Average scheduled shut down for groups without spares (B, C, E and G) turnaround days/yr = 7
(8) Scheduled production days per year = 358
(9) Operation days at plant design rate = 322.6
(10) Onstream factor, based on calendar days = 88.4%

BASELINE

Table 6.1

Illinois No. 6 Coal Burning Star Mine
ROM Coal Analysis (1)

Proximate Analysis	Wt. %
Volatile Matter	33.0
Fixed Carbon	38.3
Ash	20.0
Moisture	8.7
Ultimate Analysis	
Carbon	61.1
Hydrogen	4.2
Nitrogen	1.2
Sulfur	5.1
Chlorine	0.1
Ash	21.7
Oxygen (by difference)	6.6
Sulfur Forms	
Pyrite	3.0
Sulfitic	0.3
Organic	1.8
Ash Composition	
Phosphorus pentoxide, P_2O_5	0.1
Silica, SiO_2	43.8
Ferric Oxide, Fe_2O_3	24.1
Alumina, Al_2O_3	17.1
Titania, TiO_2	0.8
Lime, CaO	5.6
Magnesia, MgO	1.0
Sulfur Trioxide, SO_3	4.1
Potassium Oxide, K_2O	2.1
Sodium Oxide, Na_2O	0.6
Undetermined	0.7

(1) DOE's RFP on Direct Coal Liquefaction Project with Adjustment

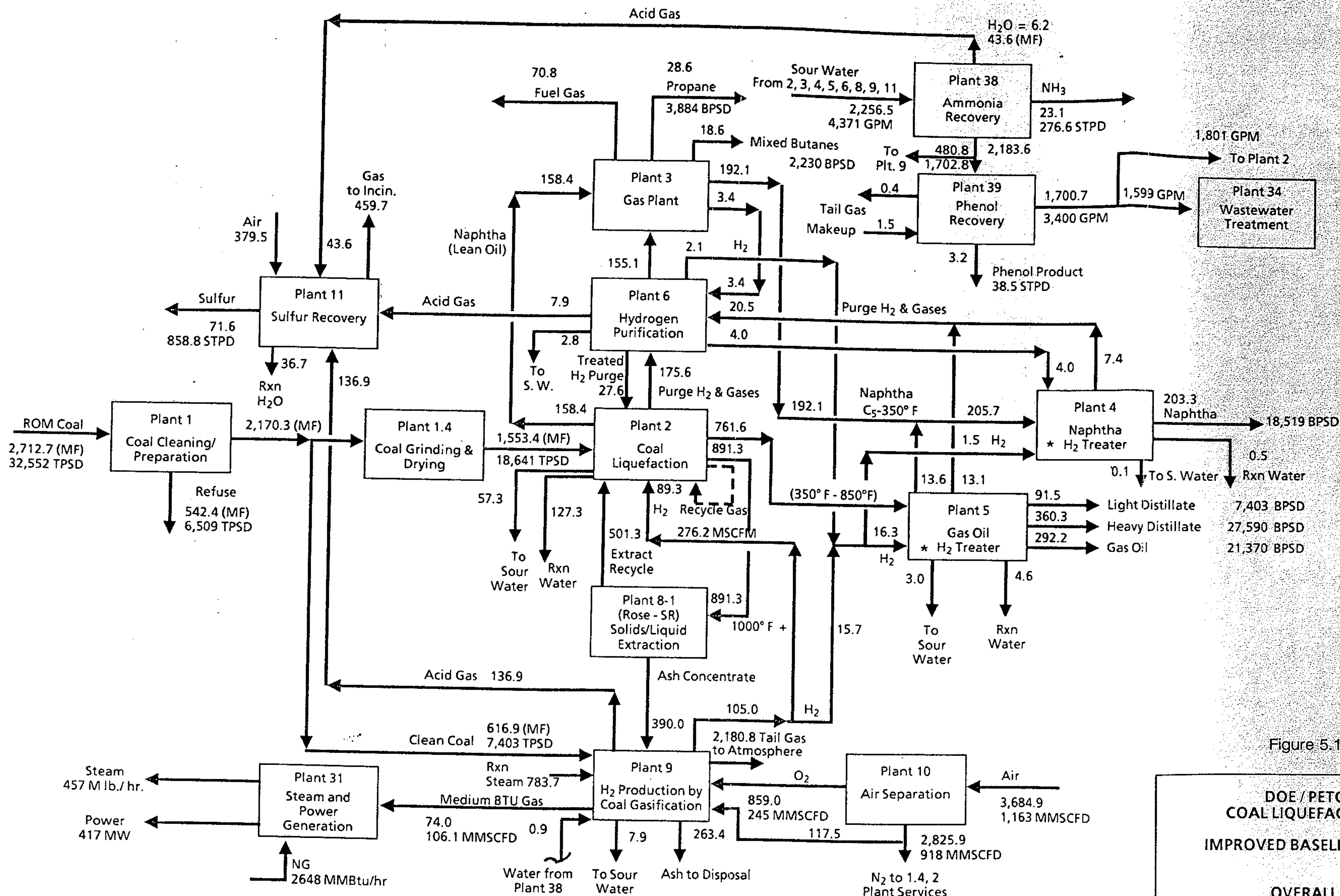

Figure 5.1

DOE / PETC COAL LIQUEFACTION

IMPROVED BASELINE CASE

OVERALL MATERIAL BALANCE

Notes:

1. Flow rates are in MLB/HR unless noted and on dry basis
2. Minor streams including steam, water, sour water, and make-up amine are not shown on this diagram
3. Flow rates around plants #38, 39, 34 are shown on wet basis

* H2 Treater = Hydrotreater

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IMPROVED BASELINE

Table 7.1

Analysis of Feed Coal to Liquefaction
Illinois No. 6 (Burning Star Mine)

Proximate Analysis (wt. %, Dry Basis)	
Volatile Matter	42.2
Fixed Carbon	46.3
Ash	11.5
Ultimate Analysis (wt. %, Dry Basis)	
Carbon	71.0
Hydrogen	4.8
Sulfur	3.2
Nitrogen	1.4
Ash	11.5
Chlorine	0.1
Oxygen (by difference)	8.0
Sulfur Forms (wt. %, Dry Basis)	
Pyrite	1.0
Sulfitic	0.1
Organic	1.9
Ash Composition (wt. % oxidized)	
Phosphorus pentoxide, P_2O_5	0.2
Silica, SiO_2	49.8
Ferric Oxide, Fe_2O_3	17.6
Alumina, Al_2O_3	19.2
Titania, TiO_2	1.0
Lime, CaO	6.3
Magnesia, MgO	1.0
Sulfur Trioxide, SO_3	2.9
Potassium Oxide, K_2O	2.0
Sodium Oxide, Na_2O	0.5
Undetermined	-0.5

Wolfowicz, Alberto Daniel

From: Avidan, Amos

Sent: Tuesday, March 18, 2003 10:36 AM

To: Wolfowicz, Alberto Daniel; Keel, Joseph

Subject: FW: Fax from Shenhua (Mar. 16)

Daniel,
Please provide me with 1. Our standard experience with coal liquefaction/gasification (we probably already had this in our previous Shenhua proposal - Lance was working on this)
2. work with Joe to come up with qualified resumes for the technical part
Amos

-----Original Message-----
From: Sassi, Angelo
Sent: Tuesday, March 18, 2003 8:05 AM
To: Avidan, Amos
Subject: FW: Fax from Shenhua (Mar. 16)

For your action. I believe that I have sent the earlier paper received from Shenhua. Please advise.

Angelo Sassi
Business Development Manager – Asia Pacific
Bechtel International
Unit 1201-1209 Pidemco Tower, No. 318 Fuzhou Road
Shanghai 200001
People's Republic of China
Tel: (86-21) 3305-4567 ext. 1235
Fax: (86-21) 6391-2126
Efax: 415-358-4529
Mobile 1: +44(0)7785-311-433 (UK)
Mobile 2: 86 135 0162 9176 (China)
Mobile 3: +1-415-867-8612
E-mail: agsassi@bechtel.com

-----Original Message-----
From: Sassi, Angelo
Sent: Tuesday, March 18, 2003 4:37 PM
To: Khedr, Emad; Lewis, Eddie
Cc: Li, Jie (P&C)
Subject: FW: Fax from Shenhua (Mar. 16)

The attached fax requires a response by 21 March. May I have your comments.

Angelo Sassi
Business Development Manager – Asia Pacific
Bechtel International
Unit 1201-1209 Pidemco Tower, No. 318 Fuzhou Road

Shanghai 200001
People's Republic of China
Tel: (86-21) 3305-4567 ext. 1235
Fax: (86-21) 6391-2126
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Mobile 1: +44(0)7785-311-433 (UK)
Mobile 2: 86 135 0162 9176 (China)
Mobile 3: +1-415-867-8612
E-mail: agsassi@bechtel.com

-----Original Message-----
From: Xiao, Lei Lesley
Sent: Monday, March 17, 2003 10:10 AM
To: Sassi, Angelo
Cc: Li, Jie (P&C)
Subject: Fax from Shenhua (Mar. 16)

Angelo,

Please find the fax from Shenhua.

Best Regards,
Lesley

FAX

Integrated Project Management Team

Shenhua Direct Coal Liquefaction Project

Fax: 86 10 82286466 (Beijing) 1 609 243 9493(Princeton)

To	:	**Mr. A. Sassi**	From	:	**P.J. Dickerson**
Company	:	**BECHTEL**	Date	:	**14March2003**
Tel no.	:		Pages total	:	**1**
Fax no.	:	**86 21 6391 2999**	Our fax ref:	:	**F-IPMT(P)/BECHTEL/ 003**

SUBJECT : **Shenhua Direct Coal Liquefaction Project – Contractor Prequalification for the Direct Coal Liquefaction and T-Star^{tm} Units**

****

Dear Mr. Sassi,

Based on your response to the Contractor Prequalification solicitation of interest FAX issued for the subject project on February 21, 2003, the IPMT are reviewing the contracting strategy and invites you to continue in the prequalification process.

As an aid in the selection/evaluation of the potential bidders, please respond to the following, not later than close of business Friday, 21March03:

1. Provide your relevant experience in coal liquefaction.
2. Provide CV's for the nominated, experienced team including project management, engineering expertise, and commissioning and start up experience.

Should you have any queries then these should be addressed to the IPMT Project Manager for these units, Peter Dickerson, on the above Princeton telefax number or via phone at 1 609 987 3053 and/or e-mail at peter.dickerson@us.abb.com.

Regards,

Peter Dickerson
IPMT Offshore Project Manager
Shenhua Direct Coal Liquefaction Project

6. Plant 1 (Coal Cleaning and Handling)

6.0 Design Basis, Criteria and Considerations

ROM coal enters the fence line of the complex. The analysis of ROM coal is shown in Table 6.1. ROM coal is cleaned by Jig Cleaning operation.

Storage capacities for ROM Coal and clean coal are as follows:

For ROM coal, "Active Storage" Pile is of 4 days capacity and remaining 24 days of "Inactive Storage".

For clean coal, storage is for 2 days of "Active Storage" pile.

Operation Basis for the base case cleaning plant (Jig) is:

2 shifts a day 5 days a week and 50 weeks per year
Third shift for maintenance
14.5 hrs of operation with 1.5 hrs for start-up, planned and unplanned outages.

Ash content of base case clean coal are as shown below:

Base case, Jig Cleaning	11.47%
Alternate 1, Heavy Medium	8.6%
Alternate 2, Spherical Agglomeration	< 4%

Size analysis for ROM Coal is shown in Table 6.2.

The basis for analysis of clean coal is shown in Table 6.3.

The production rate of this plant is based on the requirement of coal liquefaction plant (Plant 2) and coal gasification plant (Plant 9, the source for hydrogen supply)..

Coal from this coal cleaning and handling plant (Plant 1) is further processed through coal grinding and drying plant (Plant 1.4) where the coal moisture is reduced to 2 wt% and the particle size is reduced to 50% through 200 mesh screen.

Plant 1 design is on the basis of five train each train processing nominal 6000 TPSD on MF basis. The product size, ash and moisture content of clean coal from Plant 1 is shown in Table 6.4. Note that this original design was for six trains (as reported in Task II report). However, because 1) this plant is decoupled from the rest of the complex via sufficient storage facility for capital cost estimate purpose, it was decided to keep five trains instead. This change will not impact on the overall onstream factor for the complex.

<u>Production of Middlings</u>

The possibility of utilizing a potential middlings product with an ash content of around 20 percent for boilers or coal gasification was examined. The recovery of a middlings product is justified when the process sink material (refuse) contains a significant amount of material of economically usable quality. A review of the float/sink data for the design coal revealed that only a clean coal with 11.47 percent ash (Base Case) will be produced from the ROM coal, the refuse will contain no coal of the required middlings quality. The refuse will be exclusively material with an ash content above 68 percent.

Under these circumstances, additional cleaning, dewatering, handling and storage circuits will not be justified to produce a middlings product. Since the boilers or gasifier can use a fuel of 20 percent ash this requirement can be more economically met by ROM Coal.

Table 6.1

Illinois No. 6 Coal Burning Star Mine
ROM Coal Analysis [1]

	Wt. %
Proximate Analysis	
Volatile Matter	33.0
Fixed Carbon	38.3
Ash	20.0
Moisture	8.7
Ultimate Analysis	
Carbon	61.1
Hydrogen	4.2
Nitrogen	1.2
Sulfur	5.1
Chlorine	0.1
Ash	21.7
Oxygen (by difference)	6.6
Sulfur Forms	
Pyrite	3.0
Sulfitic	0.3
Organic	1.8
Ash Composition	
Phosphorus pentoxide, P_2O_5	0.1
Silica, SiO_2	43.8
Ferric Oxide, Fe_2O_3	24.1
Alumina, Al_2O_3	17.1
Titania, TiO_2	0.8
Lime, CaO	5.6
Magnesia, MgO	1.0
Sulfur Trioxide, SO_3	4.1
Potassium Oxide, K_2O	2.1
Sodium Oxide, Na_2O	0.6
Undetermined	0.7

(1) DOE's RFP on Direct Coal Liquefaction Project with Adjustment

Table 6.2

Size Analysis for ROM Coal

Size (inch or mesh)	Percent
3 x 3/8	51
3/8 x 28M	37
28M x 0	12
Total	100

Table 6.3

Analysis of Feed Coal to Liquefaction
Illinois No. 6 (Burning Star Mine)

Proximate Analysis (wt. %, Dry Basis)	
Volatile Matter	42.2
Fixed Carbon	46.3
Ash	11.5
Total	100.0
Ultimate Analysis (wt. %, Dry Basis)	
Carbon	71.0
Hydrogen	4.8
Nitrogen	1.4
Sulfur	3.2
Chlorine	0.1
Ash	11.5
Oxygen (by difference)	8.0
Total	100.0
Moisture %	8.6

Table 6.4

Product Size from Coal Cleaning Plant

Base Case		Wt %
Particle Size		
	3 x 1-1/2	9.4
	1-1/2 x 100M	90.6
Moisture		8.6
Ash		11.47

6.1 Major Equipment List

The major equipment list for this plant is included in Table 6.5.

Table 6.5

Major Equipment List

ROM Coal Receiving and Storage

Surge Bin Feed Conveyor

Tramp Iron Magnet

Surge Bin

Weigh Feeder

Plant Feed Conveyor

Baum Jig

Addition

Refuse Screen

Clean Coal Centrifugal Drying

Clean Coal Crushing

Fine Refuse Thickening and Water Recovery

Coarse Refuse Handling

Fine Refuse Disposal

Clean Coal Storage

Clean Coal Storage - Emergency File

6.2 Catalyst and Chemical Summary

For this plant the catalyst and chemicals cost is as follows:*

Start up catalyst and chemicals	$200,000
Start up first year requirement of catalyst and chemicals	$606,000

* The catalyst and chemical consumptions were given as dollar figures by the coal preparation and handling specialists.

6.3 On Stream Factor

The onstream facator for this plant is 95+%. However, the onstream factor of this plant does not impact the onstream factor of the overall complex because this plant is decoupled from the rest of the complex by adequate storage.

6.4 Operating Manpower Requirements

The operating manpower requirement for this plant is 48 operators. For full manpower requirements of this plant as well as the complex, refer to Section 40 of this report.

6.5 Plot Area Required

The total plot area required for this palnt is 1500 ft x 1000 ft.

6.6 Capital Cost and Breakdowns (First & Nth Plants)

The field costs and breakdowns for Plant 1 are given below in Table 6.6. Note that field costs for each plant do not include home office costs or contingency. These were estimated for the whole complex and are given in Section 41.

Table 6.6

Plant 1 (Coal Cleaning and Handling)
Field Costs and Breakdowns
2nd Quarter, 1991

Field Costs	**Costs ($MM)**	
Breakdown	First Plant	Nth Plant
Major Equipment	34.8	34.8
Bulk Materials	19.7	19.7
Subcontracts	--	--
Direct Labor	19.2	19.2
Distributables (Indirect)	17.3	17.3
Total Field Costs	**91.0**	**91.0**

7. Plant 1.4 - (Coal Grinding and Drying)

7.0 Design Basis, Criteria and Considerations

This plant crushes and drys coal from Coal Cleaning and Preparation Plant (Plant 1) for Coal Liquefaction Plant (Plant 2).

Clean coal enters the plant sized at 1-1/2"x0 with up to 15% moisture content and exits with 50% of the coal minus 200 mesh and with 2% moisture content. Moist clean coal from a feeder bin enters the coal mill where it is ground. Dry, heated nitrogen blown into the mill dries and carries the fine coal dust out of the mill to a dust collector unit. The dust collector separates the coal dust from the nitrogen and directs the coal to a crushed coal bin. The nitrogen is recirculated through a heater back into the mill except for a small amount which is purged. The crushed coal product is delivered to Plant 2 via a pneumatic type pump.

The plant is designed to grind and dry 17,102 TPD (dry) of 1-1/2" and less, 55 Hardgrove coal with 15% maximum feed moisture content. The final product has a size of 50% of the coal less than 200 mesh and a 2% moisture content.

The plant is intended to be operated 24 hours per day.

Inert nitrogen gas is utilized for drying and transferring the coal dust to minimize auto-ignition and explosion hazards.

The coal feed and crushed coal product bins must each provide 8 hrs of storage capacity (600 tons at 75 TPH).

7.1 Major Equipment Summary

The major equipment for this plant is listed in Table 7.1.

Table 7.1

Equipment	Description
Coal Feed Bin	600 ton, 29 ft. dia., 60° cone
Crushed Coal Product Bin	600 ton, 35 ft. dia., 60° cone, with nitrogen blanket
Fired Heater	48.6 MMBTU/hr duty, fuel fired, nitrogen gas feed, 850 °F and 1 psig design temp. and press.
Finished Coal Feed Pump	75 TPH, 50 psig outlet press., Fuller-Kinyon, pneumatic, transports pulverized coal @ 30 lb/ft^3, 2250 SCFM N_2 required, rotary feeder on inlet side
Nitrogen Recycle Fan	900 hp, 1800 rpm, WP II induction motor, Induced air fan, backward curved, including housing, inlet damper and controls
Nitrogen Bleed Damper	5300 ACFM nitrogen @ 90 °F

Table 7.1 - continued

Equipment	Description
Weigh Belt Feeder	75 TPH, 10 ft. long, 3 ft. wide, 10 ft. long bin discharge chute, feeder discharge chute
Crushed Coal Screwed Conveyor	75 TPH
Hoist for Feeders	6 tons design capacity, 25 ft. lift, motorized trolley-pendant operated hoist
Overhead Travelling Crane	30 ton capacity, 30, 10, and 10 hp motors, 40 ft. span, 70 ft. lift
Fuller Atox 25 Coal Mill	Model AM-KM-25 including a static classifier, 700 hp, 1200 rpm, WP II induction motor
Dust Collector Baghouse	Fuller Plenum-Pulse Modular, Double Row, Model 128-16-10, carbon steel construction

7.2 Onstream Factor

The onstream factor for this plant is 97.3%.

7.3 Operating Manpower Requirements

The operating manpower requirement for this plant is 17 operators. For full manpower requirements of this plant as well as the complex, refer to Section 40 of this report.

7.4 Plot Area Required

The plot area required for this plant is 250 ft. x 1800 ft.

7.5 Capital Cost and Breakdowns

The field costs and breakdowns for Plant 1.4 are given below in Table 7.2. Note that field costs for each plant do not include home office costs or contingency. These were estimated for the whole complex and are given in Section 41.

Table 7.2

Plant 1.4 (Coal Grinding and Drying)
Field Costs and Breakdowns
2nd Quarter, 1991

Field Costs	**Costs ($MM)**	
Breakdown	First Plant	Nth Plant
Major Equipment	37.8	31.5
Bulk Materials	23.8	19.8
Subcontracts	5.4	4.5
Direct Labor	20.0	16.7
Distributables (Indirect)	18.0	15.0
Total Field Costs	**105.0**	**87.5**

8. Plant 2 (Coal Liquefaction)

8.0 Design Basis, Criteria and Considerations

Coal Feed

The coal to be fed to the coal liquefaction plant is washed and dried Illinois No. 6 coal (Burning Star Mine) from Plant 1, the Coal Preparation Plant. Analysis of the basis coal is presented in Table 8.1.

Coal feed to Plant 2 is approximately:

Basis	Per Train	Total
MF basis	3,420 TPSD	17,102 TPSD
MAF basis	3,028 TPSD	15,140 TPSD

Moisture in the coal feed is 2.0 wt. % and ash (MF) content is 11.47 wt. %.

Process

The process used will be close-coupled, catalytic-catalytic, two-stage coal liquefaction (CTSL by HRI) with ashy recycle, recycle of extract from the critical solvent deashing plant, and recycle of 850°F+ to extinction.

Maximum Reactor Size

The maximum size reactor will process a feed rate of 3,028 TPSD (MAF basis), producing 12,389 BPSD of liquid products (C_5-850°F). Five trains of the maximum size operating at capacity will be required to reach the proposed production of approximately 62,000 BPSD.

Nominal Reaction Conditions

Nominal coal liquefaction conditions will be:

Reactor Inlet Pressure, psig	3200
Reactor Outlet Pressure, psig	3000
Hydrogen Partial Pressure, psia (outlet of Stage 2 reactor)	1950
Coal Feed, lb MAF/lb catalyst	1.12
Solvent/Coal Ratio, (MAF wt. basis)	2.454
Solvent, wt.%	
Distillate (1000°F-)	38.0
Residuum (1000°F+)	49.9
Ash + Unconverted Coal	12.1
Slurry Tank Temperature, °F	400
Reaction Temperature, °F	
Stage 1	790
Stage 2	760

The Coal Feed Analysis is shown in Table 8.1.

Table 8.1

ANALYSIS OF FEED COAL TO LIQUEFACTION ILLINOIS NO. 6 (BURNING STAR MINE)

Proximate Analysis (wt. %, Dry Basis)	
Volatile Matter	42.2
Fixed Carbon	46.3
Ash	11.5
Ultimate Analysis (wt. %, Dry Basis)	
Carbon	71.0
Hydrogen	4.8
Sulfur	3.2
Nitrogen	1.4
Ash	11.5
Chlorine	0.1
Oxygen (by difference)	8.0
Sulfur Forms (wt. %, Dry Basis)	
Pyrite	1.0
Sulfitic	0.1
Organic	1.9
Ash Composition (wt. % oxidized)	
Phosphorus pentoxide, P_2O_5	0.2
Silica, SiO_2	49.8
Ferric Oxide, Fe_2O_3	17.6
Alumina, Al_2O_3	19.2
Titania, TiO_2	1.0
Lime, CaO	6.3
Magnesia, MgO	1.0
Sulfur Trioxide, SO_3	2.9
Potassium Oxide, K_2O	2.0
Sodium Oxide, Na_2O	0.5
Undetermined	-0.5

Catalyst and Catalyst Addition Rates

Catalyst for the coal liquefaction process will be Amocat 1C in both stages. The catalyst has a bulk density of 35 lb/cf. Catalyst addition rates are specified to be 3.0 lb of catalyst per ton of MAF coal feed for the first stage reactor and 1.5 lb of catalyst per ton of MAF coal feed for the second stage reactor.

Hydrogen Makeup

Makeup hydrogen gas is available at the pressure required for the coal liquefaction plant at a temperature of 110°F. The composition of the makeup hydrogen is approximately 99.0% (vol.) hydrogen and 1.0% (vol.) methane.

Yields

Yields from the coal liquefaction plant are presented in Table 8.2 below:

Table 8.2

COAL LIQUEFACTION YIELDS

Yields *Wt.% MAF Coal Feed	First Stage Outlet	Overall
H_2S	2.00	2.86
H_2O	7.10	9.51
NH_3	0.95	1.39
CO	0.04	0.06
CO_2	0.09	0.14
C_1	0.91	1.84
C_2	0.74	1.43
C_3	0.85	1.52
C_4	0.40	0.79
C_5-350°F	8.00	16.12
350-450°F	4.90	7.51
450-650°F	6.76	25.11
650-850°F	15.20	21.36
850-1000°F	18.52	0.66
1000°F+	26.80	8.39
Unconverted Coal	10.20	7.21
Phenols	0.24	0.30
Ash	12.96	12.96
Hydrogen Consumption	-3.70	-6.20

Product Quality

The API gravity of the product cuts from the first stage and second stage reactors is given in Table 8.3 below:

Table 8.3

PRODUCT QUALITY

Product Cuts	Gravity (°API) First Stage	Gravity (°API) Overall
C_5-350°F	44.5	45.5
350-450°F	24.5	25.0
450-650°F	13.5	14.0
650-850°F	5.0	6.0
850-1000°F	-1.6	-1.5
1000°F+	-11.5	-10.5

Design Considerations

The design of the slurry preparation system of the Coal Liquefaction Plant was based on the concept used in the Breckinridge Project.

The capacity of an individual train was determined by HRI and it was based on reactor diameter and weight considerations. The coal throughput using the maximum-sized reactors was based on the space velocity used in Wilsonville run 257E. The liquefaction of each section including primary separation was designed by HRI. The HRI design report is included in Section 8.6.

The process, except the reaction system and slurry and hydrogen preheat system, was modeled using Simulation Science's PROCESS simulation software. The model was used to develop equipment sizing, product separations, and utility requirements for those portions of the plant not provided by HRI. Sizing information supplied by HRI was used directly in the study. This included the slurry and hydrogen preheat system, the reactor system, the high pressure separations system, and the recycle hydrogen compressor.

The material balance was developed from the information provided by HRI and extended to the rest of the plant. The overall material balance for the plant is shown in subsection 8.2, Table 8.4.

The process was developed making maximum use of air-fin coolers and condensers to a process outlet temperature of 130°F. The cooling of hot process fluids by steam generation was utilized wherever possible. Most of the steam generated was at the 150 psig level.

The separation system was developed with a two pressure level configuration. Each pressure had three separators: hot at the reactor effluent temperature (760°F), warm at approximately 550 °F, and cold at 130°F. The three separators configuration improved the purity of the recycle hydrogen stream, reduced the amount of heavy material in the gas stream sent to Plant 3, and reduced the amount of gases sent to atmospheric fractionation.

The coil outlet temperatures of the atmospheric and vacuum heaters was maximized to tube coking limitations. The pressures in the two fractionation towers was set at the lowest level practical by overhead condensing and vacuum system limitations in order to achieve as high a bottoms cut point as possible.

Two separate flush oil systems have been incorporated in the design. The light flush oil is taken from the atmospheric tower sidestream and is used for flushing instruments in slurry service. The heavy flush oil is taken from the vacuum tower upper sidestream and is used for flushing the seals of pumps in slurry service.

8.1 Major Equipment Summary

The major equipment summary for Plant 2 is shown in Table 8.4.

Table 8.4 Major Equipment Summary

Plant 2 - Coal Liquefaction

Reactors and Vessels

Equipment No.	Equipment Description	Length (T-T in ft.)	Diameter (ID in ft.)	Material	Design Conditions Pres (psig)	Design Conditions Temp (°F)	Orientation	Comments
COAL SLURRY PREPARATION								
2.1- C101	Slurry Vortex Mx Tnk Innr Shll	11.0	11.0	A-515	10	750	Vertical	
	Slurry Vortex Mx Tnk Outr Shll	16.0	13.0	A-515	10	750	Vertical	
2.1- C102	Slurry Surge Tank	43.0	18.0	A-285	10	750	Vertical	
2.1- C103	Slurry Srge Tank Vent Scrubber	32.0	4.0	A-516	10	450	Vertical	
2.1- C104	Scrubber Overhead Receiver	9.0	3.0	A-516	10	400	Horizontal	
REACTION SYSTEM								
2.3- C105	Coal Liquefaction - Stage 1	85.5	15.0	2-1/4Cr, 1Mo	3300	600	Vertical	(1)
2.4- C106	Coal Liquefaction - Stage 2	85.5	15.0	2-1/4Cr, 1Mo	3300	600	Vertical	(1)
PRIMARY SEPARATION								
2.5- C107	Hot High Pressure Separator	22.5	10.5	SA387-GR22 CL2	3300	850	Vertical	(2)
2.5- C108	Hot Low Pressure Separator	26.0	9.5	CS	150	800	Vertical	
2.5- C109	Recycle Slurry Hold Drum	24.0	9.5	CS	50	800	Vertical	
2.5- C110	Warm High Pressure Separator	18.0	9.0	SA387-GR22 CL2	3300	600	Vertical	(3)
2.5- C111	Warm Low Pressure Separator	22.5	6.5	CS	100	500	Horizontal	
2.5- C112	Recy Slry Hold Drm Cond Accu	12.0	3.0	A-516	50	700	Horizontal	Boot: 1'D X 3'
2.5- C113	Cold High Pressure Separator	27.0	9.5	SA387-GR11 CL2	3300	450	Horizontal	(4)
2.5- C114	Cold Low Pressure Separator	26.0	8.5	CS	100	450	Horizontal	
2.5- C115	Wash Water Drum	24.5	7.0	CS	10	150	Horizontal	
2.5- C116	Sour Water Drum	26.5	7.5	CS	50	150	Horizontal	
2.5- C117	Compressor Knockout	13.0	6.5	Carbon Steel	3300	450	Vertical	

• NOTE: Equipment shown is for a single train. There are six total trains.

Table 8.4 Major Equipment Summary - continued

Reactors and Ve , cont.

Equipment No.	Equipment Description	Length (T-T in ft.)	Diameter (ID in ft.)	Material	Design Conditions Pres (psig)	Design Conditions Temp (°F)	Orientation	Comments
CRUDE PRODUCT FRACTIONATION-ATMOSPHERIC TOWER								
2.6- C120	Overhead Accumulator	26.0	6.5	CS	10	300	Horizontal	Boot: 2'D X 3'
2.6- C121	Vent Gas Compress Knockout	8.0	4.0	CS	10	200	Vertical	
2.6- C126	Feed Flash Drum	29.5	10.5	A-387	150	800	Vertical	
CRUDE PRODUCT FRACTIONATION-VACUUM TOWER								
2.6- C124	Vacuum Jet Condenser Accum	16.0	4.0	CS	10	400	Horizontal	
2.6- C125	Vent Gas Compress Knockout	8.0	4.0	CS	10	150	Vertical	

Comments:
(1) 11.6 thick, 1282 ST, 347 SS Overlay, 6" refractory lined
(2) 347 SS clad, refractory lined
(3) 347 SS clad
(4) 321 SS clad

Towers

Equipment No.	Equipment Description	Height (T-T in ft.)	Diameter (ID in ft.)	Material	Design Conditions Pres (psig)	Design Conditions Temp (°F)	No. of Trays	Type of Trays
CRUDE PRODUCT FRACTIONATION								
2.6- C118	Atmospheric Fractionator	150	Trays 1-16: 8'6	CS	50	800	16	Seive Tray: 410SS Internals
			Trays 17-22: Trans 8'6"X5'6"				6	Seive
			Trays 23-44: 5'6"				22	Seive
			Trays 45-48				4	Grid
2.6- C119	AGO Stripper	30	2'6"	CS	50	700	10	Seive Tray: 410SS Internals
2.6- C122	Vacuum Fractionator	60	Trays 1-18: 16'	A-516	FV / 10	800	18	Seive
			Trays 19,20: 6'6"				2	Grid
2.6- C123	Vac Recy Solvent Stripper	30	3'6"	CS	FV / 10	700	10	Seive

Table 8.4 Major Equipment Summary - continued

Fired heaters

Equipment No.	Equipment Description	Absorbed Duty (MM Btu/hr)	Fired Duty (MM Btu/hr)	Tube Material	Design Conditions Pres (psig)	Design Conditions Temp (°F)	
REACTION SYSTEM							
2.2- F101	Coal Slurry Heater	88	115	347 SS	3300	850	
2.3- F102	Gas Heater	44	57	347 SS	3300	850	
CRUDE PRODUCT FRACTIONATION							
2.6- F103	Atmospheric Fractionator Htr	19.9	25.6		200	800	Rad: 5 CR 1/2 MO Conv: CS
2.6- F104	Vacuum Fractionator Preheater	15.7	19.9		200	800	Rad: 5 CR 1/2 MO Conv: CS

Table 8.4 Major Equipment Summary - continued

Heat Exchangers

Equipment No.	Equipment Description	Duty (MM Btu/hr)	Type of Exchanger	No. Shells/ Area/Shell (sq ft)	Design Conditions Tube P/T (psig/°F)	Design Conditions Shell P/T (psig/°F)	Material of Construction Tube	Material of Construction Shell	Air-Fin BHP	Notes
COAL SLURRY PREPARATION										
2.1- E101	Recycle Slurry Steam Generator	34.5	Shell & Tube	1/ 3530	150 / 750	200 / 400	321 SS			
2.1- E102	Recycle Solvent Cooler	4.3	Air-Fin	1/ 955	150 / 450	10 / 250	316 SS		40	
2.1- E103	Slurry Srge Tank Overhead Con	6.5	Air-Fin	1/ 715	10 / 450	10 / 250	A-516 w/304 LSS Clad		40	
PRIMARY SEPARATION										
2.5- E104	Hot LP Sep Vap Cooler	3.6	Shell & Tube	1/ 640	100 / 650	150 / 800	SA516-70 w/304 LSS Clad			
								387 GR2 w/304 LSS Clad		
2.5- E105	Hot LP Sep Vap Steam Gen	11.0	Shell & Tube	1/ 1350	200 / 400	150 / 750		SA516 GR70		
2.5- E106	1st Hydrogen Preheater	24.7	Shell & Tube	1/ 2430	3500 / 250	3300 / 600	304 LSS	304 LSS 2-1/4 CR/MO Clad		
2.5- E107	2nd Hydrogen Preheater	60.5	Shell & Tube	1/ 6640	3500 / 400	3300 / 850	304 LSS	304 LSS 2-1/4 CR/1 MO Clad		
2.5- E108	Slurry Hold Drum Vap Cond	2.4	Air-Fin	1/ 460	50 / 800	10 / 250	316 LSS		40	
2.5- E109	Warm HP Sep Vap Cooler	100.5	Air-Fin	1/ 16020	3300 / 350	10 / 250	316 LSS		80	
2.5- E110	Warm LP Sep Vap Cooler	11.2	Air-Fin	1/ 1980	150 / 300	10 / 250	Monel		120	
CRUDE PRODUCT FRACTIONATION-ATMOSPHERIC TOWER										
2.6- E111	Atmos Frac Ovhd Condenser	36.3	Air-Fin	1/ 8410	10 / 300	10 / 250	CS		80	
2.6- E112	AGO Product Cross Exchanger	5.9	Shell & Tube	1/ 2730	100 / 400	100 / 450	CS	CS		
2.6- E113	AGO Product Cooler	7.0	Shell & Tube	1/ 1620	100 / 150	100 / 450	CS	CS		
2.6- E121	Atm VG Comp Aftercooler	0.5	Air-Fin	1/ 260	50 / 300	10 / 250	CS		40	
CRUDE PRODUCT FRACTIONATION-VACUUM TOWER										
2.6- E114	LVGO Pumparound Cooler	34.6	Air-Fin	1/11400	100 / 300	10 / 250	11-13 CR		40	(1)
2.6- E115	HVGO Pumparound Steam Gen	6.2	Shell & Tube	1/ 1610	100 / 700	200 / 400	11-13 CR	SA516		(2)
2.6- E116	HVGO Pumparound Cooler	1.7	Air-Fin	1/ 150	100 / 450	10 / 250	11-13 CR		40	(1)
2.6- E117	HVGO Product Steam Gen	3.9	Shell & Tube	1/ 1125	150 / 650	200 / 400	11-13 CR	SA516		
2.6- E118	Bottoms Product Steam Gen	30.3	Shell & Tube	1/ 6740	150 / 750	200 / 400	11-13 CR	SA516		
2.6- E119	1st Steam Jet Condenser	15.6	Shell & Tube	1/ 1550	100 / 150	10 / 400	11-13 CR			(2)
2.6- E120	2nd Steam Jet Condenser	0.08	Shell & Tube	1/ 10	100 / 150	10 / 400	11-13 CR			
2.6- E122	Vac VG Aftercooler	0.003	Shell & Tube	1/ 2	100 / 150	50 / 250	CS	CS		

Notes:
(1) Design tubes for full vacuum (FV)
(2) Design shell for full vacuum (FV)

Table 8.4 Major Equipment Summary - continued

Compressors

Equipment No.	Equipment Description	Case	Flow Rate (MMSCFD)	Brake Horsepower	Pres Inlet (psig)	Design Conditions Pres Outlet (psig)	Temp (°F)	Driver	# Required
PRIMARY SEPARATION									
2.7- K101	Recycle Hydrogen		176	1,086	2,935	3,235	150	Elect Motor	1
CRUDE PRODUCT FRACTIONATION									
2.6- K102	Atmospheric Vent Gas		0.4	25	1	15	180	Elect Motor	1
2.6- K103	Vacuum Vent Gas		0.03	2	2	15	200	Elect Motor	1

Pumps

Equipment No.	Equipment Description	Case	Flow Rate (gpm)	Delta Pres (psi)	Brake Horsepower	Design Conditions Pres (psig)	Temp (°F)	Driver	# Required
COAL SLURRY PREPARATION									
2.1- G101	Scrubber Condenser Product	316 SS	1	100	1	150	200	Elect Motor	2
2.1- G102	Scrubber Sour Water	316 SS	15	50	1	100	200	Elect Motor	2
2.1- G103	Coal Slurry Booster Pump	HC250 26% CHR	1100	70	70	100	450	Elect Motor	3
REACTION SYSTEM									
2.3- G105	Slurry Charge		535	3025	3450	3300	450	Elect Motor	4
2.3- G108	Stage 1 Ebullating	347 SS	----------	----------	Proprietary	----------	----------	----------	2
2.4- G109	Stage 2 Ebullating	347 SS	----------	----------	Proprietary	----------	----------	----------	2
PRIMARY SEPARATION									
2.5- G110	Slurry Recycle Pump	Monel	1625	95	120	150	800	Elect Motor	2
2.5- G111	Recy Slr Hld Drm Cnd Acm Liq	S-6	15	40	1	100	200	Elect Motor	2
2.5- G112	Recy Slr Hld Dr Cnd Ac Sr Wtr	C-6	1	40	1	100	200	Elect Motor	2
2.5- G113	Sour Water Drum Pump	C-6	630	35	20	100	200	Elect Motor	2
2.5- G114	Wash Water LP Pump	C-6	455	75	30	100	200	Elect Motor	2
2.5- G115	Wash Water HP Pump	C-6	215	3125	545	3400	200	Elect Motor	2

Table 8.4 Major Equipment Summary - continued

Pumps, cont.

Equipment No.	Equipment Description	Case	Flow Rate (gpm)	Delta Pres (psi)	Brake Horsepower	Design Conditions Pres (psig)	Design Conditions Temp (°F)	Driver	# Required
CRUDE PRODUCT FRACTIONATION-ATMOSPHERIC TOWER									
2.6- G116	Atmos Heater Charge	13 CR	1145	150	145	150	800	Elect Motor	2
2.6- G117	Reflux/Naphtha Product	S-5	370	50	15	100	200	Elect Motor	2
2.6- G118	AGO Product	S-6	120	45	5	100	450	Elect Motor	2
2.6- G119	Bottoms Product	13 CR	1110	150	140	200	750	Elect Motor	2
2.6- G120	Atmos Ovhd Accum Sour Wat	A-7	15	50	1	100	200	Elect Motor	2
CRUDE PRODUCT FRACTIONATION-VACUUM TOWER									
2.6- G121	LVGO Pumparound	C-6	1500	50	75	FV / 100	300	Elect Motor	2
2.6- G122	HVGO Pumparound	13CR Case 25	120	50	8	FV / 100	700	Elect Motor	2
2.6- G123	HVGO Product	13CR Case	85	100	8	FV / 150	650	Elect Motor	2
2.6- G124	Bottoms Product	13CR Case 25	455	100	45	FV / 150	750	Elect Motor	2
2.6- G125	Vacuum Jet Accum Sour Water	A-7	90	50	4	100	150	Elect Motor	2
2.6- G126	Vacuum Jet Accum Product	S-6	5	50	1	100	150	Elect Motor	2

Miscellaneous

Equipment No.	Equipment Description	Flow Rate	Other Design Criteria	Design Conditions Pres (psig)	Design Conditions Temp (°F)
COAL SLURRY PREPARATION					
2.1- T101	Coal Prewetting Feeder		22' X 41' X 31', 60 bhp		
2.1- Y101	Slurry Vortex Mix Tank Mixer		75 bhp		
2.1- Y102	Slurry Surge Tank Mixer		60 bhp		
REACTION SYSTEM					
2.9/2.10	Catalyst Handling System	-------------------------	Proprietary	-------------------------	
CRUDE PRODUCT FRACTIONATION-VACUUM TOWER					
2.6- H101	1st Vacuum Steam Jet	40000 lb/hr	area ratio = 50	200	400
2.6- H102	2nd Vacuum Steam Jet	200 lb/hr	area ratio = 25	200	400

8.2 Catalyst and Chemical Summary

Catalyst and chemicals required for Plant 2 are shown below:

Catalyst or Chemical	Amocat-1C, 1-1/2", Extrudate
Quantity required for start up	2,253,000 lb
Consumption	68,130 lb/day

8.3 On-Stream Factor

The expected on-stream factor for the Coal Liquefaction Plant, is 92.3%.

8.4 Operating Manpower Requirements

The operating manpower requirement for this plant is 40 operators. For full manpower requirements of this plant as well as the complex, refer to Section 40 of this report.

8.5 Plot Area Required

The plot area required for the Coal Liquefaction Plant is approximately 750 feet by 1,000 feet.

8.6 Capital Cost and Breakdowns

The field costs and breakdowns for Plant 2 are given below in Table 8.5. Note that field costs for each plant do not include home office costs or contingency. These were estimated for the whole complex and are given in Section 41.

Table 8.5

Plant 2 (Coal Liquefaction)
Field Costs and Breakdowns
2nd Quarter, 1991

Field Costs	Costs ($MM)	
Breakdown	First Plant	Nth Plant
Major Equipment	344.4	287.0
Bulk Materials	279.6	233.0
Subcontracts	20.4	17.0
Direct Labor	249.6	208.0
Distributables (Indirect)	224.6	187.2
Total Field Costs	**1118.6**	**932.2**

5 trains
1 SPARE

5 trains

9. Plant 3 (Gas Plant)

9.0 Design Basis, Criteria and Considerations

The Gas Plant consists of the following sections:

- Absorber/deethanizer
- Lean oil stripper/debutanizer
- Depropanizer
- LPG Merox for propane and butane products
- Makeup lean oil stripper

The original intent during design phase was to maximize the overall plant reliability of this complex. Therefore, every plant was designed for the maximum reliability. For this reason this plant was designed with two 50% capacity trains instead of one 100% capacity train.

However, after review of the overall cost estimate of the complex and the overall plant reliability of the entire complex, it was determined that this plant is not so critical in determining the overall plant reliability. Therefore, as reported here, the gas plant was treated as a single 100% capacity train plant for capital cost estimate.

Feed to the Gas Plant will be tail gas from the Hydrogen Purification Plant (Plant 6). Makeup lean oil is the naphtha product from Plant 2. Lean oil purge from the lean oil stripper/debutanizer will be sent to the Naphtha Hydrotreater (Plant 4). Lean oil stripper offgas is returned to Plant 6 for treating.

The products from the Gas Plant include:

- C_3 LPG
- C_4 LPG
- Fuel Gas

The specification for the two LPG products are as follows:

Specification	C_3 LPG Max.	C_4 LPG Max.
Ethane (vol.%)	2.0	--
Propane (vol.%)	--	2.0
Butane (vol.%)	2.0	--
Pentane (vol.%)	--	2.0
Mercaptans (wt.ppm)	20	20

Design Considerations

Lean oil absorption was used as the method to recover light hydrocarbons from miscellaneous gas streams being sent to the fuel gas system because of the high recovery of propane and butanes, smaller equipment sizes, and recovery without the need for a refrigeration system. The lean oil absorber and rich oil deethanizer operations were combined into a single tower to reduce capital and operating costs.

Naphtha product from the Coal Liquefaction Plant is used as the lean oil makeup. Because the makeup rate is close to the Plant 2 production rate, the total naphtha stream was sent to the Gas Plant. The lean oil purge (Stripper/Debutanizer bottoms) is sent as feed to the Naphtha Hydrotreater. This scheme simplifies the operation of the system and reduces the amount of light components in the feed to Plant 4. The makeup lean oil is stripped prior to entering the absorption system to remove ammonia and acid gases which may contaminate LPG products or fuel gas and light hydrocarbons which may be lost to fuel gas in the absorber overhead stream.

Some pentanes are lost to fuel gas in the absorber overhead vapor stream due to vapor-liquid equilibrium. A refrigerated cooler would be required to recover this lost material; however, little additional propane recovery would be made since the recovery rate is already quite good.

Plant 3 was modeled using the PROCESS simulation software. Equipment was sized using these simulations.

9.1 Major Equipment Summary

The major equipment summary for this plant is presented in Table 9.1.

Table 9.1 Major Equipment Summary

Plant 3 - Gas Plant

Reactors and Vessels

Equipment No.	Equipment Description	Length (T-T in ft.)	Diameter (ID in ft.)	Material	Design Conditions Pres (psig)	Design Conditions Temp (°F)	Orientation	Comments
3.1- C102	Abs/Deeth Ovhd Precontactor	32.0	9.5	A-516	250	150	Horizontal	
3.2- C104	Lean Oil Stripper Ovhd Accum	25.0	7.0	A-516	200	150	Horizontal	
3.3- C106	Depropanizer Ovhd Accum	18.0	5.0	A-516	350	150	Horizontal	
3.1- C108	LO Makeup Strp Ovhd Accum	14.0	4.5	A-516	100	150	Horizontal	Boot: 1'D X 3'

Towers

Equipment No.	Equipment Description	Height (T-T in ft.)	Diameter (ID in ft.)	Material	Design Conditions Pres (psig)	Design Conditions Temp (°F)	No. of Trays	Type of Trays
3.1- C101	Absorber/Deethanizer	100	8.0	A-516	250	400	48	Valve
3.2- C103	Lean Oil Stripper	100	9.0	A-516	200	500	44	Valve
3.3- C105	Depropanizer	100	5.0	A-516	350	250	48	Valve
3.1- C107	Lean Oil Makeup Stripper	20	6.5	A-516	100	400	10	Valve

Note: The equipment is for a single train of two train design.

Table 9.1 Major Equipment Summary - continued

Heat Exchangers

Equipment No.	Equipment Description	Duty (MM Btu/hr)	Type of Exchanger	No. Shells/ Area/Shell (sq ft)	Design Conditions Tube P/T (psig/°F)	Design Conditions Shell P/T (psig/°F)	Material of Construction Tube	Material of Construction Shell	Air-Fin BHP
3.1- E101	Absorb/Deeth Ovhd Cooler	7.0	Shell & Tube	1/ 4785	100 / 150	250 / 150	CS	CS	
3.1- E102	Absorb/Deeth Intercooler	1.6	Shell & Tube	1/ 1420	100 / 150	250 / 150	CS	CS	
3.1- E103	Absorb/Deeth Reboiler	77.3	Kettle	1/ 6510	700 / 550	250 / 400	CS	CS	
3.2- E104	Lean Oil Cooler	83.2	Air-Fin	1/ 11465	200 / 500	10 / 250	CS		120
3.2- E105	Lean Oil Str Ovhd Condenser	31.5	Shell & Tube	1/ 11075	100 / 150	200 / 150	CS	CS	
3.2- E106	Lean Oil Str Reboiler	43.6	Kettle	1/ 7935	700 / 550	200 / 500	CS	CS	
3.3- E107	Depropanizer Feed/Btms Exch	0.8	Shell & Tube	1/ 200	350 / 250	350 / 200	CS	CS	
3.3- E108	Depropanizer Ovhd Condenser	7.2	Shell & Tube	1/ 2970	100 / 150	350 / 150	CS	CS	
3.3- E109	Depropanizer Reboiler	7.8	Kettle	1/ 1160	100 / 350	350 / 250	CS	CS	
3.3- E110	Depropanizer Btms Cooler	0.5	Shell & Tube	1/ 195	100 / 150	350 / 200	CS	CS	
3.1- E111	LO Makeup Strp Ovhd Cond	10.0	Air-Fin	1/ 3430	100 / 250	10 / 250	CS		40
3.1- E112	LO Makeup Strp Reboiler	21.0	Kettle	1/ 2195	700 / 550	100 / 400	CS	CS	
3.1- E113	LO Makeup Strp 1st Btms Clr	11.1	Air-Fin	1/ 1835	300 / 400	10 / 250	CS		40
3.1- E114	LO Makeup Strp 2nd Btms Clr	1.2	Shell & Tube	1/ 775	100 / 150	250 / 150	CS	CS	
3.3- E115	Depropanizer Ovhd Cooler	0.4	Shell & Tube	1/ 220	100 / 150	350 / 150	CS	CS	

Pumps

Equipment No.	Equipment Description	Flow Rate (gpm)	Delta Pres (psi)	Brake Horsepower	Design Conditions Pres (psig)	Design Conditions Temp (°F)	Driver	# Required	Mat'l
3.1- G101	Absorb/Deeth Precontact Liq	1260	50	55	300	150	Elect Motor	2	CS/CI
3.1- G102	Intercooler Pumparound	1335	50	55	300	150	Elect Motor	2	CS/CI
3.2- G103	Lean Oil Strp Reflux	885	170	125	400	150	Elect Motor	2	CS
3.2- G104	Lean Oil Circulation	1005	65	55	250	150	Elect Motor	2	CS/CI
3.3- G105	Depropanizer Reflux	200	50	9	400	150	Elect Motor	2	CS
3.1- G106	LO Makeup Strp Reflux	140	50	6	150	150	Elect Motor	2	CS
3.1- G107	LO Makeup Strp Sour Water	5	10	1	100	150	Elect Motor	2	CS
3.1- G108	LO Makeup Strp Btms	260	190	45	300	400	Elect Motor	2	CS/CI

9.6 Capital Cost and Breakdowns

The field costs and breakdowns for Plant 3 are given below in Table 9.2. Note that field costs for each plant do not include home office costs or contingency. These were estimated for the whole complex and are given in Section 41. Because there is no spare train for this first plant, the costs numbers, as shown in the table below, are the same for the first plant and Nth plant.

TABLE 9.2

Plant 3 (Gas Plant)
Field Costs and Breakdowns
2nd Quarter, 1991

Field Costs	**Costs ($MM)**	
Breakdowns	First Plant	Nth Plant
Major Equipment	8.3	8.3
Bulk Materials	5.8	5.8
Subcontracts	0.9	0.9
Direct Labor	5.4	5.4
Distributables (Indirect)	4.9	4.9
Total Field Costs	**25.3**	**25.3**

10. Plant 4 (Naphtha Hydrotreater)

10.0 Design Basis, Criteria and Considerations

The original intent during design phase was to maximize the overall plant reliability of this complex. Therefore, every plant was designed for the maximum reliability. For this reason this plant was designed with two 50% capacity trains instead of one 100% capacity train.

However, after review of the overall cost estimate of the complex and the overall plant reliability of the entire complex, it was determined that this plant is not so critical in determining the overall plant reliability. Therefore, as reported here, the gas plant was treated as a single 100% capacity train plant for capital cost estimate.

Feed to the Naphtha Hydrotreater will be the naphtha (C_5-350° F) product from the atmospheric fractionator tower at the Coal Liquefaction Plant (Plant 2) via the Gas Plant (Plant 3).

Design criteria for the Naphtha Hydrotreater is based on the following:

Reactor Inlet Pressure, psig	1,000
Reactor Outlet Pressure, psig	950
Hydrogen Partial Pressure, psia (outlet of reactor)	700
Reactor Inlet Temperature, ° F	525
Reactor Outlet Temperature, ° F	575
Chemical Hydrogen Consumption, SCF/B	125
LHSV, V/V/hr	2.0
Catalyst Type	NiMo

Table 10.1
Feeds to the Naphtha Hydrotreater

	Plant 3 Naphtha	Plant 5 Naphtha	Plant 6 K.O
Feed Rate, BPSD	17,801	1,883	308
Component, lbs/hr			
C_1	0	2	4
C_2	0	4	14
C_3	0	98	50
C_4	202	910	118
C_5 - 350	204,078	19,146	2,786
350 - 450	3,258	1,526	350
450 - 650	26	0	0
Water	0	0	256
Total	**207,564**	**21,686**	**3,578**

Characteristics of the product from the Naphtha Hydrotreater is given in Table 10.2 below:

Table 10.2

Naphtha Hydrotreater Product

	C_5-350°F
Gravity, °API	52.2
Distillation, TBP °F	
IBP	72
5% (wt.)	110
10%	138
30%	207
50%	246
70%	284
90%	328
95%	340
EP	344
Sulfur, wppm (maximum)	1.0
Nitrogen, wppm (maximum)	0.2

Design Considerations

Because the Naphtha Hydrotreater is a vapor phase reaction, only cold separators (both high pressure and low pressure) are included in the design of the plant.

The naphtha stream from the Gas Oil Hydrotreater is sent directly to the Plant 4 fractionator because it has already been treated at more severe conditions than those in the Naphtha Hydrotreater.

The fractionator was designed to use 600 psig steam for the reboiler because the bottoms temperature is 450°F and to reduce capital costs.

10.1 Major Equipment Summary

The major equipment list for the Plant is shown in Table 10.3.

TABLE 10.2 MAJOR EQUIPMENT SUMMARY

EQUIPMENT SUMMARY
Plant 4 - Naphtha Hydrotreater

Reactors and Vessels

Equipment No.	Equipment Description	Length (T-T in ft.)	Diameter (ID in ft.)	Material	Design Conditions Pres (psig)	Design Conditions Temp (°F)	Orientation	Comments
4.1- C101	Hydrotreater Reactor	22.0	6.0	A-516	1100	650	Vertical	
4.1- C102	Hydrotreater Reactor	22.0	6.0	A-516	1100	650	Vertical	
4.1- C103	High Pressure Separator	18.0	6.0	A-516	1000	150	Horizontal	Boot: 2'D X 3'
4.1- C104	Compressor Knockout Drum	8.0	4.0	A-516	1000	150	Vertical	
4.1- C105	Low Pressure Separator	17.5	5.0	A-285	250	150	Horizontal	
4.2- C107	Fractionator Ovhd Accum	19.0	5.0	A-285	200	150	Horizontal	Boot: 1'5"D X 3'
4.1- C108	Wash Water Drum	12.0	3.0		10	150	Horizontal	1 for 2 trains
4.1- C109	Sour Water Drum	12.0	3.0		50	150	Horizontal	1 for 2 trains

Towers

Equipment No.	Equipment Description	Height (T-T in ft.)	Diameter (ID in ft.)	Material	Design Conditions Pres (psig)	Design Conditions Temp (°F)	No. of Trays	Type of Trays
4.1- C106	Fractionator	40	Trays 1-7: 4.5'	A-285	200	450	7	Valve
			Trays 8-10: Trans 5' X 4.5'				3	Valve
			Trays 11-19: 5'				9	Valve

Note: The equipment shown is for a single train. There are two (2) total trains.

TABLE 10.2 MAJOR EQUIPMENT SUMMARY - continued

Fired Heaters

Equipment No.	Equipment Description	Absorbed Duty (MM Btu/hr)	Fired Duty (MM Btu/hr)	Type of Heater	Tube Material	Design Conditions Pres (psig)	Design Conditions Temp (°F)
4.1- F101	Reactor Feed Preheater	33.4	36.7			1150	550

Heat Exchangers

Equipment No.	Equipment Description	Duty (MM Btu/hr)	Type of Exchanger	No. Shells/ Area/Shell (sq ft)	Design Conditions Tube P/T (psig/°F)	Design Conditions Shell P/T (psig/°F)	Material of Construction Tube	Material of Construction Shell	Air-Fi BHP
4.1- E101	Reactor Feed/Effluent Ex	11.1	Shell & Tube	1/ 915	1050 / 600	1150 / 350	CS	CS	
4.1- E102	Reactor Effluent Cooler	38.7	Air-Fin	1/ 5895	1050 / 400	10 / 250	CS		80
4.2- E103	Fractionator Condenser	8.5	Shell & Tube	1/ 1960	100 / 150	200 / 200	CS	CS	
4.2- E104	Fractionator Reboiler	9.7	Kettle	1/ 2615	650 / 550	200 / 450	CS	CS	
4.2- E105	Fractionator Feed/Bottoms Ex	18.1	Shell & Tube	1/ 11740	250 / 450	200 / 450	CS	CS	
4.2- E106	Fract Bottoms Prod Cooler	2.7	Shell & Tube	1/ 1320	100 / 150	200 / 200	CS	CS	

Compressors

Equipment No.	Equipment Description	Flow Rate (M lb/hr)	Flow Rate (MMSCFD)	Brake Horsepower	Design Conditions Pres Inlet (psig)	Design Conditions Pres Outlet (psig)	Design Conditions Temp (°F)	Driver
4.1- K101	Recycle Hydrogen	12.5	29.5	330	915	1075	170	Elect Motor

TABLE 10.2 MAJOR EQUIPMENT CUMMARY - continued

Pumps

Equipment No.	Equipment Description	Flow Rate (gpm)	Delta Pres (psi)	Brake Horsepower	Design Conditions Pres (psig)	Design Conditions Temp (°F)	Driver	# Required
4.1- G101	Reactor Charge Pump	275	1035	200	1150	150	Elect Motor	2
4.2- G102	Fractionator Reflux Pump	225	55	9	250	150	Elect Motor	2
4.1- G103	Sour Water Drum Pump	45	35	2	100	150	Elect Motor	2 (a)
4.1- G104	Wash Water Pump	40	950	30	1050	150	Elect Motor	2 (a)

Notes:

(a) Common to both trains

10.2 Catalyst and Chemical Summary

Catalyst and chemicals requirements for this plant is shown below:

Quantity required for start up	80,000 lb
Estimated catlayst life	3 years

10.3 On Stream Factor

The on-stream factor for the Naphtha Hydrotreater is expected to be 97.1%.

10.4 Operating Manpower Requirements

The operating manpower requirement for this plant is 8 operators. For full manpower requirements of this plant as well as the complex, refer to Section 40 of this report.

10.5 Plot Area Required

The plot area required for the Naphtha Hydrotreater Plant is approximately 150 feet by 200 feet.

10.6 Capital Cost and Breakdowns

The field costs and breakdowns for Plant 4 are given below in Table 10.4. Note that field costs for each plant do not include home office costs or contingency. These were estimated for the whole complex and are given in Section 41. Because there is no spare train for the first plant, the costs numbers, as shown in Table 10.4 below, or for the first and Nth plant are the same.

TABLE 10.4

Plant 4 (Naphtha Hydrotreater)
Field Costs and Breakdowns
2nd Quarter, 1991

Field Costs	**Costs ($MM)**	
Breakdowns	First Plant	Nth Plant
Major Equipment	5.2	5.2
Bulk Materials	3.5	3.5
Subcontracts	0.5	0.5
Direct Labor	3.4	3.4
Distributables (Indirect)	3.0	3.0
Total Field Costs	**15.6**	**15.6**

11.0 Plant 5 (Gas Oil Hydrotreater)

11.0 Design, Basis Criteria and Considerations

The original intent during the design phase was to maximize the overall plant reliability of this complex. Therefore, every plant was designed for the maximum reliability. For this reason this plant was designed with two 50% capacity trains instead of one 100% capacity train.

However, after review of the overall cost estimate of the complex and the overall plant reliability of the entire complex, it was determined that this plant is not so critical in determining the overall plant reliability. Therefore, as reported here, this plant was treated as a single 100% capacity train plant for capital cost estimate.

Feeds to the Gas Oil Hydrotreater are the distillate sidestream from the atmospheric tower and the overhead liquid and the upper sidestream from the vacuum tower of the Coal Liquefaction (Plant 2). The three products (350-450° F, 450-650° F, and 650-850° F) will be separated in a fractionator on the back-end of the unit.

Characteristics of the three feeds from Coal Liquefaction are presented in Table 11.1 below:

Table 11.1

Feeds to the Gas Oil Hydrotreater

	Atmospheric Sidestream	Vacuum Overhead	Vacuum Upper SS
Feed Rate, BPSD	39,164	68	47,684
Gravity, ° API	17.9	21.0	9.0
Product Cuts (wt.%)			
C_6-350° F	1.7	4.4	
350-450° F	24.7	50.5	0.1
450-650° F	58.0	45.1	37.3
650-850° F	15.6		62.6

Design criteria for the Gas Oil Hydrotreater is based on the following:

Reactor Inlet Pressure, psig	2,600
Reactor Outlet Pressure, psig	2,500
Hydrogen Partial Pressure, psia (outlet of reactor)	1,800
Reactor Inlet Temperature, °F	600
Reactor Outlet Temperature, °F	750
Chemical Hydrogen Consumption, SCF/B	1,080
LHSV, V/V/hr	1.0
Catalyst Type	NiMo

Characteristics of the products from the Gas Oil Hydrotreater are given in Table 11.2 below:

Table 11.2

Products from the Gas Oil Hydrotreater

	350-450°F	450-650°F	650-850°F
Gravity, °API	29.9	17.3	10.5
Distillation, TBP °F			
IBP	340	414	640
5% (wt.)	348	463	645
10%	358	469	665
30%	376	531	676
50%	399	576	717
70%	414	619	759
90%	433	645	815
95%	449	655	835
EP	465	665	838
Sulfur	20	20	20
Nitrogen	500	500	500

Design Considerations

Three final products (350-450°F, 450-650°F, and 650-850°F) were combined for hydrotreating in the same unit because of the reasons below:

- The reactions conditions recommended are approximately the same for the two heavier products and the lighter product is relatively small.
- Significant savings in capital cost and operating cost are realized by hydrotreating in a common unit even though final fractionation is more complex.
- The initial fractionation on the Coal Liquefaction Plant can be made as rough cuts and thus save capital and operating costs.

The reaction system was designed with parallel reactors and only one in series. Because of the reaction conditions, the reactors were designed with two catalyst beds with an interbed hydrogen quench.

The separation system was designed with high and low pressure systems, each with hot and cold separators. There was no incentive for a warm separator as in Plant 2. The letdown from the high pressure to the low pressure systems was done through an expander turbine to improve the efficiency of the process. The expander was designed to drive the reactor feed booster pump.

It was very difficult to fractionate all three products on the same tower; therefore, the 450°F- material was taken overhead in the fractionator to a small outboard stabilizer tower to make the front-end cut on the 350-450°F product. There was no problem fractionating the 450-650°F as a sidestream product or the 650-850°F as a bottoms product.

11.1 Major Equipment Summary

The major equipment summary is shown in Table 11.3.

TABLE 11.3 MAJOR EQUIPMENT SUMMARY

Plant 5 - Gas Oil Hydrotreater

Reactors and Vessels

Equipment No.	Equipment Description	Length (T-T in ft.)	Diameter (ID in ft.)	Material	Design Conditions Pres (psig)	Design Conditions Temp (°F)	Orientation	Comments
5.1- C101	Hydrotreater Reactor	30.0	12.0	A-387	2750	850	Vertical	
5.1- C102	Hydrotreater Reactor	30.0	12.0	A-387	2750	850	Vertical	
5.1- C103	Hot High Pressure Separator	30.5	6.0	A-387	2600	550	Vertical	
5.1- C104	Cold High Pressure Separator	15.5	4.0	A-387	2600	150	Horizontal	
5.1- C105	Hot Low Pressure Separator	24.5	7.0	A-285	150	450	Horizontal	
5.1- C106	Cold Low Pressure Separator	12.0	3.5	A-285	150	150	Horizontal	Boot: 1'D X 3'
5.1- C107	Wash Water Drum	14.0	4.0	CS	10	150	Horizontal	1 for 2 trains
5.1- C108	Sour Water Drum	14.0	4.0	CS	50	150	Horizontal	1 for 2 trains
5.1- C109	H2 Recycle Comp K.O. Drum	11.0	5.5	A-387	2600	200	Vertical	
5.2- C112	Fractionator Ovhd Accum (Hot)	34.5	9.0	CS	10	400	Horizontal	
5.2- C113	Fractionator Ovhd Accum (Cold)	14.0	4.5	CS	10	150	Horizontal	Boot: 2'D X 3'
5.2- C114	Frac Ovhd Vent Comp K.O. Drum	8.0	4.0	CS	10	150	Vertical	
5.2- C116	Stabilizer Ovhd Accum (Hot)	17.5	5.0	CS	50	350	Horizontal	
5.2- C117	Stabilizer Ovhd Accum (Cold)	9.0	3.0	CS	50	150	Horizontal	Boot: 1'D X 3'

Towers

Equipment No.	Equipment Description	Height (T-T in ft.)	Diameter (ID in ft.)	Material	Design Conditions Pres (psig)	Design Conditions Temp (°F)	No. of Trays	Type of Trays
5.2- C110	Fractionator	120	13.0	A-285	50	850	60	Valve
5.2- C111	AGO Product Stripper	20	5.0	A-285	50	750	10	Valve
5.2- C115	Distillate Product Stabilizer	60	Trays 1-10: 6.	A-285	50	550	10	Valve
			Trays 11-14:				4	
			Trans 8.0 X 6.0					
			Trays 15-30: 8.0				16	

TABLE 11.3 MAJOR EQUIPMENT SUMMARY - continued

Fired heaters

Equipment No.	Equipment Description	Absorbed Duty (MM Btu/hr)	Fired Duty (MM Btu/hr)	Type of Heater	Tube Material	Design Conditions Pres (psig)	Design Conditions Temp (°F)
5.1- F101	Hydrogen Preheater	6.7	8.4		T-347	2850	650
5.2- F102	Fractionator Reboiler	54.8	72.6		T-347	50	850

Heat Exchangers

Equipment No.	Equipment Description	Duty (MM Btu/hr)	Type of Exchanger	No. Shells/ Area/Shell (sq ft)	Design Conditions Tube P/T (psig/°F)	Design Conditions Shell P/T (psig/°F)	Material of Construction Tube	Material of Construction Shell	Air-Fin BHP
5.1- E101	Reactor Effl/Feed Preheater	50.4	Shell & Tube	1/ 4540	2650 / 800	2750 / 650	CS	CS	
5.1- E102	Reactor Effl/H2 Preheater	31.2	Shell & Tube	1/ 2930	2650 / 650	2850 / 550	CS	CS	
5.1- E103	Reactor Effl/HLPS Liquid	10.1	Shell & Tube	1/ 3045	150 / 550	2600 / 600	CS	CS	
5.1- E104	Hot HP Sep Vapor Cooler	55.5	Air-Fin	1/ 7475	2600 / 450	10 / 250	T-316L		80
5.1- E105	Hot LP Sep Vapor Cooler	4.0	Air-Fin	1/ 1045	150 / 300	10 / 250	CS		40
5.1- E106	Hot HP Sep Liq Steam Gen	12.0	Shell & Tube	1/ 4425	200 / 400	150 / 550	ADM	CS	
5.2- E107	Frac Ovhd Cond	44.0	Shell & Tube	1/ 2060	100 / 150	10 / 450	CS	CS	
5.2- E108	Frac Ovhd Vapor Cond	17.7	Air-Fin	1/ 3360	10 / 400	10 / 250	CS		40
5.2- E109	AGO Prod Steam Gen	5.5	Shell & Tube	1/ 1405	200 / 400	100 / 550	ADM	CS	
5.2- E110	AGO Prod Cooler	19.8	Air-Fin	1/ 4760	50 / 450	10 / 250	ADM		40
5.2- E111	Frac Bottoms/Feed Ex	14.5	Shell & Tube	1/ 4960	150 / 800	100 / 600	CS	CS	
5.2- E112	Frac Bottoms Steam Gen	4.8	Shell & Tube	1/ 1405	200 / 400	100 / 550	ADM	CS	
5.2- E113	Frac Bottoms Cooler	12.5	Air-Fin	1/ 3570	50 / 450	10 / 250	CS		40
5.2- E114	Distillate Stabilizer Cond	12.8	Shell & Tube	1/ 895	100 / 150	50 / 450	CS	CS	
5.2- E115	Dist Stabil Ovhd Vap Cooler	2.4	Air-Fin	1/ 390	50 / 350	10 / 250	CS		40
5.2- E116	Distillate Stabil Reboiler	23.7	Kettle	1/ 6650	650 / 550	50 / 550	CS	CS	
5.2- E117	1st Distillate Prod Cooler	8.3	Air-Fin	1/ 2015	150 / 500	10 / 250	CS	CS	40
5.2- E118	2nd Distillate Prod Cooler	0.5	Shell & Tube	1/ 725	100 / 150	150 / 150	CS	CS	
5.2- E119	Frac Ovhd Vent Comp Aftercooler	0.3	Shell & Tube	1/ 80	100 / 150	50 / 250	CS	CS	

Sheet 2

TABLE 11.3 MAJOR EQUIPMENT SUMMARY - continued

Compressors

Equipment No.	Equipment Description	Flow Rate (M lb/hr)	Flow Rate (MMSCFD)	Brake Horsepower	Design Conditions Pres Inlet (psig)	Pres Outlet (psig)	Temp (°F)	Driver
5.1- K101	Recycle Hydrogen	73.5	97.2	650	2450	2690	155	Elect Motor
5.2- K102	Fractionator Ovhd Vent	4.4	0.9	45	1	15	190	Elect Motor

Pumps/Expander

Equipment No.	Equipment Description	Flow Rate (gpm)	Delta Pres (psi)	Brake Horsepower	Design Conditions Pres (psig)	Temp (°F)	Driver	# Required
5.1- G101	Reactor Charge	700	2565	1325	2750	350	Expander	2 (a)
5.1- G102	Low Press Wash Water	85	100	8	150	150	Elect Motor	2 (b)
5.1- G103	High Press Wash Water	80	2400	150	2650	150	Elect Motor	2 (b)
5.1- G104	Sour Water Drum Outlet	100	35	3	100	150	Elect Motor	2 (b)
5.2- G105	Fractionator Reflux	765	100	65	150	400	Elect Motor	2
5.2- G106	Dist Stabilizer Feed	150	20	3	50	150	Elect Motor	2
5.2- G107	Frac Ovhd Sour Water	5	50	1	100	150	Elect Motor	2
5.2- G108	AGO Product	375	145	40	200	550	Elect Motor	2
5.2- G109	Fractionator Bottoms	265	90	20	150	800	Elect Motor	2
5.2- G110	Dist Stabilizer Reflux	215	35	7	100	350	Elect Motor	2
5.2- G111	Stabilizer Ovhd Liquid Prod	30	190	5	250	150	Elect Motor	2
5.2- G112	Stabilizer Ovhd Sour Water	1	40	1	100	150	Elect Motor	2
5.2- G113	Distillate Prod	140	80	10	150	500	Elect Motor	2
5.1- Y101	Hot HP Sep Liquid Expander	715	2350	-1325	2600	550	-	1

Notes:

(a) Spare w/ motor driver shared with second train
(b) Common to both trains

11.2 Catalyst and Chemical Summary

Catalyst and chemicals required for Plant 5 are shown below:

Catalyst or Chemical	Catalyst
Quantity required for start up	490,000 lb
Consumption or estimated life	3 year life

11.3 On-Stream Factor

The expected on-stream factor for the Gas Oil Hydrotreater is 97.1%.

11.4 Operating Manpower Requirements

The operating manpower requirement for this plant is 4 operators. For full manpower requirements of this plant as well as the complex, refer to Section 40 of this report.

11.5 Plot Area Required

The plot area required for the Coal Liquefaction Plant is approximately 200 feet by 300 feet.

11.6 Capital Cost and Breakdowns

The field costs and breakdowns for Plant 5 are given below in Table 11.4. Note that field costs for each plant do not include home office costs or contingency. These were estimated for the whole complex and are given in Section 41. Because there is no spare train for the first plant, the cost numbers, as shown in Table 11.4 below, for the first plant and Nth plant are the same.

TABLE 11.4

Plant 5 (Gas Oil Hydrotreater)
Field Costs and Breakdowns
2nd Quarter, 1991

Field Costs	**Costs ($MM)**	
Breakdowns	First Plant	Nth Plant
Major Equipment	24.8	24.8
Bulk Materials	16.9	16.9
Subcontracts	2.7	2.7
Direct Labor	15.6	15.6
Distributables (Indirect)	14.0	14.0
Total Field Costs	**74.0**	**74.0**

12. Plant 6 (Hydrogen Purification)

12.0 Design Basis, Criteria and Considerations

A centralized hydrogen purification unit is being proposed. The unit will have two major sections:

1. Recovery of hydrogen from high pressure purge gas from the five coal liquefaction plants and gas oil hydrotreater.
2. Recovery of hydrogen from lower pressure purge gas from five coal liquefaction plants, the gas plant and hydrotreaters.

The first section will take sour purge gas from the coal liquefaction plants and gas oil hydrotreater. The hydrogen-rich gas will be water-washed and amine-treated to remove ammonia, carbon dioxide, and hydrogen sulfide. Part of the scrubbed gas will be recycled to plant 2 and the rest will be sent to membrane units for hydrogen recovery. This process was selected because the pressure of the hydrogen product is much higher than for a pressure swing absorber, thus saving recompression costs (both capital and operating). The hydrogen product at a minimum purity level of 99.0 mol% and H_2 product from PSA unit and will be compressed to required pressure. The nonpermeate product will be sent to the PSA unit.

The second section of the plant is fed compressed and treated low pressure gas from the overhead of the Plants 2, 3, 4, and 5. Pressure swing absorption will be used for this service because of the high recovery of hydrogen and because the feed gas pressure is consistent with the point of maximum recovery of hydrogen. The hydrogen product at a minimum of 99.0 mol% purity will be compressed and combined with the hydrogen product from the membrane unit. The light hydrocarbon tail gas stream will be sent to the Gas Plant.

The original flow scheme for the Hydrogen Purification Plant was for the compression and treating of the low pressure gases be done in the Gas Plant with the absorber/deethanizer overhead stream being sent to Plant 6 for hydrogen recovery in the pressure swing absorption (PSA) unit. Because the low pressure gases contained a high percentage of hydrogen and the resultant vapor-liquid equilibrium considerations, it was impossible to obtain an acceptable recovery of propane and butanes in the absorber/deethanizer. Therefore, the flow scheme was switched to place the PSA unit before the absorber/deethanizer. This then caused the move of the compression and treating of the low pressure gases to Plant 6.

The high pressure hydrogen purge streams were sent to a membrane unit for hydrogen recovery rather than a PSA unit because the membrane can better accept a high pressure feed stream, resulting in a higher pressure hydrogen product. This saved hydrogen compression costs. The PSA unit was preferred in the low pressure service because of the higher hydrogen recovery and lower pressure drop in the system. This also saved hydrogen compression costs.

The first stage hydrogen compression on the PSA product exited at the outlet pressure of the membrane unit. The two hydrogen streams were combined before being compressed to the required pressure. This saved capital costs.

12.1 Major Equipment Summary

The major equipment list for the plant is shown in Table 12.1.

Table 12.1

11/18/91

Major Equipment Summary

Plant 6 - Hydrogen Purification

Reactors and Vessels

Equipment No.	Equipment Description	Length (T-T in ft.)	Diameter (ID in ft.)	Material	Design Conditions Pres (psig)	Temp (°F)	Orientation	Comments	# Req
6.2- C101	1st Stg PSA Feed Comp K.O.	8.0	4.0	CS	50	150	Vertical		2
6.2- C102	2nd Stg PSA Feed Comp K.O.	8.0	4.0	CS	100	150	Vertical		2
6.2- C105	IP Amine Trt Abs Inlet Sep	8.0	4.0	CS	300	150	Vertical		2
6.2- C107	IP Amine Trt Abs Outlet Sep	8.0	4.0	CS	300	150	Vertical		2
6.1- C108	HP Amine Trt Abs Inlet Sep	11.0	5.5	A-515	1650	150	Vertical		2
6.1- C110	HP Amine Trt Abs Outlet Sep	11.0	5.5	A-515	1650	150	Vertical		2
6.2- C111	Combined Amine Btms Sep	14.0	4.0	A-515	1650	150	Horizontal		2
6.2- C113	Amine Regen Ovhd Accum	12.0	4.0	A-516-70	50	200	Horizontal		2
6.2- C114	Regen Amine Surge Drum	8.0	4.0	A-516-70	300	150	Vertical		2
6.2- C116	1st Stg PSA TG Comp K.O.	8.0	4.0	A-516	50	150	Vertical		2
6.2- C117	2nd Stg PSA TG Comp K.O.	8.0	4.0	A-516	100	150	Vertical		2
6.2- C118	1st Stg H2 Comp K.O.	8.0	4.0	A-516	300	150	Vertical		3
6.1- C119	2nd Stg H2 Comp K.O.	11.0	5.5	A-515	550	150	Vertical		3
6.1- C120	3rd Stg H2 Comp K.O.	11.0	5.5	A-515	1400	150	Vertical		3

Tanks

Equipment No.	Equipment Description	Height (T-T in ft.)	Diameter (ID in ft.)	Material	Design Conditions Pres (psig)	Temp (°F)	Orientation	Comments	# Req
6.2- C115	Makeup Amine Tank	30.0	22.0	A-516-70	5	150	Vertical		1

Sheet 1

Table 12.1 Major Equipment Summary - continued

Towers

Equipment No.	Equipment Description	Height (T-T in ft.)	Diameter (ID in ft.)	Material	Design Conditions Pres (psig)	Design Conditions Temp (°F)	No. of Trays	Type of Trays	# Req
6.2- C103	IP Water Wash Tower	16	4.0	CS	300	150	8	Valve	2
6.1- C104	HP Water Wash Tower	16	3.0	A-515	1650	150	8	Valve	2
6.2- C106	IP Amine Absorber	32	4.0	CS	300	150	16	Valve	2
6.1- C109	HP Amine Absorber	32	3.0	A-515	1650	150	16	Valve	2
6.2- C112	Amine Regenerator	32	4.5	SA-516-70	50	300	16	Valve	2

Heat Exchangers

Equipment No.	Equipment Description	Duty (MM Btu/hr)	Type of Exchanger	No. Shells/ Area/Shell (sq ft)	Design Conditions Tube P/T (psig/°F)	Design Conditions Shell P/T (psig/°F)	Material of Construction Tube	Material of Construction Shell	Air-Fin BHP	# Req
6.2- E101	PSA Feed Comp Intercooler	0.7	Air-Fin	1/ 725	100 / 250	10 / 250	CS		40	2
6.2- E102	PSA Feed Comp Aftercooler	14.8	Air-Fin	1/ 2950	300 / 400	10 / 250	CS		40	2
6.2- E103	Amine Regen Condenser	20.4	Shell & Tube	1/ 1735	100 / 150	50 / 300	CS	CS		2
6.2- E104	Amine Regenerator Reboiler	25.0	Kettle	1/ 3150	100 / 350	50 / 300	304-LSS	CS		2
6.2- E105	Lean/Rich Amine Exchanger	4.7	Shell & Tube	1/ 3870	300 / 300	300 / 300	CS	CS		2
6.2- E106	Lean Amine Cooler	1.2	Shell & Tube	1/ 450	100 / 150	300 / 150	CS	CS		2
6.2- E107	PSA TG Comp Intercooler	8.7	Air-Fin	1/ 3395	100 / 350	10 / 250	CS		40	2
6.2- E108	PSA TG Comp 1st Aftercooler	8.9	Air-Fin	1/ 2880	300 / 300	10 / 250	CS		40	2
6.2- E109	PSA TG Comp 2nd Aftercooler	3.3	Shell & Tube	1/ 4150	100 / 150	250 / 150	CS	CS		2
6.2- E110	1st Stg H2 Comp Intercooler	4.3	Air-Fin	1/ 920	600 / 400	10 / 250	CS		40	3
6.1- E111	2nd Stg H2 Comp Intercooler	19.2	Air-Fin	1/ 2800	1400 / 400	10 / 250	CS		40	3
6.1- E112	3rd Stg H2 Comp 1st Afterclr	19.6	Air-Fin	1/ 2830	3500 / 400	10 / 250	CS		40	3
6.1- E113	3rd Stg H2 Comp 2nd Afterclr	2.4	Shell & Tube	1/ 2705	100 / 150	3500 / 150	CS			3

Table 12.1 Major Equipment Summary - continued

Compressors

Equipment No.	Equipment Description	Flow Rate (M lb/hr)	Flow Rate (MMSCFD)	Brake Horsepower	Design Conditions Pres Inlet (psig)	Design Conditions Pres Outlet (psig)	Design Conditions Temp (°F)	Driver	# Req
6.2- K101	1st Stg PSA Feed Compressor	9.4	2.2	145	10	50	250	Elect Motor	2
6.2- K102	2nd Stg PSA Feed Compressor	65.8	41.4	4810	45	250	400	Elect Motor	2
6.2- K103	1st Stg PSA TG Compressor	84.6	30.6	3190	5	65	350	Elect Motor	2
6.2- K104	2nd Stg PSA TG Compressor	82.9	30.5	2500	60	220	300	Elect Motor	2
6.2- K105	1st Stage H2 Compressor	6.1	25.7	1615	220	510	350	Elect Motor	3
6.1- K106	2nd Stage H2 Compressor	24.2	102.2	7670	500	1300	400	Elect Motor	3
6.1- K107	3rd Stage H2 Compressor	24.2	102.2	7940	1295	3300	400	Elect Motor	3

Pumps

Equipment No.	Equipment Description	Flow Rate (gpm)	Delta Pres (psi)	Brake Horsepower	Design Conditions Pres (psig)	Design Conditions Temp (°F)	Driver	# Req	Material
6.2- G101	IP Amine Pump	90	230	20	300	300	Elect Motor	2	CS
6.2- G102	HP Amine Pump	20	1300	20	1650	150	Elect Motor	2	CS
6.2- G103	Amine Makeup Pump	25	50	1	100	150	Elect Motor	2	CS
6.2- G104	Amine Regen Reflux Pump	45	50	2	100	200	Elect Motor	2	CS

Miscellaneous

Equipment No.	Equipment Description	Flow Rate	Other Design Criteria	Design Conditions Pres (psig)	Design Conditions Temp (°F)	# Req
6.2- Y101	Rich Amine Mech Filter		5'TT X 1.5'D	300	300	2
6.2- Y102	Lean Amine Mech Filter		5'TT X 1.5'D	300	150	2
6.2- Y103	Lean Amine Carbon Filter		10.5'TT X 3.5'D	300	150	2
6.1- V101	Membrane Unit		Proprietary			2 trains
6.2- V102	PSA Unit		Proprietary			one 10 bed unit

12.2 Catalyst and Chemical Summary

The primary chemical used in Plant 6 is monoethanol amine (MEA).

Quantity required for start up	1,200 bbl
Consumption	30 gal/day

12.3 On-Stream Factor

The on-stream factor for the Hydrogen Purification Plant is expected to be 97.1%.

12.4 Operating Manpower Requirements

The operating manpower requirement for this plant is 12 operators. For full manpower requirements of this plant as well as the complex, refer to Section 40 of this report.

12.5 Plot Area Required

The plot area required for the Hydrogen Purification Plant is approximately 300 feet by 350 feet.

12.6 Capital Cost and Breakdowns (First & Nth Plant)

The field costs and breakdowns for Plant 6 are given below in Table 12.2. Note that field costs for each plant do not include home office costs or contingency. These were estimated for the whole complex and are given in Section 41. Because there is no spare train for the first plant, the cost numbers, as shown in Table 12.2 below, for the first plant and Nth plant are the same.

Table 12.2

Plant 6 (Hydrogen Purification)
Field Costs and Breakdowns
2nd Quarter, 1991

Field Costs	**Costs ($MM)**	
Breakdowns	First Plant	Nth Plant
Major Equipment	61.0	61.0
Bulk Materials	31.0	31.0
Subcontracts	3.6	3.6
Direct Labor	30.0	30.0
Distributables (Indirect)	27.0	27.0
Total Field Costs	**152.6**	**152.6**

13. Plant 8 (Critical Solvent Deashing Unit - ROSE-SR)

13.0 Design Basis, Criteria and Considerations

Feed Rate, BPSD 50,800

	Composition, wt%	
Component	Feed [(1)]	Ash Concentrate [(2)]
Ash	17.60	40.50
Carbon	73.80	51.66
Hydrogen	6.21	3.54
Nitrogen	0.78	0.83
Sulfur	1.61	3.47
Total	100.00	100.00

(1) Contains unconverted coal 9.8 wt% and solvent 0.9 wt%
(2) Contains unconverted coal 24.2 wt% and solvent 3.1 wt%

13.1 Major Equipment List

Equipment Number	Equipment Description
8 - C101	Asphaltene Separator
8 - C102	Flash Tower
8 - C103	DAO Separator
8 - C104	Solvent Stripper
8 - C105	Solvent Surge Drum
8 - E101	Solvent/DAO Solution Exchanger
8 - E102	Solvent Cooler
8 - E103	Solvent Condenser
8 - G101	Solvent Circulation Pump
8 - G102	Recycle Solvent Pump
8 - F101	Ash Concentrate Heater
8 - F102	Extract Heater
8 - Y101	Feed/Solvent Mixer

13.2 Catalyst and Chemical Summary

Catalyst and chemicals required for this plant is shown below:

Catalyst or Chemical	ROSE Solvent
Quantity required for start up	10,000 bbl
Consumption	300 gal/day

13.3 On-Stream Factor

The on-stream factor for the ROSE-SR unit is in excess of 95%.

13.4 Operating Manpower Requirements

The operating manpower requirement for this plant is 9 operators. For full manpower requirements of this plant as well as the complex, refer to Section 40 of this report.

13.5 Plot Area Required

The plot area required for the Critical Solvent Deashing Unit is approximately 75 feet by 150 feet.

13.6 Capital Cost and Breakdowns (First & Nth Plant)

The field costs and breakdowns for Plant 8 are given below in Table 13.1. Note that field costs for each plant do not include home office costs or contingency. These were estimated for the whole complex and are given in Section 41. Because there is no spare train for the first plant, the cost numbers, as shown in Table 13.1 below, for the first plant and Nth plant are the same.

TABLE 13.1

Plant 8 (Critical Solvent Deashing)
Field Costs and Breakdowns
2nd Quarter, 1991

Field Costs	**Costs ($MM)**	
Breakdowns	First Plant	Nth Plant
Major Equipment	13.0	13.0
Bulk Materials	10.0	10.0
Subcontracts	4.0	4.0
Direct Labor	8.0	8.0
Distributables (Indirect)	7.2	7.2
Total Field Costs	**42.2**	**42.2**

14. Plant 9 (Hydrogen Production by Coal Gasification)

14.0 Design Basis, Criteria and Considerations

Plant 9 is designed to gasify 4,386 tons/day of Ash Concentrate from ROSE-SR Plant and 5,614 tons/day of coal. Most of the syngas from the gasifiers is used to produce 416 MMSCFD of 99.9 volume percent hydrogen product used for the coal liquefaction and hydrotreating plants. Syngas in excess of the above requirement is used for medium Btu fuel gas.

<u>Feed Streams</u>

- 4,424 TPD ash concentrate from Plant 8 (ROSE-SR)
- 6,127 TPD clean MF coal from Plant 1 (Coal Preparation)
- 8,962 TPD of 99.5 volume percent oxygen from Plant 10 (Air Separation)

Feed analysis and compositions are presented in Table 14.1.

<u>Product Streams</u>

- 416 MMSCFD of 99.9 volume percent hydrogen
- 94 MMSCFD of medium Btu fuel gas
- 27 MMSCFD of acid gas containing H_2S as feed to Sulfur Plant (Plant 11)
- 414 MMSCFD of stripped CO_2 waste gas for discharge to the atmosphere
- 2812 TPD (dry basis) of slag and soot to landfill disposal

Product compositions are presented in Table 14.2.

<u>Gasifier Yields</u>

- For ash concentrate, 33.4 SCF of CO + H_2 and 8 SCF of CO_2 per pound of dry and ash-free feed
- For clean coal, 31.5 SCF of CO+H_2 and 7.2 SCF of CO_2 per pound of dry and ash-free feed
- Average about 97% carbon conversion to syngas. Unconverted carbon is rejected with slag

TABLE 14.1

GASIFICATION FEED STREAMS

Illinois No.6 Coal

Ultimate Analysis, %(wt.), Dry Basis

Carbon	71.0
Hydrogen	4.8
Nitrogen	1.4
Sulfur	3.2
Oxygen	8.1
Ash	11.5
HHV, Btu/lb	10,951

Ash Mineral Analysis, % (wt.)

SiO_2	49.8
Fe_2O_3	17.6
Al_2O_3	19.2
TiO_3	1.0
CaO	6.3
MgO	1.0
SO_3	2.9
K_2O	2.0
Na_2O	0.5
P_2O_5	0.2
Undetermined	-0.5

Ash Concentrate

Composition, % (wt.)

850-1000°F	2.3
1000°F+	28.7
Unconverted Coal	24.7
Ash	44.3

HHV, Btu/lb 8,457

Ultimate Analysis, % (wt.), Dry Basis

Carbon	48.3
Hydrogen	2.9
Nitrogen	1.1
Sulfur	3.1
Oxygen	0.3
Ash	44.3

TABLE 14.2

PRODUCT DATA

	H_2 Product Mol %	Medium Btu Gas Mol%	H_2S-Rich Off-Gas Mol.%	CO_2 Off-Gas Mol %
H_2O	0.0	0.0	0.45	1.81
H_2	99.90	85.11	2.79	0.43
CO	0.0	6.95	2.19	0.09
CO_2	0.0	2.33	64.49	89.91
$AR+N_2$	0.10	5.16	1.51	7.75
C_1	0.0	0.45	0.01	0.01
H_2S	0.0	0.0	28.50	0.0
COS	0.0	0.0	0.06	0.0
Total				
#-Mol/hr	45,676	10,309	3,007	45,444
MMSCFD	416	94	27	414

14.0.1 Technology Selection

Two coal gasification technologies, the Texaco and Shell processes, have been evaluated for synthesis gas production in Plant 9. The block flow diagrams for these two processes are presented on Figure 14.1.

The major differences between these two processes are as follows:

	Texaco	Shell
1.	Feed Type	
	Molten coal or coal slurry	Dried and pulverized coal to 70-90% through 200 mesh
2.	Operating Conditions	
	High pressure process. Pressure up to 1100 psig	Low to medium pressure process. Pressure up to 400 psig
3.	Gasifier Construction	
	Vertical cylindrical pressure vessel with refractory lining	Horizontal ellipsoidal vessel. Gasifier shell has a double-walled construction, the inner shell is refractory lined
4.	Heat Removal Methods	
	Direct quench syngas with water in the gasifier and gas scrubber	Recover heat by generating steam in the waste heat boilers
5.	Shift Conversion	
	Produce sufficient steam in the syngas for shift reaction	Steam injection is required for shift reaction to occur
6.	Hydrogen Production	
	Produces higher H_2/CO ratio (0.75) syngas. Less shift conversion required.	Produces low H_2/CO ratio (0.43) syngas which requires more shift catalyst for shift conversion to reach the same H_2 production.

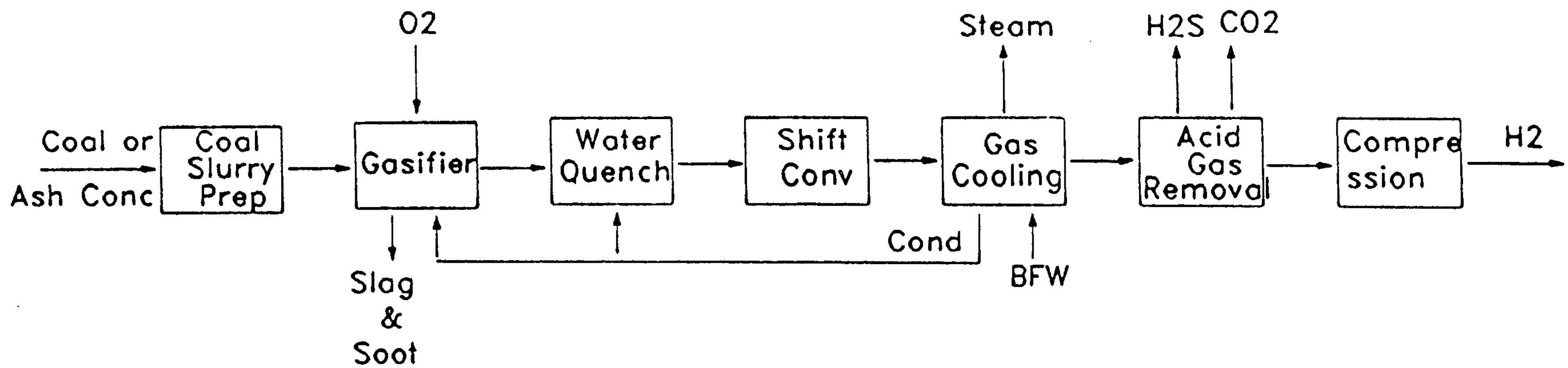
	Texaco	Shell
7.	Horsepower for Hydrogen Compression	
	Higher pressure process. Less horsepower required	Low pressure process requires more horsepower for hydrogen compression
8.	Water Requirement	
	Relatively poor quality condensate from the gas cooling sections can be used for direct quenching of syngas	More boiler feed water of higher quality is required for steam generation in the gasifier and waste heat boiler
9.	Ability to Handle ROSE bottoms	
	Its pilot plant had demonstrated that the ash-containing residues obtained from the H-Coal liquefaction plant were process efficiently	No pilot plant result has been reported for H-Coal liquefaction residues
10.	Commercial Plant Experience	
	Several large size commercial plants have been operated successfully since 1980's	Only small demonstration plants have been built

For high pressure hydrogen production, Texaco's gasification process has lower capital and utility costs, and has showed it can process H-Coal liquefaction vacuum tower bottoms, as well as ROSE-SR ash concentrate, successfully. (Reference: Texaco report DE-84-013199, February 1984). Therefore, the Texaco technology is recommended for this project as the gasification process for Plant 9.

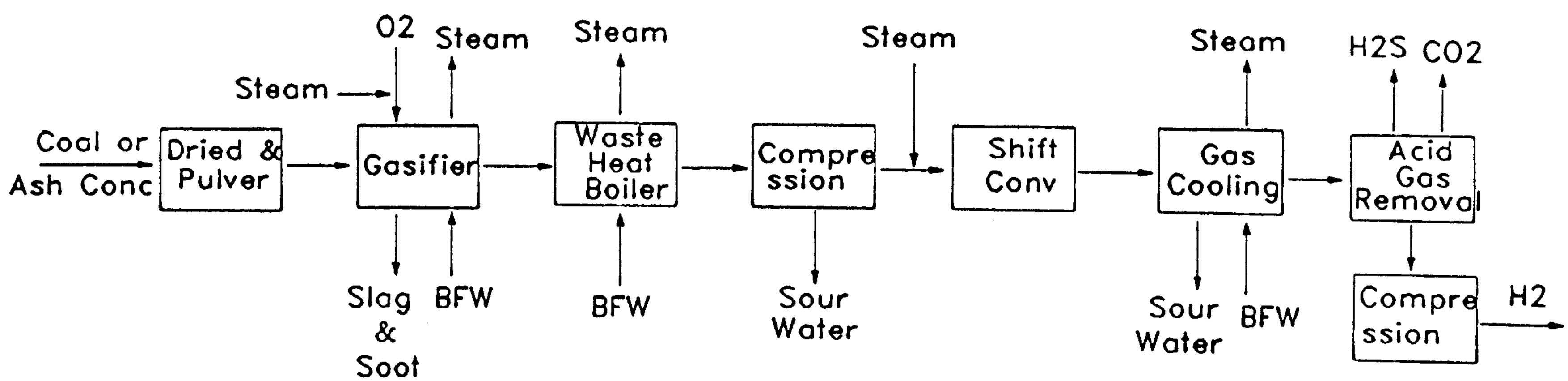
FIGURE 14.1

Block Flow Diagram – Hydrogen Production by Coal Gasification

Scheme 1 – Texaco Gasification



Scheme 2 – Shell Gasification



14.0.2 Design Considerations

The limiting size for the gasifier reactors was taken as 2,200 TPD of coal or ash concentrate. This is larger than any reactors which have been designed and built to date; however, Texaco has stated that designing this size of gasifier is achievable.

The shift reaction was designed to maximize hydrogen production. The shift reactor vessels were limited in size to 16 feet outside diameter for shop fabrication and transportation considerations.

The RECTISOL process was chosen because it has been commercially proven in this service. The process can separate carbon dioxide from hydrogen sulfide as a relatively pure stream for venting to the atmosphere. The hydrogen sulfide is sent to the Sulfur Plant. PSA is required after RECTISOL to achieve the required hydrogen purity.

14.1 Major Equipment List

The major equipment for this plant is listed in Table 14.3.

14.2 Catalyst and Chemical Summary

Catalyst and chemicals required for Plant 9 are shown below:

Catalyst or Chemical	BASF K8-11 or Haldor Topsoe SSK Catalyst
Quantity required for start up	19,000 ft^3
Consumption	3 year life

Table 14.3

Major Equipment List

Plant 9 – Coal Gasification & Shift Conversion

Type of Equipment: Reactors and Vessels

Equipment No.	Equipment Description	Number Required	Material
9.1–C101	Gasifier	6 ~~7~~	CS W/ SS Clad
9.1–C102	Slag Lock Hopper	6 ~~7~~	CS W/ SS Clad
9.1–C103	Gas Scrubber	7	CS W/ SS Clad
9.2–C104	No.1 Gas Separator	5	CS W/ SS Clad
9.2–C105	First Stage Shift Reactor	5	CS W/ SS Clad
9.2–C106	Second Stage Shift Reactor	5	CS W/ SS Clad
9.2–C107	No.2 Gas Separator	5	CS W/ SS Clad
9.2–C108	No.3 Gas Separator	5	CS W/ SS Clad
9.2–C109	Third Stage Shift Reactor	5	CS W/ SS Clad
9.2–C110	Final Gas Separator	5	CS W/ SS Clad
9.2–C111	Mercury Guard Drum	5	CS W/ SS Clad
9.1–C112	Flash Condensate Separator	3	SS
9.2–C113	Hot Condensate drum	5	CS W/ SS Clad
9.2–C114	Warm Condensate Drum	5	CS W/ SS Clad
9.1–C115	Soot Slurry Flash Drum	5	SS
9.1–C116	Vacuum Pump Separator	5	SS
9.1–C118	Vacuum Flash Drum	5	SS

Table 14.3 Major Equipment List - continued

Type of Equipment: Reactors and Vessels

Equipment No.	Equipment Description	Number Required	Material
9.1–C119	Filtrate Receiver	5	SS
9.1–C121	Blowdown Drum	3	CS
9.1–C123	Burner CW Gas Separator	5	CS
9.1–C124	Flash Water Drum	5	CS w/ Epoxy
9.1–D101	Mill Discharge Tank w/Mixer	15	CS w/ Epoxy Lining
9.1–D102	Additive Storage Tank	5	CS w/ Epoxy Lining
9.1–D103	Water Supply Tank	5	CS
9.1–D104	Slurry Run Tank w/Mixer	15	CS w/ Epoxy Lining
9.1–D105	Gray Water Tank	5	CS w/ Epoxy Lining
9.1–D106	Filter Feed Tank w/Mixer	5	SS
9.1–D107	Burner Cooling Water Tank	5	CS
9.1–D108	Vent Scrubber Tank	3	CS

Table 14.3 Major Equipment List - continued

Type of Equipment: Towers

Equipment No.	Equipment Description	Number Required	Material
9.1-C117	Flash Gas Quencher	5	SS
9.1-D120	Vent Air Separator	3	CS
9.1-D122	Vent Air Quencher	3	CS

Table 14.3 Major Equipment List - continued

Type of Equipment: Heat Exchangers

Equipment No.	Equipment Description	Number Required	Material Shell	Material Tube
9.1-E101	Mill Water Heater	5	CS	CS
9.1-E102	Flash water Cooler	10	CS	SS
9.1-E103	Make up Water Cooler	5	CS	CS
9.1-E104	Burner CW Cooler	5	CS	CS
9.2-E105	Shift Reactor Preheater	5	Alloy Clad	SS
9.2-E106	No.1 Steam Generator	5	CS	Alloy
9.2-E107	No.2 Steam Generator	5	CS	SS
9.2-E108	No.5 Steam Generator	5	CS	SS
9.2-E109	No.5 Gas Cooler	5	CS	SS
9.2-E110	Shift Gas Air Cooler	5		SS
9.2-E111	Gas Final Cooler	5	CS	SS
9.2-E112	Hg Guard Preheater	5	CS	SS
9.2-E113	No.4 Steam Generator	5	CS	SS
9.1-E114	Soot Slurry Steam Generator	5	CS	SS
9.1-E115	Soot Slurry cooler	5	CS	SS
9.1-E116	Flash Gas Cooler	6	CS	CS
9.1-E117	Gray Water Preheater	10	CS	CS
9.1-E118	Flash Quench Cooler	10	CS	CS
9.1-E119	Vent Air Quench Cooler	6	CS	CS
9.1-E120	Steam Blowdown Cooler	3	CS	CS
9.2-E121	Shift Gas Cooler	5	CS	SS
9.2-E122	No.3 Steam Generator	5	CS	SS

Table 14.3 Major Equipment List - continued

Type of Equipment: Pumps

Equipment No.	Equipment Description	Number Required	Case Material
9.1-G101	Mill Slurry Pump	15	CS
9.1-G102	Slurry Feed Pump	15	CS
9.1-G103	Gas Scrubber Circulation pump	14	CS
9.2-G104	Hot Condensate Pump	10	CS
9.2-G105	Warm Condensate Pump	10	CS
9.2-G106	Gray Water Pump	10	CS
9.1-G107	Soot Slurry Pump	10	CS
9.1-G108	Gray Water Charge Pump	10	CS
9.1-G109	Slag Fine Pump	10	CS
9.1-G110	Gray Water Feed	10	CS
9.1-G111	Flash Water Supply Pump	10	CS
9.1-G112	Flash Condensate Pump	6	CS
9.1-G113	Filter Feed Pump	10	CS
9.1-G114	Gray Water Purge Pump	10	CS
9.1-G115	Water Supply Pump	10	CS
9.1-G116	Additive Transfer Pump	10	CS
9.1-G117	Slag Sump Pump	14	CS
9.1-G118	Slag Quench Circulation Pump	14	CS
9.1-G119	Air Quencher Circulation Pump	6	CS
9.1-G120	Air Scrubber Circulation Pump	6	CS
9.1-G121	Burner Cooling Pump	10	CS

Table 14.3 Major Equipment List - continued

Type of Equipment: Vacuum Pumps

Equipment No.	Equipment Description	Number Required
9.1-H101	Vacuum Pump	10
9.1-H102	Filter Vacuum Pump	10

Type of Equipment: Air Blowers

Equipment No.	Equipment Description	Number Required
9.1-K101	Cake Blower	12
9.1-K102	Vent Air Blower	6

Type of Equipment: Fired heaters

Equipment No.	Equipment Description	Number Required	Material Tube
9.1-F101	Shift Reactor Start Up Heater	2	SS

14.3 On-Stream Factor

The expected on-stream factors for the various sections of the Coal Gasification complex is 97.7%.

14.4 Operating Manpower Requirements

The operating manpower requirement for this plant is 120 operators. For full manpower requirements of this plant as well as the complex, refer to Section 40 of this report.

14.5 Plot Area Required

The plot area required for the Coal Gasification Plant is approximately 600 feet by 1200 feet.

14.6 Capital Cost and Breakdowns (First & Nth Plant)

The field costs and breakdowns for Plant 9 are given below in Table 14.4. Note that field costs for each plant do not include home office costs or contingency. These were estimated for the whole complex and are given in Section 41.

TABLE 14.4

Plant 9 (Hydrogen Production by Coal Gasification)
Field Costs and Breakdowns
2nd Quarter, 1991

Field Costs	**Costs ($MM)**	
Breakdowns	First Plant	Nth Plant
Major Equipment	97.7	81.5
Bulk Materials	75.3	62.7
Subcontracts	12.7	10.6
Direct Labor	68.7	57.3
Distributables (Indirect)	61.9	51.6
Total Field Costs	**316.3**	**263.7**

6 TRAINS

5 TRAINS

15. Plant 10 (Air Separation)

15.0 Design Basis, Criteria and Considerations

This is a package plant, the process flow diagram of which is shown in Figure 15.1. The air separation package plants are cryogenic units producing oxygen at 99.5% (mol) purity and nitrogen at 99.9% (mol) purity. Oxygen will be delivered at the pressure required by the selected coal gasification process. Nitrogen will be used for purging, blanketing, and other utility purposes and will be delivered to the utility system at 150 psig. Liquid nitrogen will also be produced off the Air Separation Plant and stored for use during periods of high nitrogen demand.

Plant 10 consists of five parallel trains each sized for 45 MMSCFD of oxygen. Each train can operate independently and uses a low pressure cycle type process. The process features an air compressor to compress the inlet air, direct contact cooling to remove the heat of compression from the air, molecular sieve units to purify the air, fractionation columns to obtain the high purity gaseous oxygen, an expander compressor to provide the refrigeration needed for the process, and an oxygen compressor to pressurize the oxygen product for use in the Coal Gasification Plant.

15.1 Major Equipment List

Equipment Number	Equipment Description
10-C101	Molecular Sieve Unit
10-C102	Fractionation Tower (Cold Box)
10-C103	Liquid Oxygen Storage Tank
10-C104	Liquid Nitrogen Storage Tank
10-E101	Evaporative Cooler
10-G101	Circulation Pump
10-G102	Make-up Pump
10-K101	Inlet Air Compressor
10-K102	Expander
10-K103	Oxygen Compressor
10-Y101	Spray Cooler

15.2 Catalyst and Chemical Summary

No catalyst or chemicals are used in the air separation plant except for the molecular sieves material which is used for air purification. This is supplied with the packaged units.

15.3 On-Stream Factor

The on-stream factor for an Air Separation Plant is expected to be 97.1%.

15.4 Operating Manpower Requirements

The operating manpower requirement for this plant is 4 operators. For full manpower requirements of this plant as well as the complex, refer to Section 40 of this report.

15.5 Plot Area Required

The plot area required for the Air Separation Plant is approximately 350 feet by 800 feet.

15.6 Capital Cost and Breakdowns (First & Nth Plant)

The field costs and breakdowns for Plant 10 are given below in Table 15.1. Note that field costs for each plant do not include home office costs or contingency. These were estimated for the whole complex and are given in Section 41. Because there is no spare train for the first plant, the cost numbers, as shown in Table 15.1 below, for the first plant and Nth plant are the same.

TABLE 15.1

Plant 10 (Air Separation)
Field Costs and Breakdowns
2nd Quarter, 1991

Field Costs	**Costs ($MM)**	
Breakdowns	First Plant	Nth Plant
Major Equipment	104.0	104.0
Bulk Materials	20.0	20.0
Subcontracts	17.0	17.0
Direct Labor	29.0	29.0
Distributables (Indirect)	21.0	21.0
Total Field Costs	**191.0**	**191.0**

16. Plant 11 (By-Product Sulfur Recovery)

16.0 Design Basis, Criteria and Considerations

Plant Capacity

Design capacity per train 180 LT/D

	No. of Trains	Total Capacity (LT/D)
• Operating	4	720
• Design	5	900

Feed Composition

Stream Component	Acid Gas from Plant 6 mol/hr	Acid Gas from Plant 9.1 mol/hr	Acid Gas from Plant 9.3 mol/hr	Acid Gas from Plant 38 mol/hr	Total Feed mol/hr
H_2	97	14	0	288	399
H2S	552	26	893	520	1991
CO_2	27	141	1798	146	2112
N_2	0	1	45	0	46
NH_3	0	0	0	1	1
CH_4	0	0	0	1	1
CO	0	66	0	0	66
H_2	0	83	0	2	85
COS	0	1	1	0	2
Phenols	0	0	0	4	4
Other HCs	0	0	0	135	135
Total	676	332	2738	1095	4841

Product Compositions

Stream Component	Vent Gas mol/hr	Liquid Sulfur mol/hr
H2O	65	0
H2S	2	0
CO_2	3074	0
N_2	9183	0
H_2	287	0
Liquid Sulfur	0	1991
Total	12720	1991
Total sulfur, LT/D	0.7	684

Yields

- Minimum sulfur recovery for Claus sulfur plant is 95%.
- Total sulfur recovery for Plant 11 is 99.9%.

Typical Sulfur Industry Specifications

• Sulfur	99.5%	minimum
• Carbon	0.2%	maximum
• Ash	50. ppm	maximum
• H2S	50. ppm	maximum
• SO_2	50. ppm	maximum
• Color	Bright yellow	
• Arsenic, Selenium, Tellurium	Commercially free	

Three Claus trains were specified to be operational normally to achieve 100% on-line capacity in case one of the trains must be taken out of service on an emergency basis.

The SCOT process was selected for the tail gas treater for the Sulfur Plant because it is a proven process and is becoming an industry standard. It meets all present environmental regulations.

16.1 Major Equipment Summary

Major Equipment Summary is shown in Table 16.1.

Table 16.1 Major Equipment Summary

Plant 11 – Sulfur and SCOT plant

Type of Equipment: Reactors and Vessels

Equipment No.	Equipment Description	Length (T–T in ft.)	Diameter (ID in ft.)	Material	Design Conditions Pres (psig)	Design Conditions Temp (oF)	Remarks	No. of Vessels
11.1–C101	Acid Gas KO Drum	10	6	CS	75	350		5
11.1–C102	Combustion Chamber	26	8.5	CS	50	650	12″ Refractory, 3″ Insul	5
11.1–C103	First Catalyst Converter	34	12.5	CS	50	650	3″ Refractory, 3″ Insul 3 ft Bed	5
11.1–C104	Second Catalyst Converter	34	12.5	CS	50	650	3″ Refractory, 3″ Insul 3 ft Bed	5
11.1–C105	Third Catalyst Converter	34	12.5	CS	50	650	3″ Refractory, 3″ Insul 3 ft Bed	5
11.2–C106	SCOT Feed Heater	10	7.5	CS	50	650	12″ Refractory, 3″ Insul	5
11.2–C107	SCOT Catalyst Reactor	36	12.5	CS	50	650	3″ Refractory, 3″ Insul 3 ft Bed	5
11.2–C111	Reflux Accumulator	8	3	CS	75	350		5

Sheet 1

Table 16.1 Major Equipment Summary - continued

Type of Equipment: Towers

Equipment No.	Equipment Description	Height (T–T in ft.)	Diameter (ID in ft.)	Material	Design Conditions Pres. (psig)	Design Conditions Temp. (oF)	No. of Trays	Packing Ft	No. of Vessels
11.2–C108	Quench Tower	31	8	CS	75 & FV	650		10 2" Pall Rings	5
11.2–C109	SCOT Absorber	53	7.5	CS	75 & FV	350	14 SS		5
11.2–C110	SCOT Stripper	90	6	CS	75 & FV	350 3" Insul	28 SS		5

Table 16.1 Major Equipment Summary - continued

Type of Equipment: Heat Exchangers

Equipment No.	Equipment Description	Duty (MM Btu/hr)	Type of Exchanger	Tube Material	Tube Design psig/oF	Shell Material	Shell Design Conditions psig/oF	Area Ft2	No. of Exch.
11.1–E101	Acid Gas Preheater	3.66	BEM	CS	75/650	CS	650/540	5027	5
11.1–E102	Air Preheater	3.33	BEM	CS	75/650	CS	650/540	4574	5
11.1–E103	First Reheater	1.53	BEM	CS	75/650	CS	650/540	2102	5
11.1–E104	Second Reheater	1.35	BEM	CS	75/650	CS	650/540	1854	5
11.1–E105	Third Reheater	1.42	BEM	CS	75/650	CS	650/540	1068	5
11.1–E106	Waste Heat Boiler	41.34	Spel	CS	15/650	CS	200/420	4627	5
11.1–E107	Thermal Condenser	6.03	CEN	CS	50/650	CS	100/350	3663	5
11.1–E108	First Sulfur Condenser	6.30	CEN	CS	50/650	CS	100/350	4443	5
11.1–E109	Second Sulfur Condenser	2.96	CEN	CS	50/650	CS	100/350	4720	5
11.1–E110	Third Sulfur Condenser	1.81	CEN	CS	50/650	CS	100/350	2561	5
11.2–E111	Waste Heat Exchanger	4.35	CEN	CS	50/650	CS	100/350	4070	5
11.2–E112	Quench Water Cooler	14.45	AET	SS	100/350	CS	100/165	5108 2554/S	5
11.2–E113	Lean Solvent Cooler	14.97	AET	CS	100/165	CS	100/350	5572 2786/S	5
11.2–E114	Lean/Rich Solvent Exchanger	30.18	AET	CS	130/300	CS	130/300	6970 3485/S	5
11.2–E115	Overhead Condenser	19.36	Air Cooler	CS	100/300	75 HP Motor		83528 fin	5
11.2–E116	Reboiler	32.48	CKU	SS	100/350	CS	75/350	4812	5

Sheet 3

Table 16.1 Major Equipment Summary - continued

Type of Equipment: Pumps

Equipment No.	Equipment Description	Flow Rate (gpm)	Delta Pres (psi)	Brake Horsepower	Design Conditions Pres (psig)	Design Conditions Temp (oF)	Driver	Est. Driver HP	No. of Pumps
11.2–G101A/B	Quench Water Pump	969	50	81	100	200	Elec	100	10
11.2–G102A/B	Rich Solvent Pump	718	75	89.5	130	300	Elec	125	10
11.2–G103A/B	Lean Solvent Pump	861	50	71.5	130	300	Elec	100	10
11.2–G104A/B	Reflux Pump	44	40	3	75	200	Elec	5	10
11.4–G105A/B	Solvent Charge Pump	50	30	2.5	75	200	Elec	5	2
11.4–G106	Solvent Sump Pump	50	30	2.5	75	200	Elec	5	5
11.4–G107A/B	Sulfur Transfer Pump (Sump Type, Steam Jacketed)	150	65	9.5	100	350	Elec	15	10
11.4–G108A/B/C	Sulfur Loading Pump (Steam Jacketed)	275	50	13.4	100	350	Elec	20	3

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Table 16.1 Major Equipment Summary - continued

Type of Equipment: Air Blowers

Equipment No.	Equipment Description	Flow Rate (ACFM)	Diff Pres (psi)	Brake Horsepower	Design Conditions Pres (psig)	Design Conditions Temp (oF)	Driver	Est. Driver HP	No. of Equip.
11.1-K101	Sulfur Plant Air Blower	10101	13	630	50	250	Elec	700	5
11.2-K102	SCOT Air Blower	987	5	26	50	250	Elec	40	5

Type of Equipment: Miscellaneous

Equipment No.	Equipment Description	Flow Rate	Other Design Criteria	Design Conditions Pres (psig)	Design Conditions Temp (oF)	No. of Equip.
11.1-F101	Acid Gas Burner		25.4 MMbtu/hr			5
11.2-F102	Tail Gas Burner		4.8 MMbtu/hr			5
11.3-F103	Incinerator Burner		13.0 MMbtu/hr			5
11.3-Y101	Incinerator		8 ft ID x 10 ft Base, & 6.5 ft ID x 280 ft stack 6″ & 3″ Refractory			5
11.2-Y102	Quench Filter	145 gpm	Cartridge Type SS Internals	150 & FV	300	5
11.2-Y103	Lean Solvent Filter	130 gpm	Cartridge Type SS Internals	150 & FV	300	5
11.2-Y104	Solvent Sump Filter	50 gpm	Cartridge Type SS Internals	150 & FV	300	5
11.4-D101	Solvent Storage Tank	81750 gals	Cone Roof Tank CS	6″ H2O Int 1″ H2O Ext	350	2
11.4-D102	Sulfur Day Tank	53000 gals	Below Ground in a Concrete Pit	75 & FV	650	5
11.4-D103	Sulfur Storage Tank	265000 gals	CS	5 psig Int 4″ H2O Ext	350	2
11.4-D104	Solvent Sump		6'-0″ ID x 18'-0″	75 & FV	350	5

16.2 Catalyst and Chemical Summary

Catalyst and chemicals required for this plant are shown below:

Catalysts	Quantity Required for Start-Up	Consumption
Claus Catalyst Kaiser S-201	18,400 cu.ft.	(5 years)
SCOT Catalyst	6,500 cu.ft.	(5 years)
Packings		
2" SS Pall Rings	2,500 cu.ft.	(3 years)
Chemicals		
MDEA	500 Bbl	50 gpd

16.3 On-Stream Factor

The expected on-stream factor for the Sulfur Plant is 97.1%.

16.4 Operating Manpower Requirements

The operating manpower requirement for this plant is 20 operators. For full manpower requirements of this plant as well as the complex, refer to Section 40 of this report.

16.5 Plot Area Required

The plot area required for the Sulfur Plant is approximately 280 feet by 380 feet. The plot area required for the Sulfur Storage and Loading is 50 feet by 230 feet.

16.6 Capital Cost and Breakdowns (First & Nth Plant)

The field costs and breakdowns for Plant 11 are given below in Table 16.2. Note that field costs for each plant do not include home office costs or contingency. These were estimated for the whole complex and are given in Section 41. Because there is no spare train for the first plant, the cost numbers, as shown in Table 16.2 below, for the first plant and Nth plant are the same.

TABLE 16.2

Plant 11 (By-Product Sulfur Recovery)
Field Costs and Breakdowns
2nd Quarter, 1991

Field Costs	Costs ($MM)	
Breakdowns	First Plant	Nth Plant
Major Equipment	15.2	15.2
Bulk Materials	10.4	10.4
Subcontracts	1.8	1.8
Direct Labor	10.2	10.2
Distributables (Indirect)	9.1	9.1
Total Field Costs	**46.7**	**46.7**

17. Plant 19 (Relief and Blowdown Facilities)

17.0 Design Basis, Criteria and Considerations

Plant 19 is for the collection and flaring of relief and blowdown discharges from all applicable plants. It includes all the plant flare subheaders, the main flare headers, and the flare stacks. Relief and blowdown subheaders are provided for Coal Liquefaction (Plant 2), the Gas Plant (Plant 3), the Naphtha and Gas Oil Hydrotreaters (Plants 4 and 5, respectively), Hydrogen Purification (Plant 6), Solvent Recovery (Plant 8), Hydrogen Production from Coal Gasification (Plant 9), Sulfur Recovery (Plant 11), and Wastewater Treatment (Plant 34).

Two separate main headers are provided for high and low pressure relief valves. Valves with set pressures below 300 psig relieve to the low pressure header while valves with set pressures equal to or above 300 psig relieve to the high pressure header. Both high and low pressure headers are connected to a common knockout drum which is connected to the two main flare stacks (one operating and one spare).

One dedicated flare header with a separate flare stack is provided for flaring H_2S emissions from Plant 34.

A preliminary analysis of the various causes of over pressure has been made for each plant to determine which contingency governs flare header size. The various causes of over pressure considered were:

- Electrical Power Failure
- Cooling Water Failure
- Total Instrument Air Failure
- Control Valve Failure
- Inadvertent Valve Closing/Opening
- Plant Fire
- Reflux Failure
- Other Failure

The various header sizing contingencies are given in Tables 17.1, 17.2 and 17.3 on the following pages. The contingency which required the greatest header size was used for sizing. These tables summarize the contingencies selected as the basis for subheader and main header sizing.

The high pressure header accepts discharge from valves with set pressures of 300 psig or above. It has a maximum total superimposed plus built up back pressure of 75 psig which may be applied to any relief valve.

The low pressure header accepts discharge from valves with set pressures below 300 psig. For the low pressure header, the maximum total back pressure is 15 psig.

Balanced bellows-type relief valves will be used in those cases where back pressure exceeds 10% of the relief valve setting. Conventional relief valves are to be used where the back pressure is less than 10% of the valve set pressure.

This system analysis is preliminary and serves as a guide only, not a final design.

Vapor relief loads to the flare system are minimized by relieving to atmosphere where practicable without jeopardizing plant safety. In general, API RP -520, "Recommended Practice for the Design and Installation of Pressure-Relieving Systems in Refineries," and API RP -521, "Guide for Pressure Relief and Depressuring Systems," are followed.

TABLE 17.1

HIGH PRESSURE FLARE HEADER SIZING CONTINGENCIES

Plant No.	Plant Name	Contingency Used as Basis for Sizing Subheader
4	Naphtha Hydrotreater	Power Failure
5	Gas Oil Hydrotreater	Power Failure
8	Solvent Recovery	Blocked Discharge
9	H_2 Production by Coal Gasification	Blocked Discharge

TABLE 17.2

LOW PRESSURE FLARE HEADER SIZING CONTINGENCIES

Plant No.	Plant Name	Contingency Used as Basis for Sizing Subheader
2	Coal Liquefaction	Power Failure
3	Gas Plant	Cooling Water Failure
4	Naphtha Hydrotreater	Cooling Water Failure
5	Gas Oil Hydrotreater	Power Failure
6	H_2 Purification	Blocked Discharge
11	Sulfur Recovery	Blocked Discharge

TABLE 17.3

MAIN HEADER SIZING CONTINGENCIES

Flare Header	Contingency Used as Basis for Sizing Main Header
Low Pressure	Power Failure (Plants 2 and 5)
High Pressure	Blocked Discharge (Plant 9)
H_2S (Plant 34)	Cooling Water Failure

17.1 Major Lines and Equipment Summary

The major lines summary and major equipment summaries for this plant are shown separately in Tables 17.4 and 17.5 respectively.

Table 17.4
Major Lines Summary

Line Contents	From	To	Size (in.)
Atmospheric Tower and WHPS Overheads	Plant 2	Low Pressure Header	30
Stripper and Depropanizer Overheads	Plant 3	Low Pressure Header	24
OHPS Overhead	Plant 4	High Pressure Header	16
Fractionator Overhead	Plant 4	Low Pressure Header	12
HHPS Overhead	Plant 5	High Pressure Header	20
HLPS and Fractionator Overheads	Plant 5	Low Pressure Header	16
Compressor K102 Discharge	Plant 6	Low Pressure Header	18
Solvent Stream	Plant 8	High Pressure Header	10
Synthesis Gas	Plant 9	High Pressure Header	36
H_2S Acid Gas	Plant 34	H_2S Header	18
Low Pressure Discharges (< 300 psig)	Low Pressure Header	Primary Flare	36
High Pressure Discharges (>= 300 psig)	High Pressure Header	Primary Flare	36

Table 17.5
Major Equipment Summary

Equipment No.	Type	Description
19-C101	Primary Flare Knockout Drum	21'0" X 63'0" TT, Horizontal
19-F101A,B	Primary Flare Stack for High and Low Pressure Headers	42" dia. X 360' high
19-F102	H_2S Flare	6" dia. X 150' high
19-G101	Slop Oil Pump	60 bhp, 165 gpm, Electric Motor
19-G102	Slop Oil Pump	60 bhp, 165 gpm, Turbine Driven
19-K101	Slop Oil Pump Turbine	60 bhp, uses 150 lb steam

17.2 Operating Manpower Requirements

The operating manpower requirement for this plant is 2 operators. For full manpower requirements of this plant as well as the complex, refer to Section 40 of this report.

17.3 Plot Area Required

The area required for this plant is 75 ft. X 100 ft. plus a clear circular area 370 ft. in diameter for each primary flare and 150 ft. in diameter for the H_2S flare.

17.4 Capital Cost and Breakdowns (First & Nth Plant)

The field costs and breakdowns for Plant 19 are given below in Table 17.6. This plant being an OSBL plant, its field costs and breakdowns are the same for the first as well as Nth plant scenarios. Note that field costs for each plant do not include home office costs or contingency. These were estimated for the whole complex and are given in Section 41.

TABLE 17.6

Plant 19 (Relief and Blowdown)
Field Costs and Breakdowns
(First & Nth Plants)
2nd Quarter, 1991

Field Costs and Breakdowns	Costs ($MM)
Major Equipment	2.0
Bulk Materials	1.5
Subcontracts	0.1
Direct Labor	1.4
Distributables (Indirect)	1.3
Total Field Costs	**6.3**

18. Plant 20 (Tankage)

18.0 Design Basis, Criteria and Considerations

Plant 20 provides storage and delivery equipment for products and intermediates.

Products include liquid hydrocarbon fractions from the Naphtha and Gas Oil Hydrotreaters (Plants 4 and 5), propane and mixed butanes from the Gas Plant (Plant 3), sulfur from Sulfur Recovery (Plant 11), ammonia from the Ammonia Plant (Plant 38), and phenols from the Phenol Plant (Plant 39).

Intermediates include hydrocarbon fractions from Plant 2 and sour water feed for Ammonia Removal (Plant 38). The hydrocarbon fractions from Plant 2 are feed for the Naphtha and Gas Oil Hydrotreaters (Plants 4 and 5) and the Purge and Flush Oil System (Plant 36).

Plant 20 includes tanks, pumps, heat exchangers, and miscellaneous equipment required for product and intermediate storage and delivery.

Product storage

Thirty days storage is provided for the 4 liquid hydrocarbon fractions, 15 days for propane, mixed butanes, sulfur, ammonia, and phenol. Storage times were chosen to allow for variations in production and shipping rates. The 15 days of propane and ammonia storage consist of 10 days of refrigerated storage at atmospheric pressure and five days of pressurized storage at ambient temperature. Both types of storage are provided since refrigerated storage for propane and ammonia is more cost effective, and pressurized storage is required for shipment in pressurized containers at ambient temperature.

Intermediate storage

Six hours intermediate storage is provided for the liquid hydrocarbon feeds from Coal Liquefaction (Plant 2) to the Naphtha and Gas Oil Hydrotreaters (Plants 4 and 5). The 6 hour storage capacity is required to provide feedstock during plant startup (prior to Plant 2 delivery of the necessary feed). Additionally, the storage mitigates the effect on downstream plant operations due to brief interruptions in the upstream plant. Interruptions could be as a result of scheduled or unscheduled maintenance or due to operating problems.

The sour water feed (for Ammonia Removal, Plant 38) and the light and heavy flush oils (for the Purge and Flush Oil System, Plant 36) have storage times of 5, 10, and 10 days, respectively, for the same reasons discussed above (for operation during startup and to mitigate the effect of upstream plant interruptions).

Tank sizing

The following factors were considered for tank sizing:

- All tanks are sized to API 650 except for pressurized spherical tanks.
- Tanks are sized for 95% maximum working capacity.
- At least two tanks are used for each finished product to avoid the problem of running to and shipping from the same tank.
- Due to soil loading considerations, tank height is limited to 48 feet for cylindrical tanks.

18.1 Major Equipment Summary

The Major Equipment Summary for Plant 20 is shown in Table 18.1.

Table 18.1
Major Equipment Summary
Plant 20 - Tankage

Tanks (1),(2)

Equipment No.	Equipment Description	Capacity Basis (BPSD)	Days Storage	Calculated Capacity (Barrels)	Capacity (Barrels)	Dia. (Ft)	Height (Ft)	Roof/ Type	Design Conditions	
									P psig/(wc)	Temp (°F)
PRODUCTS										
20-D101A,B,C	Naphtha	19,612	30.00	619,326	217,500	180	48	Floater	2	150
20-D102A,B,C	Light Distillate	8,118	30.00	256,358	97,000	120	48	Cone	2	150
20-D103A,B,C	Heavy Distillate	22,812	30.00	720,379	269,000	200	48	Cone	2	150
20-D104A,B,C	Gas Oil	13,950	30.00	440,526	151,100	150	48	Cone	2	350
20-D105A,B	Propane	4,420	10.00	46,526	24,200	60	48	Refrigerated	1	-60
20-D106	Propane	4,420	5.00	23,263	25,000	65	--	Sphere	350	150
20-D107A,B	Mixed Butanes	3,558	15.00	56,179	30,000	69	--	Sphere	95	150
20-D108A,B	Sulfur	2,653	10.00	27,926	15,500	48	48	Cone	2	350
20-D109	Ammonia	2,367	5.00	12,458	15,000	54'9"	--	Sphere	350	150
20-D110A,B	Ammonia	2,367	10.00	24,916	12,900	48	40	Refrigerated	2	-40
20-D111A,B	Phenols	175	15.00	2,763	2,100	25	24	Cone	2	150
INTERMEDIATES										
20-D112	Naphtha Fraction	17,437	0.25	4,589	5,000	30	40	Floater	2	150
20-D113	Light Gas Oil	29,778	0.25	7,836	8,900	40	40	Cone	2	450
20-D114	Heavy Gas Oil	17,949	0.25	4,723	5,000	30	40	Cone	2	400
20-D115A,B	Sour Water Feed	124,389	5.00	654,679	335,500	230	48	Floater	2	200
20-D116	Light Flush Oil	2,800	10.0	29,474	30,100	67	48	Floater	2	450
20-D117A,B	Heavy Flush Oil	9,000	10.0	94,737	54,400	90	48	Cone	2	400

NOTES:
1. All tanks are 95% working capacity.
2. All tanks are API 650 standard sizes except for the spherical tanks.

Sheet 1

Table 18.1 Major Equipment Summary - continued

Plant 20 - Tankage

Pumps

Equipment (1) No.	Equipment Description	Flow Rate (gpm)	Delta Pres psi/(mmHG)	Brake Horsepower	Design Conditions Pres (psig)	Design Conditions Temp (°F)	Driver
PRODUCTS							
20-G101A,B	Naphtha	4,375	1,500	6,000	1,650	150	Elect Motor
20-G102A,B	Light Distillate	4,375	1,500	6,000	1,650	150	Elect Motor
20-G103A,B	Heavy Distillate	4,375	1,500	6,000	1,650	150	Elect Motor
20-G104A,B	Gas Oil	4,375	1,500	6,000	1,650	150	Elect Motor
20-G105A,B	Propane	2,000	290	700	400	150	Elect Motor
20-G106A,B	Mixed Butanes	2,000	150	350	200	150	Elect Motor
20-G107A,B,C	Sulfur	2,000	75	200	100	350	Elect Motor
20-G108A,B	Ammonia	2,000	275	700	400	150	Elect Motor
20-G109A,B	Phenols	660	80	80	130	150	Elect Motor
INTERMEDIATES							
20-G110A,B	Naphtha Fraction	510	50	50	75	150	Elect Motor
20-G111A,B	Light Gas Oil	870	50	90	120	450	Elect Motor
20-G112A,B	Heavy Gas Oil	525	50	50	75	400	Elect Motor
20-G113A,B	Sour Water Feed	4,000	50	250	75	200	Elect Motor
20-G114A,B	Light Flush Oil	85	3,300	250	3,600	450	Elect Motor
20-G115A,B	Heavy Flush Oil	265	250	75	325	400	Elect Motor

NOTES:

1. All pumps are one operating and one spare except for the sulfur pump which is 2 operating and one spare.

Sheet 1

Table 18.1 Major Equipment Summary - continued

Plant 20 - Tankage

Heat Exchangers

Equipment No.	Equipment Description	Duty (MMBTU/hr)	Type of Exchanger	No. Shells/ Area/Shell (sq ft)	Shell P/T (psig/°F)	Tube Material
PRODUCTS						
20-E102A,B,C	Gas Oil Bottom Coil	3.0	Shell & Tube	1/1200	150/366	Carbon Steel
20-E103A,B	Sulfur Bottom Coil	0.1	Shell & Tube	1/100	150/366	Carbon Steel
20-E104A,B	Sulfur Top Coil	0.1	Shell & Tube	1/100	150/366	Carbon Steel
20-E105A,B	Sulfur Suction Nozzle Coil	0.1	Shell & Tube	1/400	150/366	Carbon Steel
					150/366	
INTERMEDIATES					150/366	
20-E106	Light Gas Oil Bottom Coil	0.2	Shell & Tube	1/100	150/366	Carbon Steel
20-E107	Heavy Gas Oil Bottom Coil	0.1	Shell & Tube	1/400	150/366	Carbon Steel
20-E108	Heavy Gas Oil Suct Heater	0.1	Shell & Tube	1/400	150/366	Carbon Steel
20-E109	Light Flush Oil Bottom Coil	0.5	Shell & Tube	1/100	150/366	Carbon Steel
20-E110A,B	Heavy Flush Oil Bottom Coil	0.5	Shell & Tube	1/100	150/366	Carbon Steel

Table 18.1 Major Equipment Summary - continued

Plant 20 - Tankage

Miscellaneous

Equipment No.	Equipment Description	Flow Rate	Other Design Criteria	Design Conditions P psig/(wc)	Design Conditions Temp (°F)
20-V101	Precoat Filter, Lt Flush Oil	85 gpm	Complete package, skid mounted, consists of 2 of each item: precoat filters, regen pumps, sol'n tanks and mixers, storg bins. ASME design and construction	3,600	450
20-V102	Precoat Filter, Hv Flush Oil	265 gpm	Complete package, skid mounted, consists of 2 of each item: precoat filters, regen pumps, sol'n tanks and mixers, storg bins. ASME design and construction	325	400
20-V103	Propane Refrig & Heating Sys		Clng/Htng from 100 to -48°F 394 tons clng dty @55,000 lb/hr 837 tons htng dty @117,000 lb/hr	250	150
20-V104	Ammonia Refrig & Heating Sys		Clng/Htng from 100 to -28°F 284 tons clng dty @22,000 lb/hr 1662 tons htng dty @140,000 lb/hr	250	150
20-V105	Sr Wat Compr/Vap Recv Sys	629 ACFM	11.4 psia suct press 58 psia disch press, 100 °F	60	200

Table 18.1 Major Equipment Summary - continued

Plant 20 - Tankage

Miscellaneous

Equipment No.	Equipment Description	Flow Rate	Other Design Criteria	Design Conditions P psig/(wc)	Design Conditions Temp (°F)
20-V106	Light Gas Oil Tank Mixer		Four mixers w/ 10 hp drivers ea., side mounted for tank 20-D113	2	450
20-V107	Heavy Gas Oil Tank Mixer		Four mixers w/ 10 hp drivers ea., side mounted for tank 20-D114	2	400
20-V108	Light Flush Oil Tank Mixer		Four mixers w/ 10 hp drivers ea., side mounted for tank 20-D116	2	450
20-V109	Heavy Flush Oil Tank Mixer		Four mixers w/ 10 hp drivers ea., side mounted for tank 20-D117	2	400
20-V110	Dephenol Feed Tank Skimmr Pkg		Complete pkg includes pumps and skimmer for collecting oil in tank 20-D115A,B	(5")	200

18.2 Operating Manpower Requirements

The operating manpower requirement for this plant is 2 operators. For full manpower requirements of this plant as well as the complex, refer to Section 40 of this report.

18.3 Plot Area Required

The plot area requirement for this plant is 6000 feet x 3000 feet.

18.4 Capital Cost and Breakdowns (First & Nth Plant)

The field costs and breakdowns for Plant 20 are given below in Table 18.2. This plant being an OSBL plant, its field costs and breakdowns are the same for the first as well as Nth plant scenarios. Note that field costs for each plant do not include home office costs or contingency. These were estimated for the whole complex and are given in Section 41.

TABLE 18.2

Plant 20 (Tankage)
Field Costs and Breakdowns
(First & Nth Plants)
2nd Quarter, 1991

Field Costs	Costs ($MM)
Major Equipment	38.0
Bulk Materials	25.5
Subcontracts	3.4
Direct Labor	22.3
Distributables (Indirect)	20.1
Total Field Costs	**109.3**

19. Plant 21 (Interconnecting Piping Systems)

19.0 Design Basis, Criteria and Considerations

Plant 21 includes the fuel gas blending and distribution system and the interconnecting process and utility piping between process plants and offsites. All above ground and underground piping systems are included except fire water piping which is included in Fire Systems (Plant 33) and plant flare headers which are included in the Flare System (Plant 19). In general, water distribution piping is underground and all other piping is located above ground on pipe racks.

Fuel gas users in the complex include process fired heaters and combustion turbine generators (CTG), the coal drying heaters. Fuel for these users must be clean gas with virtually no sulfur content so that no treatment of stack gases for sulfur removal is needed.

Two types of fuel gas are produced within the complex. One is classified as high BTU gas and the other as medium BTU gas. The high and medium BTU gases have been segregated in two separate distribution systems. Natural gas can be added to either system to meet the fuel gas requirements and to maintain consistency within each system. The gas fired equipment will burn the high BTU gas while the medium BTU gas system goes to Plant 31 to produce steam and power.

Fuel Gas System

The rates and specifications of the plant fuel gas available from two sources within the facility and natural gas are summarized in Table 19.1. The rates and compositions of the first two sources in the table are from the material balances included on the process flow diagrams for the Gas Plant (Plant 3) and Hydrogen Production by gasification (Plant 9). Natural gas composition is based on the analysis used in this complex.

The material balance and equipment design for Plant 3 and Plant 9 were developed based upon a preliminary design basis.

Interconnecting Piping

The interconnecting piping consists of all the process lines and racks connecting one process plant to another, the utility headers and the branches to each process. Pipes are sized based on pressure drop and fluid velocity considerations.

The cooling water system is routed underground and process lines and other utilities are routed on the pipe racks. All the steam, condensate and boiler feedwater lines are insulated. The headers, one for each utility service, include the following:

- 600 psig steam (superheated)
- 150 psig steam (saturated)
- 50 psig steam (saturated)
- Instrument air
- Utility air
- Utility water
- Cooling water supply
- Cooling water return
- 600 psig boiler feedwater
- Potable water
- High BTU fuel gas
- Medium BTU fuel gas
- Natural gas
- Nitrogen Gas

Storm sewer, sanitary sewer, and process wastewater lines are included in the scope of Sewers and Wastewater Treating (Plant 34).

TABLE 19.1

FUEL GAS AVAILABILITY

(All Rates are TPSD)

Stream Component	High BTU Gas From Plant 3	Medium BTU Gas from Plant 9	Natural Gas
Hydrogen	27.0	210.6	--
Carbon Dioxide	0.0	126.6	--
Carbon Monoxide	9.1	240.7	--
Methane	389.7	8.8	1819.5
Ethane	311.3	0.0	108.3
Propane	77.9	0.0	38.4
Water	36.4	0.0	--
N_2	15.3	149.6	33.4
Argon	0.0	29.1	--
O_2	0.0		207.8
TOTAL	866.7	765.4	2207.4
LHV, BTU/SCF (1)	901	259	884
MM BTU/hr (LHV)	1473	1007	3510

(1) Heating values are BTU per scf based on 379 ft^3 per pound-mole. Maximum operating pressure for high BTU gas is 75 psig and minimum pressure 50 psig at the battery limits of any user. Medium BTU gas will have an operating pressure of 300-400 psig as it exits Plant 9.

19.1 Major Lines Summary

Line Contents	From	To	Size (in)
Naptha Product	Plant 4	Plant 20 Tank	6
Light Distillate Product	Plant 5	Plant 20 Tank	4
Heavy Distillate Product	Plant 5	Plant 20 Tank	6
Gas Oil Product	Plant 5	Plant 20 Tank	6
Propane Product	Plant 3	Plant 20 Tank	2
Mixed Butanes Product	Plant 3	Plant 20 Tank	2
Sulfur Product	Plant 11	Plant 20 Tank	3
Ammonia Product	Plant 38	Plant 20 Tank	2
Phenol Product	Plant 39	Plant 20 Tank	1
Naptha Product	Plant 20 Tank	Plant 20 Pump	22
Light Distillate Product	Plant 20 Tank	Plant 20 Pump	22

Major Lines Summary - continued

Line Contents	From	To	Size (in)
Heavy Distillate Product	Plant 20 Tank	Plant 20 Pump	22
Gas Oil Product	Plant 20 Tank	Plant 20 Pump	22
Naptha Product	Plant 20 Pump	Plant 22 Pipeline	14
Light Distillate Product	Plant 20 Pump	Plant 22 Pipeline	14
Heavy Distillate Product	Plant 20 Pump	Plant 22 Pipeline	14
Gas Oil Product	Plant 20 Pump	Plant 22 Pipeline	14
Propane Product	Plant 20 Pump	Plant 23 Tank Car/Truck	8
Mixed Butanes Product	Plant 20 Pump	Plant 23 Tank Car/Truck	8
Sulfur Product	Plant 20 Pump	Plant 23 Tank Car/Truck	10
Ammonia Product	Plant 20 Pump	Plant 23 Tank Car/Truck	8
Phenol Product	Plant 20 Pump	Plant 23 Tank Car/Truck	6
Naphtha Intermediate	Plant 2	Plant 20 Tank	6
Light Gas Oil Intermediate	Plant 2	Plant 20 Tank	6
Heavy Gas Oil Intermediate	Plant 2	Plant 20 Tank	6
Sour Water Header	Plants 2, 3, 4, 5, 9, 11	Plant 20 Tank	12

Major Lines Summary - continued

Line Contents	From	To	Size (in)
Light Flush Oil Intermediate	Plant 2	Plant 20 Tank	3
Heavy Flush Oil Intermediate	Plant 2	Plant 20 Tank	4
Naphtha Intermediate	Plant 20 Tank	Plant 2	6
Light Gas Oil Intermediate	Plant 20 Tank	Plant 2	6
Heavy Gas Oil Intermediate	Plant 20 Tank	Plant 2	6
Sour Water Header	Plant 20 Tank	Plant 38	12
Light Flush Oil Intermediate	Plant 20 Tank	Plant 2	3
Heavy Flush Oil Intermediate	Plant 20 Tank	Plant 2	4
Make-up Water	Plant 32	Plant 9	8
Raw Water	Raw Water Source	Plant 32	14
50 psig Steam	50 psig Steam Header	Plant 31	24

Major Lines Summary - continued

Utility Lines

Utility Header	Size (in)
600 psig Superheated Steam (720°F)	10
600 psig Saturated Steam	10
150 psig Saturated Steam	24
50 psig Saturated Steam	36
Instrument Air	3

Utility Header	Size (in)
Utility Air	2
Utility Water	6
Cooling Water Supply	48
Cooling Water Return	48
600 psig Boiler Feedwater	6
Potable Water	3
High Btu Fuel Gas	8
Medium Btu Fuel Gas	10
Natural Gas	6
Nitrogen Gas	26

Major Lines Summary - continued

Equipment No.	Type	Description
21-C101	Drum	Natural and medium Btu gas mixing, vertical, 10 ft. X 5 ft.
21-C102	Drum	Natural and high Btu gas mixing, vertical, 10 ft. X 5 ft.

19.2 Capital Cost and Breakdowns (First & Nth Plant)

The field costs and breakdowns for Plant 21 are given below in Table 19.2. This plant being an OSBL plant, its field costs and breakdowns are the same for the first as well as Nth plant scenarios. Note that field costs for each plant do not include home office costs or contingency. These were estimated for the whole complex and are given in Section 41.

TABLE 19.2

Plant 21 (Interconnecting Piping)
Field Costs and Breakdowns
(First & Nth Plants)
2nd Quarter, 1991

Field Costs Breakdown	Costs ($MM)
Major Equipment	--
Bulk Materials	23.5
Subcontracts	4.0
Direct Labor	22.5
Distributables (Indirect)	20.3
Total Field Costs	**70.3**

20. Plant 22 (Product Shipping)

20.0 Design Basis, Criteria and Considerations

Plant 22 provides the pipeline and metering system for delivery of the final oil products from the hydrotreaters (Plants 4 and 5) to down stream customers.

The equipment for this plant includes the appropriate length of 20 in. schedule 40 pipe for product delivery to down stream customers and a meter for tracking the amount of product transfered for accounting and billing purposes. The meter is provided with a 16 in. proving loop for meter testing and calibration.

The pipeline is designed to carry 4375 gpm which allows 50,000 barrels of oil product to be delivered in 8 hour batches. The pressure drop should not exceed 500 psi for every 50 miles of pipe.

Dual meters are required to assure proper recording of product delivery quantities in case of single meter failure.

20.1 Major Equipment Summary

Equipment No.	Type	Description
22-L101	Pipeline	20 in., schedule 40
22-V101	Metering System with Prover Loop	16 in. prover loop
22-V102	Pipe Cleaning Pig	For 20 in. pipe
22-V103	Pig Launcher	For launching pipe cleaning pig into the pipeline

20.2 Operating Manpower Requirements

Product shipping by pipeline is handled as part of the Oil Movement and Storage staff. Thus the manpower requirement for this plant is a fraction of an operator.

20.3 Plot Area Required

The plot area for the equipment listed in this plant is approximately 40 feet by 80 feet.

20.4 Capital Cost and Breakdowns

The field costs and breakdowns for Plant 22 are given below in Table 20.1. This plant being an OSBL plant, its field costs and breakdowns are the same for the first as well as Nth plant scenarios. Note that field costs for each plant do not include home office costs or contingency. These were estimated for the whole complex and are given in Section 41.

TABLE 20.1

Plant 22 (Product Shipping)
Field Costs and Breakdowns
(First & Nth Plants)
2nd Quarter, 1991

Field Costs Breakdowns	Costs ($MM)
Major Equipment	0.2
Bulk Materials	0.3
Subcontracts	0.1
Direct Labor	0.1
Distributables (Indirect)	0.1
Total Field Costs	**0.8**

21. Plant 23 (Tank Car/Tank Truck Loading)

21.0 Design Basis, Criteria and Considerations

The products are generally pumped from the storage tanks to the loading points at the required rate (See Table 1). One pump for each product delivers the required flow rate for phenol, ammonia, propane, and butane; however, two pumps are required for pumping molten sulfur. All operating pumps are provided with a spare. Loading pumps are included in Tankage (Plant 20). Nozzles are provided at both the Tank Car and Tank Truck loading racks such that any product can be loaded at two or more bays.

Each product is piped by a separate line to the loading racks, then branched to different loading nozzles.

All products are loaded to ambient temperatures (100 °F) except molten sulfur which is loaded at 300 °F.

21.1 Major Equipment Summary

The summary of the equipment for plant 23 is presented in Table 21.1.

21.2 Operating Manpower Requirements

The operating manpower requirement for this plant is 2 operators. For full manpower requirements of this plant as well as the complex, refer to Section 40 of this report.

21.3 Plot Area Required

Tank Car Loading

Area Required = 10,000 sqft

Tank Truck Loading

Area Required = 10,000 sqft

21.4 Capital Cost and Breakdowns

Table 21.1

Major Equipment Summary

EQUIPMENT LIST	EQUIPMENT DESCRIPTION	DESIGN CRITERIA	NUMBER
23M-101A	Tank Truck Loading Platform, structural steel construction	Per Attachment 1	3 sets
23M-101B	Tank Car Loading Platform, structural steel construction	Per Attachment 2	1 set
23L-101	Pipeline, valves and loading arms for transporting finished products form storage tanks to tank cars/tank trucks	Per Table 1	1 set
23J-101	Positive displacement flow meters with digital counters and printout capacity	Per Table 1	1 set
23K-101	A & B Butane vapor recovery compressor, CS construction	500 ACFM, suction pressure 55 PSIA, discharge pressure 75 PSIA	1 + 1 sets
3K-101A & B	Propane vapor recovery compressor, CS construction	500 ACFM, suction pressure 216 PSIA, discharge pressure 265 PSIA	1 + 1 sets

EQUIPMENT LIST	EQUIPMENT DESCRIPTION	DESIGN CRITERIA	NUMBER
23K-101A & B	Ammonia vapor recovery compressor, CS construction	500 ACFM, suction pressure 205 PSIA, discharge pressure 224 PSIA	1 + 1 sets
23K-104A & B	Molten Sulfur vapor recovery compressor, CS construction	500 ACFM, suction pressure 15 PSIA, discharge pressure 25 PSIA	1 + 1 sets
23V-101	Tank truck weigh scale with recording devices and automatic printout.	Suitable for weight of tank truck & 500 metric tons produced	1 set
23G-101	Sump Pump for weigh scale pit, CS	25 GPM, 5 HP, 3000 RPM	1 set
23V-102	Sprinkler fire system complete with alarms, sensors, energizers, & all instrumentation	water density minimum 0-25 GPM/ft^2	1 set
23V-103	Fire Hydrant System complete with approved hoses and nozzles		
23V-104	Communication system consisting of telephones (fixed & portable) and walkie talkies	6 sets	1 set

21.4 Capital Cost and breakdowns (First & Nth Plant)

The field costs and breakdowns for Plant 23 are given below in Table 21.2. This plant being an OSBL plant, its field costs and breakdowns are the same for the first as well as Nth plant scenarios. Note that field costs for each plant do not include home office costs or contingency. These were estimated for the whole complex and are given in Section 41.

Table 21.2

Plant 23 (Tank Car/Tank Truck Loading)
Field Costs and Breakdowns
(First & Nth Plants)
2nd Quarter, 1991

Field Costs Breakdown	Costs ($MM)
Major Equipment	2.0
Bulk Materials	3.4
Subcontracts	0.7
Direct Labor	3.2
Distributables (Indirect)	2.9
Total Field Costs	**12.2**

22. Plant 24 (Coal Refuse and Ash Disposal)

22. Design Basis, Criteria and Considerations

This plant is for the disposal of coal refuse from Coal Cleaning and Preparation (Plant 1) and ash or slag from the Hydrogen Production by Coal Gasification (Plant 9).

The coal refuse consists of fine and coarse material which requires separate methods of disposal. The coarse coal refuse and ash are conveyed to the coal mine via conveyor belt for disposal in land reclaimation.

The fine coal refuse material is piped as a coal water slurry to a settling basin. The bottom of the settling basin is scraped continuously to move the fine refuse slurry to the basin shores. From the basin shores, bulldozers spread the material for air drying. After the spread material is sufficiently dry to have the consistency of a filter cake, bulldozers load the material onto the conveyor for transferral back to the mine.

22.1 Major Equipment Summary

EQUIPMENT LIST

Equipment No.	Type	Size or Capacity
24-T101	Refuse conveyor belt	8500 TPD
24-T103A,B	Bulldozer	480 yd^3/hr
24-T104	Settling Basin Scraper	1545 tons solid/day

22.2 Operating Manpower Requirements

The operating manpower required for this plant is covered by the manpower requirements of Plant 1 and Plant 9.

22.3 Plot Area Required

Description	Area (Acres)
Refuse Conveyor Belt	Included within coal feed conveyor belt right of way
Settling Basin	3
Fine Refuse Slurry Drying Area	30

22.4 Capital Cost and Breakdowns (First & Nth Plant)

The field costs and breakdowns for Plant 24 are given below in Table 22.1. This plant being an OSBL plant, its field costs and breakdowns are the same for the first as well as Nth plant scenarios. Note that field costs for each plant do not include home office costs or contingency. These were estimated for the whole complex and are given in Section 41.

Table 22.1

Plant 24 (Coal Refuse and Ash Disposal)
Field Costs and Breakdowns
(First & Nth Plants)
2nd Quarter, 1991

Field Costs Breakdown	Costs ($MM)
Major Equipment	11.1
Bulk Materials	4.8
Subcontracts	1.5
Direct Labor	6.0
Distributables (Indirect)	5.4
Total Field Costs	**28.8**

23. Plant 25 (Chemical and Catalyst Handling)

23.0 Design Basis, Criteria and Considerations

This plant provides storage and handling for catalyst and chemicals used in all the plants. Additionally, it provides a consolidated location for tracking catalyst and chemical start-up and daily consumption requirements.

Plants requiring chemicals or catalysts include 2 (Coal Liquefaction), 3 (Gas Plant Separation), 4 (Naphtha Hydrotreater), 5 (Gas Oil Hydrotreater), 6 (Hydrogen Purification), 8 (Rose Solvent Recovery), 9 (Hydrogen Production via Coal Gasification), 11 (By-Product Sulfur Recovery), 32 (Raw, Cooling, and Service Water), 38 (Ammonia Removal), and 39 (Phenol Removal).

The equipment for this plant includes an enclosed warehouse for storing chemicals and catalysts and forklifts for transporting pallets of chemicals or catalysts into or out of the warehouse.

A warehouse is required to collect all chemicals into one area for distribution to the various plants as needed. Additionally, the warehouse is used as a temporary storage for spent catalyst that must be returned to the catalyst vendor for regeneration at the vendor's facilities.

This plant identifies all major plant chemical and catalyst requirements for startup and continuous operation.

23.1 Major Equipment Summary

Equipment No.	Type	Description
25-R101	Chemical & Catalyst Warehouse	100 ft. x 60 ft.
25-T101A,B	Forklift	Electric Motor, 25 hp

23.2 Catalyst and Chemical Summary

Plant 25 provides storage and handling for chemicals and catalysts used in all the plants. Table 23.1 below summarizes the start-up and consumption rates for the various chemicals or catalysts.

Table 23.1

OVERALL COMPLEX CATALYST AND CHEMICAL SUMMARY

Chemical or Catalyst	For Plant No.	Quantity Required: Start-Up	Quantity Required: Consumption
Amocat-1C, 1-1/2" Extrudate	2	2,253,000 lb	68,130 lb/day
MEA	3	100 bbl	20 gal/day
Hydrotreating Catalyst	4	80,000 lb	3 year life
Hydrotreating Catalyst	5	490,000 lb	3 year life
MEA	6	1,200 bbl	30 gal/day
Rose Solvent	8	10,000 bbl	300 gal/day
BASF K8-11 or Haldor Topsoe SSK Catalyst	9	19,000 ft^3	3 year life
2" SS Pall Ring Packing	9	3,400 ft^3	3 year life
2" CS Pall Ring Packing	9	4,300 ft^3	3 year life
Methanol	9	2,500 bbl	200 gal/day
Claus Catalyst Kaiser S-201	11	18,400 ft^3	5 year life
SCOT Catalyst	11	6,500 ft^3	5 year life
2" SS Pall Ring Packing	11	2,500 ft^3	3 year life
MDEA	11	500 bbl	50 gal/day

Chemical or Catalyst	For Plant No.	Quantity Required Start-Up	Consumption
30% Ammonia	31		936 lb/day
Sodium Sulfite	31		240 lb/day
Polymer & Chelant		7,000 lbs	
Disodium Phosphate	31	2,000 lbs	144 lb/day
Alum	32	30,000 lbs	4,680 lb/day
Polymer	32	2,000 lbs	156 lb/day
98% H_2SO_4	32	15,000 gals	15,680 lb/day
50% NaOH	32	30,000 gals	38,754 lb/day
Polymeric Dispersion	32	7,000 lbs	1,624 lb/day
Non-ionic Surfactant	32	300 lbs	24 lb/day
Chlorine	34	2,000 lbs	350 lb/day
Polymer	34	3,000 lbs	450 lb/day
PAC	34	6,000 lbs	2,000 lb/day
Phosphoric Acid as 100% H_3PO_4	38	11,0331 lb	3,460 lb/day
Dephenoliz-ation Solvent	39	7,912 lb	170 lb/day

23.3 Operating Manpower Requirements

There is no special manpower requirement for this plant. It is covered by the manpower of other plants located in the same area.

23.4 Plot Area Requirements

The plot area required for this plant is 100 ft. X 60 ft.

23.5 Capital Cost and Breakdowns (First & Nth Plant)

The field costs and breakdowns for Plant 25 are given below in Table 23.2. This plant being an OSBL plant, its field costs and breakdowns are the same for the first as well as Nth plant scenarios. Note that field costs for each plant do not include home office costs or contingency. These were estimated for the whole complex and are given in Section 41.

TABLE 23.2

Plant 25 (Catalyst and Chemicals Handling)
Field Costs and Breakdowns
(First & Nth Plants)
2nd Quarter, 1991

Field Costs Breakdown	Costs ($MM)
Major Equipment	--
Bulk Materials	--
Subcontracts	0.3
Direct Labor	--
Distributables (Indirect)	--
Total Field Costs	**0.3**