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U.S. DEPARTMENT OF ENERGY
PITTSBURGH ENERGY TECHNOLOGY CENTER

DIRECT COAL LIQUEFACTION
LOW RANK COAL STUDY

CONTRACT NO. DE-AC22 90PC89857

EXECUTIVE SUMMARY

FOR THE LOW RANK COAL STUDY

FEBRUARY 1995
PITTSBURGH, PENNSYLVANIA

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Bechtel

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February 15, 1995

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

Attention: Dr. E. B. Klunder
Project Manager

Subject: D.O.E. Coal Liquefaction
Low Rank Coal Study
Contract No. DE-AC22 90PC89857
Bechtel Job No. 20952-003
Executive Summary for The Low Rank Coal Study
Letter No. BLD-038LRC

Dear Dr. Klunder:

Attached are two copies of Executive Summary for The Low Rank Coal Study. Copies to other members of DOE, as requested by the contract, are sent directly to each of them. If you have any questions or comments, please contact me.

Sincerely yours,

Syamal K. Poddar
Project Manager

Attachment

cc: Martin Byrnes, DOE/PETC
Edward Schmidt, DOE/PETC
R. Kaplan, AMOCO
File
Gilbert V. McGurl, DOE/PETC
Sai V. Gollakota, Burns & Roe

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1. Introduction

This study is the result of several modifications to the contract DE-AC22 90PC89857 between the Pittsburgh Energy Technology Center (PETC) of the U.S. Department of Energy (DOE) and Bechtel with AMOCO as subcontractor.

This work was divided into the following two parts: 1) *Design, Capital Cost and Economics for the Low Rank Coal Study,* and 2) *Two Separate Case Studies on Direct Liquefaction of Low Rank Coal.*

Design, Capital Cost and Economics for the Low Rank Coal Study

The overall objective of this part of the study was to develop a conceptual design for a direct coal liquefaction plant processing low rank coal, considering two production schemes for hydrogen. They are, hydrogen production by coal gasification and hydrogen production by steam reforming of natural gas. The first hydrogen production scheme was selected for the low rank coal study, whereas, the second hydrogen production scheme was considered as an optional case.

Included for this study were development of a conceptual design, capital costs estimates, economics and an ASPEN/PLUS based computer simulation model of the coal liquefaction complex. Bechtel, with Amoco as team members, conducted the study.

Case Studies:

As mentioned before, there were two separate case studies. They were: *Case Study I - Lower Operating Pressure for the Coal Liquefaction Reactor* and *Case Study II - Coal Liquefaction at a Gulf Coast Location.* Each of these case studies are discussed below.

Case Study I - Lower Operating Pressure for the Coal Liquefaction Reactor

It was demonstrated during the conceptual design of the plant, it was demonstrated that the coal liquefaction plant (Plant No.2) accounts for about 28% of the total installed capital cost. Because direct liquefaction of coal is a high pressure hydrogenation process, (the liquefaction pressure for the conceptual design of the Low Rank Coal complex was 3,300 psig), the understanding of the economic impact of lower pressure operation of coal liquefaction became an important consideration.

Through a modification of the contract, DE-AC22 90PC89857, DOE/PETC authorized Bechtel/Amoco to conduct a case study, which is included in this report as Case Study I. Case Study I includes the results of incorporating the effect of two lower levels of liquefaction reactor design pressure, viz., 2000 and 1000 psig. For this case study only the hydrogen production by coal gasification was considered.

Case Study II - Coal Liquefaction at the Gulf Coast Location

The conceptual studies on Illinois No.6, as well as the low rank coal study, were conducted on the assumption that the plants were located at their respective mine mouths. As a continuation of this effort, DOE/PETC was interested in evaluating the economic incentive for locating the low rank coal liquefaction complex at a site where a wider market for refining products is available, coupled with favorable labor rates. A Gulf Coast location was selected in order to determine the economic incentive for such a site for a direct liquefaction plant, processing low rank coal from Wyoming, (Black Thunder Coal Mine). As in Case Study 1, only the hydrogen production by coal gasification case was considered for this case study.

2. Scope and Technical Approach

The scope of the study and the technical approach to accomplish the primary objectives are summarized below under three headings viz, *Low Rank Coal Study, Case Study I - Lower Operating Pressure for the Coal Liquefaction* and *Case Study II - Coal Liquefaction at a Gulf Coast location*.

Low Rank Coal Study

- A conceptual design to produce coal liquids for refining feed based on two specific Wilsonville pilot plant runs which were deemed to represent the best available runs using low rank coal.
- a capital cost estimate for the entire liquefaction complex and an economic analysis and several sensitivities on the economics,
- an ASPEN/PLUS computer simulation model, that is applicable over a wide range of capacities, for low rank coal liquefaction for both hydrogen production options.
- and a thorough documentation of underlying assumptions for the conceptual design and the economics.

Case Study I - Lower Operating Pressure for the Coal Liquefaction Reactor

- An overview on the design considerations for various plants,
- a capital cost estimate and economic evaluation for the entire liquefaction complex considering two lower levels of coal liquefaction operating pressure viz 2000 and 1000 psig. The technical approach was based on several basic assumptions. These were: the kinetics of the coal liquefaction reaction remained unchanged, compositions remained essentially constant, and there was no effect on the OSBL plants and their capital costs.

Case Study II - Coal Liquefaction at the Gulf Coast Location

- A capital cost estimate for the entire complex and the economic impact in locating the plant in the Gulf Coast (in Louisiana along the Mississippi river).

- Quantification of the economic factors and then incorporating these factors into the economic spreadsheet developed in the baseline design to calculate the Crude Oil Equivalent (COE) in dollars per bbl for the Gulf Coast location.

3. Management and Execution Philosophy

The project was managed via the concept of Configuration Management. The concept of Configuration Management was tailored to this study and condensed into two fundamental control mechanisms, i.e., 1) *Trend Control* and 2) *Change Control*. *Trend Control* is the system/procedure to identify and document potential changes (*trends*). Scope changes are the approved outcome of *Trend Control*. By *Change Control* procedure, the scope change with associated cost and schedule impacts is incorporated in the project.

In general, the project management philosophy is the same as that utilized for the baseline design with Illinois #6 as the feed coal.

The Direct Liquefaction Study with Low Rank (Sub-Bituminous) Coal (Black Thunder coal from Wyoming) started in April 1993. Like the Baseline design study, the Low Rank Coal study has been structured under seven tasks. The final report incorporating the results of the two case studies on 1) Gulf Coast location of the plant and 2) reduction in liquefaction reactor pressure were conducted in task eight. These tasks and the definition of each task are shown below in Table 1:

Table 1
Direct Liquefaction Study with Low Rank Coal
Task Structure

Task No.	Description
I	Design Basis Definition
II	Process Design
III	Cost Estimates and Economics
IV & V	Modeling
VI	Final Reports
VII	Project Management and Other Support Services
VIII	Gulf Coast Location and Reduction in Liquefaction Reactor Pressure Studies

4. D liverables

There are several deliverables for this study. The deliverables to DOE/PETC are grouped as follows:

- Monthly progress reports
- A multi-volume stand-alone report for the conceptual design of the low rank coal liquefaction plant including the alternate option of hydrogen production by steam reforming of natural gas.
- ASPEN/PLUS process simulation model and associated documentation including basic assumptions for the process simulation; Fortran files required to run the simulation model including source code; ASPEN/PLUS input files for the two alternate options and ASPEN/PLUS generated reports for the low rank coal and the alternate option to produce hydrogen by steam reforming of natural gas option.
- A stand-alone report to include the results for the following studies: *Case Study I - Lower Operating Pressure for the Coal Liquefaction Reactor* and *Case Study II - Coal Liquefaction Complex Located at the Gulf Coast Location.*

5. The Low Rank Coal Study, Hydrogen Production by Coal Gasification

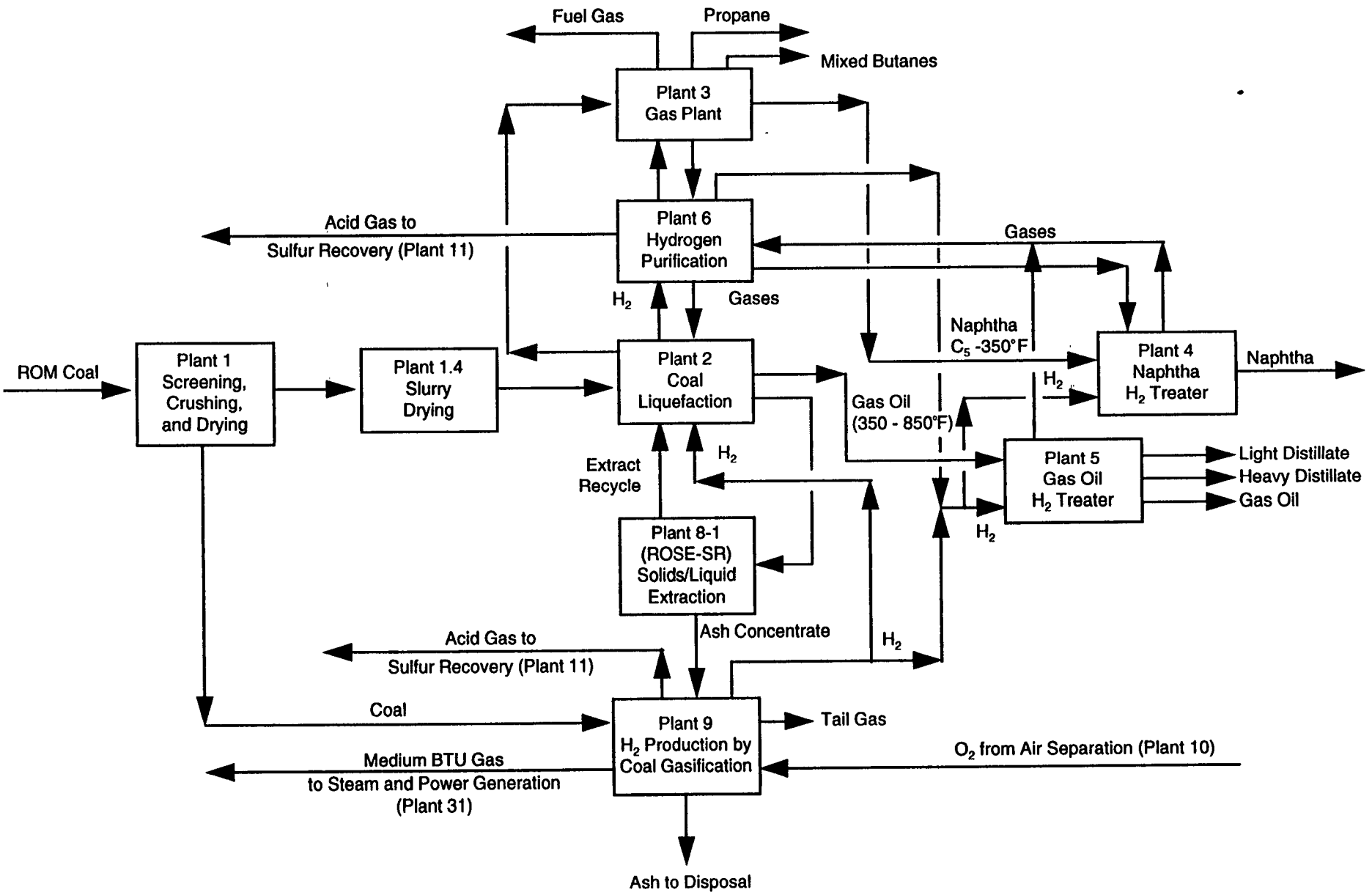
The design basis is a mine mouth plant located in Gillette, Wyoming in the Powder basin. The feed coal is low rank (Black Thunder Mine) coal. The liquefaction reactor design basis is based on experimental data generated at Advanced Coal Liquefaction Facility (pilot plant) located at Wilsonville, Alabama.

The commercial coal liquefaction complex for this study is comprised of a number of process plants supported by several off-site plants. The process plants which are designated as Inside Battery Limit (ISBL) plants are interconnected with the off-site plants designated as Outside Battery Limit (OSBL) plants.

The plant configuration is schematically shown by a simplified block flow diagram (Figure 1). This figure highlights the primary interconnections of the ISBL plants only.

Run of Mine coal enters the complex through the coal screening, crushing and grinding plant (Plant #1). The coal slurry containing 6.3% ash (MF), upon further grinding and drying to a moisture level of 2 wt% (as is) in Plant 1.4 before being fed to the liquefaction plant (Plant 2). The light products from Plant 2 are sent to the gas plant (Plant 3) for separation into fractions such as the fuel gas, propane and mixed butanes. The C_5-350°F stream goes to the Naphtha hydrotreater (Plant 4). The 350-850°F fraction from Plant 2 goes to the Gas Oil hydrotreater (Plant 5).

Figure 1
SIMPLIFIED BLOCK FLOW DIAGRAM



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The required hydrogen for the complex is provided via coal gasification in Plant 9 which utilizes Texaco technology. The coal liquefaction bottoms goes to Kerr McGee's ROSE-SR plant (Plant 8) which produces an extract that is recycled back to the liquefaction plant, and an ash concentrate stream that goes to the gasification plant (Plant 9).

The hydrogen purged from Plant 2 is recovered by the hydrogen purification plant (Plant 6), which is a combination of membrane and PSA units. The treated hydrogen is recycled back to Plant 2. Sulfur is recovered by a sulfur recovery plant (Plant 11). Sour water collected from various plants is sent through the ammonia recovery plant (Plant 38). Part of this treated water is sent to the coal gasification plant and the rest to the phenol recovery plant (Plant 39) followed by a waste water treatment plant (Plant 34). The oxygen required by the coal gasifiers is supplied by the air separation plant (Plant 10).

The most important process plant in the entire complex, often referred to as the "heart of the complex" is the coal liquefaction plant, (Plant 2). The Plant 2 design for the low rank coal case was developed by HRI, Inc. The design is for a close-coupled, catalytic-catalytic, two stage coal liquefaction (Dispersed Molybdenum in the first stage and Criterion 324 extrudates in the second stage) plant with extract recycled from the critical solvent deashing (ROSE-SR) plant.

The key operating conditions, overall product yields and design data for the baseline design case are shown in Tables 2 and 3.

The coal liquefaction complex is designed to produce approximately 60,000 barrels per day of C5+ hydrocarbon products. The primary products are C3, C4, C5-350°F (Naphtha), 350-450°F (Light Distillate), 450-650°F (Heavy Distillate) and 650-850°F (Gas Oil). Besides these, there are three by-products from the plant. They are: 1) Ammonia, 2) Sulfur, and 3) Phenols. The naphtha, distillates and gas oil products are hydrotreated to improve stability of these products for storage and transportation.

The overall material balance for the low rank coal liquefaction with hydrogen production by coal gasification is shown in Table 4.

Table 2
Key Operating Conditions

- Based on Wilsonville Pilot Plant Runs 262E and 263J (Low Rank Coal Black Thunder Mine)
- Reactor operating conditions:

Coal feed	
Rate, ton (MAF)/day	16800
Ash (MF), wt%	6.3
Temperature, °F	
First Stage	825
Second Stage	810
Catalyst Space Velocity (lb MAF coal/hr-ft^3 catalyst)	110
Catalyst Type	
1st Stage	Soluble dispersed Molybdenum (Molyvan L)
2nd Stage	Criterion 324 extrudates
Solvent/MAF Coal Ratio	2.525
Hydrogen consumption, wt% MAF Coal	5.8

Table 3
Reactor Yields and Product Qualities

Yield, Wt% MAF Coal	First Stage	Overall
CO	1.43	1.90
CO2	3.31	4.42
NH3	0.55	0.74
H2O	11.85	15.80
H2S	0.16	0.21
C1	1.21	2.68
C2	0.85	1.88
C3	0.89	1.99
C4	0.58	1.12
C5-350°F	2.45	9.90
350-450°F	2.88	7.39
450-650°F	8.20	22.17
650-850°F	7.35	19.85
850-1000°F	*22.60	0.73
1000°F	*27.59	7.71
Unconverted Coal	11.00	7.30
Ash	6.72	6.72
H2 (Consumed)	-2.90	-5.80

*estimated

Product Quality (API Gravity):

	First Stage (estimated)	Overall
IBP-350°F	46.5	47.5
350-450°F	27.4	27.9
450-650°F	17.2	17.7
650-850°F	10.9	11.9
850-1000°F	0.9	1.0
1000°F	-10.5	-9.5

Table 4
Overall Material Balanc_ for Low Rank Coal
with Hydrogen Production by Coal Gasification

Input to Complex		Output from Complex	
Stream Description	Quantity M Lbs/Hr	Stream Description	Quantity M Lbs/Hr
Coal (MAF)	1948	Propane	31
Coal (Ash)	131	Mixed Butanes	19
Air to Oxygen Plant	3166	Naphtha	143
Air to Sulfur Recovery Plant	105	Light Distillate	82
Reaction steam (H_2 Plant)	727	Heavy Distillate	316
		Gas Oil	285
		Sulfur	10
		Ammonia	14
		Phenol	3
		Reaction Water	250
		Ash/Slag	138
		High BTU Gas	85
		Medium BTU Gas	74
		Gas to Incinerator	288
		Nitrogen	2318
		Tail Gas (to Atm)	2021
Total Input	**6077**	**Total Output**	**6077**

6. Low Rank Coal, Hydrogen Production by Steam Reforming of Natural Gas

In this option, method of hydrogen is produced by steam reforming of natural gas rather than by coal gasification. In this case the ash concentrate from ROSE-SR plant is sent to a fluidized bed combustion (FBC) plant to generate high pressure steam.

Table 5 compares the product and by-product yields for the two modes of hydrogen production and Table 6 shows the overall material balance for the low rank coal design with hydrogen production by steam reforming of natural gas.

From Table 5 shows that the hydrocarbon product yields are identical for both modes of hydrogen production, however, the by-product yields are different. Significantly more sulfur by-product is produced when the hydrogen is produced by coal gasification.

This is because more sulfur bearing compounds are sent to the coal gasifier resulting in the higher sulfur production rate: 127 vs 37 tons per day.

Table 5
C mparison of Product and By-product Yields
Hydrogen Production by Coal Gasification vs. Steam Reforming

Coal (MAF) Feed Rate to liquefaction reactor	Hydrogen by Coal Gasification	Hydrogen by Steam Reforming
	TPSD 16,800	TPSD 16,800
Hydrocarbon Product Yields	**BPSD**	**BPSD**
Propane	4,268	4,268
Mixed Butanes	2,251	2,251
Naphtha	13,063	13,063
Light Distillate	6,610	6,610
Heavy Distillate	24,167	24,167
Gas Oil	21,221	21,221
TOTAL	**71,580**	**71,580**
Byproduct Yields	**TPSD**	**TPSD**
Sulfur	127	37
Ammonia	167	162
Phenol	45	45
TOTAL	**339**	**244**

Table 6
Overall Material Balance for Low Rank C al
with Hydrogen Production by Natural Gas Reforming

Input to Complex		Output from Complex	
Stream Description	Quantity M Lbs/Hr	Stream Description	Quantity M Lbs/Hr
Coal (Maf)	1400	Propane	31
Coal (Ash)	94	Mixed Butanes	19
Air to Sulfur Recovery Plant	78	Naphtha	143
Air to Fluid Bed Combustion Unit	3555	Light Distillate	82
Reaction steam (H_2 Plant)	491	Heavy Distillate	316
Natural Gas	331	Gas Oil	285
Limestone	15	Sulfur	3
		Ammonia	13
		Phenol	3
		Reaction Water	350
		Ash/Refuse	115
		High BTU Fuel Gas	79
		Flue Gas	3,646
		Medium Btu Gas	715
		Tail Gas	0.2
		Gas to Incinerator	164
Total Input	**5964**	**Total Output**	**5964**

7. Capital Cost Estimates

7.1 Methodology for Capital Cost Estimates

The overall plant cost was estimated by developing cost estimates (field cost) for each Inside Battery Limit (ISBL) plant and each Outside Battery Limit (OSBL) plant. For each plant (ISBL, as well as OSBL) the total field costs were estimated by summing the estimated costs of: 1) major equipment, 2) bulk materials, 3) sub-contracts, 4) direct labor, and 5) distributables (indirect costs).

The Nth plant (the concept of which is defined in this section) installed plant costs for the baseline case were calculated by: 1) taking the estimated ISBL plant cost for each ISBL plant, 2) adding the respective proportional amount of total OSBL costs, and then 3) adding proportional amounts of home office, engineering fee and contingency.

The Nth plant is defined as the Nth commercial plant built when the technology basis, plant design and operation are well established. The Nth plant has the following characteristics:

- Lowest reasonable plant cost contingency
- No spare trains
- Lowest reasonable engineering cost
- Shortest possible project schedule for construction and start-up
- Matured technology allowing the overall stream factor of the complex to be same as that of the first plant.

Case I - Lower Operating Pressure for the Coal Liquefaction Reactor

The overall complex was analyzed to establish the effect of lowering the operating pressure at the coal liquefaction plant. The estimated total installed cost for each of the operating pressures was developed by incorporating the capital cost for all the affected plants.

Case II - Coal Liquefaction at Gulf Coast

The estimated total installed cost for the Gulf Coast was established using the equipment parameters from the Low Rank Coal Study with hydrogen production by coal gasification with Gulf Coast construction costs and labor productivity from Bechtel's cost database.

7.2 Capital Cost for Low Rank Coal With Hydrogen Production by Coal Gasification

The capital costs estimates for the low rank coal with hydrogen production by coal gasification design that were generated by following the above methodology are shown in Table 7. These estimates, as discussed earlier, are for the "Nth Plant" scenario.

Table 7
Nth Plant Capital Costs for the Complex
Low Rank Coal Liquefaction with Hydrogen Production by Coal Gasification

Plant	No. of Trains	ISBL Plant Field Costs, 1000$	ISBL Plant Cost Adj. with OSBL Costs, 1000$	Installed Plant Costs, 1000$
1 & 1.4	10 & 4	186,500	265,000	344,600
2	4	792,400	1,125,900	1,464,200
3	1	19,200	27,300	35,500
4	1	9,500	13,500	17,600
5	1	114,000	162,000	210,600
6	1	232,800	330,800	430,200
8	1	33,400	47,500	61,700
9	5	353,000	501,600	652,300
10	5	184,600	262,300	341,100
11	1	10,200	14,500	18,800
38	1	45,200	64,200	83,500
39	1	17,300	24,600	32,000
Total		**1,998,100**	**2,839,200**	**3,692,100**

7.3 Capital Costs for Low Rank Coal with Hydrogen by Steam Reforming

The capital cost estimates for the low rank coal liquefaction with hydrogen production by steam reforming are shown in Table 8.

Table 8
Nth Plant Capital Costs for th Complex
Low Rank Coal Liquefaction
with Hydrogen Production by Natural Gas Reforming

Plant	Total No. of Trains	ISBL Plant Field Costs, 1000$	ISBL Plant Cost Adj. with OSBL Costs, 1000$	Installed Plant Costs, 1000$
1 & 1.4	10 & 4	143,600	213,100	277,200
2	4	792,400	1,175,700	1,529,500
3	1	19,200	28,500	37,100
4	1	9,500	14,100	18,300
5	1	114,000	169,100	220,100
6	1	232,800	345,400	449,400
8	1	33,400	49,600	64,500
9-01	3	144,500	214,400	278,900
10	1	21,200	31,500	40,900
11	1	3,800	5,600	7,300
38	1	44,400	65,800	85,700
39	1	17,110	25,400	33,000
Total		**1,575,900**	**2,338,100**	**3,041,800**

7.4 Capital Costs for 2,000 psig and 1,000 psig Liquefaction Pressures

The capital cost estimate for 3,300 psig is the same as for the low rank coal case design with hydrogen production by coal gasification. Estimates for 2,000 and 1,000 psig are shown in Tables 9 and 10, respectively.

Table 9
Nth Plant Capital Costs f r the Complex
Low Rank Coal Liquefaction
(2000 psig case)

Plant	Total No. of Trains	ISBL Plant Field Costs, 1000$	ISBL Plant Cost Adj. with OSBL Costs, 1000$	Installed Plant Costs, 1000$
1 & 1.4	10 & 4	186,500	271,200	352,400
2	4	664,220	966,000	1,254,800
3	1	19,200	27,900	36,300
4	1	9,500	13,800	18,000
5	1	99,410	144,600	187,800
6	1	228,580	332,400	431,900
8	1	33,400	48,600	63,200
9	5	353,000	513,400	667,000
10	5	184,600	268,610	348,800
11	1	10,200	14,800	19,300
38	1	45,200	65,700	85,400
39	1	17,300	25,200	32,700
Total		**1,851,110**	**2,692,210**	**3,497,600**

Table 10
Nth Plant Capital Costs for the Compl x
Low Rank Coal Liquefaction
(1,000 psig case)

Plant	Total No. of Trains	ISBL Plant Field Costs, 1000$	ISBL Plant Cost Adj. with OSBL Costs, 1000$	Installed Plant Costs, 1000$
1 & 1.4	10 & 4	186,500	277,600	364,700
2	4	547,200	814,400	1,070,100
3	1	19,200	28,600	37,600
4	1	9,500	14,100	18,600
5	1	84,140	125,200	164,600
6	1	231,900	345,200	453,500
8	1	33,400	49,800	65,400
9	5	353,000	525,440	690,400
10	5	184,600	274,700	361,000
11	1	10,200	15,200	20,000
38	1	45,200	67,200	88,400
39	1	17,300	25,800	33,900
Total		**1,722,140**	**2,563,240**	**3,368,200**

7.5 Capital Costs for Gulf Coast Location

The estimated capital costs for the Gulf Coast Plant location are shown in Table 11.

Table 11
Nth Plant Capital Cost for Liquefaction Complex
Low Rank Coal
Gulf Coast Location

Plant	Total No. of Trains	ISBL Plant Field Costs 1000$	ISBL Plant Cost Adj. with OSBL Costs 1000$	Installed Plant Costs 1000$
1 & 1.4	10 & 4	169,670	244,050	318,660
2	4	697,890	1,003,820	1,310,730
3	1	17,020	24,480	31,970
4	1	8,380	12,050	15,740
5	1	100,140	144,040	188,080
6	1	210,620	302,950	395,570
8	1	29,240	42,060	54,920
9	5	309,550	445,240	581,380
10	5	161,890	232,860	304,050
11	1	8,750	12,590	16,430
38	1	38,860	55,890	72,980
39	1	17,300	24,880	32,500
Total		**1,769,310**	**2,544,910**	**3,323,010**

8.0 Modeling Tools

The complete modeling package that was developed under this project was designed to be a research guidance tool to study technology advances and options in a case study approach. It does not feature optimization capabilities and is not a detailed process design tool. it was designed to predict the effects of various process and operations changes on the overall plant material and utility balances. It also was designed to predict the effects on the capital cost and operating labor. The modeling tools were developed in a way so that they are applicable to both the baseline and low rank coal cases.

A separate LOTUS spreadsheet economics model was developed that does a discounted cash flow analysis of the project taking results directly from the process simulation model output to calculate project economics.

Figure 2 shows a simplified user input-output diagram of the various computer models used in this project, and how they interact with each other. The ASPEN PLUS process simulation model is the heart of the modeling system. Although this model resides in a detailed process simulation model, many simplifying assumptions and approximations were made to keep the model manageable and still satisfy the requirements of being a research guidance tool, and not a design tool. If detailed process simulation models for design were developed, the system would have become unmanageable and would have required excessive computer resources.

The ASPEN PLUS process simulation model is based on the detailed plant designs developed for both the baseline and low rank coal cases. Fortran user block models are used to simulate most of the plants, and to predict their utilities consumptions, labor requirements and capital costs. Results are available in several forms including the normal ASPEN PLUS reports, specific plant summary reports, and an overall management summary report. A small output file also is generated for transferring the key process simulation model results to the LOTUS spreadsheet economics model.

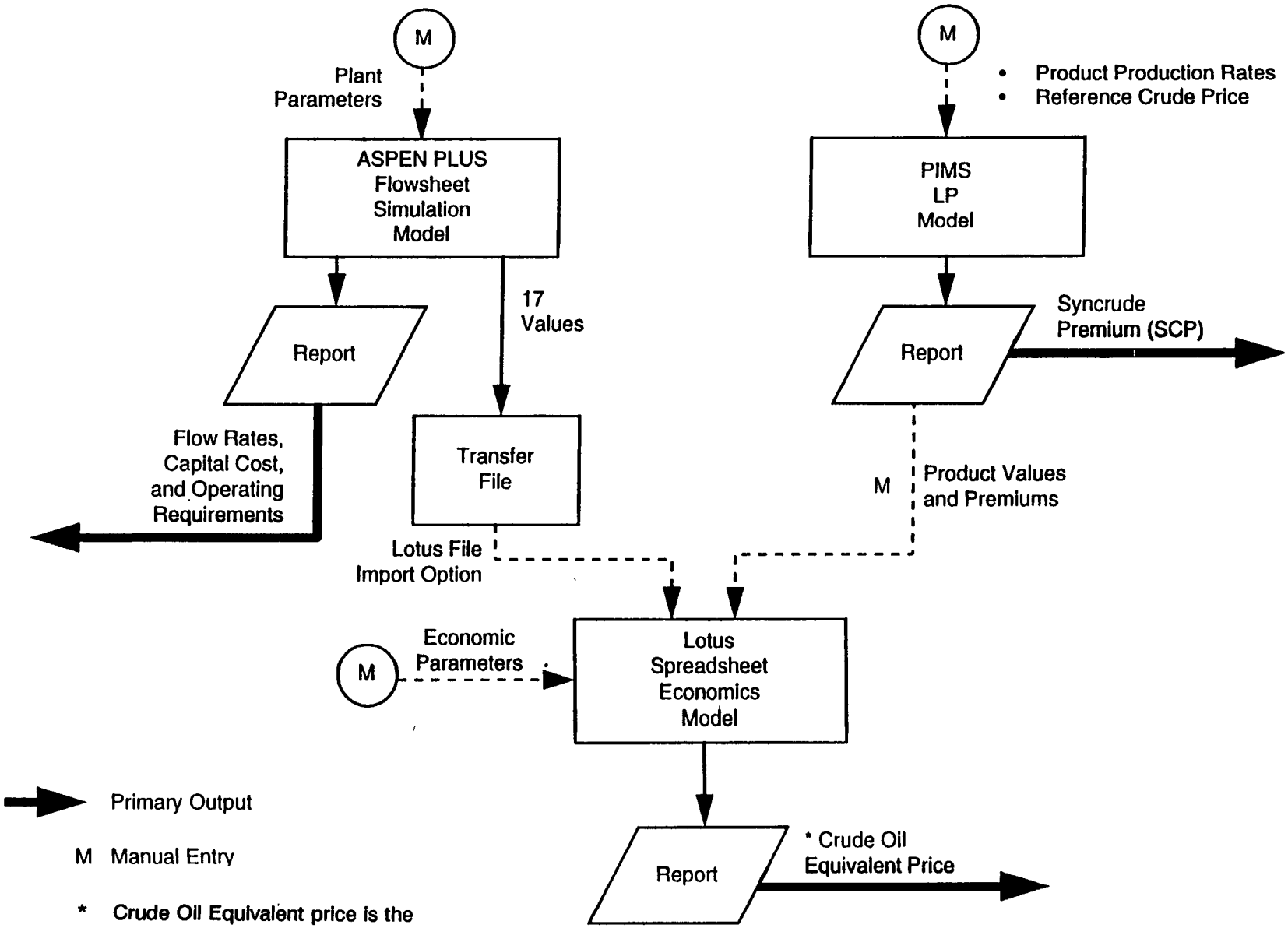
Bechtel's linear programming tool, PIMS (Process Industry Modeling System) was used to value the coal liquid products by simulating a typical PADD II (mid-western) refinery. The product valuation expressed as Syncrude premium (SCP) was used for the LOTUS spreadsheet economics model. The product valuations were calculated for various scenarios as case studies. For these scenarios, different amounts of coal liquid products were fed to the refinery with corresponding amounts of petroleum being backed out. In general, it was assumed that the naphtha fraction of the coal liquid (C_5-350°F) was sent to the reforming unit, the light distillate fraction (350-450°F) went to blending (diesel and fuel oil), the heavy distillate fraction (450-650°F) went to diesel and fuel oil blending and/or was used as Fluid Catalytic Cracking Unit (FCCU) feed, and the vacuum gas oil (650-850°F) was used as a fuel oil blending stock and/or FCCU feed.

The LOTUS spreadsheet economics model takes the results from the other two models along with user supplied economic parameters and does a complete discounted cash flow analysis. This spreadsheet generates the net present value of the project at a specified internal rate of return (IRR) on equity. It also can be used to calculate what crude oil price is required to obtain a specific internal rate of return. In addition, this spreadsheet model allows studying the effects of other economic assumptions on project economics.

Figure 2

SIMPLIFIED USER INPUT - OUTPUT DIAGRAM FOR COMPUTER MODELS USED IN

LOW RANK COAL STUDY



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9.0 Overall Product and By-product Valuation

9.1 Low Rank Coal Liquefaction Complex Located at Mine Mouth

Product Valuation

For the low rank coal study, the coal liquid products were valued utilizing Bechtel's linear programming modeling tool, PIMS (Process Industry Modeling Systems). A typical PADD II refinery configuration and crude mix with a fixed price were assumed. Also, it was assumed that the coal liquid naphtha (C5-350°F) was sent to a reforming unit, the light distillate (350-450°F) was used for blending (diesel and fuel oil), the heavy distillate (450-650°F) was used as a fuel oil blending stock and/or FCCU feed, and the vacuum gas oil (650-850°F) was used as a fuel oil blending stock and/or FCCU feed. The product valuation was then determined for various scenarios and expressed as "Syn-Crude Premium" (SCP). The SCPs varied between 1.07 and 1.27. These SCPs were used for the mine mouth cases.

By-product Valuation

The by-products from this complex are sulfur, ammonia, phenol, propane and mixed butanes. The production rate of these streams for the two low rank coal design cases: hydrogen production by coal gasification and hydrogen production by steam reforming and their assumed prices are shown in Table 12.

Table 12

By-Product Values
Liquefaction Complex Located at Mine Mouth

	Production Rate		Price
Sulfur	127	STPD	$ 47.30/ton
Ammonia	167	STPD	$200.00/ton
Phenol	45	STPD	$625.00/ton
Propane	4,268	BPSD	$ 12.29/bbl
Mixed Butanes	2,251	BPSD	$ 13.86/bbl

9.2 Product Valuation at Gulf Coast Location

LP Model Basis/Assumptions

Refinery operations for the co-processing of crude oil and coal-derived liquids were simulated using Bechtel's Process Industry Modeling System (PIMS) for a typical PAD III (Gulf Coast refinery). Two LP models were developed; a baseline model for processing

crude oil and a second model for processing crude oil and varying quantities of coal liquid. The crude oil mix was held constant for all cases.

For a range of coal liquid products from 25 to 100 percent, the corresponding SCP ratios varied from 1.07 to 1.20. A case for crude oil plus 1,000 B/D of coal liquid products resulted in a SCP ratio of 1.25.

The above results show the pricing benefit of allocating a small portion of the liquid production to possibly a number of refineries. As shown in the economic analysis, though the value of SCP was considered for the complete range 1.07 to 1.25, it is reasonable to assume that a higher value of SCP (1.25) is a realistic value for the economic analysis.

By-Product Valuation Gulf Coast

The by-products for this complex are sulfur, ammonia, phenol, propane and mixed butanes. The production rate and prices are identical to the values shown in Table 12 for hydrogen production by coal gasification. They are reproduced below for the benefit of the reader.

Table 13
By-Product Values
Liquefaction Complex Located at Gulf Coast

	Production Rate		Price
Sulfur	127	STPD	$ 47.30/ton
Ammonia	167	STPD	$ 200.00/ton
Phenol	45	STPD	$ 625.00/ton
Propane	4,268	BPSD	$ 12.29/bbl
Mixed Butanes	2,251	BPSD	$ 13.86/bbl

10. Economics and Sensitivities

10.1 Economics of Low Rank Coal Study

The economic analysis to determine the Crude Oil Equivalent price (COE) in $/bbl was carried out using the LOTUS 1-2-3 based spreadsheet model developed by Amoco. There were several key assumptions made in carrying out this analysis.

Key Assumptions

Project start date	January, 1994
Years of construction	4
Years of operation	25
Depreciation, years	10
Maintenance, % initial capital	1
Working capital, % revenue	10
Working capital, % liquid	50
Owner's cost, % initial capital first year operation	5
Bank interest rate	8
Federal income tax rate, %	34
Percent equity	25
Percent IRR on equity	15
General inflation %	3
Raw material price escalation	same as general inflation of 3%
State Tax	0
SCP	1.07

Results

The results of the economic analysis are presented separately for the low rank coal cases with hydrogen production by coal gasification and hydrogen production by steam reforming. These results are shown in Tables 14 and 15, respectively. They were obtained at 15% IRR on equity. Each of these two tables has three sections. These are: 1) Model Input section (based on overall plant material balance), 2) Input Data Relating to Key Assumptions, Construction, Schedules, and Feed and Product Costs, and 3) Results Summary.

As shown in Table 14, the low rank coal case with hydrogen production by coal gasification results in an equivalent crude oil price of $32.75/bbl. For the optional case where hydrogen is produced by steam reforming of natural gas, the Crude Oil Equivalent price is $33.85/bbl (as shown in Table 15).

Table 14
Economic Analysis of Low Rank Coal Case with Hydrogen Produced by Coal Gasification

Model Input (based on overall plant material balance)

ROM coal feed rate, MTSD[1]	24.951
Coal cleaning refuse rate, MTSD[1]	0.0
Ash production rate, MTSD[1]	1.664
Natural gas rate, MMMBTU/SD	109.783
Electricity purchase, MEGA-WH/SD	0.00
Raw water make-up, MMGSD	12.641
Naphtha production, MBSD	12.916
Light distillate production, MBSD	6.633
Heavy distillate Production, MBSD	24.078
Gas oil production, MBSD	21.358
Liquid propane production, MBSD	4.182
Mixed butanes production, MBSD	2.246
Ammonia production, MTSD[1]	0.167
Phenol production, MTSD[1]	0.045
Sulfur production, MTSD[1]	0.124
Number of operators/boardmen	430
Total installed capital, $MM (E-yr)	3692.1 4th quarter 1993

Tabl 14 - continu d

Input data relating to key assumptions,
construction schedule, and feed and product costs

Total installed capital, $MM (base year)	3719.5
Operating factor, percent	88.4
Percent plant operational, 1st yr.	100.0
Percent plant operational, 2nd yr.	100.0
Percent plant operational, 3rd yr.	100.0
Refuse disposal cost, $/S-ton (base yr)	2.00
Ash disposal cost, $S-ton (base yr)	5.00
Catalyst & Chemicals (prod), $MM/MBSD (base yr)	1.23*
Operator pay rate, $/op./hr. (base yr)	18.50
Overhead factor (benefits, etc.)	1.40
Other labor costs, $MM/yr (base yr)	14.27
Maintenance, taxes & insurance % init. cap.	1.00
Sales, Admin., Research, $MM/yr (base yr)	0.0
Percent capital 1st yr. construction	20.0
Percent capital 2nd yr. construction	30.0
Percent capital 3rd yr. construction	30.0
Percent capital 4th yr. construction	20.0
Working capital percent revenue	10.0
Percent liquid of working cap.	50.0
Owner's cost, % init. cap., 1st yr op.	5.00
ROM coal (MF) price, $/S-ton (base yr)	6.16
Natural gas price, $/MMBTU (base yr)	2.00
Electricity price, $/KWH (base yr)	0.050
Raw water, $/MGAL (base yr)	2.50
General inflation, percent/yr	3.00
Constr. cost index (CCI), %yr	3.00
Coal escalation+, percent/yr	3.00
Crude oil escalation+, percent/yr	3.00
Natural gas escalation+, percent/yr	3.00
Naphtha syncrude prem.	1.07
Naphtha price, $BBL (base yr)	0.00
Light distillate syncrude prem.	1.04

Table 14 - continued

Light distillate price, $/BBL (base yr)	0.00
Heavy distillate syncrude prem	1.09
Heavy distillate price, $BBL (base yr)	0.00
Gas oil syncrude prem.	1.04
Gas oil price, $/BBL (base yr)	0.00
Liquid propane price, $/BBL (base yr)	12.29
Mixed butane price, $/BBL (base yr)	13.86
Ammonia price, $S-ton (base yr)	200.00
Mixed phenol price, $/S-ton (base yr)	625.00
Sulfur price, $/short-ton (base yr)	47.30
Construction start = Jan 1 (base yr)	1994
Percent equity	25
Imputed interest rate, %/yr	0.00
Bank interest rate, percent/yr	8.00
Federal income tax rate, %/yr	34.00
State income tax rate, %/yr	0.00
Fixed cost, % init. cap. (0 = not used)	0.00
Term of loan, years (fixed)	10
Years of construction (fixed)	4
Years of operation (fixed)	25
Depreciation, years (fixed)	10

Result Summary

Base year	1994
Total capital	$3719.5 MM
Syn Crude Premium (SCP)	1.07
Crude Oil Equivalent (PADD II)	32.75 $/BBL (base yr)

(1) Rates are in 1000 short tons per stream day

Note:
M = 1000X
MM = 1000 X M
MMM = 1000 X MM

* Calculated value
+ Inflation included

Table 15
Economic Analysis of Low Rank Coal
with Hydrogen Production by Steam Reforming of Natural Gas

Model Input (based on overall plant material balance)

ROM coal feed rate, MTSD[1]	17.929
Coal cleaning refuse rate, MTSD[1]	0.0
Ash production rate, MTSD[1]	1.38
Natural gas rate, MMMBTU/SD	321.052
Electricity purchase, MEGA-WH/SD	0.0
Raw water make-up, MMGSD	12.725
Naphtha production, MBSD	12.916
Light distillate production, MBSD	6.633
Heavy distillate Production, MBSD	24.078
Gas oil production, MBSD	21.358
Liquid propane production, MBSD	4.182
Mixed butanes production, MBSD	2.246
Ammonia + oxygen production, MTSD[1]	0.167
Phenol production, MTSD[1]	0.045
Sulfur production, MTSD[1]	0.37
Number of operators/boardmen	328
Total installed capital, $MM (E-yr)	3041.9 4th quarter 1993

Table 15 - continued

Input data relating to key assumptions,
construction schedule, and feed and product costs

Total installed capital, $MM (base year)	3064.5
Operating factor, percent	88.4
Percent plant operational, 1st yr.	100.0
Percent plant operational, 2nd yr.	100.0
Percent plant operational, 3rd yr.	100.0
Refuse disposal cost, $/S-ton (base yr)	2.00
Ash disposal cost, $S-ton (base yr)	5.00
Catalyst & chemicals, f(prod), $MM/MBSD (base yr)	1.23*
Operator pay rate, $/op./hr. (base yr)	18.50
Overhead factor (benefits, etc)	1.40
Other labor costs, $MM/yr (base yr)	14.27
Maintenance, taxes & insurance % init. cap.	1.00
Sales, Admin., Research, $MM/yr (base yr)	0.00
Percent capital 1st yr. construction	20.0
Percent capital 2nd yr. construction	30.0
Percent capital 3rd yr. construction	30.0
Percent capital 4th yr. construction	20.0
Working capital percent revenue	10.0
Percent liquid of working cap.	50.0
Owner's cost, % init. cap., 1st yr op.	5.00
ROM coal (MF) price, $/S-ton (base yr)	6.16
Nat. gas price, $/MMBTU (base yr)	2.00
Electricity price, $/KWH (base yr)	0.050
Raw water, $/MGAL (base yr)	2.50
General inflation, percent/yr	3.00
Constr. cost index (CCI), %/yr	3.00
Coal escalation+, percent/yr	3.00
Crude oil escalation+, percent/yr	3.00
Natural gas escalation+, percent/yr	3.00
Naphtha syncrude prem.	1.07
Naphtha price, $BBL (base yr)	0.00
Light distillate syncrude premium	1.04

Table 15 - continued

Light distillate price, $/BBL (base yr)	0.00
Heavy distillate syncrude prem	1.09
Heavy distillate price, $/BBL (base yr)	0.00
Gas oil syncrude prem.	1.04
Gas oil price, $/BBL (base yr)	0.00
Liquid propane price, $/BBL (base yr)	12.29
Mixed butane price, $/BBL (base yr)	13.86
Ammonia price, $S-ton (base yr)	200.00
Mixed phenol price, $/S-ton (base yr)	625.00
Sulfur price, $/short-ton (base yr)	47.30
Construction start = Jan 1 (base yr)	1994
Percent equity	25
Imputed interest rate %/yr	0.00
Bank interest rate, percent/yr	8.00
Federal income tax rate, %/yr	34.00
State income tax rate, %/yr	0.00
Fixed cost, % initial capital (0 = not used)	0.00
Term of loan, years (fixed)	10
Years of construction (fixed)	4
Years of operation (fixed)	25
Depreciation, years (fixed)	10

Result Summary

Base year	1994
Total capital	$3064.5 MM
Syn Crude Premium (SCP)	1.07
Crude Oil Equivalent (PADD II)	33.85 $/BBL (base yr)

(1) Rates are in 1000 short tons per stream day

Note:
M = 1000X
MM = 1000 X M
MMM = 1000 X MM

* Calculated value
+ Inflation included

Sensitivities on Economics

A sensitivity analysis on economics was done to determine the impact of changes in capital, raw material, owner's equity, price escalation (per EIA) on coal, natural gas and crude oil, and syncrude premium, respectively. Results of this analysis are given in Table 16.

Table 16

ECONOMICS	
Case	**COE $/bbl**
Low Rank Coal with H_2 production by coal gasification	32.75
Low Rank Coal with H_2 production from natural gas	33.85

SENSITIVITIES (H_2 Production by Coal Gasification)		
Item	**Change**	**Δ $/bbl**
• Capital	± 10%	± 2.35
	± 25%	± 6.10
• Raw Material		
Coal	± 25%	± 0.55
Natural Gas	± 25%	± 0.70
• Owner's Equity	± 100%	± 3.68
• Price Escalation, per EIA		- 7.84
Coal	+ 1.6	
Natural gas	+ 3.5	
Crude oil	+ 2.9	
• Syncrude Premium	+0.20	- 5.14

As shown in table 16, a change in capital cost by 10% changes the Crude Oil Equivalent price by $2.35/bbl and a 25% change causes a change of $6.10/bbl for the Crude Oil Equivalent price. A 25% change in coal and natural gas price individually changes the Crude Oil Equivalent price by $0.55/bbl and $0.70/bbl respectively.

Increasing the owner's equity by 100% (25% to 50%) increases the Crude Oil Equivalent price by $3.68/bbl.

When coal, natural gas and crude oil are individually allowed to escalate per the EIA forecast, instead of at the fixed rate of 3% (inflation), the equivalent crude oil price decreases by 7.84/bbl. The increase in syncrude premium to 1.27 results in a drop in the Crude Oil Equivalent price by $5.14/bbl.

In order to test out the effect of inflation rate on COE price, a sensitivity study was conducted on the various level of inflation, starting from 0% to a maximum of 3% per year with 1% increment. In previous calculations of 15% IRR on equity, the calculation includes 3% yearly inflation.

Table 17

Rate of Inflation Sensitivities on Economic Results

Rate of Inflation % per year	COE $ per bbl
0	39.10
1	36.85
2	34.75
3	32.75

10.2 Economics for Case Study I - Lower Operating Pressure for the Coal Liquefaction Reactor

The economic analysis to determine the Crude Oil Equivalent price (COE) for the three pressure cases in $/bbl was carried out by using the LOTUS 1-2-3 based spreadsheet model. There were several key assumptions made in carrying out this analysis.

Key Assumptions

In order to compare the economics for the different pressure cases on the same basis the key economic assumptions were the same.

Project Start Date	January, 1994
Years of construction	4
Years of operation	25
Depreciation, Years	10
Maintenance, % initial capital	1
Working capital, % revenue	10
Working capital, % liquid	50
Owner's cost, % initial capital first year operation	5
Bank interest rate	8
Federal income tax rate, %	34
Percent equity	25
Percent IRR on equity	15
General inflation %	3
Raw material price escalation	same as general inflation of 3%
State Tax	0
SCP	1.07

Results

Table 18 shows the results which were obtained at 15% IRR on equity. This table has three sections. These are: 1) Model Input Section (based on overall plant material balance), 2) Input Data Relating to Key Assumptions, Construction, Schedules, and Feed and Product Costs, and 3) Results Summary.

As shown in Table 18, the low rank coal case with coal liquefaction at 3,300, 2,000 and 1,000 psig correspond respectively to a crude oil equivalent (COE) prices of $32.74/bbl, $31.46/bbl and $30.61/bbl, respectively.

Table 18
Economic Analysis of Low Rank Coal Liquefaction Case with Hydrogen Produced by Coal Gasification

Model Input (based on overall plant material balance)

	3,300 psig	2,000 psig	1,000 psig
ROM coal feed rate, MTSD[1]	24.951	24,951	24,951
Coal cleaning refuse rate, MTSD[1]	0.0	0.0	0.0
Ash production rate, MTSD[1]	1.664	1.664	1.664
Natural gas rate, MMMBTU/SD	109.783	109.783	109.783
Electricity purchase, MEGA-WH/SD	0.00	0.00	0.00
Raw water make-up, MMGSD	12.641	12.641	12.641
Naphtha production, MBSD	12.916	12.916	12.916
Light distillate production, MBSD	6.633	6.633	6.633
Heavy distillate Production, MBSD	24.078	24.078	24.078
Gas oil production, MBSD	21.358	21.358	21.358
Liquid propane production, MBSD	4.182	4.182	4.182
Mixed butanes production, MBSD	2.246	2.246	2.246
Ammonia production, MTSD[1]	0.167	0.167	0.167
Phenol production, MTSD[1]	0.045	0.045	0.045
Sulfur production, MTSD[1]	0.124	0.124	0.124
Number of operators/boardmen	430	430	430
Total installed capital,$MM(E-yr),4th qtr 1993	**3,692.1**	**3,497.6**	**3,368.2**

Tabl 18 - continued

Input data relating to key assumptions,construction schedule, & feed & product costs

	3,300 psig	2,000 psig	1,000 psig
Total installed capital, $MM (base year)	3719.5	3523.5	3393.2
Operating factor, percent	88.4	88.4	88.4
Percent plant operational, 1st yr.	100.0	100.0	100.0
Percent plant operational, 2nd yr.	100.0	100.0	100.0
Percent plant operational, 3rd yr.	100.0	100.0	100.0
Refuse disposal cost, $/S-ton (base yr)	2.00	2.00	2.00
Ash disposal cost, $S-ton (base yr)	5.00	5.00	5.00
Catalyst & chemicals f(prod), $MM/MBSD (base yr)	1.23*	1.23*	1.23*
Operator pay rate, $/op./hr. (base yr)	18.50	18.50	18.50
Overhead factor (benefits, etc)	1.40	1.40	1.40
Other labor costs, $MM/yr (base yr)	14.27	14.27	14.27
Maintenance, taxes & insurance % init. cap.	1.00	1.00	1.00
Sales, Admin., Research, $MM/yr (base yr)	0.0	0.0	0.0
Percent capital 1st yr. construction	20.0	20.0	20.0
Percent capital 2nd yr. construction	30.0	30.0	30.0
Percent capital 3rd yr. construction	30.0	30.0	30.0
Percent capital 4th yr. construction	20.0	20.0	20.0
Working capital percent revenue	10.0	10.0	10.0
Percent liquid of working cap.	50.0	50.0	50.0
Owner's cost, % init. cap., 1st yr op.	5.00	5.00	5.00
ROM coal (MF) price, $/S-ton (base yr)	6.16	6.16	6.16
Natural gas price, $/MMBTU (base yr)	2.00	2.00	2.00
Electricity price, $/KWH (base yr)	0.050	0.050	0.050
Raw water, $/MGAL (base yr)	2.50	2.50	2.50
General inflation, percent/yr	3.00	3.00	3.00
Constr. cost index (CCI), %/yr	3.00	3.00	3.00
Coal escalation+, percent/yr	3.00	3.00	3.00
Crude oil escalation+, percent/yr	3.00	3.00	3.00
Natural gas escalation+, percent/yr	3.00	3.00	3.00
Naphtha syncrude prem.	1.07	1.07	1.07
Naphtha price, $BBL (base yr)	0.00	0.00	0.00
Light distillate syncrude prem.	1.04	1.04	1.04

Table 18 - continued

	3,300 psig	2,000 psig	1,000 psig
Light distillate price, $/BBL (base yr)	0.00	0.00	0.00
Heavy distillate syncrude prem	1.09	1.09	1.09
Heavy distillate price, $BBL (base yr)	0.00	0.00	0.00
Gas oil syncrude prem.	1.04	1.04	1.04
Gas oil price, $/BBL (base yr)	0.00	0.00	0.00
Liquid propane price, $/BBL (base yr)	12.29	12.29	12.29
Mixed butane price, $/BBL (base yr)	13.86	13.86	13.86
Ammonia price, $S-ton (base yr)	200.00	200.00	200.00
Mixed phenol price, $/S-ton (base yr)	625.00	625.00	625.00
Sulfur price, $/short-ton (base yr)	47.30	47.30	47.30
Construction start = Jan 1 (base yr)	1994	1994	1994
Percent equity	25	25	25
Imputed interest rate, %/yr	0.00	0.00	0.00
Bank interest rate, percent/yr	8.00	8.00	8.00
Federal income tax rate, %/yr	34.00	34.00	34.00
State income tax rate, %/yr	0.00	0.00	0.00
Fixed cost, % init. cap. (0 = not used)	0.00	0.00	0.00
Term of loan, years (fixed)	10	10	10
Years of construction (fixed)	4	4	4
Years of operation (fixed)	25	25	25
Depreciation, years (fixed)	10	10	10
R sult Summary			
Base year	1994	1994	1994
Total capital $MM	3719.5	3523.5	3393.2
Syn Crude Premium (SCP)	1.07	1.07	1.07
Crude Oil Equivalent (PADD II) (base year) $/BBL	32.75	31.46	30.61

(1) Rates are in 1000 short tons per stream day

Note:
M = 1000X
MM = 1000 X M
MMM = 1000 X MM

* Calculated value
+ Inflation included

10.3 Economics for Case Study II - Coal Liquefaction at Gulf Coast

The economic analysis to determine the Crude Oil Equivalent price (COE) in $/bbl was carried out by using the LOTUS 1-2-3 based spreadsheet model. The following key assumptions were made in carrying out this analysis.

Key Assumptions

Site	Wyoming	Gulf Coast
Project Start Date	January, 1994	January, 1994
Years of construction	4	4
Years of operation	25	25
Depreciation, Years	10	10
Maintenance, % initial capital	1	1
Working capital, % revenue	10	10
Working capital % liquid	50	50
Owner's cost, % initial capital first year operation	5	5
Bank interest rate	8	8
Federal income tax rate, %	34	34
Percent equity	25	25
Percent IRR on equity	15	15
General inflation %	3	3
Raw material price escalation	same as general inflation of 3%	same as general inflation of 3%
State Tax	0	0
SCP	1.07	See Table 19

Table 19
Economic Analysis of Wyoming vs Gulf Coast

Model Input (based on overall plant material balance)

Site	Wyoming	Gulf Coast
SCP	1.07	See Table 19
ROM coal feed rate, MTSD[1]	24.951	24.951
Coal cleaning refuse rate, MTSD[1]	0.0	0.0
Ash production rate, MTSD[1]	1.664	1.664
Natural gas rate, MMMBTU/SD	109.783	109.783
Electricity purchase, MEGA-WH/SD	0.00	0.00
Raw water make-up, MMGSD	12.641	12.641
Naphtha production, MBSD	12.916	12.916
Light distillate production, MBSD	6.633	6.633
Heavy distillate Production, MBSD	24.078	24.078
Gas oil production, MBSD	21.358	21.358
Liquid propane production, MBSD	4.182	4.182
Mixed butanes production, MBSD	2.246	2.246
Ammonia production, MTSD[1]	0.167	0.167
Phenol production, MTSD[1]	0.045	0.045
Sulfur production, MTSD[1]	0.124	0.124
Number of operators/boardmen	430	430
Total installed capital, $MM (E-yr), 4th qtr 1993	3692.1	3323.0

Tabl 19 - continued

Input data relating to key assumptions,construction schedule, & feed & product costs

Site	Wyoming	Gulf Coast
SCP	1.07	See Table 19
Total installed capital, $MM (base year)	3719.5	3347.7
Operating factor, percent	88.4	88.4
Percent plant operational, 1st yr.	100.0	100.0
Percent plant operational, 2nd yr.	100.0	100.0
Percent plant operational, 3rd yr.	100.0	100.0
Refuse disposal cost, $/S-ton (base yr)	2.00	2.00
Ash disposal cost, $S-ton (base yr)	5.00	See Table 19
Catalyst & Chemicals f(prod), $MM/MBSD (base yr)	1.23*	1.23*
Operator pay rate, $/op./hr. (base yr)	18.50	18.50
Overhead factor (benefits, etc)	1.40	1.40
Other labor costs, $MM/yr (base yr)	14.27	9.25
Maintenance, taxes & insurance % init. cap.	1.00	1.00
Sales, Admin., Research, $MM/yr (base yr)	0.0	0.0
Percent capital 1st yr. construction	20.0	20.0
Percent capital 2nd yr. construction	30.0	30.0
Percent capital 3rd yr. construction	30.0	30.0
Percent capital 4th yr. construction	20.0	20.0
Working capital percent revenue	10.0	10.0
Percent liquid of working cap.	50.0	50.0
Owner's cost, % init. cap., 1st yr. op.	5.00	5.00
ROM coal (MF) price, $/S-ton (base yr)	6.16	See Table 19
Natural gas price, $/MMBTU (base yr)	2.00	1.82
Electricity price, $/KWH (base yr)	0.050	0.060
Raw water, $/MGAL (base yr)	2.50	2.20
General inflation, percent/yr	3.00	3.00
Constr. cost index (CCI), %/yr	3.00	3.00
Coal escalation+, percent/yr	3.00	3.00
Crude oil escalation+, percent/yr	3.00	3.00
Natural gas escalation+, percent/yr	3.00	3.00
Naphtha syncrude prem.	1.07	See Table 19
Naphtha price, $BBL (base yr)	0.00	0.00
Light distillate syncrude prem.	1.04	See Table 19

Table 19 - continued

Site	Wyoming	Gulf Coast
SCP	1.07	See Table 19
Light distillate price, $/BBL (base yr)	0.00	0.00
Heavy distillate syncrude prem	1.09	1.09
Heavy distillate price, $BBL (base yr)	0.00	0.00
Gas oil syncrude prem.	1.04	See Table 19
Gas oil price, $/BBL (base yr)	0.00	0.00
Liquid propane price, $/BBL (base yr)	12.29	12.29
Mixed butane price, $/BBL (base yr)	13.86	13.86
Ammonia price, $S-ton (base yr)	200.00	200.00
Mixed phenol price, $/S-ton (base yr)	625.00	625.00
Sulfur price, $/short-ton (base yr)	47.30	47.30
Construction start = Jan 1 (base yr)	1994	1994
Percent equity	25	25
Imputed interest rate, %/yr	0.00	0.00
Bank interest rate, percent/yr	8.00	8.00
Federal income tax rate, %/yr	34.00	34.00
State income tax rate, %/yr	0.00	0.00
Fixed cost, % init. cap. (0 = not used)	0.00	0.00
Term of loan, years (fixed)	10	10
Years of construction (fixed)	4	4
Years of operation (fixed)	25	25
Depreciation, years (fixed)	10	10
Result Summary		
Base year	1994	1994
Total capital $MM	3719.5	3347.7
Syn Crude Premium (SCP)	1.07	See Table 19
Crude Oil Equivalent $BBL (base year)	32.75	See Table 19
PADD	II	III

(1) Rates are in 1000 short tons per stream day

Note:
M = 1000X
MM = 1000 X M
MMM = 1000 X MM

* Calculated value
+ Inflation included

Results

Results are shown in Tables 19 and 20. They were obtained at 15% IRR on equity.

Table 19 has three sections. These are: 1) Model Input Section (based on overall plant material balance), 2) Input Data Relating to Key Assumptions, Constructions, Schedules, and Feed and Product costs, and 3) Results Summary.

Table 20 summarizes the results as outlined below.

- **Cost of the coal delivered to the plant.** This cost is a function of the ROM coal (MF) price which is $6.16 /S-ton at the mine plus the cost of coal transportation. For this calculation we considered that Plant No.1, crushing and grinding remained in Wyoming and the coal was shipped with a moisture content of 12.9% to the Gulf Coast.

  For the coal transportation cost, Bechtel's transportation department estimated 15.00 dollars per ton, (100 ton minimum per rail car); one has to keep in mind. However, that in actual practice this will be a negotiable price and can vary. Therefore, in order to study the sensitivity of this parameter, the economics were calculated for the Gulf Coast for a range of coal transportation costs from 0.00 to 20.00 $/S-ton. Results are shown in Table 20.

- **Ash Disposal Cost.** The produced ash would be disposed of by shipping it back to the mine for refilling. The ash is in a vitrified stage. Consequently it is not necessary to use closed shipping containers. Therefore, the ash transportation cost would be the same as the coal transportation cost. The adjusted ash disposal cost for the different cases and the corresponding results in terms of COE price are shown in Table 20.

  SCP Values. In Section 9.2 under the heading of *Product Valuation at Gulf Coast Location*, the PIMS study to establish the synthetic crude premium ratios were discussed in detail. To explore the sensitivity to this ratio, we computed the economics for the two extreme values: 1.07 and 1.25.

Table 20
Summary of Economic Results

	Wyoming	Gulf Coast				
Coal transportation ($/S-ton)	0.00	0.00	5.00	10.00	15.00	20.00
Coal Cost ($/S-ton MF)	6.16	6.16	11.91	17.66	23.41	29.16
Ash disposal ($/ton)	5.00	5.00	7.50	12.50	17.50	22.50
COE, ($/Bbl @ SCP - 1.07)	32.74	28.81	30.97	33.19	35.40	37.62
COE, ($Bbl @ SCP - 1.25)	—	24.66	26.50	28.40	30.30	32.20

Note: To compute the ash disposal cost for the Gulf Coast, we started with half of the Wyoming cost, 2.50 $/ton. This is because the ash was already in transportation mode. To this amount we added the ash transportation cost as shown.

11. Discussion and Conclusions

The results presented in the various sections of this report are for a low rank subbituminous coal from the Black Thunder Mine located in Gillette, Wyoming. The pilot plant work was conducted at the Advanced Coal Liquefaction Research Facility in Wilsonville, Alabama (runs 262E and 263J). The precision and accuracy of the economic evaluation are subject to the scope and constraints of the study and the assumptions made during its execution. The key assumptions are included in Section 10 of this report. Besides, there are a number of common inherent limitations for both cases of the study. Some of these common limitations are:

Capital cost estimates were made with an accuracy of ± 30%. This level of accuracy in cost estimation did not require a detailed engineering of plants.

- Capital cost estimates were based on the "Nth plant" concept, and the plant operating factor was assumed to be the same as the "First plant" of the baseline design. The "Nth plant" assumes that the direct coal liquefaction technology is a mature technology, and that there are many similar plants already constructed and operating. Therefore, the uncertainties regarding engineering, construction and operability of a "Nth plant" are at a minimal level. No spare train for any plant was included in the design and capital cost estimates.

  The valuation of the various product streams was achieved by introducing a syncrude premium factor (SCP) which relates the coal liquefaction plant product value to a typical crude oil. Although SCP was determined in a rigorous manner using the Bechtel proprietary linear programming (LP) refinery model, PIMS, this still is an approximate value. Product valuation for all cases is discussed in Section 9.

Although the above mentioned limitations are inherent for both types of coal (low rank coal case and the baseline Illinois coal case) being investigated, relative comparisons of the results of the economic evaluation should be reasonably accurate.

11.1 Low Rank Coal Study

Two hydrogen production options were investigated: hydrogen production by coal gasification and hydrogen production by steam reforming of natural gas.

The ASPEN PLUS modeling package which was developed for the two low rank coal cases is an extension of what was developed for the baseline and improved baseline cases. The modeling package developed for this study should be considered as a research guidance tool, and not as a detailed process design tool. It was designed only to predict the effects of various process and operation changes on the overall plant material and utility balances, operating labor, and capital costs. Comparisons demonstrate that the model predicts reasonably well the capital cost of each ISBL plant as well as the feed and product flow rates of each ISBL plant.

Tables comparing the model predictions with the design results can be found in the body of the main report.

For the same internal rate of return (15%), the Crude Oil Equivalent (COE) price is lower for the case with hydrogen production by coal gasification ($32.75) than for the case with hydrogen production by steam reforming ($33.85).

In conclusion, there is no economic incentive to produce hydrogen by natural gas reforming for this particular low rank coal liquefaction case, in light of the natural gas price ($2.00/MMBTU) assumed for this study. Therefore, we recommend that some of the options which were looked at during the baseline study should be reexamined within the context of this study. The other recommendation is to carry out a similar economic study considering total integration of the coal liquefaction plant with an existing refinery.

11.2 Case Study I - Lower Operating Pressure for the Coal Liquefaction Reactor

Three cases were investigated: Coal liquefaction at 3,300, 2000 and 1000 psig liquefaction pressures. The results show that for the same internal rate of return (15%), the Crude Oil Equivalent (COE) prices are: $32.74/bbl, $31.46/bbl and $30.61/bbl for the 3,300, 2,000 and 1,000 psig cases, respectively.

Figure 3 shows a plot of coal liquefaction operating pressure (psig) vs COE, $/BBL. The solid line represents the calculated points by the Amoco economic model. The broken line represents the regression equation shown on the figure.

This case study demonstrates the directional impact on the overall economics of lowering the coal liquefaction reactor pressure. A set of experimental data and correlations showing the kinetics and hydrodynamics of low pressure operation will be beneficial to quantify such effects in a more rigorous fashion. This study suggests that there is a definite economic incentive to continue research efforts in developing low pressure coal liquefaction catalysts and generating kinetic and reactor hydrodynamic data.

11.3 Case Study II - Coal Liquefaction at Gulf Coast

Several cases were investigated and they are summarized in Table 19 and Figure 4. The various product streams were valued by introducing syncrude premium factors (SCP) which relate the coal liquefaction plant product values to a typical crude oils in a PADD II refinery for the Wyoming site and a PADD III refinery for the Gulf Coast site. Although the SCPs were determined in a rigorous manner using the Bechtel proprietary linear programming (LP) refinery model, PIMS, this is only an approximation. The PIMS LP model was developed based on a typical petroleum refinery located in PADD II making two different product slates. The behavior of the coal liquid products in the refinery was estimated based on the published properties and processing data of similar coal liquids. Because such data are limited at present, improvements only can be achieved by having better characterization data of various coal liquid streams.

Figure 4 shows the dependence of COE on coal transportation costs. Thus, it is concluded:

- For an SCP value of 1.07, the coal transportation cost must be equal or less than 8.00 $/ton for the Gulf Coast to be an economically attractive site.
- For an SCP of 1.25 or higher, the Gulf Coast is more attractive than Wyoming as a possible site as long as the coal transportation cost is less than $20/S-ton.
- For any intermediate value of SCP, the economic benefit to relocate the plant to the Gulf Coast is very much dependent on the negotiated transportation costs for coal and slag.

Figur 3

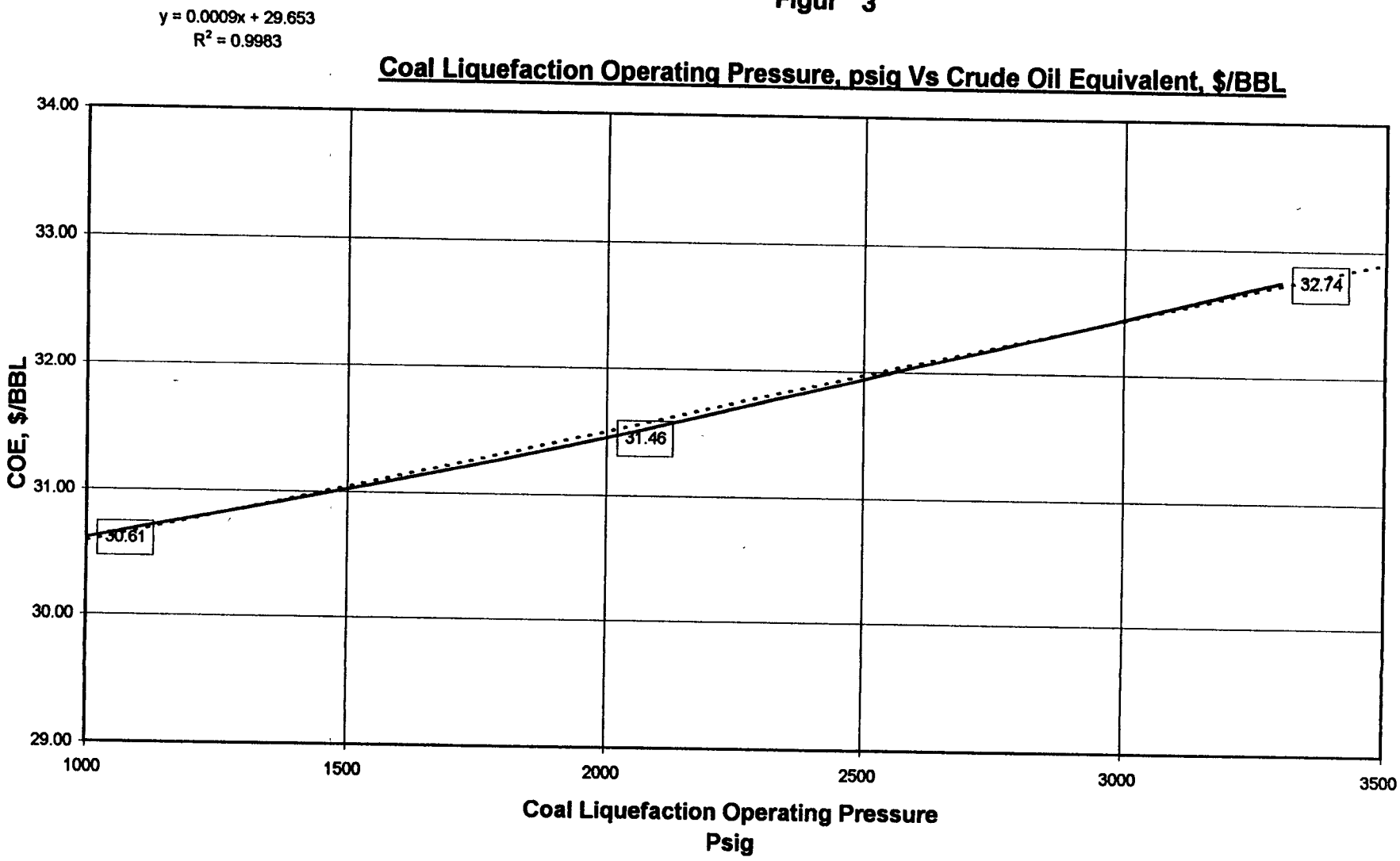
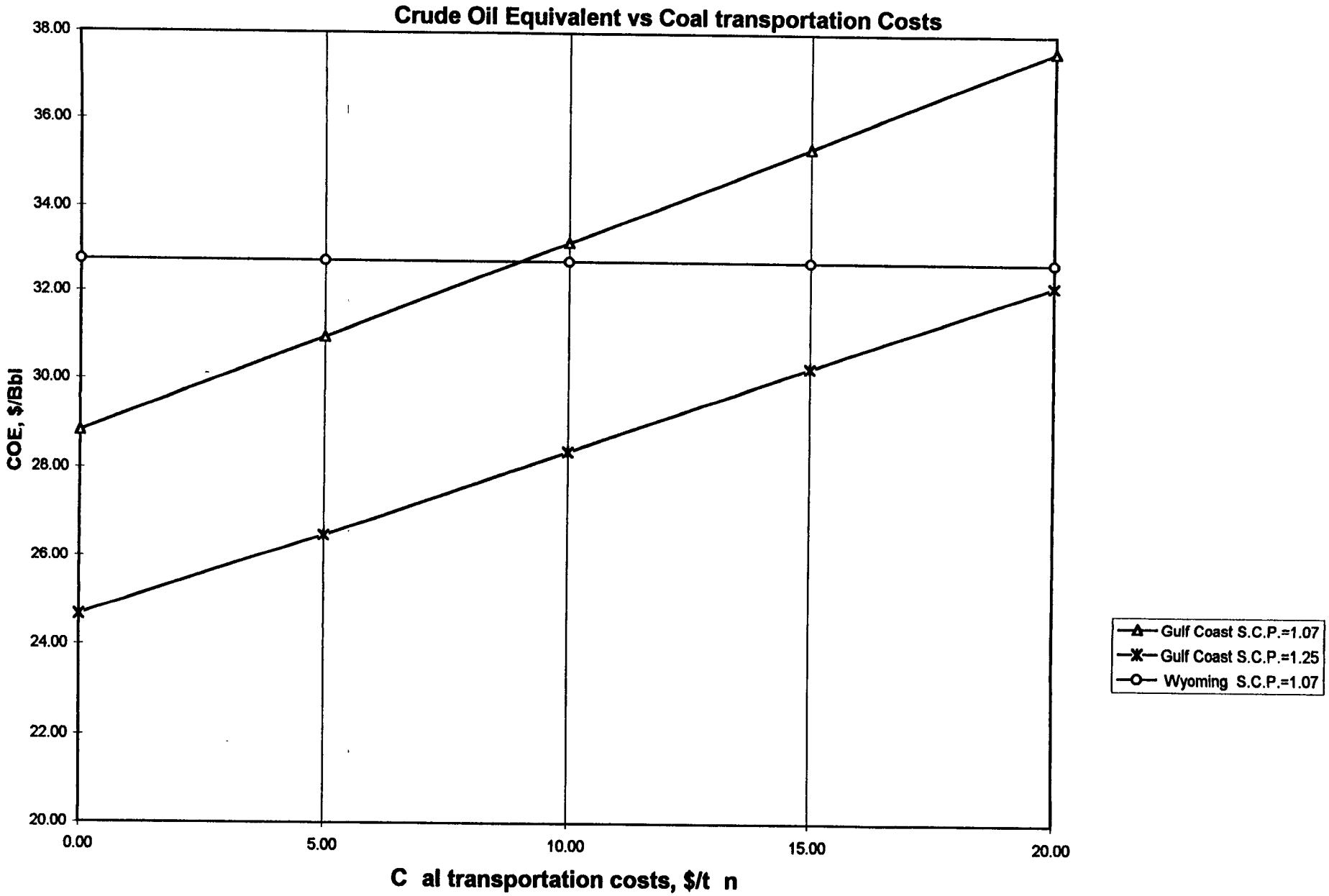

y = 0.0009x + 29.653
R² = 0.9983
Coal Liquefaction Operating Pressure, psig Vs Crude Oil Equivalent, $/BBL
34.00
33.00
32.00
31.00
30.00
29.00
COE, $/BBL
30.61
31.46
32.74
1000
1500
2000
2500
3000
3500
Coal Liquefaction Operating Pressure
Psig

Figure 4


Crude Oil Equivalent vs Coal transportation Costs
COE, $/Bbl
38.00
36.00
34.00
32.00
30.00
28.00
26.00
24.00
22.00
20.00
0.00
5.00
10.00
15.00
20.00
C al transportation costs, $/t n
Gulf Coast S.C.P.=1.07
Gulf Coast S.C.P.=1.25
Wyoming S.C.P.=1.07

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