APPENDIX B

DIRECT COAL LIQUEFACTION

This Appendix presents process descriptions and cost estimates for three direct liquefaction technologies: H-Coal; Exxon Donor Solvent; and Solvent Refined Coal-II. All of the estimates are for plants capable of producing 50,000 barrels of liquids per stream day (BPSD). Each presentation has two subdivisions: Process description and raw cost estimates. A final section presents estimates for all three systems.

Also considered in this chapter is the important question of upgrading the liquid products generated by these direct liquefaction processes. It's essential that the cost of upgrading be included when comparing the prices of useable products from direct liquefaction to those from other synfuel technologies and to prices of conventional fuels.

There is, however, some dispute over how much upgrading is required. More specifically, some observers claim liquefaction products can be marketed as boiler fuels without upgrading the necessary adjustments to boiler combustion equipment. Others disagree and question the market potential of hydrogen deficient fuels. All observers realize, however, upgrading would be required to yield products such as finished gasoline.

If refining is required, the complicated issue of how to allocate refinery costs must be addressed. A final section of this chapter includes a discussion of the refining needs of direct liquefaction products.

While the designs for liquefaction plants can get quite elaborate, there are really three key segments to a liquefaction site. The first segment covers coal preparation equipment such as the crushers and grinders. A second segment includes the actual liquefaction chamber and all the equipment used to prepare inputs to that chamber. The third and final segment covers the equipment used to treat the liquids and gases that come out of the liquefaction segment.

The fundamental differences among the three processes studied herein occur because of differences in the method of liquefaction. Remember that the goal of any synfuel process is the same - get rid of coal's solid matter and add hydrogen - but there are many ways to achieve that goal. The National Academy of Sciences in a recent report defined three classes of direct liquefaction technologies.1/

- Pyrolysis involves heating coal in the absence of air and oxygen to yield oils, gases, and a solid called char; when hydrogen is present during pyrolysis it is called hydrocarbonization. The amount and type of yields depend on the coal type as well as on process conditions such as temperature and pressure.

- Solvent extraction is a process in which coal is mixed with a chemical solvent capable of transfering hydrogen to the coal at high pressures and temperatures. Heating the coal breaks the physical attractions among carbon and hydrogen already in the coal so that new molecules with a greater number of hydrogen atoms can be formed. Technologies included in this class are Exxon Donor Solvent and Solvent Refined Coal, both studied herein, plus Consol Synthetic Fuel and Costeam.

- Catalytic Liquefaction is a process in which the addition of hydrogen to coal is accelerated through the use of a catalyst; a catalyst is any substance which accelerates a chemical reaction, but does not become part of the product. Coal combined with the catalyst is heated in the presence of hydrogen under relatively high temperatures and pressures. Examples in this category include H-coal, studied herein, synthoil, and the Bergius Process.

As noted, one of the processes studied herein, H-Coal, involves Catalytic Liquefaction while the other two, EDS and SRC-II, involve solvent extraction techniques. The latter two processes differ in their manner of delivering hydrogen to the liquefaction chamber. With the Exxon Donor Solvent process, the chemical solvent carries hydrogen and, in addition, pure hydrogen is pumped into the chambers. With the Solvent Refined Coal process, the chemical solvent is not hydrogenerated.

1/ Assessment of Technology For the Liquefaction of Coal, Washington, D.C., 1977.

H-COAL PROCESS DESCRIPTION

The H-Coal process developed by Hydrocarbon Research incorporates an innovative approach to direct liquefaction by simultaneously decomposing the coal (coal dissolution), adding hydrogen to it (hydroconversion), and removing sulfur (hydrodesulfurization). As noted, H-Coal is Catalytic Liquefaction so all of these reactions are accelerated with a catalyst. The overall processing sequence is depicted in Figure B-1.

The plant design which served as the basis of the cost estimate consists of coal liquefaction plant along with the required support, utility, and offsite facilities to compromise a self-sufficient operation. Coal is received by rail shipment, stored, crushed, and dried. Coal is then liquefied by the H-Coal technology in which coal and hydrogen react at elevated temperature and pressure (on the order of 850° F and 3000 psig) to produce a range of liquids and gases.

The gases and liquids coming out of the reactor are separated into a number of products by a series of flashes and by fractionation. Primary products include stabilized naphtha, turbine fuel, and distillate boiler fuel.

Support units, in addition to coal crushing and drying, include the air separation plant to produce oxygen, the hydrogen plant in which left overs from the H-Coal liquefier are gasified and converted to hydrogen, a gas plant in which byproduct propane and butane are recovered, a light ends separation unit for recovering and recycling unreacted hydrogen, a sour water stripping unit, a sulfur recovery plant, and plant storage and shipping facilities.

Utility services include a full range of systems necessary for operation of the plant such as steam, electric power, fuel gas distribution, cooling water, instrument air, boiler feedwater treating, potable water, firewater, storm and wastewater facilities, and sanitary water treating. Electric power in sufficient amounts to satisfy the in-plant requirements is generated by combined-cycle gas turbines. These turbines are fired by residual fuel gas from the liquefaction plant and supplemented by LPG.

Offsite requirements include such items as administration building, laboratory, change and guard houses, maintenance building and equipment, warehouse, firehouse, roads, fencing, onsite railroad trackage, and like items.

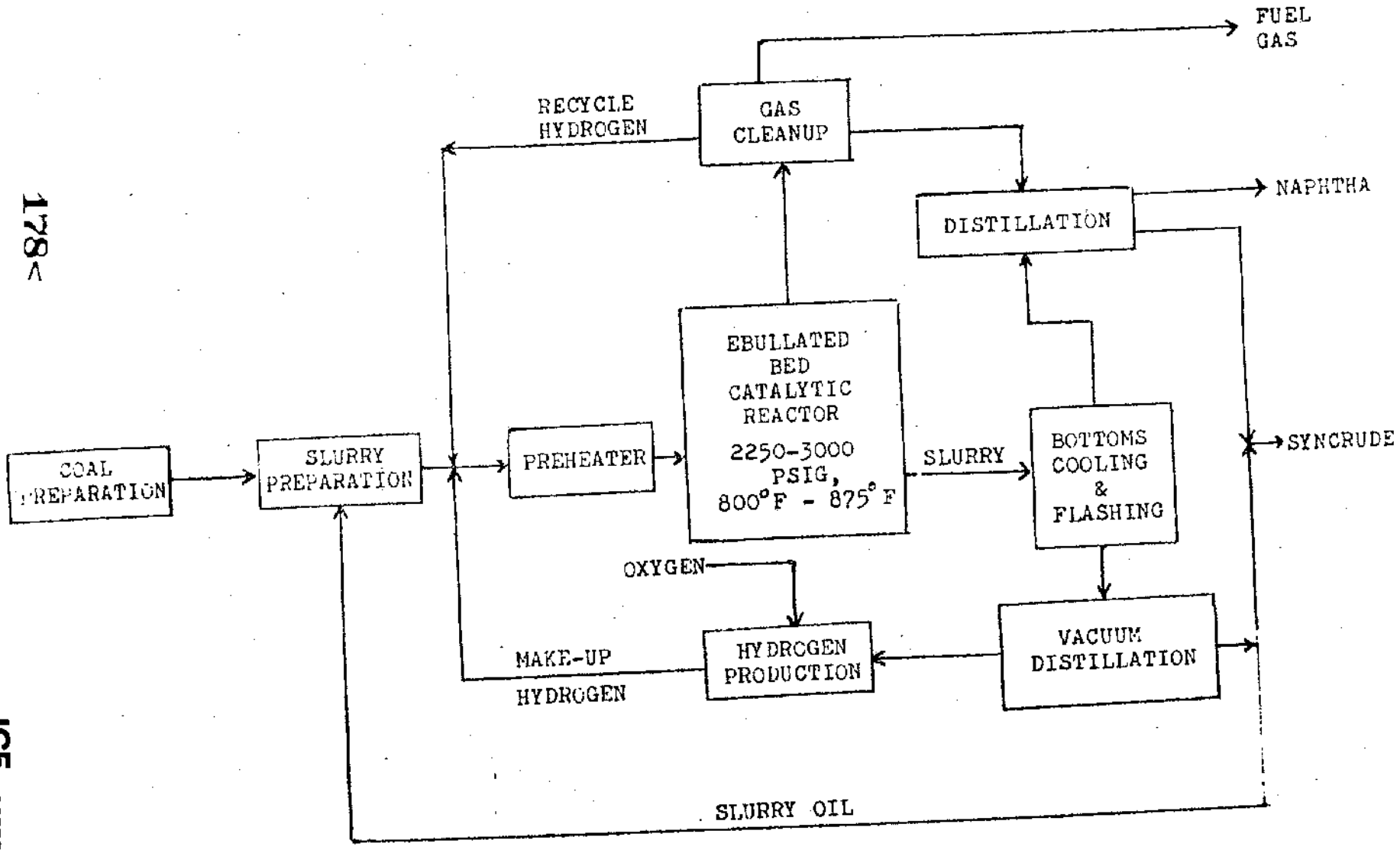
The liquid products from the plant include LPG, naphtha, and low-sulfur fuel oil (LSFO). Ammonia and sulfur by-products are also produced.

H-Coal Raw Cost Estimates

Capital cost estimates developed by Fluor are shown in Table B-1 for an H-Coal plant using Illinois No. 6 coal and in Table B-2 for a comparable plant

Figure B-1

H-COAL PROCESS: PRINCIPAL STEPS IN THE PROCESS



using Wyodak coal. At the Wyoming site the plant is shown to cost $500 million more. Three points explain much of that increase.

- Wyoming coal has a much lower Btu content so a greater tonnage has to be handled (about 21,000 tons stream day at the Wyoming site versus about 16,000 at the Illinois site). For this reason, equipment for coal preparation and liquefaction is about $170 million more for the H-Coal process using Wyodak coal.

- More hydrogen is added in the Wyoming comparison case so $100 million is added to the hydrogen plant cost estimate. As will be seen, there is downstream compensation because the products from the Wyoming site require less upgrading.

- The Wyoming site estimate includes $131 million for a construction camp and labor premium; these expenses reflect the extra effort required to attract and hold a labor force in the isolated production areas of the Western United States.

Tables B-3 and B-4 present estimates of the operating costs and product yields for the two plants. As expected, there are two noticeable differences. First, a greater number of tons of coal are used at the Wyoming site. Second, a narrower range of products with higher hydrogen content are produced at that site.

EXXON DONOR SOLVENT

Process Description

The Exxon Donor Solvent (EDS) cost estimate is based on a mine-mouth coal conversion plant designed to produce 50,000 barrels per day of coal liquids from 24,000 tons per day of cleaned Illinois No. 6 coal. The plant contains two parallel processing trains which are fed from two large coal mines each producing 3.5 million T/YR of cleaned coal. A simplified diagram of the process is shown in Figure B-2.

In the Illinois coal case, coal is crushed, mixed and dried with a "hydrogen donor solvent" in a coal slurry drier and liquefied in a tubular reactor which is filled with hydrogen. The liquefaction reactor operates at high pressure and temperature (2000 psig and 840^{o}F). Gases and liquids coming out of the reactor are separated via distillation into light hydrocarbon gases, liquid products, a vacuum bottoms slurry containing the coal ash, and the spent solvent stream.

The light hydrocarbon gas from liquefaction and the flexicoker is steam reformed to provide the hydrogen required for liquefaction and solvent hydrogenation. In addition, a cryogenic hydrogen concentration unit is provided to recover hydrogen from the liquefaction purge gas.

TABLE B-1

ESTIMATED CAPITAL COSTS FOR PRODUCTION
OF LIQUID FUELS BY H-COAL FROM ILLINOIS NO. 6 COAL
THOUSANDS OF MID-1980 DOLLARS*

Plant Size - TS/D	16,370**
Plant Section	
Coal Preparation	45,000
Liquefaction	345,000
Light Ends Processing	41,000
Hydrogen Plant	206,000
Oxygen Plant	100,000
Emission Control System	21,000
Effluent Control System	40,000
Storage	48,000
Utilities	156,000
Offsites	94,000
Sub Total	1,096,000
Prepaid Royalties @ 0.5% Investment	5,000
Project Contingencies	165,150
Process Contingencies	69,000
TOTAL	1,335,150

* Southern Illinois Location
Sales Tax Included @ 5% of Total Materials.

** Adjusted to 50,000 BPSD of Total Liquid Products. Average Scaling Factor Applied = 0.836. Coal rate is in T/SD of dry coal. All other cases are in T/SD of coal "as received" unless otherwise noted.

TABLE B-2

ESTIMATED CAPITAL COSTS FOR PRODUCTION
OF LIQUID FUELS BY H-COAL FROM WYODAK COAL
THOUSANDS OF MID-1980 DOLLARS*

Plant Size - TS/D	20,548**
Plant Section	
Coal Preparation	96,000
Liquefaction	464,000
Light Ends Processing	15,000
Hydrogen Plant	304,000
Oxygen Plant	119,000
Emission Control System	17,000
Effluent Control System	34,000
Storage	25,000
Utilities	188,000
Offsites***	250,000
Sub Total	1,512,000
Prepaid Royalties @ 0.5% Investment	8,000
Project Contingencies	228,000
Process Contingencies	92,800
TOTAL	1,840,800

* Wyoming Location
Sales Tax Included @ 5%

** Flour estimate was Adjusted to 50,000 BPSD of Total Liquid Products. Average Scaling Factor Applied = 0.836. Coal rate in T/SD of dry coal.

*** Includes Construction Camp and overtime premium ($131,000 thousands dollars).

TABLE B-3

ESTIMATED YIELDS AND OPERATING REQUIREMENTS
FOR THE PRODUCTION OF LIQUID FUELS BY H-COAL
FROM ILLINOIS NO. 6 COAL

(For 50,000 BPSD of Liquid Products)
(All Dollars Mid-1980)

VARIABLE COSTS

Coal, T/SD	16,370
Water, 10^3 $/SD	3.54
Power, 10^3 KWH/SD	0.00
Catalyst and Chemicals, 10^3 $/SD	44.40
Ash Disposal, 10^3 $/SD	2.94

FIXED COSTS, 10^3 $/CD

Operating Labor	22.6
Overhead	62.0
Maintenance	105.7
Subtotal	190.3

YIELDS

Hydrocarbons	BPSD	°API
Naphtha	15,173	52.3
Turbine Fuel	18,395	18.5
Distillate Boiler Fuel	9,926	4.9
Butane	3,796	110.0
Propane	2,710	147.7
TOTAL	50,000	

Non-Hydrocarbons	TPD
Ammonia	187
Sulfur	559
Crude Mixed Phenols	45
Ash to Disposal	1,961

Note:
1. All tons are short tons.
2. Coal rate in T/SD dry coal.

TABLE B-4

ESTIMATED YIELDS AND OPERATING REQUIREMENTS FOR THE PRODUCTION OF LIQUID FUELS BY H-COAL FROM WYODAK COAL

(For 50,000 BPSD of Liquid Products)
(All Dollars Mid-1980)

VARIABLE COSTS

Coal, T/SD	20,548
Water, 10^3 $/SD	3.87
Power, 10^3 KWH/SD	0.00
Catalyst and Chemicals, 10^3 $/SD	52.54
Ash Disposal, 10^3 $/SD	0.00

FIXED COSTS, 10^3 $/CD

Operating Labor	22.6
Overhead	65.8
Maintenance	114.8
Sub-Total	203.2

YIELDS

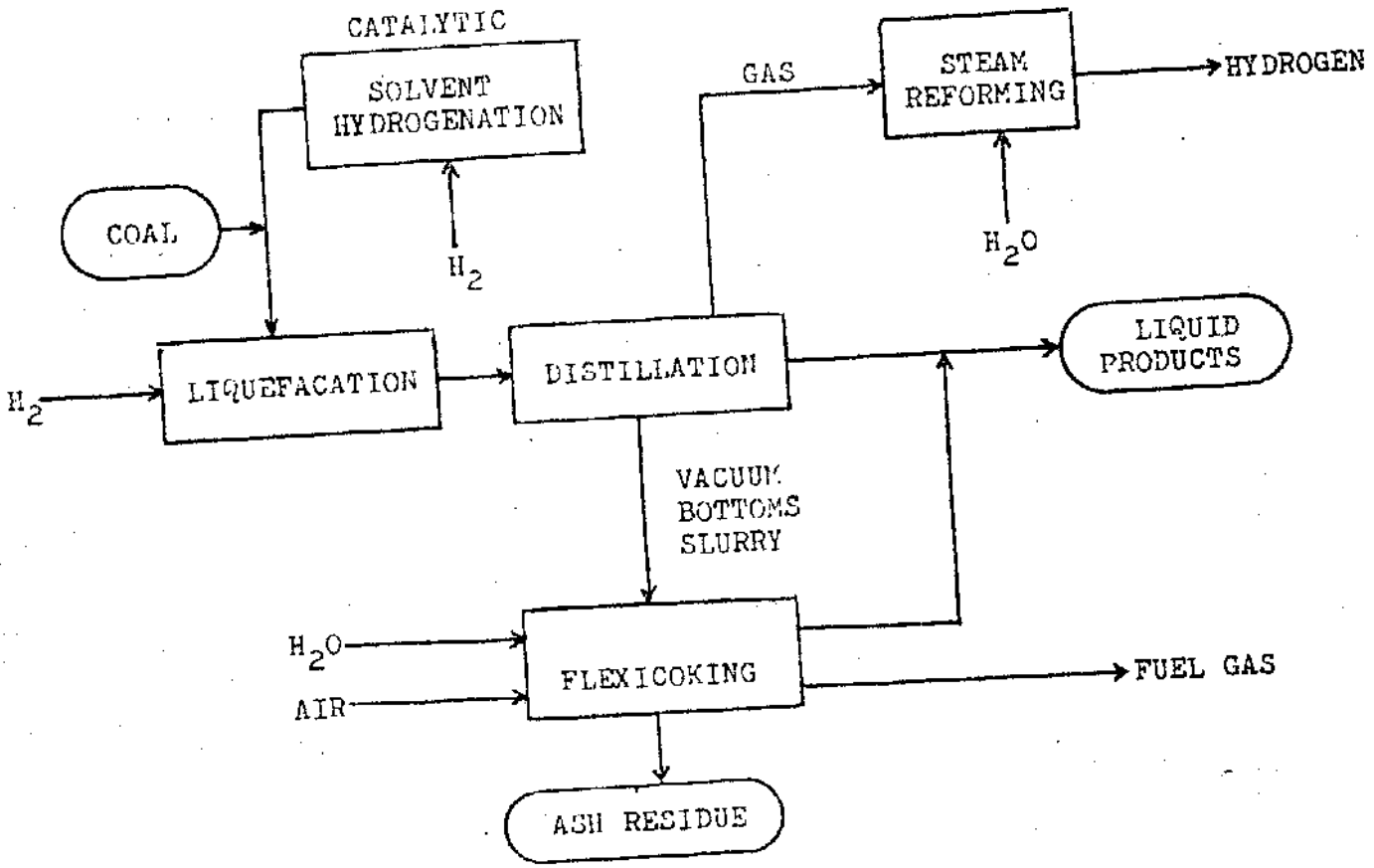
Hydrocarbons	BPSD	°API
Naphtha	22,700	54.3
Turbine Fuel	17,600	27.8
Distillate Boiler Fuel	9,700	10.9
TOTAL	50,000	

Non-Hydrocarbons	TPD
Ammonia	166
Sulfur	581
Crude Mixed Phenols	23
Ash to Disposal	1,544

Note:
1. All tons are short tons.
2. No slag disposal cost assumed in Wyoming area.
3. Coal rate in T/SD dry coal.

FIGURE B-2

BLOCK FLOW DIAGRAM - EXXON DONOR SOLVENT PROCESS



The spent solvent is fed to solvent hydrogenation where it is hydrotreated in a fixed bed, catalytic reactor to restore the donatable hydrogen to the recycle solvent. The hydrogen donor solvent is returned to the slurry drier.

The vacuum bottoms slurry is fed to a flexicoker where it is pyrolyzed to make additional liquid and gas products and a coke stream which is gasified with steam and air to provide a low-BTU fuel gas (115/BTU/SCF HHV) for plant fuel.

Raw Cost Estimate

Capital costs developed by Exxon Research and Development are shown in Table B-5 for a plant using Illinois No. 6 coal. A detailed estimate for a Wyoming coal was not given in the referenced Exxon report which stated that the total investment for either an Illinois or a Wyoming EDS plant should be about the same. This appears at variance with the H-coal estimates but may be due to process differences and the degree of process optimization reflected for the two coals. Further investigation of this point may be warranted.

Table B-6 displays the estimated operating cost and product yields from EDS.

A quick comparison of the EDS and H-coal processes using Illinois coal does not reveal substantial differences. The capital cost for EDS is about $100 million higher, considerably more coal is required, and the product mix changes to include more naphtha and fuel oil.

SRC-II PROCESS DESCRIPTION

A diagram of the SRC-II process is shown in Figure B-3. Raw coal is pulverized and dried in the coal preparation area, then mixed with the hot slurry solvent. The coal-solvent mixture (in the range 1.5-2.5 parts of slurry to one part of coal) is pumped together with hydrogen, through a preheater to a reactor, or "dissolver."

The substance coming out of the dissolver goes first to a high pressure separator which, as its name implies, separates gases and liquids. The hot gases from this separator consist of unreacted hydrogen, methane and other light hydrocarbons, plus hydrogen sulfide (H_2S) and carbon dioxide (CO_2). The gas is first sent to an acid gas treating unit for removal of H_2S and CO_2. A portion of the treated gas is then further processed in a cryogenic unit for removal of much of the methane and other light hydrocarbons. A mixture of methane and ethane recovered in the cryogenic unit is produced for sale as pipeline gas, while propane and butane are recovered for sale as liquid petroleum gases. The H_2S removed in the acid gas treating unit is converted to elemental sulfur in a standard Claus unit.

TABLE B-5

ESTIMATED CAPITAL COSTS FOR EDS PRODUCTION
OF LIQUID FUELS FROM ILLINOIS NO. 6 COAL
THOUSANDS OF MID-1980 DOLLARS*

Plant Size - T/SD	20,000**
Plant Section	
Liquefaction/Solvent Hydrogenation	411,000
Flexicoking	181,000
Light Ends Processing	11,000
Hydrogen Plant	250,000
Emission Control	33,000
Effluent Control	19,000
Storage	30,000
Utilities	97,000
Coal Preparation and General Offsites	138,000
Sub Total	1,170,000
Prepaid Royalties @ 0.5% Investment	6,000
Project Contingency	176,400
Process Contingency	82,000
TOTAL	1,434,600

* Rural Illinois Location/Sales Tax Included.

** Adjusted to 50,000 BPSD of Total Liquid Products
Average Scaling Factor Used = .830

TABLE B-6

ESTIMATED YIELDS AND OPERATING REQUIREMENTS FOR THE EDS PRODUCTION OF LIQUID FUELS FROM ILLINOIS NO. 6 COAL

(For 50,000 BPSD of Liquid Products)
(All Dollars Mid-1980)

VARIABLE COSTS

Coal, T/SD	20,000
Water, 10^3 $/SD	3.00
Power, 10^3 KWH/SD	35.98
Catalyst and Chemicals, 10^3 $/SD	19.70
Ash Disposal, 10^3 $/SD	3.59

FIXED COSTS, 10^3 $/CD

Operating Labor	26.7
Overhead	73.1
Maintenance	124.6
Subtotal	224.4

YIELDS

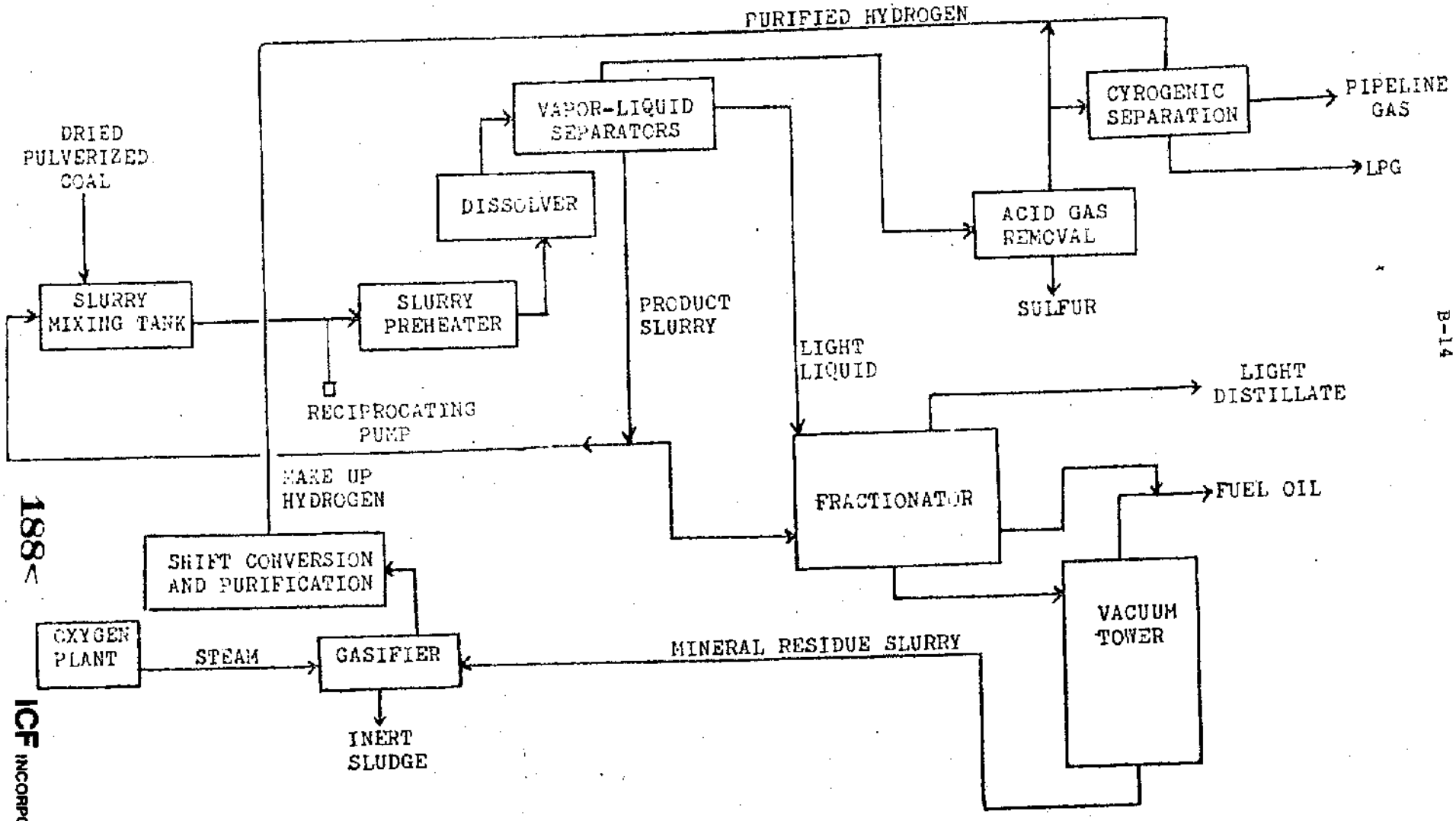
Hydrocarbons	BPSD	°API
Naphtha	18,390	42.1
Turbine Fuel	24,920	0.0
Butane	3,260	110.0
Propane	3,430	147.7
TOTAL	50,000	

Non-Hydrocarbons	TPD
Ammonia	103
Sulfur	653
Ash to Disposal	2,396

Note: All tons are short tons.

Figure B-3

BLOCK FLOW DIAGRAM - SRC II PROCESS



The liquid from the high pressure separator is split into two major streams. One of these streams is solvent which will be recycled The other liquids go into a piece of equipment called a fractionator which turns them into the products desired all along-light distillate oil, fuel oil, and the like.

The bottoms from the vacuum tower, consisting of all of the undissolved mineral residue plus the vacuum residue portion of the dissolved coal, goes to an oxygen-blown gasifier for ultimate conversion to hydrogen. The synthesis gas produced in the gasifier goes through a shift conversion step for conversion of steam and carbon monoxide to hydrogen plus carbon dioxide, then to an acid gas removal step for removal of the carbon dioxide. The hydrogen (94% pure) is then compressed and fed as make-up hydrogen to the preheater-dissolver to the SRC-11 process.

All of the waste water streams from the process are collected and sent to a distillation unit for removal of ammonia. After ammonia removal; the water is sent to a phenols recovery unit for separation of phenols. The ammonia and phenols are recovered for sale as by-products. Even after such purification, however, the waste water is not discharged to the surrounding area, but is recycled to the process to avoid any possibility of adverse environmental effects.

Raw Cost Estimate

Table B-7 contains the capital cost estimate for an SRC-11 system using Illinois No. 6 coal. The estimates of operating cost and product yields are shown in Table B-8.

Comparing SRC-11 to EDS and H coal reveals some minor differences falling within the overall reliability of the estimates. The SRC-II capital costs are the highest of the three, about $200 million higher than H-Coal and $100 million higher than EDS. With respect to product mix the SRC process yields much of its product as fuel oil and therefore has the narrowest range of yield for the three processes.

REFINING NEEDS AND PRODUCT PRICES

As noted in the beginning of this chapter, there is some question over the need to hydro process the products of direct liquefaction processes and the degree of hydrogeneration required. For the purposes of this report, however, it is assumed upgrading is required to bring the products up to the level found with conventional petroleum products.

To give some rough indication of the effect of refining on the cost of liquefaction products, capital and operating costs were developed for refining the products from each liquefaction process. Estimates were based on Mobil Oil Research and Development Corpoation's data for hydrorefining coal liquids.

TABLE B-7

ESTIMATED CAPITAL COSTS FOR SRC-II PRODUCTION
OF LIQUID FUELS FROM ILLINOIS NO. 6 COAL
THOUSANDS OF MID-1980 DOLLARS*

Plant Size - T/SD	20,325**
Plant Section	
Coal Preparation	63,000
Reaction Section	195,000
Light Ends Processing	30,000
Hydrogen Plant	254,000
Oxygen Plant	129,000
Emission Plus Effluent Control	104,000
Storage	36,000
Utilities	369,000
Offsites	109,000
Sub Total	1,289,000
Prepaid Royalties @ 0.5% Investment	7,000
Project Contingency	194,400
Process Contingency	39,000
TOTAL	1,529,400

* U.S. Gulf Location/Sales Tax Included

** Adjusted to 50,000 BPSD of Total Liquid Products. Average Scaling Factor Used = 0.830. Coal rate is in T/SD dry coal.

TABLE B-8

ESTIMATED YIELDS AND OPERATING REQUIREMENTS FOR THE SRC-II PRODUCTION OF LIQUID FUELS FROM ILLINOIS NO. 6 COAL

(For 50,000 BPSD of Liquid Products)
(All Dollars Mid-1980)

VARIABLE COSTS	
Coal, T/SD	20,325
Water, 10^3 $/SD	4.00
Power, 10^3 KWH/SD	0.00
Catalyst and Chemicals, 10^3 $/SD	17.5
Ash Disposal, 10^3 $/SD	3.65
FIXED COSTS, 10^3 $/CD	
Operating Labor	26.6
Overhead	73.0
Maintenance	124.3
Subtotal	223.9

YIELDS

Hydrocarbons	BPSD	°API
Naphtha	8,700	37.0
Turbine Fuel	36,800	5.0
LPG (Propane/butane)	4,500	125.0
TOTAL	50,000	
High Btu Fuel Gas (MMSCF/SD)	18.8	

Non-Hydrocarbons	TPD
Ammonia	230
Sulfur	694
Crude Mixed Phenols	56
Ash to Disposal	2,434

Note:
1. All tons are short tons.
2. Coal rate is in T/SD dry coal.

It is assumed here that natural gas is used as the source of hydrogen needed for upgrading. If the refinery was integrated with the direct liquefaction plant, that hydrogen may be produced at less expense using some of the plant products. As natural gas prices rise, these refining costs will become an even more important component of synfuel product costs.

Tables B-9 through B-16 present the relevant cost data. As can be seen the total capital costs range from about $200 million for H-coal, to $240 million for EDS, to $291 million for SRC-II. Natural gas use, the key operating cost is ranked similarly with the H-coal refinery unit taking less than half of that required by the refinery system suited to SRC-II.

TABLE B-9

ESTIMATED CAPITAL COSTS FOR REFINERY UPGRADING
OF H-COAL LIQUID PRODUCTS
THOUSANDS OF MID-1980 DOLLARS*

	Naphtha Hydrotreater	Turbine Fuel Hydrotreater	Distillate Boiler Fuel Hydrotreater	Hydrogen Plant (Steam Reform Natural Gas)
Plant Size, BPSD**	15,173	18,395	9,926	55.4
Hydrogen Plant, MMSCFD				24,900
Plant Section				
Hydrogen Plant	10,700	51,500	45,200	
Hydrotreater	5,100	2,600	3,500	
Emissions Control	1,200	1,500	2,000	
Effluent Control	300	3,100	2,300	
Utilities	1,500	7,600	6,700	7,900
General Offsites				
Sub Total	18,800	66,300	59,700	32,800
Prepaid Royalties @ 0.5% of Interest	100	300	300	200
Contingency	3,000	11,000	9,900	3,300
TOTAL	21,900	77,600	69,960	36,300

* Mid-West Location. Sales Taxes Included @ 5%.

** All Plant Sizes are adjusted to correspond to the liquid product volumes produced from a 50,000 BPSD Total Liquids H-Coal Plant. Scaling factors of 0.75 for hydrotreating and 0.70 for Hydrogen Production were applied. Hydrogen Plant Investments is based on Steam Reforming Methane.

TABLE B-10

ESTIMATED YIELDS AND OPERATING REQUIREMENTS FOR THE REFINERY UPGRADING OF H-COAL LIQUID FUELS

	Naphtha Hydrotreater	Turbine Fuel Hydrotreater	Boiler Fuel Hydrotreater	Hydrogen Plant
VARIABLE COSTS				
Natural Gas (Feed To Hydrogen Plant)** MMBtu/SD	-	-	-	25,420
Water, 10^3 $/SD	0.025	.224	.103	
Fuel, MMBtu/SD	1,065	2,503	1,412	(3,015)
Power, 10^3 KWH/SD	10.20	161.0	113.0	57.9
Catalyst and Chemicals, 10^3 $/SD	0.334	2.93	2.99	584
FIXED COSTS, 10^3 $/CD				
Operating Labo.	1.02	1.37	1.37	1.12
Overhead	1.83	4.45	4.13	2.04
Maintenance	2.40	8.50	7.66	2.74
Sub Total				

YIELDS

Hydrocarbons	Naphtha	Distillate	Residual	Hydrogen
Liquid Product, BPSD	15,070	19,436	10,689	
Fuel Gas, MMBtu/SD	641	1,208	3,933	
Hydrogen, MMSCF/SD	-	-	-	55.4
Non-Hydrocarbons				
Sulfur, TPSD	1.02	2.49	1.42	
Ammonia, TPSD	1.30	16.5	13.2	
Liquid Product, °API	54.0	27.8	23.0	
Liquid Feed, BPSD	15,173	18,395	9,926	
Hydrogen Consumption				
SCF/Bbl	210	1,380	2,703	

* All Requirements Shown Are Adjusted to Correspond to the Liquid Product Volumes Produced From a 50,000 BPSD Totals Liquids H-Coal Plant. All tons are short tons.

** Hydrogen Plant Requirements are Based on steam reforming on methane. The hydrogen plant is sized to meet the requirements of the Naphtha and Fuel Oil Hydrotreaters.

TABLE B-11

ESTIMATED CAPITAL COSTS FOR REFINERY UPGRADING
OF EDS LIQUID PRODUCTS
THOUSANDS OF MID-1980 DOLLARS

	Naphtha Hydrotreater	Fuel Oil Hydrotreater	Hydrogen Plant
Plant Size, BPSD**	18,390	24,920	-
Hydrogen Plant, MMSCFD	-	-	95.2
Plant Section			
Hydrogen	18,200	99,400	36,100
Hydrotreater	6,200	7,600	
Emissions Control	1,800	4,200	
Effluent Control	700	5,000	11,500
Utilities	2,600	14,000	
General Offsites			
Sub Total	29,500	130,800	47,600
Prepaid Royalties @ 0.5% of Investment	100	700	300
Contingency	4,800	21,600	4,800
TOTAL	34,400	153,100	52,700

Mid-West Location. Sales Taxes Included @ 5%.

** All Plant Sizes are adjusted to correspond to the liquid product volumes produced from a 50,000 BPSD Total Liquids H-Coal Plant. Scaling factors of 0.75 for hydrotreating and 0.70 for Hydrogen Production were applied. Hydrogen Plant Investment is based on Steam Reforming Methane.

TABLE B-12

ESTIMATED YIELDS AND OPERATING REQUIREMENTS FOR THE REFINERY UPGRADING OF EDS LIQUID PRODUCTS
(All Dollars Mid-1980)*

	Naphtha Hydrotreater	Fuel Oil Hydrotreater	Hydrogen Plant
VARIABLE COSTS			
Natural Gas (Feed to Hydrogen Plant)** MMBtu/SD	-	-	43,682
Water, 10^3 $/SD	0.066	.242	
Fuel, MMBtu/SD	1,876	3,586	(5,181)
Power, 10^3 KWH/SD	40.0	308.2	99.5
Catalyst and Chemicals, 10^3 $/SD	1.410	10.73	.999
FIXED COSTS, 10^3 $/CD			
Operating Labor	1.02	1.37	1.12
Overhead	2.34	7.58	2.50
Maintenance	3.77	16.78	3.96
Subtotal			

YIELDS

Hydrocarbons	Naphtha	Residual	Hydrogen
Liquid Product, BPSD	18,511	27,001	
Fuel Gas, MMBtu/SD	2,202	12,644	
Hydrogen, MMSCF/SD	-	-	95.2
Non-Hydrocarbons			-
Sulfur, TPSD	6.79	30.1	.55
Ammonia	13.81	29 35	56.31
Liquid Product, °API	51.0	26.1	-
Liquid Feed, BPSD	18,390	24,920	-
Hydrogen Consumption, SCF/bbl	905	2,151	-

* All requirements shown are adjusted to correspond to the Liquid Product Volumes Produced from a 50,000 BPSD total liquids EDS Plant. All tons are short tons.

** Hydrogen Plant Requirements are based on steam reforming of methane. The Hydrogen plant is sized to meet the requirements of the Naphtha and Fuel Oil Hydrotreater.

TABLE B-13

ESTIMATED CAPITAL COSTS FOR REFINERY UPGRADING
OF SRC-II LIQUID PRODUCTS
THOUSANDS OF MID-1980 DOLLARS

	Naphtha Hydrotreater	Fuel Oil Hydrotreater	Hydrogen Plant
Plant Size, BPSD**	8,700	36,800	-
Hydrogen Plant, MMSCFD	-	-	130.6
Plant Section			
Hydrogen	132,900	-	45,000
Hydrotreater	3,600	9,800	
Emissions Control	1,100	4,400	
Effluent Control	400	8,000	
Utilities	1,600	19,700	14,400
General Offsites			
Sub Total	27,600	174,800	59,400
Prepaid Royalties @ 0.5% of Investment	100	900	300
Contingency	2,900	19,000	6,000
TOTAL	20,600	204,700	65,700

Mid-West Location. Sales Taxes Included @ 5%.

** All Plant Sizes are adjusted to correspond to the liquid product volumes produced from a 50,000 BPSD Total Liquids H-Coal Plant. Scaling factors of 0.75 for hydrotreating and 0.70 for Hydrogen Production were applied. Hydrogen Plant Investments is based on Steam Reforming Methane.

TABLE B-14

ESTIMATED YIELDS AND OPERATING REQUIREMENTS FOR THE REFINERY UPGRADING OF SRC-II LIQUID PRODUCTS (All Dollars Mid-1980)*

	Naphtha Hydrotreater	Fuel Oil Hydrotreater	Hydrogen Plant
VARIABLE COSTS			
Natural Gas (Feed to Hydrogen Plant)** MMBtu/SD	-	-	59,924
Water, 10^3 $/SD	0.024	.695	
Fuel, MMBtu/SD	918	8,761	(7,107)
Power, 10^3 KWH/SD	19.7	490.4	136.4
Catalyst and Chemicals, 10^3 $/SD	0.763	10.3	1.370
FIXED COSTS, 10^3 $/CD			
Operating Labor	1.02	1.37	1.12
Overhead	1.77	9.72	3.87
Maintenance	2.46	22.46	4.93
Subtotal			

YIELDS

Hydrocarbons	Naphtha	Residual	Hydrogen
Liquid Product, BPSD	8,963	41,024	
Fuel Gas, MMBtu/SD	1,212	3,885	
Hydrogen, MMSCF/SD	-	-	130.6
Non-Hydrocarbons			
Sulfur, TPSD	3.55	19.75	
Ammonia	8.18	67.08	56.31
Liquid Product, °API	47.6	27.4	-
Liquid Feed, BPSD	8,700	36,800	-
Hydrogen Consumption, SCF/Bbl	1,056	2,200	-

* All requirements shown are adjusted to correspond to the Liquid Product Volumes Produced from a 50,000 BPSD total liquids EDS Plant. All tons are short tons.

** Hydrogen Plant Requirements are based on steam reforming of methane. The Hydrogen plant is sized to meet the requirements of the Naphtha and Fuel Oil Hydrotreater.

TABLE B-15

ESTIMATED CAPITAL COSTS FOR REFINERY UPGRADING
OF H-COAL LIQUID PRODUCTS FROM WYODAK COAL
THOUSANDS OF MID-1980 DOLLARS

	Naphtha Hydrotreater	Fuel Oil Hydrotreater	Hydrogen Plant
Plant Size, BPSD**	22,700	9,700	-
Hydrogen Plant, MMSCFD	-	-	22.4
Plant Section			
Hydrogen	14,500	21,300	13,200
Hydrotreater	6,900	3,100	
Emissions Control	1,600	1,400	
Effluent Control	400	1,300	
Utilities	2,000	3,100	4,200
General Offsites			
Sub Total	25,400	30,200	17,400
Prepaid Royalties @ 0.5% of Investment	100	200	100
Contingency	4,100	5,000	1,700
TOTAL	29,600	35,400	19,200

Mid-West Location. Sales Taxes Included @ 5%.

** All Plant Sizes are adjusted to correspond to the liquid product volumes produced from a 50,000 BPSD Total Liquids H-Coal Plant. Scaling factors of 0.75 for hydrotreating and 0.70 for Hydrogen Production were applied. Hydrogen Plant Investments is based on Steam Reforming Methane.

TABLE B-16

ESTIMATED YIELDS AND OPERATING REQUIREMENTS FOR THE REFINERY UPGRADING OF WYODAK COAL
(All Dollars Mid-1980)*

	Naphtha Hydrotreater	Fuel Oil Hydrotreater	Hydrogen Plant
VARIABLE COSTS			
Natural Gas (Feed to Hydrogen Plant)** MMBtu/SD	-	-	10,278
Water, 10^3 $/SD	0.037	0.703	
Fuel, MMBtu/SD	1,593	906	(1,219)
Power, 10^3 KWH/SD	15.26	64.9	23.4
Catalyst and Chemicals, 10^3 $/SD	0.515	1.65	0.235
FIXED COSTS, 10^3 $/CD			
Operating Labor	1.02	1.37	1.12
Overhead	2.15	2.70	1.56
Maintenance	3.25	3.89	1.45
Subtotal			

YIELDS

Hydrocarbons	Naphtha	Residual	Hydrogen
Liquid Product, BPSD	22,545	10,193	
Fuel Gas, MMBtu/SD	959	834	
Hydrogen, MMSCF/SD	-	-	22.4
Non-Hydrocarbons			
Sulfur, TPSD	1.53	1.06	
Ammonia	1.94	6.6	
Liquid Product, °API	55.5	14.6	-
Liquid Feed, BPSD	22,700	9,700	-
Hydrogen Consumption, SCF/Bbl	150	1,960	-

* All requirements shown are adjusted to correspond to the Liquid Product Volumes Produced from a 50,000 BPSD total liquids EDS Plant. All tons are short tons.

** Hydrogen Plant Requirements are based on steam reforming of methane. The Hydrogen plant is sized to meet the requirements of the Naphtha and Fuel Oil Hydrotreater.

PRIMARY REFERENCES FOR
APPENDIX B

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