Section 2

SUMMARY AND DISCUSSION

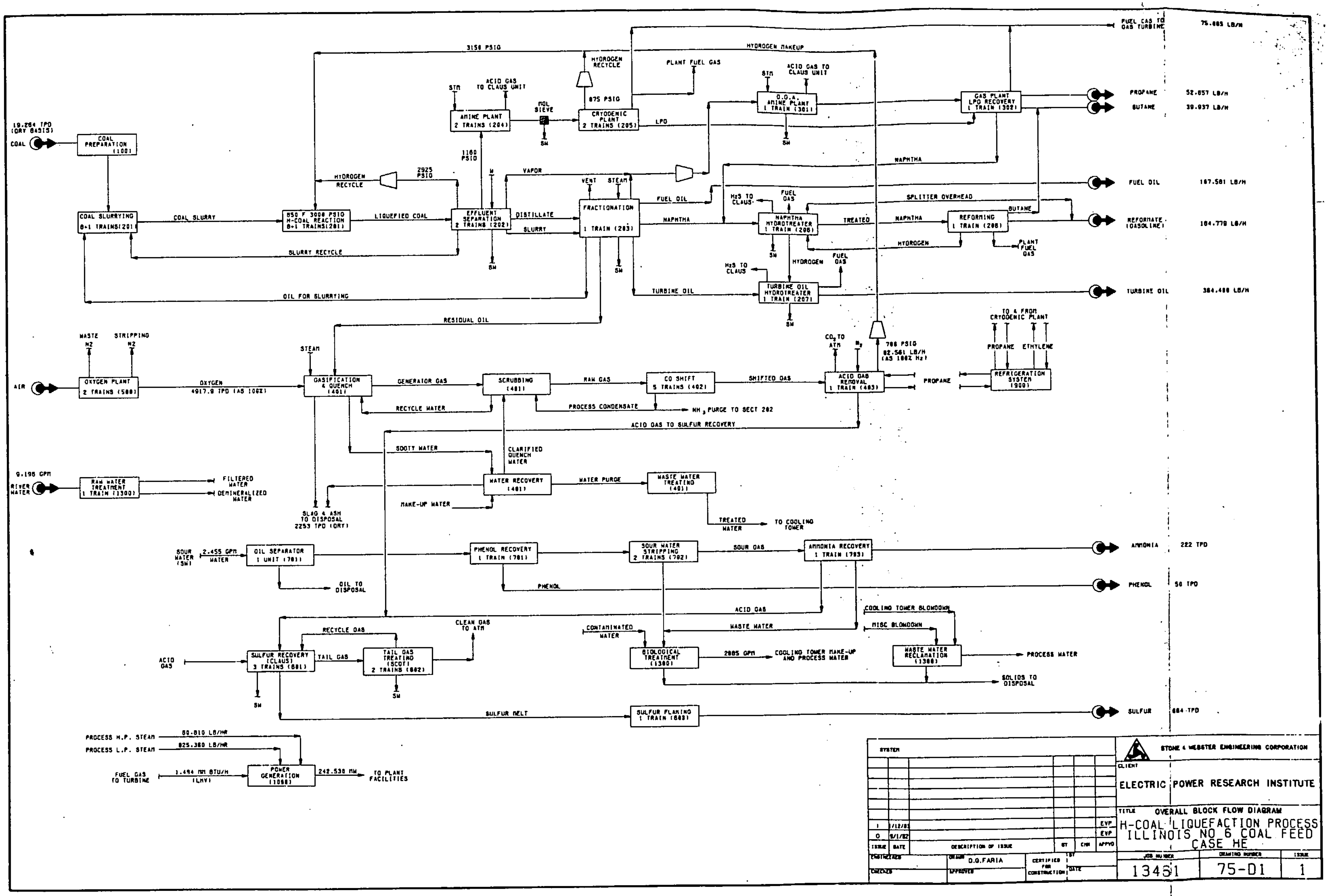
SUMMARY

This study was undertaken to develop preliminary process designs, cost estimates, and manufacturing costs for two approaches to converting coal into clean liquid fuels. The first approach is by direct liquefaction via the H-Coal process, and the second approach is by indirect liquefaction utilizing the Texaco coal gasification process combined with Lurgi methanol synthesis. For direct liquefaction, two coals were considered - Illinois No. 6 and Wyodak. The indirect liquefaction case considered production of methanol from Illinois No. 6 coal. Block flow diagrams for the three cases considered are shown in Drawings 75 D-1, 75 D-2, and 75 D-20.

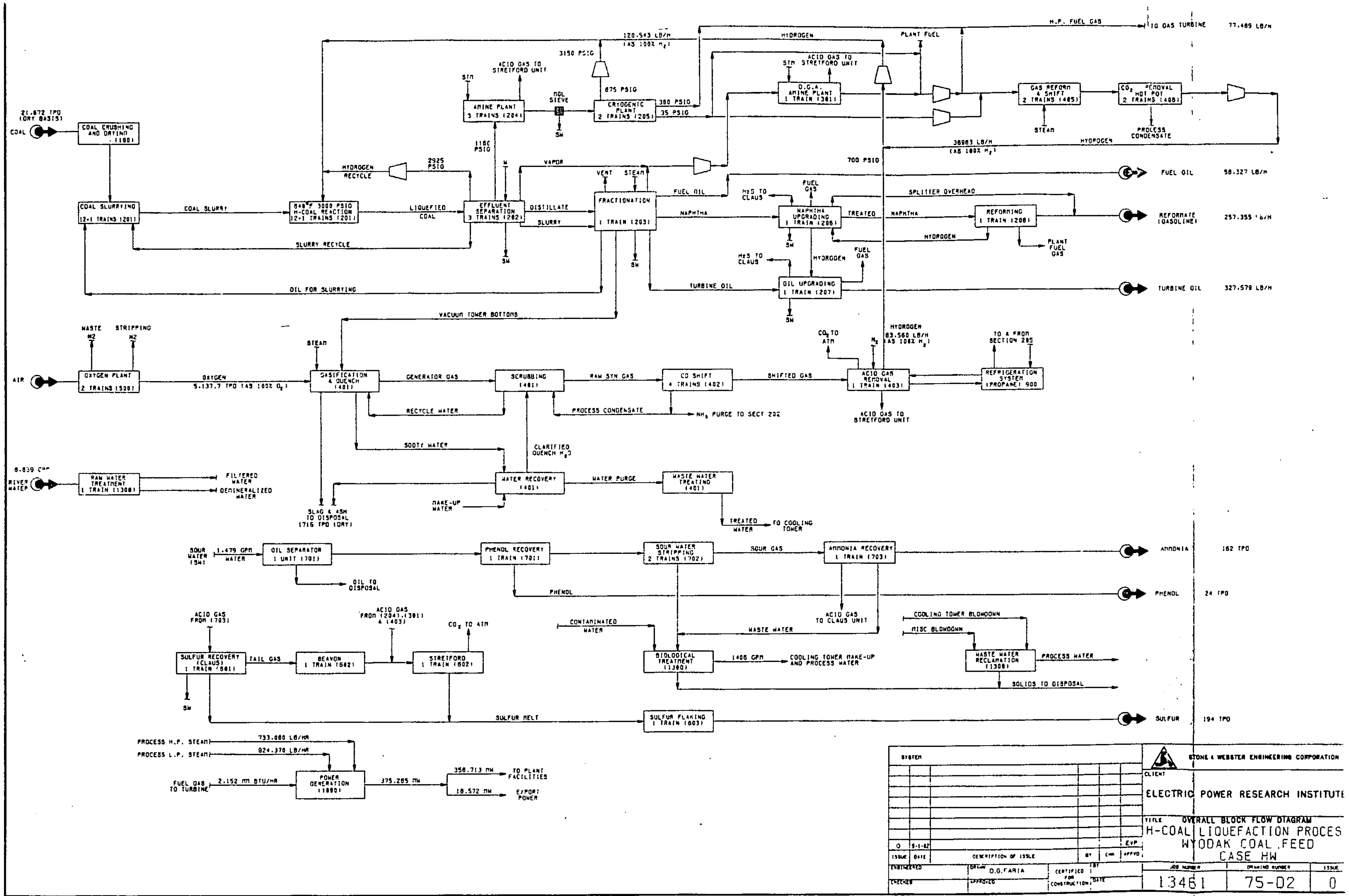
For the direct liquefaction case, the H-Coal process developed by Hydrocarbon Research Inc. (HRI) was employed, and the designs and cost estimates were prepared based on information obtained from HRI. The block flow diagram for the Illinois No. 6 coal case is presented in Drawing 75 D-1. Coal is slurried with recycle oil from the fractionation system and charged to the reaction system together with fresh and recycled hydrogen. The hydrogenation reaction takes place in the presence of a suitable catalyst using an ebullated bed reactor system. Liquid effluent from this system is separated into primary liquid products, gases, and a residual oil representing the bottoms from vacuum distillation of the products. The primary liquid products are upgraded as required to marketable quality. Gases are processed through gas recovery and cryogenic separation to recover hydrogen, remove sulfur, and separate propane and butane products from the fuel gas. The vacuum bottoms, which contain liquids boiling above 1000°F, all of the ash, and any unconverted coal, is gasified with oxygen using the Texaco gasification process to produce a synthesis gas. This synthesis gas is converted to the make-up hydrogen required for the process. The various effluent treating and offsite facilities necessary to provide a complete self-contained project are also included.

Drawing 75 D-2 shows the corresponding case for the processing of Wyodak coal. This plant is identical in its essential features to the Illinois No. 6 case with respect to coal liquefaction and primary product separation. The higher moisture content of the Wyodak coal, however, places a greater burden on the coal drying facilities and contributes to the lower thermal efficiency in this case. The Wyodak coal design basis requires more hydrogen for liquefaction than is produced by gasification of vacuum bottoms. Consequently, it is necessary to provide supplemental hydrogen produced by steam reforming of low molecular weight hydrocarbons. In order to supply both the reformer feedstock and the plant fuel requirements, all of the light hydrocarbons are consumed and there is no net propane and butane product in this case.

The coal-to-methanol block flow diagram is presented in Drawing 75 D-20. In this case, Texaco gasification is used to produce a synthesis gas from a slurry of Illinois No. 6 coal and water. This synthesis gas is processed through the CO shift reaction and acid gas removal to produce a feed to the methanol plant having the requisite CO/H_2 ratio and purity. The Lurgi methanol process was employed in this evaluation. Again the requisite offsite and environmental features are included to accomplish a complete self-contained facility.



COAL
19,264 TPD (DRY BASIS)
COAL PREPARATION (100)
COAL SLURRYING 8+1 TRAINS(201)
COAL SLURRY
850 F 3000 PSIG H-COAL REACTION 8+1 TRAINS(201)
LIQUEFIED COAL
EFFLUENT SEPARATION 2 TRAINS (202)
SLURRY RECYCLE
OIL FOR SLURRYING
3150 PSIG
HYDROGEN RECYCLE
2925 PSIG
1160 PSIG
AMINE PLANT 2 TRAINS (204)
STM
ACID GAS TO CLAUS UNIT
MOL SIEVE
CRYOGENIC PLANT 2 TRAINS (205)
875 PSIG
HYDROGEN MAKEUP
PLANT FUEL GAS
LPG
D.G.A. AMINE PLANT 1 TRAIN (301)
GAS PLANT LPG RECOVERY 1 TRAIN (302)
FUEL GAS TO GAS TURBINE
VAPOR
VENT
STEAM
DISTILLATE
SLURRY
FRACTIONATION 1 TRAIN (203)
FUEL OIL
NAPHTHA
H2S TO CLAUS
FUEL GAS
NAPHTHA HYDROTREATER 1 TRAIN (206)
TREATED
NAPHTHA
REFORMING 1 TRAIN (208)
SPLITTER OVERHEAD
BUTANE
HYDROGEN
PLANT FUEL GAS
TURBINE OIL
TURBINE OIL HYDROTREATER 1 TRAIN (207)
PROPANE
BUTANE
FUEL OIL
REFORMATE (GASOLINE)
TURBINE OIL
SW
RESIDUAL OIL
WASTE N2
STRIPPING N2
AIR
OXYGEN PLANT 2 TRAINS (500)
OXYGEN
4917.9 TPD (AS 100%)
STEAM
GASIFICATION & QUENCH (401)
GENERATOR GAS
SCRUBBING (401)
RAW GAS
CO SHIFT 5 TRAINS (402)
SHIFTED GAS
ACID GAS REMOVAL 1 TRAIN (403)
CO2 TO ATM
N2
700 PSIG
82,561 LB/H (AS 100% H2)
TO & FROM CRYOGENIC PLANT
PROPANE
ETHYLENE
REFRIGERATION SYSTEM (900)
RECYCLE WATER
PROCESS CONDENSATE
NH3 PURGE TO SECT 202
ACID GAS TO SULFUR RECOVERY
SOOTY WATER
CLARIFIED QUENCH WATER
WATER RECOVERY (401)
WATER PURGE
WASTE WATER TREATING (401)
TREATED WATER
TO COOLING TOWER
MAKE-UP WATER
SLAG & ASH TO DISPOSAL 2253 TPD (DRY)
9,196 GPM
RIVER WATER
RAW WATER TREATMENT 1 TRAIN (1300)
FILTERED WATER
DEMINERALIZED WATER
SOUR WATER (SW)
2,455 GPM WATER
OIL SEPARATOR 1 UNIT (701)
OIL TO DISPOSAL
PHENOL RECOVERY 1 TRAIN (701)
PHENOL
SOUR WATER STRIPPING 2 TRAINS (702)
SOUR GAS
AMMONIA RECOVERY 1 TRAIN (703)
AMMONIA
222 TPD
PHENOL
50 TPD
ACID GAS
WASTE WATER
CONTAMINATED WATER
COOLING TOWER BLOWDOWN
MISC BLOWDOWN
RECYCLE GAS
CLEAN GAS TO ATM
ACID GAS
SULFUR RECOVERY (CLAUS) 3 TRAINS (601)
TAIL GAS
TAIL GAS TREATING (SCOT) 2 TRAINS (602)
BIOLOGICAL TREATMENT (1300)
2085 GPM
COOLING TOWER MAKE-UP AND PROCESS WATER
WASTE WATER RECLAMATION (1300)
PROCESS WATER
SOLIDS TO DISPOSAL
SULFUR MELT
SULFUR FLAKING 1 TRAIN (603)
SULFUR
PROCESS H.P. STEAM
PROCESS L.P. STEAM
FUEL GAS TO TURBINE
1,494 MM BTU/H (LHV)
POWER GENERATION (1000)
242,530 MW
TO PLANT FACILITIES
STONE & WEBSTER ENGINEERING CORPORATION
CLIENT
ELECTRIC POWER RESEARCH INSTITUTE
TITLE OVERALL BLOCK FLOW DIAGRAM
H-COAL LIQUEFACTION PROCESS
ILLINOIS NO 6 COAL FEED
CASE HE
D.G.FARIA
13461
75-D1
1



COAL
21,872 TPD (DRY BASIS)
COAL CRUSHING AND DRYING (100)
COAL SLURRYING (2-1 TRAINS (201)
COAL SLURRY
840°F 3000 PSIG H-COAL REACTION (2-1 TRAINS (201)
LIQUEFIED COAL
EFFLUENT SEPARATION 3 TRAINS (202)
SLURRY RECYCLE
OIL FOR SLURRYING
HYDROGEN RECYCLE
2925 PSIG
AMINE PLANT 3 TRAINS (204)
ACID GAS TO STRETFORD UNIT
MOL SIEVE
CRYOGENIC PLANT 2 TRAINS (205)
3150 PSIG
875 PSIG
350 PSIG
35 PSIG
120,543 LB/H (AS 100% H_2)
HYDROGEN
PLANT FUEL
H.P. FUEL GAS
TO GAS TURBINE
77,489 LB/H
D.G.A. AMINE PLANT 1 TRAIN (301)
ACID GAS TO STRETFORD UNIT
GAS REFORM & SHIFT 2 TRAINS (405)
CO_2 REMOVAL HOT POT 2 TRAINS (406)
STEAM
PROCESS CONDENSATE
36983 LB/H (AS 100% H_2)
700 PSIG
VAPOR
VENT
STEAM
DISTILLATE
SLURRY
FRACTIONATION 1 TRAIN (203)
FUEL OIL
58,327 LB/H
H_2S TO CLAUS
FUEL GAS
SPLITTER OVERHEAD
NAPHTHA
NAPHTHA UPGRADING 1 TRAIN (206)
TREATED NAPHTHA
REFORMING 1 TRAIN (208)
REFORMATE (GASOLINE)
257,355 LB/H
PLANT FUEL GAS
TURBINE OIL
OIL UPGRADING 1 TRAIN (207)
327,579 LB/H
VACUUM TOWER BOTTOMS
AIR
WASTE N_2
STRIPPING N_2
OXYGEN PLANT 2 TRAINS (530)
OXYGEN 5,137.7 TPD (AS 100% O_2)
GASIFICATION & QUENCH (401)
GENERATOR GAS
SCRUBBING (401)
RAW SYN GAS
CO SHIFT 4 TRAINS (402)
SHIFTED GAS
ACID GAS REMOVAL 1 TRAIN (403)
CO_2 TO ATM
HYDROGEN 83,560 LB/H (AS 100% H_2)
TO & FROM SECTION 285
REFRIGERATION SYSTEM (PROPANE) 900
ACID GAS TO STRETFORD UNIT
RECYCLE WATER
PROCESS CONDENSATE
NH_3 PURGE TO SECT 202
SOOTY WATER
CLARIFIED QUENCH H_2O
6,659 GPM RIVER WATER
RAW WATER TREATMENT 1 TRAIN (1300)
FILTERED WATER
DEMINERALIZED WATER
WATER RECOVERY (401)
WATER PURGE
WASTE WATER TREATING (401)
MAKE-UP WATER
SLAG & ASH TO DISPOSAL 1716 TPD (DRY)
TREATED WATER
TO COOLING TOWER
SOUR WATER (SW)
1,479 GPM WATER
OIL SEPARATOR 1 UNIT (701)
OIL TO DISPOSAL
PHENOL RECOVERY 1 TRAIN (701)
SOUR WATER STRIPPING 2 TRAINS (702)
SOUR GAS
AMMONIA RECOVERY 1 TRAIN (703)
AMMONIA
162 TPD
PHENOL
24 TPD
ACID GAS TO CLAUS UNIT
ACID GAS FROM (703)
ACID GAS FROM (204),(301) & (403)
CO_2 TO ATM
SULFUR RECOVERY (CLAUS) 1 TRAIN (601)
TAIL GAS
BEAVON 1 TRAIN (642)
STRETFORD 1 TRAIN (602)
CONTAMINATED WATER
WASTE WATER
BIOLOGICAL TREATMENT (1300)
1406 GPM
COOLING TOWER MAKE-UP AND PROCESS WATER
COOLING TOWER BLOWDOWN
MISC BLOWDOWN
WASTE WATER RECLAMATION (1300)
PROCESS WATER
SOLIDS TO DISPOSAL
SULFUR MELT
SULFUR FLAKING 1 TRAIN (603)
SULFUR
194 TPD
PROCESS H.P. STEAM
733,080 LB/HR
PROCESS L.P. STEAM
824,376 LB/HR
FUEL GAS TO TURBINE
2,152 MM BTU/HR
POWER GENERATION (1800)
375,285 MW
356,713 MW
TO PLANT FACILITIES
18,572 MW
EXPORT POWER
SW
STONE & WEBSTER ENGINEERING CORPORATION
CLIENT
ELECTRIC POWER RESEARCH INSTITUTE
TITLE OVERALL BLOCK FLOW DIAGRAM
H-COAL LIQUEFACTION PROCESS
WYODAK COAL FEED
CASE HW
O.G.FARIA
13461
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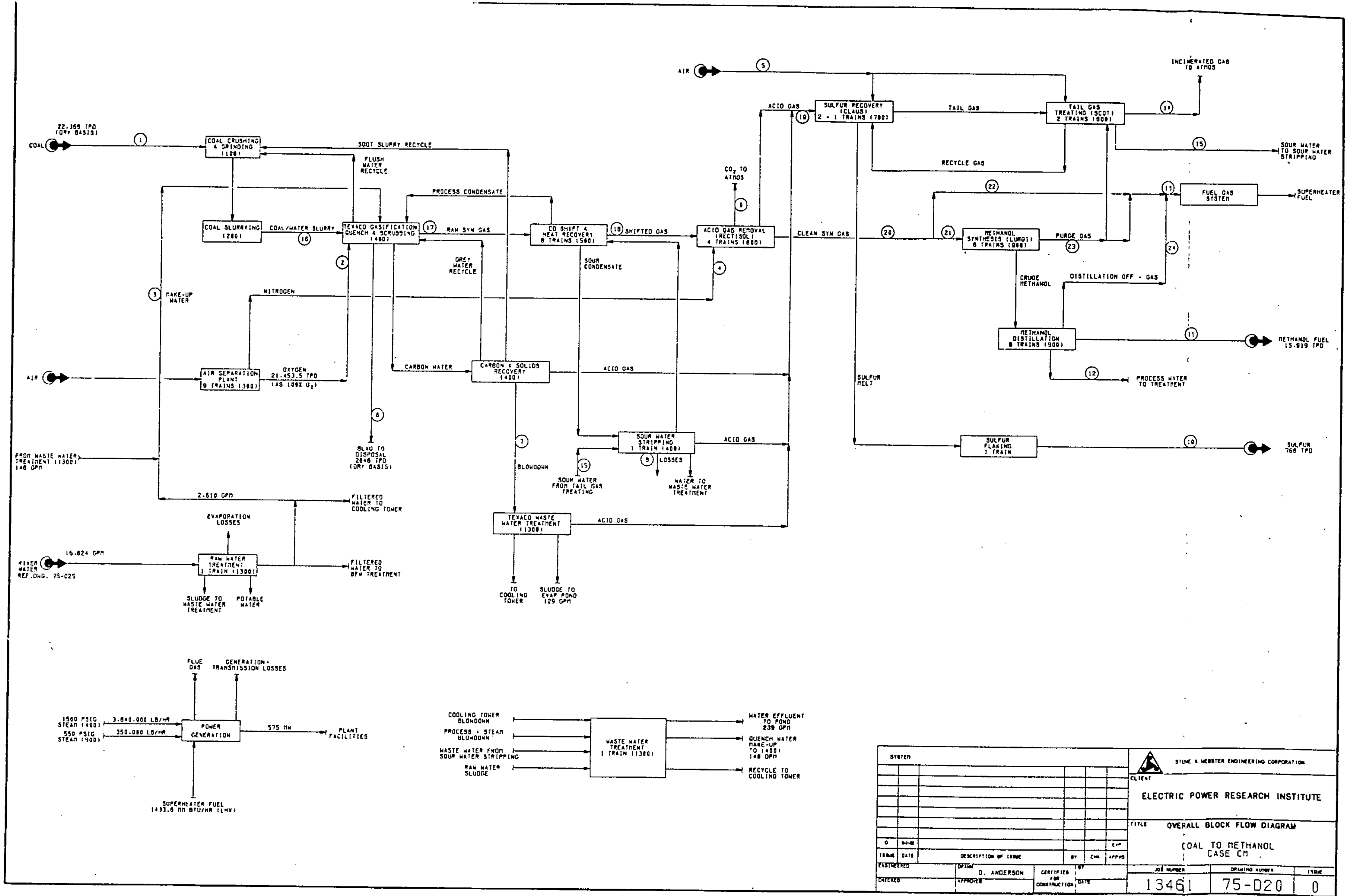
OVERALL BLOCK FLOW DIAGRAM
COAL TO METHANOL CASE CM
ELECTRIC POWER RESEARCH INSTITUTE
STONE & WEBSTER ENGINEERING CORPORATION
D. ANDERSON
13461
75-D20
0
COAL
22,359 TPD (DRY BASIS)
COAL CRUSHING & GRINDING (100)
SOOT SLURRY RECYCLE
FLUSH WATER RECYCLE
COAL SLURRYING (200)
COAL/WATER SLURRY
TEXACO GASIFICATION QUENCH & SCRUBBING (400)
PROCESS CONDENSATE
RAW SYN GAS
CO SHIFT & HEAT RECOVERY
SHIFTED GAS
SOUR CONDENSATE
GREY WATER RECYCLE
ACID GAS REMOVAL (RECTISOL) 4 TRAINS (600)
CO2 TO ATMOS
CLEAN SYN GAS
ACID GAS
AIR
SULFUR RECOVERY (CLAUS) 2 + 1 TRAINS (700)
TAIL GAS
TAIL GAS TREATING (SCOT) 2 TRAINS (800)
RECYCLE GAS
INCINERATED GAS TO ATMOS
SOUR WATER TO SOUR WATER STRIPPING
FUEL GAS SYSTEM
SUPERHEATER FUEL
METHANOL SYNTHESIS (LURGI)
PURGE GAS
CRUDE METHANOL
DISTILLATION OFF - GAS
METHANOL DISTILLATION
METHANOL FUEL
PROCESS WATER TO TREATMENT
SULFUR MELT
SULFUR FLAKING 1 TRAIN
SULFUR 768 TPD
MAKE-UP WATER
NITROGEN
AIR SEPARATION PLANT 9 TRAINS (300)
OXYGEN 21,453.5 TPD (AS 100% O2)
CARBON WATER
CARBON & SOLIDS RECOVERY (400)
SLAG TO DISPOSAL 2646 TPD (DRY BASIS)
BLOWDOWN
SOUR WATER STRIPPING 1 TRAIN (400)
LOSSES
SOUR WATER FROM TAIL GAS TREATING
WATER TO WASTE WATER TREATMENT
FROM WASTE WATER TREATMENT (1300) 148 GPM
2,610 GPM
FILTERED WATER TO COOLING TOWER
EVAPORATION LOSSES
RIVER WATER REF. DWG. 75-C25
15,624 GPM
RAW WATER TREATMENT 1 TRAIN (1300)
FILTERED WATER TO BFW TREATMENT
SLUDGE TO WASTE WATER TREATMENT
POTABLE WATER
TEXACO WASTE WATER TREATMENT (1300)
TO COOLING TOWER
SLUDGE TO EVAP POND 129 GPM
FLUE GAS
GENERATION + TRANSMISSION LOSSES
1500 PSIG STEAM (400)
550 PSIG STEAM (900)
350,000 LB/HR
POWER GENERATION
575 MW
PLANT FACILITIES
COOLING TOWER BLOWDOWN
PROCESS + STEAM BLOWDOWN
WASTE WATER FROM SOUR WATER STRIPPING
RAW WATER SLUDGE
WASTE WATER TREATMENT 1 TRAIN (1300)
WATER EFFLUENT TO POND 239 GPM
QUENCH WATER MAKE-UP TO (400) 148 GPM
RECYCLE TO COOLING TOWER

Sections 5, 6, and 7 of this report present the detailed information on the designs prepared for the three cases, and Section 8 summarizes the investment, operating, and production costs developed based on these designs. Tables 2-1, 2-2, and 2-3 summarize the results for the three cases under consideration.

Table 2-1 presents results for H-Coal processing of Illinois No. 6 coal, Case HE. A feed rate of 21,891 st/sd* of coal is processed to produce 62,116 bbl/sd of liquid products at a thermal efficiency, based on the primary fuel products, of 69.7 percent. Liquid product yield, on a fuel oil equivalent basis (based on 5.85 x 10^6 Btu per barrel), amounts to 58,154 FOE bbl/sd.

Estimated capital requirements are also presented. Plant investment, including contingencies, is estimated to be 2.6 billion dollars and total capital requirements, including startup expenses, working capital, etc., are estimated to be 2.8 billion dollars. All of these data are developed on an instantaneous plant basis using mid-1982 dollars without allowance for the cost of funds during construction, tax credits, or the impact of inflation.

Also presented in Table 2-1 are fixed and variable operating cost data. These amount respectively to $\$1.32/10^6$ Btu and $\$0.41/10^6$ Btu of fuel product for a nonregulated producer.

Similar summary data are presented for the Wyodak case in Table 2-2 and then for the coal-to-methanol case in Table 2-3.

It is important to realize that all plant cost estimates presented in this report are for mature technology, say fifth-of-a-kind systems. Costs for first commercial plants could be greater than those shown here. Sensitivity to capital cost increase is shown in Tables 2-4 and 2-5.

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* short tons/stream day. The term stream day represents one full operating day. The term stream factor is equivalent to the annual capacity factor.

Table 2-1

A. CAPITAL AND PRODUCTS SUMMARY
CASE HE

Capital Requirements	Mid-1982 ($$10^6$)
Total Estimated Base Cost	$2,032
Contingencies	563
Total Plant Investment	2,595
Initial Fill of Catalysts & Chemicals	20
Total Plant Facilities Investment (PFI)	2,615
Land	6
Organization & Start-up	72
Working Capital	107
Prepaid Royalties	13
Total Capital (nonregulated producer)	$2,813

Material Balance	st/sd	lb/hr	bbl/sd	10^6 Btu/hr (HHV)
Coal (as received)				
Illinois No. 6	21,891	1,824,243[a]		20,339
Fuel Products[b]				
Gasoline Blend		184,779	16,010	3,580
Turbine Fuel		364,400	27,393	6,735
Fuel Oil		107,581	6,880	1,880
Propane		52,857	7,175	1,137
Butane		39,937	4,658	843
Total Fuel Products			62,116	14,175
			58,154[c]	
Gasoline and Heavier Products			50,031[c]	
By-Products				
Ammonia	222	18,498		169
Sulfur	664	55,340		221
Phenols	50	4,206		59

[a] MF Coal = 1,605,344 lb/hr

[b] Thermal Efficiency based on primary products = 69.7%

[c] Fuel Oil Equivalent basis, FOE bbl = 5.85×10^6 Btu

Table 2-1 (cont'd)

B. OPERATING COSTS AND CREDITS SUMMARY - CASE HE
100% ANNUAL CAPACITY FACTOR

Operating Costs	Mid-1982 $\$10^3$/yr	$\$/10^6$ Btu Output[a]
Fixed - Operating Labor - 82 operator jobs/shift @ \$17.25/man-hour (with 35% payroll burden)	12,391	
Maintenance Labor - 40% of maintenance cost	24,942	
Maintenance Materials - 60% of maintenance cost	37,414	
Administration and Support Labor - 30% of operating and maintenance labor	11,200	
General and Administration Costs - 0.7% of PFI (for nonregulated producer only)	18,302	
Taxes and Insurance - 2% of Escalated PFI	43,571	
Total Fixed Cost	147,820	1.32
Variable - Water	2,900	
Catalyst & Chemicals	43,298	
Ash Disposal	4,646	
Total Variable Cost	50,844	0.41
Coal Intake - Illinois No. 6 @ $\$1.89/10^6$ Btu	336,740	2.71
By-Product Credits		
Ammonia @ \$70/st	5,672	0.05
Sulfur @ \$62.50/st	15,148	0.12
Phenols	--	--
Total Operating Costs (nonregulated producer)		4.27

[a] Unit costs calculated for 90% Annual Capacity Factor

Table 2-2

A. CAPITAL AND PRODUCTS SUMMARY
CASE HW

Capital Requirements	Mid-1982 ($\$10^6$)
Total Estimated Base Cost	$2,535
Contingencies	784
Total Plant Investment	3,319
Initial Fill of Catalysts & Chemicals	22
Total Plant Facilities Investment (PFI)	3,341
Land	6
Organization & Start-up	85
Working Capital	75
Prepaid Royalties	17
Total Capital (nonregulated producer)	$3,524

Material Balance	st/sd	lb/hr	bbl/sd	10^6 Btu/hr (HHV)
Coal (as received)				
Wyodak	30,960	2,580,000[a]		20,626
Fuel Products[b]				
Gasoline Blend		257,355	21,772	5,046
Turbine Fuel		327,579	25,880	6,210
Fuel Oil		58,327	3,743	1,028
Total Fuel Products			51,395 50,396[c]	12,284
By-Products				
Ammonia	162	13,476		123
Sulfur	194	16,161		64
Phenol	24	2,000		28
Export Power		18,572 (kW)		63

[a] MF Coal = 1,805,999 lb/hr

[b] Thermal Efficiency based on primary products = 59.6%

[c] Fuel Oil Equivalent basis, FOE bbl = 5.85 x 10^6 Btu

Table 2-2 (cont'd)

B. OPERATING COSTS AND CREDITS SUMMARY - CASE HW
100% ANNUAL CAPACITY FACTOR

Operating Costs	Mid-1982 $\$10^3$/yr	$\$/10^6$ Btu Output[a]
Fixed - Operating Labor - 82 operator jobs/shift @ $17.25/man-hour (with 35% payroll burden)	12,391	
Maintenance Labor - 40% of maintenance cost	34,536	
Maintenance Materials - 60% of maintenance cost	51,803	
Administration & Support Labor - 30% of operating and maintenance labor	14,078	
General & Administration Costs - 0.7% of PFI (for nonregulated producer only)	23,385	
Taxes and Insurance - 2% of Escalated PFI	55,672	
Total Fixed Cost	191,865	1.98
Variable - Water	2,724	
Catalyst & Chemicals	49,287	
Ash Disposal	3,539	
Total Variable Cost	55,550	0.52
Coal Intake - Wyodak @ $\$0.75/10^6$ Btu	135,510	1.26
By-Product Credits		
Ammonia @ $70/st	4,139	0.04
Sulfur @ $62.50/st	4,426	0.04
Phenols	---	---
Export Power @ $0.05/kWh	8,135	0.08
Total Operating Costs (nonregulated producer)		3.60

[a] Unit costs calculated for 90% Annual Capacity Factor

Table 2-3

A. CAPITAL AND PRODUCTS SUMMARY
CASE CM

Capital Requirements	Mid-1982 ($$10^6$)
Total Estimated Base Cost	$2,416
Contingencies	475
Total Plant Investment	2,891
Initial Fill of Catalysts & Chemicals	24
Total Plant Facilities Investment (PFI)	2,915
Land	6
Organization & Start-up	76
Working Capital	110
Prepaid Royalties	15
Total Capital (nonregulated producer)	$3,122

Material Balance	st/sd	lb/hr	bbl/sd	10^6 Btu/hr (HHV)
Coal (as received) Illinois No. 6	25,418	2,118,182[a]		23,616
Methanol Product[b]	15,919	1,326,594	111,870 52,209[c]	12,726
By-Product Sulfur	768	64,000		255

[a] MF Coal = 1,864,000 lb/hr

[b] Thermal Efficiency based on methanol product = 53.9%

[c] Fuel Oil Equivalent basis, FOE bbl = 5.85 x 10^6 Btu

Table 2-3 (cont'd)

B. OPERATING COSTS AND CREDITS SUMMARY - CASE CM
100% ANNUAL CAPACITY FACTOR

Operating Costs	Mid-1982 $\$10^3$/yr	$\$/10^6$ Btu Output[a]
Fixed - Operating Labor - 60 operator jobs/shift @ \$17.25/man-hour (with 35% payroll burden)	9,067	
Maintenance Labor - 40% of maintenance cost	23,949	
Maintenance Materials - 60% of maintenance cost	35,923	
Administration and Support Labor - 30% of operating and maintenance labor	9,905	
General and Administration Costs - 0.7% of PFI (for nonregulated producer only)	20,404	
Taxes and Insurance - 2% of Escalated PFI	48,576	
Total Fixed Cost	147,824	1.47
Variable - Water	5,243	
Catalyst & Chemicals	8,968	
Ash Disposal	5,457	
Total Variable Cost	19,668	0.18
Coal Intake - Illinois No. 6 @ \$1.89/10^6 Btu	390,996	3.51
By-Product Credit		
Sulfur @ \$62.50/st	17,520	0.16
Total Operating Costs (nonregulated producer)		5.00

[a] Unit costs calculated for 90% Annual Capacity Factor

Based on these investment and operating cost data, production cost estimates have been developed utilizing the EPRI Engineering and Economic Evaluations (E&EE) computer program. This program and its utilization are described in the Appendix of this report, and Section 8 presents the development of production costs using the above data and the computer output. The results of these evaluations are summarized in Tables 2-4 and 2-5.

Table 2-4 presents data for the case of nonregulated producers using 100 percent equity financing. Basic economic parameters used in developing these data are:

- 8.5 percent annual inflation rate
- 18.3 percent return on equity (9.0 percent excluding inflation)
- five-year construction period - startup January 1990

A complete schedule of the assumptions used is presented in Table 8-2. Accounting for these various factors, including an allowance for funds during construction, the total capital requirements are 5.7, 7.2, and 6.4 billion dollars for Cases HE, HW, and CM, respectively. These factors result in more than double the mid-1982 costs for the 1990 capital requirement in as-built (or current) dollars.

Using these data and the EPRI E&EE computer program, required selling prices were developed for the three cases. Required selling price is expressed in mid-1982 dollars and is defined as the price which, if escalated at the inflation rate, together with coal and other operating costs, will yield the specified return on equity. The prices developed for the three case studies are $9.06/10^6 Btu, $10.46/10^6 Btu, and $10.94/10^6 Btu for H-Coal (Illinois No. 6), H-Coal (Wyodak) and Methanol, respectively.

When products are sold at a competitive market price substantially different from the required price for the base case, the rate of return is affected. For example, if the competitive market price is $6.50/10^6 Btu, based on mid-1982 conditions, the DCF return for the nonregulated producer would be 12.86, 11.27, and 8.22 percent for Cases HE, HW, and CM, respectively. These rates of return compare with 18.3 percent for the base case. The returns would be even less attractive at present (mid-1983) depressed market conditions.

Results of sensitivity studies are also presented in Table 2-4 which illustrate the impact of several variables. Since the required selling price is considerably above the current price for petroleum products, options which reduce this price are of greatest interest. One of the more interesting is the use of a leveraged financing arrangement which, when based on 75 percent debt financing at 12 percent interest, reduces the required selling prices to $6.50, $6.68, and $7.75/10^6 Btu for the cases studied. Another interesting but speculative approach is the possibility of expensing of the equity during construction, which also has a substantial impact on the required selling price.

Table 2-5 presents similar data for the case in which the producer is a regulated, investor-owned utility. On this basis, required product manufacturing costs are substantially lower due principally to the leveraged approach to financing. In this case, the mid-1982 levelized costs are $5.78, $5.66, and $6.88/10^6 Btu for the three cases studied. These prices approach the level of petroleum product prices just prior to the current depression in prices and show that the technologies under study can be attractive in the long term in an economic environment reflecting a net shortfall of liquid petroleum.

Sensitivities for the regulated utility have been studied. For each case, the levelized selling price for the regulated utility is substantially below the required selling price of the nonregulated producer.

Unfortunately, these levelized regulated company production costs present an overly simplified picture when considering utility company ownership. Product costs in the initial years of production will be substantially higher than the levelized costs (in constant 1982 dollars) owing to the fact that the capital-related charges are extremely high. In the later years of the project life, production costs become lower than the levelized costs (in constant 1982 dollars) as the capital-related charges become very low. Table 2-5 shows annual production costs for all three cases and the relationship of these annual costs to the levelized cost. This table demonstrates, for example, that although the constant dollar levelized cost for H-Coal (Illinois No. 6)-based liquids produced by a regulated company has been estimated to be $5.78/10^6$ Btu, the first year production cost is substantially higher at $9.55/10^6$ Btu. A potential problem to be overcome by a regulated utility owner of such a plant is how to recover the high initial years production costs in the face of significantly lower petroleum fuel oil and natural gas prices.

Table 2-4

PLANT INVESTMENT AND REQUIRED PRODUCT SELLING PRICES
NONREGULATED PRODUCER

Case	HE	HW	CM
Process	H-Coal	H-Coal	Lurgi Methanol
Coal	Illinois No. 6	Wyodak	Illinois No. 6
Plant Investment - $\$10^6$			
Plant Facilities - Mid-1982 basis	2,615	3,341	2,915
Total Capital - Jan 1990 startup	5,733	7,198	6,367
Required Product Selling Price - Base Case Mid-1982 $\$/10^6$ Btu - Levelized	9.06	10.46	10.94
Return on equity when product is sold at competitive fuel price, %/yr[a]	12.86	11.27	8.22
Sensitivity Studies - impact on required selling price - $\$/10^6$ Btu (% change)			
After tax return on equity increases to 25%	12.85 (+41.8)	15.98 (+52.8)	15.63 (+42.9)
35% increase in plant facilities investment	10.71 (+18.2)	12.90 (+23.3)	12.99 (+18.7)
3%/yr increase in real cost of coal	10.24 (+13.0)	10.85 (+3.7)	12.46 (+13.9)
10% decrease in thermal efficiency	10.07 (+11.1)	11.62 (+11.1)	12.16 (+11.1)
10% increase in thermal efficiency	8.24 (-9.1)	9.51 (-9.1)	9.95 (-9.1)
Inflation rate decreases to 5%/yr	8.95 (-1.2)	10.27 (-1.8)	10.80 (-1.3)
75% debt financing @ 12% interest	6.50 (-28.3)	6.68 (-36.1)	7.75 (-29.2)
Expensing of investment during construction			
100% equity	7.72 (-14.8)		
50% debt @ 12%, 50% equity	6.01 (-33.7)		

[a] Return on equity, base case, 18.3% per year. Assume competitive fuel price (mid-1982 basis) is $\$6.50/10^6$ Btu.

Table 2-5

PLANT INVESTMENT AND REQUIRED PRODUCT SELLING PRICES
REGULATED PRODUCER - INVESTOR-OWNED UTILITY

Case	HE	HW	CM
Process	H-Coal	H-Coal	Lurgi Methanol
Coal	Illinois No. 6	Wyodak	Illinois No. 6
Plant Investment - $\$10^6$			
Plant Facilities - Mid-1982 basis	2,615	3,341	2,915
Total Capital - Jan 1990 startup	5,300	6,640	5,882
Required Product Selling Price - Base Case Mid-1982 $\$/10^6$ Btu			
- Levelized	5.78	5.66	6.88
- First year (1990)	9.55	11.26	11.54
- Third year (1992)	7.91	8.85	9.51
- Fifth year (1994)	6.57	6.87	7.86
- Tenth year (1999)	5.36	5.07	6.36
- Fifteenth year (2004)	4.87	4.32	5.76
- Thirtieth year (2019)	4.53	3.73	5.36
Sensitivity Studies - impact on required selling price (levelized) - $\$/10^6$ Btu (% change)			
3%/yr increase in real cost of coal	7.59 (+31.3)	6.28 (+11.0)	9.22 (+34.0)
35% increase in plant facilities investment	6.36 (+10.0)	6.52 (+15.2)	7.60 (+10.5)
10% decrease in thermal efficiency	6.42 (+11.1)	6.29 (+11.1)	7.64 (+11.1)
Inflation rate decreases to 5%	5.85 (+1.2)	5.73 (+1.2)	6.97 (+1.3)
10% increase in thermal efficiency	5.25 (-9.1)	5.15 (-9.1)	6.25 (-9.1)

To illustrate the impact of the various elements which contribute to the production cost of the primary liquid products, a tabulation of these elements for the H-Coal Illinois coal case is presented in Table 2-6. The capital-related charges are developed as the difference between the total cost and the sum of the coal and operating costs. It will be noted that the capital-related charges are more than half of the total cost, with coal and operating costs being less significant factors, in that order. It is apparent that factors impacting the magnitude of capital-related costs will have a major impact on the attractiveness of projects of this nature. This observation is consistent with the earlier discussion of the impact of financing leverage on the required selling price.

Table 2-6

MID-1982 PRODUCTION COSTS
H-COAL ILLINOIS - CASE HE
NON-REGULATED PRODUCER

Item	Product Cost[c] $\$/10^6$ Btu
Coal	2.71
Fixed Operating Costs	1.32
Variable Operating Costs	0.41
By-Product Credits	(0.17)
Capital Related Charges[a]	4.79
Total	9.06[b]

[a] By difference (includes specified return on equity)

[b] Required selling price calculated by E&EE computer program

[c] At 90% Annual Capacity Factor

DISCUSSION

Comparison of Illinois No. 6 and Wyodak Coals as H-Coal Feedstocks

Table 2-7 presents data comparing these coals and the results of this study for processing of these coals. The salient points of this comparison are:

1. The two cases studied are based on production of essentially the same quantity of gasoline and heavier liquid products (50,031 bbl/sd vs. 50,396 bbl/sd) on an FOE basis. A major liquid yield difference is the propane and butane produced in the Illinois No. 6 case.

2. The quantity of coal required in the Wyodak case is over 40 percent greater than for the Illinois No. 6 case. This is due to several factors including:

   -- The higher moisture and oxygen content of the Wyodak coal

   -- Lower carbon content of Wyodak coal

3. The capital cost is higher for the Wyodak case for the following reasons:

   -- More H-Coal reactors are required (12 vs. 8).

   -- Hydrogen consumption is substantially higher (6.27 weight percent on dry coal vs. 4.89 weight percent) due principally to the higher oxygen content. This leads to the need for hydrogen production via reforming to supplement gasification of vacuum tower bottoms.

   -- Coal drying requirements are greater.

4. These same factors impact both the thermal efficiency (69.7 percent for Illinois No. 6 vs. 59.6 percent for Wyodak) and the operating costs ($\$1.73/10^6$ Btu for Illinois vs. $\$2.50/10^6$ Btu for Wyodak).

5. Offsetting these factors to some degree is the coal cost - $\$1.89/10^6$ Btu for Illinois No. 6 vs. $\$0.75/10^6$ Btu for Wyodak. The greater quantity of Wyodak coal affects this advantage somewhat, resulting in contributions to product costs of $\$2.71/10^6$ Btu vs. $\$1.26/10^6$ Btu for Illinois No. 6 and Wyodak, respectively.

6. The net result of these factors is a significantly lower required selling price for coal liquids produced from Illinois No. 6 - $\$9.06/10^6$ Btu vs. $\$10.46/10^6$ Btu for Wyodak.

Table 2-7

H-COAL DIRECT LIQUEFACTION
COMPARISON OF ILLINOIS NO. 6 AND WYODAK COALS
NONREGULATED PRODUCER

Case	HE Illinois No. 6	HW Wyodak
Total Fuel Product Yield - bbl/sd (FOE)[a]	58,154	50,396
Gasoline and Heavier Liquid Product Yield, bbl/sd (FOE)[a]	50,031	50,396
Coal Feed - st/sd (As Received)	21,891	30,960
Ultimate Analysis - wt%		
Carbon	69.76	66.58
Hydrogen	4.91	4.93
Nitrogen	1.47	1.05
Sulfur	3.47	1.14
Oxygen	8.88	19.22
Ash	11.51	7.08
Water - wt%	12.0	30.0
Total Capital Requirement		
- Mid-1982 $\$10^6$	2,813	3,524
- \$/(FOE bbl Gasoline and Heavier Liquid Product/sd)	56,225	69,926
Thermal Efficiency, %	69.7	59.6
Coal Cost, $\$/10^6$ Btu	1.89	0.75
Non-Capital Contributions to Required Product Selling Price, $\$/10^6$ Btu[b]		
Coal	2.71	1.26
Operating Costs	1.73	2.50
By-Product Credits	(0.17)	(0.16)
Total Non-Capital Contributions	4.27	3.60
Capital Related Charges	4.79	6.86
Required Product Selling Price[bc]	9.06	10.46

[a] FOE barrel = 5.85×10^6 Btu.

[b] Product selling price is the levelized price in mid-1982 $\$/10^6$ Btu.

[c] At 90% Annual Capacity Factor

arison of H-Coal vs. Methanol

le 2-8 compares the results obtained from studying the processing of Illinois . 6 by H-Coal with the use of the same coal to produce methanol. The l-to-methanol case is based on Texaco Gasification of coal coupled with Lurgi hanol synthesis. The principal points of this comparison are:

1. The H-Coal case produces more total products than the methanol case. The difference is largely represented by the propane and butane products of the H-Coal process.

2. The methanol case requires approximately 10 percent higher capital investment.

3. The two approaches show a significant difference in thermal efficiency: 69.7 percent for H-Coal vs. 53.9 percent for methanol production. For the methanol design a conservative estimate of coal slurry concentration (60% solids) was used. A higher solids concentration would improve the efficiency of methanol production and would decrease the cost difference between methanol and H-Coal liquids.

4. The result of these differences is a 20 percent higher required selling price for methanol: $\$10.94/10^6$ Btu vs. $\$9.06/10^6$ Btu.

Since the products of these two cases differ in character, comparative evaluation requires consideration of the relative value of the products produced. For example, taking average costs from the Monthly Energy Review (DOE/EIA-0035, 83/02) for mid-1982 and using DOE standard heating values in Btu/bbl (same reference), it is possible to calculate a composite value for the H-Coal Case HE product of $\$6.80/10^6$ Btu, mid-1982 basis. Should the composite product value be $\$9.06/10^6$ Btu, as in Case HE, then the individual product values can be estimated by simple ratio as long as the relative price structure is unchanged. The following table illustrates this point:

	Av. Price Wholesale Mid-1982 $/bbl	DOE Std. HHV 10^6Btu/bbl	Mid-1982 Product Values $\$/10^6$Btu	Case HE Rates 10^6Btu/hr	Est. HE Product Values $\$/10^6$Btu
C_3	17	3.836	4.43	1137	5.90
C_4	29	4.326	6.70	843	8.93
Prem. Mogas	43[a]	5.253	8.19	3580	10.91
Turbine Oil	41[b]	5.825	7.04	6735	9.38
Fuel Oil	30[c]	6.287	4.77	1880	6.36
Total			6.80	14175	9.06

By this estimating procedure, it appears that methanol at $\$10.94/10^6$ Btu (Table 2-4) and Case HE Premium Mogas at $\$10.91/10^6$ Btu are about equivalent heatwise. On the other hand, it appears that methanol would not be competitive heatwise with the Case HE turbine fuel fraction at $\$9.38/10^6$ Btu.

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a Premium motor gasoline retail price adjusted for tax, transportation, and markup - about 40¢/gal. ($17/bbl).

b Equated with No. 2 oil.

c Equated to low S (< 0.3% w) No. 6 oil.

Table 2-8

COMPARISON OF H-COAL DIRECT LIQUEFACTION
WITH INDIRECT LIQUEFACTION (METHANOL)
BASIS: ILLINOIS NO. 6 COAL
NONREGULATED PRODUCER

Case	HE H-Coal	CM Coal to Methanol
Total Fuel Product Yield, bbl/sd (FOE)[a]	58,154	52,209
Gasoline and Heavier Liquid Product Yield, bbl/sd (FOE)	50,031	52,209
Coal Feed, st/sd (As Received)	21,891	25,418
Total Capital Requirement		
- Mid-1982 $\$10^6$	2,813	3,122
- $/(FOE bbl Gasoline and Heavier Liquid Product/sd)	56,225	59,798
Thermal Efficiency, %	69.7	53.9
Non-Capital Contributions to Required Product Selling Price[b], $\$/10^6$ Btu		
Coal	2.71	3.51
Operating Costs	1.73	1.65
By-product Credits	(0.17)	(0.16)
Total Non-Capital Contributions	4.27	5.00
Capital Related Charges	4.79	5.94
Required Product Selling Price[bc]	9.06	10.94

[a] FOE barrel = 5.85×10^6 Btu.

[b] Required selling price is the levelized price in mid-1982 $\$/10^6$ Btu.

[c] At 90 percent stream factor.

Technical Commentary

H-Coal Development Status. H-Coal is a direct catalytic hydroliquefaction process developed by Hydrocarbon Research Inc. (HRI) for conversion of coal to high-quality, clean liquids. Development and demonstration of the conversion process has been carried out on bench-scale units and in a Process Development Unit (PDU) since 1963. Eighteen types of coals have been evaluated in over 60,000 hours of operation (1).

Critical operating experience was gained with commercial-scale equipment at the 200-600 ton/day H-Coal Pilot Plant at Catlettsburg, Kentucky. The Catlettsburg Pilot Plant operated 2 1/2 years through December 1982 to demonstrate its performance on eastern and western coals and to provide a basis for the design and construction of full-scale, commercial H-Coal facilities (2).

Test runs were conducted with both Illinois No. 6 and Wyodak coals in the Syncrude mode (all distillate products). The primary goal of the pilot plant runs was to confirm the yields achieved in the PDU at comparable operating conditions and at the targeted catalyst addition rates. The normalized reactor yields achieved in the Pilot Plant are compared with the PDU design yields in Tables 2-9 and 2-10.

The tables demonstrate very good reactor scale-up. The product boiling point distributions are somewhat different from the PDU runs, but this corresponds to the slightly higher indicated hydrogen uptake. The apparent discrepancy in the residuum and unconverted coal values is attributed to the use of different analytical procedures for determining unconverted coal in the pilot plant product (quinoline extraction) and in the PDU product (filtration). The important consideration is the yield of residuum plus unconverted coal. In the Wyodak test a higher yield of total distillate oil was obtained in the pilot plant than was obtained in PDU Run 10. This result may in part be due to the excellent chemical performance by the Amocat 1A catalyst used in this study. However, significant catalyst loss was experienced due to attrition. Further development of this catalyst appears necessary for commercial application.

Nevertheless, it appears that, although there are minor differences from the PDU studies, scale-up of the conversion section of the pilot plant was very successful. On the other hand, the design and operation of the remainder of the plant did not demonstrate adequate distillate product recovery. For example, the heavy oil cut as produced was about 80 percent light oil, and about 80 percent of the heavy oil was obtained with the vacuum bottoms product. Thus, the pilot plant did not provide adequate experience in separating and handling these heavy cuts.

The H-Coal coal liquefaction process is available for licensing through HRI, Inc.

Table 2-9

NORMALIZED H-COAL REACTOR YIELDS BASIS
ILLINOIS NO. 6 COAL

Component	Pilot Plant Run 8 Dry Coal Wt %	PDU-5 Period 29 Dry Coal Wt%	Design Basis Case HE Dry Coal Wt%
H_2S	2.67	2.64	2.64
NH_3	0.65	1.08	1.08
H_2O	6.67	6.67	6.65
CO/CO_2	—	0.48	0.53
C_1-C_3	11.77	10.68	10.63
C_4-400	22.41	18.74	18.69
400-650	16.46	20.37	20.41
650-975	8.81	7.96	7.97
Residuum	21.26	19.00	19.00
Unconverted Coal	3.46	5.78	5.78
Ash	11.31	11.51	11.51
Total	105.47	104.91	104.89
Total Distillate Oil C_4-975	47.68	47.07	47.07
Residuum Plus Unconverted Coal	24.72	24.78	24.78

Table 2-10

NORMALIZED H-COAL REACTOR YIELDS BASIS
WYODAK COAL

Component	Pilot Plant Run 10 Dry Coal Wt %	PDU-10 Period 30B Dry Coal Wt%	PDU-6[a] Period 17 Dry Coal Wt%
H_2S	0.74	0.34	0.87
NH_3	0.63	0.31	0.75
H_2O	15.47	15.39	17.13
CO/CO_2	1.36	2.54	2.90
C_1-C_3	9.29	9.98	12.14
C_4-400	25.95	22.12	23.93
400-650	14.60	13.20	12.22
650-975	9.33	10.86	10.05
Residuum	10.65	11.27	11.46
Unconverted Coal	9.12	10.72	7.09
Ash	9.13	8.84	7.73
Total	106.28	105.57	106.27
Total Distillate Oil C_4-975	49.88	46.18	46.20
Residuum Plus Unconverted Coal	19.77	21.99	18.55

[a] Design Basis for Case HW

Process Considerations for Illinois No. 6 and Wyodak Coals as H-Coal Feedstock. The following table compares the coal properties in the two cases studied:

Type	Illinois No. 6 Eastern Bituminous Wt %	Wyodak Western Subbituminous Wt %
Moisture	12.0	30.0
Sulfur	3.47	1.14
Oxygen	8.88	19.22
Ash	11.51	7.08

The first significant difference is the higher moisture content of the Wyodak coal, which results in additional investment for coal handling and drying facilities. Operating requirements are also increased. Wyodak coal, being subbituminous in character, introduces difficult drying problems, especially in the low range (2-3 percent moisture). Commercial feasibility must be demonstrated.

The second major difference is the high oxygen content in the Wyodak coal feed. As occurs with high moisture, oxygen, when converted to water in the reactor, reduces hydrogen partial pressure, increases hydrogen makeup, and requires additional equipment trains to process the coal.

The lower sulfur and ash in the Wyodak coal offer little to offset the increased process requirements for higher moisture and oxygen.

Texaco Gasification Status. Since 1953 the Texaco Synthesis Gas Generation Process (TSGGP) has been licensed throughout the world as an energy efficient technology for converting gaseous and liquid hydrocarbons, including high-sulfur residual petroleum fuels and tars, into synthesis gas. More than 80 operating plants have been licensed in 23 countries. Nearly all of the recent TSGGP plants have employed liquid feedstocks and most of those are based on heavy oil. Commercial experience is lacking, however, on the gasification of high ash liquid feeds as encountered in coal liquefaction.

Closely related to TSGGP is the Texaco Coal Gasification Process (TCGP), which gasifies solid feedstocks. Projects now demonstrating the TCGP process, or presently under construction, include:

- Ruhrkohle - Ruhrchemie at Oberhausen - Holten, Germany
- Tennessee Valley Authority (TVA) at Muscle Shoals, Alabama
- Tennessee Eastman Company at Kingsport, Tennessee
- Cool Water Coal Gasification Project near Barstow, California

Texaco Heat Recovery Design. One of the features in the design of the oil-fed TSGGP is the production of high pressure steam from the hot (2000° to 2500°F) generator gas. This heat recovery process includes a radiant boiler and a convection boiler, which contribute to the overall thermal efficiency of the plant.

In the Texaco Coal Gasification Process (TCGP), the development of similar heat exchange designs poses problems owing to the presence of coal, slag, ash, and soot in the gas. While current reports indicate that the design problems are being resolved in the plants cited above, large scale commercial operation is not yet proven, and the coal-to-methanol plant developed in this study did not incorporate the complete design for a high pressure steam recovery system. Instead, only the radiant boiler was used to produce high pressure steam and the partially cooled gas was water quenched to saturation. This is a more conservative design approach at the expense of lower efficiency. An improvement in the overall thermal efficiency of 5-6 percent can be expected when the convection boiler has been tested further so that it can be used with confidence.

Methanol Synthesis Status. The first Lurgi low pressure methanol synthesis plant began operation in 1971. Lurgi had built several high pressure methanol plants prior to the introduction of their low pressure process. Presently, twenty-one low pressure methanol synthesis plants using the Lurgi process are onstream or under construction. A special patented tubular reactor is used for the conversion of carbon monoxide, carbon dioxide, and hydrogen to methanol. The major advantage of this reactor is the very gentle treatment of the catalyst, which is kept at reasonably constant temperature by transferring the heat of reaction into boiler feedwater for the production of steam.

Also available for methanol synthesis is the Imperial Chemical Industries (ICI) process. The ICI process uses a quench type reactor with downstream heat recovery. A similar coal-to-methanol study for EPRI, using the ICI methanol process, is reported by Fluor (3).

Plant Configuration Options

This study has been based on consideration of totally integrated self-sufficient projects. The only inputs are coal, raw water, air, labor, and operating supplies. In certain circumstances, it may be desirable to consider options which do not completely utilize the by-products produced and/or utilize other inputs such as natural gas or electric power. This is particularly true in the H-Coal cases. Some of these options are described below.

Vacuum Tower Bottoms as Fuel. The system for gasification of coal liquefaction bottoms represents a major cost item and a certain element of technical risk. A possible use of the vacuum bottoms would be as fuel for the production of plant steam and power as well as for export power. Alternatively, this material could be sold for its fuel value. While the ash content would be substantially higher than the charge coal, the sulfur content would be less. For Case HE (H-Coal, Illinois No. 6) the qualities would be as follows:

	Feed coal	H-Coal Vacuum Tower Bottoms
Ash, wt %	11.51	29.55
Sulfur, wt %	3.47	2.40
HHV (MF) Btu/lb	12,669.5	10,422

The market value of vacuum tower bottoms as a fuel is questionable owing to the potential environmental difficulties associated with its combustion.

Reforming for Hydrogen Production. Hydrogen can be produced by reforming light hydrocarbons rather than by gasification of coal liquefaction bottoms. This route is substantially lower in both capital cost and technical risk. The gaseous products produced in the liquefaction process, however, are insufficient to provide both the feedstock for hydrogen production and the fuel for plant operation. Consequently, in this case it would be necessary to import reformer feedstock - most conveniently, natural gas.

Possible Future Studies

This present work was initiated at a time when the general perception was one of a continued shortfall in crude oil supplies coupled with an increasing demand for liquid fuels leading to ever escalating liquid fuel prices.

A combination of factors, including the current worldwide recession, the impact of increased prices on consumption as well as on exploration and production efforts, and the success of fuel-switching strategies, have now created a temporary "surplus" in crude oil supplies. Accordingly, the general perception has been reversed to create a climate in which expectations are for continued ample crude oil and natural gas, coupled with the probability of liquid fuel prices remaining constant or even decreasing in real terms.

Notwithstanding the current situation, however, recent history has shown that surplus can rapidly change to shortfall in the wake of international events. It is still important to note that crude oil is being consumed at a greater rate than net additions to proven reserves.

Against this background of price and supply uncertainty, it is important to assess the near and long term role of liquid fuels in the nation's requirements for electric power generation. If there is a long term role for liquid fuels in power generation, then it is also important to address the development of strategies to accomplish commercialization of appropriate technologies to ensure supplies of liquids for the longer term.

The data base developed in the course of the present study represents a consistent basis for development and analysis of these questions. Outlined below are suggested approaches to addressing these issues.

Estimation of Utility Liquid Fuel Requirements for Existing Plants

In 1974, the first full year after the Arab embargo, utility liquid fuel consumption, in millions of barrels per year, was:

No. 6 fuel oil	483
Turbine fuel	53
Total	536

This level had been reached as a result of the availability of low cost supplies of petroleum products from overseas sources coupled with increasingly stringent environmental restrictions which encouraged coal-to-oil conversions.

By 1981, the picture had changed considerably and the corresponding figures, in millions of barrels per year, were:

No. 6 fuel oil	340
Turbine fuel	11
Total	351

Principal factors leading to the reduction have been:

- Decreased use and/or retirement of existing, older oil-fired plants as newer nuclear and coal-fired facilities entered service

- Reconversion of coal designed plants from oil back to coal

- Use of gas instead of oil in the wake of the gas "bubble" of recent years

In order to measure the extent of the market for utility fuels for existing stations, it is suggested that the following analysis be made:

1. Using the survey of existing oil-fired electrical utilities developed in EPRI report AP-2342 (4), assess these facilities with respect to:

   -- Capacity

   -- Years of remaining life

   -- Probable load factor

   -- Potential for coal conversion

2. Analyze the impact of developing coal conversion technologies on the requirements for liquids in these facilities. Such technologies include:

   -- Use of coal slurries to transport coal from central storage to the consuming station

   -- Coal slurry combustion

   -- Slagging combustors

3. Develop a parametric analysis of the potential and probable role of liquid fuels in this market based on the data developed above using the cost data produced in this study.

<u>Assessment of the Potential Role of Liquid Fuels in New Power Generating Plants</u>

During the course of Phase 1 of the North East Coal Utilization Program (NECUP), an approximate analysis was made of this application. The basis for this study was comparison of two alternatives:

- A new coal-fired power plant complete with coal handling facilities, stack gas scrubbing, and ash and sludge disposal

- A new liquid fueled combined cycle gas turbine supplied by coal-derived liquids

The result of the analysis was that the costs of producing power by these two routes intersected at a load factor of approximately 40 percent. Below this point the liquid-fueled gas turbine example was the more attractive option, with the coal-fired option being more attractive at higher load factors. The conclusion is the desirability of maintaining high operating factors on capital intensive facilities.

The specific crossover point is necessarily approximate since the curves representing cost vs. load factor have similar slopes and the costs for the two options were not developed in detail in the earlier work.

This analysis could be repeated using the data base developed here for liquid fuel cost together with a coal fired power plant cost developed on a consistent basis.

Such a consistent analysis, performed in sufficient detail to quantify both the probable crossover points and the sensitivity of the conclusion to site specific factors, could be an important element in developing capacity addition/replacement strategies involving gas turbine applications. A result could be near-term utilization of gas turbines and/or combined cycles based on gas or petroleum liquids with two future options for coal-derived fuel:

1. Coal gasification for base load use, or

2. Coal liquids for intermittent or peaking services.

System specific revenue requirements analyses based on generation expansions are required to identify the potential benefits to be derived from a long-term supply of liquid fuels for utility consumption.

Strategies for Achieving Commercialization of Coal Liquefaction

Since studies, such as the one above, suggest a long term requirement for liquid fuel supply for utilities, it is appropriate that consideration be given to development and support of strategies which would ensure the availability of the necessary technology base for development of significant coal liquids production when required.

Several initiatives have proceeded to advanced states of project development, but none has yet achieved commercial success.

Development of First Generation Options

Since stand-alone projects for synthetic liquid fuels have not been found to be economically viable, a study of first generation options may be in order. The object of this study would be to develop and evaluate options which could decrease cost and risks, thereby increasing the probability of near term installation of commercial scale facilities. Possibilities include:

Refinery Location. This option was considered in a preliminary fashion in NECUP Phase II (EPRI Report No. AP-1671). Advantages of this option include:

- Manufacture of hydrogen from refinery gas or from petroleum coke or asphalt
- Availability of the necessary skills and support infrastructure
- Integration of refinery and synfuels plant separation and handling facilities

National Support

The results of this and other recent studies of coal liquefaction have indicated strongly that the economic feasibility of producing liquid fuels from coal in a period of declining crude oil prices is poor. History has shown, however, that, after an extended period of relative price stability, it is likely that crude oil prices will once again experience significant real price growth over general inflation. When this does occur, it will be critical from a national security standpoint to have demonstrated a capability to produce large quantities of liquid fuels from coal.

For these presently uneconomic processes, support by the Federal government (possibly through the Synthetic Fuels Corporation) could be an effective mechanism for getting the first generation plants built and operating. Incentives which would effectively stimulate the development of first generation coal liquefaction plants could include:

- Price guarantees and/or supports.
- Loan guarantees.
- Tax incentives such as expensing of construction costs during the construction period.
- Tax forgiveness during the early operating years.
- Government issue of low-interest, tax-free "synthetic fuels bonds," specifically for construction of synthetic fuels facilities.

Without such financial incentives it does not seem likely that industry can, in the near future, provide the U.S. with the demonstrated capability to produce liquid fuels and ultimately to minimize or eliminate our dependence on foreign fuel supplies.

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