TECHNOLOGY ASSESSMENT GUIDE
No. 9a
H-COAL DIRECT LIQUEFACTION

CHAPTER ONE: EXECUTIVE SUMMARY

1.1 OVERALL PROSPECTS FOR THE TECHNOLOGY

The H-Oil process was originally developed by Hydrocarbon Research Inc. (HRI) as a means of converting heavy oil residues to lighten fractions. The H-Coal process is an extension of this earlier technology in which coal is converted primarily to either a boiler fuel or a refinery syncrude by means of direct catalytic hydroliquefaction. Final products of the process include light hydrocarbon gases and an array of distillate materials ranging from light and heavy distillate fuels to heavy residuum. The process can be modified to favor production of light or heavy compounds.

The process has been thoroughly and successfully tested in laboratory equipment. While this continues for process improvement studies, a 600 TPD pilot plant is in operation. The high yields and one step liquefaction featured by the process together with its feedstock flexibility and adjustable product slate make this process quite attractive, particularly in cases where feedstock availability (or price) or product demand may shift among the various alternatives. Continued support for the H-Coal program from the Department of Energy is in question at this time but this should not be taken as a reflection on the overall merit of the process.

1.2 ENGINEERING ASPECTS

A schematic of the H-Coal process, in its most elementary form, does not differ significantly from what many would consider to be the simplest "generic" direct coal liquefaction process. In execution however, the process has several distinct features:[1-1]

- Reaction occurs in a catalytic ebbulated bed which promotes coal liquefaction, solvent hydrogenation and product upgrading simultaneously in one vessel.
- Hydroclones are used to recover a low solids residuum oil stream which is used to slurry the incoming coal feed.
- Liquefaction reactor effluent is separated by distillation.
- Liquefaction bottoms can be gasified by partial oxidation for hydrogen generation.
- The process produces high yields of distilled, low sulfur liquids from bituminous and subbituminous coals and lignites (40 to 50 wt % C_4-975°F liquid yield on dry coal). These high yields are obtained in the presence of a synthetic catalysts, and are not dependent on the catalytic nature of coal ash.
- Catalyst replacement occurs continuously at the rate of 1-2 percent per day, which allows control over deactivation, provides constant product quality, allows for continuous regeneration and provides for high unit service factors.

- Operating conditions can be varied to meet flexibile product slate requirements.

- The ebbulated bed assures good temperature control throughout the reactor, using the energy of the reaction to heat the feed slurry to the reaction temperature. The continuous liquid phase in this well-mixed system provides an excellent heat sink to assure reactor stability and a high degree of operability.

1.3 CURRENT COSTS

The total capital requirement for this 125 trillion Btu per year plant is $2.4 billion, which is dominated by a plant investment of $1.6 billion and interest during construction of $569 million. Working capital ($99 million) and start-up costs ($17 million) comprise most of the remainder.

Annual operating and maintenance costs (at a 90 percent plant capacity factor) total $160 million, which is dominated by labor, taxes and insurance and maintenance supplies. By-product credits given for sulfur, ammonia, and phenols offset these operating costs to a net of $139 million annually.

Taken together with a 20 percent capital charge, these expenses result in a product cost of $\$5.51/10^6$ Btu, which is exclusive of coal costs. With coal assumed to be $\$1.50/10^6$ Btu, the total product cost rises to $\$7.70/10^6$ Btu, which corresponds to an oil price of approximately $45 per barrel. It should be remembered that this represents an average product cost on a Btu basis. Individual product costs will vary somewhat from this figure.

1.4 RESEARCH AND DEVELOPMENT DIRECTIONS

The current H-Coal experimental program emphasizes work in three areas. Bench scale units are being used for process improvement studies, while PDU tests have concentrated on confirmation of the design basis, operating conditions and modes of operation for the large pilot plant and full sized commercial facilities.

Process feasibility performance, and product yields are currently being proven in the 600 TPD pilot plant, which will provide the necessary data for direct scale up to commercial sized facilities. Continuing R&D on the process is expected to produce better catalysts, modes of operation and demonstrate the full versatility of the ebbulated bed reactor in handling various coals.

The current H-Coal development program includes the laboratory, PDU and pilot plant activities described, plus engineering process development and economic studies, product testing, upgrading and end-use studies. It is scheduled for completion at the end of 1982.

References

1-1. Eccles, R.M. and G.R. Vaux. "Current Status of H-Coal Commercialization," Chemical Engineering Progress, May 1981.

CHAPTER TWO: ENGINEERING SPECIFICATIONS

2.1 GENERAL DESCRIPTION OF THE TECHNOLOGY

The H-Coal process for coal liquefaction, developed by Hydrocarbon Research, Inc. (HRI), is a process by which coal can be converted to clean liquid fuels. The process incorporates an innovative approach to direct liquefaction in which coal dissolution, hydroconversion and hydrodesulfurization reactions are simultaneously achieved in a single stage ebullated bed reactor in the presence of a heterogenous catalyst.

The primary products of the H-Coal process include naptha, turbine oil and distillate fuel oil. This study assumes the utilization of Illinois No. 6 bituminous coal as feed coal from which a substantial amount of LPG is also produced as a net product.

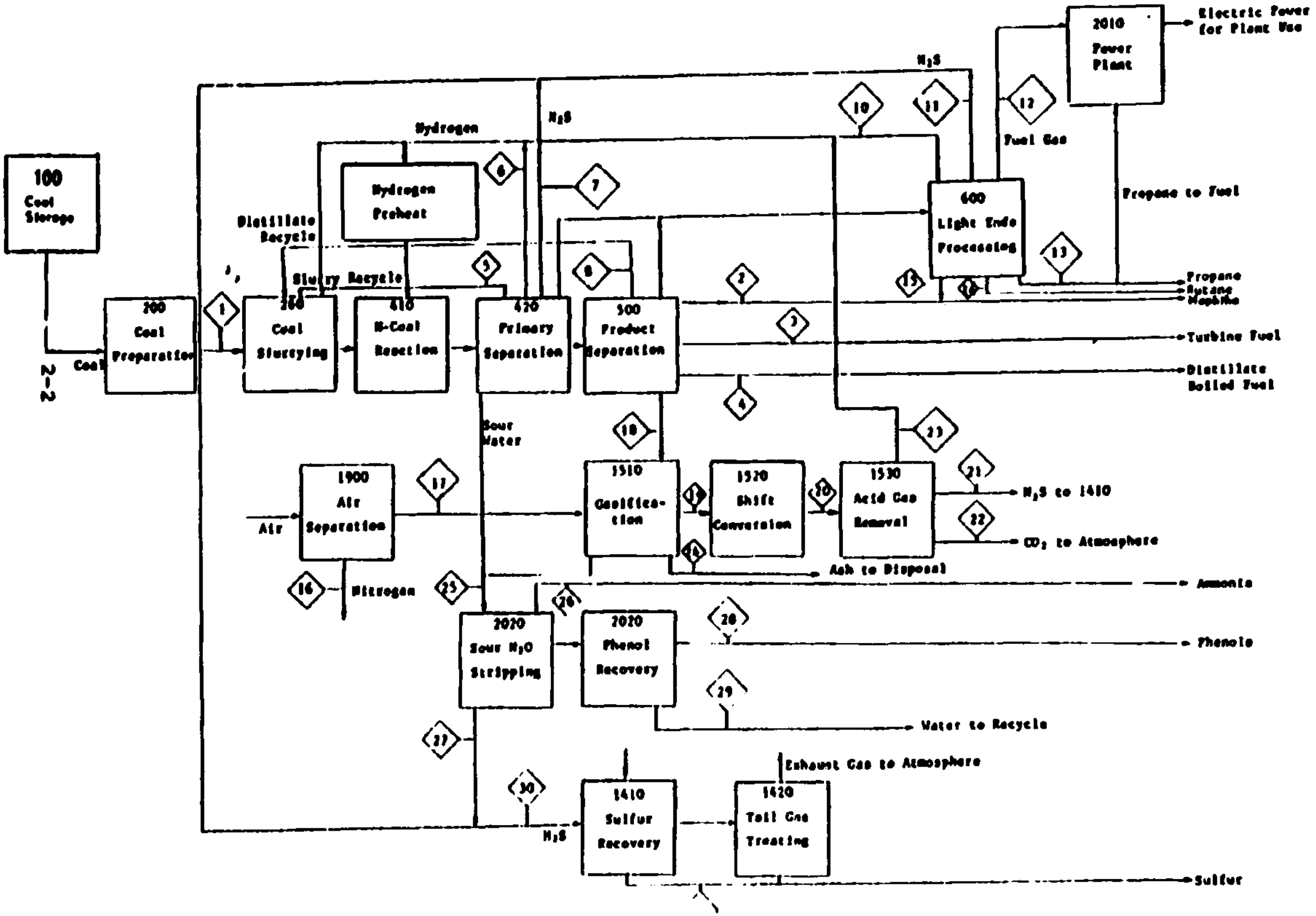
2.2 PROCESS FLOW, ENERGY AND MATERIAL BALANCES

A conceptual process flow diagram for the H-Coal process is illustrated in Figure 2-1. Numbers corresponding to major plant areas are shown in the figure and listed in Table 2-1.

Raw coal is first crushed and dried in plant area 200 before being slurried with a process generated recycle oil. A portion of the total hydrogen needed for reaction is added to the slurry after pressurization to 200 atmospheres. The remaining hydrogen is preheated and injected directly into the bottom of the ebullated bed reactor along with the pressurized slurry. Hydrogen addition is split in this way to facilitate temperature control in the reactor; temperature measurement in the reactor is used as the basis for controlling the degree of hydrogen preheat. Only a portion of the hydrogen is subjected to this temperature control because introduction of the

FIGURE 2.

H-COAL CONCEPTUALIZED PROCESS FLOW DIAGRAM



remaining hydrogen prior to the reactor effectively increases the residence time for chemical reaction. Bettor process control is also achieved by using this split stream technique, since the smaller flow rate of hydrogen can respond more rapidly to changes in temperature requirements. Depending upon the product slate desired, the rate of hydrogen consimption may vary. boiler fuel will be produced at realyively high reactor throughputs and low hydrogen consumption rates. Synthetic crude oil requires more hydrogen, resulting in a lower bottoms product yield.

The reactor feed slurry is continuously charged to the ebulated bed reactor which operates at approximately 850°F and 3000 psi (maximum). The upward flow of the reaction mixture maintains the cobalt-molybdenum catalyst pellets in a fluidized state. Catalyst activity is maintained by the semi-continuous addition of fresh catalyst and the withdrawal of spent catalyst.

The reactor effluent, which contains some unconverted coal but negligible amounts of catalyst, is flashed in areas 420 (primary separation). The flash bottoms are further processed by hydroclone here and in area 500 (product separation). A liquid-solid separator and a vacuum distillation column is used. The hydroclone overhead stream (stream 5) consists of the recucle solvent which is pumped back to the slurry preparation unit. A solids-laden residue consisting of unreacted coal and very heavy liquids is recovered from the solid liquid separation step, and is used in area 1500 (gasification, shift and acid gas removal) for hydrogen manufacture. Light overhead streams from both area 420 and 500 are collected for recovery of valuable C_1 through C_2 and naphtha range light ends in area 600. Recycle hydrogen is also collected here, and H_2S is recovered for further processing in a Selexol unit.

Final products of the process consist of the light hydrocarbon gas separated from the reactor flash overhead stream, and an array of distillate materials ranging from light and heavy distillate fuels to heavy residuum.

Table 2-1

Relevant H-Coal Process Area Numbers

100	COAL STORAGE AND HANDLING
200	COAL PREPARATION
	210 Crushing and Grinding 240 Drying 260 Coal Slurrying
400	HYDROGENATION
	410 Reaction 420 Primary Separation
500	PRODUCTION SEPARATION AND PROCESSING
	510 Fractionation
600	LIGHT ENDS PROCESSING
	610 Amine Plant 620 Gas Plant ("LPG") 630 Cryogenic Fractionation
1400	SULFUR RECOVERY AND TAIL GAS TREATING
	1410 Sulfur Recovery 1420 Tail Gas Treating
1500	HYDROGEN PLANT
	1510 Gasification 1520 Shift Conversion 1530 Acid Gas Removal
1900	AIR SEPARATION
2000	UTILITIES AND SUPPORT SYSTEMS
	2010 Steam Generation and Power Recovery 2020 Wastewater Treating and Water Supply
2100	OFFSITES AND MISCELLANEOUS

Stream flow rates and compositions for the H-Coal process are presented in Table 2.2. Overall energy and material balances are presented in Table 2.3.

2.3 PLANT SITING AND SIZING ISSUES AND CONSTRAINTS

The complete H-Coal commercial facility includes the liquefaction plant and the necessary support systems, utilities and off-site facilities needed for self-sufficient operation.

Support facilities include units for coal preparation, gas separation and recovery, sour water stripping, sulfur recovery, and product storage and shipping. The plant is self-sufficient, providing its own utilities for supply water, steam, electric power and waste water treatment.

Local resources must be capable of providing 7.2 million tons of coal per year and 10.7 million gallons of raw water per day.

2.4 RAW MATERIALS AND SUPPORT SYSTEM REQUIREMENTS

2.4.1 Coal Quantities and Quality

This analysis assumes an energy yield of 125 x 10^{12} Btu per year, as determined by the Higher Heating Values of the products. The process would require 7.2 million tons per year of Illinois No. 6 bituminous coal in order to achieve the desired energy yield. An ultimate analysis of this feed coal is presented in Table 2.4.

STREAM NO.	1	2	3	4	5	6	7		9
Description Temperature (°F) Pressure (psig) Flow (lbs/hr)	COAL FEED	NAPTHA TO STORAGE	TURBINE OIL TO STORAGE	DISTILLATE BOILER FUEL TO STORAGE	SLURRY RECYCLE	H_2 RECYCLE	PRIMARY H_2S PURGE	DISTILLATE RECYCLE	SWEET AND SOUR GAS
H_2						197,278			7,331
N_2 & Inerts						11,770			7,354
CO						15,946			9,973
H_2S							8,205		4,915
NH_3									
H_2O			595	290			1,199	150	314
CO_2							14,132		6,097
Light Ends		1,706					507		178,420
IBP-100°F		7,307							21,046
100-200°F		33,385	4						19,821
200-300°F		68,317	682	7	38			5	3,862
300-400°F		50,272	58,948	197	3,384			44	733
400-800°F			245,494	156,594	2,140,784			59,983	
800-975°F				24,354	46,930			22,235	
Residium									
Coal	1,646,000								
Ash									
TOTAL	1,646,000	160,988	305,723	181,441	2,199,137	224,994	24,043	82,417	238,720

TABLE 2.2

H-Coal Detailed Process Streams

STREAM NO.	10	11	12	13	14	15	16	17	18
Description	RECOVERED OXYGEN	ACID GAS	FUEL GAS	PROPANE TO STORAGE	BUTANE TO STORAGE	NAPTHA TO STORAGE	WASTE NITROGEN	OXYGEN	VACUUM TOWER BOTTOMS
Temperature (°F)	55	120	45	110	110	110			
Pressure (psig)	295	10	1						
Flow (lbs/hr)									
H_2	7,104		227						
N_2 & Inerts	424		6,930				1,358,599	10,221	
CO	574		9,399						
H_2S		4,815							
NH_3									
H_2O		314							
CO_2		6,097							
O_2							47,165	401,195	
Light Ends		237	89,245	49,010	38,844	1,084			
IBP-100°F					1,992	19,054			
100-200°F					223	19,598			
200-300°F						3,862			
300-400°F						733			
400-800°F									7,355
800-975°F									36,493
Residium									312,744
Coal									95,140
Ash									189,458
TOTAL	8,102	11,463	105,801	49,010	39,059	44,331	1,405,764	411,416	641,190

TABLE 2.2 (Cont'd)

STREAM NO. Description Temperature (°F) Pressure (psig) Flow (lbs/hr)	19 EFFLUENT TO SHIFT CONV. 426 770	20 COOLED, SHIFTED GAS 110 695	21 ACID GAS TO SULFUR RECOV. 120 8	22 WASTE CO_2 0	23 RECYCLED H_2 84 665	24 ASH TO DISPOSAL	25 SOUR WATER FEED	26 AMMONIA	27 ACID GAS TO SULFUR RECOVERY
H_2	37,160	85,819		129	85,690				
N_2 & Inerts	15,671	15,671		119	15,552				
CO	703,361	27,265		206	27,058				
H_2S	17,190	16,096	16,042	14			30,700		30,700
NH_3	1,169						18,754	18,754	
H_2O	1,415,904	3,936	1,352	1,907	677	95,442	1,227,241		36,046
CO_2	204,321	1,264,776	67,531	1,193,378	4,867		2,178		2,178
Light Ends	3,925	3,925		144	3,781				
IBP-100°F									
100-200°F									
200-300°F									
300-400°F									
400-800°F									
800-975°F									
Residium									
Coal									
Ash						189,458			
Soot						7,696			
TOTAL	2,398,703	1,418,488	84,925	1,195,897	137,626	292,596	1,278,873	18,754	68,924

TABLE 2.2 (Cont'd)

STREAM NO. Description Temperature (°F) Pressure (psig) Flow (lbs/hr)	28 RECOVERED PHENOLS	29 RECYCLE WATER	30 ACID GAS FEED	31 SULFUR TO STORAGE					
H_2									
N_2 & Inerts									
CO									
H_2S			59,762						
NH_3									
H_2O	1,113	1,190,082	38,911						
CO_2			89,938						
Light Ends			744						
Phenol	4,557								
IBP-100°F			59						
100-200°F									
200-300°F									
300-400°F									
400-800°F									
800-975°F									
Residium									
Coal									
Ash									
Sulfur				41,093					
TOTAL	5,670	1,190,082	189,413	41,093					

TABLE 2.2 (Cont'd)

Table 2.3

Mass and Energy Balance*
Illinois #6

Heat Input	Flow Rate lb/hr	Heat of Combustion Btu/lb (HHV)	Total Heat 10^6 Btu/hr (HHV)
Coal (MF)F	1,646,000	12,669.5	20,854.3
Heat Output			
Naphtha	205,345	19,798	4,065.4
Turbine Fuel	305,128	18,457	5,631.8
Boiler Fuel	181,151	17,767	3,218.5
Butane	39,060	21,278	831.1
Propane	24,131	21,661	522.7
Ammonia	18,798	9,668	181.7
Sulfur	56,179	3,983	223.8
Phenols	4,557	13,997	63.8
TOTAL			14,738.8

Overall Process Efficiency: $\frac{14{,}738.8}{20{,}854.3} \times 100 = 70.7\%$

* At 100% plant capacity

TABLE 2.4

Illinois No. 6 Coal Analysis

Ultimate Analysis	Wt %
Carbon	69.76
Hydrogen	4.91
Nitrogen	1.47
Sulfur	3.47
Oxygen	8.88
Ash	11.51
	100.00

2.4.2 Catalysts and Other Required Materials

The H-Coal process of liquefaction requires approximately one pound of catalyst for every ton of coal feed (approximately 6.5 tons of catalyst per day). Other process chemicals are needed for light ends processing, emissions and effluent control, and utilities operation. A summary of the catalysts and chemicals utilized in this process are listed in Table 2.5.

2.4.3 Water Requirements

Raw water requirements amount to 10.7 million gallons per day.

2.4.4 Product Handling and Transport Requirements

Storage capability must be sufficient to contain products safely between shipments. Floating-roof tanks would be provided for naptha storage. Turbine fuel, distillate boiler fuel and phenol storage requires fixed roof tanks. Ammonia would be stored in refrigerated spheres, while liquid sulfur would be flaked and stored in hoppers. Propane and butane would be stored at atmospheric pressure in refrigerated tanks.

2.5 EFFECT OF COAL TYPE

The H-Coal process is capable of accepting a wide range of coal types over a variety of operating conditions. High yields of distilled, low-sulfur liquids have been demonstrated with bituminous and subbituminous coals and lignites. Some of the coals run in the H-Coal process include:

- Eastern U. S.

  Illinois No. 6
  Indiana No. 5
  Kentucky 9/14

- Eastern U. S. (continued)
  - Kentucky 11
  - Pittsburgh Seam (Consol No. 8)

- Western U. S.

  - Wyodak
  - Utah D.
  - Big Horn
  - Colorado
  - Black Mesa

- Lignites (U. S.)

  - Texas
  - North Dakota

- Foreign

  - Australian Brown
  - German "Steinkohle"
  - Others

Table 2.6 summarizes some typical H-Coal yields based on pounds per 100 pounds of dry coal. The two columns compare yields for two different modes of operation, the syncrude and the fuel oil modes. High yields of distillate liquids are achieved in the syncrude mode. In the fuel oil mode, a heavy product slate is produced due to less severe operating conditions.

TABLE 2.5

Summary of Catalysts and Chemicals

Unit	Catalyst or Chemical	Initial Supply	Annual Makeup
200	American Cyanamid HDS-1442A Catalyst	782,728 lb	6,520,000 lb
	Startup Oil	14,000 bbl	
300	DGA (diglycolamine) $.69/lb	100,000 lb	20,000 lb
400	Sour Shift Catalyst	1,200,000 lb	230,000 lb
	Selexol Solvent	2,200,000 lb	185,000 lb
600	Activated Alumina	360,000 lb	70,000 lb
900	Lime	56 ton	2,600 ton
	Soda Ash	48 ton	2,300 ton
	Sulfuric Acid (93 percent)	92 ton	2,000 ton
	Caustic Soda (100 percent)	12 ton	140 ton

TABLE 2.6

Typical Yields for the H-Coal Liquefaction Process

Yields lb/100 lb Dry Coal	Illinois Bituminous Syncrude	 Product Oil
H_2	(5.3)	(3.4)
H_2O, CO, CO_2	7.1	6.5
H_2S, NH_3	3.6	2.2
$C_1 - C_3$	11.2	6.8
C_4 - 400° F Naptha	18.7	13.4
400 - 975° F Fuel Oil	29.1	20.8
975°F + Bottoms (including Ash)	35.6	53.7
	100.0	100.0

2.6 AIR POLLUTION CONTROL TECHNOLOGY

2.6.1 Ability of Existing Technology to Meet Regulations

Although there are no governing standards for synthetic fuels at this time, it is reasonable to assume that the H-Coal plant discussed herein would be required to meet applicable regulations established for utility and petrochemical plants.

Sulfur is recovered in a series of steps throughout the H-Coal process. Final cooling of gases from the reactor produces condensation of a large volume of sour water which is sent to the wastewater treating. The remaining cooled gas goes to acid gas removal. Sulfur compounds, particularly H_2S, are removed here and sent to the sulfur plant for recovery.

The H-Coal process utilizes a two-stage Claus plant for converting H_2S to elemental sulfur. This process involves the combustion of one-third of the H_2S to SO_2 followed by catalytic reduction of the combined gases to elemental sulfur. The sulfur is produced in a liquid form and is converted to flakes for transport.

The sulfur content of the Claus plant tail gas stream is reduced to an environmentally acceptable level in the sulfur plant tail gas treating unit, utilizing the Beavon process. Overall conversion of the combined Claus and tail gas units exceeds 99.9%.

NO_x emissions must be defined and controlled according to the specific application of the process. NO_x production can be decreased by designing for a lower flame temperature and by using low excess air. Available references suggest that a satisfactory process by which NO_x may be removed will be available soon for the process.

Fugitive particulate emissions from furnaces can be controlled with cyclones, electrostatic precipitators or scrubbers. Particulates in raw gas, such as ash and soot, are removed by a water scrubbing tower. The residual ash and soot may be separated from the sour water slurry by means of a settling pond or slurry.

Carbon dioxide is removed from the hydrogen stream using hot carbonate scrubbing. The CO_2 vent stream comprises approximately half as much as the total weight of coal fed to the plant.

Other gaseous effluents released during the H-Coal process include nitrogen, and purge and vent gases. These emissions may also be reduced to an acceptable level using appropriate emission control technologies.

2.6.2 Impacts on Process Efficiency

No accurate data are available as to the combined impact on process efficiency of all air pollution control systems for the H-Coal process. However, it is fair to say that only the Selexol portion of the air pollution control system would have any notable effect on plant efficiency. Cyclones, filters and electrostatic precipitators require very little energy. Depending on coal type, the maximum impact on process efficiency of the Selexol system would probably be on the order of 1%.

2.7 WATER POLLUTION CONTROL TECHNOLOGY

2.7.1 Ability of Existing Technology to Meet Regulations

Although no aqueous effluent standards relating specifically to coal conversion plants have been set, such pollutants emitted by the H-Coal plant should be within those established for similar facilities.

2.7.2 Water Recycling Systems

The primary liquid stream from gas separation and cleanup is the sour water system. After removal of oil, moisture is condensed by cooling the gas further, producing a sour water stream, which contains a wide range of contaminant including compounds of sulfur, nitrogen or oxygen, as well as some oil, possible solids, and certain trace elements. The sour water is sent to waste water treating where contaminants are removed so that it can be reused as makeup to the cooling water circuit. Clean up of the sour water will be accomplished by solvent extraction of phenols and stripping for removal of ammonia and H_2S.

Raw water is pumped from a storage reservoir through granular media filters for removal of any sediments as pretreatment for the boiler feedwater makeup. Back wash is directed to the cooling tower systems.

A boiler feedwater treating scheme has been provided which will minimize the effluent and produce high-purity water required for the steam generator. Solids are removed in this process by reverse osmosis and ion exchange. The amount of soluble salts in the demineralizer regeneration waste stream is also reduced. The reverse osmosis concentrate is sent to the cooling tower systems. Wastes from the demineralizer are sent to aqueous disposal while brackish and rinse streams are recycled to the primary reverse osmosis unit.

Cooling water for process heat rejection, condensation of steam from turbines and cooling of mechanical equipment is provided by the cooling tower and cooling water system. Two systems are provided: one serving only the utility and off-site areas which is oil free, and the other providing cooling water for the process users throughout the plant. The latter, which may be oil contaminated, receives blowdown from the utility cooling tower system as makeup.

Other water recycle systems include the utility and potable water systems, the fire water system, the steam and power generation system and the steam and condensate systems.

2.7.3 Impacts on Plant Efficiency

Treatment of wastewater is necessary to the H-Coal process in order to remove solids and other contaminants. Much of the treated stream is recycled for use as cooling water. The treatment process facilitates efficient use of raw water, because it allows recycling of some wastewater back to the plant. The actual extent of water recycling employed will depend on the circumstances of each individual site selected. The current plant consumption of over 10 million gallons per day of raw water includes some recycling, but does not represent the use of recycling to its greatest extent which might be required in circumstances of low water availability or high cost. The use of water recycling systems requires additional capital investment in addition to its impact on process efficiency, which is roughly 2% under maximum recycling conditions.

2.8 SOLID WASTE HANDLING

2.8.1 Disposal Requirements

Solid waste is generated by the H-Coal process in the form of ash from the utility boiler and coal gasification, spent catalyst from hydroliquefaction, chemicals from sulfur recovery, salts and concentrated brines from treated purged cooling water, and sludges from wastewater treatment units.

Ash from gasification is separated from the sour water so it can be disposed of by burial. Ash residue from the utility boiler may also be disposed of by burial.

Spent catalyst may be returned to the manufacturer for reworking and metals recovery, or it may be buried or stored. Soluble salts and concentrated brine residue from wastewater recovery may be disposed of by ocean disposal, storage or sale. Purged chemical solution from the sulfur recovery unit may be disposed by incineration or be sent to wastewater treating.

Sludge produced by wastewater treatment may be combined with ash residues and disposed of in a landfill.

2.8.2 Leachate Problems

Leaching of trace metals or other contaminants from disposed ash into ground or surface water may be possible. Further study may be required regarding leaching of sulfur, calcium, and magnesium, as well as trace metals, in order to mitigate this potential problem.

2.9 OSHA ISSUES

Coal storage and preparation can expose workers to noise from milling operations and coal dust. Coal dust can cause black lung disease. Another danger is that coal piles can spontaneously combust. Dust can be controlled by wetting the coal pile, which will also reduce fire risk.

The higher boiling fractions produced by the H-Coal process are high in polynuclear aromatic hydrocarbons (PAH), such as benzene and benzopyrene, which promote or cause cancers.[2-2] Worker exposure to these end-products must be minimized. The coal is slurried with a process-derived oil which is high in heavier boiling fractions and therefore in PAH. Therefore, exposure to the slurry must be avoided. Contact with potentially carcinogenic materials is most likely to occur during maintenance and cleaning operations.

2.10 PROCESS PERFORMANCE FACTORS

2.10.1 Product Characteristics and Marketability

The products of the H-Coal process are naphtha, mid-distillate and distillate boiler fuel. The H-Coal liquids are very low in sulfur compared to typical petroleum fractions. The oxygen and nitrogen contents are higher. No residual oil products are produced. Table 2.7 summarizes typical product qualities.

The coal liquids produced in the process may require some upgrading prior to their ultimate use. After hydrotreating to remove sulfur, nitrogen and oxygen contaminants, the naphtha is an excellent quality feedstock for catalytic reforming to produce a high octane gasoline blend stock. It can also be used for chemical production.

The mid-distillate product can be used as a residential heating oil, diesel fuel, jet fuel or turbine fuel depending on the degree of hydrotreating. The distillate boiler fuel can be used directly as boiler fuel or upgraded to meet specific utilization requirements.

Table 2.7[2-2]

Typical H-Coal Liquid Product Qualities

Operating Mode	Illinois Bituminous (Burning Star) Syncrude
Naphtha (IBP/350°FS)	
°API	52.3
C	85.3
H	13.8
O	0.56
N	0.24
S	0.07
Mid-Distillate (350/600°F)	
°API	18.5
C	88.4
H	10.1
O	1.0
N	0.47
S	0.08
Distillate Boiler Fuel (500/800°F)	
°API	4.9
C	89.4
H	8.6
O	1.3
N	0.63
S	0.08

2.11 TECHNOLOGY STATUS AND DEVLLOPMENT POTENTIAL

2.11.1 Current Status

The H-Coal process has been under development at Hydrocarbon Research, Inc. for more than 15 years. Eighteen different coal types have been evaluated in over 54,000 hours of operation. The process has been developed and demonstrated utilizing bench-scale units processing up to 25 pounds of coal per day and in a process development unit (PDU) processing 3.5 tons per day of coal.

The process is currently being demonstrated on a larger scale at the H-Coal pilot plant in Catlettsburg, Kentucky. The plant is designed to feed up to 600 TPD of coal to produce 1,800 bbl/day of liquid product. The projected pilot plant evaluation period is two years. During this time, performance and product yields will be confirmed.

HRI's parent company, Dynaelectron Corp., initially supported development of the H-Coal process. As the process advanced, funding became available through other companies; the current sponsors are the U.S. Department of Energy, the Electric Power Research Institute, Ashland Oil, Inc., Standard Oil of Indiana, Conoco Coal Development, Mobile Oil Corp., the Commonwealth of Kentucky, and Ruhrkohle, AG.

The design of a commercial H-Coal liquefaction plant has been initiated under the sponsorship of the U.S. DOE. The plant will be located in Breckinridge County, Kentucky. The plant will be designed to feed about 23,000 TPD of run-of-mine Illinois No. 6 coal and produce 50,000 bbl/day of hydrocarbon liquid products and approximately 30 MSCF/day of SNG.

2.11.2 Key Technical Uncertainties

Process reliability and efficiency have been demonstrated for the bench-scale and PDU size equipment and is now being demonstrated in commercial size equipment at the Catlettsburg pilot plant. Several uncertainties which could not be determined on laboratory-scale equipment will be demonstrated during pilot plant operation including:

- the mechanical operability and reliability of commercial-scale equipment
- provision of products for commercial testing at rates of 100-300 TPD
- verification of yields in commercial size equipment
- collection of scale-up and engineering data
- determining appropriate materials for construction
- establishment of maintenance requirements for key items of equipment.

2.11.3 Availability for Commercial Production

The U.S. DOE has authorized work currently being performed on the design of the commercial scale H-Coal plant in Breckinridge County, Kentucky. The schedule calls for follow-on phases, including construction, leading to start up of the commercial plant about mid-1986. Hydrocarbon Research, Inc. is also involved in feasibility studies for other commercial scale facilities, including a major program for a foreign client.

2.11.4 Unit Design and Construction Time

Estimated time required for design, procurement, construction, and start up of a commercial H-Coal facility will be approximately five years.

2.12 REGIONAL FACTORS INFLUENCING ECONOMICS

2.12.1 Resource Constraints

As outlined in Section 2.3 above, the H-Coal plant would require 7.2 million tons of coal per year and 10.7 million gallons of raw water per day. The resources would need to be consistently available for the duration of the plant's operating lifetime.

2.12.2 Environmental Control Constraints

Gaseous, aqueous and solid effluents generated by the plant are described in sections 2.6, 2.7, and 2.8 respectively. The regulations regarding the particular types and quantities of pollutants produced would depend on local metereology, topography, and existing air and water quality.

2.12.3 Siting Constraints

The site selected for the complex must be located near the required coal and water resources. In addition, several hundred acres of relatively flat land area capable of safely supporting the required heavy equipment would be required for the actual plant.

References

2-1. Fluor Engineers and Constructors, Inc. *Engineering Evaluation of Conceptual Coal Conversion Plant Using H-Coal Liquefaction Process.* EPRI AF-1297. Project 411-4. December 1979.

2-2. Eccles, R.M., and DeVaux, G.R. "Current Status of H-Coal Commercialization." *Chemical Engineering Progress* Vol. 77, No. 5 (May 1981) 80-85.

SECTION THREE: ECONOMIC ANALYSIS

This section presents information on the economics of the H-Coal process.

3.1 Introduction and Methodology

3.1.1 Methodology

This report relied on an economic analysis of the H-Coal process prepared by Fluor (3-1). The data presented in (3-1) were scaled to 125 trillion Btu per year, and corrected to 1980 dollars. The data were then used to compute product costs.

3.1.2 Scaling Exponents

The plant capacity of the reference H-Coal plant was 91.43 trillion Btu per year. Costs were scaled using the scaling exponents shown in Table 3-1, which were estimated based on the number of trains in each area. Areas with two or fewer trains were scaled with an exponent, of 0.7, while an area using more than two trains was scaled with a 1.0 exponent. The areas using more than two trains would be expanded by adding more parallel trains, and so no economies of scale would be realized.

3.1.3 Price Indices

Costs were updated from 1979 to 1980 dollars using the indices given in the Background section.

3.1.4 Economic Criteria

The standard economic criteria discussed in the Background section were used to estimate the total capital requirement and final product costs. The investment schedule used was 8 percent, 25 percent, 35 percent, and 32 percent in years 1 through 4 of construction.

3.1.5 Contingencies

A project contingency of 15 percent was added to the subtotal of the installed cost of all equipment and miscellaneous investments (contractor's fees, taxes, equipment, engineering, general and administrative, and miscellaneous). The contingency is meant to cover increases in costs which arise as the plant design is completed.

A process contingency of 25 percent of the cost of Area 400 and 10 percent of Area 1500 was added to cover technical uncertainties in these areas.

TABLE 3-1

SCALING EXPONENTS[a]

AREA	ITEM	SCALING EXPONENT
200	Coal preparation	0.7
400	Hydrogenation	1.0
600	Light ends processing	0.7
1300	Acid gas removal	0.7
1400	Sulfur recovery and tail gas treating	0.7
1500	Hydrogen plant	0.7
1900	Air separation	0.7
2000	Utilities and support systems	0.7
2100	Offsites and miscellaneous	0.7
--	Operating labor	0.6

Source: ERCO estimates.

3.2 Capital Costs

3.2.1 Itemized Capital Costs

The total plant investment is $1619.8 million, as is shown in Table 3-2. Hydrogenation, Area 400, where the coal is liquefied, is the most expensive area at $431.7 million. The hydrogen plant, Area 1500, is the second most expensive area at $234.0 million.

The total capital requirement amounts to $2,406.6 million, as is also shown on Table 3-2. Interest during construction was estimated at $568.6 million, the second largest expense after the total plant investment. Working capital at $98.8 million and Start-Up at $97.2 million, are also important costs.

3.2.2 Variability of Capital Costs

Capital costs were calculated mostly by scaling in-house cost data to the needs of the project (3-1, p. 6-15). The level of detail of the costing was not available from the report. However, it appears that no major cost estimates were deleted. In addition, conservative contingencies were added by ERCO. As a result, the accuracy of the estimate probably lies within ±30 percent.

TABLE 3-2

TOTAL CAPITAL REQUIREMENT - H-COAL[a]

AREA	ITEM	COST (10^6 $)	PERCENT OF SUBTOTAL
100	Coal storage and handling	(in 200)	--
200	Coal preparation	51.8	4.0
400	Hydrogenation	431.7	33.4
500	Product separation and processing	(in 600)	--
600	Light ends processing	48.5	3.7
1300	Acid gas removal and gas cleaning		
	1320 Ammonia recovery	(in 1340)	--
	1340 Phenol recovery	45.5	3.5
1400	Sulfur recovery and tail gas treating	23.6	1.8
1500	Hydrogen plant	234.0	18.1
1900	Air separation	113.2	8.7
2000	Utilities and support systems	182.4	14.1
2100	Offsites and miscellaneous	163.6	12.6
	Subtotal	1294.3	100.0
	Process contingency	131.3	
	Product contingency	194.2	
Total plant investment		1619.8	
	Interest during construction	568.6	
	Working capital @ 6.1%	98.8	
	Start-up @ 6.0%	17.4	
	Initial charge of catalysts and chemicals	6.9	
	Land	2.4	
	Royalties	8.1	
Total capital requirement		2406.6	

[a] Source: 3-1, updated to third-quarter 1980 dollars and scaled to 125 trillion Btu/year by ERCO.

3.3 Operating and Maintenance Costs

Annual gross operating and maintenance (O&M) costs total $160.1 million, as is shown in Table 3-3. The largest cost item is local taxes and insurance, at $40.5 million. Total plant labor amounts to $43.0 million. Maintenance supplies would cost $31.7 million.

By-product credits of $21.2 million for sulfur, ammonia and phenol production partially offset O&M costs. Sulfur credits total $7.9 million, ammonia credits $10.4 million, and phenol credits $2.9 milion. After gross O&M costs and by-product credits are totaled, net O&M costs are $138.9 million, as is shown in Table 3-3.

3.3.2 Variability of Operating and Maintenance Costs

No major omissions were found in the O&M cost estimates. Most estimates were factored directly from the capital cost estimates using the methods described in the reference report (3-1, pp. 6-6 to 6-9). By-product credits are derived using the material balance.

The variabilty of the O&M cost estimates probably lies within the ±30 percent range of the capital cost estimate.

TABLE 3-3

NET OPERATING AND MAINTENANCE EXPENSES - H-COAL[a]

ITEM	ANNUAL COST (10^6 $)	PERCENT OF TOTAL
Gross Operating and Maintenance Expenses		
Administration and general overhead	19.9	12.4
Local taxes and insurance	40.5	25.3
Labor		
Operation	11.9	7.4
Maintenance	21.1	13.2
Supervision	10.0	6.2
Total	43.0	26.9
Maintenance supplies	31.7	19.8
Catalysts and chemicals	20.1	12.6
Purchased water	1.5	0.9
Ash disposal	3.4	2.1
Total Gross Operating and Maintenance	160.1	100.0
By-Product Credits	(10^6 $)	
Sulfur	(7.9)	
Ammonia	(10.4)	
Phenols	(2.9)	
Total	(21.2)	
Net O & M Costs	(10^6 $)	
Gross O & M costs	160.1	
By-product credit	(21.2)	
Total	138.9	

[a] Source: (3-1), corrected to third quarter 1980 dollars, adjusted and scaled by ERCO. Ninety percent capacity factor assumed.

3.4 Effect of Technology Development on Costs

As the number of H-Coal plants in service increases, capital costs will decline in real dollars due to the effects of experience. Ten percent has been estimated as the upper limit on the experience factor for new energy process technology (see Background).

The 10 percent experience factor is valid only for the plant costs accounted for by new technology. Some sections of the H-Coal plant employ mature technologies whose costs would decline little as more H-Coal plants are built. Novel components include the hydrogenation and hydrogen plant areas and account for about 55 percent of the total plant investment. Therefore, the experience factor for H-Coal technology would be 55 percent times 10 percent, or about 6 percent. Each doubling of H-Coal production capacity would result in a 6 percent reduction in unit capital costs.

3.5 Product Costs

The coal liquids produced by the plant have three cost components: capital charges, net O&M costs, and fuel costs. A non-fuel product cost can be computed from the capital charges and the net O&M costs using the formula described in the Background section. This non-fuel cost indicates the cost of converting coal to synthetic liquid fuel. From Table 3-2, and 3-3, the total capital requirement is $2,406.6 million and the net O&M cost is $138.9 million. With a capacity factor of 90 percent and a plant capacity of 125×10^{12} Btu/yr, the non-fuel product cost is:

$$P = \frac{(\$2{,}406.6 \times 10^6 \times 20\%) + \$138.9 \times 10^6}{125 \times 10^{12} \text{ Btu} \times 90\%}$$

$$= \underset{\text{(capital costs)}}{\$4.28/10^6 \text{ Btu}} + \underset{\text{(O\&M costs)}}{\$1.23/10^6 \text{ Btu}}$$

$$= \underset{\text{(Total non-fuel product cost)}}{\$5.51/10^6 \text{ Btu}}$$

The total non-fuel product cost is \$5.51/10^6 Btu, with capital costs of \$4.28/million Btu, and O&M costs of \$1.23/ 10^6 Btu.

The non-fuel cost can be combined with a cost of coal to yield a total product price using the formula given in the Background. The overall coal to gas efficiency of the process is 68.4 percent, not including sulfur, ammonia and phenols. With a coal cost of \$1.50/10^6 Btu, the product cost can be computed as follows:

$$E = \underset{\text{(capital and O\&M costs)}}{\$5.51/10^6 \text{ Btu}} + \underset{\text{(coal costs)}}{\frac{\$1.50/10^6 \text{ Btu}}{.684 \text{ efficiency}}}$$

$$= \underset{\text{(capital and O\&M costs)}}{\$5.51/10^6 \text{ Btu}} + \underset{\text{(coal costs)}}{\$2.19/10^6 \text{ Btu}}$$

$$= \underset{\text{(total product cost)}}{\$7.70/10^6 \text{ Btu}}$$

The total product cost would be \$7.70/10^6 Btu. This corresponds to an oil price of approximately \$45/barrel.

References

3-1. Fluor Engineers and Constructors, "Engineering Evaluation of Conceptual Coal Conversion Plant Using the H-Coal Process" Electric Power Research Institute AF-1297, December 1979.