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PROCESS DESIGN AND ECONOMIC EVALUATION OF A 100,000-BBL/DAY SYNTHOIL PLANT*

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ABSTRACT

A complete process design was prepared for a conceptual 100,000-bbl/day grass-roots Synthoil facility charging 50,000 tons/day of Western Kentucky coal. The facility consisted of about 15 process units including a 12,000-ton/day oxygen plant, an entrained-bed gasification plant, gas treating facilities, and a 2000-ton/day sulfur plant. The process design basis was established using experimental data obtained at Pittsburgh Energy Research Center on a 1/2-ton/day bench-scale unit. Reactor operating pressure was 4000 psig, and total hydrogen consumption was 556 million std. cu. ft./day. Process flow diagrams, material and energy balances, and equipment sizes were developed for all of the process units. The estimated overall capital investment for the facility was $1900 million based on 1976 dollars, of which $1670 million was depreciable capital. The cost of the coal mine was not included. Using the discounted cash flow procedure, the cost of the product oil was calculated and plotted as a function of the cost of coal and the annual after-tax rate of return on equity. This was done for four capital structures ranging from 100% equity to 95% debt, using an annual interest rate on debt of 9%. As an example of the results, the cost of the product oil was $22.60/bbl with a debt-equity ratio of 70/30, a 12% annual after-tax rate of return on equity, and a coal cost of $20/ton.

1. INTRODUCTION

This paper describes a conceptual process design of a 100,000-barrel/day Synthoil facility and gives the results of an economic evaluation based on this design.

This work was done for ERDA/Fossil Energy, Division of Major Facility Project Management, now the Department of Energy.

The objectives of the evaluation were the following:

(1) To provide an estimate of the cost of producing synthetic liquid fuel from coal by the Synthoil process on a commercial scale.

(2) To assess the state of development of the process, the adequacy of the experimental data for design purposes, the possible areas of difficulty in process or equipment scale-up, and the status of the process as a candidate for commercial demonstration.

(3) To provide recommendations for additional research and development where needed.

The evaluation produced a complete process design for a grass-roots facility. The design included process flow diagrams, mass and energy balances, equipment sizing, and cost estimates.[1]

The facility had a nominal production capacity of 100,000 bbl/stream day at design throughput, and was located in the eastern interior region of the United States. The design feed is a Western Kentucky coal with a sulfur content of 5.5 wt %. The product is a heavy fuel oil with a sulfur content of 0.4% to 0.6%. Net liquid production is 97,216 bbl/stream day.

Total coal consumption is 50,133 tons/stream day, based on an as-received total moisture content of 9.2 wt % and as as-received higher heating value (HHV) of 10,445 Btu/lb. Coal consumption in the various parts of the facility is as follows:

	tons/stream day
Coal to Synthoil reaction section	32,069
Coal to hydrogen production	11,894
Coal to steam and power production	6,170
Total coal consumption	50,133

All utilities are generated onsite, and there is no net export of steam or electricity. All fuel gas produced is consumed onsite for process heat and steam production. The coal-fired power plant uses wet limestone slurry flue-gas desulfurization for emissions control.

2. PROCESS DESIGN BASIS

The process design basis for the Synthoil unit was developed from experimental results obtained at Pittsburgh Energy Research Center (PERC). However, as of July 1976, there were a number of process questions still unresolved. Some of the specific concerns were:

- Sufficient experimental data were not available to provide a basis for selecting design conditions. Among the process variables requiring further investigation are reactor pressure, hydrogen partial pressure, slurry space velocity, and slurry and gas mass velocities. Longer runs are needed to demonstrate process operability, product quality, and catalyst life.
- The catalytic mode of development faces significant problems in reactor scale-up. Catalyst life has not been adequately demonstrated. If a deactivation-resistant catalyst can be developed, it still remains to be demonstrated that a fixed-bed catalytic reactor of large diameter can operate for long periods without plugging, excessive coke laydown, or flow maldistribution.
- Efficient recovery of heat from the reactor effluent is a difficult engineering problem. The inability to recover this heat economically would cause an appreciable reduction in overall thermal efficiency. The design in this study was based on the use of effluent-feed heat exchangers, but the practicability of this operation remains to be proved.

- Some of the other portions of the facility were also based on incomplete information. Uncertainties were present primarily in the gasifier, solids-liquid separation, and residue carbonizer designs.

Bearing in mind the qualifications just mentioned, run no. FB-39 was selected as the basis for the operating conditions and yields. The feed for this run was a Western Kentucky coal, and the operating pressure was 4000 psig.

Table 1 shows the process design basis developed from the PERC data. Table 2 shows the analysis of the Western Kentucky coal, and Table 3 shows the estimated Synthoil reactor yields based on the PERC data.[2]

Tables 1, 2, and 3 are based on an as-received total moisture content of 4.2%. The actual coal received at the coal handling facility was assumed to contain 9.2% moisture. The moisture content is reduced to 4.2% during pulverization. The yields shown in Table 3 apply after this drying step.

The heat of reaction in the Synthoil reactor is estimated at 6000 to 10,000 Btu/lb of hydrogen consumed. This corresponds to the estimated temperature rise of 50°F across the reactor. An end-of-run pressure drop of 100 psi was assumed.

Catalyst life was assumed to be six months. It was assumed that the catalyst is not regenerated.

The required hydrogen purity in the recycle gas, after adding makeup hydrogen, was assumed to be 80 vol % (minimum).

Table 1. Process design basis 100,000 bbl/SD Synthoil plant

Reactor Conditions	
Operating pressure, psig	4,000
Inlet temperature, °F	810
Outlet temperature, °F	860
Slurry composition, wt % coal	35
Slurry space velocity: lb slurry/hr-ft^3 of catalyst volume	261
Gas velocity: scf/hr-ft^2 reactor cross section	197,000
Hydrogen consumption (chemical consumption), scf H_2/ton as-received coal[a]	15,000
Total gas flow to reactor, scf/lb slurry	52
Hydrogen purity required in recycle gas, vol % (minimum)[b]	80

[a] This does not include solubility losses and purge gas losses. It represents the actual disappearance of uncombined hydrogen across the reactor. As-received coal has 4.2 wt % total moisture content.

[b] Measured after adding makeup gas.

Table 2. Analysis of Western Kentucky coal[a]

Proximate analysis, wt %, as received	
Moisture	4.2
Ash	16.5
Volatile matter	36.2
Fixed carbon	43.1
Total	100.0
Ultimate analysis, wt %, as received	
Hydrogen	4.8
Carbon	60.7
Nitrogen	1.2
Oxygen	11.3
Sulfur	5.5
Ash	16.5
Total	100.0
Forms of sulfur, wt %	
Sulfate	0.47
Pyritic	3.08
Organic	1.95
Calorific value, Btu/lb, HHV	11,020

[a] Ohio County, Western Kentucky, seams 9, 11, 12, and 13, as received. This table is based on 4.2% total moisture. The raw coal feed to the facility is assumed to be the same coal as above but with an additional 5% moisture (9.2% total).

Table 3. Estimated Synthoil product yields on Western Kentucky coal[a]

Yields per ton of as-received coal, lb[b]	
Naphtha	36
Centrifuged product oil	976
Centrifuged residue:	
Unconverted material and ash	442
Oil left in residue	176
Methane	70
Ethane	30
Propane	20
H_2S and NH_3	101
Water	229
Total	2080[c]

[a] Yields based on Sayeed Akhtar, James J. Lacey, Murray Weintraub, Alan A. Reznik, and Paul M. Yavorsky, "The Synthoil Process-Material Balance and Thermal Efficiency," AIChE Meeting, Dec. 1-5, 1974, Washington, D.C., plus additional information on make-gas analysis. (ref. 2).

[b] Based on 4.2 wt % total moisture content.

[c] Hydrogen addition is 80 lb per ton of as-received coal.

3. OVERALL PROCESS FLOW

The flow through the facility is shown on the overall block flow diagram, Fig. 1.

The coal preparation unit receives coal from the mine and grinds it to the proper size. Slurry for the Synthoil unit is also prepared in this unit.

In the Synthoil unit, the coal slurry is reacted with hydrogen at 4000 psig over a fixed bed of cobalt molybdate catalyst. Recycle gas (about 78% hydrogen) is separated from the reactor effluent. Solids are separated by both centrifugation and filtration; the centrifugation step provides the clarified recycle oil used for feed-slurry preparation.

Under the design conditions assumed for Western Kentucky coal, the Synthoil process will consume about 14,200 std. cu. ft. of H_2/ton of as-received coal (9.2% moisture). In addition to this chemical consumption, there are solubility and purge losses. Solubility losses occur as a result of the solubility of hydrogen in the liquid stream leaving the high-pressure separator. Purge losses result from the venting of a portion of the recycle gas to the fuel gas system, which is necessary to avoid the buildup of excessive levels of nitrogen and argon. These losses are estimated at about 22% of the chemical consumption. The total hydrogen requirement of the process, therefore, is in the neighborhood of 17,300 std. cu. ft./ton of as-received coal, or 556 million std. cu. ft./day. This is produced by steam oxygen gasification of residual process char and additional fresh coal.

The gasifier, oxygen plant, CO shift units, and gas cleanup units are all part of the hydrogen production and purification train. Raw gas (containing mostly CO, CO_2, and H_2) from the gasifier is treated to remove H_2S and CO_2. Most of the CO content is then converted to additional hydrogen in CO shift units. After final CO_2 removal, the 98.5% purity makeup gas is compressed to 4250 psig.

Hydrogen sulfide recovered in the various gas treating units is converted to elemental sulfur. Ammonia, crude phenols, and H_2S are

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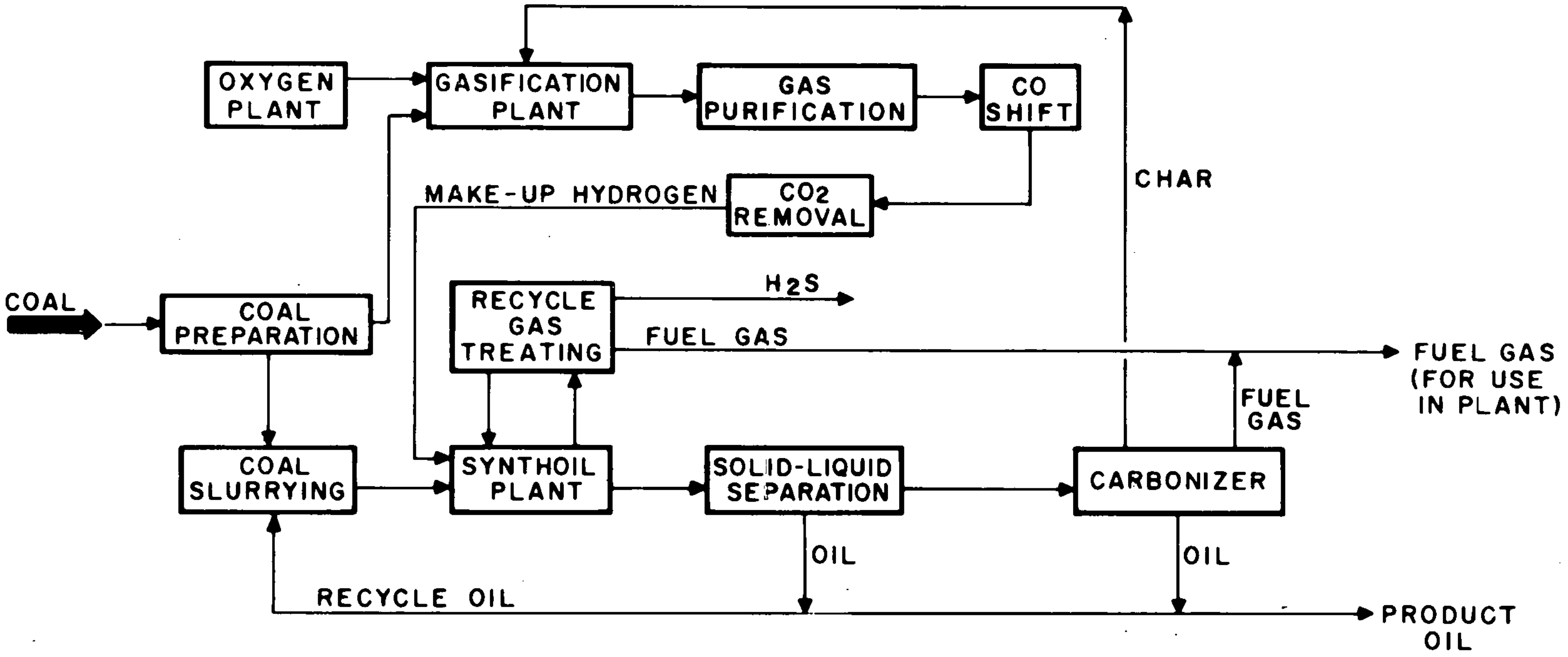

Fig. 1. Synthoil Facility - Overall Block Flow Diagram.

recovered from sour waste water.

Liquid products from the Synthoil unit go to a small distillation unit where wash solvent and absorption oil fractions are prepared for use within the facility.

3.1 Coal Preparation

The coal preparation unit receives mined coal from trucks and prepares it for use in other units of the facility. A 20-day coal reserve (900,000 tons) will be stockpiled to compensate for fluctuations in supply and usage.

From the active pile, 6170 tons/stream day of coal is conveyed to the power plant to supply total facility requirements for 600-psig steam. Coal from the active pile is also conveyed to the bunker from which it is further transported to the gasification unit at a rate of 11,894 tons/stream day. Coal from the bunker also feeds the Synthoil slurry preparation section.

3.2 Synthoil Unit

The feed heating and reaction section of the Synthoil unit consists of four identical parallel trains or modules. These can be operated independently and shut down separately. Each train has its own feed pumps, fired heaters, reactors, heat exchange system, flash separators, and recycle gas system. Each module is shut down every six months for catalyst replacement.

Each of the four modules has eight reactors. The reactors are in parallel and have an inside diameter of 9 ft and a height of 25 ft. Each reactor has three catalyst beds, each 5 ft deep, with provision for injecting quench hydrogen between the beds for temperature control.

The design described here is based on the use of reactor effluent-reactor feed heat exchangers. There is considerable question as to whether these exchangers are practicable in view of the extreme fouling conditions anticipated. However, the thermal efficiency of the process would be severely penalized if it were assumed that this method of heat recovery is not possible.

The number of reactors required is an important factor in determining the arrangement and cost of the unit. With a reactor inlet pressure of about 4100 psig, the maximum reactor diameter is limited by the maximum plate thicknesses that can be used in vessel fabrication. The reactor design used here is the cold-wall refractory-lined type.

3.2.1 Description of one module

Feed slurry is mixed with makeup hydrogen and is passed first through the effluent-feed heat exchangers and then through the fired heaters, entering the reactors at 810°F. The reactor effluent at 860°F is used to preheat the feed and then goes to a 350-psig steam generator. Leaving the steam generator at 550°F, the reactor effluent enters the high-pressure high-temperature separators. The vapor phase from this separation goes through heat exchangers where it is used to preheat the makeup hydrogen. Then it goes through air and water coolers, entering the high-pressure low-temperature separators at 100°F.

The vapor phase from the high-pressure low-temperature separators undergoes diethanolamine (DEA) scrubbing and then proceeds to methane absorber columns. Here lean oil is used to remove a portion of the methane and other gases that tend to build up in the recycle system.

Each module has one recycle gas compressor driven by a 12,000-hp steam turbine.

3.2.2 Synthoil reaction and product filtration

The liquid underflow from the low-pressure high-temperature separator is transferred to the centrifuge feed tank. The tank feeds vertical, solid-bowl centrifuges with continuous overflow and underflow discharge. The clarified overflow is returned to coal slurry preparation. This stream represents almost two-thirds of the centrifuge feed by weight. The centrifuges are equal in number (27) to the rotary drum filters which follow. Surge tankage is provided between the centrifuges and filters to permit independence of operation. The thickened solids slurry from the underflow of the centrifuges enters the surge tanks, which are provided with agitators to maintain the solids in suspension.

3.3 Recycle Gas and Fuel Gas DEA Treating Units

This unit treats gas streams flashed from the Synthoil reaction section at two different pressure levels. A 30 wt % solution of DEA is used in two independent absorbers, one at 3985 psia and the other at 195 psia. In the first absorber, more than 97% of the H_2S is removed, leaving less than 70 ppmv in the treated gas recycled to the Synthoil unit. The low-pressure absorber produces a 190-psia fuel gas containing about 100 ppmv H_2S. A common regenerator is used, and the evolved H_2S goes to the Claus sulfur plant.

3.4 Gasification Unit

The gasification unit produces the hydrogen necessary for hydrogenating coal in the Synthoil reactors. Part of the hydrogen is made by gasifying char obtained from the low-temperature carbonization of oil-bearing residue from the filtration section of the Synthoil unit. The remaining hydrogen requirement is provided by gasifying raw coal along with the char.

This unit consists of two parallel trains which can operate independently of each other. The gasifiers are of the entrained-flow, slagging-type, designed to operate at 245 psig with a temperature of about $3400^{\circ}F$ in the combustion zone. Each gasifier has an inside diameter of 10 ft and a height of approximately 110 ft with an outer pressure shell containing an inner shell of tube-wall-type construction covered with castable refractory in the combustion zone. Heat is recovered by generating 350-psig saturated steam from boiler feed water flowing through the water-wall tubes.

The Babcock and Wilcox Company supplied basic process information, heat and material balances, and a partial cost estimate for an entrained-flow gasification unit of their design.

3.5 Raw Gas Treating Unit

This unit removes most of the acid gases from the gasifier effluent coming from the gasification plant. The Benfield activated hot potassium carbonate process was selected for this service. The process hydrolyzes most of the COS to CO_2 and H_2S, which can then be absorbed in solution. Capital and operating costs were provided by the Benfield Corporation.

Acid gases evolved overhead from the solution stripper are sent to a Claus sulfur plant for sulfur recovery. The treated gas is sent to high-temperature CO shift conversion.

3.6 High-Temperature CO Shift Conversion Unit

This unit uses three stages of high-temperature CO shift to increase the hydrogen concentration of the gasifier make gas by reacting CO and H_2O. Three stages of catalytic reaction over a sulfur-tolerant cobalt-molybdate catalyst reduce the CO concentration from 60 mole % to less than 5 mole % on a CO_2-free basis.

Reactor conditions, catalyst volumes and prices, steam requirements, and other information were supplied by Girdler Chemicals, Inc.

3.7 Low-Temperature CO Shift Feed-Gas Treating Unit

This unit removes essentially all remaining H_2S and most of the CO_2 from the effluent stream from high-temperature CO shift. The process is based on the Benfield Corporation's HiPure Process. The capital and operating costs used were provided by the Benfield Corporation.

3.8 Low-Temperature CO Shift Conversion Unit

In this unit, treated gas from the final H_2S removal plant undergoes further water-gas shift conversion to produce additional hydrogen. A low-temperature, highly active catalyst is used. Catalyst volume, price, reactor pressure drop, and operating temperatures were provided by Girdler Chemicals, Inc.

3.9 Low-Temperature Shift Product-Gas CO_2 Removal Unit

This unit removes CO_2 from the low-temperature shift effluent prior to its final compression to 4265 psia for use as makeup hydrogen. A split-stream Benfield hot potassium carbonate process was used. The requirement for removing CO_2 from the makeup gas stems from the need for maintaining hydrogen purity in the Synthoil recycle gas system.

3.10 Sulfur Plant

This plant converts H_2S to elemental sulfur by the modified Claus process. The Claus section is followed by tail gas treating using the Beavon process, with residual H_2S conversion to sulfur in a redox-type unit. Costs and utility requirements were furnished by the Ralph M. Parsons Company. Overall sulfur recovery exceeds 99.5%. Sulfur production from this unit is 1880 long tons/stream day.

After the final condenser in the Claus section of the plant, the tail gas must be treated to remove remaining sulfur-containing gases to meet EPA limits, since even a four-reactor Claus plant appears unable to meet SO_2 emission guidelines without further treating. The Beavon Process, incorporating a redox unit, was included to remove H_2S to very low levels. The combination of hydrogenation followed by removal of H_2S in the redox unit reduces the total sulfurous gas content of the tail gas to less than 100 ppmv.

3.11 Oxygen Plant

The oxygen plant design, capital cost, and operating requirements were supplied by the Linde Division of Union Carbide Corporation. There are six 2000-ton/day modules supplying a total of 11,200 tons/stream day of oxygen of 99.5% purity. The main impurity is argon, with a minor amount of nitrogen.

3.12 Low-Temperature Carbonization Unit

Solids-containing residue from the filtration section of the Synthoil unit carries with it an appreciable quantity of product oil. The purpose of low-temperature carbonization is to recover this oil, along with a quantity of gaseous hydrocarbons, and to prepare the remaining char for feed to the gasification unit.

3.13 Sulfur Recovery (Redox type)

This unit treats the acid gas stream from the low-temperature CO shift feed gas treating plant, which contains about 0.25 mole % H_2S on a dry basis. The redox process used is essentially the same as that used in connection with the tail-gas treating section of the Claus plant.

3.14 Sour Water Stripper

Condensate streams from the Synthoil reaction plant and the low-temperature carbonization plant contain approximately equimolar concentrations of H_2S and NH_3. In addition, there are some phenolic compounds. Capital and operating costs were supplied by Chem-Pro Equipment Corporation for the phenolic recovery section and by Chevron Research Company for the H_2S and NH_3 recovery sections, based on proprietary designs.

The bottoms from the H_2S stripper are fed to an ammonia stripper. The ammonia is removed overhead, compressed, and purified to yield agricultural grade anhydrous ammonia, at 5 ppm by weight H_2S maximum and 1000 ppm by weight H_2O maximum. The clean water removed in the bottoms is cooled to $130^{\circ}F$ and sent to the industrial water system for reuse.

3.15 Product Distillation

The product distillation unit is used for the preparation of special fractions needed in various parts of the facility. A light oil fraction is prepared for use as absorber oil in the recycle gas purification system of the Synthoil unit, and another is used as wash in the filtration section.

4. UTILITIES AND AUXILIARY SYSTEMS

The fresh water (raw water) supply is assumed to come from a river two miles from the site boundary. Total fresh water consumption is 35,300 gal./min., or 1,210,000 bbl/day. Cooling tower losses account for about 87% of the total water consumption, as shown in Table 4. Net water consumed in chemical reactions (gasification, CO shift, Synthoil) is relatively minor (974 gal./min.).

Process cooling is provided both by air and by cooling tower water. There are two natural draft hyperbolic atmospheric wet cooling towers with a combined capacity of 11,800 million Btu/hr with a 30°F rise and a 9°F approach to atmospheric wet bulb temperature.

Air cooling usage in the facility amounts to 3,300 MMBtu/hr (million Btu/hr). Since the assumed plant location is in the eastern United States, no attempt was made to maximize air cooling.

Electricity generation is provided by three 100-MW turbine-generators, one of which is a spare. The 350-psig steam supply for these units, about 2.65 million lb/hr, comes from process waste heat steam generators. An additional 1.6 MW is produced in the oxygen plant.

All of the process-derived fuel gas generated within the facility is used as fuel for process fired heaters and steam generators. Raw fuel gas streams are treated by DEA absorption to remove H_2S to a level of about 100 ppmv before being burned as fuel. The total heating value of the fuel gas produced and consumed is about 6150 MMBtu/day.

Two pulverized-coal-fired boilers normally generate 3.3 million lb/hr of steam at 600 psig and 750°F. This steam is used in condensing turbines with a condensing pressure of 4 in. Hg abs. About 1.7 million lb/hr of steam is used in the oxygen plant compressor drives. Most of the remainder is used to drive the Synthoil makeup and recycle gas compressors.

Based on the September 1975 report on sulfur oxide control technology by the Commerce Technical Advisory Board, we concluded that the power plant design should be based on the use of wet limestone slurry scrubbing to control SO_2 emissions.[3] The use of low-Btu gas or synthetic coal liquids would be much more expensive.

Table 4. Overall water balance

	gal./min.
Water intake:	
Raw water intake	35,262
Water in feed coal (9.2% moisture)	769
Total	36,031
Disposition:	
Cooling tower losses including blowdown	30,520
Slag slurry effluent	3,538
Vented from coal drying	346
Water in coal burned in boiler plant	95
Water in fuel gas burned	44
Waste water from water treating	200
Consumed in chemical reactions (net)	974
Vented in tail gases	140
Boiler plant blowdown	100
Flue gas desulfurization	a
Miscellaneous	74
Total	36,031

[a] Water used in the flue gas desulfurization system is supplied from cooling tower blowdown.

The scrubber modules are designed so that six modules can carry the full operating load while the seventh is shut down for cleaning. This is in accordance with the operating procedure at La Cygne.[4]

4.1 Wet Scrubber Waste Disposal System

The wet scrubber waste disposal system handles the waste sulfate-sulfite sludge and fly ash from the coal-fired boiler limestone-slurry scrubbing modules. The wet sludge first goes to thickeners where it is partially dewatered to 25%-35% solids by weight. The sludge is then treated with a stabilizing additive to promote hardening. The treated sludge is pumped by slurry pipeline to a disposal area where it is used as landfill.

5. OVERALL THERMAL EFFICIENCY

The overall thermal efficiency is 59.6%, as shown in Fig. 2. The efficiency used here is defined as the total heating value of the fuel products divided by the heating value of the total coal consumed in the facility.

The heating value of the product oil was estimated to be 6.40 MMBtu/bbl. Some of the data indicate that the HHV could be as high as 6.50 MMBtu/bbl, in which case the thermal efficiency would be about 60.5%.

6. CAPITAL INVESTMENT

As shown in Table 5, the estimated overall capital investment is about $1900 million, consisting of $1670 million depreciable and $230 million nondepreciable capital. The cost of the coal mine is not included. Coal delivered to the plant is considered to be an operating expense, and its cost is treated as a variable in the economic analysis. Interest during construction is not included in the capital investment but is accounted for in the calculation of the product price. All costs are on a first-quarter 1976 basis. Estimated costs of some of

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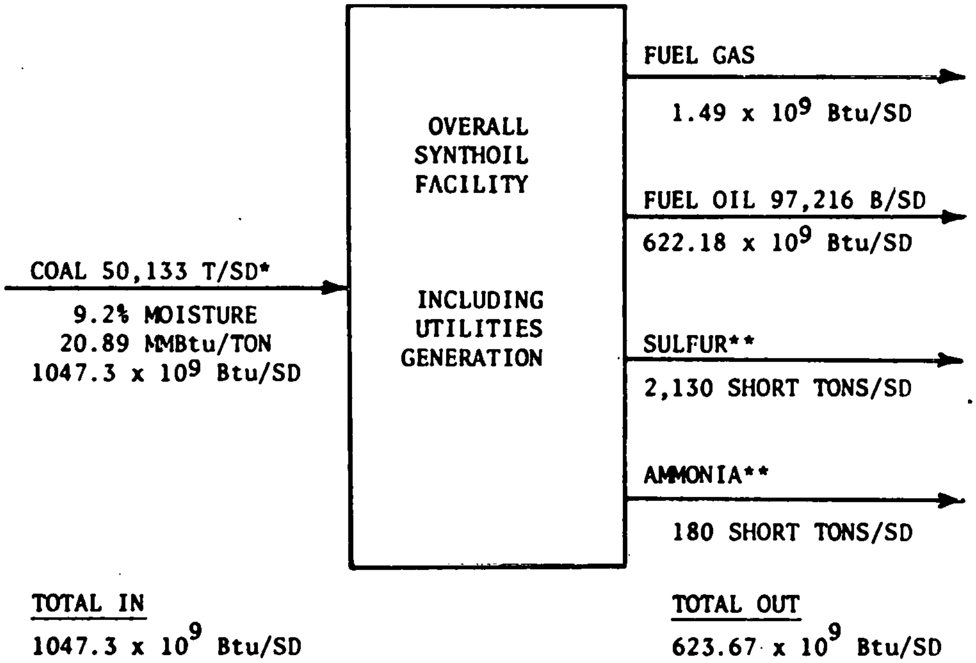

$$\text{OVERALL THERMAL EFFICIENCY} = \frac{623.67}{1047.3} = 59.6\%$$

*Synthoil 32,069 T/SD, gasification 11,894 T/SD, utilities generation 6,170 T/SD.

**Heating values of sulfur and ammonia are not included in thermal output.

Fig. 2. Overall thermal efficiency for 100,000-bbl/stream day Synthoil facility. Higher heating values (HHV) are used throughout.

Table 5. Capital investment summary - 100,000-bbl/stream day Synthoil facility

	Capital investment ($\$10^6$)
Depreciable capital	
Site development	9.1
Process plants	1273.0
Utilities systems	310.5
Buildings	13.4
Auxiliaries and offsite facilities	21.2
Equipment and machinery	6.2
Paid-up process royalties	1.5
Subtotal	1634.9
Start-up modifications (2%)	32.7
Total depreciable capital	1667.6
Nondepreciable capital	
Working capital	168.3
Initial catalysts and chemicals	9.8
Other start-up costs	49.0
Land and land rights	2.0
Total nondepreciable capital	229.1
Total capital investment	1896.7

the process units were furnished by vendors. The remaining units were estimated by the factor method, using factors applied to the major process equipment costs to arrive at a total installed plant cost.

7. OPERATING COSTS

The total annual operating cost is $128 million at 90% onstream efficiency. This amounts to $4/bbl of product, or about 7.7% of total depreciable capital per year. This includes supplies, maintenance, catalyst and chemicals, labor, overhead, property insurance, and limestone. It does not include recovery of capital (depreciation), return on investment, interest on debt, taxes, coal, and credit for by-products. Limestone was estimated at $5/ton.

Total maintenance (materials and labor) was estimated at 4% of depreciable plant investment per year.

Payroll burden was estimated at 35% of total payroll. This includes social security, unemployment insurance, sick pay, vacation pay, other fringe benefits, and shift differentials.

8. PRODUCT PRICE

Using the discounted cash flow procedure, the price of the product oil was calculated as a function of coal cost and annual after-tax rate of return on equity capital. This was done for four capital structures ranging from 100% equity to 95% debt, using an annual interest rate on debt of 9%. The resulting product price is highly dependent on the capital structure. Typical examples of the results are shown in Tables 6 and 7. The product price in these tables is given in $/bbl. By-product credits were included for sulfur at $60/long ton and anhydrous ammonia at $160/ton. Reducing the sulfur credit to $25/long ton would increase the price of the product oil by $0.70/bbl. A change of $10/ton in the price of ammonia would change the product cost by $0.02/bbl.

Product price calculations were based on a five-year construction period followed by a 20-year operation period. Total onstream efficiency

Table 6. Estimated price of Synthoil product using 100% equity financing[a]

	Product price ($/bbl), at indicated rate of return on equity[b]		
Coal, $/ton	10%	12%	15%
10	21.60	24.80	30.10
15	24.20	27.40	32.70
20	26.80	30.00	35.30
25	29.40	32.60	37.90

[a] Product transportation, distribution, and marketing costs are not included. Investment tax credit of 7% is included.

[b] Annual after-tax rate of return on equity.

Table 7. Estimated price of Synthoil product using 70% debt, 30% equity financing[a,b]

	Product price ($/bbl), at indicated rate of return on equity[c]		
Coal, $/ton	10%	12%	15%
10	16.70	17.40	18.50
15	19.30	20.00	21.10
20	21.90	22.60	23.70
25	24.50	25.20	26.30

[a] Product transportation, distribution, and marketing costs are not included. Investment tax credit of 7% is included.

[b] Annual interest rate on debt is 9%.

[c] Annual after-tax rate of return on equity.

of the plant was assumed to be 50% in the first year, 70% in the second year, and 90% thereafter.

The results shown were based upon a federal income tax rate of 48%, a state income tax rate of 3%, and a federal investment tax credit of 7%. Depreciation for tax purposes was calculated by the sum of the years' digits method using a life of 16 years.

Property taxes and insurance were estimated at 3% of fixed capital investment based on a property tax rate of 1.5 to 2.0% and an insurance rate of 1.0 to 1.5% of property value.

The product prices are shown in Figs. 3, 4, and 5. In each case, the debt-equity ratio and tax structure are fixed, and the product price is plotted as a function of the price of coal, with the annual after-tax rate of return on equity as a parameter.

9. EMISSION AND EFFLUENT LIMITATIONS

The emission limitations suggested for the pollutants from the Synthoil plant were based on those promulgated for similar industries, particularly petroleum refining and steam-electric power generating. A compilation was made of pertinent federal and state (Illinois, Kentucky, and New Mexico) emission limitations. This served as primary source material for guidelines specific to the Synthoil process.

The suggested limitations took into consideration the assumption that the plant would be located in the eastern interior region.

The principal sources of solid wastes from the Synthoil plant are slag from the process gasification plant and sludge from the utility power plant. The slag is primarily ash from the pulverized coal and carbonization char with traces of unreacted carbon and tightly bound sulfur from the gasifier. Other sources of solid wastes are the rock reject from coal crushing, settled solids in the coal storage run-off holding-pond, solids in the biochemical treatment holding pond, and discarded Benfield process solids. The nature of all of these solids permits their disposal at the mine site or landfill, except the FGD sludge which requires settling and stabilization at the Synthoil facility.

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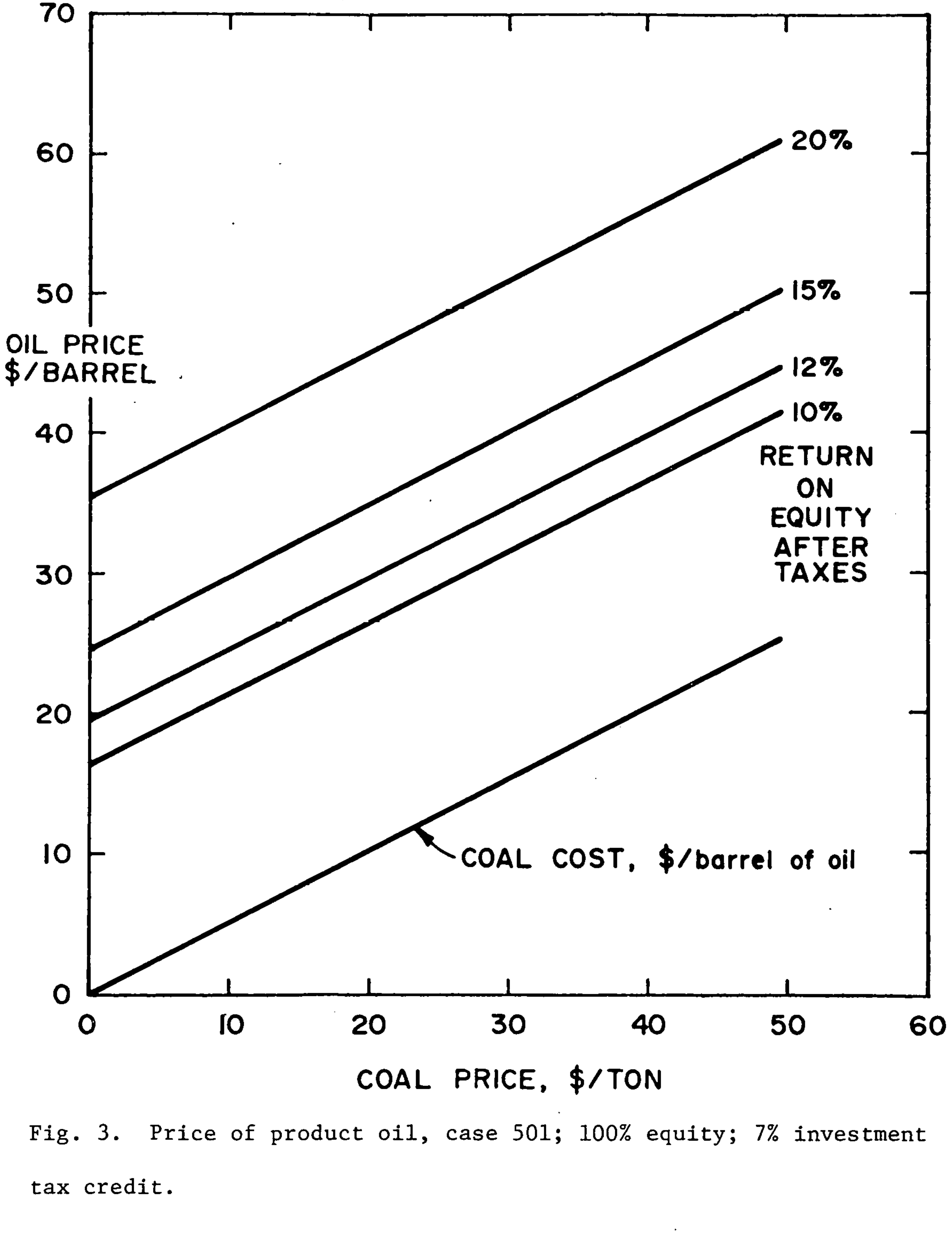

Fig. 3. Price of product oil, case 501; 100% equity; 7% investment tax credit.

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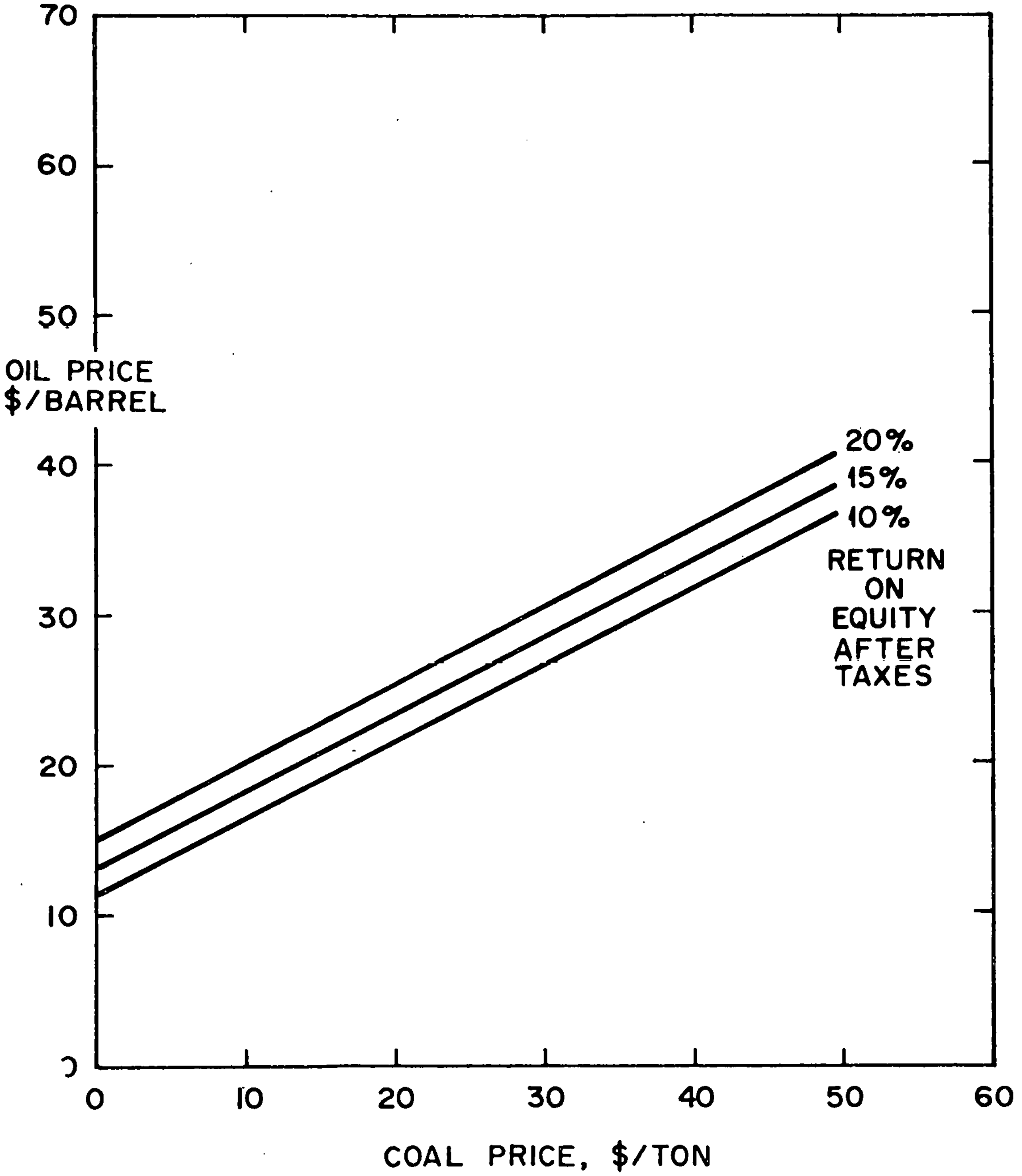

Fig. 4. Price of product oil, case 503; 70% debt at 9% annual interest, 30% equity at rate of return indicated.

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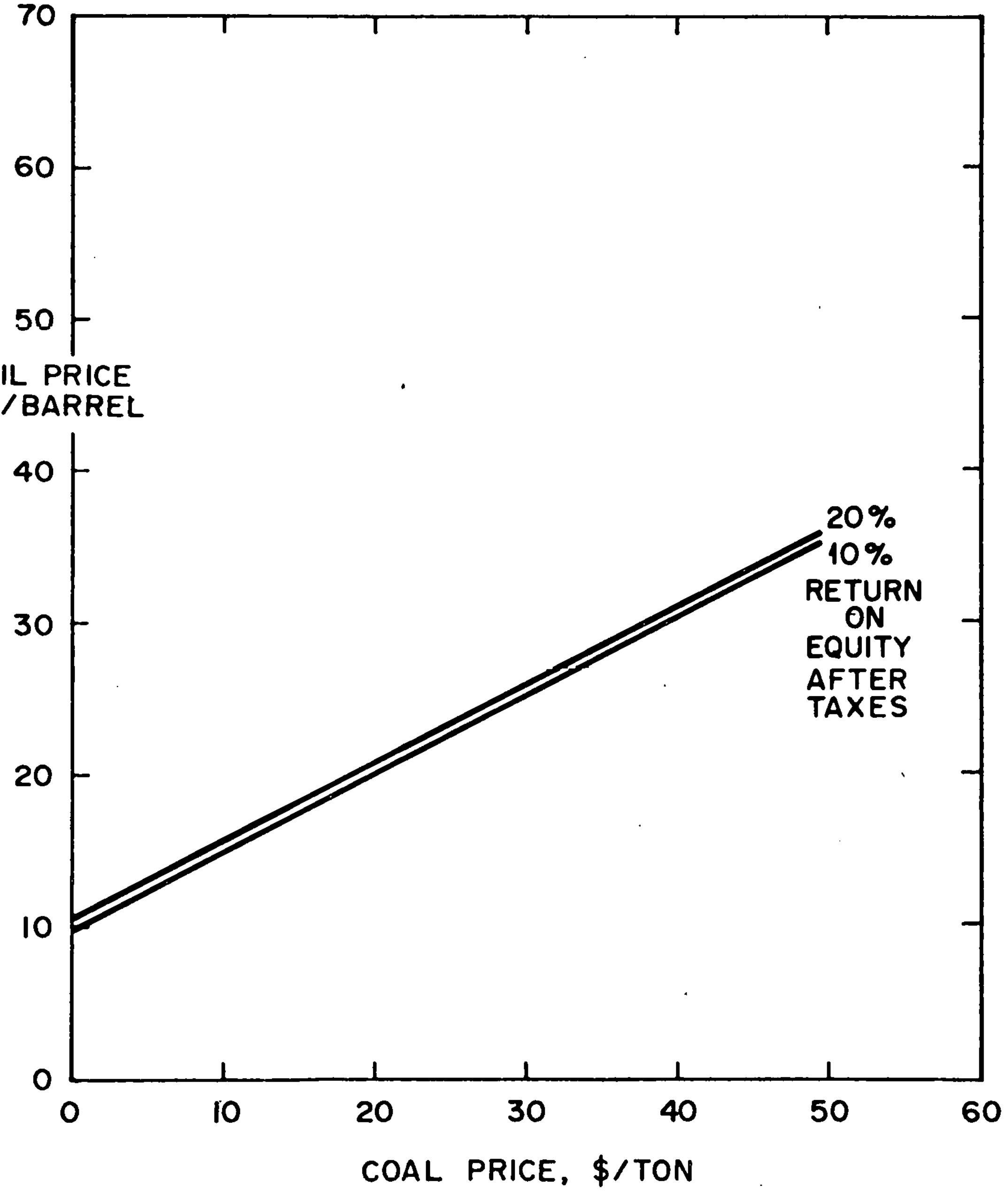

Fig. 5. Price of product oil, case 504; 95% debt at 9% annual interest, 5% equity at rate of return indicated.

10. REFERENCES

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