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VOLUME ONE

BACKGROUND AND SUMMARY

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COAL BASED SYNTHETIC FUEL
TECHNOLOGY ASSESSMENT GUIDES

1.0 BACKGROUND

This study was prepared by Energy Resources Co. Inc., under contract No. 01-80-EI-1065300 with the Energy Information Administration of the Department of Energy. This study was initiated to provide up-to-date data particularly on the economic performance but also regarding engineering details and effects of government policy on current available and more advanced synthetic fuels technologies based on coal. Technologies based on oil shale, tar sands and other resources may be viable in their own right but are not addressed in this study.

1.1 OBJECTIVES AND SCOPE

The main objective of this contract effort was the preparation of seventeen Technology Assessment Guides (TAGs) which comprise Volume two. The data contained within the TAGs is to be used in the EIA's computer analyses. Of prime concern in developing the Assessment Guides was maintaining a level of consistency in the data presented. This facilitates the comparison of one technology to another on an equal basis, makes the information more suited for use as computer input, and allows the reader more rapid access to the desired information.

Although the TAGs were restricted to coal based synthetic fuels technologies, a wide variety of process types were chosen. These included low, medium, and high Btu gasification, liquefaction and conversion to methanol, coal-oil mixtures, and pyrolysis. Within each category, where possible, at least one

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process was chosen which represents currently available technology, and one which may be considered advanced generation technology. These advanced processes chosen for study demonstrated a reasonable chance of becoming commercially successful within the United States over the 20 year period of interest, based upon the opinions expressed in independent reports, and the judgment of the authors. Estimation of the accuracy of the economic analysis was also a goal of the study. Data for each process studied was obtained primarily from one main source, although other sources were used to support the main process design reference. Literature sources are clearly referenced at the end of each chapter. Data which is not individually referenced can be assumed to come from the main reference for the study which is listed first in the reference list. Remarks made without accompanying references at the end of the chapter are the opinions of the authors.

1.2 REPORT ORGANIZATION

The bulk of the study results are embodied in the seventeen technical assessment guides presented in volume two. Each assessment guide summarizes the results of the technical and economic feasibility analysis which was performed for the particular technology being studied, as the process would be applied on a commercial scale. Analysis results for each TAG are presented in a brief executive summary preceding the technical discussion.

The basic outline followed for each Assessment Guide is presented in Table 1-1.

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Table 1-1

General Outline For Technical Assessment Guides

CHAPTER ONE: EXECUTIVE SUMMARY

1.1 Overall Prospects for the Technology
1.2 Engineering Aspects
1.3 Current Costs
1.4 Research and Development Directions

CHAPTER TWO: ENGINEERING SPECIFICATIONS

2.1 General Description of the Technology

2.2 Process Flow, Energy, and Material Balances

2.3 Plant Siting and Sizing Issues and Constraints

2.4 Raw Material and Support System Requirements
- 2.4.1 Coal quantities and quality
- 2.4.2 Catalysts and other required materials
- 2.4.3 Water requirements

2.5 Effect of Coal Type

2.6 Air Pollution Control Technology
- 2.6.1 Ability of existing technology to meet regulations
- 2.6.2 Impacts on process efficiency

2.7 Water Pollution Control Technology
- 2.7.1 Ability of existing technology to meet regulations
- 2.7.2 Water recycling systems
- 2.7.3 Impacts on plant efficiency

2.8 Solid Waste Handling
- 2.8.1 Disposal requirements
- 2.8.2 Leachate problems

2.9 OSHA Issues

2.10 Process Performance Factors
- 2.10.1 Product characteristics and marketability
- 2.10.2 Capacity factors, flexibility, reliability

2.11 Technology Status and Development Potential
- 2.11.1 Current status
- 2.11.2 Key technical uncertainties
- 2.11.3 Availability for commercial production
- 2.11.4 Unit design and construction times

2.12 Regional Factors Influencing Economics
- 2.12.1 Resource constraints
- 2.12.2 Environmental control constraints
- 2.12.3 Siting constraints

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Table 1-1 (continued)

General Outline For Technical Assessment Guides

CHAPTER THREE: ECONOMIC ANALYSES

3.1 Methodology and Introduction
- 3.1.1 Methodology
- 3.1.2 Scaling exponents
- 3.1.3 Price indices
- 3.1.4 Economic criteria
- 3.1.5 Contingencies

3.2 Capital Costs
- 3.2.1 Itemized capital costs
- 3.2.2 Variability of capital costs

3.3 Operating and Maintenance Costs
- 3.3.1 Itemized operating and maintenance costs
- 3.3.2 Variability of operating and maintenance costs

3.4 Effect of Technology Development on Costs

3.5 Product Costs

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Although the report organization allows for some repetition of data, this format was selected to make inter-process comparisons easier. The reader should always keep in mind that, although the TAGs have been prepared according to consistent set of criteria, process design information has been adapted from a variety of sources which will inevitably introduce variability in the process comparisons.

Limitations on the availability of data constrained the completeness or format of some sections. This is reflected by an appropriate comment in the case of limited data, and by omission of chapter subcategories where data availability affects format.

Technical Analysis

Following the executive summary for each TAG (Chapter One),, process technical characteristics are reviewed in Chapter Two. In addition to describing the process using mass and energy balances, process siting issues and constraints are discussed. Requirements for raw materials and support systems are evaluated, including coal, catalysts, water, and product handling. Process impacts on the environment are reviewed from air quality, water quality and solid waste perspectives. Issues affecting the health of plant employees are also discussed. Process performance factors, including product characteristics, capacity factors, and process flexibility and reliability are reviewed to provide an indication of commercial applicability. Current technology status and development potential are discussed to provide the reader with a time-scale for the commercial development of each technology. Regional factors affecting economics, such as local environmental regulations, resource constraints and siting limitations are also examined. Several key technical assumptions underlie the analysis presented in each of the Technical Assessment Guides. These assumptions are designed to insure a degree of consistency between TAGs to allow interprocess comparisons, and also to assure that the design basis chosen for each realistically represents commercial applications of the technology as it might occur during the next twenty years.

One of the most important technical assumptions involves the plant size. Because of differing commercial applications for each technology, various plant sizes were assumed:

TAG No.	and Technology Type	Plant Capacity 10^{12} Btu/Year
1.	Wellman-Galusha Low-Btu Gasification (Current Technology)	10
2.	Combustion Engineering Low-Btu Gasification (Advanced Technology)	50
3.	Lurgi Medium-Btu Gasification (Current Technology)	50
4a,b.	Koppers-Totzek and Texaco Medium-Btu Gasification (Advanced Technology)	50
5.	Lurgi-ANG High-Btu Gasification (Current Technology)	91.25 (250 x 10^9 Btu/Day)
6a,b, c.	IGT HYgas, Exxon Catalytic and BGC Lurgi High-Btu Gasification (Advanced Technology)	91.25
7.	Fischer-Tropsch Indirect Liquefaction (Current Technology)	125
8.	Mobil Indirect Liquefaction (Advanced Technology)	125
9a,b, c.	H-Coal, EDS Direct, SRC-II Liquefaction (Advanced Technology)	125
10.	ICI Coal-to-Methanol	125
11.	Coal Oil Mixtures	35
12.	Occidental Research Pyrolysis	148

To facilitate consistency within the TAGs, each commercial plant design study was based upon a general system of plant area numbers. Thus, a comprehensive list of plant areas found in all of the conversion processes studied forms the basis for this numerical cataloging.

100 COAL STORAGE AND HANDLING

- 110 Coal Storage
- 120 Coal Handling and Transportation

200 COAL PREPARATION

- 210 Crushing and Grinding
- 220 Pulverization
- 230 Beneficiation
- 240 Drying
- 250 Size Classification
- 260 Slurry Preparation

300 GASIFICATION

- 310 Gasification
- 320 Ash Quench and Handling
- 330 Solids Reslurring
- 340 Catalyst Recovery
- 350 Preheat

400 HYDROGENATION/REGENERATION

- 410 Reaction
- 420 Primary Separation
- 430 Reaction Preheat

500 PRODUCT SEPARATION AND PROCESSING

- 510 Fractionation
- 520 Naphtha Stabilization

600 LIGHT ENDS PROCESSING

- 610 Amine Plant
- 620 Gas Plant ("LPG")
- 630 Cryogenic Fractionation

700 PYROLYSIS AND CHAR COMBUSTION

- 710 Reaction
- 720 Char Handling and Combustion

800 CYCLONE SEPARATION

900 OIL QUENCH AND SEPARATION SYSTEM

1000 LIQUID PRODUCTS UPGRADING

1100 CHAR DESULFURIZATION

1200 RAW GAS HANDLING

- 1210 Particulate Removal
- 1220 Gas Quenching and Cooling
- 1230 Gas Heating

1300 ACID GAS REMOVAL AND GAS PURIFICATION

- 1310 H_2S, CO_2, and SO_2 Removal
- 1320 Ammonia Recovery
- 1330 Tar and Oil Separation
- 1340 Phenol Recovery

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

1600 GAS COMPRESSION/EXPANSION

1700 SHIFT CONVERSION

1800 METHANATION AND OTHER CATALYTIC REFORMING

1900 AIR COMPRESSION AND SEPARATION

2000 UTILITIES AND SUPPORT SYSTEMS

- 2010 Steam Generation and Power Recovery
- 2020 Wastewater Treating and Water Supply
- 2030 Solids Disposal
- 2040 Plant and Instrument Air
- 2050 Aqueous Phenol Recovery
- 2060 Aqueous Ammonia Recovery

2100 OFFSITES AND MISCELLANEOUS

- 2110 Flare and Incineration
- 2120 Tankage, Shipping and Receiving
- 2130 Other Support Facilities

Any desired plant configuration can therefore be represented by selecting from this list the applicable plant areas. The economic analysis is also based on these area numbers.

Plant Area 100 includes all facilities for live and dead storage of coal, and all conveying or other equipment used for moving the coal from storage. All methods of preparing the as received coal for further use are covered in Area 200. Plant Area 300 covers all activities directly associated with coal gasification, but is not applicable in several of the other TAGs. The reactor area for most coal liquefaction areas is hydrogenation, Area 400. Product Separation and Processing, and Light Ends Processing also both apply primarily to liquefaction. Area 700, Pyrolysis and Char Combustion is exclusively used for TAG 12, Occidental Research Pyrolysis. Cyclone Separation and Oil Separation may be applied in gasification and pyrolysis. Liquid Products Upgrading is generally used for liquefaction. Char Desulfurization is applied to pyrolysis. Area 1200, Raw Gas Cooling is used extensively in gasification plants, but can be applied in any process which generates a hot gas stream during primary reaction. Areas 1300 and 1400 Acid Gas Removal and Gas Cleaning, and Sulfur Recovery and Tail Gas Treating are used in all gasification systems, including those that serve liquefaction plants. The Hydrogen Plant of Area 1500 is an example of such a subordinate gasification system used in support of a liquefaction plant. Plant Area 1600 deals with changes in gas pressure which are required prior to sale, for either economic reasons or to meet product quality specifications. When used in gasification plants, expanders or compressors are generally the last major processing step.

Shift Conversion is frequently used in high-Btu gas plants to provide a source of hydrogen for Methanation and other Catalytic Reforming steps (Area 1800). Air Separation, Area 1900, produces high purity oxygen for use in oxygen blown gasification processes. Plant Area 2000 is a broad category covering Utility and Support Systems for all coal based synthetic fuels technologies. Plant Area 2100 is a catchall category covering Offsites and Miscellaneous operations. This category covers structures, buildings, and any non-process equipment. Because it applies to all processes in a general way, it is included in the list of plant areas for each TAG, but not in the process flow diagram.

Energy and material balances have been based on plant operation at 100 percent capacity. Plant sizing on a Btu-basis promotes consistency within each technology category to facilitate comparisons. The output of each plant as measured in physical units (SCF, BBl, etc.) was then determined from the heating value of each product. The conversion factors used for each plant were as follows:

TAG. No.	Product	Heating Value
1	Low-Btu Gas	137 Btu/SCF
2	Low-Btu Gas	112 Btu/SCF
3	Medium-Btu Gas	293 Btu/SCF
4	Medium-Btu Gas	274 Btu/SCF (K-T)
		293 Btu/SCF (Texaco)
5	High-Btu Gas	977 Btu/SCF
6	High-Btu Gas	991 Btu/SCF (Hygas)
		1067 Btu/SCF (Exxon)
		955 Btu/SCF (BGC)

TAG. No.	Product	Heating Value
7	Indirect Lique-faction Products	4.73 MM Btu/BBL (1035 Btu/SCF for SNG)
8	Indirect Lique-faction Products	5.105 MM Btu/BBL
9	Direct Lique-faction Products	5.82 MM Btu/BBL (H-Coal) 5.71 (EDS-Illinois Coal) 5.75 (SRC-II)
10	Methanol	2.68 MM Btu/BBL
12	Pyrolysis	5.82 MM Btu/BBL (Liquids) 13,100 Btu/lb (Char)

In cases where plants produce a spectrum of different products, each plant has been sized to produce the total Btu output indicated on the first list above. Quantities of liquids relative to gases produced are in the same Btu proportion as in the reference plant design. Actual physical production units of liquids and gaseous products are then determined by the heating value numbers given above. For example, in the case of TAG No. 7, Fischer-Tropsch liquefaction, the reference plant is sized to produce a total of 525 x 10^9 Btu/day, or 191 x 10^{12} Btu/stream year. This production rate is split 51 percent to SNG and 49 percent to liquids on a Btu basis. The TAG will then describe a plant with a capacity of 125 x 10^{12} Btu/year, split 63.75 x 10^{12} Btu/y (51%) to SNG and 61.25 x 10^{12} Btu/y to liquids in the original product spectrum (22% naphtha, 21% diesel, 21% fuel oil, etc.).

Economic Analysis

Because the plant designs shown in the TAGs were based upon information obtained from many diverse sources, assumptions regarding coal properties, site location and general plant requirements may differ. In fact, one criterion used in selecting design studies as references was that a fairly wide scope of possible circumstances be represented in the final report by the collective groups of TAGs. Even though some technical assumptions vary from one design to the next, assumptions used within any given design are internally consistent.

Unlike the case for technical assumptions, the economic assumptions underlying the analysis in Section III of each TAG could be consistently applied through the study to each technology. This is to enable the comparison of diverse technologies on the same economic basis.

These assumptions covered the following aspects of plant economic evaluation:

1. Scaling cost values to standard plant sizes;
2. Escalation of literature cost estimates in normal dollars to standard year dollars;
3. Value of plant by-products;
4. Economic criteria such as working capital and startup costs;
5. Contingency values appropriate to process and project attributes;
6. Effects of technology development on costs; and

7. Conversion of capital and operating costs into energy product costs.

The standard assumptions employed in each of these areas are described below.

Scaling Factors

Plant sizes used as the basis in literature design studies were scaled to the typical commercial sizes mentioned earlier. For example, low-Btu gasification (conventional technology) will be most commonly applied on-site in industrial retrofit situations, and therefore was chosen to be small (10×10^{12} Btu/year). Advanced low-Btu gasification technologies will be used for larger industrial parks or, more probably, combined cycle power generation. Therefore, the advanced low-Btu gasification technology was scaled to 50×10^{12} Btu/year.

Literature cost values were scaled to standard sizes according to the following formula:

$$\text{New Plant Costs} = \left(\frac{\text{New Plant Size}}{\text{Reference Plant Size}}\right)^{se} \times \begin{array}{l}\text{Reference}\\ \text{Plant Cost}\\ \text{Estimate}\end{array}$$

where se is the cost scaling exponent.

The scaling exponent embodies the effect of economics of scale on plant costs. For each technology covered, a unique 'se' factor was estimated, based on cost engineering principles. For most technologies, the scaling exponent was between .7 and 1.0. These exponents are indicative of very limited declines in costs with larger scale. This is attributable to the fact that literature cost estimates are for plants of size sufficient to embody all economies of scale.

Standard Dollars

Third quarter 1980 dollars were used as the standard year dollar for all technologies. Appropriate costs indices were used to escalate technology cost components to third quarter 1980 dollars.

The Chemical Engineering Plant Cost Index was used for elements of the erected cost of the plant. The Chemical Engineering Plant Cost Index is a weighted average of the equipment, construction, and engineering costs incurred during the construction of chemical process plants. Because equipment costs were generally not presented independently of engineering and construction costs in the references, each element of construction costs could not be inflated separately. The Chemical Engineering Index, as a weighted average of all elements of the construction cost, is a valid substitute for inflating each element of plant costs separately.

Catalyst and chemical costs were corrected with the Producer Price Index for industrial chemicals. The Bureau of Labor statistics index of wages in the petroleum refining industry was used to inflate labor costs.

Water and ash disposal costs were assumed to increase at the general rate of inflation, and so the Gross National Product (GNP) deflator was used for these cost elements.

Third-quarter 1980 values for each index used, and the cost categories inflated by each index, are shown in Table 1-2. In Table 1-3, historical and base values of each index are presented.

Table 1-2

Cost Indices and Prices

ITEM	INFLATOR OR PRICE USED	THIRD QUARTER 1980 VALUE OR PRICE
Constructed equipment costs, maintenance, local taxes and insurance, land, royalties, spare parts, contractor's fees, construction indirects, productivity, design.	*Chemical Engineering* Plant Cost Index	266.2
Non-maintenance labor, administration and general overhead, operating supplies	Bureau of Labor Statistics Hourly Wages in Petroleum Refining Series	$11.06
Chemicals and catalysts	Producer Price Index for Industrial Chemicals	326.2
Purchased water	GNP Deflator	179.2
Ash disposal	GNP Deflator	179.2
By-product ammonia	Market Prices	7¢/lb
By-product sulfur	Market Prices	$40/long ton
By-product sulfuric acid	Market Prices	$13/short ton
By-product hydrocarbons	Market Prices	$160.62/short ton
By-product electricity	Market Prices	3.5¢/kWh

Table 1-3

Inflators or Series Over Time

	INFLATOR			
YEAR	CHEMICAL ENGINEERING PLANT COST INDEX[a]	BUREAU OF LABOR STATISTICS PETROLEUM REFINING HOURLY WAGE SERIES (IN DOLLARS PER HOUR)[b]	GROSS NATIONAL PRODUCT DEFLATOR[c]	PRODUCER PRICE INDEX FOR INDUSTRIAL CHEMICALS[d]
1974	165.4	$ 6.01	116.0	151.7
1975	182.4	$ 6.93	127.2	206.9
1976	192.1	$ 7.78	133.8	219.3
1977	204.1	$ 8.48	141.6	223.9
1978	218.8	$ 9.32	152.1	225.6
1979	238.7	$10.08	162.8	264.0
1980[e]	266.2	$11.06	179.2	326.2

[a]Source: Chemical Engineering, May 8, 1978, January 26, 1981; 1963 = 100.

[b]Source: Bureau of Labor Statistics. Values are hourly gross average non-supervisory wages in the petroleum refining and related industries.

[c]Source: Department of Commerce, 1972 = 100.

[d]Source: Department of Commerce, 1967 = 100.

[e]Third-quarter value.

By-Product Values

Hydrocarbon by-products of gasification, such as tars, oils, phenols, and naptha, were valued at $160.62/ton. It was assumed that these by-products would be unsuitable for upgrading, and so would be burned as fuel, accounting for the relatively low price. Hydrocarbon and electricity outputs of a synthetic fuels plant were valued as by-products only when they accounted for less than 2 percent of the plant output in British thermal units (Btu). Otherwise, these outputs were considered part of the main product stream. Electricity was valued at 10,000 Btu/kWh to account for the amount of coal which would need to be burned by a utility to generate one kilowatt-hour.

Ammonia was credited at $140/short ton, and electricity at 3.5¢/kWh. By-product prices used are shown in Table 1-2. Sulfur prices, at $40/long ton, are lower than actual 1980 prices of $50-55/long ton. This discount was made because the market for elemental sulfur is relatively small, and by-product sulfur from coal conversion plants will probably force market prices down. By-product credits were computed by multiplying annual production by 1980 prices.

Economic Criteria

Standard economic criteria were used to estimate certain costs other than direct operating and construction costs. These costs include working capital, startup costs, and interest during construction. The criteria used for these costs are listed below:

1. Working Capital: 6.1% of Total Plant Investment

2. Startup Costs: 6% of Total Plant Investment

3. Interest during construction: 15% annual compounded interest applied to construction expenditures during each year of construction. Interest is paid on each years' expenditures as if the entire sum were borrowed at the beginning of the year.

4. Plant Life: 20 years

5. Capacity Factor: 90%

6. Capital Charge Rate: 20%.

Contingencies

Two contingencies were applied to the capital cost estimates: A process contingency and a project contingency. The process contingency covers technical uncertainties within a particular process which might cause costs to increase. The process contingency was applied on an area-by-area basis according to the level of technical development of each area as is shown in Table 1-4. The process contingency varies from 0 percent for a commercialized technology to 50 percent for a technology not yet at the pilot plant stage. These contingencies were derived judgmentally by ERCO with reference to industry contacts.

A project contingency of 15 percent was applied to the total of the costs of each area and unit (not including process contingencies) and contractor's fees. This project contingency is meant to allow for unanticipated cost increases, which usually arise as the plant design is made more complete.

Table 1-4

Process Contingencies Applied to Plant Area Costs

LEVEL OF TECHNICAL DEVELOPMENT	PERCENT CONTINGENCY
No Pilot Plant	50
Pilot Plant	25
Demonstration Plant	10
Commercially Proven	0

Effect of Technology Development on Costs

As the number of synthetic fuel plants in service increases, capital costs will decline in real dollars due to the effects of experience. Experience is an inverse relationship betwen the cumulative number of units of an item produced and the unit cost of production. Experience is usually demonstrated with a log-linear curve which exhibits a constant percent decline in the unit cost of capacity for each doubling of completed production capacity. The experience factor is the slope of the curve. For example, a 10 percent experience factor implies that the cost of the fourth plant would be 81 percent (90 percent times 90 percent) of the cost of the first plant. Ten percent has been estimated as the upper limit on the experience factor for new energy process technology.[1]

The 10 percent experience factor is valid only for the plant costs accounted for by new technology. Most sections of a synthetic fuel plant employ mature technologies whose costs would decline little as more synthetic fuel plants were built. The accumulated volume of production of these mature technologies is so large that the construction of one or several plants would result in small additional cost reductions because of experience. Novel components typically account for 15-60 percent of the total plant investment. Therefore, the experience factor for synthetic fuel technology would be 15-60 percent times 10 percent, or about 2 percent to 6 percent. Each doubling of synthetic fuel production capacity would result in a 2-6 percent reduction in unit capital costs.

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[1]Hederman, W.F. (Rand Corporation). "Prospects for the Commercialization of High-Btu Coal Gasification." U.S. Department of Energy, April 1978, Number R-2294-DOE, pp. 48-50.

Unit Non-Fuel Energy Costs

The cost of the synthetic fuel is composed of three components: capital charges associated with plant capital costs, plant operating and maintenance (O&M) costs, and coal costs. The cost of the product fuels excluding the cost of coal (non-fuel costs) indicates the cost of converting coal to synthetic fuel product. Non-fuel costs can be computed from capital charges and O&M costs according to the formula:

$$P = \frac{(K \times CRF) + OM}{CAP \times F}$$

where

- P is the non-fuel product price;
- K is the total capital requirement of the plant;
- F is the capacity factor, 90%;
- CRF is the capital recovery factor, assumed to be 20%;
- OM are net annual operating and maintenance costs.

For example, assume K = \$2500 million, OM = 80 ~~\$30~~ million, CAP = 91.25×10^{12} Btu/year. Then, the non-fuel product price would be:

$$P = \frac{(\$2500 \times 10^6 \times 20\%) + \$80 \times 10^6}{91.25 \times 10^{12} \times 90\%}$$

$$= \underset{\text{(Capital Costs)}}{\$6.09/10^6 \text{ Btu}} \quad + \quad \underset{\text{(Operating and Maintenance Costs)}}{\$\overset{.97}{\cancel{.88}}/10^6 \text{ Btu}}$$

$$= \underset{\text{(total non-fuel cost)}}{\overset{7.06}{\cancel{\$6.97}}/10^6 \text{ Btu}}$$

Unit Product Costs

Unit Product Costs are computed from the non-fuel product cost and the cost of coal according to the formula:

$$E = P + \frac{Coal}{EFF}$$

where

- E is the total unit product cost;
- P is the non-fuel product cost;
- Coal is the price of coal in dollars per million Btu, assumed to be $1.50;
- EFF is the overall thermal efficiency of the process.

For example, assume P equal to $6.46/million Btu, EFF equal to 65 percent. Then the unit total energy cost would be:

7.06

$$E = \$\cancel{6.97}/10^6 \text{ Btu} + \frac{\$1.50 / 10^6 \text{ Btu}}{.65}$$

(non-fuel costs from previous example) (cost of coal)

7.06

$$= \$\cancel{6.97}/10^6 \text{ Btu} + \$2.31/10^6 \text{ Btu}$$

(non-fuel cost) (coal cost)

9.93

$$= \$\cancel{8.77}/10^6 \text{ Btu}$$

(total product cost)

This amount is presented as an example only, and is not meant to represent any technology in particular. For reference, the price of crude oil was approximately $6.90/million Btu in March 1981.

1.3 PUBLIC POLICY

Major government efforts to spur coal-based synthetic fuel market acceptance can be divided into two categories:

1. Department of Energy research and development (R&D), financial incentives, and financial assistance.

2. Synthetics Fuels Corporation financial assistance to synthetic fuels projects.

Department of Energy

Department of Energy (DOE) R&D efforts are concentrated in the Office of Fossil Energy. R&D is focused on the development of new technologies, especially in the area of high-Btu gasification and direct liquefaction. Some effort has been directed toward improvement of existing technologies through the development of better materials and catalysts.

Until 1981, the DOE had planned to build several demonstration plants to spur the commercialization of advanced coal conversion technologies. Planned were a Solvent Refined Coal solids (SRC-I), a Solvent Refined Coal liquids plant (SRC-II), an H-Coal direct liquefaction plant, a high-Btu gasification plant and a medium Btu gasification plant. These plants were to be of commercial scale and to cost many billions of dollars. During 1981, the program to build these plants was ended.

In addition to its other efforts, the DOE issued solicitations for financial assistance to synthetic fuels projects under the Alternative Fuels Production Act (P.L. 96-126) in 1980. One hundred and ten projects, for a total of approximately $200 million, were awarded feasibility study grants or cooperative agreements. Cooperative agreements are cost-sharing agreements to advance the design or construction of projects already considered feasible. Of the 110 awards, 24 were to projects to produce coal-based fuels. Ten of the 24 were to produce methanol for sale or for conversion to gasoline and five for medium-Btu gas production, with the nine others divided between coal-oil mixtures, low- and high-Btu gasification and indirect liquefaction projects. A second round of solicitations was made during the fall of 1980 and the awards were targeted in December 1980. The awards, however, were rescinded. The Department of Energy can also offer financial assistance to a small number of synthetic fuels projects under authority of the Federal Non-nuclear Energy Research and Development Act interim synthetic fuels program. This program will continue until the Synthetic Fuels Corporation is declared operational. As of May 1981, the DOE was nearing a decision on selection of a maximum of ten projects for financial assistance.

Synthetic Fuels Corporation

The Synthetic Fuels Corporation was established by the Energy Security Act (ESA) of 1980. Its mandate is to foster the creation of a synthetic fuels industry in the United States by providing financial assistance to synthetic fuels producers. The SFC is to act only as a catalyst to private industry synthetic fuel development. Where private capital is available, the SFC will not provide assistance.

Under the ESA, synthetic fuels include fuels derived from oil shale and tar sands in addition to the liquid and gaseous coal-derived fuels and coal-oil mixtures described in this report.

The SFC was set the goal of creating a synthetic fuels industry with production of 500,000 barrels per day of oil equivalent by 1987 and 2,000,000 barrels per day by 1992. To implement this goal, the SFC was appropriated $6.2 billion for 1981 and part of 1982. The ESA also authorized appropriations of up to $20 billion to the SFC through 1984. In 1984, the SFC will be required to submit to Congress a comprehensive strategy for the achievement of its goals. If Congress accepts this strategy, Congress can authorize the appropriation of another $68 billion. In the near term (through mid-1982), however, the amount of financial assistance available is $6.2 billion.

The SFC can use a variety of methods to foster the creation of a synthetic fuel industry. These include:

1. Price guarantees, through which the SFC guarantees a minimum price for the products of a synthetic fuels plant.

2. Purchase agreements through which the SFC contracts to buy the outputs of a synthetic fuel facility.

3. Loan guarantees, through which the SFC agrees to guarantee loans to synthetic fuel facility producers.

4. Loans to the synthetic fuel producer.

5. Joint ventures with the synthetic fuel producer, in which the SFC will finance and own a share of the synthetic fuel project.

Synthetic Fuels Corporation Effects

Assuming appropriations continue at authorized levels, the SFC has the resources necessary to spur synthetic fuels market penetration of a particular technology if this technology fits into the SFC's overall strategy. As of June 1981, this strategy had not been fully documented. However, the SFC outlined some of the criteria it will use for choosing one technology or project over another.[1]

The SFC will favor projects in which:

1. Project sponsors make a significant investment and will bear an important financial risk.

2. Financial assistance to the project is in the form of contingent liabilities such as loan guarantees, price guarantees, or purchase agreements.

3. The proposal shows sound promise of commercial viability. Operationally, this means that the SFC will favor projects which appear to be able to operate at a profit and to show a satisfactory rate of return either upon completion or within a relatively short time thereafter.

4. The technology has been successfully demonstrated on a commercial scale or where, for some other reason, the SFC has determined that the technical and engineering risks are prudent.

The first two of these criteria judge the financial structure of the proposed project. They are neutral with respect to the technology proposed. The last two criteria focus on the economic and technical viability of the projects and favor a conventional, proven technology such as Lurgi gasification, Koppers-Totzek gasification and to some extent Texaco gasification and the ICI methanol process.

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[1]United States Synthetic Fuels Corporation. "Assisting the Development of Synthetic Fuels." 1980.

The SFC issued a solicitation for proposals for requests for financial assistance which closed on March 31, 1981. As of June 1981, the evaluation of these proposals was still in progress, and the SFC had not yet made any awards. In Table 1-5, a list of the gasification projects is presented for which aid was requested. As Table 1-5 shows, Lurgi and Texaco technology predominate, and so, on the basis of simple probability, it is these technologies which are most likely to be supported by the SFC. Table 1-6 presents a list of the coal liquefaction projects which requested financial aid. The most common proposals are for plants to indirectly liquefy coal to methanol. Some of the project sponsors intend to catalytically convert the methanol to gasoline. It must be noted that the coal-based projects in Tables 1-5 and 1-6 face stiff competition for SFC funds from oil shale and tar sands based projects.

Table 1-5

Coal Gasification Projects Submitted To The Synthetic Fuels Corporation[a,b]

DEVELOPERS	PRODUCT GAS HEATING VALUE[c]	LOCATION	GASIFIER	SIZE
North Alabama Coal Gasification Project (Originally through TVA)	Medium	Murphy Hill, AL	K-T or Texaco	600×10^6 scf/day
Arkansas Power and Light	Medium	Redfield, AR	Texaco	120×10^9 Btu/day
Texaco and Pacific Gas and Electric	Medium	Monterey, CA	Texaco	225 MW
Texaco, Southern California Edison, EPRI, Bechtel, GE	Medium	Daggett, CA	Texaco	100 MW
Billings Energy Corporation	Medium	Forest City, IA	Texaco	3.1×10^9 Btu/day
Sirco Energy, Bechtel, Cities Service, Conoco, PPG, United Energy Resources	Medium	Lake Charles, LA	Lurgi	125×10^9 Btu/day
Gulf States Utilities, Westinghouse Electric	Medium	Calcasiew, LA	Westinghouse	100 MW

[a]Source: Energy Daily, Volume 9, Number 65, April 3, 1981, pp. 4-8.

[b]Projects submitted to the Synthetic Fuels Corporation for financial assistance during first solicitation, ending March 31, 1981.

[c]High >900 Btu/scf; Medium <900 Btu/scf, but >250 Btu/scf.

Table 1-5 (CONT.)

Coal Gasification Projects Submitted To The Synthetic Fuels Corporation[a,b]

DEVELOPERS	PRODUCT GAS HEATING VALUE[c]	LOCATION	GASIFIER	SIZE
Crow Indian Tribe	High	Crow Reservation, MT	Lurgi	125×10^6 scf/day
Tenneco	High	Wibaux City, MT	Lurgi	280×10^9 Btu/day
Consolidated Natural Gas, Standard Oil of Ohio	High	Pt. Pleasant, WV	BGC/Lurgi	NA
Great Plains Gasification Associates	High	Mercer City, ND	Lurgi	137.5 scf/day
Northwest Pipeline Corporation	High	Beardner, OR	Lurgi	250×10^6 scf/day
City of Memphis	Medium	Memphis, TN	U-Gas	50×10^9 Btu/day
Transco Energy Corporation	Medium	Franklin, TX	Lurgi	125×10^9 Btu/day
Westinghouse Electric Corporation	Medium	Fairmont, WV	Westing-house	2,560 BPD
WYCOAL Gas, Inc.	High	Converse City, WY	Lurgi Texaco	300 Mscf/day

[a]Source: Energy Daily, Volume 9, Number 65, April 3, 1981, pp. 4-8.

[b]Projects submitted to the Synthetic Fuels Corporation for financial assistance during first solicitation, ending March 31, 1981.

[c]High >900 Btu/scf; Medium <900 Btu/scf, but >250 Btu/scf.

Table 1-6

Coal Liquefaction Projects Submitted To The Synthetic Fuels Corporation For Financial Aid[a]

DEVELOPERS	LOCATION	PROCESS	PRODUCTS	SIZE
Cook Inlet Region Co. Placer Amex, Inc.	Granite Point, AK	Lurgi Gasification	Methanol	54,000 BPD
Energy Transition Corp.	Moffat County, CO	KBW	Methanol	50/500 X 10^6 GPY
Coal Fuel Conversion Company, Timbesline Fuels	Trinidad, CO	Ott Direct Hydrogenation	No. 6 Fuel Oil	1,000 BPD
MAPCO	White County, IL	Texaco Gasification Lurgi Methanol	Methanol	35,000 BPD
Clark Oil and Refining	St. Clair County, IL	Mobil	Gasoline	12,000 BPD
W.R. Grace	Henderson, KY	Texaco, Mobil	Gasoline	50,000 BPD
Ashland, Airco	Breckinridge County, KY	H-Coal	Product slate	50,000 BPD
Texaco	Convent, LA.	Texaco	Methanol	3,500 TPD
EG&G	Fall River, MA	Texaco	Methanol, Electricity	758,000 GPD 13,000 MWH/ day
Energy Transition Corp.	Grants, NM	NA	Methanol	50 X 10^6 GPY

[a]Source: The Energy Daily, Volume 9, Number 65, April 3, 1981, pp. 4-8

[b]Projects submitted during solicitation ending March 31, 1981.

Table 1-6 (CONT.)

Coal Liq efaction Projects Submitted To
The Synthetic F els Corporation For Financial Aid[a]

DEVELOPERS	LOCATION	PROCESS	PRODUCTS	SIZE
Energy Transition Corp.	Creswell, NC	KBW	Methanol	156,000 GPD
A.C. Valley Corp.	Lisbon, PA.	Koppers, ICI, Mobil	Gasoline	10,000 BPD
Westinghouse Electric Co.	Cambria and Somerset City, PA.	Westinghouse	Methanol	100,000 BPD
Koppers and Cities Service Corp.	Oak Ridge, TN	KBW, Pullman-Kellogg, Mobil	Gasoline	50,000 BPD
Emery Synfuels Associates	Emery County, UT	Lurgi	Methanol, High-Btu Gas	389 X 10^6 GPY methanol, 22.7 X 10^9 SCF Gas
Hercules, Inc., Norfolk and Western Railway, United Coal Co.	Montgomery County, VA.	Mobil	Gasoline	23,000 BPD
World Energy, Inc.	Wyoming	Underground Gasification	NA	NA
Kaneb Service Co., Koppers Co., Northwestern Mutual Life Insurance	Gillette, WY	KBW, Lurgi, Mobil	Gasoline	19,377 BPD

[a]Source: The Energy Daily, Volume 9, Number 65, April 3, 1981, pp. 4-8
[b]Projects submitted during solicitation ending March 31, 1981.