5.0 ECONOMICS

The most important key to early and successful commercialization of coal conversion is estimated product cost. Accurate technical and economic data are required for development of good product cost estimates for commercial plants.

The best available cost estimates for the various processes came from many different organizations with significant differences in experience and interest. Most of the cost studies were done for DOE by private firms. In general, manufacturing companies who may someday be in the business of owning and operating coal conversion plants tended to have "safer" costs than contractors who hope to construct the plants.

The details of each cost study were examined and evaluated. To the extent necessary to achieve consistency, component costs were adjusted as described below. The new cost components were used for product cost determination.

The basic conversion plant in this study has a coal feed rate of 25,000 tons/day of dry coal with a heating value of 11,200 Btu/lb-dry. Electric power is generated within the plant by burning coal when the waste heat recovery systems are unable to provide the full power requirement. For processes where the product slate could be varied, optimization was based on maximum products energy. An operating factor of 0.9 was assigned (328.5 operating days per year).

The product cost for a plant averaged over a particular time - usually a year - is the total cost attributed to that time period divided by the energy content of the products made during that time period. (See Equation 5.2)

To actually apply this simple relationship requires the specification of many parameters relating to time, capital and operating costs. These are summarized here and explained further in Appendix 2.

All cost estimates in this study use the same financial parameters. Costs results are presented in constant mid-1979 dollars with no assumptions as to further inflation. As has been the case in the past with many other kinds of new industry, particularly where sophisticated processing is involved, the relationship between cost for a subsequent plant and general inflation trends or established cost indices is uncertain. Inflation effects are discussed in Appendix 3.

The data needed to determine product cost is conveniently described in four sets:

1) Coal cost
2) Operating cost
3) Capital cost
4) Products

5.1 COAL

The amount of coal required for the basis plant would be greater than the outputs for most single existing mines in the U.S. In many parts of the U.S., 25,000 tons/day would be large for a new mining development and several mining projects would be required to supply this rate. Such considerations require site-specific studies. This report is based on a coal price of $\$1.00/10^6$Btu delivered to the plant. This cost is nominal for mid-1979. All calculations for product prices are easily redone for any other assumed coal prices.

5.2 OPERATING COST

All other costs required, in addition to the cost for purchase of coal, are grouped as operating costs. These include labor, consumable supplies, maintenance, fees and taxes. Labor is determined by estimating total people required and pay scales. Maintenance, operating fees and taxes are commonly estimated as a percentage of total capital investment. The actual percentage used in determined by experience and related to both the activity and location. This estimate is shown in Appendix 2.

5.3 CAPITAL COST

A total capital investment for each process is required to allow a product cost to be calculated. After studying the capital cost estimates available for each process, the information judged best from various sources was used as a start for the capital cost shown in Table 5.1. Plant size was adjusted where necessary by the use of a capital cost-to-plant size exponential rule commonly used by estimators:

$$\frac{C_2}{C_1} = \beta^{\gamma} \tag{5.1}$$

Equation 5.1 is recognized in many handbooks as a generally accurate relationship for capital requirements for many types of manufacturing plants. β is the capacity ratio. The value for the exponent γ depends upon the type of equipment and size limits for single production units. Where a single system is changed in capacity a value of 0.65 was used. Where capacity is changed by varying the number of multiple-parallel units, a γ equal to 0.90 was used.

Among unit operation categories, equipment costs were put on a consistent basis by checking unit costs wherever they could be identified. Unit costs are usually given as $/ft^2 for heat exchangers, $/BHP for compressors, $/lb for pressure vessels, $/Btu for fired heaters, etc. Private sources and established vendors were used to check unit costs, recognizing that these values depend strongly on size and materials of construction.

The capital costs in Table 5.1 are bare plant costs without the auxiliaries such as buildings, paving, utility requirements, etc., required for an integrated plant. A factor of 1.63 was developed from a group of cost studies for coal conversion plants to cover the auxiliaries and also provide a 10% contingency for capital investment. This multiplier was applied to the base plant costs to give total plant investment for each process in 1979$.

Table A in Appendix 2 shows the total capital investment required for a basis plant for each of the processes studied. This investment is considered realistic for some later plant after operating experience is obtained. The first two or three plants for each process will very likely cost more.

The financial parameters which relate to cost for capital are shown in Table 5.2. This is the set of values recommended by the ESCOE Costing Guidelines (Ref. 27). The working capital requirement is included in the 1.63 factor described above. No special allowances are made for plant start-up cost. These extra costs can be handled in several different ways but the effect on product cost is negligible.

5.3.1 Utility Financing

Because some of the coal conversion plants considered here may be suitable for ownership by utilities, the possibility of utility financing is included. This gives a product cost advantage since there are lower effective costs for capital. The prospects are better at present for utility rather than private ownership of coal conversion plants because a utility has a more assured chance for full recovery of plant costs.

5.3.2 Private Financing

A normal business environment for project financing does not now exist for large-scale coal conversion. Estimated product prices are not competitive with world market prices for petroleum products and natural gas. Uncertainties of the world petroleum market and of Federal government regulations raise other doubts.

It appears unlikely that any private company will try to launch a coal liquefaction plant on any significant scale without some government support or mandate such as the following:

1) Federal loan guarantee for the debt portion of the financing.
2) Additional investment tax credits.
3) Price support or product subsidy.
4) Mandated reduction of imports or blend of non-petroleum fuels.

Table 5.1: PLANT CAPITAL REQUIREMENTS
Major On-Site Plant Cost in Millions of mid-1978$

Category / Process	SRC-I	SRC-II	EDS	H-FO	H-Syn	FT	M	CO_2Acc Hi Btu	CO_2Acc Low Btu	HyG	BIG	Synth	LUR	CE	WEST	WEST SYN
Major Source Ref.	(18)	-	(5)	(2)	(2)	(19)	(12, 20)	(17)	(17)	(1)	(1)	(10)	(1, 17)	-	(21)	-
Coal preparation	63	63	63	84	84	63	63	90	90	63	63	63	90	63	63	63
H_2 or gasification	152	253	190	138	158	228	228	175	176	169	170	-	143	169	157	53
O_2 plant	84	129	-	67	87	117	175	-	-	57	99	99	114	-	-	80
(T/D)	(6,800)	(13,000)	-	(5,400)	(7,200)	(11,070)	(12,000)	-	-	(4,620)	(8,350)	(8,350)	(10,000)	-	-	(16,000)
Gas shift	-	-	-	30	35	-	40	56	58	41	56	56	30	-	-	-
Acid gas & sulfur plants	60	60	60	57	57	57	57	160	160	120	120	120	136	72	48	57
Reactor section	160	195	180	140	210	55	106	60	0	64	46	60	90	-	-	-
Conversion	-	-	-	-	-	100	75	10	10	-	-	38	20	332	312	42
Gas plant	107	30	-	30	25	25	10	-	-	-	-	12	-	-	-	-
Flexicoker	-	-	160	-	-	-	-	-	-	-	-	-	-	-	-	-
Pollution systems	44	44	44	40	40	40	40	44	44	44	44	44	55	44	44	24
Solvent Hydro. or catalyst prep.	-	-	82	-	-	3	-	40	40	13	14	12	-	-	-	-
Compression	-	-	-	-	-	-	-	30	0	30	-	30	28	98	30	-
TOTAL:	670	774	779	586	696	688	744	665	578	601	612	534	706	778	654	421

Notes:
1. M includes HF Alkylation
2. Some EDS cost included in Flexicoker
3. SRC-I includes filtration
4. All costs shown above are considered bare cost and have not been confirmed with process developers. These costs contain no contingencies or required supporting facilities.
5. See Section 1.2 for process abbreviations.
6. Some liquefaction processes use oxygen to produce hydrogen.

TABLE 5.2

FINANCIAL ANALYSIS PARAMETERS
FOR THE BASE CASES

Sponsor: A large investor-owned firm. Capable of financing project and claiming tax credits as they occur.

Dollar Method: Then-Current Dollars.

Dollar Date for Base Year Estimate, 1979

Schedules	Time, Years	
Construction	4	
Operations	20	
Retirement	(Instant)	
Construction Expenditure Rate (% year)	9/-4,25/3,36/-2,30/-1	
Plant Start-up Efficiences (% each year)	50/1,90/2,100/3, etc.	
Type of Firm	UTILITY	PRIVATE
Discount Rates (% per year)		
Debt Financing	10	10
Equity Financing	17	17
Financial Structure		
Debt (% total)	65	40
Equity (% total)	35	60
Escalation Rates (% per year)		
General Rate	7	7
Depreciation Methods		
Tax Life (years)	15	15
Method	SYD	SYD
Tax Rates and Schedules		
Effective Income Tax Rate	0.50	0.50
Federal Income Tax Rate	0.46	0.46
Effective Investment Tax Credit Rate (ITC), %	9%	9%
ITC Claim Schedule & year, % of investment	Year of Occurence	
Income and Other Tax Credit	Year of Occurence	
Capital Factor	.081	.115

5.4 PRODUCTS AMOUNT

The fourth and last data set required to calculate product cost is the amount of product produced by the plant. The assignment of an operating factor together with the daily outputs of products for each process (shown in Table 4.5) and the product specifications (given in Appendix 1) allow calculation on an annual basis for product quantities on both an energy and volume basis.

All the product quantities used together with the individual costs described above are shown in Table A of Appendix 2.

5.5 PRODUCT COST

The equation for product cost is expressed as:

$$P = \frac{F + M + kC}{G} \qquad (5.2)$$

where:
- P = Product cost in \$/million Btu
- F = Annual fuel cost in \$
- M = All other operating costs in \$/year
- k = Capital factor
- C = Total capital investment
- G = Millions of Btu in product heating value produced in a year

The data from Table 5.2 give values for k of 0.081 for utility financing and 0.115 for private financing. The derivation of these values is described further in Appendix 2. Using equation 5.2, all product costs on an energy basis were calculated and are shown in Table 5.3. This table also identifies the fraction of product cost attributable to feed coal, capital, and other operating costs.

The reference product price, P_r, was defined in Section 2.3.3 as:

$$P_r = \frac{F + M + kC}{\Sigma\, f_i\, B_i} \qquad (2.3)$$

Table 5.3: PRODUCT COST - ENERGY BASIS

Process	Type of Financing			
	Utility		Private	
	$\$/10^6$Btu	F/C/M (%)	$\$/10^6$Btu	F/C/M (%)
SRC-I	3.38	56/20/24	3.67	52/26/22
SRC-II	3.62	53/22/25	3.95	49/28/23
EDS	3.96	52/22/26	4.32	48/28/24
H-Coal - Fuel Oil	3.30	59/18/23	3.56	55/24/21
H-Coal - Syncrude	3.58	55/20/25	3.89	50/27/23
Fischer-Tropsch	4.99	55/21/24	5.41	51/27/23
M-Gasoline	4.84	53/21/26	5.26	48/28/24
Methanol	4.37	54/21/25	4.76	50/27/23
HYGAS	3.45	59/19/22	3.72	55/25/20
Synthane	3.46	61/18/21	3.72	58/23/19
CO_2 Acceptor - SNG	3.55	56/20/24	3.85	52/26/22
LURGI	3.89	56/21/25	4.22	50/27/23
BIGAS	3.62	59/19/22	3.91	54/26/20
CO_2 Acceptor-SYNGAS	2.79	63/19/18	3.01	58/25/17
Westinghouse-SYNGAS	2.42	66/15/19	2.57	62/20/18
Westinghouse	6.12	57/20/23	6.64	53/26/21
CE	6.08	53/22/25	6.65	48/29/23

Note: Costs fractions are: F = Coal
C = Capital
M = Operating and Maintenance

The calculated reference product costs for premium gasoline as the reference fuel are shown in Table 5.4 with utility financing. Costs using the product value technique are also shown on these tables in common market units. Table 5.5 shows comparable costs with private financing.

The purposes for using the product value technique are:

1) ranking the processes on a value-of-product basis
2) reasonably allocating costs to individual products for multi-product plants

5.6 COST COMPARISON

The costs for product shown in Tables 5.3, 5.4 and 5.5 are grouped by major product category. Comparisons within groups and between different kinds of products both have significance. No single process shown is expected to be the complete answer to future fuel requirements. There are now and will continue to be needs for all of the energy forms shown.

The cost on an energy basis ($\$/10^6$ Btu) as shown in Table 5.3 is not sufficient to compare the various processes. This is because there are several types of products from some processes and the products have value in the market place which are not related to heating value alone. This is the primary reason the product value technique has been used in this study. If the processes are ranked in order of energy costs and reference product prices, the order will vary within groups depending on which method is chosen. This emphasizes the need for making process comparisons using a basis as detailed and specific to the particular need as possible. Capital cost estimates are always more accurate if they are site-specific. Product cost is affected by capital cost and many other inputs. In addition, the reference product price depends on prices expected for all products.

As indicated earlier, confidence or accuracy assigned to most product costs shown in this report are fairly low. The subject of cost sensitivity is discussed in Appendix 3.

Table 5.4: PRODUCTS COSTS - VALUE BASIS WITH UTILITY FINANCING

Process	Product	Cost	Energy Cost $/10^6 Btu	Reference Price $/10^6 Btu
SRC-I	SRC Solid	106.72 $/Ton	3.38	6.67
	Fuel Oil	23.53 $/Bbl		
SRC-II	LPG	19.23 $/Bbl	3.62	5.59
	Naphtha	23.84 $/Bbl		
	Fuel Oil	19.72 $/Bbl		
	Gas	5.59 $/10^6 Btu		
EDS	Propane	18.66 $/Bbl	3.96	5.40
	Butane	20.22 $/Bbl		
	Naphtha	23.03 $/Bbl		
	Fuel Oil	19.05 $/Bbl		
	C2 - Gas	5.04 $/10^6 Btu		
H-Coal Fuel Oil	Naphtha	21.70 $/Bbl	3.30	5.09
	Fuel Oil	17.96 $/Bbl		
	Gas	5.09 $/10^6 Btu		
H-Coal Syncrude	Naphtha	20.51 $/Bbl	3.58	4.81
	Fuel Oil	16.97 $/Bbl		
	Gas	4.81 $/10^6 Btu		
Fischer-Tropsch	Gasoline	24.84 $/Bbl	4.99	5.52
	LPG	18.99 $/Bbl		
	No. 2 Oil	23.54 $/Bbl		
	Fuel Oil	19.47 $/Bbl		
	Med Btu Gas	5.52 $/10^6 Btu		
	C2 - Gas	5.52 $/10^6 Btu		
M-Gasoline	Gasoline	24.55 $/Bbl	4.84	4.91
	LPG	16.89 $/Bbl		
Methanol	Methyl Fuel	11.33 $/Bbl	4.37	4.54
	Methanol	12.26 $/Bbl		
HYGAS	SNG	3.51 $/10^6 Btu	3.45	3.51
	Naphtha	14.97 $/Bbl		
Synthane	SNG	3.58 $/10^6 Btu	3.46	3.58
	CHAR	26.92 $/Ton		
CO_2 Acceptor	SNG	3.55 $/10^6 Btu	3.55	3.55
LURGI	SNG	3.95 $/10^6 Btu	3.89	3.95
	Tar Oil	16.79 $/Bbl		
	Naphtha	16.84 $/Bbl		
BIGAS	SNG	3.67 $/10^6 Btu	3.62	3.62
CO_2 Acceptor	SYNGAS	2.79 $/10^6 Btu	2.79	2.79
Westinghouse Syngas	SYNGAS	2.42 $/10^6 Btu	2.42	2.42
Westinghouse	Electric Power	6.14 $/10^6 Btu	6.12	2.35
		2.1 ¢/kWh		
C-E	Electric Power	6.08 $/10^6 Btu	6.08	2.34
		2.1 ¢/kWh		

Table 5.5: PRODUCT COSTS - VALUE BASIS WITH PRIVATE FINANCING

Process	Product	Cost	Energy Cost $/10^6 Btu	Reference Price $/10^6 Btu
SRC-I	SRC Solid	115.68 $/Ton	3.67	7.23
	Fuel Oil	25.51 $/Bbl		
SRC-II	LPG	20.98 $/Bbl	3.95	6.10
	Naphtha	27.28 $/Bbl		
	Fuel Oil	21.52 $/Bbl		
	Gas	6.10 $/$10^6$ Btu		
EDS	Propane	20.36 $/Bbl	4.32	5.89
	Butane	22.06 $/Bbl		
	Naphtha	25.11 $/Bbl		
	Fuel Oil	20.78 $/Bbl		
	C2 - Gas	5.89 $/$10^6$ Btu		
H-Coal Fuel Oil	Naphtha	23.37 $/Bbl	3.56	5.48
	Fuel Oil	19.33 $/Bbl		
	Gas	5.48 $/$10^6$ Btu		
H-Coal Syncrude	Naphtha	22.26 $/Bbl	3.89	5.22
	Fuel Oil	18.42 $/Bbl		
	Gas	5.22 $/$10^6$ Btu		
Fischer-Tropsch	Gasoline	26.96 $/Bbl	5.41	5.99
	LPG	20.61 $/Bbl		
	No. 2 Oil	25.54 $/Bbl		
	Fuel Oil	21.13 $/Bbl		
	Med Btu Gas	5.99 $/$10^6$ Btu		
	C2 Gas	5.99 $/$10^6$ Btu		
M-Gasoline	Gasoline	26.70 $/Bbl	5.26	5.34
	LPG	18.37 $/Bbl		
Methanol	Methyl Fuel	12.36 $/Bbl	4.76	4.95
	Methanol	13.37 $/Bbl		
HYGAS	SNG	3.79 $/$10^6$ Btu	3.72	3.79
	Naphtha	16.16 $/Bbl		
Synthane	SNG	3.84 $/$10^6$ Btu	3.72	3.84
	CHAR	28.88 $/Ton		
CO_2 Acceptor	SNG	3.85 $/$10^6$ Btu	3.85	3.85
LURGI	SNG	4.29 $/$10^6$ Btu	4.22	4.29
	Tar Oil	18.23 $/Bbl		
	Naphtha	18.29 $/Bbl		
BIGAS	SNG	3.91 $/Bbl	3.91	3.91
CO_2 Acceptor	SYNGAS	3.01 $/$10^6$ Btu	3.01	3.01
Westinghouse Syngas	SYNGAS	2.57 $/$10^6$ Btu	2.57	2.57
Westinghouse	Electric Power	6.63 $/$10^6$ Btu	6.64	2.55
		2.3 ¢/kWh		
C-E	Electric Power	6.66 $/$10^6$ Btu	6.65	2.56
		2.3 ¢/kWh		

Comparing product costs based on conceptual plant designs serves as neither a promise nor a guarantee for the future. It is a useful and necessary exercise in R&D planning. Planning and estimates have their limits and to proceed beyond these limits, operation of demonstration plants at meaningful rates is necessary. Recognizing that more than a dozen independent variables are required to determine a product cost and that fiscal parameters change rapidly during times of high inflation rate helps one understand why so many different costs are often claimed for the same process.

6.0 COMMERCIALIZATION PROSPECTS

The goal of Federal efforts is commercialization of all appropriate coal converson processes. Some of the impediments to commercialization have been touched upon above. Additional particular considerations follow.

6.1 COMMERCIAL COMPATIBILITY

Ideally, for retrofit applications, the fuel products derived from coal should be completely interchangeable and miscible with the fuels they are replacing. In addition, for all fuels, sulfur and other regulated emissions should be within legal limits without use of flue gas scrubbing. At this time, these requirements can be met by the coal-derived products. A remaining question involves liquid miscibility because certain of the heavy coal liquids produce small amounts of sediment when mixed in certain proportions with petroleum products. This is not a major impediment and several solutions are available. The solutions include segregating fuels and avoiding critical proportions when blending.

Gas fuels from coal would find ready applications if their cost was truly competitive with fuel now being used. All processes described are considered to be for base load applications.

6.2 SOCIAL COMPATIBILITY

One of the primary, if not controlling, goals of the nation's technical and economic system is to provide each citizen with the highest possible standard of living which can be achieved in an environmentally acceptable manner. The development and commercialization of coal conversion technology can assist in meeting that goal. However, the production of significant quantities of products would require the creation of a totally new industry. Demographic shifts, triggered by the need to develop coal resources and build and operate converson plants in hitherto sparsely populated regions, will create the need for new social, governmental and economic infrastructures.

The social problems arising from commercialization of coal conversion technology are not greatly different among any of the proposed technologies. The problems of coal mine development may be more obvious in the Western coal fields where little industrial development has occured. But expansion of mining operations in the historic regions of Appalachia and the Midwest will also precipitate social displacements and will require careful planning. Construction of vast coal conversion plants will necessitate temporary employment of large numbers of construction workers, sometimes at remote sites with inadequate educational facilities and few social amenities. Local governments may find it difficult to provide social services for a transitory activity when the tax revenues may not be available until plant construction is completed and operations started.

After mine and plant operations have commenced, many of the social problems will be greatly reduced or eliminated. Assuming conventional taxation for coal mining and conversion facilities, the revenues will help fund the necessary programs and facilities needed to maintain a socially acceptable working and living environment. Careful attention to environment control systems will assure minimum environmental intrusion by the facilities.

There are positive social benefits as well. Payrolls, improved rail and highway transportation systems, upgraded educational facilities, and broadened cultural opportunities are some of the more evident and realizable social benefits.

6.3 UTILITY APPLICATIONS

The gas and electric utilities in the United States have shown an interest in commercializing coal conversion technology. Dwindling gas resources have led gas companies to seek supplemental gas supplies from foreign suppliers and to develop marginal natural gas resources which previously were considered uneconomic. Electric utilities have had to find clean fuel replacements for fuel oil and natural gas. A keystone of national energy policy is increased use of coal. The larger utilities have the technological capability, the economic and reliability incentives together with the capacity to commercialize emerging coal conversion technology when conditions determine this to be their best choice.

The first commercial high-Btu gas plants are likely to be jointly funded by several gas companies. The gas would either be shared equitably among all of the participants or sold to an adjacent interstate pipeline. The national high pressure pipeline network is sufficiently integrated to allow any pipeline company to receive gas either by direct delivery or by displacement. The high-Btu gas would be fully interchangeable with natural gas so it could be injected into the pipeline system in any proportion. The mixture would be indistinguishable from conventional natural gas except for a slight, though tolerable, reduction in heating value in some instances. It would be transported and marketed through the same facilities and in the same manner as natural gas. A local distribution company could build and operate a high-Btu gas plant but only a few of the very largest utilities require the continuous output of an economic size plant.

Low and intermediate industrial fuel gas plants also offer gas utilities the opportunity to extend existing gas supplies. It is necessary to segregate those gases from normal systems. In the future, industrial customers, in a limited geographical region, may be able to purchase industrial fuel gas from their local utility to replace natural gas. The natural gas thus released would be available for other customers. Utilities can provide the capital, technical capability and marketing knowledge needed to develop a single or multiple customer supply system. Geographical dispersion of customers is limited by transportation economics. A balance must be struck between the savings from large central plant operations and the cost of transporting gas. Some industrial customers may be able to justify an economically sized plant solely for their own needs, in which case the utility could provide technical and engineering services or could own and operate the plant for the industrial user.

Electric utilities see coal conversion technology as a possible means of utilizing high sulfur coal. Solid, liquid and gaseous fuels have been considered for electric utility applications. Gaseous fuels may be used in a gas turbine/steam turbine combined cycle unit with higher overall generating efficiency. Gaseous fuels have a limitation in electric utility applications - they are difficult to store. Therefore, the gasification system must have good load following capability. Also good efficiences are desirable at both part load and full load. Liquid fuels or solid fuels, on the other hand, can be stored so the conversion plant can operate at full capacity for best economy, while the power generating unit follows the electric load demand.

Combined cycles offer the possibility of higher fuel efficiency, lower generating costs and improved system performance. Because of the inherent high efficiency, combined cycle systems would be used for base load, insofar as possible. However, it is desirable that they too have good load following and turn-down capability.

6.4 TIME REQUIREMENTS

For a pioneer plant of significant size, meaning a feed rate of at least 6,000 tons/day of coal, the design and field construction time for the prototypes will require at least three years. This includes no allowances for unusual weather conditions, geographic or legal obstacles. The same process in a larger unit could easily require five years.

Time is an important dimension in project economics. Any real project financial schedule must include all time considerations for construction and start-up. Construction and start-up delays cause permanent increases in product cost.

6.5 CONSTRAINTS ON COMMERCIALIZATION

Commercialization constraints may be generally classified in five categories: technical, economic, financial, institutional and social. Institutional constraints include limits imposed by Federal, state and local regulations. Social constraints include both demographic limits on availability of manpower and environmental requirements which limit available sites. There are strong interactions between many of the constraints. For example, the institutional constraints on product price may limit the availability of capital.

Technical constraints on commercialization of coal conversion relate primarily to the state of development. Only a very few of the conversion processes have been operated on a full commercial scale. Some may not perform well with all U.S. coals. Pilot plant and larger-scale tests of gasification and liquefaction systems have been integrated with auxiliary functions to demonstrate the technical feasibility and operability of several of the processes. But uncertainty still exists and there are needs for performance assurance which can only be resolved in a true commercial-scale operation. All unresolved risks impede commercialization. Equipment builders are sometimes reluctant to provide performance guarantees. Potential customers are unwilling to enter into long-term contracts when both reliability of service and cost are uncertain. Numberous methods of risk sharing, such as loan guarantees, firm purchase prices and tax incentives, have been proposed. Some method of reducing the risk and improving the return on unproven technology during the early stages of industry development is essential if the concepts now being developed are to be commercialized.

Economic impediments are related both to technical and market risk. The costs for coal-derived fuels will be significantly higher than conventional fuel today. Customers are uncertain about the future cost of energy. It seems clear that future costs will be higher and availability of conventional oil and gas less. The economic constraint on commercialization of coal-derived fuels is more complex than the simple belief that a coal conversion industry will suddenly become viable when the price for petroleum rises to a predetermined cost. The implication that such a situation exists, given in many cost studies of the past, has damaged the credibility of the technical community.

In "Barriers to Commercialization" presented at the Coal Dilemma II Symposium in February 1979, R. F. Hill made reference to the "receding break-even point". The concept that the conceptual cost for coal-derived fuels is some undefined function of the cost of oil is well supported by a study of conventional fuel prices and estimated clean manufactured fuel prices over the past decade. The increases in estimated cost for coal-derived fuels are significantly greater than the corrections required for inflation. Any uncertainty that a project will "break even" serves as an absolute barrier even though such uncertainty may not be apparent to the public.

The most evident impediment to commercialization has been the difficulty in financing commercial projects. Utility financing has traditionally included a large proportion of debt funding. This reduced the cost of capital and thereby reduced the cost of utility service. But in order to maintain reasonable debt/equity ratios, utilities must now raise billions of dollars of both debt and equity capital if they are to finance coal conversion facilities. A single facility could represent a majority of the capitalization for many companies. Thus they would need to form joint ventures or find other means for reducing their financial exposure.

Lending institutions require assurance, through assured cost recovery from ratepayers, loan guarantees or other risk minimizing devices, that debt costs will be recovered. The alternative to some form of assurance to the bondholders is additional equity capital, or a higher interest rate for debt capital. Either alternative could significantly increase the project and product costs.

Institutional constraints are manifested primarily in the regulatory problems encountered. The multiplicity of government permits required has increased the problems of siting and planning coal conversion facilities.

Social and environmental implications must be carefully considered. The coal conversion inudstry will create massive new production centers which, if not carefully planned, could create social and environmental disturbances. There will be some areas which cannot tolerate even carefully planned developments. The screening process, which assures problems will be avoided, is time consuming and, for the near term, has caused delays in commercialization. As planning techniques improve and guidelines for siting of energy facilities develop, many of the delay causes can be eliminated.

6.6 REGULATORY PROSPECTS

The coal conversion industry and the companies which participate in the construction and operation of coal conversion facilities will be faced with several types of government regulation at Federal, state and local levels. At the Federal level, regulation will primarily be concerned with the siting, pricing and safety of plants producing substitute gas which will be transported in the interstate pipeline network. State regulators will concern themselves with the siting and environmental impact of facilities which serve markets wholly within a state, while local jurisdictions will deal with siting and land use impacts of facilities. Although jurisdictional limits are not clearly drawn, it appears the Federal agency with primary authority for approval of the construction of facilities and sale of SNG will be the Federal Energy Regulatory Commission (FERC). Electricity production and pricing regulation will fit into the historic pattern of FERC regulation of interstate sales and state regulation of intrastate operations.

6.6.1 SNG Regulation

Federal authority to regulate the transportation of SNG is based on the Natural Gas Act which requires the FERC to regulate facilities and rates for the transportation of natural gas and mixtures of natural gas and substitute gas (SNG) in interstate commerce. If the gas from a gasification process is sold wholly within the state where it is manufactured and is not mixed with interstate gas, the FERC would not be involved. This is likely to be the case for medium and low-Btu gas. However, for high-Btu gas production, if it is mixed with natural gas for interstate sale the FERC regulates the price of the gas and the rates charged for transportation of the gas to consumers. At present, in order to construct a high-Btu gas plant the builder must submit extensive technical, economic, environmental and financial data to the FERC. Public hearings are held to allow all interested parties to submit information in support of, or in opposition to, the proposed plant. A major concern has been the length of time required for the hearing procedure. The principle issues which are evaluated by the FERC are:

- Technical feasibility of the process. Has it been commercially proven? What is the possibility of technological failure or obsolescence?
- Economic feasibility. Will the plant design result in the minimum cost for safe, reliable and environmentally acceptable operations?
- Financial feasibility. Is the proposed financing plan sound? Will it result in the lowest reasonable cost to the purchasers of the gas?
- Environmental feasibility. Will the plant have minimum impact on the environment? Are the proposed environmental safeguards adequate?
- Impact on ratepayers. How will the construction and operating costs be shared by the ratepayers? Will the cost of the gas be "rolled in", that is, averaged with all other gas sources, or will the gas be sold under incremental rates to certain groups of customers?

Based on the voluminous documentation provided by both advocates and opponents of the plant, the FERC issues a decision which either denies the application or grants the company the right to sell SNG in interstate commerce under fixed contractual conditions. The initial sale price, escalation allowances, price adjustment for part load operation and other price modifications are controlled by the initial authorization. The SNG may also be subject to proposed incremental pricing rules which would shift most of the higher costs to lower priority users.

Construction and pricing of high-Btu utility gas from wholly intrastate facilities are the responsibility of the state utility regulatory agency. Most states exercise only limited authority through the setting of rates for utility service. Preconstruction authorization is not required in many states but the sale price for gas is normally scruntinized to assure that the costs are reasonable.

Regulatory authority over intermediate and low-Btu gas plants has not been clearly defined. If the product gas is sold to a number of customers solely by the producer or sold to a small number of customers in a limited area, utility type regulation may not be applicable. But regardless of the utility regulatory stance, environmental regulations will still apply. A combined gas/electric plant poses a special situation. A portion of the product gas might be sold directly to users while the balance is used for power generation. Even though the direct sale of gas may not be regulated, the price of the gas to the electric utility would almost certainly be regulated by state authorities.

6.7 ENVIRONMENTAL IMPACT

Coal conversion facilities will create stresses on the environment. The industry will cause changes in the social and physical environment which must be recognized. Potential changes must be understood and actions taken to minimize the impact. The social effects have already been discussed in Section 6.2. The industrial and commercial infrastructure needed to support the new industry will itself spawn many environmental effects. The current developmental effort is structured to identify potential environmental problems and to develop effective means of making the processes environmentally acceptabe. With this complete systems approach to solving the problems as they are created, ultimate acceptance of the industry should be accelerated.

The environmental problems of coal mining are not unique to the coal conversion industry. As the nation's use of coal for power generation and industrial applications grows, the concerns will increase. The rapid evolution of a gasification and/or liquefaction industry could increase the scope of the problems. Surface mining to utilize the large Western coal deposits will require an irreversible commitment of the natural resources underlying extensive areas previously used only for limited agricultureal purposes. Land reclamation is vital to avoid permanent loss of this natural resource. Mine drainage water and fugitive dust can create both nuisance and health hazard problems unless carefully controlled. Deep mining of Eastern coals for conversion facilities may result in less visible effects, but it can result in land subsidence which would affect the value of surface land. Mine drainage and downstream contamination of water supplies is a problem unless careful water control practices are followed. Surface facilities such as cleaning plants and storage and loading areas could also create air and water pollution hazards unless carefully controlled. The technology for adequate water, air and land protection exists and strict enforcement laws will minimize the intrusion of mining operation for the coal conversion industry on the environment.

Within the conversion facilities, environmental problems are caused largely by the sulfur and ash content of the coal; the disposition of trace elements in the coal; and handling and disposition of liquid hydrocarbons and waste water streams. Coal storage and handling will create dust and drainage water disposition problems, but careful water management and drainage control should minimize external effects. Coal conversion processes usually operate at elevated pressures so gas streams are carefully contained to minimize product loss and assure process integrity. The processing concentrates the sulfur compounds and makes recovery somewhat easier than from power plant stack gas streams. However, in conversion facilities where some or all of the coal is burned as fuel, stack effluents must be monitored and contamination reduced to within required limits.

Most of the processes which are being considered produce some liquid effluent streams. Liquid handling processes require careful handling procedures to assure that leaks or spills do not occur, or are controlled without environmental damage. Gaseous fuel processes produce by-product streams which may contain phenols and other potentially harmful materials. Contaminated waste water streams must be treated before disposal. Coal contains a wide variety of trace elements including heavy metals. Studies have indicated these materials are discharged from the process either in the ash or foul water streams. Although indications are that the elements in ash are chemically inert and the possibility of leaching into the soil is limited, care must be taken in ash disposal. Wash water treatment can reduce trace elements content of effluent streams to acceptable levels.

Coal conversion plants will create concerns about land use and aesthetics. Plants constructed in areas which previously had little or no industrial development will intrude upon scenic vistas and the coal transportation network may detract from aesthetic values. These impacts can be minimized by careful selection of plant sites which utilize topographical screening. But it will not be possible to avoid all effects when these large facilities are built. In more heavily industrialized areas the aesthetic impacts will be less but still evident.