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Costs To Convert Coal To Methanol

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FOREWORD

This Work Assignment was initiated by the Emission Control Technology Division, Environmental Protection Agency, 2565 Plymouth Road, Ann Arbor, Michigan 48105. The effort on which this report is based was accomplished by the Department of Emissions Research and the Department of Energy Conversion and Combustion Technology of Southwest Research Institute, 6220 Culebra Road, San Antonio, Texas 78284. This program, authorized by Work Assignment 9 under Contract 68-03-3162, was initiated August 18, 1983 and was completed September 28, 1984. The program was identified within Southwest Research Institute as Project 03-7338-000.

This Work Assignment was conducted by Mr. David S. Moulton, Research Engineer and Mr. Norman R. Sefer, Senior Research Engineer. Mr. Chares Hare was Project Manager and was involved in the initial technical and fiscal negotiations and subsequent major program decisions. The EPA Project Officers were Messrs. Robert J. Garbe and Craig A. Harvey of the Technical Support Staff, Environmental Protection Agency.

ABSTRACT

This report provides estimated costs of producing methanol transportation fuel from coal. Estimates were made for mine-mouth plants in five different coal producing regions, and uniform methods were used so the estimated sales prices could be compared for market analysis. In addition to plant-gate prices, delivered prices were estimated for three major market areas. With presently available transportation, the lowest delivered prices were for methanol production based in the southern lignite coal region. If new methanol-compatible pipelines were to be constructed, the lowest delivered prices would be for production based in the western subbituminous coal region. In the western subbituminous region, limited water resources would make extensive planning and careful site selection necessary, but they would not prevent the development of a coal-to-methanol industry. By-product carbon dioxide sales for enhanced oil recovery could reduce the required plant-gate methanol price in some areas near oil fields amenable to carbon dioxide injection techniques.

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I. SUMMARY

Methanol has received considerable attention as a possible future transportation fuel because it can be used in properly designed vehicles, and large amounts could be produced from domestic coal reserves. Coal is mined in many different locations, and the properties of the coal differ from place to place. Mining costs, water availability, climate, and taxes also vary, and as a result, the cost of producing methanol from coal should differ significantly from place to place. In addition, the availability and cost of transportation could make a significant impact on delivered methanol prices. The objective of this study was to use uniform methods to estimate the cost of producing methanol at different coal fields so the estimated sales prices could be compared for market analysis. A rapidly growing market for methanol as a transportation fuel was assumed.

The production of methanol from coal requires three major steps: coal gasification, gas conditioning, and methanol synthesis. Several individual processes are involved in each step and an overall processing scheme was developed for this study by putting together individual processes. Process selections included the Texaco gasification process, the selective SELEXOL® process for acid-gas removal, and the Imperial Chemical Industries (ICI) process for methanol synthesis. The following criteria were used for process selection.

- Commercially available or very close
- Usable on a wide variety of feedstocks
- Economic
- Environmentally sound
- Reliable, low anticipated down time

Methanol prices were estimated for production based on five types of coal, representing five different coal-producing regions. They were eastern high-sulfur bituminous, midwestern high-sulfur bituminous, western subbituminous, southern lignite, and northern lignite coals. Material balances were developed for the major processes based on each coal's characteristics and the process requirements. Then groups of processing equipment, termed 'process modules', were sized based on their throughput. Capital and operating costs were estimated for mine-mouth plants in each of the five producing regions, and credits were taken for by-products where feasible.

Required plant-gate selling prices were calculated for each plant assuming four different discounted-cash-flow rates of return on investment ranging from 10 to 25%.

The lowest plant-gate methanol prices were for production based in the western subbituminous region and in the southern lignite region. In those regions, the price was about \$0.52 to \$0.58 per gallon, depending on coal prices, for 15% rate of return on investment. Prices in the northern lignite region were about \$0.69 to \$0.73 per gallon. Prices for the plants using the high-sulfur coal in the eastern and midwestern regions were \$0.79 and \$0.86 per gallon, respectively. By-product credits for sales of carbon dioxide for use in enhanced oil recovery were found to have a significant effect on the methanol price. For example, without by-product sales the methanol price for production based in the southern lignite region would be \$0.71 per gallon, rather than \$0.55 per gallon with by-product sales credits. Both prices were calculated assuming a 15% rate of return on investment. The prices are based on 1984 dollars. Prices based on 1990 dollars can be obtained by using a 1.328 multiplier on the 1984 dollar prices.

Transportation costs were estimated for moving the methanol from the producing regions to major market areas. Chicago, New York City, and Atlanta were studied as typical market locations. Transportation costs were estimated using two different assumptions: transportation by the least-cost method or combination of methods available in 1984, and transportation by hypothetical, newly-constructed pipelines. The right of eminent domain was assumed for the new pipeline construction. Transportation costs were estimated for the presently available methods based on telephone quotes, and were calculated for newly constructed pipelines using capital and operating cost figures supplied by a pipeline engineering company.

Plant-gate prices and transportation costs were used to determine delivered prices. With presently available transportation, the lowest delivered prices were for production based in the southern lignite region. With newly constructed pipelines, the lowest delivered prices were for production based in the western subbituminous region. Three locations would gain a major benefit from newly constructed pipelines: the western subbituminous and northern lignite producing regions, and the Atlanta market area.

Water availability could be a major restriction on industrial development in arid western regions. An analysis of water costs and availability in this study indicated that with adequate planning and careful site selection, water availability would not prevent the development of a coal-to-methanol industry in the western subbituminous region. Also, a large increase in water cost would make only a slight difference in methanol price. Neither water availability nor other siting limitations were significant problems in any of the other producing regions.

Some of the issues which would affect the delivered methanol prices merit further study. These include the effects of water availability and credits for CO_2 sales which are presented as case studies toward the end of the report. These issues are very site and time-specific. For a particular plant location, a thorough analysis of water availability will be required, particularly in the west, as part of the construction planning and permitting procedures. This will involve the acquistion of additional data and extensive review of federal, state, and local planning activities. Similarly, prior to construction of a plant, a thorough market analysis for CO_2 sales including CO_2 transportation, and technical and economic analyses for its use in individual oil fields should be made. These issues were studied in this report from a general viewpoint and the sensitivity factors are indicative of potential rather than specific results.

II. INTRODUCTION

Methanol may become a major transportation fuel. It can be made from any of several concentrated sources of carbon including conventional hydrocarbon fuels, coal, peat and biomass. The technical problems associated with the use of methanol as a transportation fuel are being widely investigated and it may become a practical fuel for properly designed vehicles. The problems do not appear to be insoluble; no major breakthroughs are required. Because methanol can be made from coal, it could become an attractive domestic alternative to petroleum-derived vehicle fuels. The energy content of our domestic coal reserve is about 100 times as great as our petroleum reserves. The use of our coal reserves to provide methanol vehicle fuel could significantly increase our energy security.

The huge deposits of coal in this country contain several different types of coal. A number of factors which affect methanol production costs are known to vary widely among these coal deposits. These include compositional factors such as sulfur, moisture, and ash contents, and geological factors relating to ease and costs of mining. The availability of water for industrial use is a major issue in arid regions, and markets for by-products differ from place to place. Less important variables include the effects of climate on building costs and differences in state and local taxes.

The delivered costs of methanol are further affected by transportation variables. Some areas with factors favoring low production costs, such as the western low-sulfur coal fields, have no access to inexpensive water transportation and only a very limited local market because of the low population density. Other areas are served by extensive networks of existing product pipelines, but they may not be available for methanol shipment because of high demand for shipping other products, and questions of materials compatability. Newly constructed pipelines built specifically to allow methanol shipments need to be considered for the development of a large-scale methanol fuel industry.

A number of previous studies have been made to determine coal-to-methanol production costs. These have generally been made for specific sites using particular processes and financial assumptions. Each study has had a somewhat different basis, thus it has been difficult to compare the effects on delivered price that would result from locating plants in different parts of the country utilizing locally obtained coal in each plant. The objective of this study is to use uniform methods to estimate the cost of producing methanol at different coal fields. Making estimates on the same basis provides sales prices which can be compared among the different regions for market analysis.

Factored estimate methods based on publicly available studies were used to obtain capital and operating costs. Particular attention was paid to items which were variable by region. The capital and operating costs were used to calculate required selling price for several rates of return on investment. Resources did not allow detailed engineering design and optimization, or construction specifications. However, the methods employed do allow reasonable estimates for delivered methanol costs, and the variations can be assigned to differences among producing regions. Transportation costs were estimated and the delivered prices were used to project development of the coal-to-methanol industry in various coal producing regions, assuming the industry would grow rapidly.

Five types of coal were considered in this study. These were eastern high-sulfur bituminous, midwestern high-sulfur bituminous, western low-sulfur subbituminous, northern lignite and southern lignite. A composition was chosen for each coal generally representative of actual coal samples of the type and locality. The eastern and midwestern coal compositions were intended to represent high-sulfur resources with little chance for utilization in direct combustion, due to increasingly stringent controls on sulfur emissions.

The coal compositions were used to develop material balances for major process modules which were then sized by throughput. Cost estimates were made using literature values for similar process modules, adjusted for inflation and throughput. Offsites, which include land, utilities, administrative buildings, piping, roads, and other improvements which are not a direct part of the production process, were estimated based on process requirements and projected plant employment. Building costs were estimated on a square foot basis utilizing the experience of Southwest Research Institute architects. Operating costs were based on literature values, publicly available statistics, and raw material price forecasts made by SwRI.

Costs of product transportation were estimated using similar procedures. Transportation costs for existing transportation methods were derived from quotes obtained by telephone from several carriers. Costs for newly constructed pipelines were calculated from capital and operating cost estimates for several rates of return on investment. Raw data were supplied by a major pipeline engineering firm which provided consultant services for this part of the project. Both the plant-gate methanol prices and the new pipeline transportation costs were calculated to obtain the required rates of return using the discounted cash flow method.

Siting limitations and by-product sales credits were studied from a general viewpoint. Water availability in the western subbituminous region was the only major siting limitation found. Credits for CO_2 sales for use in enhanced oil recovery were found to have a major effect on the required methanol sales price. Both factors were very site and time-specific and would merit much further study for an individual plant. In addition, the technology for using CO_2 in enhanced oil recovery was developing rapidly and some changes in the potential market were expected. The potential effects that water availability and CO_2 credits could have on the required methanol sales price were presented as case studies.

Plant locations were projected based on lowest delivered cost. Three cities, New York City, Chicago, and Atlanta, representing three major regions of the country, were used for delivery locations. It was assumed that production would rise rapidly to 100×10^6 gal/day and that this total would be apportioned among the three regions in the same ratio as recent gasoline sales.

III. PROCESS DESCRIPTION

The overall processing scheme is shown in Figure 1. The main unit operations, and flow directions for the principal materials and utilities are included. Several criteria were used to select the individual processes:

- o Commercially available or very close
- o Usable on a wide variety of feed stocks
- o Economic
- o Environmentally sound
- o Reliable, low anticipated down time

Gasification

Table 1 lists characteristics of six gasifiers which appear to be applicable to methanol production and which meet the requirements of this study. All are commercial now or could become commercial within five years. The Lurgi and BGC/Lurgi products are high in methane and are advantageous where methane is a desired product. The Shell and Texaco processes are more attractive because of their product distributions and high energy efficiencies.

There are some possible disadvantages of the Texaco process. In the reactor, molten slag contacts the refractory which could lead to early refractory failure. However, this problem was apparently solved during process development. Another possible problem concerns preparation of the lignite feedstocks. The high moisture content of lignites makes grinding difficult and the slurry feed to the gasifier could have too much water. The alternative would be to dry the lignite, but most competing processes require drying anyway so this is not a big disadvantage to the Texaco process. Overall, lignite feeding seems to require special engineering and design work, but problems that might occur were judged to be solvable. The successful start-up of the Texaco gasifiers in the Cool Water Plant has provided additional confidence in this selection.

The Texaco entrained flow process was selected for the coal gasification. It includes the gasification, cooling, ash dewatering, and slag dewatering blocks in Figure 1. Advantages over competing processes include the following:

- o Drying is not required for bituminous or subbituminous coals
- o The high pressure reactor reduces downstream compression costs
- o Steam feed is not required

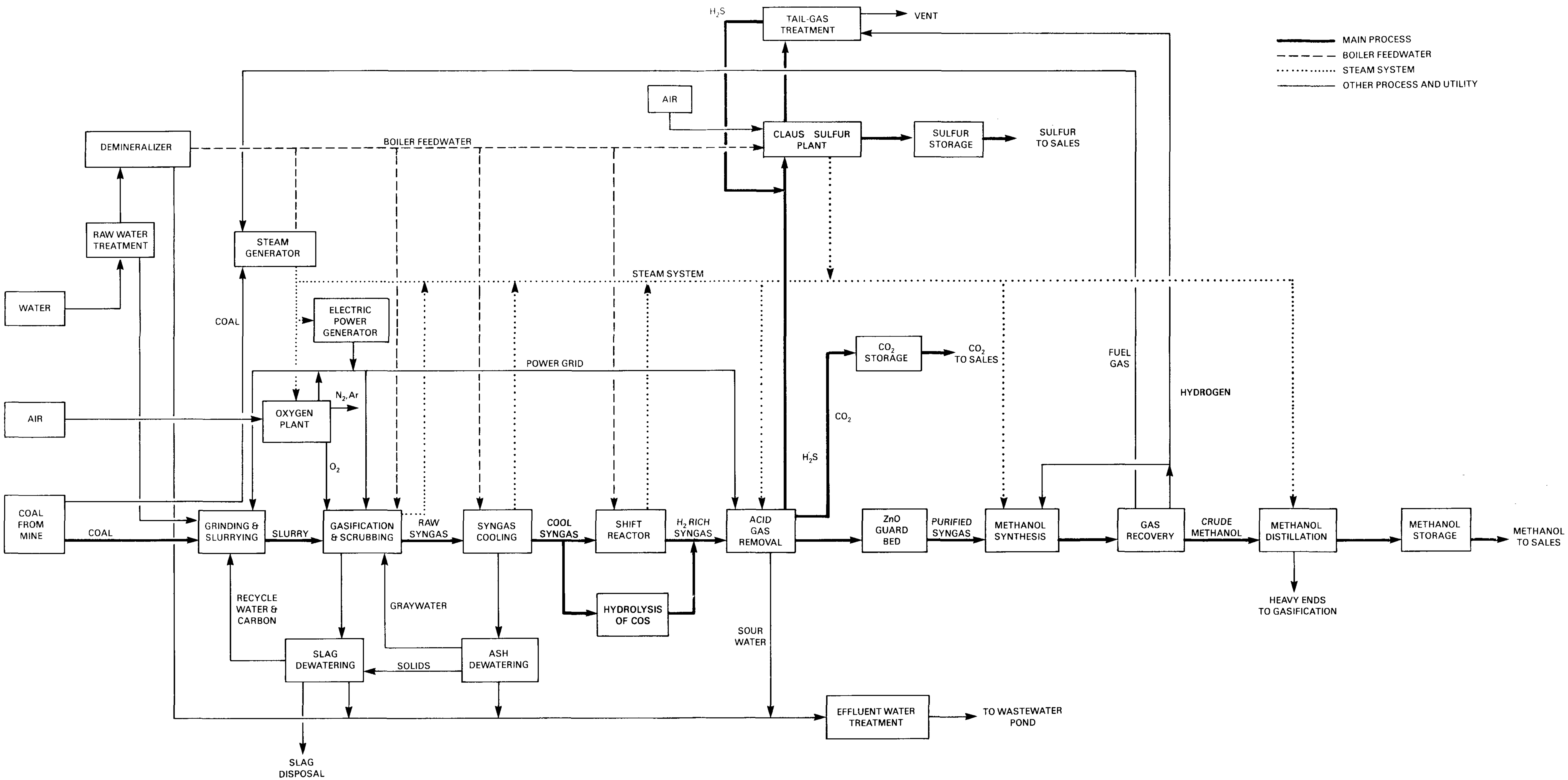

FIGURE 1
FLOW CHART OF COAL TO METHANOL PROCESS SCHEME

TABLE 1.
CHARACTERISTICS OF SOME COMMERCIAL AND NEAR COMMERCIAL COAL GASIFIERS (1-7)*

Gasifier	Lurgi		BGC Lurgi	Koppers-Totzek	Shell	Texaco		Westinghouse
Commercial Status	Commercial		Near Commerical	Commercial	Late 1980's	Cool Water Mid 1984		Keystone in SFC Negotiations
Type of Contact	Fixed Bed		Fixed Bed	Entrained Flow	Entrained Flow	Entrained Flow		Fluidized Bed
Coal Preparation	Dry 2 x ¼ (< 10% fines)		Dry 2 x ¼ (< 35% fines)	Dry < 2% H_2O 70% < 200 M	Dry < 5% H_2O Grind	No Drying Grind H_2O slurry		Dry ¼ x 0
Coal Feed Method	Top Lock Hoppers		Top Lock Hoppers	Screw Conveyors	Pressurized Pneumatic	Slurry Pump		Pneumatic
Solid Recycle	No		Optional	No	Yes	No		Yes
Temperature, ^{o}F	1000-2000		1300-3300	2700	2500	2300		1900
Pressure, psig	350-450		350-450	0	392	690		230
Relative, O_2 feed	n/a		low	high	high	high		low
Relative steam feed	high		low	n/a	None	None		n/a
Slag/refractory contact	No slag		Flux (lowers M.P.)	L.P. steam outside refractory	H.P. steam in wall	Slag contacts the refractory		No Slag
Energy Efficiency								
Cold gas only	80		88	67	80	77		81
Cold gas + hydrocarbons	89		90	67	80	77		81
Including steam	89		90	85	94	95		90
Product Composition, Volume, %								
Hydrogen	39	45	29	36	30	39	35	n/a
Carbon monoxide	17	16	59	52	60	38	48	n/a
Carbon dioxide		31	3.3		2		17	n/a
Methane	9	8.5	8.7	0	0	0.5	0.5	n/a
Other Hydrocarbons, lb per lb of CO_2 free gas		3.9	1.7	0	0	0	0	n/a
Information Source, Reference No.	7	5	5	7	3	7	5	6

* Numbers in parentheses designate references at the end of this report.
n/a Not available

- o Energy efficiency and product gas composition compare favorably
- o There are no size requirements for the coal particles
- o It accepts both caking and non-caking coals

Gas Preparation

Before the synthesis gas can be used in a methanol reactor two major changes must be made in its composition. These are adjustment of the hydrogen to carbon monoxide ratio, and the removal of sulfur compounds. The ratio is adjusted through use of the water gas shift reaction:

$$CO + H_2O \rightleftharpoons H_2 + CO_2$$

Most methanol synthesis reactors require a small amount of CO_2 in the feed, but when coal is used as the feedstock, a large amount of excess CO_2 is produced in the shift reactor and it must be removed to obtain the required synthesis gas composition. Two types of catalysts are available for the water-gas shift reaction; one requires some sulfur in the feed, the other requires a sulfur-free feed. The sulfur-tolerant process was selected because it appears to have less stringent operating requirements. This selection requires placement of the shift reactor ahead of the sulfur removal processes.

While most of the sulfur from the gasifier is in the form of hydrogen sulfide (H_2S), which can be readily removed from the gas stream, some is present as carbonyl sulfide (COS) which is difficult to remove. In the shift reactor COS reacts with water to form hydrogen sulfide:

$$COS + H_2O \rightleftharpoons H_2S + CO_2$$

However, the final hydrogen to carbon monoxide ratio is controlled by by-passing part of the gas stream around the shift reactor. To remove COS from the by-pass stream, a reactor is used which contains a catalyst selective to the COS-water reaction and does not promote the water gas shift reaction. With this arrangement, nearly all the sulfur in the feed to the acid-gas removal section is in the form of H_2S.

There are two types of acid-gas removal processes: selective and non-selective. In non-selective processes, several acid gases, in this case H_2S and CO_2, are removed in a mixture, but in selective processes, relatively concentrated streams of each acid gas are produced. A high H_2S concentration in the stream from the acid gas removal section is advantageous for the later production of elemental sulfur. Also, the growing importance of carbon dioxide in enhanced oil recovery processes makes it a valuable by-product in some areas. The selective SELEXOL® process was chosen for this step.

Elemental sulfur is the desired final form of the sulfur impurities because it is easily handled and is a valuable by-product. Of the available sulfur production processes, the Claus process was selected because of reliability. In the Claus process, part of the H_2S stream is oxidized to form sulfur dioxide (SO_2). The two sulfur compounds react first in a thermal reactor, then in a series of catalytic reactors to form elemental sulfur:

$$2H_2S + SO_2 \rightarrow 3S + 2H_2O$$

The Claus reaction does not proceed to completion; there are still some sulfur gases left over in the tail-gas. The SCOT process, which uses hydrogen to convert the left-over SO_2 back to H_2S, was selected to treat the tail-gas. The H_2S is then separated from the rest of the tail-gas and sent back to the Claus feed.

The available acid gas removal processes do not get the H_2S concentration low enough to prevent damage to the methanol synthesis catalyst. A zinc-oxide absorption bed, or guard-bed, is used to remove the last traces of sulfur before the synthesis gas enters the methanol reactor.

Methanol Synthesis

Several very competitive processes are available for methanol synthesis. The reaction is favored by high pressure; the higher the temperature, the more pressure is required. At low temperatures the reaction rates are too slow. Historically, more active catalysts have been sought to provide an acceptable reaction rate at lower temperatures than used in the previous generation of reactors. This allowed the use of lower pressures with savings in reactor capital cost and in compression energy requirements. For this reason, high pressure processes such as Vulcan Cincinnati were not considered. The Wentworth process is a recent variation of the high pressure processes and several advantages are claimed, but whether these advantages offset the higher compression cost was difficult to determine without using proprietary, commercial scale data and experience. (8-9) Chem System's new liquid phase process was not close enough to commercial demonstration for these purposes. Mitsubishi Gas Chemicals' process is similar to the Imperial Chemical Industries' (ICI) process, but the catàlyst may have a shorter lifetime.

Other major process licensors include Lurgi and Haldor Topsoe. Brief process summaries for their methanol processes were recently published based on information provided by the licensors. (10) Table 2 is a comparison based on these summaries. Both Fluor and Synthetic Fuels Associates (SFA) have compared the ICI and Lurgi process. Fluor(11) found their costs comparable when considering both capital and operating costs. Catalyst life is 3-5 years for each. SFA (12) points out that there are differences in the kinds of utilities required and that they favor ICI's process where utilities are based on coal or gas combustion, but they favor Lurgi's process where utilities are based on steam generation from waste heat boilers. The large number of operating ICI plants, utilities based on coal, and the fact that costs are believed to be comparable were the bases for choosing the ICI process for methanol synthesis.

The ICI process is based on a quench type, catalytic reactor. The reaction between hydrogen and carbon monoxide to produce methanol is highly exothermic causing the temperature to rise out of limits before a very high conversion of the feedstock has been achieved. In ICI's reactor, the feed contacts a series of catalyst beds, and between the beds additional cooled feed is mixed in to bring the temperature back into the proper range. The catalyst is based on copper oxide, but the exact composition and methods of formulation are proprietary. It may contain zinc oxide and alumina or chromia, which are believed to prevent copper oxide crystal growth, because crystal growth reduces the catalyst's useful lifetime. Other processes use different catalysts and have different methods of controlling the temperature.

Coal Properties and Material Balances

Coal properties selected for this study are given in Table 3. The references contain descriptions of coal with similar properties. Calculated material balances for the gasifier and other major process modules are shown in Tables 4 through 9.

TABLE 2. CHARACTERISTICS OF SOME METHANOL SYNTHESIS PROCESSES [10]

	Haldor Topsoe	ICI	Lurgi
Reactor Type	Fixed bed Radial flow	Fixed bed down flow	Tubular
Heat Removal	Heat exchange between stages	cold feed gas, between cat. beds	water jacket for steam
Pressure, psig	700-1000	750-1500	1000-1500
Temperature, ^{o}F	-	400-570	460-520
No. Plants Operating	-	28	14
Plants in Des. or Const.	-	12	7
Size of Plants, Bbl$^{(1)}$/d	-	400-20,000	1200-20,000
Feed and Fuel, 10^6 Btu$^{(2)}$/Bbl$^{(1)}$			
Natural Gas Feed	29.0	29.0	28.2
Heavy Oil Feed	-	31.0	36.3
Coal Feed	-	-	38.7
Electric Power, kWh/Bbl$^{(1)}$			
Natural Gas Feed	1.9	4.4	-
Heavy Oil Feed	-	11.0	-
Coal Feed	-	-	-
Cooling Water Requirements, 10^3 Gal/Bbl$^{(1)}$			
Natural Gas Feed	4.32	2.32	-
Heavy Oil Feed	-	2.93	-
Water Consumption, Gal/Bbl$^{(1)}$			
Natural Gas Feed	26.3	38.2	103
Heavy Oil Feed	-	24.9	83
Coal Feed	-	-	126
Catalysts & Chemicals, \$/Bbl$^{(1)}$			
Natural Gas Feed	-	0.188	0.126
Heavy Oil Feed	-	0.226	0.063
Coal Feed	-	-	0.075

\- Not available
(1) Bbl = barrel or 42 gallons of methanol product
(2) Based on higher heating value

TABLE 3. PROPERTIES OF COALS

Coal Type	Eastern High-Sulfur Bituminous	Midwestern High-Sulfur Bituminous	Western Sub-bituminous	Southern Lignite	Northern Lignite
Coal Moisture Content, %	2.1	12.4	6.39	32.0	36.0
Proximate Analysis (dry basis)					
Vol. matter, %	42.3	39.5	46.48	42.1	45.9
Fixed carbon, %	49.0	46.2	46.48	39.4	42.3
Ash, %	8.6	14.2	7.04	15.6	11.8
Ultimate Analysis, (MAF)					
Carbon, %	79.3	79.03	72.95	73.70	70.2
Hydrogen, %	5.7	5.61	5.35	5.61	5.3
Sulfur, %	4.0	5.49	0.65	2.33	1.3
Nitrogen, %	1.2	1.32	0.86	1.47	0.8
Oxygen, %	9.8	8.54	20.19	16.89	22.4
Higher Heating Value, BTU/lb (AF)	14,170	12,757	11,558	8,500	7,100
Ash Fusibility (Reducing)					
Initial Deformation, °F	-	1,975	-	-	2,185
Softening Temp., °F	2,080	2,140	2,230	2,280	2,210
Fluid Temp., °F	-	-	2,250	-	2,265
Information Source, Reference No.	13, 14	15, 16	13, 17	18,19	18, 19

\- Not available

TABLE 4. MATERIAL BALANCES FOR GASIFIER

Coal Type	Eastern High-Sulfur Bituminous	Midwestern High-Sulfur Bituminous	Western Sub-bituminous	Southern Lignite	Northern Lignite
Stream and Components, 1000 lb mols/day except as noted:					
Slurry Gasifier Feed:					
Coal, raw, ton/day	9097	10850	10052	15172	16161
Coal, moisture free ton/day	8909	9551	9409	10314	10340
Water	1239	1243	1225	1231	1229
Oxygen Gasifier Feed:					
O_2	561.4	566.5	498.4	529.0	491.9
N_2	1.78	1.79	1.58	1.67	1.56
Ar	9.68	9.77	8.59	9.12	8.48
Raw Gas Product					
CO	774	776	766	769	768
H_2	561	555	570	565	567
CO_2	294	295	291	292	292
H_2O	1098	1096	1094	1118	1116
H_2S	19.06	26.32	3.33	11.87	4.27
COS	1.26	1.740	0.220	0.784	0.282
NH_3	6.66	6.68	6.58	6.62	6.60
CH_4	5.79	5.80	5.72	5.75	5.74
N_2	5.42	6.17	3.66	7.50	6.72
Ar	9.68	9.77	8.59	9.12	8.48
Total Raw Gas	2775	2779	2749	2786	2775
Ash, Slag Tons/day	766	1356	662	1609	1220

TABLE 5. MATERIAL BALANCES FOR SHIFT REACTOR AND COS HYDROLYZER, FEED STREAMS

Coal Type	Eastern High-Sulfur Bituminous	Midwestern High-Sulfur Bituminous	Western Sub-bituminous	Southern Lignite	Northern Lignite
Stream and Components, 1000 lb mols/day except as noted:					
Shift Reactor Feed					
CO	569	573	558	563	562
H_2	412	410	415	414	415
CO_2	216	218	212	214	214
H_2O	982	990	961	974	967
H_2S	14.01	19.43	2.43	8.69	3.12
COS	0.927	1.28	0.161	0.573	0.206
CH_4	4.26	4.28	4.17	4.21	4.20
N_2	3.99	4.56	2.66	5.49	4.91
Ar	7.12	7.21	6.26	6.68	6.20
Total Shift Feed	2210	2228	2162	2191	2175
COS Hydrolyzer Feed					
CO	205	203	208	206	207
H_2	149	145	154	151	152
CO_2	77.9	77.3	78.9	78.3	78.5
H_2O	147	154	148	156	155
H_2S	5.05	6.89	0.901	3.18	1.148
COS	0.333	0.455	0.060	0.210	0.076
CH_4	1.53	1.52	1.55	1.54	1.54
N_2	1.44	1.62	0.99	2.01	1.81
Ar	2.57	2.56	2.33	2.44	2.28
Total COS Hyd. Feed	590	592	595	600	600

TABLE 6. MATERIAL BALANCES FOR SHIFT REACTOR AND COS HYDROLYZER, PRODUCT STREAMS

Coal Type	Eastern High-Sulfur Bituminous	Midwestern High-Sulfur Bituminous	Western Sub-bituminous	Southern Lignite	Northern Lignite
Stream and Components, 1000 lb mols/day except as noted:					
Shift Product					
CO	171	172	167	169	168
H_2	811	811	806	808	808
CO_2	615	620	603	609	607
H_2O	584	588	570	579	574
H_2S	14.75	20.46	2.55	9.15	3.29
COS	0.185	0.257	0.0321	0.115	0.042
CH_4	4.26	4.28	4.17	4.21	4.20
N_2	3.99	4.56	2.66	5.49	4.91
Ar	7.12	7.21	6.26	6.68	6.20
Total Shift Product	2210	2228	2162	2191	2175
Hydrolyzer Product					
CO	205	203	208	206	207
H_2	149	145	155	151	152
CO_2	78.3	77.6	79.0	78.5	78.6
H_2O	147	153	148	156	155
H_2S	5.369	7.326	0.958	3.379	1.220
COS	0.0125	0.0183	0.0024	0.0084	0.0031
CH_4	1.53	1.52	1.55	1.54	1.54
N_2	1.44	1.62	0.99	2.01	1.81
Ar	2.57	2.56	2.33	2.44	2.28
Total Hydrolyzer Product	590	592	595	600	600

TABLE 7. MATERIAL BALANCES FOR ACID GAS REMOVAL AND GUARD BED GAS CONDITIONING PROCESSES, FEED STREAMS

Coal Type	Eastern High-Sulfur Bituminous	Midwestern High-Sulfur Bituminous	Western Sub-bituminous	Southern Lignite	Northern Lignite
Stream and Components, 1000 lb mols/day except as noted:					
Feed (Combined Shift and Hydrolyzer product, dry)					
CO	376	375	375	375	375
H_2	959	957	960	959	960
CO_2	694	698	682	688	685
H_2O	1.09	1.09	1.07	1.08	1.08
H_2S	20.12	27.8	3.51	12.5	4.51
COS	0.198	0.275	0.035	0.123	0.044
Inerts	20.9	21.7	18.0	22.4	20.9
Total Feed	2071	2080	2040	2058	2045

TABLE 8. MATERIAL BALANCES FOR ACID GAS REMOVAL AND GUARD BED GAS CONDITIONING PROCESSES, PRODUCT STREAMS

Coal Type	Eastern High-Sulfur Bituminous	Midwestern High-Sulfur Bituminous	Western Sub-bituminous	Southern Lignite	Northern Lignite
Stream and Components, 1000 lb mols/day except as noted:					
H_2S Rich Product					
CO	0.187	0.187	0.188	0.187	0.188
H_2	-	-	-	-	-
CO_2	50.30	69.47	8.78	31.3	11.27
H_2O	0.011	0.011	0.011	0.010	0.011
H_2S	20.12	27.79	3.51	12.53	4.51
COS	0.148	0.206	0.026	0.092	0.033
Inerts	-	-	-	-	-
Total H_2S Rich Product	70.76	97.66	12.52	44.13	16.01
CO_2 Rich Product					
CO	0.563	0.561	0.563	0.563	0.563
H_2	0.289	0.287	0.288	0.289	0.288
CO_2	573	558	603	586	604
H_2O	0.011	0.011	0.011	0.011	0.011
H_2S	-	-	-	-	-
COS	0.050	0.069	0.009	0.031	0.011
Inerts	-	-	-	-	-
Total CO_2 Rich Product	574	559	604	587	605
Methanol Synthesis Feed Gas					
CO	375	374	374	374	375
H_2	959	956	960	959	960
CO_2	70.3	70.4	70.3	70.3	70.3
H_2O	1.06	1.07	1.05	1.05	1.05
H_2S	0	0	0	0	0
COS	0	0	0	0	0
Inerts	20.9	21.7	18.0	22.4	20.9
Total Methanol Feed	1426	1424	1424	1427	1427

TABLE 9. MATERIAL BALANCE FOR METHANOL SYNTHESIS REACTOR, ALL COALS*

	Streams, 1000 lb mols/day		
Components	Feed	Purge Gas	Raw Methanol
CO	374	3.30	0.073
H_2	960	32.18	0.137
CO_2	70.3	8.58	1.97
H_2O	1.05	0.017	71.36
Methanol	-	0.931	429.6
Light Ends	-	-	0.24
Higher Alcohols	-	-	0.24
CH_4	5.72	5.58	0.141
N_2	3.66	3.62	0.040
Ar	8.59	8.56	0.034
TOTAL	1424	62.76	503.8

* Stream compositions for the methanol synthesis reactors were the same for each coal type. This material balance is for one of them.

IV. PLANT-GATE COSTS

Capital Expenditures

The sizes of the streams calculated in the material balances provide a basis for estimating the process module costs. Capital expenditures are estimated for equipment of differing sizes by using the following general relationship, called the power law (20):

$$\text{Cost} = A\,(\text{Capacity})^F$$

The term F is typically 0.6 where increases in capacity are achieved by increasing the size of the processing units, and between 0.9 and 1.0 where increases in capacity are achieved by increasing the number of processing units. Values for A and F were obtained by a least squares regression of published costs for processing modules. In some cases only one published cost was obtained for a processing module adequately representative of the module planned in this study. In each of these cases, the size is in the range where increased capacity is achieved by increasing the size of the processing units and the value 0.6 was assigned for F. Table 10 gives the values for A and F, the units to be used for the capacity, and the capacity range for which the equation is considered valid. The results are in 1980 dollars. The cost of flue gas desulfurization units for the boiler was based on a model by Rubin, Bloyd, and Molberg (21). The estimated capital expenditures for the major process units are given in Table 11. Most of the raw data used for the capital expenditure estimates were given in 1980 dollars. Those which were not were adjusted for inclusion in the tables. In the last part of this section, the summaries are given in 1984 dollars.

TABLE 10. FACTORS IN COST ESTIMATION RELATIONSHIP

Process Module	Capacity Units	Capacity Range	F	A,$$10^6$ -1980	References
Coal Preparation	tons/day	1,000 - 20,000	0.497	161,170	(51,58, 61)
Oxygen Plant	lb mols O_2/hr	2,000 - 50,000	0.905	15,400	(51,52,54,55,58-60)
Gasification	tons coal/day	5,000 - 20,000	0.745	194,200	(51,58,61)
Gas Conditioning	lb mols shift feed/hr	70,000 - 150,000	0.674	14,680	(51,52,54)
Acid Gas Removal					
H_2S	lb mols H_2S/hr	100 - 2,000	0.600	1,218,000	(54,58)
CO_2	lb mols CO_2/hr	5,000 - 50,000	0.600	77,283	(54,58)
Sulfur Plant	lb mols H_2S/hr	100 - 2,000	0.709	197,900	(51,55,58,60,61)
Methanol Synthesis*	lb mols MeOH/hr	10,000 - 50,000	0.854	22,097	(51,52,54,60)
Methanol Distillation	lb mols feed/hr	15,000 - 30,000	0.600	32,728	(53,59)
Steam and Power	kilowatts	40,000 - 100,000	0.600	68,800	(51,52,54)

* Includes initial charge of methanol synthesis catalyst.

TABLE 11. CAPITAL EXPENDITURES FOR MAJOR PROCESS MODULES (1000$, 1980)

Process Module	Eastern High-Sulfur	Mid-Western High-Sulfur	Western Sub-bituminous	Southern Lignite	Northern Lignite
Coal Preparation	17,114	18,914	17,814	22,648	23,118
Oxygen Plant	152,385	153,630	136,820	144,400	135,205
Gasification	182,275	213,188	199,190	287,219	303,804
Gas Conditioning	34,948	35,140	34,435	34,745	34,574
Acid Gas Removal	108,510	123,690	61,771	90,757	66,252
Sulfur Plant	25,211	31,698	7,310	18,020	8,732
Methanol Synthesis*	103,600	103,600	103,600	103,600	103,600
Methanol Distillation	13,665	13,665	13,665	13,665	13,665
Steam and Power	48,850	49,654	49,667	51,711	52,528
Flue Gas Desulfurization	16,340	18,526	0	19,735	17,475
TOTAL	702,898	761,705	624,272	786,500	758,953

* Includes initial charge of methanol synthesis catalyst.

The utilities constitute a major portion of the offsite costs. Estimates of utilities consumption and production were made for each process module in the following categories:

- o Electric Power
- o Water
  - Cooling
  - Raw
  - Demineralized
  - Boiler feed
  - Condensate
- o Steam
  - 1500 psig
  - 100 psig
  - 50 psig
- o Fuel Gas

The estimates were made by analogy with published utility summaries for similar processes. (22,23,24,25,26). Estimates in each category were summarized and the equivalent heat requirement or credit was calculated for the electric power, fuel gas, boiler feed water loss, and each category of steam. The heat requirement was used to calculate the non-process coal requirement for each plant. The capital expenditures for utilities were based on the total electric power requirement.

Other offsite expenditures were estimated by various methods. Condensate treatment, piping, methanol storage, and sulfur handling were estimated using the same mathematical relationship used for estimating most of the process module costs. The required acreage was estimated based on the total coal use, anticipated number of employees, the approximate sizes of the process units, and the size of land parcels available in the different coal producing regions. Land costs were estimated based on phone conversations with local taxing authorities. Building sizes were estimated based on function and anticipated occupancy. Building costs per square foot were based on recent contracts and adjusted using experience factors for rural locations in the different parts of the country supplied by the Southwest Research Institute architects. The capital expenditures for offsites are summarized in Table 12.

TABLE 12. CAPITAL EXPENDITURES FOR OFFSITES
($1,000 - 1980)

Function	Eastern High-Sulfur Bituminous	Midwestern High Sulfur Bituminous	Western Sub-bituminous	Southern Lignite	Northern Lignite
Utilities	54718	55626	55531	57809	58658
Condensate Treatment	1427	1480	1266	1379	1292
Piperack and Yard piping	14572	14572	14010	13730	14291
Methanol Storage	9556	9556	9188	9004	9372
Sulfur Handling	15345	21197	2572	8452	3308
Land Acquistion	659	606	242	747	455
Site work, roads, parking, & landscape	3393	3393	3131	3001	3262
Admin. Offices	322	322	297	285	309
Cafeteria	457	457	422	404	440
Shops Building	934	934	862	826	898
Warehouse	467	467	431	414	449
Garage	208	208	192	184	200
Chem. Laboratory	249	249	230	220	240
Chem. & Mat'l. Storage	415	415	383	367	399
Change Room	156	156	144	138	150
Fire Station	75	75	69	66	72
Total Offsites	102953	109713	88970	97026	93795

People experienced in permitting indicate that costs do not vary significantly from region to region. Permitting costs were estimated at two million dollars (1980) in any of the coal producing locations.

Costs of catalysts and chemicals were estimated based on information in the Fluor and Oak Ridge reports (11,22,27,28), a report by Badger Plants Inc. (29), and phone conversation with a methanol manufacturer. The results are shown in Table 13.

TABLE 13. INITIAL CATALYST AND CHEMICAL INVENTORY COST, $1,000 (1980)

	Eastern High-Sulfur Bituminous	Midwestern High-Sulfur Bituminous	Western Sub-bituminous	Southern Lignite	Northern Lignite
Gas Conditioning					
Shift reaction	1602	1615	1567	1588	1577
COS hydrolysis	110	111	111	111	111
Acid Gas Removal					
Selexol for CO_2	1401	1364	1474	1433	1477
Selexol for H_2S	4874	6732	850	3035	1093
ZnO guard bed	145	144	144	145	145
Sulfur Plant					
Claus catalyst	105	145	18	65	24
SCOT hydrogenation	82	113	14	51	18
SCOT solvent	54	75	9	34	12
Utilities					
Water treatment	29	29	29	29	29
(Methanol synthesis catalysts included in process module estimates).					
TOTAL	8402	10327	4216	6491	4341

Royalty cost estimates were made with the aid of guidelines supplied by phone from the process licensors. Actual royalties are often subject to extensive negotiation, and the licensors requested that the individual process royalties not be published. A summary is given in Table 14. All the royalties are capital charges rather than operating charge royalties except for those charged by Texaco, which has both a capital charge and a small operating royalty. Texaco provides some technical services in return for the operating royalty and process data.

TABLE 14. CAPITAL EXPENDITURES FOR ROYALTIES ($\$10^6$, 1980)

	Eastern High-Sulfur Bituminous	Midwestern High-Sulfur Bituminous	Western Sub-bituminous	Southern Lignite	Northern Lignite
Cost	6.50	6.53	6.26	6.39	6.30

The start-up costs and working capital estimates are based on other estimates. The start-up costs for each plant were estimated at 8.0% of the total process investment which includes the process modules, the initial charge of catalysts and chemicals, and the royalties. The working capital was taken as total operating expenditures for one month, plus one extra month's coal cost, plus two extra months labor cost, plus one year's catalyst and chemical make-up costs.

Some adjustments were made to the capital costs before they were used in calculating the sales price. Factors were applied to the depreciable assets to adjust their cost to an effective cost which included the payment of state use taxes. Table 15 shows the states and the use tax factors.

TABLE 15. FACTORS FOR ESTIMATING EFFECT OF STATE USE TAXES

	State	Factor
Eastern High-Sulfur Bituminous	Ohio	1.000
Midwestern High-Sulfur Bituminous	Illinois	1.009375
Western Subbituminous	Wyoming	1.040
Southern Lignite	Texas	1.040
Northern Lignite	North Dakota	1.040

Installed process plants cost more in cold climates than in mild climates. Extra insulation, heat tracing, and heavy duty construction add to costs in cold climates. Engineers with experience in process plant economics estimate the cost differential to be 15% between the Gulf Coast and the Canadian border. The locations used in the studies which formed the basis for this estimate were in the north central part of the country. Two of the selected coal producing regions were in areas with climates significantly different; these were the northern lignite area and the southern lignite area. The factor 1.05 was applied to the northern lignite case and 0.95 was applied to the southern lignite case to account for climatic effects.

All of the costs were adjusted for inflation to 1984 dollars. The Nelson Cost Indexes for refinery construction are published periodically in the Oil and Gas Journal, and they were used to adjust the capital costs to 1983 dollars. Adjustment to 1984 dollars was made with a projected 10% inflation rate. Table 16 gives the adjusted capital costs.

TABLE 16. CAPITAL COST SUMMARIES ($\$10^6$ - 1984)

	Eastern High-Sulfur Bituminous	Midwestern High-Sulfur Bituminous	Western Sub-bituminous	Southern Lignite	Northern Lignite
Process Modules	968.6	1059.5	894.7	1070.8	1142.1
Offsites	141.9	152.6	127.5	132.1	141.1
Initial Chemicals	11.6	14.4	5.8	9.3	6.2
Royalties	9.0	9.0	8.6	8.8	8.7
Permitting	2.8	2.8	2.8	2.8	2.8
Start-up	78.7	86.6	72.7	87.1	92.6
Working Capital	39.6	47.2	25.2	28.7	29.5
TOTAL	1252.1	1372.0	1137.3	1339.7	1422.9

Operating Costs

Operating cost estimates were developed from several sources. Coal costs are one of the largest expenses and forecasts of coal price involve a considerable amount of uncertainty. Published forecasts in industry journals typically extend prices for only one or two years in advance. The Energy Information Agency has compiled statistics on steam coal prices since 1972, and they project prices out to 1995, apparently based on a constant rate of price increase. (30) Coal price forecasts used in design of coal gasification systems have typically been higher. (31,32) Several coal producers and utility coal consumers contacted by phone expect coal price increases to eventually exceed the inflation rate.

The published information and the phone conversations generally concerned contract prices, that is, the prices paid when demand can be met from current operations. If production must be expanded, typically by opening new mines, the prices paid would have to be somewhat higher. This marginal price is typically about 20 percent above average contract prices.

High sulfur coal costs were expected to show no major long-term change. Although the sulfur content of the high-sulfur coals studied here is above the high-sulfur coal average, in making SwRI's coal price forecast, further downward adjustments in price were not made because of two conflicting pressures. The current oil glut is expected to be temporary, and overall coal prices are expected to increase faster than inflation because of the long term energy shortage. However, demand for coal with the high sulfur content considered here is expected to decline relative to the total demand because of controls on gaseous sulfur emissions. With these considerations, high-sulfur coal prices were forecast to remain steady, in constant dollars, throughout the plant life.

The low-sulfur coal prices seem to be more subject to increases because fuel-switching may increase in the future. However, this will be somewhat dependent on governmental decisions and legal interpretations which make it difficult to forecast the extent of fuel switching. To see how coal price increases might affect the product price, calculations were made based on four different, twenty year, constant dollar forecasts:

1. Coal cost low, remaining near 1984 levels.
2. Coal cost rises slowly, increasing about 45%.
3. Coal cost rises rapidly, increasing about 90%.
4. Coal cost high and constant, well above 1984 levels.

The coal cost forecasts are summarized in Table 17.

TABLE 17. COAL COST FORECASTS, \$/Ton (Constant 1984 \$)

Years From 1990 Plant Startup	1-5	6-10	11-15	16-20
Eastern High-Sulfur Bituminous	31.70	31.70	31.70	31.70
Midwestern High-Sulfur Bituminous	34.30	34.30	34.30	34.30
Western Subbituminous				
Coal Cost Low	11.00	11.00	11.00	11.00
Coal Cost Rises Slowly	11.00	12.67	14.33	16.00
Coal Cost Rises Rapidly	11.00	14.00	17.00	20.00
Coal Cost High	15.00	15.00	15.00	15.00
Southern Lignite				
Coal Cost Low	9.50	9.50	9.50	9.50
Coal Cost Rises Slowly	9.50	11.00	12.50	14.00
Coal Cost Rises Rapidly	9.50	12.50	15.50	18.50
Coal Cost High	13.50	13.50	13.50	13.50
Northern Lignite				
Coal Cost Low	9.50	9.50	9.50	9.50
Coal Cost Rises Slowly	9.50	11.00	12.50	14.00
Coal Cost Rises Rapidly	9.50	12.50	15.50	18.50
Coal Cost High	13.50	13.50	13.50	13.50

The total coal consumption is given for each plant in Table 18. Coal consumption is the total required for the process material balances, plus the utility boiler requirements.

TABLE 18. TOTAL COAL CONSUMPTION

Coal Type	Coal, 10^6 ton/year
Eastern High-Sulfur Bituminous	3.93
Midwestern High-Sulfur Bituminous	4.81
Western Subbituminous	4.26
Southern Lignite	6.91
Northern Lignite	7.20

The cost of water is a much lower fraction of the total operating costs than the cost of coal. Water costs do not respond to supply in the same way that other resources do because prices are regulated and because it is usually impractical to transport it over long distances. Elements of the water cost include the facilities to acquire the water and do preliminary treatment, and the operating costs. For surface water, facilities costs would include pumps and the construction of reservoirs and treatment plants to remove both suspended and dissolved impurities. For deep groundwater, facilities costs would include well drilling, pumps, and treatment plants to remove dissolved impurities. Pump operation for lifting water from a deep well requires a large amount of energy and can be quite expensive compared to pump operation for moving water on the surface.

Reliable information on water costs in areas where surface water is plentiful was published by Ebasco Services, (33) which was based on information supplied by the Illinois Water Resources Board. Fluor (25) estimated water costs in the northern lignite fields and Pritchard (34) provided information applicable to deep groundwater in an arid, western subbituminous coal region. Water cost forecasts are given in Table 19 and the water consumption for the principal in-plant uses is given in Table 20. Other utilities were produced in plant and costs were included elsewhere.

TABLE 19. WATER COSTS

Coal Type	1984, $/1000 Gallons
Eastern High-Sulfur Bituminous	0.072
Midwestern High-Sulfur Bituminous	0.072
Western Subbituminous	1.155
Southern Lignite	0.150
Northern Lignite	0.115

TABLE 20. WATER CONSUMPTION
(10^9 Gal/year)

Coal Type	Process	Cooling	Other	Total
Eastern High-Sulfur Bituminous	0.98	10.36	3.12	14.46
Midwestern High-Sulfur Bituminous	0.98	11.90	3.12	16.00
Western Subbituminous	0.97	6.50	3.12	10.59
Southern Lignite	0.97	8.50	3.12	12.59
Northern Lignite	0.97	6.60	3.12	10.69

The high cooling-water requirement for the plants using high-sulfur coal is due to consumption in the large acid gas removal sections required for those plants.

The annual costs of catalysts and chemicals were estimated based on information in the Fluor and Oak Ridge reports (11,22,27,28), the report by Badger Plants (29) and a phone conversation with a methanol manufacturer. The results are shown in Table 21.

TABLE 21. ANNUAL CATALYST AND CHEMICAL COSTS,
\$1,000 (1980)

Process Module	Eastern High-Sulfur Bituminous	Midwestern High-Sulfur Bituminous	Western Sub-bituminous	Southern Lignite	Northern Lignite
Gas conditioning					
Shift reaction	321	323	314	318	315
COS hydrolysis	37	37	37	37	37
Acid Gas Removal					
Selexol for CO_2	177	172	186	181	187
Selexol for H_2S	616	851	107	383	116
ZnO guard bed	145	144	144	145	145
Sulfur Plant					
Claus catalyst	20	27	3	12	5
Hydrogenation	24	33	4	15	5
SCOT solvent	162	224	28	101	36
Utilities					
Water treatment	431	431	431	431	431
Methanol synthesis	4411	4411	4411	4411	4411
TOTAL	6344	6653	5665	6034	5688

Operating labor costs were estimated from the numbers of employees projected in several labor categories. The number of employees required for various sections of the plant were estimated based on published sources (11,32) and experience with similar units. The numbers are indicated on the organization chart shown in Figure 2. Operating labor rates shown in Table 22 were estimated with the aid of information supplied by the Bureau of Labor Statistics and industry sources.

TABLE 22. ESTIMATED LABOR RATES, 1984 Dollars/Hour

Labor Category	Eastern High-Sulfur Bituminous	Midwestern High-Sulfur Bituminous	Western Sub-bituminous	Southern Lignite	Northern Lignite
Process Engineer	20.13	20.13	19.23	21.12	19.23
Sr. Plant Operators	18.26	18.26	18.08	16.52	17.52
Plant Operators	14.55	14.55	14.29	13.08	13.91
Drivers	13.39	13.39	14.37	11.81	13.47
Chemist	15.56	15.86	15.16	16.64	15.16
Sr. Lab Technician	17.89	18.19	17.48	18.65	17.41
Lab. Technician	13.95	13.95	13.80	12.03	13.52
Purchasing	15.39	15.39	16.85	14.65	16.85
Ins. & Personnel	14.54	13.81	14.53	13.85	13.85
Acctg. & Payroll	10.56	10.03	10.41	10.06	10.06
Sales	13.04	12.38	12.85	12.42	12.42
Secretaries	10.00	9.50	9.86	9.53	9.86
Nurse	13.13	12.47	12.95	12.51	12.95

Supervision, benefits (labor burden), and overhead were estimated using the same factors, applied to the operating labor cost, for each plant. Supervision was estimated at 20% of the operating labor, burden at 35% of the operating labor plus supervision, and the overhead at 35% of the operating labor plus supervision plus burden. The total amounts of annual labor cost are shown in Table 23.

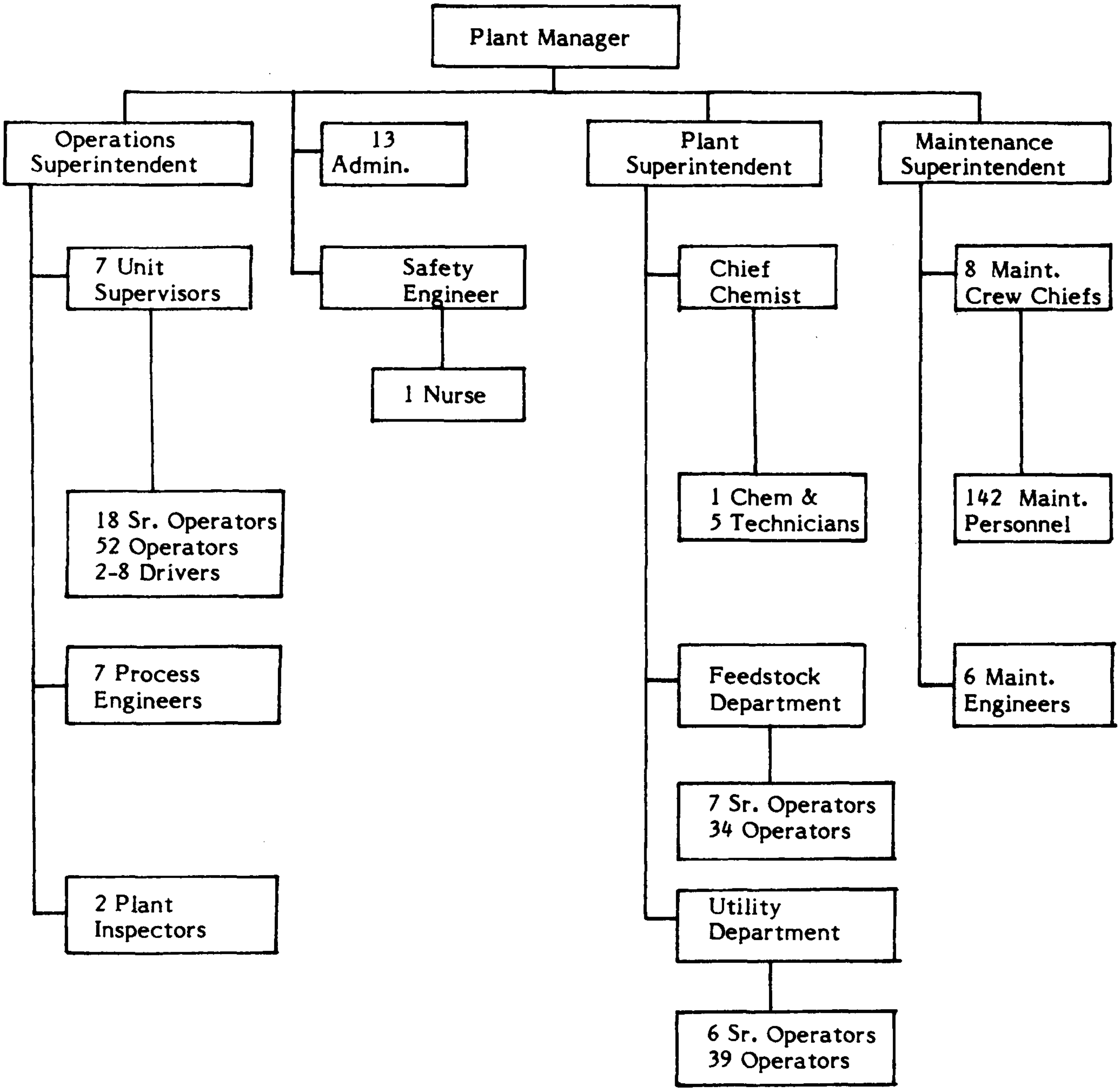

FIGURE 2. METHANOL-FROM-COAL PLANT ORGANIZATION CHART

TABLE 23. ANNUAL OPERATING LABOR COST
($\$10^6$, 1984)

Coal Type	Cost
Eastern High-Sulfur Bituminous	12.55
Midwestern High-Sulfur Bituminous	13.10
Western Subbituminous	12.93
Southern Lignite	11.69
Northern Lignite	12.24

Annual maintenance costs were estimated at 4.0% of the process module costs; annual totals are shown in Table 24. Two-thirds of the maintenance cost is estimated for materials and one-third is estimated for maintenance labor.

TABLE 24. ANNUAL MAINTENANCE COSTS
($\$10^6$, 1984)

Coal Type	Cost
Eastern High-Sulfur Bituminous	38.74
Midwestern High-Sulfur Bituminous	42.38
Western Subbituminous	35.79
Southern Lignite	42.83
Northern Lignite	45.68

Insurance and local tax cost estimates were made. Annual insurance costs were estimated at 1.0% of the cost of the process modules, plus the offsites, plus the initial chemical inventory. Local taxes were estimated based on phone information provided by representative local taxing authorities in each region. Local taxes generally make only a very small contribution to the overall product price in industries of this type, and would normally be included only in much more detailed cost studies. However, they do vary among different regions of the country, and they were included here because in this study an evaluation of the regional differences was an important objective. They were grouped with the insurance for calculation purposes. Totals are shown in Table 25.

TABLE 25. ANNUAL INSURANCE AND LOCAL TAX COSTS ($\$10^6$, 1984)

Coal Type	Cost
Eastern High-Sulfur Bituminous	25.24*
Midwestern High-Sulfur Bituminous	14.81
Western Subbituminous	11.02
Southern Lignite	13.18*
Northern Lignite	12.97

* First year only, costs decline slightly in succeeding years.

State taxes were estimated based on the main provisions of the state tax laws, utilizing credits for local taxes where applicable. The states used for these estimates were the same as given in Table 15 for the use taxes. Federal tax was estimated at 46% of the income less state taxes and depreciation.

Credit for By-Products

Two by-products make contributions to the plant economics, and both show considerable variation by region. These are sulfur and carbon dioxide. Sulfur prices were estimated from listings in recent issues of the Chemical Marketing Reporter and are given in Table 26. Northern and western prices were lower because of their distance from major markets in fertilizer manufacture, and their proximity to inexpensive Canadian supplies. Prices in the southern lignite region were estimated slightly lower because those producers would compete with Houston area oil refiners who have ready access to water transportation.

TABLE 26. ESTIMATED PRICES FOR CRUDE BRIGHT SULFUR (1984 $/Long Ton)

Eastern High-Sulfur Bituminous	110
Midwestern High-Sulfur Bituminous	110
Western Subbituminous	75
Southern Lignite	90
Northern Lignite	80

Most studies of methanol plant economics have not taken any credit for carbon dioxide. However, its use in enhanced oil recovery has increased in recent years and its potential sale has become a significant factor. Literature pertaining to possible markets and competing sources was examined for guidance in estimating CO_2 sales. Science Applications Inc. (35) studied demand in four basins for a 15 year CO_2 injection life with results given in Table 27:

TABLE 27. TOTAL CARBON DIOXIDE DEMAND (35)

	Carbon Dioxide Demand	
Oil Producing Basin	MMSCFD*	TPD**
Permian Basin and Texas Gulf Coast	8228	478,000
Williston Basin (North Dakota, Montana)	194	11,300
Appalachian Basin (Ohio, West Virginia)	68	3,900
Los Angeles Basin	309	17,900

* Million standard cubic feet per day

** Tons per day

Industry sources have indicated that there are major markets near the western subbituminous and the northern lignite coal regions. Although CO_2 injection for enhanced oil recovery has been demonstrated in Appalachian fields (36), the oil fields in that region are small, shallow, and the potential market is very small. (37) Also, the procedure would be economic only if CO_2 could be obtained at a low price. The same is true of the Illinois basin fields where the potential market appears to be even lower. (35) No projects are underway or planned in Illinois, but CO_2 use is increasing in the other basins of interest. (38-40)

The principal competing source of CO_2 was natural deposits obtained from wells. Some was available as a by-product in natural gas, but other wells produced nearly pure CO_2. Natural CO_2 was available for oil fields near the western subbituminous coal region, the southern lignite region, and the eastern high-sulfur region. However, CO_2 pipelines several hundred miles long would be required in each case. One pipeline has recently gone into service bringing CO_2 from southern Colorado to the Permian Basin.

The pattern of CO_2 use in an individual project results in reduced sales over a period of time. Typically, CO_2 use remains nearly constant for about 5 years until CO_2 content in the product oil gets high enough to make recovery and recycle profitable. New CO_2 use then declines for several years until it is used only to replace losses. To maintain constant sales, new projects would need to be found during the plant life.

With this background, decisions were made about the prospects for CO_2 sales. They were necessarily somewhat arbitrary. Since the technology is relatively young, new developments could significantly alter the sales pattern from that given in Table 28. The decisions include the percent of production expected to be sold, the period of sales, the maximum number of plants expected to sell CO_2, and the price. The sales patterns in Table 28 were used in calculating the plant-gate annual credits for CO_2 sales.

TABLE 28. CARBON DIOXIDE PRICES AND EXPECTED SALES

Coal Type	CO_2 Produced, TPD	Percent of Production Sold	Sales Period	Max. No. Plants	Price, $/Ton
Eastern High-Sulfur Bituminous	12600	10%	Plant Life	4	20
Midwestern High-Sulfur Bituminous	12300	0	-	-	-
Western Subbituminous	13300	60	5 yr, decline	3	30
Southern Lignite	12900	100	Plant life	10	25
Northern Lignite	13300	60	5 yr, decline	5	35

Economic Assumptions

Several economic assumptions were used with the information given in the preceding sections for calculating the plant-gate price of methanol. Four different discounted-cash-flow rates of return were used to show the effect on sales price. Different rates of return would be expected with different financing arrangements. Plants built with equity financing typically expect 20-25% rate of return on investment, while those built with some sort of government participation are willing to accept a lower rate of return. The government participation could take the form of a subsidy, a loan guarantee, or a price support. Price supports seem likely in view of the successful negotiation of price support agreements by Union Oil Shale and Cool Water Coal Gasification. Actual rates of return differ from industry to industry and vary with market conditions, but 18% is typical for manufacturing industries. Energy companies are very competitive and generally receive lower rates of return, typically about 12%, although investment funds are not generally available for new projects unless economic studies indicate about 20 to 25% rate of return. For a plant built with governmental participation, a selling price equivalent to about 12% rate of return could probably be negotiated. For a plant built with equity financing, 20% would seem a reasonable rate of return if the technology and markets are well established. If an equity-financed plant were seen as a pioneering venture, investors would expect a higher rate of return, 25% or greater. Other economic assumptions used in the calculations included the following:

- Project life was 20 years
- Construction schedule -

Year	Percent Spent
1	12
2	23
3	30
4	23
5	12

- Depreciation using the accelerated cost recovery system -

Year	Percent Depreciated
1	15
2	22
3	21
4	21
5	21

- A 10% federal investment tax credit was taken, but no energy investment credits were taken.

- Income was assumed to be continuous for determining the present worth factors used in the discounted-cash-flow method (41).
- Four discounted-cash-flow rates of return on investment were used: 10, 15, 20, and 25%. The method of calculation was based on income distributed evenly throughout each year.

A computer program was written which uses an iterative procedure for calculating the required sales price. It has provision for running a series of cases with minor variations, without requiring re-input of the data which remain constant between cases. Options allowed year by year changes in any operating costs or credits which were expected to vary over the project life, cash outlays and recoveries, and the incorporation of site specific items, such as the coal severance tax or license report fees, not covered in the general operating cost categories. Temporary modifications were made on a case-by-case basis to accommodate unusual items such as state tax credits for local taxes, or a state net worth tax. The program was written to meet the needs of this project, and as these needs were developed the program was expanded by putting additional subroutines at the end, so program elements are not all arranged in the same sequence as calculations occur. A complete listing of the program is given in Appendix A.

The computer program was used to calculate plant-gate methanol prices for all five coal types. The results, shown in Table 29, indicate that coal-derived methanol can be produced for the lowest cost in the western subbituminous region, if sufficient water is available. Costs in the southern lignite region are only slightly higher. Costs in the northern lignite region are about midway between the lower cost regions and the high cost eastern and midwestern regions using high-sulfur coal. The prices indicate that the rate of return on investment has much more influence on the methanol price than the coal cost in the ranges studied. Coal cost projections were given in Table 17.

The computer output for each calculated price includes a year-by-year listing of the cash outlays, sales, earnings, taxes, cash flow, and present values. It also includes the payout period and tables showing each operating expense, both in annual dollars and as a percent of the total operating expenses. An example printout is included in Appendix B.

TABLE 29. PLANT-GATE METHANOL PRICES, 1984 $/GALLON

Return on Investment, %	10	15	20	25
Eastern High-Sulfur	0.608	0.790	1.037	1.345
Midwestern High-Sulfur	0.651	0.862	1.144	1.496
Western Subbituminous				
Coal Cost Low	0.363	0.520	0.732	1.000
Coal Cost Rises Slowly	0.372	0.527	0.738	1.004
Coal Cost Rises Rapidly	0.379	0.533	0.743	1.008
Coal Cost High	0.388	0.546	0.759	1.027
Southern Lignite				
Coal Cost Low	0.353	0.544	0.800	1.121
Coal Cost Rises Slowly	0.364	0.553	0.808	1.127
Coal Cost Rises Rapidly	0.376	0.563	0.816	1.133
Coal Cost High	0.390	0.582	0.840	1.162
Northern Lignite				
Coal Cost Low	0.470	0.688	0.983	1.356
Coal Cost Rises Slowly	0.482	0.699	0.991	1.362
Coal Cost Rises Rapidly	0.495	0.709	0.999	1.368
Coal Cost High	0.509	0.729	1.025	1.399

In 1984, by comparison, conventionally produced methanol prices were low. Most methanol was made from natural gas and some U.S. plants were closed or operating below capacity. In world markets, there was an oversupply of methanol, yet some new plants had recently come on stream, or were nearing completion in areas of the world with sources of inexpensive natural gas feedstocks. No major new market areas were expected, except the automotive fuel market just beginning to develop. The potential automotive fuel market was much larger than the available, conventional supply both in the U.S.A. and worldwide. (42) However, without rapid growth of the fuel market, the low methanol prices were expected to continue with little change for several years. Spot prices for U.S. Gulf coast delivery were frequently between $0.40 and $0.45 per gallon and contract prices for rail-car or truck shipment were generally below $0.50 per gallon. The plant-gate costs for coal-derived methanol would be significantly higher except for the western subbituminous and the lignite regions at 10% return on investment.

Siting Limitations

Despite the low price of methanol produced in the western subbituminous region, plant siting would present some difficulties. In some localities, the coal is at excessive depth, and there are significant hazards associated with underground mining. Aquifer disruption and acid mine drainage can cause problems there, just as in other coal fields. However, the western subbituminous coal deposits are very large, and most of these problems can be avoided by careful selection of the mine location. The principal constraint on siting is the water supply, and it has been the subject of extensive controversy, but it also seems to be a solvable problem.

A review by the U.S. Office of Technology Assessment (43) discusses the restraints on water use in the western subbituminous mining region. Surface water allocations are based on average streamflows rather than on expected minimum streamflows, the basis used in most of the eastern U.S. Furthermore, the western streamflows show large season-to-season variations and large year-to-year variations. (43,44) If water allocation could be obtained, large reservoirs would be required to avoid water shortages. However, reservoir construction in highly scenic western areas has usually been controversial and strong local opposition has prevented, delayed, or forced alteration of many reservoir construction plans.

Ground water resources in the western subbituminous region have not been extensively developed. There are some shallow groundwater aquifers, but they are generally believed to be insufficient for industrial needs. (43,45) The Madison and related formations appear to contain a significant groundwater resource at greater depth. (46) The safe yield has been estimated at 75,500 acre feet (24.6×10^9 gallons) per year, but drilling depths range from 4000 to 20,000 feet. (43) The water will be expensive and the estimated safe yield would support only a little more than two of the coal-to-methanol plants in this study. Actual plants will most likely use a combination of water sources, supplementing whatever surface water can be obtained with wells.

Water conservation can significantly reduce the water consumption relative to the normal water requirements. Cooling consumes the largest fraction of water used in a coal-to-methanol plant, and dry cooling towers are available, but seldom used because of cost. It is significant that one of the very few dry cooling towers constructed in the U.S. is on a small power plant located in the western subbituminous region. Larinoff (47) has written a critical review of dry cooling tower cost estimates, and it appears that dry cooling towers cost about 4 times as much as wet cooling towers to build. They also require more electric power, which for the coal-to-methanol plants considered here means a larger boiler and electric generator and higher coal consumption. Larinoff's data were used to estimate the cost of producing methanol from western subbituminous coal using both dry cooling towers and other water conservation measures to reduce the total water consumption to about 20% of the normal requirement.

The Yellowstone River in southern Montana contains sufficient water for extensive synfuels development; its' average stream flow is about 2000 x 10^9 gallons per year, large compared to the methanol plant requirement of 11 x 10^9 gallons per year. It goes close to the northern edge of a large subbituminous coal field, but many acceptable mine locations would be located 40-70 miles away. Transportation could raise the water cost to about $4.00 per 1,000 gallons and estimates were made based on this figure with and without credit taken for CO_2 sales. These can be compared to the base case which has normal water usage, water cost at $1.15 per 1000 gallons, and allows credit for CO_2 sales. For these estimates, the coal price forecast termed 'price rises slowly' was used.

The results, shown in Table 30, indicate that a large increase in water cost causes only a slight increase in product price. For plants with normal water usage, cases A and D, using high cost water increases the product price by less than 4 cents per gallon. For plants with low water usage, the use of high cost water increases the product price only about one cent per gallon, cases C and E. The cost attributed to low water use ranges from 2 to 10 cents per gallon of product when water costs are normal, cases A and B. Loss of CO_2 credits would increase costs about 9 cents per gallon, cases B and C.

The effect that loss of credits for CO_2 sales would have on the required selling price was also calculated for production in the pertinent producing areas. The calculations were made for 15% return on investment and for coal price projections termed 'coal prices rises slowly'. The greatest effect was in the southern lignite region for which some additional calculations were made using the other rates of return. The results are shown in Table 31, and they again indicate the major effect CO_2 sales credits should have on methanol plant economics.

TABLE 30. EFFECT OF VARIABLES ON PRICE OF METHANOL IN THE WESTERN SUBBITUMINOUS REGION, 1984 $/GALLON

Case	Case Description	Return on Investment, %			
		10	15	20	25
A	Base case, normal water cost & usage, credit for CO_2 sales	0.372	0.527	0.738	1.004
B	Case A, + low water usage	0.393	0.567	0.804	1.103
C	Case A, + low water usage, no CO_2 credit	0.477	0.655	0.897	1.200
D	Case A, + high water cost	0.411	0.566	0.777	1.043
E	Case A, + high water cost & low water usage, no CO_2 credit	0.484	0.662	0.904	1.208

TABLE 31. EFFECT OF CARBON DIOXIDE SALES CREDITS ON THE PLANT GATE METHANOL PRICE, 1984 $/GALLON

Case	CO_2 Credits	No Co_2 Credits
Eastern High Sulfur	0.790	0.806
Midwestern High Sulfur*	0.862	0.862
Western Subbituminous	0.527	0.615
Southern Lignite		
Return on Investment, %		
10	0.364	0.518
15	0.553	0.707
20	0.808	0.961
25	1.127	1.280
Nothern Lignite	0.699	0.801

* Credits for CO_2 sales were not expected in the midwestern high-sulfur region, see Tables 27 and 28.

Water supply is important for development in the western subbituminous region, but it is not an impediment to development in any of the other regions. Reports by the U.S. Water Resources Council (48) and by Scott, Pfeiffer and Gronhovd of North Dakota State University (45) indicate adequate surface water supply for synfuel development in most of the northern lignite mining region. Similarly, Smoller (49), and Mathewson and Cason (50) report that both surface water supplies and shallow ground water supplies are adequate for extensive development in Eastern Texas and Louisiana where the largest and highest quality portion of the southern lignite resource is concentrated.

Eastern Low-Sulfur Coal

There are deposits of low-sulfur coal in the eastern part of the country which could be used for methanol production. Many low-sulfur coal mines in the central Appalachian mining region produce low-ash, high heating-value material. It tends to be agglomerating in character, favorable for coke production. These properties make the eastern low-sulfur coal very expensive, but also favorable for methanol production.

For coal gasification, coke is an undesirable product and agglomerating coals cannot be used in some types of coal gasifiers. However, the entrained beds used for the Texaco coal gasifiers can handle agglomerating coal. The low sulfur content should allow reductions in the cost of acid gas removal equipment and eliminate the need for flue-gas desulfurizers on the boiler. The low ash content would allow operation with about 10% lower coal consumption for process feedstock than the corresponding high-sulfur case. Similarly, the high heating value would allow about 25% lower consumption for utilities production, resulting in about 13% less coal purchased than for the high-sulfur case.

Capital expenditures would be lower with low-sulfur coal. Based on approximate material balances (not shown) about 10% savings were inferred for the gasifier and coal preparation plant. Savings for acid gas removal would be about 35% and for the sulfur plant about 75%. Flue gas desulfurization for the utility boiler should not be required. There would be a very small savings, about 5%, for the oxygen plant, but for other process modules costs would be about the same. Offsite savings were estimated at 10%, mostly for reduced sulfur handling facilities. Capital expenditures for the process modules and offsites together were estimated to cost 14% less than for the eastern high-sulfur case. Capital expenditures for royalties, chemicals and plant startup would be slightly less. The only area requiring a higher capital expenditure was working capital which was higher because of the coal price. For coal at $50 per ton, the working capital requirement was about 12% higher.

Coal was the dominating feature of the operating costs. Because of its high value for both steam and coking purposes the price was estimated at $50 per ton.

Water consumption and the cost of maintenance were each estimated to be about 10% lower than for the high-sulfur case. It seemed unlikely that any income could be obtained from carbon dioxide sales, and sulfur production was lower.

A plant-gate price for 15% return on investment was calculated for the eastern low-sulfur case using the estimates discussed above. A plant location in Virginia was assumed for state tax calculations. A coal price at $50 per ton is believed to be reasonable, but to see the effect of coal price changes, an additional calculation was made for coal at $70 per ton. The required methanol sales prices were $0.78 and $0.87 per gallon respectively.

The price was not significantly different from the high sulfur case at $0.79 per gallon. The high cost of coal tends to offset the benefits gained elsewhere in the plant. If low-sulfur coal could be obtained for about $30 to $35 per ton, perhaps by a plant-owned reserve which was easily mined, the methanol price would probably be reduced to about $0.70 per gallon. However, eastern low-sulfur coal prices in that range for 1990 and beyond should be regarded as fortuitous.

<u>Methanol Cost Distribution</u>

It is of interest to consider the contribution which different parts of the methanol production process make to the plant-gate price. The coal-to-methanol process can be divided into four major cost areas: coal purchase, coal gasification, gas preparation, and methanol synthesis. The contribution to the plant-gate cost was estimated for each area except for coal purchase by dividing the plant capital and operating costs among the areas and calculating a product price for each. The contribution of coal cost was estimated from the cases where calculations were made for two different coal prices, with adjustments for differences in coal use and price where needed.

Each of the plant cost areas included several process modules and related operations. The coal gasification area included coal preparation, gasification, cooling, ash and slag handling, and the oxygen plant. The gas preparation area included the shift reaction, COS hydrolysis, acid gas removal, sulfur production, synthesis gas purification in the guard bed, and flue-gas desulfurization at the boiler. Methanol synthesis included gas recovery, methanol distillation and storage.

Utilities and some operating costs were assigned in proportion to the process module costs. Other operating costs which could be readily identified with plant areas were assigned based on use as determined for the overall plant-gate price estimation. For example, 67% of the chemical use was assigned to the methanol synthesis area. All by-product credits were arbitrarily assigned to the gas preparation area.

Three cases were examined. The first case, shown in Figure 3, was for midwestern high-sulfur coal feedstock. The second and third cases, Figures 4 and 5, were for western low-sulfur coal feedstock with and without credit allowed for carbon-dioxide sales. In all three cases, coal gasification was the major price contributor, accounting for about half of the plant-gate price. For the western low-sulfur coal, gas preparation was the least contributor to the price if carbon dioxide sales credits were allowed, otherwise coal purchase was the least contributor. Methanol synthesis was the least contributor in the midwestern high-sulfur coal case. The fact that coal gasification is such a large contributor to the price indicates that improvements in gasification economy would have a major effect on the plant-gate methanol price.

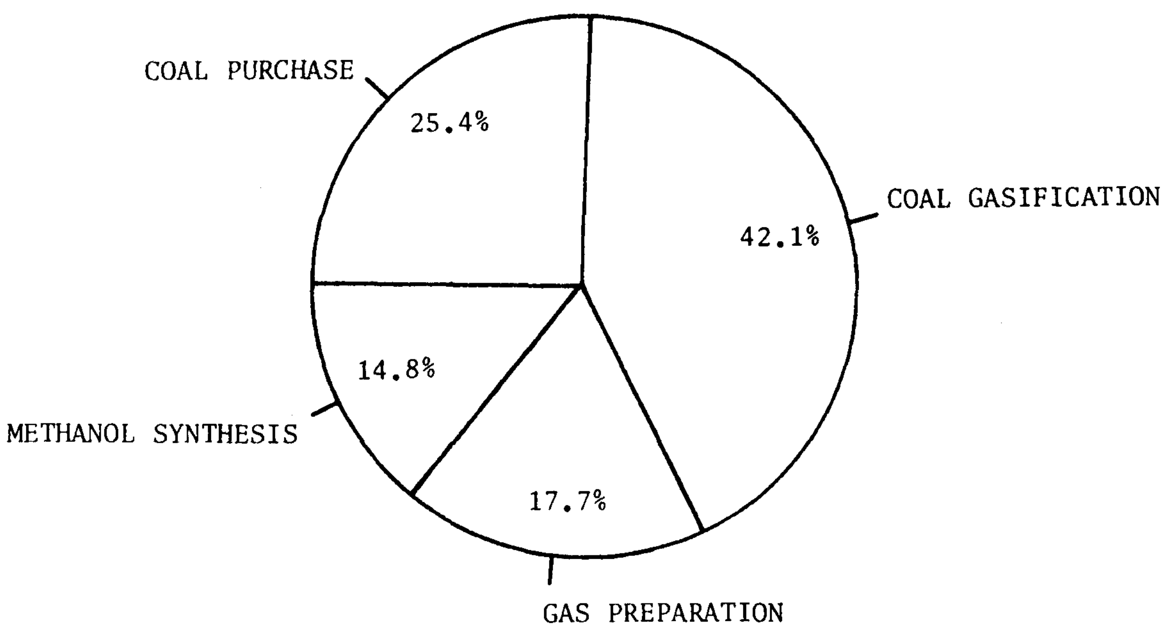

FIGURE 3. COST DISTRIBUTION FOR METHANOL PRODUCTION IN THE MIDWESTERN HIGH-SULFUR COAL REGION

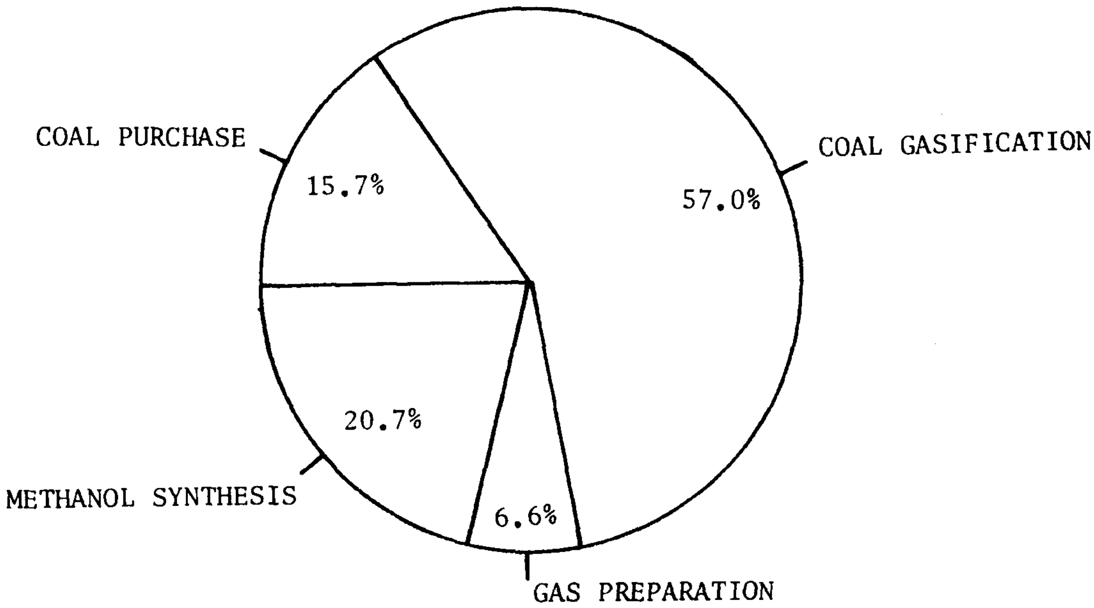

FIGURE 4. COST DISTRIBUTION FOR METHANOL PRODUCTION IN THE WESTERN SUBBITUMINOUS COAL REGION

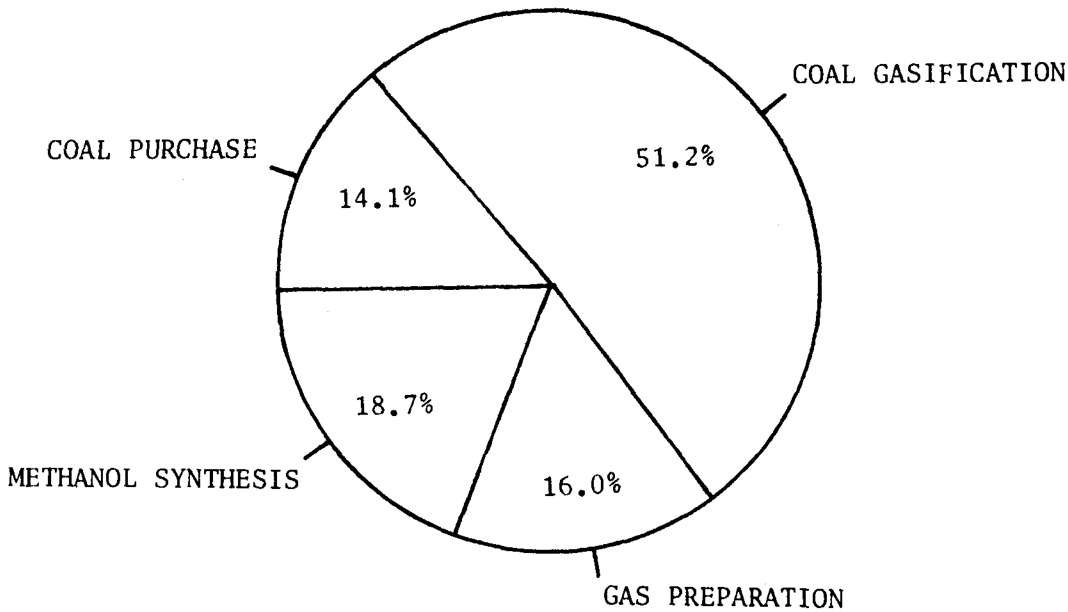

FIGURE 5. COST DISTRIBUTION FOR METHANOL PRODUCTION IN THE WESTERN SUBBITUMINOUS COAL REGION, ASSUMING NO CREDIT FOR CARBON DIOXIDE SALES

V. TRANSPORTATION COSTS AND DELIVERED PRICES

Transportation costs for bringing coal-derived methanol from mine-mouth plants to the three representative delivery locations were estimated for readily available means of transportation and for newly constructed pipelines. Three readily available means of transportation were investigated:

- o Existing product pipelines
- o Barge service operating in the Great Lakes area, inland rivers and tributaries, and surrounding coastal waters
- o Unit train/railroad tanker

Existing Product Pipelines

There appears to be very little precedence in the industry in moving methanol via existing product pipelines. Reasons for this condition, expressed by personnel at the different pipeline companies contacted, are the effects that methanol would produce on pipeline seals and valves due to its corrosive nature and the presence of water in the pipelines. No one, however, ruled out the possibility of moving methanol via pipeline in the future should demand and production increase. For the purpose of this study, assuming that methanol were treated as other products moved via pipeline, the present cost would average between $0.60 and $0.80 per thousand barrel miles.

While existing product pipelines are inexpensive means of transportation, they have limited availability. The only line into the northern lignite region carries liquefied petroleum gases, but the operating requirements for this type of line differ significantly from lines carrying other liquid products, and it would be difficult to adapt it for carrying methanol. There are no product lines in the western subbituminous region, and very few between the southern lignite region and Chicago. Most products from gulf coast refineries going to the Chicago area use water transportation. Extensive, large product pipelines are in place from the gulf coast to Atlanta and on to New York City, but these are very highly utilized. Since methanol can replace gasoline only on about a 2 to 1 basis, pipeline transportation for only about 50% of the fuel methanol could be gained by assuming an equivalent quantity of gasoline to be backed out of the market. With high pipeline utilization, questions about methanol incompatibility, and lack of service to some of the less expensive producing areas, the existing network of product pipelines at the time of this report was assumed to be not readily available. The problems did not seem insurmountable, and pipeline transportation was expected to become available in the future.

Water and Rail Transportation

For water transportation of methanol, points of pick-up and delivery are limited. For this study, the gulf coast area, the Chicago area, the eastern Ohio River, and New York City could be used. There are no navigable water-ways near the northern lignite or the western subbituminous regions. The southern lignite region is near, but not adjacent to water transportation and rail transportation would be required for about 150 miles. Only the midwestern and eastern producing locations are adjacent to water transportation. Telephone quotes obtained from several marine barge companies and several railroads are summarized in Appendix C. The information was used as a basis for estimating the transportation costs given in Table 32.

TABLE 32. ESTIMATED COSTS OF METHANOL TRANSPORTATION USING READILY AVAILABLE MEANS, 1984 $/GALLON

	Chicago	New York City	Atlanta
Eastern High-Sulfur Bituminous	0.113[b]	0.189[a,b]	0.142[a]
Midwestern High-Sulfur Bituminous	0.020[b]	0.085[b]	0.186[a]
Western subbituminous	0.396[a]	0.452	0.431[a]
Southern Lignite	0.125	0.125	0.208
Northern Lignite	0.353[a]	0.423	0.421[a]

a - rail transportation only
b - water transportation only

The routes used for making the estimates in Table 32 were those which appeared to result in the lowest cost. Rail transportation is very expensive for short distances, but the cost per mile goes down on very long routes. For example, rail costs from the western subbituminous or northern lignite producing regions to the Mississippi River are almost as high as rail costs direct to Atlanta. Only in the case of the southern lignite could savings be realized by utilizing water transportation over part of a route to Atlanta. New York City would receive all its supply by water transportation, except for that produced in the eastern high-sulfur bituminous region, from where the rail cost is about the same as the cost of barging it down the Ohio and Mississippi Rivers and on around Florida. Production from the western subbituminous region would go by rail to St. Louis, then utilize water transportation. It is possible to transport by water from St. Louis to New York City via the Great Lakes, but the cost is slightly more than twice the gulf coast route; however, in an actual case it may be the best route for destinations between eastern Michigan and western Pennsylvania. Production from the northern lignite area would also travel by rail to the Mississippi River, but the junction would vary with the season. Most of the time, water transportation would begin in Minneapolis, but during the winter, rail transportation could be required to as far south as St. Louis. Chicago could receive methanol by water transportation from both the eastern and the midwestern high-sulfur regions. For methanol produced in the western and the northern lignite regions, the rail cost differential between the Mississippi River and Chicago is so small that it would be impractical to make the transfer.

Transportation cost estimates show that three areas would have critical needs for lower cost transportation. Costs are very high for western subbituminous and northern lignite producing regions, and for the Atlanta consuming region.

New Pipeline Construction

New means of transportation could be very important to the development of a coal-derived methanol industry. Newly constructed pipelines could provide inexpensive transportation for regions where existing transportation methods were lacking, or prohibitively expensive, and could affect the geographic distribution of a future coal-to-methanol industry. To obtain an estimate of transportation costs using a newly constructed pipeline, consultant services were purchased from the Williams Brothers Engineering Company. They were asked to provide estimated capital costs, operating and maintenance costs, and other economic data for two methanol-compatible, pipeline systems. The northern pipeline system had two origin points, one in the northern lignite region, and the other in the western subbituminous region. Lines from each origin point met in South Dakota and continued as a single line to terminals in Chicago and New York City. The southern pipeline system originated in the southern lignite region and proceeded to terminals in Atlanta and New York City. The Williams Brothers report is included in Appendix D.

The transportation costs were calculated using the computer program discussed previously. A 20-year project lifetime was assumed, a cash outlay was taken the first year for filling the line, and a cash recovery was taken the last year for recovering 90 percent of the line fill. Results are shown in Table 33, assuming 90% utilization, in terms of barrel miles shipped.

TABLE 33. ESTIMATED COSTS OF METHANOL TRANSPORTATION IN NEWLY CONSTRUCTED PIPELINES, 1984 $/1000 BARREL MILES

Return on Investment, %	10	15	20	25
N.L.* - Junction	1.450	1.907	2.481	3.156
W.S.* - Junction	1.352	1.797	2.357	3.015
Junction - New York City	1.143	1.533	2.022	2.594
S.L.* - New York City	1.320	1.744	2.278	2.905

* Producing regions, N.L. = northern lignite, W.S. = western subbituminous, and S.L. = southern lignite

The transportation costs calculated for 20% return on investment were used as guidelines in estimating the transportation costs on a gallon basis given in Table 34. They should be regarded as fairly low estimates because of the assumed 90% utilization. While this is achieved in present products lines, it may be optimistic to assume such a high utilization for pipelines dependent on a future industry. However, even if the costs were to be 20 or 30% higher than in the above estimates, the savings over the presently available means would be, in most cases, quite large.

TABLE 34. ESTIMATED COSTS OF METHANOL TRANSPORTATION IN NEWLY CONSTRUCTED PIPELINES, 1984 $/GALLON

Producing Region	Chicago	New York City	Atlanta
Eastern High-Sulfur Bituminous	0.020	0.022	0.031
Midwestern High-Sulfur Bituminous	0.015	0.048	0.023
Western Subbituminous	0.045	0.081	0.080
Southern Lignite	0.052	0.082	0.040
Northern Lignite	0.044	0.079	0.075

It should be emphasized that the estimated costs in Table 34 are based on the assumption that the pipeline would acquire the right of eminent domain. This allows the pipeline owner to acquire pipeline right-of-way via condemnation proceedings if a landowner refuses compensation for his property. Without the right of eminent domain, the transportation costs would be higher than estimated and it is very possible that difficulties in obtaining right-of-way could prevent pipeline construction entirely.

Some other options are locally available which are attractive, but no attempt has been made to estimate costs based on them. For example, a short pipeline connecting a methanol producer in the southern lignite region to the nearest navigable waterway should facilitate transportation to New York City at attractive rates. Similarly, a pipeline from the Ohio River in western Pennsylvania may be able to follow existing corridors to Cleveland and reduce transportation costs between the eastern high-sulfur coal region and consumers near the Great Lakes. An existing crude oil pipeline was built from North Dakota and adjacent parts of Canada to a refinery near Duluth when expectations of crude oil production were greater than later realized. This line probably has a low utilization, and it may become attractive to revamp it for methanol carriage. Short additions to the line could bring it within easy reach of the northern lignite region and some of the western subbituminous region.

Delivered Prices

The plant-gate costs, the transportation costs, the effects of plant designs allowing reduced water consumption in the western subbituminous region, and the effects of by-product credits were used to estimate delivered prices. The geographic distribution of plant locations was modeled based on delivered price and an arbitrary demand limit for each of the consuming locations. The total demand limit was set at 100×10^6 gallons per day proportioned among the three consuming locations relative to the regional gasoline sales during 1982 and 1983. Figure 6 shows the producing locations, the representative consuming locations and the states used for each of the regional sales compilations. This procedure yielded the following regional demand limits in millions of gallons per day:

	Demand Limit, Million Gallons Per Day
Chicago	36.7
New York City	36.3
Atlanta	27.0

The lowest delivered prices provided the basis for plant location. The lowest price to any location was found first, then the next lowest, until the demand limit had been reached in each region. The plant-gate costs for 15% return on investment and the coal cost forecast labeled 'coal cost rises slowly' were used in determining the delivered prices.

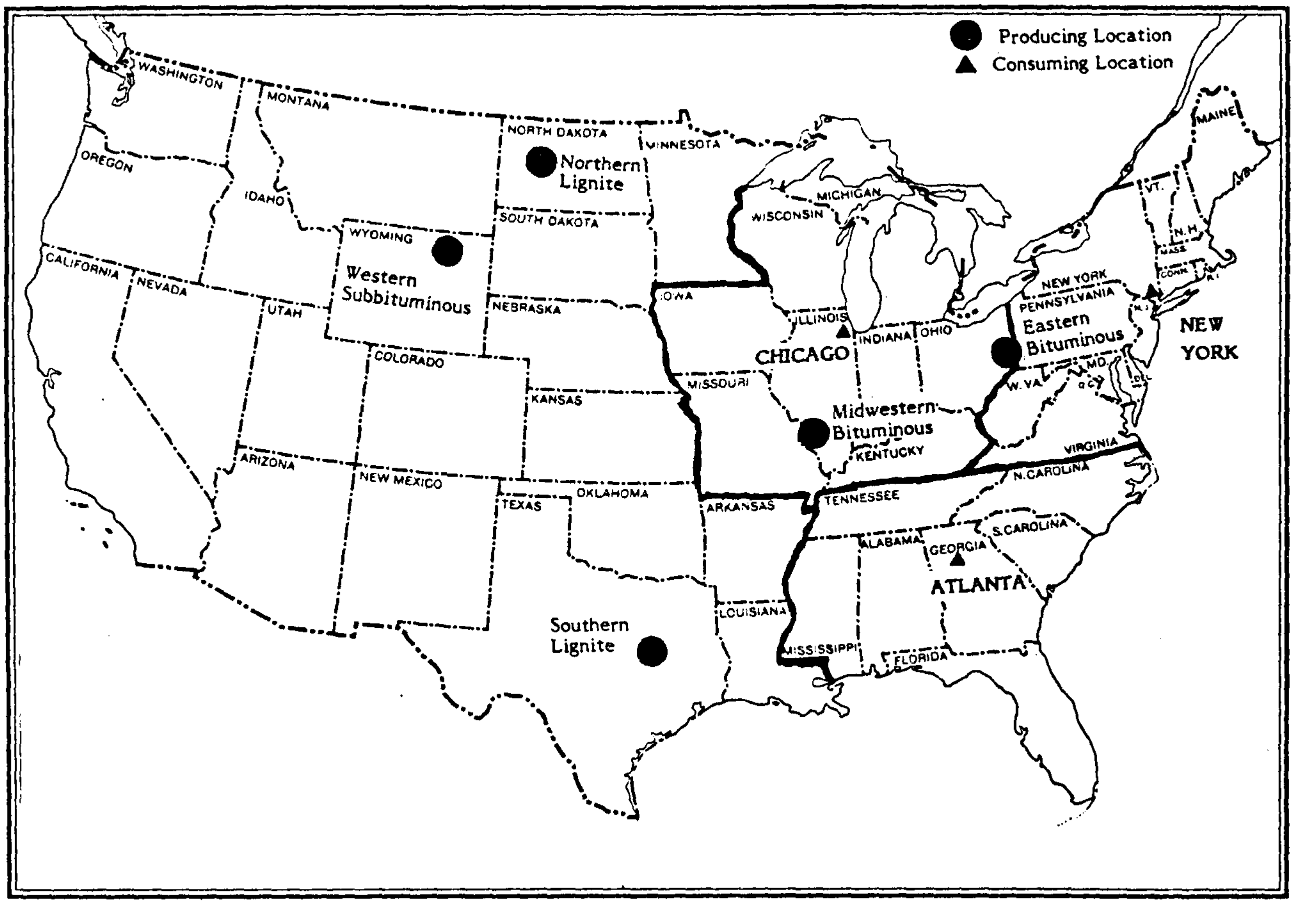

FIGURE 6. MAP SHOWING PROJECTED METHANOL PRODUCING REGIONS AND REPRESENTATIVE CONSUMING LOCATIONS WITH THEIR ASSOCIATED AREAS

The number of plants producing at the lowest price in each location was limited by the expected sales of carbon dioxide shown in Table 28, and by water supply limitations in siting plants in the western subbituminous region. Delivered prices differing by less than five cents per gallon were regarded as equivalent and the amount of methanol was divided equally.

Results for the readily available means of transportation are shown in Table 35. The geographic distribution of methanol plants shows production concentrated heavily in the southern lignite region with 34 plants and 72% of the total production. There were no plants in the northern lignite region because the plant-gate costs were higher than other western production and transportation costs were too high to compete with eastern and midwestern production.

TABLE 35. DELIVERED METHANOL PRICES USING BEST ESTIMATE OF WATER AVAILABILITY, AND READILY AVAILABLE TRANSPORTATION, 1984 $/GALLON

Producing Region	No. of Plants	Plant-Gate Cost,* $/Gal.	Sales, 10^6 Gal./Day	Chicago Cost $/Gal.	N.Y.C. Cost $/Gal.	Atlanta Cost $/Gal.
Southern Lignite	10	0.553	10.5	-	0.678	-
			10.5	0.695	-	-
Southern Lignite	18	0.707	25.2	-	0.832	-
		0.707	12.6	0.849	-	-
Midwestern Bituminous	6	0.862	12.6	0.882	-	-
Southern Lignite	6	0.707	12.6	-	-	0.915
Eastern Bituminous	4	0.790	8.4	-	-	0.932
Eastern Bituminous	1	0.806**	2.1	-	--	0.948
Western Subbituminous	2	0.527	4.2	-	-	0.958

* Assumes 15% return on investment and coal costs that rise slowly.

** The higher cost on this line is due to loss of credits for CO_2 sales.

For newly-constructed pipelines, two development models were considered for the western subbituminous region based on water limitations. The first model represented the best estimate of water availability, and two plants were allowed with normal water use, four plants with low water use but normal water price, and an unrestricted number with both low water use and high water price. The results, shown in Table 36, indicate production concentrated in the western subbituminous region. Plants are also located in the southern and northern lignite region, but their numbers were nearly limited to the number of plants with a CO_2 market.

TABLE 36. DELIVERED METHANOL PRICES USING BEST ESTIMATE OF WATER AVAILABILITY, AND NEWLY CONSTRUCTED PIPELINE TRANSPORTATION, 1984 $/GALLON

Producing Region	No. of Plants	Plant-Gate Cost,* $/Gal.	Sales, 10^6 Gal./Day	Chicago Cost $/Gal.	N.Y.C. Cost $/Gal.	Atlanta Cost $/Gal.
Western Subbituminous	2	0.527	1.4	0.572	-	-
			1.4	-	-	0.607
			1.4	-	0.608	-
Southern Lignite	10	0.553	7.0	-	-	0.593
			7.0	0.605	-	-
			7.0	-	0.635	-
Western Subbituminous	1	0.567	0.7	0.612	-	-
			0.7	-	-	0.647
			0.7	-	0.648	-
Western Subbituminous	3	0.655**	2.1	0.700	-	-
			2.1	-	-	0.735
			2.1	-	0.736	-
Western Subbituminous	23	0.662	21.3	0.707	-	-
			5.1	-	-	0.742
			21.9	-	0.743	-
Southern Lignite	4	0.707	8.4	-	-	0.747
Northern Lignite	5	0.699	3.5	0.743	-	-
			3.5	-	-	0.774
			3.5	-	0.778	-

* Assumes 15% return on investment and coal costs that rise slowly.

** The higher cost on this line is due to loss of credits for CO_2 sales.

The second development model for the western subbituminous region assumed more stringent restrictions on development. No plants were allowed with normal water use, three plants were allowed with low water use but normal water prices, and only seven additional plants were allowed with low water use and high water prices. As shown in Table 37, these restrictions caused two concentrated areas of production; besides the 10 plants in the western subbituminous region, 21 plants would be located in the southern lignite region. Only eight plants would be located in the northern lignite region and four in the eastern bituminous region. With either of the development models for the western subbituminous region, the existence of inexpensive pipeline transportation would prevent midwestern production from competing effectively and would severely limit eastern production.

TABLE 37. DELIVERED METHANOL PRICES USING NEWLY CONSTRUCTED PIPELINE TRANSPORTATION, WESTERN DEVELOPMENT RESTRICTED BY WATER AVAILABILITY, 1984 $/GALLON

Producing Region	No. of Plants	Plant-Gate Cost, $/Gal.	Sales, 10^6 Gal./Day	Chicago Cost $/Gal.	N.Y.C. Cost $/Gal.	Atlanta Cost $/Gal.
Southern Lignite	10	0.553	7.0	-	-	0.593
			7.0	0.605	-	-
			7.0	-	0.635	-
Western Subbituminous	3	0.567	2.1	0.612	-	-
			2.1	-	-	0.647
			2.1	-	0.648	-
Western Subbituminous	7	0.662	4.9	0.707	-	-
			4.9	-	-	0.742
			4.9	-	0.743	-
Northern Lignite	5	0.699	3.5	0.743	-	-
			3.5	-	-	0.774
			3.5	-	0.778	-
Southern Lignite	11	0.707	9.9	-	-	0.747
			6.5	0.759	-	-
			6.5	-	0.789	-
Eastern Bituminous	4	0.790	4.2	0.810	-	-
			4.2	-	0.812	-
Northern Lignite	8	0.764	8.4	0.808	-	-
			8.4	-	0.843	-

Credit for CO_2 sales, as shown in Table 31, made a significant effect on the plant-gate methanol price. The effect was greatest in the regions where most of the plants were located as portrayed in the above tables. The loss of credit for CO_2 sales was examined to see how plant siting would be affected. The results are shown in Tables 38 through 40.

There were few changes in the pattern of plant siting and delivered costs for the case using readily available transportation. There were 33 plants with 70% of the total production in the southern lignite region, and no plants in the western subbituminous region. A comparison of Tables 38 and 35 shows that three plants lost in those regions were gained by the eastern and midwestern bituminous regions. The lowest delivered prices were higher without the CO_2 credits, but the highest prices were about the same because of the expected market limitations for the CO_2 where credit was taken.

TABLE 38. DELIVERED METHANOL PRICES USING BEST ESTIMATE OF WATER AVAILABILITY, READILY AVAILABLE TRANSPORTATION, AND NO CO_2 SALES CREDIT, 1984 $/GALLON

Producing Region	No. of Plants	Plant-Gate Cost $/Gal	Sales 10^6 Gal./ Day	Chicago Cost $/Gal	N.Y.C. Cost $/Gal	Atlanta Cost $/Gal
Southern Lignite	26	0.707	36.3	-	0.832	-
			18.9	0.832	-	-
Midwestern Bituminous	8	0.862	16.8	0.882	-	-
Southern Lignite	7	0.707	14.7	-	-	0.915
Eastern Bituminous	6	0.806	12.6	-	-	0.948

For the case of newly constructed pipeline transportation and best estimate of water availability there was a shift in plant siting from both lignite regions toward the western subbituminous region. With credit for CO_2 sales, Table 36, the combined lignite regions had 19 plants and 40% of the total production. Without credit for CO_2 sales, Table 39, there were only eight plants with 17% of the total production, all located in the southern lignite region. The remaining 83% was in the western subbituminous region.

When western development was restricted by water availability, the plant siting was shifted back toward the southern lignite region. With western development restricted, Table 40, the southern lignite region had 31 plants and 65% of the total production. The loss of credits for CO_2 sales resulted in the loss of all 13 plants shown in the northern lignite region in Table 37. The southern lignite region gained 10 plants and the eastern bituminous region gained three plants.

TABLE 39. DELIVERED METHANOL PRICES USING BEST ESTIMATE OF WATER AVAILABILITY, NEWLY CONSTRUCTED PIPELINE TRANSPORTATION, AND NO CO_2 SALES CREDIT, 1984 \$/GALLON

Producing Region	No. of Plants	Plant-Gate Cost \$/Gal	Sales 10^6 Gal./Day	Chicago Cost \$/Gal	N.Y.C. Cost \$/Gal	Atlanta Cost \$/Gal
Western Subbituminous	2	0.615	1.4	0.660	-	-
			1.4	-	-	0.695
			1.4	-	0.696	-
Western Subbituminous	4	0.655	2.8	0.700	-	-
			2.8	-	-	0.735
			2.8	-	0.736	-
Western Subbituminous	34	0.662	32.5	0.707	-	-
			22.8	-	-	0.742
			16.1	-	0.743	-
Southern Lignite	8	0.707	16.8	-	0.789	-

TABLE 40. DELIVERED METHANOL PRICES USING NEWLY CONSTRUCTED PIPELINE TRANSPORTATION, WESTERN DEVELOPMENT RESTRICTED BY WATER AVAILABILITY, AND NO CO_2 SALES CREDIT, 1984 \$/GALLON

Producing Region	No. of Plants	Plant-Gate Cost \$/Gal	Sales 10^6 Gal./Day	Chicago Cost \$/Gal	N.Y.C. Cost \$/Gal	Atlanta Cost \$/Gal
Western Subbituminous	3	0.655	2.1	0.700	-	-
			2.1	-	-	0.735
			2.1	-	0.736	-
Western Subbituminous	7	0.662	4.9	0.707	-	-
			4.9	-	-	0.742
			4.9	-	0.743	-
Southern Lignite	31	0.707	20.0	-	-	0.747
			29.7	0.759	-	-
			14.6	-	0.789	-
Eastern Bituminous	7	0.806	14.7	-	0.828	-

Future Prices

Early in 1984 it was necessary to estimate the inflation rate between 1983 and 1984 to express plant-gate costs in 1984 dollars. At that time the inflation rate was expected to be about 10%. Toward the end of the project, that figure appeared to be high, and the real inflation rate was probably closer to 4%. If the 4% figure is proven correct, the correction factor 0.945 should be applied to prices reported here in 1984 dollars.

Several factors, such as the high federal budget deficit, which were related to high inflation rates were still present in 1984. The inflation rate was expected to increase, but because of changes in monetary policy by the Federal Reserve Board, it was not expected to return to the high rates experienced in the late 1970's. An inflation rate at 5% was projected for 1985 and 6% for the years 1986-1990.

The inflation rate was expected to be quite uniform. No reasons were found to expect differences in the inflation rate among the different coal producing regions. In 1984, crude oil prices appeared to be quite stable, which would imply a slightly lower inflation rate for transportation than for production, but not enough to alter the conclusions reached in this study. However, for the past few years, long term crude oil price forecasts had gone awry, and events in the Middle East were still seen as capable of causing big changes in both price and supply. Such changes would, of course, affect the transportation costs much more than the methanol production costs. Assuming stability in crude-oil prices, the factor 1.328 should be used to convert 1984 dollar prices as reported here to 1990 dollar prices.

VI. CONCLUSIONS

1. Based on the assumptions made in this study, methanol can be produced from coal in the southern lignite and western subbituminous regions at lower cost than in the eastern and midwestern bituminous coal regions. Costs in the northern lignite region would be about midway between the others.

2. Without pipelines, the presently available transportation to major market areas is more expensive for production in the western subbituminous and in the northern lignite regions than for other producing regions. The presently available transportation is also more expensive for delivery in the Atlanta market area than for the Chicago or New York City market areas.

3. For the production and transportation costs projected in this study, and using presently-available, non-pipeline transportation, the delivered prices of methanol would favor industry development in the southern lignite region.

4. With presently-available, non-pipeline transportation, utilization of methanol fuel would be favored in the New York City and Chicago areas over the Atlanta area. This result occurs because Atlanta, unlike most major cities in the other regions, is not adjacent to water transportation, however several other cities in the area such as Mobile, Miami, and Charleston are adjacent to water, so this result does not apply over the whole area.

5. This study indicates that new pipeline construction, requiring the right of eminent domain, could provide a significant reduction in the delivered methanol price. New pipelines would be particularly useful to serve the western subbituminous and northern lignite producing regions, and the Atlanta market area. If these pipelines were constructed, delivered prices would favor industry development in the western subbituminous producing region and utilization of the methanol fuel would not be favored in any market area over other areas.

6. The analyses of water resources presented here indicates that water availability will not prevent development of a coal-to-methanol industry in the western subbituminous region, but it will make siting more difficult. A detailed water plan must be given high priority in western siting considerations, and it may still be necessary to pay high prices for water, or to transport it a considerable distance. However, if water were much more expensive the cost of methanol would only be slightly higher. The use of dry cooling towers and other similar measures to conserve water would also make the methanol slighty more expensive. However, neither high-cost water nor water conservation were expected to cause a methanol price high enough to change the western regions' favorable economic position relative to other producing regions.

7. No major siting limitations were found for any producing region except the water supply in the western subbituminous region.

8. Carbon dioxide has potential as an important by-product in areas where it could be used for enhanced oil recovery. Credits for its sale could have a major effect on the required methanol selling price in the southern lignite, the western subbituminous, and the northern lignite regions. The loss of all credits for CO_2 was found to have little or no impact on plant siting if the industry relies on presently available transportation without pipelines. If new pipelines were extensively available, the loss of CO_2 credits would result in delivered methanol prices which should favor industry development in the western bituminous region. If western development were restricted, the southern lignite region would be favored. For individual plants, the possibility of CO_2 sales merits serious consideration and careful study.

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APPENDIX A
Program for Calculating Sales Price and Return on Investment

APPENDIX A

PROGRAM FOR CALCULATING SALES PRICE AND RETURN ON INVESTMENT

LANGUAGE: BASIC/1000C

```
10   DIM A$[70],Cf(60),Co(60),Dft(50),Dp(60),Ccf(60)
15   DIM Ebt(60),Ex(60),Fit(60),Dcp(60),Dct(20,100)
20   DIM Pv(60), Pvf(60), Roi(60), Rrpv(60),Fp(60)
25   DIM Sit(60),Sp(60),Tpv(60),Ti(60),Up(60),Bp1s(60),Bp2s(60)
30   DIM Rcst1(60),Rcst2(60),Rcst3(60),Rm1c(60),Rm2c(60),Rm3c(60)
35   DIM Rm1a(60),Rm2a(60),Rm3a(60),Ut(60),La(60),Ma(60),Ilt(60)
40   DIM Otc(60),Bp1p(60),Bp1a(60),Bp2p(60),Bp2a(60),Rp1(60)
0041 DIM Rp2(60),Rp3(60),Utp(60),Lap(60),Map(60),Iltp(60),Otp(60)
0042 DIM Bpp1(60),Bpp2(60),Opp(13),Sitp(60),Fitp(60)
45   PRINT "THIS PROGRAM CALCULATES EITHER RETURN ON INVESTMENT OR "
50   PRINT "REQUIRED SALES PRICE.  THE FIRST PART OF THE PROGRAM "
55   PRINT "REQUESTS INPUTS.  AFTER THEY ARE ENTERED YOU WILL HAVE "
60   PRINT "A CHANCE TO REVIEW AND CORRECT THEM.  "
65   PRINT
70   PRINT
75   GOSUB 360                    !  NAME INPUT
80   GOSUB 380                    !  PROJECT COST AND TIME INPUTS
85   GOSUB 710           !  TAX INFO. INPUTS
90   GOSUB 805           !  ROI INFO. INPUTS
95   GOSUB 985           !  OPERATING EXPENSE INPUTS
100  GOSUB 1590          !  EDIT ALL INPUTS
101  IF K$ <> "C" THEN 105
102  GOSUB 4300
105  Rr$ = ""
110  IF E$ = "C" THEN 250
115  GOSUB 1090          !  PRES. VALUE FACTORS
120  I=1
125  GOSUB 1115          !  (FIRST SALES PRICE EST.)
130  GOSUB 1205          !  (EARN, TAX, CASH FLOW) + (SUM RETURN)
135  IF I>1 THEN 155
140  I=I+1
145  GOSUB 1530          !  (NEW SALES ESTIMATE)
150  GOTO 130
155  IF ABS(Up(I)-Up(I-1))< Spa*Up(I)  THEN  346
160  IF I>3 THEN 180
165  I=I+1
170  GOSUB 1530         !  (NEW SALES ESTIMATE)
175  GOTO 130
180  Ds3=ABS(Up(I-3)-Up(I-2))
185  Ds2 = ABS(Up(I-2)-Up(I-1))
190  Ds1 = ABS(Up(I-1)-Up(I))
195  IF Ds3 > Ds2 OR Ds3 > Ds1 THEN 140
200  PRINT " SUCCESSIVE CALCULATIONS DO NOT IMPROVE "
205  PRINT " THE SOLUTION.  THESE PRICES WERE TRIED: "
210  FOR L = 1 TO I
214 FIXED 6
215  PRINT " SALES PRICE TRIAL ";L;" WAS "; Up(L)   ; "PER" ;G$
216 FIXED 0
220  NEXT L
225  PRINT " DO YOU WISH TO PRINT THE OUTPUT (Y) "
230  PRINT " OR QUIT WITH NO OUTPUT (N)?  CHOICE Y EVENTUALLY ALLOWS A RERUN."
```

```
235   INPUT F$
240   IF F$ = "N" THEN 8000
245   GOTO 346
250   GOSUB 1205           ! EARNINGS, TAX + CASH FLOW
255   GOSUB 1475           !INITIAL EST. RATE OF RETURN
260   I=0
265   Roi(I) = Roip
270   GOSUB 1090           !  CALC. PRESENT VALUE FACTORS
275   GOSUB 1445           !  PRESENT VALUES AND SUMS
280   Rrpv(I) = Tpv(Pl)
285   IF I<2 THEN 300
290   Dv = ABS(Rrpv(I)-Rrpv(I-1))
295   IF Dv > ABS(Rrpv(I) + Rrpv(I-1)) THEN 330
300   I=I+1
305   IF Rrpv(I-1) > 0 THEN 320
310   Roip = Roi(I-1)-1
315   GOTO 265
320   Roip = Roi(I-1) + 1
325   GOTO 265
330   Roip = (Rrpv(I)/Dv) + Roi(I)       ! FINAL ROI INTERPOLATION
335   GOSUB 1090                         ! CALC. PRESENT VALUE FACTORS
340   GOSUB 1445                         ! CALC. PRESENT VALUES AND SUMS
345   GOSUB 1115            ! FOR ONLY THE PRESENT VALUE OF CASH OUTLAYS
346   IF K$ <> "C" THEN 350
347   GOSUB 4400             ! FOR OPERATING EXPENSE % BY CATEGORY
350   GOSUB 2040            ! PRINT OUTPUTS.  (END OF MAIN PROGRAM).
360   PRINT " ENTER NAME OF PROJECT AND/OR CASE NUMBER "
365   PRINT " 70 CHARACTERS MAX "
370   INPUT A$
375   RETURN
380   PRINT " ENTER THE TOTAL PROJECT COSTS "
385   INPUT Pc
390   PRINT " ENTER TOTAL YEARS FOR PROJECT LIFE, "
395   PRINT " INCLUDING CONSTRUCTION YEARS "
400   INPUT Pl
405   PRINT " ENTER TOTAL YEARS FOR CONSTRUCTION "
410   INPUT Cy
415   Yd1 = Cy + 1
420   GOSUB 595            .!  DEPRECIATION  INPUTS
425   RETURN
430   PRINT
435   PRINT
440   PRINT " CONSTRUCTION SCHEDULE ENTRIES "
445   PRINT
450   PRINT " ENTER PERCENT SPENT IN EACH CONSTRUCTION YEAR- "
455   PRINT
460   FOR Y = 1 TO Cy
465   PRINT " PERCENT SPENT IN YEAR ";Y;" = "
470   INPUT Cp(Y)
475   Co(Y) = (Pc*Cp(Y))/100
480   NEXT Y
485   PRINT " FOR HOW MANY OTHER YEARS WILL THERE "
490   PRINT " BE CASH OUTLAYS OR RECOVERIES ? (MAXIMUM = 20) "
495   INPUT Yco
500   FOR Z = 1 TO Yco
505   PRINT " ENTER A YEAR NO., IT'S NET CASH OUTLAYS, "
507  PRINT " AND IF NOT DEPRECIABLE, THE LETTER N."
510   PRINT " (FOR EXAMPLE 17,12900,N).  USE A - SIGN FOR CASH "
515   PRINT " RECOVERIES, (FOR EXAMPLE 35,-52500, ) "
520   INPUT Y,C,Dep$
525   Co(Y)  = C
535   IF C<0 OR Dep$="N" THEN 560
538   Ya = Y + Tdy
540   FOR Yy = Y TO Ya
545   Aa = Yy - Y + Yd1
550   Dct(Z,Yy) = C*(Dp(Aa)/100)
```

```
555  NEXT Yy
560  NEXT Z
565  FOR Y = Yd1 TO P1
570  FOR Dc = 1 TO Yco
575  Dft(Y) = Dft(Y) + Dct(Dc,Y)
580  NEXT Dc
585  NEXT Y
590  RETURN
595  PRINT " ENTER COST OF DEPRECIABLE ASSETS "
600  INPUT Da
605  PRINT " ENTER NUMBER OF YEARS FOR TAX DEPRECIATION "
610  PRINT " AFTER END OF CONSTRUCTION "
615  INPUT Tdy
620  PRINT " IS TAX DEPRECIATION STRAIGHT LINE ? Y OR N "
625  INPUT D$
630  Yde = Cy + Tdy
635  IF D$ = "N" THEN 665
640  FOR Y = Yd1 TO Yde
645  Dft(Y) = Da/Tdy
650  Dp(Y) = 100/Tdy
655  NEXT Y
660  GOTO 700
665  PRINT " ENTER PERCENT DEPRECIATED EACH YEAR "
670  PRINT " STARTING WITH THE YEAR AFTER CONSTRUCTION ENDS "
675  FOR Y = Yd1 TO Yde
680  PRINT " PERCENT DEPRECIATED IN YEAR  ";Y;" = "
685  INPUT Dp(Y)
690  Dft(Y) = (Da*Dp(Y))/100
695  NEXT Y
700  GOSUB 430              !  CONST. CASH OUTLAYS INPUTS
705  RETURN
710  Ftr = 0.46
715  PRINT " ENTER PERCENT FEDERAL CORPORATE TAX RATE "
720  PRINT " (DEFAULT IS 46%).  IN THIS PROGRAM STATE TAX IS "
725  PRINT " A FEDERAL TAX DEDUCTION "
730  INPUT C$
735  IF LEN(C$) = 0 THEN  755
740  Ftr = (VAL(C$))/100
745  Str = 0
755  PRINT " ENTER PERCENT STATE CORPORATE OR FRANCHISE "
760  PRINT " TAX RATE (DEFAULT IS 0%).  IN THIS PROGRAM "
765  PRINT " FEDERAL TAX IS NOT A STATE TAX DEDUCTION "
770  INPUT Strp
775  Str = Strp/ 100
781  PRINT
784  PRINT " ENTER THE PERCENT INVESTMENT TAX CREDIT "
785  PRINT " APPLICABLE (FEDERAL) - NOT APPLIED TO CASH OUTLAYS FOLLOWING "
790  PRINT " THE INITIAL CONSTRUCTION"
795  INPUT Itcp
800  RETURN
805  PRINT " IS RETURN ON INVESTMENT TO BE CALCULATED (C)"
810  PRINT " OR SUPPLIED BY YOU (S) ? ENTER C OR S.  "
815  INPUT E$
820  IF E$ = "C" THEN 885
825  IF E$ = "S" THEN 845
830  PRINT " ROI MUST EITHER BE CALCULATED (C) OR SUPPLIED (S) "
835  PRINT " ENTER C OR S PLEASE. "
840  GOTO 815
845  PRINT " ENTER RETURN ON INVESTMENT IN PERCENT. "
850  INPUT Roip
855  PRINT " ENTER REQUIRED ACCURACY FOR SALES PRICE. "
860  PRINT " MUST BE BETWEEN 0.01% AND 100% OF SALES PRICE. "
865  INPUT Spap
870  IF Spap < 0.01 THEN Spap = 0.01
875  IF Spap > 100 THEN Spap = 100
880  Spa = Spap/100
```

```
885  PRINT " ENTER ANNUAL SALES VOLUME,UNITS. FOR EXAMPLE-- 185,TON"
890  INPUT Sv, G$
895  IF E$ = "S" THEN 980
900  PRINT " IF SALES PRICE WILL BE CONSTANT OVER PROJECT LIFE, "
905  PRINT " ENTER SALES PRICE PER  ";G$;".  IF YOU WISH TO SUPPLY"
910  PRINT " FORECAST PRICES, ENTER F"
915  INPUT J$
920  IF J$ = "F" THEN 955
925  Jm = VAL(J$)*Sv
930  FOR Y = Yd1 TO P1
935  Fp(Y) = VAL(J$)
940  Sp(Y) = Jm
945  NEXT Y
950  GOTO 980
955  FOR Y = Yd1 TO P1
960  PRINT " ENTER FORECAST PRICE FOR YEAR  ";Y
965  INPUT Fp(Y)
970  Sp(Y) = Fp(Y)*Sv
975  NEXT Y
980  RETURN
985  PRINT " IF NET ANNUAL OPERATING EXPENSES WILL BE CONSTANT "
990  PRINT " OVER THE PROJECT LIFE, ENTER THE AMOUNT.  IF YOU WISH "
995  PRINT " TO SUPPLY NET EXPENSES FOR EACH YEAR, ENTER F.  IF"
1000 PRINT " YOU WISH TO SUPPLY EXPENSES BY CATEGORY, ENTER C."
1005 INPUT K$
1010 Expt = 0
1015 IF K$ = "F" THEN 1050
1020 IF K$ = "C" THEN 1080
1025 FOR Y = Yd1 TO P1
1030 Ex(Y) = VAL(K$)
1035 Expt = Expt + Ex(Y)
1040 NEXT Y
1045 GOTO 1085
1050 FOR Y = Yd1 TO P1
1055 PRINT " ENTER FORECAST NET OPERATING EXPENSE FOR YEAR  ";Y
1060 INPUT Ex(Y)
1065 Expt = Expt + Ex(Y)
1070 NEXT Y
1075 GOTO 1085
1080 GOSUB 2500
1085 RETURN
1090 Rf = 1/(1 + (Roip/100))
1095 FOR Y = 1 TO P1
1100 Pvf(Y) = ((Rf^Y)-(Rf^(Y-1)))/LOG(Rf)
1105 NEXT Y
1110 RETURN
1115 Sf=0
1120 Tvco = 0
1125 IF E$ = "C" THEN 1150
1130 FOR Y = Yd1 TO P1
1135 Sf = Sf + Pvf(Y)          ! SUM OF PRESENT VALUE FACTORS
1140 NEXT Y
1145 Sfa = Sf/(P1-Cy)          ! AVERAGE OF PRESENT VALUE FACTORS
1150 FOR Y = 1 TO P1
1155 Tvco = Tvco + Pvf(Y)*Co(Y)   ! TOTAL PRESENT VALUES OF ALL CASH OUTLAYS
1160 NEXT Y
1165 IF E$ = "C" THEN 1200
1170 Sfr = Str + (Ftr*(1-Str))    ! COMBINED STATE AND FED. TAX RATE (EST.)
1175 Sa = (((Tvco/Sfa) - (Da*Sfr))/(1-Sfr) + Expt)/ (P1-Cy)  ! EST. AVG.
             ! ANNUAL SALES
1180 FOR Y = Yd1 TO P1
1185 Sp(Y) = Sa
1190 NEXT Y
1195 Up(I) = Sa/Sv             ! TRIAL UNIT PRICE
1200 RETURN
```

```
1205 Ccfc = 0
1206 FOR Y = Yd1 TO P1
1210 Ebt(Y) =  Sp(Y) - Ex(Y)       ! EARNINGS BEFORE TAXES
1215 Sit(Y)=(Ebt(Y)-Dft(Y))*Str   ! STATE INC./FRANCHISE TAX
1220 Ti(Y) = Ebt(Y) - Dft(Y) - Sit(Y) ! FEDERAL TAXABLE INCOME
1225 IF Ebt(Y) < 0 THEN Sit(Y) = 0 AND Ti(Y) = 0
1230 NEXT Y
1235 Itc = (Itcp/100)*Da    ! FEDERAL INVESTMENT TAX CREDIT
1240 Fitl = Ftr*Ti(Yd1)     ! FEDERAL INCOME TAX LIABILITY
1245 FOR Y = Yd1 TO P1
1250 IF Fitl>=25000 THEN 1290
1255 IF Itc <= Fitl THEN 1275
1260 Fit(Y) = 0
1265 Itc = Itc - Fitl
1270 GOTO 1355
1275 Fit(Y) = Fitl-Itc          ! FEDERAL INCOME TAX
1280 Itc = 0
1285 GOTO 1355
1290 IF Itc < 25000 THEN 1330
1295 Ft1 = Fitl - 25000
1300 Itc = Itc - 25000
1305 Tric = 0.85*Ft1
1310 IF Tric<=Itc THEN 1345
1315 Fit(Y) = Ft1 - Itc
1320 Itc = 0
1325 GOTO 1355
1330 Fit(Y) = Fitl - Itc        ! FEDERAL INCOME TAX
1335 Itc = 0
1340 GOTO 1355
1345 Itc = Itc - Tric
1350 Fit(Y) = Ft1 - Tric
1355 Fitl = Ftr*Ti(Y+1)
1360 IF Y - Yd1 > 15 THEN Itc = 0
1365 NEXT Y
1370 Ccf(0) = 0
1375 Tpv(0) = 0
1380  FOR Y = 1 TO P1
1385 Cf(Y) = Ebt(Y) - Co(Y) - Sit(Y) - Fit(Y)    ! CASH FLOW
1395 Ccf(Y) = Ccf(Y-1) + Cf(Y)                   ! CUMULATIVE CASH FLOW
1400 IF Ccfc > 0 OR Ccf(Y) < 0 THEN 1405
1402 GOSUB 1441
1405 IF E$ = "C" THEN 1435
1410 Pv(Y) = Cf(Y)*Pvf(Y)          ! PRESENT VALUES OF CASH FLOWS
1415 Tpv(Y) = Tpv(Y-1) + Pv(Y)     ! CUMULATIVE PRES. VALUES OF CASH FLOWS
1435 NEXT Y
1440 RETURN
1441 Pop = Y - 1 + ((-1)*(Ccf(Y-1)))/(Ccf(Y)-Ccf(Y-1))
1442 Ccfc = 1
1443 RETURN
1445 Tpv(0) = 0
1450 FOR Y = 1 TO P1
1455 Pv(Y) = Cf(Y)*Pvf(Y)
1460 Tpv(Y) = Tpv(Y-1) + Pv(Y)
1465 NEXT Y
1470 RETURN
1475 Tci = 0
1480 Tco = 0
1485 Fh = INT((P1 - Cy)/2 ) + Cy   ! YR. NO. TO END FIRST HALF CASH INTAKES
1490 FOR Y = Yd1 TO Fh
1495 Tci = Tci + Cf(Y)          ! EST. FIRST HALF CASH INTAKES
1500 NEXT Y
1505 FOR Y = 1 TO P1
1510 Tco = Tco + Co(Y)          ! TOTAL CASH OUTLAYS
1515 NEXT Y
1520 Roip = (100*Tci)/(Tco*(Fh-Cy))    ! INITIAL ESTIMATE RATE OF RETURN
1525 RETURN
```

```
1530 Tcf = 0
1535 FOR Y = Yd1 TO P1
1540 Tcf = Tcf + Cf(Y)
1545 NEXT Y
1550 Sa = Sa*(1-((1+(Roip/4))*(Tpv(P1)/Tcf)))    ! NEW ANNUAL SALES ESTIMATE
1555 FOR Y = Yd1 TO P1
1560 Sp(Y) = Sa                 ! FOR OUTPUT LISTING OF ANNUAL SALES
1565 NEXT Y
1570 Up(I) = Sa/Sv              ! NEW UNIT PRICE ESTIMATE
1575 RETURN
1580 IF ((Y-1)/5-INT((Y-1)/5)) = 0 THEN PRINT  ! SPACE TOP AND AFTER 5
1585 RETURN
1590 PRINT
1595 PRINT
1600 PRINT " INPUTS WILL BE SHOWN IN SECTIONS FOR CHECKING.  "
1605 PRINT
1610 PRINT " A. PROGRAM NAME: "
1615 PRINT
1620 PRINT A$
1625 GOSUB 2005
1630 IF Z$ <> "N" THEN 1640
1635 GOSUB 360
1640 PRINT " B.   PROJECT DATA "
1645 PRINT "      TOTAL PROJECT COST =   "; Pc
1650 PRINT "      PROJECT LIFE INCLUDING CONSTRUCTION =   "; P1
1655 PRINT "      CONSTRUCTION PERIOD IS TO BE   "; Cy ; "  YEARS"
1660 GOSUB 2005
1665 IF Z$ <> "N" THEN 1675
1670 GOSUB 380
1675 PRINT " C.   DEPRECIATION: "
1680 PRINT "      DEPRECIABLE ASSETS=  "; Da
1685 PRINT
1690 FOR Y = Yd1 TO Yde
1695 PRINT "      % DEPRECIATION FOR YEAR  "; Y ;" = ";Dp(Y)
1700 NEXT Y
1705 GOSUB 2005
1710 IF Z$ <> "N" THEN 1720
1715 GOSUB 595
1720 PRINT " D.   CONSTRUCTION AND OTHER OUTLAYS:  "
1725 FOR Y = 1 TO Cy
1730 PRINT "      PERCENT SPENT IN YEAR  "; Y ; "FOR CONSTRUCTION =  ";Cp(Y)
1735 NEXT Y
1738 PRINT
1740 FOR Y = Yd1 TO P1
1745 IF Co(Y) = 0 THEN 1755
1750 PRINT "      CASH OUTLAYS FOR YEAR  ";Y ;"= ";Co(Y)
1755 NEXT Y
1760 GOSUB 2005
1765 IF Z$ <> "N" THEN 1775
1770 GOSUB 430
1775 PRINT
1780 PRINT " E.   TAX INFORMATION: "
1785 PRINT "      FEDERAL TAX RATE IS ";100*Ftr;"PERCENT, AND THE STATE "
1790 PRINT "      INCOME OR FRANCHISE TAX RATE IS  ";Strp;" PERCENT"
1795 PRINT
1800 PRINT "      THE INVESTMENT TAX CREDIT IS ";Itcp;" PERCENT "
1805 PRINT "      OF THE DEPRECIABLE ASSETS NOT INCLUDING CASH OUTLAYS"
1810 GOSUB 2005
1815 IF Z$ <> "N" THEN 1825
1820 GOSUB 710
1825 PRINT "F.    RETURN ON INVESTMENT (ROI): "
1830 PRINT "      ROI IS TO BE   "
1835 IF E$ = "C" THEN PRINT "      CALCULATED FROM SALES YOU SUPPLY" ELSE 1845
```

```
1840 GOTO 1850
1845 PRINT "      SUPPLIED BY YOU FOR CALCULATION OF REQUIRED SELLING PRICE."
1850 IF E$ = "C" THEN 1870
1855 PRINT "      ROI IS ";Roip;"  PERCENT AND THE SELLING PRICE"
1860 PRINT "      ACCURACY IS ";Spap; " PERCENT OF THE SELLING PRICE."
1865 PRINT
1870 PRINT "      ANNUAL SALES VOLUME IS ";Sv; G$
1875 IF E$ = "S" THEN 1920
1880 PRINT "      ANNUAL CASH INTAKES FROM SALES WILL BE BASED ON "
1885 PRINT "      THESE PRICES:"
1890 PRINT
1895 PRINT "YEAR  ", "FORECAST PRICE"
1900 FOR Y = Yd1 TO P1
1905 GOSUB 1580
1910 PRINT Y, Fp(Y)
1915 NEXT Y
1920 GOSUB 2005
1925 IF Z$ <> "N" THEN 1935
1930 GOSUB 805
1935 PRINT " G. NET OPERATING EXPENSES: "
1936 IF K$ = "C" THEN 1967
1940 PRINT
1945 PRINT " YEAR ", "OPER.  EXPENSES"
1950 FOR Y = Yd1 TO P1
1955 GOSUB 1580
1960 PRINT Y, Ex(Y)
1965 NEXT Y
1966 GOTO 1970
1967 GOSUB 3500
1970 GOSUB 2005
1975 IF Z$ <> "N" THEN 1985
1980 GOSUB 985
1985 PRINT " INPUT REVIEW COMPLETED - BUT THERE IS ALWAYS ANOTHER CHANCE. "
1990 PRINT " WOULD YOU LIKE TO REVIEW THE INPUTS AGAIN ?  Y OR N  "
1995 INPUT Z$
2000 IF Z$ = "Y" THEN 1590 ELSE 2035
2005 PRINT
2010 Z$ = ""
2015 PRINT " IS THIS SECTION CORRECT ?  ENTER N TO RESUBMIT THE SECTION, "
2020 PRINT " OR CARRIAGE RETURN TO CHECK THE NEXT SECTION.  ALSO, USE THE"
2025 PRINT " CARRIAGE RETURN FOR VALUES WHICH ARE ALREADY CORRECT."
2030 INPUT Z$
2035 RETURN
2040 PRINT " DO YOU WANT A PAUSE (P) BETWEEN PAGES FOR CUSTOM PRINTOUT,"
2041 PRINT " OR DO YOU WANT CONTINUOUS (C) PRINTOUT?"
2042 INPUT A1$
2043 IF A1$<>"P" AND A1$<>"C" THEN 2040
2044 PRINT A$
2045 PRINT
2046 Pr = 1
2050 PRINT " PAGE 1 -- CASH OUTLAYS AND DEPRECIATION "
2055 PRINT
2060 PRINT " YR. "; "CASH OUTLAYS","SALES","EARNINGS", "TAX"
2065 PRINT "      ";"   ","   ","BEFORE TAX","DEPRECIATION"
2070 PRINT
2075 FIXED 0
2080 FOR Y= 1 TO P1
2085 GOSUB 1580
2090 PRINT USING 2445; Y ; Co(Y),Sp(Y),Ebt(Y),Dft(Y)
2095 NEXT Y
2100 GOSUB 2455
2105 PRINT A$
2110 PRINT
2115 PRINT "PAGE 2 -- TAXES AND CASH FLOW "
2120 PRINT
```

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2125 PRINT "YR. "; "STATE","TAXABLE","FEDERAL","CASH"
2130 PRINT "    ";" TAX","INCOME (FED.)","TAX","FLOW"
2135 PRINT
2140 FOR Y = 1 TO P1
2145 GOSUB 1580
2150 PRINT USING 2445; Y ;Sit(Y),Ti(Y),Fit(Y),Cf(Y)
2155 NEXT Y
2160 GOSUB 2455
2165 PRINT A$
2170 PRINT
2175 FIXED 3
2180 PRINT "PAGE 3 -- CUMULATIVE CASH FLOWS AND PRESENT VALUES "
2185 PRINT "            FOR "; Roip ; " PERCENT RETURN ON INVESTMENT"
2190 FIXED 0
2195 PRINT
2200 PRINT "YR.   ";"CUMULATIVE ","PRESENT ","PRESENT","CUMULATIVE"
2205 PRINT "      ";"CASH FLOW ","VALUE FACTOR", "VALUES","PRES. VALUES"
2210 PRINT
2215 FOR Y= 1 TO P1
2220 GOSUB 1580
2225 PRINT USING 2450; Y ;Ccf(Y),Pvf(Y),Pv(Y),Tpv(Y)
2230 NEXT Y
2235 GOSUB 2455
2240 PRINT A$
2245 PRINT
2250 PRINT "APPENDIX A -- PRICE, RETURN AND OTHER INFORMATION"
2255 PRINT
2260 IF J$ = "F" THEN 2300
2265 IF E$ = "C" THEN 2300
2270 FIXED 6
2275 PRINT "     THE PRICE IS "; Up(I)      ;"PER "; G$
2280 FIXED 0
2285 PRINT "     VALUE OF AVERAGE ANNUAL SALES: ";Sa
2290 FIXED 4
2295 PRINT "     REQUIRED ACCURACY:      ";Spap;"%"
2300 PRINT
2305 FIXED 1
2310 PRINT "     THE RETURN ON INVESTMENT IS "; Roip ; "PERCENT"
2315 FIXED 2
2320 PRINT
2325 PRINT "     THE PAYOUT PERIOD IS "; Pop ; "YEARS."
2330 PRINT
2335 FIXED 0
2340 PRINT
2345 PRINT "     THE TOTAL PRESENT VALUES OF ALL CASH OUTLAYS:    ";Tvco
2350 IF E$ = "S" THEN 2365
2355 PRINT "     TOTAL CASH OUTLAYS:       ";Tco
2356 PRINT
2360 IF E$ = "C" THEN 2405
2365 PRINT "     THIS SOLUTION REQUIRED ";I ;"ITERATIONS"
2370 PRINT "     THE FOLLOWING SALES WERE TRIED: "
2375 FIXED 4
2380 PRINT
2385 PRINT "ITERATION","PRICE / ";G$
2390 FOR W = 1 TO I
2395 PRINT W , Up(W)
2400 NEXT W
2401 IF K$ <> "C" THEN 2405
2402 GOSUB 4600
2405 GOSUB 2455
2410 PRINT
2411 IF K$ <> "C" THEN 2415
2412 GOSUB 3500
2413 Pr = 0
2414 GOSUB 4900
2415 PRINT " IF YOU WISH TO RE-EDIT THE INPUTS, AND RERUN THE PROGRAM, "
2420 PRINT " ENTER  RR "
2425 INPUT Rr$
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2430 STANDARD
2435 IF Rr$ = "RR" THEN 5000 ELSE 7980
2440 RETURN
2445 IMAGE DD,11D,16D,20D,20D
2446 IMAGE DD,10D.DD,17D,15D.DD,10X,DD.3D
2447 IMAGE DD,13D.2D,2X,12D.3D,14D.DD,2X,11D.3D
2448 IMAGE DD,3X,K,8X,K,20D,12X,2D.3D
2450 IMAGE DD,13D,6X,Z.6D,17D,2X,20D
2455 PRINT
2456 IF A1$ = "C" AND Pr = 1 THEN 2492
2460 PRINT
2465 PRINT " THE PROGRAM HAS PAUSED.  THE TERMINAL MAY BE PUT IN LOCAL MODE"
2470 PRINT " TO PRINT OUT OR MANIPULATE THE DISPLAY.  WHEN READY FOR THE "
2475 PRINT " NEXT PAGE, ENSURE THE TERMINAL IS IN REMOTE MODE AND TYPE"
2480 PRINT " CONT.  IF YOU WISH TO QUIT, TYPE STOP.  CAUTION!!!!  "
2485 PRINT " STOP CAUSES LOSS OF ALL DATA!!! "
2490 PAUSE
2491 GOTO 2495
2492 FOR P5 = 1 TO 10
2493 PRINT
2494 NEXT P5
2495  RETURN
2500 PRINT " INPUTS CAN BE MADE IN THESE OPERATING COST CATEGORIES:"
2505 PRINT "     3 RAW MATERIALS (UNIT COST, ANNUAL CONSUMPTION EACH)"
2510 PRINT "     UTILITIES"
2515 PRINT "     TOTAL OPERATING LABOR"
2520 PRINT "     TOTAL MAINTENANCE "
2525 PRINT "     INSURANCE PLUS LOCAL TAXES"
2530 PRINT "     ONE OTHER COST ITEM, YOU NAME IT"
2535 PRINT "     2 BY-PRODUCT CREDITS (UNIT PRICE, ANNUAL SALES EACH)"
2540 PRINT
2541 PRINT
2542 PRINT "!!!   CAUTION   !!! "
2543 PRINT
2544 PRINT " IN THE NEXT SECTION, A ZERO INPUT IS NOT RECOGNIZED - THE"
2545 PRINT " COMPUTER WILL ASSIGN THE PREVIOUS YEAR'S VALUE TO THE"
2546 PRINT " CURRENT YEAR.  IF ZERO IS DESIRED, IT CAN BE APPROXIMATED"
2547 PRINT " BY A VERY SMALL NUMBER."
2548 GOSUB 7945
2550 IF Sk$ = "S" THEN 2635
2551 B1=1
2555 PRINT "      ENTER THE NAME OF THE FIRST RAW MATERIAL:"
2560 INPUT Rm1$
2565 FOR Y = Yd1 TO P1
2570 PRINT " ENTER UNIT COST FOR YEAR ";Y;".  IF SAME AS PREVIOUS "
2575 PRINT " YEAR, MAKE NO ENTRY."
2580 INPUT Rm1c(Y)
2590 IF Rm1c(Y) = 0 THEN Rm1c(Y) = Rm1c(Y-1)
2595 NEXT Y
2596 GOSUB 4800
2600 FOR Y = Yd1 TO P1
2605 PRINT " ENTER ANNUAL USE FOR YEAR ";Y;".  IF SAME AS PREVIOUS "
2610 PRINT " YEAR, MAKE NO ENTRY."
2615 INPUT Rm1a(Y)
2625 IF Rm1a(Y) = 0 THEN Rm1a(Y) = Rm1a(Y-1)
2630 NEXT Y
2635 PRINT
2636 PRINT " THE NEXT CATEGORY IS THE SECOND RAW MATERIAL,"
2640 GOSUB 7945
2645 IF Sk$ = "S" THEN 2727
2646 B2=1
2650 PRINT "ENTER THE NAME OF THE SECOND RAW MATERIAL:"
2655 INPUT Rm2$
2660 FOR Y = Yd1 TO P1
2665 PRINT " ENTER UNIT COST FOR YEAR ";Y;".  IF SAME AS PREVIOUS "
2670 PRINT " YEAR, MAKE NO ENTRY."
2675 INPUT Rm2c(Y)
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2685 IF Rm2c(Y) = 0 THEN Rm2c(Y) = Rm2c(Y-1)
2690 NEXT Y
2692 GOSUB 4800
2695 FOR Y = Yd1 TO P1
2700 PRINT " ENTER ANNUAL USE FOR YEAR ";Y;".  IF SAME AS PREVIOUS "
2705 PRINT " YEAR, MAKE NO ENTRY."
2710 INPUT Rm2a(Y)
2720 IF Rm2a(Y) = 0 THEN Rm2a(Y) = Rm2a(Y-1)
2725 NEXT Y
2727 PRINT
2728 PRINT " THE NEXT CATEGORY IS THE THIRD RAW MATERIAL,"
2730 GOSUB 7945
2735 IF Sk$ = "S" THEN 2817
2736 B3=1
2740 PRINT "ENTER THE NAME OF THE THIRD RAW MATERIAL:"
2745 INPUT Rm3$
2750 FOR Y = Yd1 TO P1
2755 PRINT " ENTER UNIT COST FOR YEAR ";Y;".  IF SAME AS PREVIOUS "
2760 PRINT " YEAR, MAKE NO ENTRY."
2765 INPUT Rm3c(Y)
2775 IF Rm3c(Y) = 0 THEN Rm3c(Y) = Rm3c(Y-1)
2780 NEXT Y
2781 GOSUB 4800
2785 FOR Y = Yd1 TO P1
2790 PRINT " ENTER ANNUAL USE FOR YEAR ";Y;".  IF SAME AS PREVIOUS "
2795 PRINT " YEAR, MAKE NO ENTRY."
2800 INPUT Rm3a(Y)
2810 IF Rm3a(Y) = 0 THEN Rm3a(Y) = Rm3a(Y-1)
2815 NEXT Y
2817 PRINT
2818 PRINT " THE NEXT CATEGORY IS THE TOTAL UTILITIES,"
2820 GOSUB 7945
2825 IF Sk$ = "S" THEN  2931
2826 B4=1
2840 PRINT " IF UTILITIES COST WILL BE CONSTANT OVER THE"
2845 PRINT " PROJECT LIFE, ENTER THE AMOUNT.  IF YOU WISH "
2850 PRINT " TO SUPPLY FORECAST COSTS, ENTER F.  IF UTILITIES"
2855 PRINT " WILL BE PRODUCED ON-SITE (COSTS INCLUDED ELSE-"
2860 PRINT " WHERE), ENTER P."
2865 INPUT Ut$
2870 IF Ut$ = "P" THEN 2931
2875 IF Ut$ = "F" THEN 2900
2880 FOR Y = Yd1 TO P1
2885 Ut(Y) = VAL(Ut$)
2890 NEXT Y
2895 GOTO 2931
2900 FOR Y = Yd1 TO P1
2905 PRINT " ENTER ANNUAL UTILITY COST FOR YEAR ";Y;" IF SAME AS "
2910 PRINT " PREVIOUS YEAR , MAKE NO ENTRY."
2915 INPUT Ut(Y)
2925 IF Ut(Y) = 0 THEN Ut(Y) = Ut(Y-1)
2930 NEXT Y
2931 PRINT
2932 PRINT " THE NEXT CATEGORY IS THE TOTAL LABOR,"
2933 GOSUB 7945
2934 IF Sk$ = "S" THEN 3012
2935 PRINT " IF LABOR COST WILL BE CONSTANT OVER THE"
2940 PRINT " PROJECT LIFE, ENTER THE AMOUNT.  IF YOU WISH "
2945 PRINT " TO SUPPLY FORECAST COSTS, ENTER F."
2950 INPUT La$
2951 B5=1
2955 IF La$ = "F" THEN 2980
2960 FOR Y = Yd1 TO P1
2965 La(Y) = VAL(La$)
2970 NEXT Y
2975 GOTO 3012
```

```
2980 FOR Y = Yd1 TO P1
2985 PRINT " ENTER ANNUAL LABOR COST FOR YEAR ";Y;" IF SAME AS "
2990 PRINT " PREVIOUS YEAR , MAKE NO ENTRY."
2995 INPUT La(Y)
3005 IF La(Y) = 0 THEN La(Y) = La(Y-1)
3010 NEXT Y
3011 PRINT
3012 PRINT " THE NEXT CATEGORY IS THE TOTAL MAINTENANCE,"
3013 GOSUB 7945
3014 IF Sk$ = "S" THEN 3092
3015 PRINT " IF MAINTENANCE COST WILL BE CONSTANT OVER THE"
3020 PRINT " PROJECT LIFE, ENTER THE AMOUNT.  IF YOU WISH "
3025 PRINT " TO SUPPLY FORECAST COSTS, ENTER F."
3030 INPUT Ma$
3031 B6=1
3035 IF Ma$ = "F" THEN 3060
3040 FOR Y = Yd1 TO P1
3045 Ma(Y) = VAL(Ma$)
3050 NEXT Y
3055 GOTO 3092
3060 FOR Y = Yd1 TO P1
3065 PRINT " ENTER ANNUAL MAINTENANCE COST FOR YEAR ";Y;" IF SAME AS "
3070 PRINT " PREVIOUS YEAR , MAKE NO ENTRY."
3075 INPUT Ma(Y)
3085 IF Ma(Y) = 0 THEN Ma(Y) = Ma(Y-1)
3090 NEXT Y
3092 PRINT
3093 PRINT " THE NEXT CATEGORY IS INSURANCE PLUS LOCAL TAXES,"
3095 GOSUB 7945
3098 IF Sk$ = "S" THEN 3176
3099 B7=1
3100 PRINT " IF INSURANCE AND LOCAL TAXES WILL BE CONSTANT OVER THE"
3105 PRINT " PROJECT LIFE, ENTER THE AMOUNT.  IF YOU WISH "
3110 PRINT " TO SUPPLY FORECAST COSTS, ENTER F."
3115 INPUT I1t$
3120 IF I1t$ = "F" THEN 3145
3125 FOR Y = Yd1 TO P1
3130 I1t(Y) = VAL(I1t$)
3135 NEXT Y
3140 GOTO 3176
3145 FOR Y = Yd1 TO P1
3150 PRINT " ENTER INSURANCE AND LOCAL TAX COST FOR YEAR ";Y
3155 PRINT " IF SAME AS THE PREVIOUS YEAR , MAKE NO ENTRY."
3160 INPUT I1t(Y)
3170 IF I1t(Y) = 0 THEN I1t(Y) = I1t(Y-1)
3175 NEXT Y
3176 PRINT
3177 PRINT " THE NEXT CATEGORY IS GENERAL; A NAME WILL BE REQUESTED."
3180 GOSUB 7945
3182 IF Sk$ = "S" THEN 3272
3183 B8=1
3185 PRINT " ENTER THE NAME OF ANOTHER COST CATEGORY:"
3190 INPUT Ot$
3195 PRINT " IF ";Ot$;" COST WILL BE"
3200 PRINT " CONSTANT OVER THE PROJECT LIFE, ENTER THE AMOUNT."
3205 PRINT " IF YOU WISH TO SUPPLY FORECAST COSTS, ENTER F."
3210 INPUT Otc$
3215 IF Otc$ = "F" THEN 3240
3220 FOR Y = Yd1 TO P1
3225 Otc(Y) = VAL(Otc$)
3230 NEXT Y
3235 GOTO 3272
3240 FOR Y = Yd1 TO P1
3245 PRINT " ENTER ";Ot$;" COST FOR YEAR ";Y
3250 PRINT " IF SAME AS THE PREVIOUS YEAR , MAKE NO ENTRY."
3255 INPUT Otc(Y)
3265 IF Otc(Y) = 0 THEN Otc(Y) = Otc(Y-1)
3270 NEXT Y
```

```
3272 PRINT
3273 PRINT " THE NEXT CATEGORY IS THE FIRST BY-PRODUCT CREDIT."
3275 GOSUB 7945
3277 IF Sk$="S"THEN 3350
3278 B9=1
3280 PRINT "ENTER THE NAME OF THE FIRST BY-PRODUCT:"
3285 INPUT Bp1$
3290 FOR Y = Yd1 TO P1
3295 PRINT " ENTER UNIT PRICE FOR YEAR ";Y;".  IF SAME AS PREVIOUS "
3300 PRINT " YEAR, MAKE NO ENTRY."
3305 INPUT Bp1p(Y)
3310 IF Bp1p(Y) = 0 THEN Bp1p(Y) = Bp1p(Y-1)
3315 NEXT Y
3316 GOSUB 4800
3320 FOR Y = Yd1 TO P1
3325 PRINT " ENTER ANNUAL SALES VOLUME FOR YEAR ";Y;" .  IF SAME AS"
3330 PRINT " PREVIOUS YEAR, MAKE NO ENTRY."
3335 INPUT Bp1a(Y)
3340 IF Bp1a(Y) = 0 THEN Bp1a(Y) = Bp1a(Y-1)
3345 NEXT Y
3350 PRINT
3355 PRINT " THE LAST CATEGORY IS THE SECOND BY-PRODUCT CREDIT."
3360 GOSUB 7945
3362 IF Sk$="S"THEN 3435
3363 B10=1
3365 PRINT "ENTER THE NAME OF THE SECOND BY-PRODUCT:"
3370 INPUT Bp2$
3375 FOR Y = Yd1 TO P1
3380 PRINT " ENTER UNIT PRICE FOR YEAR ";Y;".  IF SAME AS PREVIOUS "
3385 PRINT " YEAR, MAKE NO ENTRY."
3390 INPUT Bp2p(Y)
3395 IF Bp2p(Y) = 0 THEN Bp2p(Y) = Bp2p(Y-1)
3400 NEXT Y
3401 GOSUB 4800
3405 FOR Y = Yd1 TO P1
3410 PRINT " ENTER ANNUAL SALES VOLUME FOR YEAR ";Y;" .  IF SAME AS"
3415 PRINT " PREVIOUS YEAR, MAKE NO ENTRY."
3420 INPUT Bp2a(Y)
3425 IF Bp2a(Y) = 0 THEN Bp2a(Y) = Bp2a(Y-1)
3430 NEXT Y
3435 RETURN
3500 PRINT A$
3502 FIXED 0
3505 PRINT
3510 PRINT "APPENDIX B--OPERATING COST DETAIL, ";Rm1$;" PAGE 1"
3515 PRINT
3520 IF B1 = 0 THEN 3575
3521 IF Pr = 1 THEN 3524
3522 GOSUB 7945
3523 IF Sk$ = "S" THEN 3605
3524 PRINT
3525 PRINT "YR. ";Rm1$,Rm1$,Rm1$,"PERCENT OF"
3530 PRINT "    ";"UNIT COST","ANNUAL CONS.","COST","EXPENSES *"
3535 PRINT
3545 FOR Y= 1 TO P1
3550 GOSUB 1580
3555 PRINT USING 2446; Y;Rm1c(Y),Rm1a(Y),Rcst1(Y),Rp1(Y)
3560 NEXT Y
3565 GOSUB 2455
3570 GOTO 3585
3575 PRINT " NO ENTRIES FOR THE FIRST RAW MATERIAL, PAGE 1 SKIPPED."
3580 GOTO 3605
3585 PRINT A$
3600 PRINT
3605 IF B2 = 0 THEN 3660
3607 PRINT
```

```
3608 PRINT "APPENDIX B--OPERATING COST DETAIL, ";Rm2$;" PAGE 2"
3609 PRINT
3610 IF Pr = 1 THEN 3614
3611 GOSUB 7945
3612 IF Sk$ = "S" THEN 3690
3614 PRINT "YR.  ";Rm2$,Rm2$,Rm2$,"PERCENT OF"
3615 PRINT "     ";"UNIT COST","ANNUAL CONS.","COST","EXPENSES *"
3620 PRINT
3625 FOR Y= 1 TO P1
3630 GOSUB 1580
3635 PRINT USING 2446; Y;Rm2c(Y),Rm2a(Y),Rcst2(Y),Rp2(Y)
3645 NEXT Y
3650 GOSUB 2455
3655 GOTO 3670
3660 PRINT " NO ENTRIES FOR SECOND RAW MATERIAL, PAGE 2 SKIPPED."
3665 GOTO 3690
3670 PRINT A$
3685 PRINT
3690 IF B3 = 0 THEN 3745
3692 PRINT
3693 PRINT "APPENDIX B--OPERATING COST DETAIL, ";Rm3$;" PAGE 3"
3694 PRINT
3695 IF Pr = 1 THEN 3699
3696 GOSUB 7945
3697 IF Sk$ = "S" THEN 3775
3699 PRINT "YR.  ";Rm3$,Rm3$,Rm3$,"PERCENT OF"
3700 PRINT "     ";"UNIT COST","ANNUAL CONS.","COST","EXPENSES *"
3705 PRINT
3710 FOR Y= 1 TO P1
3715 GOSUB 1580
3718 PRINT USING 2446; Y;Rm3c(Y),Rm3a(Y),Rcst3(Y),Rp3(Y)
3730 NEXT Y
3735 GOSUB 2455
3740 GOTO 3755
3745 PRINT " NO ENTRIES FOR THE THIRD RAW MATERIAL, PAGE 3 SKIPPED."
3750 GOTO 3775
3755 PRINT A$
3770 PRINT
3775 IF B4 = 0 AND B5 = 0 THEN 3845
3777 PRINT
3778 PRINT "APPENDIX B--OPERATING COST DETAIL, UTILITIES AND LABOR, PAGE 4"
3779 PRINT
3780 IF Pr = 1 THEN 3784
3781 GOSUB 7945
3782 IF Sk$ = "S" THEN 3875
3784 PRINT "YR.  ";"UTILITIES","UTILITIES %","LABOR","LABOR %"
3785 PRINT "     ";"COST","OF EXPENSES *","COST","OF EXPENSES *"
3790 PRINT
3800 FOR Y= 1 TO P1
3805 GOSUB 1580
3810 IF Ut$ = "P" THEN 3825
3815 PRINT USING 2447; Y;Ut(Y),Utp(Y),La(Y),Lap(Y)
3820 GOTO 3830
3825 PRINT USING 2448; Y;" (IN-PLANT) ","0.000",La(Y),Lap(Y)
3830 NEXT Y
3835 GOSUB 2455
3840 GOTO 3855
3845 PRINT " NO ENTRIES FOR UTILITIES OR LABOR, PAGE 4 SKIPPED"
3850 GOTO 3875
3855 PRINT A$
3870 PRINT
3875 IF B6 = 0 AND B7 = 0 THEN 3930
3877 PRINT
3878 PRINT "APPENDIX B--OPERATING COST DETAIL, MAINT., INS. & LCL TAX PAGE 5"
3879 PRINT
```

```
3880 IF Pr = 1 THEN 3884
3881 GOSUB 7945
3882 IF Sk$ = "S" THEN 3960
3884 PRINT "YR.  ";"MAINTENANCE","MAINTENANCE %","INSURANCE","INS & LCL TAX %"
3885 PRINT "     ";"COST","OF EXPENSES * ","& LOCAL TAX","OF EXPENSES *"
3890 PRINT
3895 FOR Y= 1 TO P1
3905 GOSUB 1580
3910 PRINT USING 2447; Y;Ma(Y),Map(Y),Ilt(Y),Iltp(Y)
3915 NEXT Y
3920 GOSUB 2455
3925 GOTO 3940
3930 PRINT " NO ENTRIES FOR EITHER MAINTENANCE OR FOR INSURANCE "
3931 PRINT " PLUS LOCAL TAXES, PAGE 5 SKIPPED"
3935 GOTO 3960
3940 PRINT A$
3955 PRINT
3960 IF B8 = 0  THEN 4010
3961 PRINT
3962 PRINT "APPENDIX B--OPERATING COST DETAIL, OTHER COSTS, PAGE 6"
3963 PRINT
3965 IF Pr = 1 THEN 3969
3966 GOSUB 7945
3967 IF Sk$ = "S" THEN 4040
3969 PRINT "YR.  "; Ot$,Ot$
3970 PRINT "     "; "COST","% OF EXPENSES *"
3975 PRINT
3980 FOR Y= 1 TO P1
3985 GOSUB 1580
3990 PRINT USING 2447; Y;Otc(Y),Otp(Y)
3995 NEXT Y
4000 GOSUB 2455
4005 GOTO 4020
4010 PRINT " NO ENTRIES FOR 'OTHER' COSTS, PAGE 6 SKIPPED"
4015 GOTO 4040
4020 PRINT A$
4035 PRINT
4040 IF B9 = 0 THEN 4085
4042 PRINT
4043 PRINT "APPENDIX B--OPERATING COST DETAIL, ";Bp1$;" PAGE 7"
4044 PRINT
4045 IF Pr = 1 THEN 4049
4046 GOSUB 7945
4047 IF Sk$ = "S" THEN 4115
4049 PRINT "YR.  ";Bp1$,Bp1$,Bp1$,"PERCENT OF"
4050 PRINT "     ";"UNIT PRICE","ANNUAL SALES","CREDIT","EXPENSES *"
4055 PRINT
4060 FOR Y= 1 TO P1
4065 GOSUB 1580
4070 PRINT USING 2446; Y;Bp1p(Y),Bp1a(Y),Bp1s(Y),Bpp1(Y)
4075 NEXT Y
4080 GOSUB 2455
4082 GOTO 4095
4085 PRINT " NO ENTRIES FOR THE FIRST BY-PRODUCT, PAGE 7 SKIPPED"
4090 GOTO 4110
4095 PRINT A$
4110 PRINT
4115 IF B10 = 0 THEN 4165
4117 PRINT
4118 PRINT "APPENDIX B--OPERATING COST DETAIL, ";Bp2$;" PAGE 8"
4119 PRINT
4120 IF Pr = 1 THEN 4124
4121 GOSUB 7945
4122 IF Sk$ = "S" THEN 4182
4124 PRINT "YR.  ";Bp2$,Bp2$,Bp2$,"PERCENT OF"
4125 PRINT "     ";"UNIT PRICE","ANNUAL SALES","CREDIT","EXPENSES *"
4130 PRINT
4135 FOR Y= 1 TO P1
```

```
4140 GOSUB 1580
4145 PRINT USING 2446; Y;Bp2p(Y),Bp2a(Y),Bp2s(Y),Bpp2(Y)
4150 NEXT Y
4160 GOTO 4170
4165 PRINT " NO ENTRIES FOR SECOND BY-PRODUCT, PAGE 8 SKIPPED"
4170 PRINT
4175 PRINT "* EXPENSES INCLUDE OPERATING EXPENSES (NO CREDITS), PLUS"
4180 PRINT " STATE AND FEDERAL TAXES"
4181 GOSUB 2455
4182 PRINT
4185 RETURN
4300 Expt=Trm1=Trm2=Trm3=Tut=Tla=Tma=Tilt=Totc=Tbp1=Tbp2=0
4305 FOR Y=Yd1 TO P1
4306 Rcst1(Y) = Rm1c(Y)*Rm1a(Y)
4307 Rcst2(Y) = Rm2c(Y)*Rm2a(Y)
4308 Rcst3(Y) = Rm3c(Y)*Rm3a(Y)
4310 Trm1 = Trm1 + Rcst1(Y)
4311 Bp1s(Y) = Bp1p(Y)*Bp1a(Y)
4312 Bp2s(Y) = Bp2p(Y)*Bp2a(Y)
4315 Trm2 = Trm2 + Rcst2(Y)
4320 Trm3 = Trm3 + Rcst3(Y)
4325 Tut = Tut + Ut(Y)
4330 Tla = Tla + La(Y)
4335 Tma = Tma + Ma(Y)
4340 Tilt = Tilt + Ilt(Y)
4345 Totc = Totc + Otc(Y)
4350 Tbp1 = Tbp1 + Bp1s(Y)
4355 Tbp2 = Tbp2 + Bp2s(Y)
4360 Ex(Y)=Rcst1(Y)+Rcst2(Y)+Rcst3(Y)+Ut(Y)+La(Y)+Ma(Y)+Ilt(Y)+Otc(Y)
4361 Ex(Y) = Ex(Y) - Bp1s(Y) - Bp2s(Y)
4365 Expt = Expt + Ex(Y)
4380 NEXT Y
4385 RETURN
4400 Txp = Tsit = Tfit = 0
4405 FOR Y = Yd1 TO P1
4407 Tsit = Tsit + Sit(Y)
4408 Tfit = Tfit + Fit(Y)
4410 Xxp = Ex(Y) + Sit(Y) + Fit(Y) + Bp1s(Y) + Bp2s(Y)
4415 Rp1(Y) = (100*Rcst1(Y))/Xxp
4420 Rp2(Y) = (100*Rcst2(Y))/Xxp
4425 Rp3(Y) = (100*Rcst3(Y))/Xxp
4430 Utp(Y) = (100*Ut(Y))/Xxp
4435 Lap(Y) = (100*La(Y))/Xxp
4440 Map(Y) = (100*Ma(Y))/Xxp
4445 Iltp(Y) = (100*Ilt(Y))/Xxp
4450 Otp(Y) = (100*Otc(Y))/Xxp
4455 Bpp1(Y) = (100*Bp1s(Y))/Xxp
4460 Bpp2(Y) = (100*Bp2s(Y))/Xxp
4461 Sitp(Y) = (100*Sit(Y))/Xxp
4462 Fitp(Y) = (100*Fit(Y))/Xxp
4465 Txp = Txp + Xxp  ! TOTAL EXPENSES (NO CREDITS) PLUS TAXES.
4470 NEXT Y
4475 Opp(1) = (100*Trm1)/Txp
4480 Opp(2) = (100*Trm2)/Txp
4485 Opp(3) = (100*Trm3)/Txp
4490 Opp(4) = (100*Tut)/Txp
4495 Opp(5) = (100*Tla)/Txp
4500 Opp(6) = (100*Tma)/Txp
4505 Opp(7) = (100*Tilt)/Txp
4510 Opp(8) = (100*Totc)/Txp
4515 Opp(9) = (100*Tsit)/Txp
4520 Opp(10) = (100*Tfit)/Txp
4525 Opp(11) = (100*Tbp1)/Txp
4530 Opp(12) = (100*Tbp2)/Txp
4535 RETURN
4600 PRINT
```

```
4605 PRINT
4610 PRINT "            PROJECT LIFE FRACTIONAL EXPENSE SUMMARY"
4611 PRINT
4612 PRINT
4615 PRINT "EXPENSE CATEGORY ---------------PERCENT OF TOTAL EXPENSES *"
4619 Cr$ = " (CREDIT) "
4620 FIXED 3
4621 IMAGE 30X,DD.3D
4622 IMAGE 10X,DD.3D
4623 IMAGE 10X,K,10X,DD.3D
4625 PRINT
4630 PRINT Rm1$;".",
4631 PRINT USING 4621; Opp(1)
4635 PRINT Rm2$;".",
4636 PRINT USING 4621; Opp(2)
4640 PRINT Rm3$;".",
4641 PRINT USING 4621; Opp(3)
4645 PRINT "UTILITIES",
4646 PRINT USING 4621; Opp(4)
4650 PRINT "OPERATING LABOR",
4651 PRINT USING 4621; Opp(5)
4652 PRINT
4655 PRINT "MAINTENANCE",
4656 PRINT USING 4621; Opp(6)
4660 PRINT "INSURANCE PLUS LOCAL TAXES",
4661 PRINT USING 4622; Opp(7)
4670 PRINT Ot$;".",
4671 PRINT USING 4621; Opp(8)
4675 PRINT "STATE TAX",
4676 PRINT USING 4621; Opp(9)
4680 PRINT "FEDERAL TAX",
4681 PRINT USING 4621; Opp(10)
4685 PRINT
4690 PRINT Bp1$;".",
4691 PRINT USING 4623;Cr$,Opp(11)
4695 PRINT Bp2$;".",
4696 PRINT USING 4623;Cr$,Opp(12)
4700 PRINT
4705 PRINT
4710 PRINT " * EXPENSES INCLUDE OPERATING EXPENSES (NO CREDITS),PLUS"
4715 PRINT " STATE AND FEDERAL TAXES."
4720 RETURN
4800 PRINT
4805 PRINT
4810 PRINT " COST/PRICE SECTION COMPLETED.  NEXT, ENTER THE ANNUAL"
4815 PRINT " VOLUME IN CONSISTENT UNITS."
4820 PRINT
4825 PRINT
4830 RETURN
4900 PRINT A$
4905 PRINT
4910 PRINT "APPENDIX C--TAXES AS A PERCENT OF TOTAL EXPENSES *"
4915 PRINT
4920 PRINT "YR. ";"STATE TAX","STATE TAX","FEDERAL TAX","FEDERAL TAX"
4925 PRINT "    ";"AMOUNT","% OF EXPENSES *","AMOUNT","% OF EXPENSES *"
4930 PRINT
4935 FOR Y = 1 TO P1
4940 GOSUB 1580
4945 PRINT USING 2447; Y;Sit(Y),Sitp(Y),Fit(Y),Fitp(Y)
4950 NEXT Y
4955 PRINT
4960 PRINT "* EXPENSES INCLUDE OPERATING EXPENSES (NO CREDITS), PLUS"
4965 PRINT " STATE AND FEDERAL TAXES"
4970 RETURN
5000 PRINT " DO YOU WISH TO READ THE RE-RUN EDIT SUGGESTIONS ? (Y OR N)"
5001 INPUT Re$
5010 IF Re$ = "N" THEN 100
5015 PRINT " THE FIRST STEP IN A RERUN IS TO EDIT ALL INPUTS.  INPUT VARIABLES"
```

```
5020 PRINT " WILL REMAIN THE SAME UNLESS CHANGED.  WHEN CARRIAGE RETURN IS"
5025 PRINT " KEYED IN RESPONSE TO A (?), THE VARIABLE REMAINS UNCHANGED FROM"
5030 PRINT " THE PREVIOUS RUN."
5035 PRINT
5040 PRINT "  IF OPERATING EXPENSES WERE ENTERED BY CATEGORY, SECTIONS MAY"
5045 PRINT " BE SKIPPED WITHOUT ALTERING THE INPUT VARIABLES.  ALSO, KEYING"
5050 PRINT " CARRIAGE RETURN IN THIS SECTION DOES NOT GIVE THE PREVIOUS YEAR'S"
5055 PRINT " VALUE AS IT DID IN THE FIRST RUN, INSTEAD IT CAUSES THE VALUE"
5060 PRINT " USED IN THE PREVIOUS RUN TO BE RETAINED.  HOWEVER, THE YEAR TO"
5065 PRINT " YEAR REPEAT FEATURE CAN BE UTILIZED BY KEYING IN A (0).  FOR"
5070 PRINT " EXAMPLE, IN A RERUN  YOU MAY WISH TO CHANGE LABOR COSTS TO"
5075 PRINT " 13.682E6 FOR YEARS 14 THROUGH 21.  IT MAY BE ENTERED FOR YEAR"
5080 PRINT " NUMBER 14 THEN REPEATED FOR YEARS 15 - 21 BY KEYING 0 CARRIAGE"
5085 PRINT " RETURN.  DURING INPUT CHECKING, CALCULATED VARIABLES WILL BE"
5090 PRINT " SHOWN AS LEFT OVER FROM THE PREVIOUS RUN, BUT THEY WILL BE "
5095 PRINT " CHANGED DURING CALCULATION."
6000 GOTO 100
7945 Sk$ = ""
7946 PRINT " IF YOU WISH TO SKIP THE NEXT CATEGORY, ENTER S."
7950 INPUT Sk$
7965 PRINT
7970 RETURN
7980 PRINT " DO YOU REALLY WANT TO QUIT AND LOSE ALL YOUR INPUT DATA ?"
7981 PRINT " (Y OR N)"
7982 INPUT Rq$
7984 IF Rq$ = "Y" THEN 8000 ELSE 5000
8000 STOP
8010 END
```

Some program modifications were required to handle the state tax for the eastern high-sulfur case. The state chosen for this case, Ohio, has a net worth tax and it was convenient to temporarily modify the program to handle it. For broader applications it could be desirable to write this feature into the program as a regular option. The following printout shows the lines which were modified; changes are circled.

```
15    DIM Ebt(60),Ex(60),Fit(60),Dcp(60),Dct(20,100)
20    DIM Pv(60), Pvf(60), Roi(60), Rrpv(60),Fp(60),Oc(26)

1215 Sit(Y)=(Ebt(Y)-Dft(Y))*Str   ! STATE INC./FRANCHISE TAX
1216 Nwt = 0.0582*(Pc-Da+(Da*(1-0.05*(Y-5))))
1217 IF Nwt > Sit(Y) THEN Sit(Y) = Nwt
1218 Sit(Y) = Sit(Y) + Oc(Y)
1220 Ti(Y) = Ebt(Y) - Dft(Y) - Sit(Y) ! FEDERAL TAXABLE INCOME

3250 PRINT " IF SAME AS THE PREVIOUS YEAR , MAKE NO ENTRY."
3255 INPUT Oc(Y)

3995 NEXT Y
3996 PRINT
3997 PRINT " *** STATE TAX CREDITS FOR LOCAL TAXES WERE USED TO CALCULATE"
3998 PRINT " THE STATE TAX AND ARE NOT INCLUDED HERE."
4000 GOSUB 2455

4715 PRINT " STATE AND FEDERAL TAXES."
4716 PRINT
4717 PRINT " *** STATE TAX CREDITS FOR LOCAL TAXES WERE USED TO CALCULATE"
4718 PRINT " THE STATE TAX AND ARE NOT INCLUDED HERE."
4720 RETURN
```

APPENDIX B
Example Computer Output for One Complete Price Calculation

WESTERN LOW-SULFUR---CASE 7

PAGE 1 -- CASH OUTLAYS AND DEPRECIATION

YR.	CASH OUTLAYS	SALES	EARNINGS BEFORE TAX	TAX DEPRECIATION
1	131555160	0	0	0
2	252147390	0	0	0
3	328887900	0	0	0
4	252147390	0	0	0
5	131555160	0	0	0
6	0	553683020	499568987	146387850
7	0	553683020	499573940	214702180
8	0	553683020	499578893	204942990
9	0	553683020	499583846	204942990
10	0	553683020	499588799	204942990
11	0	553683020	487953752	0
12	0	553683020	476318705	0
13	0	553683020	464713658	0
14	0	553683020	453078611	0
15	0	553683020	441452564	0
16	0	553683020	441457517	0
17	0	553683020	441462470	0
18	0	553683020	441467423	0
19	0	553683020	441472376	0
20	0	553683020	441477329	0
21	0	553683020	441482282	0
22	0	553683020	441487235	0
23	0	553683020	441492188	0
24	0	553683020	441497141	0
25	0	553683020	441502094	0

WESTERN LOW-SULFUR---CASE 7

PAGE 2 -- TAXES AND CASH FLOW

YR.	STATE TAX	TAXABLE INCOME (FED.)	FEDERAL TAX	CASH FLOW
1	0	0	0	-131555160
2	0	0	0	-252147390
3	0	0	0	-328887900
4	0	0	0	-252147390
5	0	0	0	-131555160
6	0	353181137	64871423	434697564
7	0	284871760	131041009	368532930
8	0	294635903	135532515	364046377
9	0	294640856	135534794	364049052
10	0	294645809	135537072	364051727
11	0	487953752	224458726	263495026
12	0	476318705	219106604	257212100
13	0	464713658	213768282	250945375
14	0	453078611	208416161	244662450
15	0	441452564	203068179	238384384
16	0	441457517	203070458	238387059
17	0	441462470	203072736	238389734
18	0	441467423	203075014	238392408
19	0	441472376	203077293	238395083
20	0	441477329	203079571	238397757
21	0	441482282	203081850	238400432
22	0	441487235	203084128	238403107
23	0	441492188	203086406	238405781
24	0	441497141	203088685	238408456
25	0	441502094	203090963	238411131

WESTERN LOW-SULFUR---CASE 7

PAGE 3 -- CUMULATIVE CASH FLOWS AND PRESENT VALUES
FOR 20.000 PERCENT RETURN ON INVESTMENT

YR.	CUMULATIVE CASH FLOW	PRESENT VALUE FACTOR	PRESENT VALUES	CUMULATIVE PRES. VALUES
1	-131555160	0.914136	-120259285	-120259285
2	-383702550	0.761780	-192080802	-312340087
3	-712590450	0.634817	-208783480	-521123567
4	-964737840	0.529014	-133389446	-654513013
5	-1096293000	0.440845	-57995411	-712508424
6	-661595436	0.367371	159695142	-552813282
7	-293062506	0.306142	112823496	-439989786
8	70983871	0.255119	92874977	-347114808
9	435032923	0.212599	77396383	-269718425
10	799084650	0.177166	64497460	-205220966
11	1062579676	0.147638	38901889	-166319077
12	1319791776	0.123032	31645242	-134673835
13	1570737151	0.102526	25728530	-108945305
14	1815399601	0.085439	20903637	-88041668
15	2053783985	0.071199	16972706	-71068962
16	2292171044	0.059332	14144080	-56924882
17	2530560778	0.049444	11786866	-45138016
18	2768953186	0.041203	9822498	-35315518
19	3007348269	0.034336	8185507	-27130011
20	3245746026	0.028613	6821333	-20308678
21	3484146458	0.023844	5684508	-14624171
22	3722549565	0.019870	4737143	-9887028
23	3960955346	0.016559	3947663	-5939365
24	4199363802	0.013799	3289756	-2649608
25	4437774933	0.011499	2741494	91886

WESTERN LOW-SULFUR---CASE 7

APPENDIX A -- PRICE, RETURN AND OTHER INFORMATION

THE PRICE IS .722352 PER GALLON
AVERAGE ANNUAL SALES: 553683020
REQUIRED ACCURACY: .0100 %

THE RETURN ON INVESTMENT IS 20.0 PERCENT

THE PAYOUT PERIOD IS 7.81 YEARS.

THE TOTAL PRESENT VALUES OF ALL CASH OUTLAYS: 712508424
THIS SOLUTION REQUIRED 18 ITERATIONS
THE FOLLOWING SALES WERE TRIED:

ITERATION	PRICE / GALLON
1.0000	.8675
2.0000	.8176
3.0000	.7848
4.0000	.7631
5.0000	.7490
6.0000	.7397
7.0000	.7336
8.0000	.7297
9.0000	.7271
10.0000	.7254
11.0000	.7243
12.0000	.7236
13.0000	.7231
14.0000	.7228
15.0000	.7226
16.0000	.7225
17.0000	.7224
18.0000	.7224

PROJECT LIFE FRACTIONAL EXPENSE SUMMARY

EXPENSE CATEGORY		PERCENT OF TOTAL EXPENSES *
COAL.		19.492
WATER.		3.970
CHEMICALS.		2.381
UTILITIES		.000
OPERATING LABOR		3.943
MAINTENANCE		10.497
INSURANCE PLUS LOCAL TAXES		3.234
CORP. LICENSE.		.016
STATE TAX		.000
FEDERAL TAX		56.467
SULFUR.	(CREDIT)	.428
CARBON DIOXIDE.	(CREDIT)	15.080

* EXPENSES INCLUDE OPERATING EXPENSES (NO CREDITS),PLUS STATE AND FEDERAL TAXES.

WESTERN LOW-SULFUR---CASE 7

APPENDIX B--OPERATING COST DETAIL, PAGE 1

YR.	COAL UNIT COST	COAL ANNUAL CONS.	COAL COST	PERCENT OF EXPENSES *
1	.00	0	.00	.000
2	.00	0	.00	.000
3	.00	0	.00	.000
4	.00	0	.00	.000
5	.00	0	.00	.000
6	15.00	4259900	63898500.00	30.776
7	15.00	4259900	63898500.00	23.338
8	15.00	4259900	63898500.00	22.962
9	15.00	4259900	63898500.00	22.962
10	15.00	4259900	63898500.00	22.963
11	15.00	4259900	63898500.00	17.402
12	15.00	4259900	63898500.00	17.660
13	15.00	4259900	63898500.00	17.924
14	15.00	4259900	63898500.00	18.198
15	15.00	4259900	63898500.00	18.480
16	15.00	4259900	63898500.00	18.480
17	15.00	4259900	63898500.00	18.480
18	15.00	4259900	63898500.00	18.480
19	15.00	4259900	63898500.00	18.480
20	15.00	4259900	63898500.00	18.480
21	15.00	4259900	63898500.00	18.480
22	15.00	4259900	63898500.00	18.481
23	15.00	4259900	63898500.00	18.481
24	15.00	4259900	63898500.00	18.481
25	15.00	4259900	63898500.00	18.481

WESTERN LOW-SULFUR---CASE 7

APPENDIX B--OPERATING COST DETAIL, PAGE 2

YR.	WATER UNIT COST	WATER ANNUAL CONS.	WATER COST	PERCENT OF EXPENSES *
1	.00	0	.00	.000
2	.00	0	.00	.000
3	.00	0	.00	.000
4	.00	0	.00	.000
5	.00	0	.00	.000
6	1.16	11266600	13012923.00	6.267
7	1.16	11266600	13012923.00	4.753
8	1.16	11266600	13012923.00	4.676
9	1.16	11266600	13012923.00	4.676
10	1.16	11266600	13012923.00	4.676
11	1.16	11266600	13012923.00	3.544
12	1.16	11266600	13012923.00	3.596
13	1.16	11266600	13012923.00	3.650
14	1.16	11266600	13012923.00	3.706
15	1.16	11266600	13012923.00	3.763
16	1.16	11266600	13012923.00	3.763
17	1.16	11266600	13012923.00	3.763
18	1.16	11266600	13012923.00	3.763
19	1.16	11266600	13012923.00	3.763
20	1.16	11266600	13012923.00	3.764
21	1.16	11266600	13012923.00	3.764
22	1.16	11266600	13012923.00	3.764
23	1.16	11266600	13012923.00	3.764
24	1.16	11266600	13012923.00	3.764
25	1.16	11266600	13012923.00	3.764

WESTERN LOW-SULFUR---CASE 7

APPENDIX B--OPERATING COST DETAIL, PAGE 3

YR.	CHEMICALS UNIT COST	CHEMICALS ANNUAL CONS.	CHEMICALS COST	PERCENT OF EXPENSES *
1	.00	0	.00	.000
2	.00	0	.00	.000
3	.00	0	.00	.000
4	.00	0	.00	.000
5	.00	0	.00	.000
6	7805000.00	1	7805000.00	3.759
7	7805000.00	1	7805000.00	2.851
8	7805000.00	1	7805000.00	2.805
9	7805000.00	1	7805000.00	2.805
10	7805000.00	1	7805000.00	2.805
11	7805000.00	1	7805000.00	2.126
12	7805000.00	1	7805000.00	2.157
13	7805000.00	1	7805000.00	2.189
14	7805000.00	1	7805000.00	2.223
15	7805000.00	1	7805000.00	2.257
16	7805000.00	1	7805000.00	2.257
17	7805000.00	1	7805000.00	2.257
18	7805000.00	1	7805000.00	2.257
19	7805000.00	1	7805000.00	2.257
20	7805000.00	1	7805000.00	2.257
21	7805000.00	1	7805000.00	2.257
22	7805000.00	1	7805000.00	2.257
23	7805000.00	1	7805000.00	2.257
24	7805000.00	1	7805000.00	2.257
25	7805000.00	1	7805000.00	2.257

WESTERN LOW-SULFUR---CASE 7

APPENDIX B--OPERATING COST DETAIL, PAGE 4

YR.	UTILITIES COST	UTILITIES % OF EXPENSES *	LABOR COST	LABOR % OF EXPENSES *
1	(IN PLANT)	0.000	0	.000
2	(IN PLANT)	0.000	0	.000
3	(IN PLANT)	0.000	0	.000
4	(IN PLANT)	0.000	0	.000
5	(IN PLANT)	0.000	0	.000
6	(IN PLANT)	0.000	12927000	6.226
7	(IN PLANT)	0.000	12927000	4.721
8	(IN PLANT)	0.000	12927000	4.645
9	(IN PLANT)	0.000	12927000	4.645
10	(IN PLANT)	0.000	12927000	4.645
11	(IN PLANT)	0.000	12927000	3.521
12	(IN PLANT)	0.000	12927000	3.573
13	(IN PLANT)	0.000	12927000	3.626
14	(IN PLANT)	0.000	12927000	3.682
15	(IN PLANT)	0.000	12927000	3.739
16	(IN PLANT)	0.000	12927000	3.739
17	(IN PLANT)	0.000	12927000	3.739
18	(IN PLANT)	0.000	12927000	3.739
19	(IN PLANT)	0.000	12927000	3.739
20	(IN PLANT)	0.000	12927000	3.739
21	(IN PLANT)	0.000	12927000	3.739
22	(IN PLANT)	0.000	12927000	3.739
23	(IN PLANT)	0.000	12927000	3.739
24	(IN PLANT)	0.000	12927000	3.739
25	(IN PLANT)	0.000	12927000	3.739

WESTERN LOW-SULFUR---CASE 7

APPENDIX B--OPERATING COST DETAIL, PAGE 5

YR.	MAINTENANCE COST	MAINTENANCE % OF EXPENSES *	INSURANCE & LOCAL TAX	INS & LCL TAX % OF EXPENSES *
1	.00	.000	.00	.000
2	.00	.000	.00	.000
3	.00	.000	.00	.000
4	.00	.000	.00	.000
5	.00	.000	.00	.000
6	34410000.00	16.573	10603000.00	5.107
7	34410000.00	12.568	10603000.00	3.873
8	34410000.00	12.365	10603000.00	3.810
9	34410000.00	12.365	10603000.00	3.810
10	34410000.00	12.366	10603000.00	3.810
11	34410000.00	9.371	10603000.00	2.888
12	34410000.00	9.510	10603000.00	2.930
13	34410000.00	9.652	10603000.00	2.974
14	34410000.00	9.800	10603000.00	3.020
15	34410000.00	9.951	10603000.00	3.066
16	34410000.00	9.952	10603000.00	3.066
17	34410000.00	9.952	10603000.00	3.066
18	34410000.00	9.952	10603000.00	3.066
19	34410000.00	9.952	10603000.00	3.067
20	34410000.00	9.952	10603000.00	3.067
21	34410000.00	9.952	10603000.00	3.067
22	34410000.00	9.952	10603000.00	3.067
23	34410000.00	9.952	10603000.00	3.067
24	34410000.00	9.952	10603000.00	3.067
25	34410000.00	9.952	10603000.00	3.067

WESTERN LOW-SULFUR---CASE 7

APPENDIX B--OPERATING COST DETAIL, PAGE 6

YR.	CORP. LICENSE COST	CORP. LICENSE % OF EXPENSES *
1	.00	.000
2	.00	.000
3	.00	.000
4	.00	.000
5	.00	.000
6	99060.00	.048
7	94107.00	.034
8	89154.00	.032
9	84201.00	.030
10	79248.00	.028
11	74295.00	.020
12	69342.00	.019
13	64389.00	.018
14	59436.00	.017
15	54483.00	.016
16	49530.00	.014
17	44577.00	.013
18	39624.00	.011
19	34671.00	.010
20	29718.00	.009
21	24765.00	.007
22	19812.00	.006
23	14859.00	.004
24	9906.00	.003
25	4953.00	.001

WESTERN LOW-SULFUR---CASE 7

APPENDIX B--OPERATING COST DETAIL, PAGE 7

YR.	SULFUR UNIT PRICE	SULFUR ANNUAL SALES	SULFUR CREDIT	PERCENT OF EXPENSES *
1	.00	0	.00	.000
2	.00	0	.00	.000
3	.00	0	.00	.000
4	.00	0	.00	.000
5	.00	0	.00	.000
6	75.00	18686	1401450.00	.675
7	75.00	18686	1401450.00	.512
8	75.00	18686	1401450.00	.504
9	75.00	18686	1401450.00	.504
10	75.00	18686	1401450.00	.504
11	75.00	18686	1401450.00	.382
12	75.00	18686	1401450.00	.387
13	75.00	18686	1401450.00	.393
14	75.00	18686	1401450.00	.399
15	75.00	18686	1401450.00	.405
16	75.00	18686	1401450.00	.405
17	75.00	18686	1401450.00	.405
18	75.00	18686	1401450.00	.405
19	75.00	18686	1401450.00	.405
20	75.00	18686	1401450.00	.405
21	75.00	18686	1401450.00	.405
22	75.00	18686	1401450.00	.405
23	75.00	18686	1401450.00	.405
24	75.00	18686	1401450.00	.405
25	75.00	18686	1401450.00	.405

WESTERN LOW-SULFUR---CASE 7

APPENDIX B--OPERATING COST DETAIL, PAGE 8

YR.	CARBON DIOXIDE UNIT PRICE	CARBON DIOXIDE ANNUAL SALES	CARBON DIOXIDE CREDIT	PERCENT OF EXPENSES *
1	.00	0	.00	.000
2	.00	0	.00	.000
3	.00	0	.00	.000
4	.00	0	.00	.000
5	.00	0	.00	.000
6	30.00	2908000	87240000.00	42.018
7	30.00	2908000	87240000.00	31.864
8	30.00	2908000	87240000.00	31.350
9	30.00	2908000	87240000.00	31.350
10	30.00	2908000	87240000.00	31.351
11	30.00	2520000	75600000.00	20.589
12	30.00	2132000	63960000.00	17.677
13	30.00	1745000	52350000.00	14.685
14	30.00	1357000	40710000.00	11.594
15	30.00	969300	29079000.00	8.410
16	30.00	969300	29079000.00	8.410
17	30.00	969300	29079000.00	8.410
18	30.00	969300	29079000.00	8.410
19	30.00	969300	29079000.00	8.410
20	30.00	969300	29079000.00	8.410
21	30.00	969300	29079000.00	8.410
22	30.00	969300	29079000.00	8.410
23	30.00	969300	29079000.00	8.410
24	30.00	969300	29079000.00	8.410
25	30.00	969300	29079000.00	8.410

* EXPENSES INCLUDE OPERATING EXPENSES (NO CREDITS), PLUS STATE AND FEDERAL TAXES

WESTERN LOW-SULFUR---CASE 7

APPENDIX C--TAXES AS A PERCENT OF TOTAL EXPENSES *

YR.	STATE TAX AMOUNT	STATE TAX % OF EXPENSES *	FEDERAL TAX AMOUNT	FEDERAL TAX % OF EXPENSES *
1	.00	.000	.00	.000
2	.00	.000	.00	.000
3	.00	.000	.00	.000
4	.00	.000	.00	.000
5	.00	.000	.00	.000
6	.00	.000	64871422.82	31.244
7	.00	.000	131041009.40	47.862
8	.00	.000	135532515.18	48.704
9	.00	.000	135534793.56	48.705
10	.00	.000	135537071.94	48.707
11	.00	.000	224458725.72	61.129
12	.00	.000	219106604.10	60.555
13	.00	.000	213768282.48	59.965
14	.00	.000	208416160.86	59.355
15	.00	.000	203068179.24	58.728
16	.00	.000	203070457.62	58.729
17	.00	.000	203072736.00	58.730
18	.00	.000	203075014.38	58.731
19	.00	.000	203077292.76	58.732
20	.00	.000	203079571.14	58.733
21	.00	.000	203081849.52	58.734
22	.00	.000	203084127.90	58.736
23	.00	.000	203086406.28	58.737
24	.00	.000	203088684.66	58.738
25	.00	.000	203090963.04	58.739

* EXPENSES INCLUDE OPERATING EXPENSES (NO CREDITS), PLUS STATE AND FEDERAL TAXES

APPENDIX C
Telephone Quotes for Costs of Water and Rail Transportation

APPENDIX C

Telephone Quotes for Costs of Water and Rail Transportation

Water

1. For shipment size at 80,000 barrels, the cost is $2.00 per barrel from the Houston, TX port up the Mississippi and Illinois Rivers to Lamont, IL (20 miles south of Chicago). Due to low bridge restriction, local tug boats to tow barges into Chicago proper must be subcontracted at an additional cost of $6,500.00 per shipment.

2. For 70,000 barrels minimum 90,000 barrels maximum shipment, the cost is $16.00 per ton or $2.21 per barrel from the Houston, TX port to Joliet, IL (30 miles SW of Chicago on the Illinois River). Subcontracting of local tug boats into Chicago proper is also necessary.

3. For 10,000 barrel barge shipments, the cost is $15.00 per ton or $2.07 per barrel from the Houston, TX port up the Mississippi and Illinois Rivers into Chicago proper. No bridge restrictions.

4. For 50,000 barrels minimum the cost is $2.15 per barrel from Galveston, TX around the east coast to New York City, New York.

5. For 50,000 barrel minimum per shipment the cost is $2.46 per barrel from Chicago to Buffalo, New York via the Great Lakes. Can also move up the St. Lawrence River around the Northeast coast into New York City at a cost of $8.10 per barrel.

Costs for loading and unloading of the methanol were not addressed in any of the above estimates.

Rail

The feasibility of moving methanol by unit train - a series of specially designed and built railroad cars interconnected to form a single unit for loading and unloading - was investigated. It appears that some of the railroad companies that were contacted can provide this service at a lower cost than the standard individual tanker car. However, in order to formulate a price quote, amount, duration and frequency of shipments must be known. Therefore, the price quotes that were obtained are based on the standard individual tanker cars ranging from 52,800 to 19,000 lb capacity. The capacity size of the cars vary depending on availability, weight restrictions, etc. The larger the capacity size, the lower than the cost. Rail prices are usually stated in dollars per hundred pounds.

The following are price quotes for rail transportation of methanol from locations near the five regions locations to Chicago, Atlanta, and New York City.

1. From Wheeling, W. VA to Chicago, IL, 180,000 lb capacity car at $2.04 per 100 wt or $5.65 per barrel.

   From Wheeling W. VA to Atlanta, GA: 190,000 lb capacity car at $2.16 per 100 wt or $5.98 per barrel.

   From Wheeling W. VA to New York City, NY 180,000 lb capacity car at $2.36 per 100 wt or $6.90 per barrel.

2. From Palastine, TX to Chicago, IL; 180,000 lb capacity car at $1.67 per 100 wt or $4.62 per barrel.

   From Palastine, TX to Atlanta, GA; 180,000 lb capacity car at $3.44 per 100 wt or $9.52 per barrel.

   From Palestine, TX to New York City, NY; 130,000 lb capacity car at $2.44 per 100 wt or $6.75 per barrel.

3. From St. Louis, MO to Chicago, IL; 130,000 lb capacity car at $1.80 per 100 wt or $4.98 per barrel.

   From St. Louis, MO to Atlanta, GA; 130,000 lb capacity car at $2.83 per 100 wt or $7.83 per barrel.

   From St. Louis, MO to New York City, NY 64,000 lb capacity car at $5.04 per 100 wt or $13.96 per barrel.

4. From Beulah, ND to Chicago, IL; 52,800 lb capacity car at $5.33 per 100 wt or $14,81 per barrel.

   From Beulah, ND to Atlanta, GA; 52,800 lb capacity car at $6.36 per 100 wt or $17.67 per barrel.

   From Beulah, ND to New York City, NY; 52,800 capacity car at $7.40 per 100 wt or $20.56 per barrel.

   From Gillette, WY to Chicago, IL; 52,800 lb capacity car at $5.99 per 100 wt or $16.64 per barrel.

   From Gillette, WY to Atlanta, GA; 52,800 lb capacity car at $6.52 per 100 wt or $18.12 per barrel.

   From Gillette, WY to New York City, NY; 52,800 capacity car at $8.42 per 100 wt or $23.40 per barrel.

5. From Palastine, TX to Houston and Galveston, TX for further movement via waterway; 52,800 lb capacity car at $1.46 per 100 wt or $4.06 per barrel.

APPENDIX D

Report on Pipeline Economic Factors

Williams Brothers
Engineering Company

Resource Sciences Park
6600 South Yale Avenue
Tulsa, Oklahoma 74136
Phone: (918) 496-5020
Telex 497493 WBEC TUL
Facsimile (918) 496-5034

September 6, 1984

Southwest Research Institute
Post Office Drawer 28510
6220 Culebra Road
San Antonio, Texas 78284

Attention: Mr. David S. Moulton

Subject: Methanol Pipeline Transportation

Dear Mr. Moulton:

In response to the Statement of Work issued by Southwest Research Institute dated July 24, 1984, Williams Brothers Engineering Company has prepared preliminary design and cost data for potential pipeline systems transporting methanol from the North-Central and South-Central regions of the United States to New York City. Data was developed for two methanol pipeline systems: one to transport 400,000 barrels per day from sources in Wyoming and North Dakota to markets in Chicago, Illinois and New York City; the second to transport 300,000 barrels per day from a source in Texas to markets in Atlanta, Georgia and New York City. This data will be used by Southwest Research to calculate pipeline transportation costs for comparison to other potential modes of methanol transportation.

It must be emphasized that much of the data presented herein is definitely conceptual in nature. Attempts at optimizing the pipeline design, a normal part of the pipeline transportation cost analysis process, have been minimal due to the time constraints placed on the assignment. The data presented does constitute a reasonable set of pipeline system design and cost characteristics which should be suitable for your purposes at this time.

Routes and Capacities

For the northern pipeline system, origin points in Campbell County, Wyoming and Mercer County, North Dakota were specified by the Statement of Work. Brule County, South Dakota was selected as a convenient junction location for the origin pipeline segments, being approximately 320 miles from Campbell

County and 280 miles from Mercer County. From the junction point, the selected route proceeds across northern Iowa and Illinois to Chicago, then continuing across northern Indiana and Ohio, central Pennsylvania, and northern New Jersey into New York City. The estimated distance from the junction point in South Dakota to New York City is 1,300 miles. The selected route is basically straight line from point to point, with slight adjustment to minimize major river crossings. Elevations are estimated at 4,500 feet above sea level in Campbell County, 2,000 feet in Mercer County, 1,500 feet in Brule County, 600 feet at Chicago, and 0 feet at New York City. Design capacities for the pipeline segments are 200,000 barrels (8.4 million gallons) per day for both the Wyoming to South Dakota and North Dakota to South Dakota segments and 400,000 barrels (16.8 million gallons) per day for the South Dakota to New York segment.

The origin point of the southern pipeline system is in Milam County, Texas, from where the selected route proceeds across southern Louisiana and Mississippi and central Alabama to Atlanta, then continuing across western South Carolina and North Carolina, central Virginia and Maryland, southeastern Pennsylvania, and north central New Jersey into New York City. The estimated length of the pipeline is 1,520 miles. The selected route is basically straight line from its origin to Baton Rouge, Louisiana, at which point it joins an existing pipeline corridor occupied by Colonial Pipeline. The route follows the Colonial corridor into Pennsylvania and continues on a straight line into New York. Elevations are estimated at 500 feet above sea level in Milam County, 1,000 feet at Atlanta, and 0 feet at New York City. Design capacity for the pipeline is 300,000 barrels (12.6 million gallons) per day.

Pipeline Design

Applicable parts of the Department of Transportation regulation for transportation of hazardous liquids by pipeline (Part 195, Title 49, Code of Federal Regulations) and incorporated references, plus principles of fluid flow in pipe were used in preparing the design, construction, operations and maintenance data presented herein. Pipeline sizing and pumping requirements are based on transporting methanol with a specific gravity of 0.795 and a kinematic viscosity of 0.74 centistokes.

Initial pipe and pump station selection was based on the following factors:

- Internal design pressure of 1,440 psig and design factor of 0.72
- Pipe material to be API 5L Grade X-60 priced at $800 per ton
- Pipe wall thickness to be standard API wall thickness
- Pipe sized to produce a friction head loss of between 25 and 50 feet per mile
- 75 percent pumping unit efficiency
- Pump station costs of $1,200 per installed horsepower

Using these factors, various combinations of pipe size and pumping capacity for each flowrate were evaluated on an initial investment cost basis, with the lowest cost combination being selected for development of more detailed construction and operating data. The selected pipeline systems are described in Table 1.

Capital Requirements

Capital requirements for constructing each of the four pipeline segments described in Table 1 have been estimated and are displayed in Table 2. All costs are based on estimated current material prices and labor rates and no escalation to year of construction has been included. Total costs, in millions of 1984 dollars, for the four pipeline segments are:

Wyoming to South Dakota	$106.3
North Dakota to South Dakota	95.7
South Dakota to New York	742.1
Texas to New York	721.2

Economic Factors

The Statement of Work issued by Southwest Research requested information on typical or reasonable values for certain items considered in evaluating pipeline economics. The following discussion addresses these points:

* Project Life

  Although the useful life of a pipeline facility can sometimes extend to 50 years or longer, a project life of 20 to 25 years is typically assumed when evaluating the potential revenues from a proposed pipeline investment. This is due to the risks involved in forecasting the business aspects of pipeline operation such as growth or decline of product supply or demand, competition, etc.

* Number of Years Required for Construction

  The duration of physical construction activity on a pipeline system is determined by the number of construction spreads used, their rate of progress, and the success of pre-construction planning. It is estimated that approximately 1.5 years would be required to complete construction on the methanol pipelines studied. The duration of pre-construction activity is much more difficult to predict and probably will be considerably longer than that for construction. Pre-construction activities would include engineering, environmental study, survey, acquisition of agreements and permits from landowners and responsible governmental and regulatory agencies, materials procurement, and contracting. It is recommended that a minimum of 3 years be allowed for completion of pre-construction activity.

* Approximate Percent of Construction Funds Spent Each Year of Construction

  Assuming a project duration of 5 years from commencement of pre-construction to completion of construction and demobilization, reasonable estimates of percentage of capital requirements spent per year would be:

Year	%
1	1
2	2
3	22
4	50
5	25

* Percent of the Capital Outlay Which is Depreciable

  One hundred percent of the monies considered as initial investment are depreciable.

* Amount and Timing of Other Capital Outlays during the Project Life

  Once the pipeline is ready for service it must be filled with methanol before normal operation begins. The cost of line fill is the product of the volume required and its unit value to the owner. For the two pipeline systems studied, line fill volumes would be 5.14 million barrels for the northern system and 3.52 million barrels for the southern system. No other capital outlays should be required, outside of normal operating and maintenance costs, unless operating conditions change at some time in the future. Examples of such change would be a significant increase in volume to be transported, the addition of new methanol source or delivery points, or investment in new technology advances which might decrease operating costs. At this point, estimating the amount of capital expenditures for these purposes will require additional input from Southwest Research.

Operating Expenses

An estimate of the annual operating and maintenance expenses for each of the four pipeline segments described in Table 1 are summarized in Table 3. All costs are presented in 1984 dollars. These costs would not be expected to change substantially during the project life if adjustments for inflation are taken into account.

Some of the criteria used in estimating operating and maintenance expenses were:

- Intermediate pump stations are unmanned. Initial pump stations and delivery terminals are manned continuously.

- Power costs are based on an average charge of 6 cents per kwh of power consumed by mainline pumping units. Power cost is the largest single item of expense in operating the pipeline systems and is a significant factor to be considered when optimizing pipeline design.

- Insurance and ad valorem taxes are calculated at 1.5 percent of initial investment.

<u>Taxes and Depreciation</u>

In response to the Southwest Research request for guidance on certain tax and depreciation matters, we offer the following comments:

* State income tax levies are usually considered insignificant at this stage of a cost of transportation study and are ignored. Also, there is little uniformity from state to state on methods of calculating state tax. However, if provision is to be made for state income taxes, 2 percent of pretax income would be a reasonable annual average to use.

* Southwest Research Institute assumptions of a ten percent investment tax credit, five year accelerated cost recovery system for depreciation and no energy investment tax credits appear to be appropriate.

* Regarding areas unique to pipelines which may affect project economics, Southwest Research Institute should be aware of the necessity of the pipeline owner to obtain the right of eminent domain. This allows the owner to acquire pipeline right-of-way via condemnation proceedings if a landowner refuses reasonable compensation for his property. Without this privilege, acquisition of right-of-way is likely to be much more costly than we have estimated, if not virtually impossible.

Williams Brothers
Engineering Company

We appreciate the opportunity you have given us for participating in this project and sincerely hope that the information presented herein fully satisfies your requirements. If we can be of further service, please do not hesitate to call.

Very truly yours,

WILLIAMS BROTHERS ENGINEERING COMPANY

Mike Friese

Michael M. Friese
Project Manager

MMF:slm/5803-001
Attachments

TABLE 1

METHANOL PIPELINE SYSTEM FACILITIES

	Wyoming to South Dakota	North Dakota to South Dakota	South Dakota to New York	Texas to New York
Line Length, Miles	320	280	1,300	1,520
Flow Rate, MBPD	200	200	400	300
Pipe Diameter and Wall Thickness, Inches	18 x 0.312	18 x 0.312	26 x 0.438	22 x 0.375
No. of Pump Stations	3	3	9	14
Installed Brake Horsepower per Station	7,000	7,000	13,000	10,000
No. Delivery Terminals	0	0	2	2

TABLE 2

CAPITAL REQUIREMENTS FOR CONSTRUCTING PIPELINES

	Wyoming to South Dakota	North Dakota to South Dakota	South Dakota to New York	Texas to New York
ROW and Land	4.8	4.2	27.3	35.8
Line Pipe	39.9	34.9	323.5	271.5
Coating	2.1	1.8	12.3	12.1
Scraper Traps, Valves, and Other Materials	3.7	3.6	18.3	21.4
Pipeline Construction	29.6	26.3	179.5	187.8
Pump Stations and Terminals	12.8	12.8	87.7	101.7
Engineering, Construction Management and Inspection	8.3	7.5	58.2	56.6
Subtotal	101.2	91.1	706.8	686.9
Contingency @ 5%	5.1	4.6	35.3	34.3
Total	106.3	95.7	742.1	721.2

Notes: (1) Costs are in millions of 1984 dollars.
(2) Costs for project financing, initial line fill, and environmental studies and permitting are not included.

TABLE 3

ANNUAL OPERATING AND MAINTENANCE COSTS

	Wyoming to South Dakota	North Dakota to South Dakota	South Dakota to New York	Texas to New York
Operations Payroll	0.36	0.34	1.45	1.95
Supervisory Payroll	0.20	0.19	0.61	0.90
Communications	0.04	0.04	0.17	0.20
Automotive	0.03	0.03	0.09	0.13
Power	6.65	7.09	40.78	48.38
Pipeline Maintenance	0.10	0.08	0.39	0.46
Station Maintenance	0.11	0.11	0.59	0.70
Contract Services	0.03	0.02	0.10	0.12
Insurance and Ad Valorem Tax	1.59	1.44	11.13	10.82
Miscellaneous	.05	.05	2.77	3.18
TOTAL	9.16	9.39	58.08	66.84

Note: Costs are in millions of 1984 dollars.

TECHNICAL REPORT DATA
(Please read Instructions on the reverse before completing)

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15. SUPPLEMENTARY NOTES

16. ABSTRACT

This report provides estimated costs of producing methanol transportation fuel from coal. Estimates were made for mine-mouth plants in five different coal producing regions, and uniform methods were used so the estimated sales prices could be compared for market analysis. In addition to plant-gate prices, delivered prices were estimated for three major market areas. With presently available transportation the lowest delivered prices were for methanol production based in the southern lignite coal region. If new methanol-compatible pipelines were to be constructed, the lowest delivered prices would be for production based in the western subbituminous coal region. In the western subbituminous region, limited water resources would make extensive planning and careful site selection necessary, but they would not prevent the development of a coal-to-methanol industry. By-product carbon dioxide sales for enhanced oil recovery could reduce the required plant-gate methanol price in some areas near oil fields amenable to carbon dioxide injection techniques. Contains a literature review with 50 references.

17. KEY WORDS AND DOCUMENT ANALYSIS

a. DESCRIPTORS		b. IDENTIFIERS/OPEN ENDED TERMS	c. COSATI Field/Group
Coal	Manufacturing	Coal rank	
Bituminous Coal	Coal gasification	Methanol	
Subbituminous Coal	Carbinols		
Lignite	Desulfurization		
Cost Estimates	Prices		
Conversion	Transportation		

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