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Factored Estimates for Eastern Coal Commercial Concepts

Interim Report — Joint Department of Energy - Gas Research Institute Coal Gasification Program

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EXECUTIVE SUMMARY

Conceptual commercial designs were prepared for BI-GAS, HYGAS Steam-Oxygen and Steam-Iron, and Synthane processes to compare the economics with the conventional Lurgi process. Of these processes, only the Lurgi process is commercially available.

An additional DOE-Private Industry program is developing demonstration plant designs for two other processes. These two processes are not considered within the scope of this report. With the exception of the Lurgi process, the conceptual plant designs presented in this report are not based on pilot plant data, but rather are derived from computerized projections of bench-scale and PDU data. The conventional Lurgi process design is based on projections from information developed during the A.G.A. Westfield trials on eastern coal.

It should be appreciated that the computerized projections for the BI-GAS, HYGAS Steam-Oxygen, HYGAS Steam-Iron, and the Synthane processes do not ensure that these processes can be operable at conditions assumed for preparation of these cost estimates. The BI-GAS and Steam-Iron process have not been operated successfully on the pilot plant scale nor has the HYGAS process ever been integrated with the Steam-Iron process as is assumed in the cost estimate for this combination of processes. The HYGAS Steam-Oxygen and Synthane pilot plants have been operated but not at the conditions assumed for these cost estimates. Thus, the actual realization of the estimated costs presented is dependent on considerable future developmental effort.

For each of these five processes, capital costs and the cost of operation using an eastern bituminous coal have been estimated to determine the cost of pipeline gas. All plant designs and cost estimates, including the Lurgi plant, have been based on a consistent set of design criteria, economic ground rules, and estimating procedures.

The total capital requirement for utility financing and the average of the variable gas cost over the twenty-year depreciation period, as computed by the utility financing method, are shown in the following table. It is emphasized that these results, their use and interpretation, as well as each of the derived parameters that have been used in their calculations, are inseparable from the assumptions used in their preparation.

EXECUTIVE SUMMARY Continued

ASSUMPTIONS The assumptions are presented in the attached appendix "Design and Gas Cost Basis." Although every attempt has been made to provide realistic and meaningful guidelines, the assumptions used in this process comparison report may be different from the cost basis used by individual companies as they prepare cost estimates for specific processes at specific plant locations using actual coal sources. The resulting gas costs also do not include the cost of gas transportation from the plant to the actual gas user. Since the major gas users are located in the mid-western and eastern United States, this transportation factor is felt to be far less significant for eastern than for western locations.

LIMITATIONS This report includes only eastern coal processes funded as part of the DOE or DOE-GRI coal gasification program. Therefore, the two processes in the DOE-Private Industry Demonstration Plant program are not reported. The cost projections in this report assume fully developed, second generation gasification processes and are intended only to identify promising candidates for commercialization. Thus, the relative position of processes, and certainly their absolute capital and gas costs, may change as pilot plant data becomes available. Even as this report is being prepared, some further data has been made available which could not be incorporated.

The accuracy of these Total Plant Investment estimates is estimated to be ±20%. The significance of variations between costs of the processes presented should be considered in the light of this accuracy. Variations in gas costs of all second generation processes from $3.64 to $3.94 per million Btu are probably only indicative rather than significant. The study indicates that these processes might be less costly than the Lurgi process - the gas cost of which is estimated at $4.66 per million Btu. The lack of any meaningful combined operation and the need for development of advanced gas turbines makes it difficult to attach great credibility to the Steam-Iron HYGAS combination.

LIMITATIONS Continued

In considering the commercialization potential of processes, it is important to bear in mind that other factors will impact directly or indirectly on gas cost and process acceptability. These include such items as scale-up, degree of integrated system demonstration, technical risk, insurability, projected plant availability, environmental compatibility, the ability to economically process a specific coal type, and the like. To the extent that these factors can be accommodated by proper design and costing guidelines, these supplemental factors have been considered in this report. However, detailed discussion or review of these supplemental, but important, issues is beyond the scope of this report. It is ultimately also important to consider the inevitable effect of inflation on the gas price of all of these processes. This in general enhances the value of a process which can be rapidly commercialized.

EXECUTIVE SUMMARY Continued

COST SUMMARY

PROCESS	CAPITAL REQUIREMENT MILLIONS OF DOLLARS (1)	GAS COST (5) DOLLARS/MMBTU
IGT STEAM-Oxygen HYGAS	1170	3.69
IGT Steam-Iron HYGAS (2)		
Selexol Gas Treating, 25 mills/kWh Power Credit	1580	3.51
Benfield Gas Treating, 25 mills/kWh Power Credit (3)	1540	3.40
Selexol Gas Treating, 10 mills/kWh Power Credit (4)	1580	4.44
Benfield Gas Treating, 10 mills/kWh Power Credit (3) (4)	1540	4.34
BCR BI-GAS	1110	3.64
PERC Synthane	1270	3.94
Lurgi	1478	4.66

(1) The Cost Basis is January 1, 1976.

(2) The power recovery section for the Steam-Iron process was designed for maximum power recovery using expanders and gas turbines projected to be available by 1985. The 10 mill cases were added to indicate sensitivity to power credit.

(3) These values were obtained by substituting a Benfield unit for the Selexol unit for acid gas removal. The sulfur recovery, effluent treating, and steam and water systems were revised as a result of the substitution.

(4) The capital requirements for these two cases are the same as those for the 25 mill power credit. The gas cost change is solely due to the change in by-product credit without the redesign of the power recovery section. Different gas costs would be obtained if the plant design was optimized for the 10 mill power credit.

(5) These gas costs are the numerical average calculated by the Utility Financing Method for the 20 year depreciation period. Details of this calculation are shown in Appendix A.

INTRODUCTION

The joint Coal Gasification Program of the Department of Energy and the Gas Research Institute was organized to accelerate the development of new processes through the pilot plant stage for producing high Btu pipeline quality gas from coal. There are five processes in the program at various stages of development. The CO_2 Acceptor pilot plant has concluded its test operations. Four others, the Steam-Oxygen HYGAS and Steam-Iron HYGAS, BCR BI-GAS, and PERC Synthane, are still being tested at the pilot plants. A commercial scale demonstration plant is being designed for the Steam-Oxygen HYGAS process in parallel with continued pilot plant operation to develop design data.

A comparison of these processes using both eastern and western coal feeds is included in the program. As a bench-mark for comparison with present technology, each of the studies contains a Lurgi plant designed to the same guidelines and coal feed. This report presents the results of the comparison of the plants with eastern bituminous coal feed. The CO_2 Acceptor process, however, is not suitable for processing bituminous coal. Therefore, it is not included in this report.

As evaluation contractor for the program, C F Braun & Co has the responsibility for comparative evaluation of these processes. For comparative evaluation, commercial concept designs have been developed using process data provided by the process development contractors and gas processing technology available from process licensors. The capital and operating costs for each of the commercial concept designs have been estimated using a consistent set of guidelines formulated for this specific purpose. The cost of pipeline gas from each of the processes was computed in accordance with the procedures included in Appendix A.

PURPOSE

The potential of new processes for producing pipeline gas at a lower cost than from first generation processes has been recognized. But an impartial comprehensive analysis using consistent design, estimating, and economic guidelines has been published only for a western subbituminous coal feed[1]. It is the purpose of this study to perform such an analysis for an eastern bituminous coal, even though the processes have not been fully developed, to provide preliminary information in the following areas.

1 Order-of-magnitude estimates of capital investment

2 Order-of-magnitude estimates of operating costs

3 Coal and water requirements

4 Plant thermal efficiency

5 Relative cost of pipeline gas produced from the processes under development

6 A comparison between the second generation processes and a selected first generation process

7 Identify and clarify potential problems in development of commercial gasification processes through companion studies on these commercial concept designs.

The first generation process chosen for comparison was Lurgi, since it has been selected by a number of firms for construction of first generation plants. It is thus considered a bench-mark for comparison with second generation processes by most firms interested in future construction of coal gasification plants. For this comparison, the Lurgi process has been modified to follow the Design and Gas Cost Basis as closely as possible. This study thus represents an attempt to evaluate, as realistically as possible with preliminary data, the economic potential of various gasification processes on the same basis.

(1) Factored Estimates for Western Coal Commercial Concepts, Department of Energy Report Number FE-2240-5, October 1976.

DESIGN BASIS INFORMATION

The commercial concept designs for the processes in the combined program were developed using data supplied by the respective process developers. Initially the contractors were asked to supply a heat and material balance around the gasification section, or enough basic data to develop these balances. Other specific design data on the gasification process was supplied by the contractor. As the design work proceeded, contact was maintained with each of the process contractors through an exchange of letters, meetings, and telephone conversations.

The process information thus solicited from each of the contractors was used to prepare conceptual commercial designs. These designs were prepared according to previously agreed upon and carefully defined guidelines. The individual assumptions used as design bases have been collected together and presented as Appendix A, entitled Design and Gas Cost Basis.

It should be appreciated that the operability of these processes at the design conditions assumed has not been verified. Until this verification has been achieved, the designs must be considered tentative and achievement of the gas costs based on these designs must be considered problematic.

For the Steam-Iron HYGAS process, gas costs for both 25 mills/kWh and 10 mills/kWh export power credit are presented. The 25 mills/kWh power credit is based on the production of non-interruptible baseload power and represents both capital and energy charges for new power plant capacity. The 10 mills/kWh power credit is based on interruptible power, and includes only energy related charges for power. The basic design of the power recovery section for the Steam-Iron HYGAS process has been optimized based on a 25 mills/kWh export power credit. The gas cost for the 10 mills/kWh power credit reflects only a change in by-product credit without the redesign of the power recovery section that would optimize the plant for the 10 mills/kWh power credit.

The cost estimates for the Steam-Iron HYGAS process must be considered the most tenuous of those presented. The use of the Steam-Iron process to provide hydrogen for the HYGAS process remains to be studied, and both the solids removal prior to the power recovery section and the expanders and gas turbine require a major development effort.

DESIGN BASIS INFORMATION Continued

Except for the Steam-Iron HYGAS process, all of these designs are based on selective acid gas removal using the Selexol process.

Because of the low concentration of carbon dioxide acid gas in the Steam-Iron HYGAS process reactor synthesis gas, a non-selective acid gas removal unit was used. Some additional cost savings are possible for this process by substituting a hot carbonate acid gas removal unit (Benfield) for the non-selective Selexol unit. Costs based on this substitution are presented as an alternative case.

At the completion of the design work, overall heat and material balance summaries were prepared for each of the gasification processes. The summary material balances thus generated are presented in Tables I-A through I-E, while the summary energy balances are presented in Tables II-A through II-E.

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TABLE I-A
SUMMARY MATERIAL BALANCE
IGT STEAM-OXYGEN HYGAS PROCESS

INLET STREAMS	LBS/HR	PERCENT OF TOTAL
Coal to Process, Dry	1,127,000	12.7
Water in Coal to Process	72,000	0.8
Coal to Steam Plant, Dry	115,600	1.3
Water in Coal to Steam Plant	7,400	0.1
Oxygen to Gasifier	245,000	2.8
Combustion Air	3,175,700	35.7
Raw Water	4,138,400	46.6
TOTAL	8,881,100	100.0

OUTLET STREAMS	LBS/HR	PERCENT OF TOTAL
Product Gas	457,500	5.2
CO_2 Vent	946,600	10.7
Cooling Tower Losses	3,080,700	34.7
Flue Gas	3,830,300	43.1
Ammonia	7,700	0.1
Sulfur	50,900	0.6
By-Product Oil	34,600	0.4
Sludge Removed in BiOx	5,000	0.1
Waste Solids, Dry	175,100	2.0
Water in Waste Solids	80,600	0.9
Steam and Water Losses	209,900	2.4
Miscellaneous Losses	2,200	0.0
TOTAL	8,881,100	100.0

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TABLE I-B
SUMMARY MATERIAL BALANCE
IGT STEAM-IRON HYGAS PROCESS

INLET STREAMS	LBS/HR	PERCENT OF TOTAL
Coal to Process, Dry	1,679,700	8.8
Water in Coal to Process	107,300	0.6
Combustion Air	7,615,600	39.7
Air to Pretreater	1,552,300	8.1
Air to Gasifier	2,329,000	12.1
Raw Water	5,877,000	30.7
Iron Ore	2,700	
TOTAL	19,163,600	100.0

OUTLET STREAMS	LBS/HR	PERCENT OF TOTAL
Product Gas	466,100	2.4
Cooling Tower Losses	4,104,600	21.3
Flue Gas	13,878,200	72.4
Ammonia	11,600	0.1
Sulfur	55,700	0.3
By-Product Oil	28,400	0.1
Organics Removed in BiOx	2,400	-
Waste Solids, Dry	282,900	1.5
Water in Waste Solids	128,600	0.7
Steam and Water Losses	205,100	1.1
TOTAL	19,163,600	100.0

TABLE I-C
SUMMARY MATERIAL BALANCE
BCR BI-GAS PROCESS

INLET STREAMS	LBS/HR	PERCENT OF TOTAL
Coal to Process, Dry	1,016,900	13.9
Water in Coal to Process	64,900	0.9
Coal to Steam Plant, Dry	154,700	2.1
Water in Coal to Steam Plant	9,900	0.1
Oxygen to Gasifier	453,700	6.2
Combustion Air	1,906,700	26.1
Raw Water	3,689,300	50.7
TOTAL	7,296,100	100.0

OUTLET STREAMS	LBS/HR	PERCENT OF TOTAL
Product Gas	444,000	6.1
CO_2 Vent	1,252,600	17.2
Cooling Tower Losses	2,773,100	38.0
Flue Gas	2,328,900	31.9
Ammonia	9,200	0.1
Sulfur	52,000	0.7
Waste Solids, Dry	151,000	2.1
Water in Waste Solids	62,400	0.9
Steam and Water Losses	214,000	2.9
Miscellaneous Losses	8,900	0.1
TOTAL	7,296,100	100.0

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TABLE I-D
SUMMARY MATERIAL BALANCE
PERC SYNTHANE PROCESS

INLET STREAMS	LBS/HR	PERCENT OF TOTAL
Coal to Process, Dry	1,421,000	15.1
Water in Coal to Process	90,700	1.0
Oxygen to Gasifier	397,600	4.2
Combustion Air	3,587,700	38.1
Raw Water	3,919,900	41.6
TOTAL	9,416,900	100.0

OUTLET STREAMS	LBS/HR	PERCENT OF TOTAL
Product Gas	444,500	4.7
CO_2 Vent	1,041,400	11.1
Cooling Tower Losses	2,545,600	27.1
Flue Gas	4,414,300	46.9
Ammonia	13,400	0.1
Sulfur	58,400	0.6
By-Product Oil	49,900	0.5
Organics Removed in BiOx	11,300	0.1
Waste Solids, Dry	138,500	1.5
Water in Waste Solids	42,200	0.4
Char Exporting (Dry)	56,500	0.6
Ash in Char Exporting	28,800	0.3
Water in Char Exporting	198,900	2.1
Steam and Water Losses	355,400	3.8
Miscellaneous Losses	17,800	0.2
TOTAL	9,416,900	100.0

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TABLE I-E
SUMMARY MATERIAL BALANCE
LURGI PROCESS

INLET STREAMS	LBS/HR	PERCENT OF TOTAL
Coal to Process, Dry		
To Gasifiers	1,203,700	10.7
To Steam Plant	229,000	2.0
Water in Coal	91,500	0.8
Oxygen to Gasifier	639,700	5.7
Combustion Air	3,564,000	31.7
Raw Water	5,535,100	49.1
TOTAL	11,263,000	100.0

OUTLET STREAMS	LBS/HR	PERCENT OF TOTAL
Product Gas	460,000	4.1
CO_2 Vent	1,491,600	13.3
Cooling Tower Losses	4,393,600	39.0
Flue Gas	4,248,000	37.7
Ammonia	10,300	0.1
Sulfur	58,000	0.5
By-Product Oil	19,300	0.2
Phenol	3,700	0.0
Organics Removed in BiOx	1,300	0.0
Waste Solids, Dry	179,200	1.6
Water in Waste Solids	75,100	0.7
Steam and Water Losses	302,900	2.7
Miscellaneous Losses	15,900	0.1
TOTAL	11,263,000	100.0

TABLE II-A
SUMMARY ENERGY BALANCE
IGT STEAM-OXYGEN HYGAS PROCESS

	MM BTU/HR	PERCENT OF TOTAL
ENERGY INPUT		
Coal to Process, HHV	14,865	90.7
Coal to Steam Plant, HHV	1,525	9.3
Total Input	16,390	100.0
ENERGY DISTRIBUTION		
Product Gas, HHV	10,444	63.7
By-Products, HHV		
Ammonia	74	0.5
Sulfur	200	1.2
Oil	629	3.8
Subtotal Product and By-Products	11,347	69.2
Consumption and Losses	5,043	30.8
Total Energy Distribution	16,390	100.0
Cold Gas Efficiency, Percent		63.7
Plant Thermal Efficiency, Percent		69.2

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TABLE II-B
SUMMARY ENERGY BALANCE
IGT STEAM-IRON HYGAS PROCESS

	MM BTU/HR	PERCENT OF TOTAL
ENERGY INPUT		
Coal to Process, HHV	22,156	100.0
Total Input	22,156	100.0
ENERGY DISTRIBUTION		
Product Gas, HHV	10,445	47.2
By-Products, HHV		
Ammonia	112	0.5
Sulfur	208	0.9
Oil	463	2.1
Export Power, HHV	2,203	9.9
Subtotal Product, By-Products and Export Power	13,431	60.6
Consumption and Losses	8,725	39.4
Total Energy Distribution	22,156	100.0
Cold Gas Efficiency, Percent		47.2
Plant Thermal Efficiency, Percent		60.6

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TABLE II-C
SUMMARY ENERGY BALANCE
BCR BI-GAS PROCESS

	MM BTU/HR	PERCENT OF TOTAL
ENERGY INPUT		
Coal to Process, HHV	13,412	86.8
Coal to Steam Plant, HHV	2,040	13.2
Total Input	15,452	100.0
ENERGY DISTRIBUTION		
Product Gas, HHV	10,544	68.2
By-Products, HHV		
Ammonia	89	0.6
Sulfur	200	1.3
Subtotal Product and By-Products	10,833	70.1
Consumption and Losses	4,619	29.9
Total Energy Distribution	15,452	100.0
Cold Gas Efficiency, Percent		68.2
Plant Thermal Efficiency, Percent		70.1

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TABLE II-D
SUMMARY ENERGY BALANCE
PERC SYNTHANE PROCESS

	MM BTU/HR	PERCENT OF TOTAL
ENERGY INPUT		
Coal to Process, HHV	18,744	100.0
Total Input	18,744	100.0
ENERGY DISTRIBUTION		
Product Gas, HHV	10,417	55.6
By-Products, HHV		
Ammonia	122	0.6
Sulfur	236	1.3
Oil	829	4.4
Export Char, HHV	789	4.2
Subtotal Product and By-Products	12,393	66.1
Consumption and Losses	6,351	33.9
Total Energy Distribution	18,744	100.0
Cold Gas Efficiency, Percent		55.6
Plant Thermal Efficiency, Percent		66.1

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TABLE II-E
SUMMARY ENERGY BALANCE
LURGI PROCESS

	MM BTU/HR	PERCENT OF TOTAL
ENERGY INPUT		
Coal to Process, HHV	15,877	84.0
Coal to Steam Plant, HHV	3,029	16.0
Total Input	18,906	100.0
ENERGY DISTRIBUTION		
Product Gas, HHV	10,410	55.1
By-Products, HHV		
Ammonia	99	0.5
Sulfur	233	1.2
Oil	660	3.5
Subtotal Product and By-Products	11,402	60.3
Consumption and Losses	7,504	39.7
Total Energy Distribution	18,906	100.0
Cold Gas Efficiency, Percent		55.1
Plant Thermal Efficiency, Percent		60.3

ESTIMATE DESCRIPTION

The estimates are ORDER-OF-MAGNITUDE type based on engineering data taken from the process flow diagrams of each process as presented in Technical Appendix I and the engineered equipment as described in takeoff pages provided in Technical Appendix II. The takeoff pages detail the type, quantity, and design of the equipment. The unit estimate summaries provide a breakdown of costs by type of equipment, and the plant investment summary provides a breakdown of costs for each process by unit. The total installed costs provide the basis for the gas cost calculation.

ENGINEERED EQUIPMENT The engineered equipment costs were obtained from supplier rough price quotations, by adjusting prices from quotations of similar equipment, and in-house estimates. An allowance for miscellaneous equipment is included to cover known cost items that are required for a completely engineered process unit, but are individually too small to justify the time to develop them for a factored estimate.

INSTALLATION FACTORS Where factored estimates are used to compare plants using different processes, a greater degree of consistency is required. The more commonly used method of applying an overall unit installation multiplier does not allow for dissimilarity of engineered equipment that exists between units of the two processes under comparison. Individual installation factors applicable to a specific type of engineered equipment have been used to allow for differences in metallurgy, pressures and temperatures, field fabrication, and the like. This method results in reasonable order-of-magnitude costs, and a greater degree of consistency both between units of the same process as well as between units of other processes. The installation factors are based on experience and judgment in engineering and construction of similar equipment for refinery and chemical plants.

GENERAL FACILITIES This item covers costs for site preparation, electrical distribution, yard piping, buildings, flare system, tankage, shipping and receiving facilities, sulfur storage, potable and sanitary water, holding ponds, plant roads, and the like. The estimate includes approximately ten percent of the total cost exclusive of home office cost, fee and contingency.

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ESTIMATE DESCRIPTION Continued

CONTRACTOR'S HOME OFFICE COSTS AND FEE The home office cost covers project management, engineering, purchasing, estimating, cost control, scheduling, accounting, and other home office and consulting costs. Approximately ten percent of the total cost, exclusive of contingency, is included to cover contractor's home office costs and fee.

CONTINGENCY This is included as approximately fifteen percent of the total cost in accordance with the design and gas cost basis. Contingency covers unknowns in terms such as engineered equipment sizing and pricing, materials of construction, installation factors, and the percentaged items, general facilities and contractor's home office costs.

ESCALATION The capital cost estimates for these processes are based on January 1976 costs with no forward escalation included.

FOOTNOTE CASES The estimate adjustments for these cases were obtained from process study information, or from adjustments based on resizing major equipment and ratios based on engineering judgement. The potential for error in such approximations is somewhat larger than for the base cases.

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ECONOMIC SUMMARIES

The completed conceptual commercial designs have provided the data needed to calculate the 20 years average cost of producing pipeline gas from coal by each of the following gasification processes.

1 IGT Steam-Oxygen HYGAS Process

2 IGT Steam-Iron HYGAS Process

3 BCR BI-GAS Process

4 PERC Synthane Process

5 Lurgi Process

These costs have been computed using utility financing according to procedures described in the Design and Gas Cost Basis presented in Appendix A. The specific data estimated for each gasification process to permit the calculation of the gas cost include plant investment, capital requirements, and annual operating costs.

A plant Investment Summary has been prepared to permit direct comparison of costs for similar sections of each process. A summary of the plant installed cost for all processes by unit is shown in Table III. A more detailed tabulation of the installed cost estimates by process unit is given in Tables III-A through III-R as shown below.

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ECONOMIC SUMMARIES Continued

TABLE	UNIT	TITLE
III-A	11	Coal Storage and Reclaiming
III-B	12	Coal Preparation
III-C	13	Coal Pretreatment
III-D	14	Coal Feeding
III-E	15	Gasification
III-F	15	Power Recovery
III-G	16	Raw Gas Quench
III-H	17	Shift Conversion
III-I		Lurgi Process Area
III-J	18	Acid Gas Removal
III-K	19	Methanation
III-L	20	Effluent Treating
III-M	21	Sulfur Recovery
III-N	22	Solids Disposal
III-O	23	Product Gas Drying
III-P	30	Steam and Power
III-Q	31	Plant Water System
III-R	32	Oxygen Plant

The calculations of the gas cost for each process is summarized in a set of five tables. These tables are numbered IV, IV-A, IV-B, and IV-C through VIII, VIII-A, VIII-B, and VIII-C. Titles of the tables for the IGT Steam-Oxygen HYGAS process are shown here.

IV Summary of Capital and Operating Costs, IGT Steam-Oxygen HYGAS Process

IV-A Capital Requirements, IGT Steam-Oxygen HYGAS Process

IV-B Annual Operating Costs, IGT Steam-Oxygen HYGAS Process

IV-C Annual Maintenance Costs, IGT Steam-Oxygen HYGAS Process

Gas costs calculated for each of the processes are summarized in Table IX.

DOE-GRI | TABLE III | Project 4568-NW

PLANT INVESTMENT SUMMARY, EASTERN BITUMINOUS COAL

Coal Gasification Plant | FACTORED ESTIMATES | March 1, 1978

		IGT HYGAS STEAM-OXYGEN (1)	IGT HYGAS STEAM-IRON (1)	BCR BI-GAS (1)	PERC SYNTHANE (1)	LURGI (1)
11	Coal Storage & Reclaiming	$ 12,000,000	$ 12,000,000	$ 12,000,000	$ 12,000,000	$ 12,000,000
12	Coal Preparation	20,000,000	26,000,000	30,000,000	27,000,000	5,000,000
13	Coal Pretreatment	34,000,000	40,000,000			
14	Coal Feeding	18,000,000	20,000,000	14,000,000	11,000,000	
15	Gasification	52,000,000	105,000,000	49,000,000	59,000,000	
15	Power Recovery		333,000,000			
16	Raw Gas Quench	52,000,000	53,000,000	31,000,000	32,000,000	
17	Shift Conversion	27,000,000		29,000,000	31,000,000	
	Lurgi Process Area (2)					255,000,000
18	Acid Gas Removal	101,000,000	78,000,000	98,000,000	86,000,000	100,000,000
19	Methanation	26,000,000	21,000,000	28,000,000	29,000,000	46,000,000
20	Effluent Treating	41,000,000	39,000,000	29,000,000	71,000,000	22,000,000
21	Sulfur Recovery	76,000,000	93,000,000	72,000,000	79,000,000	82,000,000
22	Solids Disposal	10,000,000	9,000,000	12,000,000	5,000,000	3,000,000
23	Product Gas Drying	800,000	800,000	800,000	800,000	800,000
30	Steam and Power	112,000,000	13,000,000	114,000,000	171,000,000	158,000,000
31	Plant Water Systems	34,000,000	43,000,000	31,000,000	32,000,000	50,000,000
32	Oxygen Plant	41,000,000		67,000,000	63,000,000	91,000,000
	General Facilities Site Preparation, Electrical Distribution, Yard Piping, Buildings, Flare System. Tankage, Shipping & Receiving Facilities, Sulfur Storage, Potable & Sanitary Water, Holding Ponds, Plant Roads	73,000,000	98,000,000	69,000,000	79,000,000	92,000,000
	Installed Cost	$ 729,800,000	$ 983,800,000	$ 685,800,000	$ 787,800,000	$ 916,800,000
	Contractors Home Office Cost and Fee	81,200,000	109,200,000	76,200,000	87,200,000	102,200,000
	Subtotal	$ 811,000,000	$1,093,000,000	$ 762,000,000	$ 875,000,000	$1,019,000,000
	Contingency	119,000,000	167,000,000	118,000,000	135,000,000	151,000,000
	Total Plant Investment	$ 930,000,000	$1,260,000,000(3)	$ 880,000,000	$1,010,000,000	$1,170,000,000

(1) These estimates are based on January 1976 costs with no forward escalation.
(2) Lurgi Process Area contains units equivalent in their functions to Units 14, 15, 16, and 17 for the other processes.
(3) Total plant investment for the case in which Benfield acid gas removal is substituted for Selexol is $1,230,000,000.

C F BRAUN & CO

DOE-GRI — TABLE III A — Project 4568-NW

UNIT 11, COAL STORAGE AND RECLAIMING

FACTORED ESTIMATES

Eastern Coal — March 1, 1978

	IGT HYGAS STEAM-OXYGEN	IGT HYGAS STEAM-IRON	BCR BI-GAS	FERC SYNTHANE	LURGI
Engineered Equipment					
Pumps	$ 26,000	$ 26,000	$ 26,000	$ 26,000	$ 26,000
Conveying Equipment	1,125,000	1,287,000	1,077,000	1,213,000	1,239,000
Belts	8,000	8,000	8,000	8,000	8,000
Elevators	7,000	7,000	7,000	7,000	7,000
Feeders	26,000	26,000	26,000	26,000	26,000
Chutes					
Bins and Hoppers	25,000	25,000	25,000	25,000	25,000
Mills (Sample Crusher)	7,000	7,000	7,000	7,000	7,000
Weigh Scales	6,000	6,000	6,000	6,000	6,000
Other Equipment	280,000	300,000	280,000	300,000	260,000
Belt Trailers	740,000	750,000	740,000	750,000	740,000
Traveling Boomstacker	1,100,000	1,000,000	1,050,000	1,050,000	1,100,000
Bucket Wheel Reclaimer	100,000	100,000	100,000	100,000	100,000
Transfer Car	32,000	32,000	32,000	32,000	32,000
Magnetic Separators	10,000	10,000	10,000	10,000	10,000
Samplers					
Allowance for Miscellaneous	208,000	216,000	206,000	240,000	214,000
Total Engineered Equipment	$ 3,700,000	$ 3,900,000	$ 3,600,000	$ 3,800,000	$ 3,800,000
Installed Cost	$ 12,000,000	$ 12,000,000	$ 12,000,000	$ 12,000,000	$ 12,000,000

These estimates are based on January 1976 costs with no forward escalation

DOE-GRI | Eastern Coal | Project 4568-NW | March 1, 1978

TABLE III-B
UNIT 12, COAL PREPARATION
FACTORED ESTIMATES

	IGT HYGAS STEAM-OXYGEN	IGT HYGAS STEAM-IRON	BCR BI-GAS	PERC SYNTHANE	LURGI
Engineered Equipment					
Tanks	$ 8,000		$ 28,000	$ 28,000	
Agitators			12,000	12,000	
Pumps	36,000	$ 29,000	91,000	78,000	
Conveying Equipment		1,346,000	841,000	433,000	$ 910,000
Belts	1,171,000	3,000	20,000		25,000
Feeders		834,000	32,000	16,000	386,000
Chutes	448,000				
Bins	3,050,000	4,110,000	2,665,000	2,700,000	290,000
Mills	500,000	750,000	6,810,000	7,800,000	18,000
Weigh Scales	8,000	27,000	31,000	23,000	
Separation Equipment					
Dust Collectors	141,000	166,000	77,000	33,000	91,000
Screens	360,000	612,000	105,000	84,000	
Other Equipment					
Samplers	5,000	5,000	28,000	24,000	
Car Puller		49,000	49,000		
Car Shaker		14,000	14,000		
Allowance for Miscellaneous	273,000	355,000	497,000	569,000	80,000
Total Engineered Equipment	$ 6,000,000	$ 8,300,000	$ 11,300,000	$ 11,800,000	$ 1,800,000
Installed Cost	$ 20,000,000	$ 26,000,000	$ 30,000,000	$ 27,000,000	$ 5,000,000

These estimates are based on January 1976 costs with no forward escalation.

These estimates are based on January 1976 costs with no forward escalation.

C F BRAUN & CO

DOE-GRI — Eastern Coal — Project 4568-NW — March 1, 1978

TABLE III-C
UNIT 13, COAL PRETREATMENT
FACTORED ESTIMATES

	IGT HYGAS STEAM-OXYGEN	IGT HYGAS STEAM-IRON	BCR BI-GAS	PERC SYNTHANE	LURGI
Engineered Equipment					
Reactors	$ 4,680,000	$ 6,880,000			
Cyclones	1,378,000	1,906,000			
Pressure Vessels	464,000	840,000			
Exchangers					
Shell and Tube					
Surface Condensers with Jet Ejectors	250,000	4,000			
Pumps	189,000	144,000			
Compressors	5,811,000	5,585,000			
Conveying Equipment					
Belts	437,000	755,000			
Feeders	85,000	138,000			
Chutes	15,000	15,000			
Bins	1,640,000	1,960,000			
Weigh Scales	92,000	104,000			
Dust Collectors	54,000				
Allowance for Miscellaneous	705,000	969,000			
Total Engineered Equipment	$ 15,800,000	$ 19,300,000			
Installed Cost	$ 34,000,000	40,000,000			

These estimates are based on January 1976 costs with no forward escalation.

C F BRAUN & CO

DOE-GRI | TABLE III-D | Project 4568-NW

UNIT 14, COAL FEEDING

Eastern Coal | FACTORED ESTIMATES | March 1, 1978

	IGT HYGAS STEAM-OXYGEN	IGT HYGAS STEAM-IRON	BCR BI-GAS	PERC SYNTHANE	LURGI
Engineered Equipment					
Pressure Vessels	$ 976,000	$ 1,801,000			
Storage Tanks			$ 834,000	$ 634,000	
Exchangers					
Shell and Tube	220,000	964,000	1,020,000		
Surface Condensers with Jet Ejectors	217,000				
Pumps	3,177,000	3,510,000	2,280,000	2,786,000	
Compressors	1,160,000	1,124,000			
Other Equipment					
Samplers			10,000	10,000	
Allowance for Miscellaneous	350,000	401,000	256,000	170,000	
Total Engineered Equipment	$ 6,100,000	$ 7,800,000	$ 4,400,000	$ 3,600,000	
Installed Cost	$ 18,000,000	20,000,000	$ 14,000,000	$ 11,000,000	

(1) Unit function is included in Lurgi Process Area - No separate estimate here
These estimates are based on January 1976 costs with no forward escalation.

C F BRAUN & CO

DOE-GRI | Project 4568-NW

Eastern Coal | March 1, 1978

TABLE III-E
UNIT 15, GASIFICATION
FACTORED ESTIMATES

	IGT HYGAS STEAM-OXYGEN	IGT HYGAS STEAM-IRON	BCR BI-GAS	PERC SYNTHANE	LURGI
Engineered Equipment					
Gasifiers	$ 33,200,000	$ 33,200,000	$ 3,500,000	$ 24,600,000	
Reactors		28,200,000			
Cyclones	216,000	2,358,000	732,000	858,000	
Pressure Vessels		242,000	5,972,000	4,366,000	
Exchangers					
Shell and Tube	180,000		3,731,000		
Air Coolers		762,000		390,000	
Pumps			478,000	408,000	
Compressors		257,000			
Steam Injector				42,000	
Ore Belt Conveyor		146,000			
Bin		470,000			
Dust Collector Package		67,000			
Allowance for Miscellaneous	704,000	1,398,000	787,000	836,000	
Total Engineered Equipment	$ 34,300,000	$ 67,100,000	$ 15,200,000	$ 31,500,000	
Installed Cost	$ 52,000,000	$ 105,000,000	$ 49,000,000	$ 59,000,000	

(1) Unit function is included in Lurgi Process Area - No separate estimate here
These estimates are based on January 1976 costs with no forward escalation.

C F BRAUN & CO

DOE-GRI | TABLE III-F | Project 4568-NW

Eastern Coal | UNIT 15, POWER RECOVERY FACTORED ESTIMATES | March 1, 1978

	IGT HYGAS STEAM-OXYGEN	IGT HYGAS STEAM-IRON	BCR BI-GAS	PERC SYNTHANE	LURGI
Engineered Equipment					
Pressure Vessels		$ 2,232,000			
Exchangers					
Shell and Tube		1,682,000			
Surface Condensers with Jet Ejectors		3,068,000			
Air Coolers		1,210,000			
Pumps		88,000			
Compressors		88,822,000			
Includes Steam Turbines, Gas Turbines, Expanders, and Generator Sets					
Waste Heat Boiler Package		57,800,000			
Separation Equipment					
Dust Collector Package		2,630,000			
Cyclones		460,000			
Allowance for Miscellaneous		5,608,000			
Total Engineered Equipment		$ 163,600,000			
Installed Cost		$ 333,000,000			

These estimates are based on January 1976 costs with no forward escalation.

These estimates are based on January 1976 costs with no forward escalation.

DOE-GRI | TABLE III-G | Project 4568-NW

Eastern Coal

UNIT 16, RAW GAS QUENCH
FACTORED ESTIMATES

March 1, 1978

	IGT HYGAS STEAM-OXYGEN	IGT HYGAS STEAM-IRON	BCR BI-GAS	PERC SYNTHANE	LURGI (1)
Engineered Equipment					
Columns	$ 3,795,000	$ 2,606,000	$ 3,260,000	$ 2,040,000	
Pressure Vessels	1,388,000	$ 2,580,000	1,062,000	1,555,000	
Tanks	95,000	165,000			
Exchangers					
Shell and Tube	6,421,000	5,738,000	5,270,000	6,298,000	
Air Coolers	2,060,000	3,044,000			
Pumps	211,000	95,000	364,000	254,000	
Allowance for Miscellaneous	730,000	772,000	444,000	453,000	
Total Engineered Equipment	$ 14,700,000	$ 16,000,000	$ 10,400,000	$ 10,200,000	
Installed Cost	$ 52,000,000	$ 53,000,000	$ 32,000,000	$ 32,000,000	

(1) Unit function is included in Lurgi Process Area - No separate estimate here.
These estimates are based on January 1976 costs with no forward escalation.

C F BRAUN & CO

DOE-GRI	TABLE III-H	Project 4568-NW
Eastern Coal	UNIT 17, SHIFT CONVERSION FACTORED ESTIMATES	March 1, 1978

	IGT HYGAS STEAM-OXYGEN	IGT HYGAS STEAM-IRON	BCR BI-GAS	PERC SYNTHANE	LURGI (1)
Engineered Equipment					
Reactors	$ 2,968,000		$ 3,456,000	$ 2,956,000	
Pressure Vessels	452,000		428,000	348,000	
Exchangers					
Shell and Tube	5,580,000		3,702,000	5,938,000	
Air Coolers	780,000		1,880,000	980,000	
Allowance for Miscellaneous	420,000		434,000	578,000	
Total Engineered Equipment	$ 9,200,000		$ 9,900,000	$ 10,800,000	
Installed Cost	$ 27,000,000		$ 29,000,000	$ 31,000,000	

(1) Unit function is included in Lurgi Process Area - No separate estimate here.
These estimates are based on January 1976 costs with no forward escalation.

C F BRAUN & CO

DOE-GRI	TABLE III-I LURGI PROCESS AREA	Project 4568-NW
Eastern Coal	FACTORED ESTIMATES	March 1, 1978

Lurgi Proprietary Units consist of

Gasification
Lock Gas Storage and Compression
Gas Cooling
Gas Liquor Separation
Shift Conversion
Phenol Extraction
Gas Liquor Stripping
Gasifier Ash Disposal

Installed Cost	$255,000,000

This estimate is based on January 1976 costs with no forward escalation.

C F BRAUN & CO

DOE-GRI — Eastern Coal — Project 4568-NW — March 1, 1978

TABLE III-J
UNIT 18, ACID GAS REMOVAL
FACTORED ESTIMATES

	IGT HYGAS STEAM-OXYGEN	IGT HYGAS STEAM-IRON	BCR BI-GAS	PERC SYNTHANE	LURGI
Engineered Equipment					
Columns	$ 5,874,000	$ 3,826,000	$ 8,200,000	$ 7,320,000	$ 8,853,000
Reactors	900,000	776,000	1,300,000	940,000	720,000
Pressure Vessels	784,000	940,000	2,473,000	1,094,000	2,069,000
Tanks	18,000	16,000	18,000	18,000	24,000
Exchangers					
Shell and Tube	2,814,000	4,600,000	3,448,000	3,130,000	4,116,000
Surface Condensers with Jet Ejectors	968,000		698,000	260,000	642,000
Pumps	3,047,000	758,000	3,513,000	2,766,000	2,773,000
Compressors	5,260,000	3,230,000	3,220,000	3,190,000	3,400,000
Refrigeration Package	5,760,000	5,370,000	5,580,000	5,100,000	4,080,000
Other Equipment					
Cartridge Filters	42,000	10,000	42,000	50,000	24,000
Allowance for Miscellaneous	1,333,000	974,000	1,408,000	1,232,000	1,399,000
Total Engineered Equipment	$ 26,800,000	$ 20,500,000	$ 29,900,000	$ 25,100,000	$ 28,100,000
Installed Cost	$101,000,000	$ 78,000,000	$ 98,000,000	$ 86,000,000	$100,000,000

These estimates are based on January 1976 costs with no forward escalation.

C F BRAUN & CO

DOE-GRI — Eastern Coal — Project 4568-NW — March 1, 1978

TABLE III-K
UNIT 19, METHANATION
FACTORED ESTIMATES

	IGT HYGAS STEAM-OXYGEN	IGT HYGAS STEAM-IRON	BCR BI-GAS	PERC SYNTHANE	LURGI
Engineered Equipment					
Reactors	$ 2,810,000	$ 1,870,000	$ 3,250,000	$ 2,520,000	$ 5,760,000
Pressure Vessels	154,000	132,000	112,000	269,000	292,000
Exchangers					
Shell and Tube	3,314,000	2,969,000	3,791,000	3,538,000	3,528,000
Surface Condensers with Jet Ejectors	72,000		78,000	150,000	210,000
Air Coolers	365,000	354,000	574,000		1,050,000
Pumps	12,000		12,000	24,000	14,000
Compressors	1,050,000	366,000	1,204,000	2,094,000	5,220,000
Combustion	300,000	300,000	300,000	300,000	400,000
Allowance for Miscellaneous	423,000	309,000	479,000	405,000	826,000
Total Engineered Equipment	$ 8,500,000	$ 6,300,000	$ 9,800,000	$ 9,300,000	$ 17,300,000
Installed Cost	$ 26,000,000	$ 21,000,000	$ 28,000,000	$ 29,000,000	$ 46,000,000

These estimates are based on January 1976 costs with no forward escalation.

C F BRAUN & CO

DOE-GRI — Eastern Coal — Project 4568-NW — March 1, 1978

TABLE III-L
UNIT 20, EFFLUENT TREATING
FACTORED ESTIMATES

	IGT HYGAS STEAM-OXYGEN	IGT HYGAS STEAM-IRON	BCR BI-GAS	PERC SYNTHANE	LURGI
Engineered Equipment					
Columns	$ 693,000	$ 516,000	$ 759,000	$ 1,860,000	
Pressure Vessels	178,000		170,000	671,000	
Ammonia Storage Spheres	1,305,000	1,824,000	1,368,000	2,125,000	
Exchangers					
Shell and Tube	593,000	398,000	874,000	1,809,000	
Air Coolers	255,000		513,000	3,295,000	
Pumps	36,000	12,000	39,000	80,000	
Ammonia Removal Package	884,000	1,362,000	1,179,000	1,517,000	
Bio-Oxidiation Package					
Equipment	1,925,000	2,491,000		4,307,000	$ 3,022,000
Tanks	241,000	293,000		377,000	432,000
Pumps	132,000	148,000		205,000	207,000
Allowance for Miscellaneous	358,000	356,000	248,000	854,000	239,000
Total Engineered Equipment	$ 6,600,000	$ 7,400,000	$ 5,150,000	$ 17,100,000	$ 3,900,000
Installed Cost	$ 41,000,000	$ 39,000,000	$ 29,000,000	$ 71,000,000	$ 22,000,000

These estimates are based on January 1976 costs with no forward escalation.

DOE-GRI | Project 4568-NW

Eastern Coal | March 1, 1978

TABLE III-M
UNIT 21, SULFUR RECOVERY
FACTORED ESTIMATES

	IGT HYGAS STEAM-OXYGEN	IGT HYGAS STEAM-IRON	BCR BI-GAS	PERC SYNTHANE	LURGI
Engineered Equipment					
Columns	$ 9,327,000	$ 11,150,000	$ 7,863,000	$ 9,206,000	$ 8,976,000
Reactors	700,000	720,000	390,000	282,000	776,000
Pressure Vessels	1,557,000	1,673,000	1,479,000	1,174,000	588,000
Tanks	265,000	437,000	432,000	392,000	520,000
Exchangers					
Shell and Tube	236,000	932,000	705,000	711,000	574,000
Vaporizer Package	460,000	446,000	300,000	210,000	410,000
Scrubber Feed/Effluent Exchanger	1,450,000	2,421,000	720,000	1,220,000	1,975,000
Air Coolers	1,104,000	415,000	580,000	480,000	366,000
Pumps	277,000	438,000	280,000	326,000	637,000
Compressors	3,128,000	4,252,000	4,080,000	4,168,000	3,860,000
Combustion Includes Heaters, Burners, Stack	2,500,000	3,150,000	2,010,000	2,308,000	4,880,000
Allowance for Miscellaneous	1,096,000	1,366,000	961,000	1,023,000	1,238,000
Total Engineered Equipment	$ 22,100,000	$ 27,400,000	$ 19,800,000	$ 21,500,000	$ 24,800,000
Installed Cost	$ 76,000,000	$ 93,000,000	$ 72,000,000	$ 79,000,000	$ 82,000,000

These estimates are based on January 1976 costs with no forward escalation.

DOE-GRI | TABLE III-N | Project 4568-NW

Eastern Coal | UNIT 22, SOLIDS DISPOSAL | March 1, 1978

FACTORED ESTIMATES

	IGT HYGAS STEAM-OXYGEN	IGT HYGAS STEAM-IRON	BCR BI-GAS	PERC SYNTHANE	LURGI
Engineered Equipment					
Pressure Vessels	$ 212,000	$ 376,000	$ 452,000		
Tanks	203,000	301,000	300,000		
Exchangers					
Surface Condensers with Jet Ejectors	74,000				
Air Coolers with Jet Ejectors			177,000		
Pumps	454,000	236,000	234,000	$ 8,000	$ 7,000
Conveyors	512,000	672,000	264,000	182,000	287,000
Pug Mill	204,000	218,000	210,000	213,000	208,000
Separation Equipmemt					
Rotary Vacuum Filters	540,000	750,000	800,000		
Sieve Bend Package	77,000	109,000	91,000		
Ash Cooler Package	172,000		261,000	765,000	251,000
Allowance for Miscellaneous	152,000	138,000	111,000	82,000	47,000
Total Engineered Equipment	$ 2,600,000	$ 2,800,000	$ 2,900,000	$ 1,250,000	$ 800,000
Installed Cost	$ 10,000,000	$ 9,000,000	$ 12,000,000	$ 5,000,000	$ 3,000,000

These estimates are based on January 1976 costs with no forward escalation.

TABLE III-O
UNIT 23, PRODUCT GAS DRYING
FACTORED ESTIMATES

	IGT HYGAS STEAM-OXYGEN	IGT HYGAS STEAM-IRON	BCR BI-GAS	PERC SYNTHANE	LURGI
Engineered Equipment					
Glycol Dehydration Package	$ 500,000	$ 500,000	$ 500,000	$ 500,000	$ 500,000
Installed Cost	$ 800,000	$ 800,000	$ 800,000	$ 800,000	$ 800,000

These estimates are based on January 1976 costs with no forward escalation.

DOE-GRI

Eastern Coal

TABLE III-P
UNIT 30, STEAM AND POWER
FACTORED ESTIMATES

Project 4568-NW

March 1, 1978

	IGT HYGAS STEAM-OXYGEN	IGT HYGAS STEAM-IRON	BCR BI-GAS	PERC SYNTHANE	LURGI
Engineered Equipment					
Pressure Vessels	$ 235,000	$ 235,000	$ 357,000	$ 235,000	$ 252,000
Tanks	310,000	310,000	310,000	310,000	310,000
Exchangers					
Surface Condensers with Jet Ejectors	840,000		1,302,000	1,348,000	1,158,000
Pumps	900,000	1,050,000	1,173,000	1,359,000	1,771,000
Compressors and Blowers	1,926,000	1,756,000	1,926,000	1,926,000	1,926,000
Combustion					
Boilers	34,800,000		30,700,000	58,600,000	66,750,000
Superheaters	15,600,000		13,600,000	8,600,000	6,300,000
Electrostatic Precipitators	4,700,000		4,320,000	7,000,000	8,500,000
Power Generator Sets	5,000,000		6,750,000	10,200,000	6,800,000
Other Equipment					
Centrifuges				5,500,000	
Allowance for Miscellaneous	1,589,000	149,000	1,562,000	2,522,000	2,233,000
Total Engineered Equipment	$ 65,900,000	$ 3,500,000	$ 62,000,000	$ 97,600,000	$ 96,000,000
Installed Cost	$112,000,000	$ 13,000,000	$114,000,000	$171,000,000	$158,000,000

These estimates are based on January 1976 costs with no forward escalation.

DOE-GRI — TABLE III-Q — Project 4568-NW

Eastern Coal — UNIT 31, PLANT WATER SYSTEM — March 1, 1978

FACTORED ESTIMATES

	IGT HYGAS STEAM-OXYGEN	IGT HYGAS STEAM-IRON	BCR BI-GAS	PERC SYNTHANE	LURGI
Engineered Equipment					
Pressure Vessels	$ 25,000	$ 13,000	$ 28,000	$ 23,000	$ 24,000
Tanks	105,000	150,000	40,000	136,000	108,000
Exchangers					
Surface Condensers with Jet Ejectors	124,000			270,000	
Pumps	1,396,000	1,374,000	1,302,000	1,362,000	2,165,000
Cooling Tower including Chlorination	2,100,000	2,560,000	1,950,000	1,940,000	2,760,000
Cold and Warm Lime Clarification	940,000	1,350,000	860,000	910,000	1,350,000
Filters and Demineralizers	980,000	980,000	1,520,000	590,000	390,000
Deaerators	260,000	370,000	200,000	330,000	510,000
Sodium Softeners	280,000	580,000		370,000	840,000
Condensate Polisher			210,000	190,000	150,000
Waste Water Evaporation Package	10,200,000	14,700,000	9,300,000	9,300,000	18,800,000
Allowance for Miscellaneous	790,000	1,123,000	790,000	779,000	1,403,000
Total Engineered Equipment	$ 17,200,000	$ 23,200,000	$ 16,200,000	$ 16,200,000	$ 28,500,000
Installed Cost	$ 34,000,000	$ 43,000,000	$ 31,000,000	$ 32,000,000	$ 50,000,000

These estimates are based on January 1976 costs with no forward escalation.

DOE-GRI	TABLE III-R	Project 4568-NW
Eastern Coal	UNIT 32, OXYGEN PLANT FACTORED ESTIMATES	March 1, 1978

	IGT HYGAS STEAM-OXYGEN	IGT HYGAS STEAM-IRON	BCR BI-GAS	PERC SYNTHANE	LURGI
Oxygen Plant Package	$ 40,100,000		$ 66,000,000	$ 62,000,000	$ 89,400,000
Installed Cost	$ 41,000,000		$ 67,000,000	$ 63,000,000	$ 91,000,000

These estimates are based on January 1976 costs with no forward escalation.

C F BRAUN & CO

DOE-GRI — TABLE IV — Project 4568-NW

SUMMARY OF CAPITAL AND OPERATING COSTS

Washington, D C — IGT STEAM-OXYGEN HYGAS PROCESS — March 1, 1978

	UTILITY FINANCING AVERAGE GAS COST
Capital Costs, $ Million	
Total Plant Investment	$ 930.00
Initial Charge of Catalysts and Chemicals	9.58
Allowance for Funds Used During Construction	156.94
Paid-Up Royalties	5.24
Start-Up Costs	37.51
Working Capital	27.58
TOTAL CAPITAL REQUIREMENT	$1,166.85
Operating Costs, $ Million/Year	
Raw Materials	130.28
Catalysts and Chemicals	3.81
Purchased Water	1.56
Labor	
Process Operating Labor	2.95
Supervision	0.59
Administration and General Overhead	2.12
Operating Supplies	0.89
Total Maintenance	30.39
Local Taxes and Insurance	13.95
Ash Disposal	1.01
TOTAL GROSS OPERATING COSTS/YEAR	$ 187.55
TOTAL BY-PRODUCT CREDITS	25.10
TOTAL NET OPERATING COSTS/YEAR	$ 162.45
AVERAGE GAS COST, $/MM Btu	3.69

January 1976 cost basis

C F BRAUN & CO

DOE-GRI	TABLE IV-A CAPITAL REQUIREMENT	Project 4568-NW
Washington, D C	IGT STEAM-OXYGEN HYGAS PROCESS	March 1, 1978

(IN MILLIONS OF DOLLARS)

	UTILITY FINANCING AVERAGE GAS COST	
TOTAL PLANT INVESTMENT		
Installed Cost	$729.80	
Contractor's Home Office Costs and Fee	81.20	
SUBTOTAL	$811.00	
Project Contingency (15% of Subtotal)	119.00	
		$930.00
INITIAL CHARGE OF CATALYST AND CHEMICALS		
Catalysts (Initial Charge)	$ 4.55	
Chemicals (Initial Charge)	5.03	
		9.58
PAID-UP ROYALTIES		5.24
ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION (Total Plant Investment X Average Spending Period in Years X 9%)		156.94
START-UP COSTS (20% of Total Annual Gross Operating Costs)		37.51
WORKING CAPITAL (14 Day Inventory of Raw Materials + Materials and Supplies at 0.9% of Total Plant Investment + Net Receivables at 1/24 Annual Gas and By-Product Revenue at Calculated Sales Price)		27.58
TOTAL CAPITAL REQUIREMENT		$1,166.85

January 1976 cost basis

C F BRAUN & CO

DOE-GRI	TABLE IV-B	Project 4568-NW
	ANNUAL OPERATING COSTS	
Washington, D C	IGT STEAM-OXYGEN HYGAS PROCESS	March 1, 1978

(IN MILLIONS OF DOLLARS)

RAW MATERIALS		
Coal (15,864 tons/day @ $25.00/ton)		$130.28
CATALYSTS AND CHEMICALS		
Catalysts (Replacement)	$ 2.19	
Chemicals (Makeup + Consumption)	1.62	
		3.81
PURCHASED WATER (8,240 GPM @ $0.4/1000 Gal)		1.56
LABOR		
Process Operating Labor (53 men/shift @ $6.70/hr)	$ 2.95	
Supervision (20% of Direct Labor)	0.59	3.54
ADMINISTRATION AND GENERAL OVERHEAD (60% of Labor)		2.12
OPERATING SUPPLIES (30% of Process Operating Labor)		0.89
TOTAL MAINTENANCE		30.39
LOCAL TAXES AND INSURANCE (1.5% of Total Plant Investment)		13.95
ASH DISPOSAL		1.01
TOTAL GROSS ANNUAL OPERATING COSTS		$187.55
BY-PRODUCT CREDITS		
Sulfur (50,880 lbs/hr @ $25/long ton)	$ 4.48	
Ammonia (7,750 lbs/hr @ $170/ton)	5.20	
Light Oil (81.5 gpm @ $0.40/gal)	15.42	
		25.10
TOTAL NET ANNUAL OPERATING COSTS		$162.45

January 1976 cost basis

DOE-GRI	TABLE IV-C	Project 4568-NW
	ANNUAL MAINTENANCE COSTS	
Washington, D C	IGT STEAM-OXYGEN HYGAS PROCESS	March 1, 1978

(IN MILLIONS OF DOLLARS)

UNIT NO	UNIT	UNIT COST	MAINTENANCE FACTOR PERCENT	MAINTENANCE COST
11	Coal Handling and Storage	$ 15.29	6	$ 0.92
12	Coal Preparation	25.49	6	1.53
13	Coal Pretreatment	43.33	6	2.60
14	Coal Feeding	22.94	6	1.38
15	Gasification	66.26	6	3.98
16	Raw Gas Quench	66.26	6	3.98
17	Shift Conversion	34.41	3	1.03
18	Acid Gas Removal	128.71	3	3.86
19	Methanation	33.13	3	0.99
20	Liquid Effluent Treatment	52.25	3	1.57
21	Sulfur Recovery	96.85	3	2.91
22	Solids Disposal	12.74	3	0.38
23	Product Gas Drying	1.02	3	0.03
30	Steam and Power	142.71	1	1.43
31	Plant Water System	43.33	3	1.30
32	Oxygen Plant	52.25	3	1.57
	All Other Utilities and Offsites	93.03	1	0.93
	TOTAL	$930.00		$30.39

Annual Maintenance Costs $ 30.39

$$\text{Average Maintenance Factor} = \frac{30.39}{930.00} = 0.0327$$

C F BRAUN & CO

DOE-GRI	TABLE V	Project 4568-NW
	SUMMARY OF CAPITAL AND OPERATING COSTS	
Washington, D C	IGT STEAM-IRON HYGAS PROCESS	March 1, 1978

	UTILITY FINANCING AVERAGE GAS COST
Capital Costs, $ Million	
Total Plant Investment	$1,260.00
Initial Charge of Catalysts and Chemicals	7.88
Allowance for Funds Used During Construction	212.63
Paid-Up Royalties	13.67
Start-Up Costs	49.97
Working Capital	37.18
TOTAL CAPITAL REQUIREMENT	$1,581.33
Operating Costs, $ Million/Year	
Raw Materials	176.24
Catalysts and Chemicals	1.89
Purchased Water	2.22
Labor	
Process Operating Labor	2.95
Supervision	0.59
Administration and General Overhead	2.12
Operating Supplies	0.89
Total Maintenance	42.39
Local Taxes and Insurance	18.90
Ash Disposal	1.64
TOTAL GROSS OPERATING COSTS/YEAR	$ 249.83
TOTAL BY-PRODUCT CREDITS	151.34
TOTAL NET OPERATING COSTS/YEAR	$ 98.49
AVERAGE GAS COST, $/MM Btu	3.51

January 1976 cost basis

DOE-GRI	TABLE V-A	Project 4568-NW
	CAPITAL REQUIREMENT	
Washington, D C	IGT STEAM-IRON HYGAS PROCESS	March 1, 1978

(IN MILLIONS OF DOLLARS)

		UTILITY FINANCING AVERAGE GAS COST
TOTAL PLANT INVESTMENT		
Installed Cost	$ 983.80	
Contractor's Home Office Costs and Fee	109.20	
SUBTOTAL	$1,093.00	
Project Contingency (15% of Subtotal)	167.00	
		$1,260.00
INITIAL CHARGE OF CATALYST AND CHEMICALS		
Catalysts (Initial Charge)	$ 1.33	
Chemicals (Initial Charge)	6.55	
		7.88
PAID-UP ROYALTIES		13.67
ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION (Total Plant Investment X Average Spending Period in Years X 9%)		212.63
START-UP COSTS (20% of Total Annual Gross Operating Costs)		49.97
WORKING CAPITAL (14 Day Inventory of Raw Materials + Materials and Supplies at 0.9% of Total Plant Investment + Net Receivables at 1/24 Annual Gas and By-Product Revenue at Calculated Sales Price)		37.18
TOTAL CAPITAL REQUIREMENT		$1,581.33

January 1976 cost basis

DOE-GRI	TABLE V-B	Project 4568-NW
Washington, D C	ANNUAL OPERATING COSTS IGT STEAM-IRON HYGAS PROCESS	March 1, 1978

(IN MILLIONS OF DOLLARS)

RAW MATERIALS		
Coal (21,440 tons/day @ $25.00/ton)	$176.11	
Iron Ore (20.4 tons/day @ $20.0/ton)	0.13	
		$176.24
CATALYSTS AND CHEMICALS		
Catalysts (Replacement)	$ 0.58	
Chemicals (Makeup + Consumption)	1.31	
		1.89
PURCHASED WATER (11,760 GPM @ $0.4/1000 Gal)		2.22
LABOR		
Process Operating Labor (53 men/shift @ $6.70/hr)	$ 2.95	
Supervision (20% of Direct Labor)	0.59	
		3.54
ADMINISTRATION AND GENERAL OVERHEAD (60% of Labor)		2.12
OPERATING SUPPLIES (30% of Process Operating Labor)		0.89
TOTAL MAINTENANCE		42.39
LOCAL TAXES AND INSURANCE (1.5% of Total Plant Investment)		18.90
ASH DISPOSAL		1.64
TOTAL GROSS ANNUAL OPERATING COSTS		$249.83
BY-PRODUCT CREDITS		
Sulfur (53,400 lbs/hr @ $25/long ton)	$ 4.70	
Ammonia (11,560 lbs/hr @ $170/ton)	7.75	
Naptha and Light Oil (65 gpm @ $0.38/gal)	11.68	
Surplus Electric Power (645,400 kWh/hr @ $0.025/kWh)	127.21	
		151.34
TOTAL NET ANNUAL OPERATING COSTS		$ 98.49

January 1976 cost basis

DOE-GRI	TABLE V-C	Project 4568-NW
	ANNUAL MAINTENANCE COSTS	
Washington, D C	IGT STEAM-IRON HYGAS PROCESS	March 1, 1978

(IN MILLIONS OF DOLLARS)

UNIT NO	UNIT	UNIT COST	MAINTENANCE FACTOR PERCENT	MAINTENANCE COST
11	Coal Handling and Storage	$ 15.37	6	$ 0.92
12	Coal Preparation	33.30	6	2.00
13	Coal Pretreatment	51.23	6	3.07
14	Coal Feeding	25.61	6	1.54
15	Gasification	560.97	3.42*	19.19
16	Raw Gas Quench	67.88	4.91*	3.33
18	Acid Gas Removal	99.90	3	3.00
19	Methanation	26.90	3	0.81
20	Liquid Effluent Treatment	49.95	3	1.50
21	Sulfur Recovery	119 11	3	3.57
22	Solids Disposal	11.53	3	0.35
23	Product Gas Drying	1.02	3	0.03
30	Steam and Power	16.65	1	0.17
31	Plant Water System	55.07	3	1.65
	All Other Utilities and Offsites	125.51	1	1.26
	TOTAL	$1,260.00		$42.39

Annual Maintenance Costs $ 42.39

$$\text{Average Maintenance Factor} = \frac{42.39}{1,260.00} = 0.0336$$

*These maintenance factors have been adjusted to account for low maintenance items that have been included in units which normally have a higher maintenance factor.

January 1976 cost basis

DOE-GRI	TABLE VI	Project 4568-NW
Washington, D C	SUMMARY OF CAPITAL AND OPERATING COSTS BCR BI-GAS PROCESS	March 1, 1978

	UTILITY FINANCING AVERAGE GAS COST
Capital Costs, $ Million	
Total Plant Investment	$ 880.00
Initial Charge of Catalysts and Chemicals	11.65
Allowance for Funds Used During Construction	148.50
Paid-Up Royalties	5.51
Start-Up Costs	35.35
Working Capital	26.06
TOTAL CAPITAL REQUIREMENT	$1,107.07
Operating Costs, $ Million/Year	
Raw Materials	122.83
Catalysts and Chemicals	5.35
Purchased Water	1.40
Labor	
Process Operating Labor	2.78
Supervision	0.56
Administration and General Overhead	2.00
Operating Supplies	0.83
Total Maintenance	26.94
Local Taxes and Insurance	13.20
Ash Disposal	0.84
TOTAL GROSS OPERATING COSTS/YEAR	$ 176.73
TOTAL BY-PRODUCT CREDITS	10.78
TOTAL NET OPERATING COSTS/YEAR	$ 165.95
AVERAGE GAS COST, $/MM Btu	3.64

January 1976 cost basis

DOE-GRI | TABLE VI-A | Project 4568-NW

CAPITAL REQUIREMENTS

Washington, D C | BCR BI-GAS PROCESS | March 1, 1978

(IN MILLIONS OF DOLLARS)

		UTILITY FINANCING AVERAGE GAS COST
TOTAL PLANT INVESTMENT		
Installed Cost	$685.80	
Contractor's Home Office Costs and Fee	76.20	
SUBTOTAL	$762.00	
Project Contingency (15% of Subtotal)	118.00	
		$ 880.00
INITIAL CHARGE OF CATALYST AND CHEMICALS		
Catalysts (Initial Charge)	$ 5.39	
Chemicals (Initial Charge)	6.26	
		11.65
PAID-UP ROYALTIES		5.51
ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION (Total Plant Investment X Average Spending Period in Years X 9%)		148.50
START-UP COSTS (20% of Total Annual Gross Operating Costs)		35.35
WORKING CAPITAL (14 Day Inventory of Raw Materials + Materials and Supplies at 0.9% of Total Plant Investment + Net Receivables at 1/24 Annual Gas and By-Product Revenue at Calculated Sales Price)		26.06
TOTAL CAPITAL REQUIREMENT		$1,107.07

January 1976 cost basis

C F BRAUN & CO

DOE-GRI	TABLE VI-B	Project 4568-NW
Washington, D C	ANNUAL OPERATING COSTS BCR BI-GAS PROCESS	March 1, 1978

(IN MILLIONS OF DOLLARS)

RAW MATERIALS		
Coal (14,960 tons/day @ $25/ton)		$122.83
CATALYSTS AND CHEMICALS		
Catalysts	$2.61	
Chemicals	2.74	
		5.35
PURCHASED WATER (7379 GPM @ $0.4/1000 Gal)		1.40
LABOR		
Process Operating Labor (50 men/shift @ $6.70/hr)	$2.78	
Supervision (20% of Direct Labor)	0.56	
		3.34
ADMINISTRATION AND GENERAL OVERHEAD (60% of Labor)		2.00
OPERATING SUPPLIES (30% of Process Operating Labor)		0.83
TOTAL MAINTENANCE		26.94
LOCAL TAXES AND INSURANCE (1.5% of Total Plant Investment)		13.20
ASH DISPOSAL		0.84
TOTAL GROSS ANNUAL OPERATING COSTS		$176.73
BY-PRODUCT CREDITS		
Sulfur (52,300 lbs/hr @ $25/long ton)	$4.60	
Ammonia (9,220 lbs/hr @ $170.00/ton)	6.18	
		10.78
TOTAL NET ANNUAL OPERATING COSTS		$165.95

January 1976 cost basis

C F BRAUN & CO

DOE-GRI Washington, D C	TABLE VI-C ANNUAL MAINTENANCE COSTS BCR BI-GAS PROCESS	Project 4568-NW March 1, 1978

(IN MILLIONS OF DOLLARS)

UNIT NO	UNIT	UNIT COST	MAINTENANCE FACTOR PERCENT	MAINTENANCE COST
11	Coal Handling and Storage	$ 15.40	6	$ 0.92
12	Coal Preparation	38.50	6	2.31
14	Coal Feeding	17.96	6	1.08
15	Gasification	62.88	6	3.77
16	Raw Gas Quench	39.78	6	2.39
17	Shift Conversion	37.21	3	1.12
18	Acid Gas Removal	125.75	3	3.77
19	Methanation	35.93	3	1.08
20	Liquid Effluent Treatment	37.21	3	1.12
21	Sulfur Recovery	92.39	3	2.77
22	Solids Disposal	15.40	3	0.46
23	Product Gas Drying	1.02	3	0.03
30	Steam and Power	146.28	1	1.46
31	Plant Water System	39.78	3	1.19
32	Oxygen Plant	85.97	3	2.58
	All Other Utilities and Offsites	88.54	1	0.89
	TOTAL	$880.00		$26.94

Annual Maintenance Costs $ 26.94

$$\text{Average Maintenance Factor} = \frac{26.94}{880.00} = 0.0306$$

January 1976 cost basis

C F BRAUN & CO

DOE-GRI	TABLE VII	Project 4568-NW
	SUMMARY OF CAPITAL AND OPERATING COSTS	
Washington, D C	PERC SYNTHANE PROCESS	March 1, 1978

	UTILITY FINANCING AVERAGE GAS COST
Capital Costs, $ Million	
Total Plant Investment	$1,010.00
Initial Charge of Catalysts and Chemicals	10.02
Allowance for Funds Used During Construction	170.44
Paid-Up Royalties	6.28
Start-Up Costs	41.22
Working Capital	30.38
TOTAL CAPITAL REQUIREMENT	$1,268.34
Operating Costs, $ Million/Year	
Raw Materials	148.98
Catalysts and Chemicals	4.33
Purchased Water	1.48
Labor	
Process Operating Labor	2.78
Supervision	0.56
Administration and General Overhead	2.00
Operating Supplies	0.83
Total Maintenance	29.31
Local Taxes and Insurance	15.15
Ash Disposal	0.66
TOTAL GROSS OPERATING COSTS/YEAR	$ 206.08
TOTAL BY-PRODUCT CREDITS	35.21
TOTAL NET OPERATING COSTS/YEAR	$ 170.87
AVERAGE GAS COST, $/MM Btu	3.94

January 1976 cost basis

C F BRAUN & CO

DOE-GRI	TABLE VII-A	Project 4568-NW
	CAPITAL REQUIREMENTS	
Washington, D C	PERC SYNTHANE PROCESS	March 1, 1978

(IN MILLIONS OF DOLLARS)

	UTILITY FINANCING AVERAGE GAS COST	
TOTAL PLANT INVESTMENT		
Installed Cost	$787.80	
Contractor's Home Office Costs and Fee	87.20	
SUBTOTAL	$875.00	
Project Contingency (15% of Subtotal)	135.00	
		$1,010.00
INITIAL CHARGE OF CATALYST AND CHEMICALS		
Catalysts (Initial Charge)	$ 4.66	
Chemicals (Initial Charge)	5.36	
		10.02
PAID-UP ROYALTIES		6.28
ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION (Total Plant Investment X Average Spending Period in Years X 9%)		170.44
START-UP COSTS (20% of Total Annual Gross Operating Costs)		41.22
WORKING CAPITAL (14 Day Inventory of Raw Materials + Materials and Supplies at 0.9% of Total Plant Investment + Net Receivables at 1/24 Annual Gas and By-Product Revenue at Calculated Sales Price)		30.38
TOTAL CAPITAL REQUIREMENT		$1,268.34

January 1976 cost basis

C F BRAUN & CO

DOE-GRI	TABLE VII-B	Project 4568-NW
Washington, D C	ANNUAL OPERATING COSTS PERC SYNTHANE PROCESS	March 1, 1978

(IN MILLIONS OF DOLLARS)

RAW MATERIALS		
Coal (18,140 tons/day @ $25.00/ton)		$148.98
CATALYSTS AND CHEMICALS		
Catalysts (Replacement)	$2.26	
Chemicals (Makeup + Comsumption)	2.07	
		4.33
PURCHASED WATER (7,840 GPM @ $0.4/1000 Gal)		1.48
LABOR		
Process Operating Labor (50 men/shift @ $6.70/hr)	$2.78	
Supervision (20% of Direct Labor)	0.56	
		3.34
ADMINISTRATION AND GENERAL OVERHEAD (60% of Labor)		2.00
OPERATING SUPPLIES (30% of Process Operating Labor)		0.83
TOTAL MAINTENANCE		29.31
LOCAL TAXES AND INSURANCE (1.5% of Total Plant Investment)		15.15
ASH DISPOSAL		0.66
TOTAL GROSS ANNUAL OPERATING COSTS		$206.08
BY-PRODUCT CREDITS		
Sulfur (58,400 lbs/hr @ $25/long ton)	$5.14	
Ammonia (13,350 lbs/hr @ $170.00/ton)	8.95	
Light Oil (43 gpm @ $0.40/gal)	8.17	
Tar (87 gpm @ $0.20/gal)	8.24	
Char and Coal Fines (56,540 lbs/hr @ 21.11/ton)	4.71	
		35.21
TOTAL NET ANNUAL OPERATING COSTS		$170.87

January 1976 cost basis

C F BRAUN & CO

DOE-GRI	TABLE VII-C	Project 4568-NW
	ANNUAL MAINTENANCE COSTS	
Washington, D C	PERC SYNTHANE PROCESS	March 1, 1978

(IN MILLIONS OF DOLLARS)

UNIT NO	UNIT	UNIT COST	MAINTENANCE FACTOR PERCENT	MAINTENANCE COST
11	Coal Handling and Storage	$ 15.38	6	$ 0.92
12	Coal Preparation	34.62	6	2.08
14	Coal Feeding	14.10	6	0.85
15	Gasification	75.64	6	4.54
16	Raw Gas Quench	41.03	6	2.46
17	Shift Conversion	39.74	3	1.19
18	Acid Gas Removal	110.26	3	3.31
29	Methanation	37.18	3	1.12
20	Liquid Effluent Treatment	91.03	3	2.73
21	Sulfur Recovery	101.28	3	3.04
22	Solids Disposal	6.41	3	0.19
23	Product Gas Drying	1.02	3	0.03
30	Steam and Power	219.23	1	2.19
31	Plant Water System	41.03	3	1.23
32	Oxygen Plant	80.77	3	2.42
	All Other Utilities and Offsites	101.28	1	1.01
	TOTAL	$1,010.00		$29.31

Annual Maintenance Costs $ 29.31

$$\text{Average Maintenance Factor} = \frac{29.31}{1,010.00} = 0.0290$$

January 1976 cost basis

C F BRAUN & CO

DOE-GRI	TABLE VIII	Project 4568-NW
	SUMMARY OF CAPITAL AND OPERATING COSTS	
Washington, D C	LURGI PROCESS	March 1, 1978

	UTILITY FINANCING AVERAGE GAS COST
Capital Costs, $ Million	
Total Plant Investment	$1,170.00
Initial Charge of Catalysts and Chemicals	26.79
Allowance for Funds Used During Construction	197.44
Paid-Up Royalties	4.54
Start-Up Costs	45.11
Working Capital	33.73
TOTAL CAPITAL REQUIREMENT	$1,477.61
Operating Costs, $ Million/Year	
Raw Materials	150.27
Catalysts and Chemicals	11.41
Purchased Water	2.09
Labor	
Process Operating Labor	3.34
Supervision	0.67
Administration and General Overhead	2.40
Operating Supplies	1.00
Total Maintenance	35.86
Local Taxes and Insurance	17.55
Ash Disposal	0.98
TOTAL GROSS OPERATING COSTS/YEAR	$ 225.57
TOTAL BY-PRODUCT CREDITS	20.52
TOTAL NET OPERATING COSTS/YEAR	$ 205.05
AVERAGE GAS COST, $/MM Btu	4.66

January 1976 cost basis

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C F BRAUN & CO

DOE-GRI	TABLE VIII-A CAPITAL REQUIREMENTS LURGI PROCESS	Project 4568-NW
Washington, D C		March 1, 1978

		UTILITY FINANCING AVERAGE GAS COST
TOTAL PLANT INVESTMENT		
Installed Cost	$ 916.80	
Contractor's Home Office Costs and Fee	102.20	
SUBTOTAL	1,019.00	
Project Contingency	151.00	
		$1,170.00
INITIAL CHARGE OF CATALYST AND CHEMICALS		
Catalysts (Initial Charge)	$ 19.33	
Chemicals (Initial Charge)	7.46	
		26.79
PAID-UP ROYALTIES		4.54
ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION (Total Plant Investment X Average Spending Period in Years X 9%)		197.44
START-UP COSTS (20% of Total Annual Gross Operating Costs)		45.11
WORKING CAPITAL (14 Day Inventory of Raw Materials + Materials and Supplies at 0.9% of Total Plant Investment + Net Receivables at 1/24 Annual Gas and By-Product Revenue at Calculated Sales Price)		33.73
TOTAL CAPITAL REQUIREMENT		$1,477.61

January 1976 cost basis

C F BRAUN & CO

DOE-GRI Washington, D C	TABLE VIII-B ANNUAL OPERATING COSTS LURGI PROCESS		Project 4568-NW March 1, 1978

RAW MATERIALS		
Coal (18,246 tons/day @ $25.00/ton)		$150.27
CATALYSTS AND CHEMICALS		
Catalysts	$9.58	
Chemicals	1.83	
		11.41
PURCHASED WATER (11,070 GPM @ $0.40/1000 Gal)		2.09
LABOR		
Process Operating Labor (60 men/shift @ $6.70/hr)	$3.34	
Supervision (20% of Operating and Maintenance Labor)	0.67	
		4.01
ADMINISTRATION AND GENERAL OVERHEAD (60% of Labor)		2.40
OPERATING SUPPLIES (30% of Process Operating Labor)		1.00
TOTAL MAINTENANCE		35.86
LOCAL TAXES AND INSURANCE (1.5% of Total Plant Investment)		17.55
ASH DISPOSAL		0.98
TOTAL GROSS ANNUAL OPERATING COSTS		$225.57
BY-PRODUCT CREDITS		
Sulfur (58,000 lbs/hr @ $25.00/long ton)	$5.10	
Ammonia (10,250 lbs/hr @ $170.00/ton)	6.87	
Phenols (7 gpm @ $0.20/gal)	0.66	
Naphtha (26 gpm @ $0.38/gal)	4.67	
Light Oil (17 gpm @ $0.40/gal)	3.22	
		20.52
TOTAL NET ANNUAL OPERATING COSTS		$205.05

January 1976 cost basis

C F BRAUN & CO

DOE-GRI	TABLE VIII-C	Project 4568-NW
	ANNUAL MAINTENANCE COSTS	
Washington, D C	LURGI PROCESS	March 1, 1978

UNIT NO	UNIT	UNIT COST	MAINTENANCE FACTOR PERCENT	MAINTENANCE COST
11	Coal Handling and Storage	$ 15.31	6	$ 0.92
12	Coal Preparation	6.38	6	0.38
	Lurgi Proprietary Units	325.43	5*	16.27
18	Acid Gas Removal	127.62	3	3.83
19	Methanation	58.70	3	1.76
20	Liquid Effluent Treatment	28.08	3	0.84
21	Sulfur Recovery	104.65	3	3.14
22	Solids Effluent Treatment	3.83	3	0.11
23	Product Gas Treating	1.02	3	0.03
30	Steam and Power	201.64	1	2.02
31	Plant Water System	63.81	3	1.91
32	Oxygen Plant	116.13	3	3.48
	All Other Utilities and Offsites	117.40	1	1.17
	TOTAL	$1,170.00		$35.86

Annual Maintenance Costs $ 35.86

$$\text{Average Maintenance Factor} = \frac{35.86}{1{,}170.00} = 0.0306$$

*This maintenance factor has been adjusted to account for low maintenance items that have been included in units which normally have a higher maintenance factor.

January 1976 cost basis

C F BRAUN & CO

DOE-GRI — GAS COST SUMMARY — Project 4568-NW

Washington, DC — March 1, 1978

PROCESS	CAPITAL REQUIREMENT MILLIONS OF DOLLARS (1)	GAS COST (5) DOLLARS/MMBTU
IGT STEAM-Oxygen HYGAS	1170	3.69
IGT Steam-Iron HYGAS (2)		
Selexol Gas Treating, 25 mills/kWh Power Credit	1580	3.51
Benfield Gas Treating, 25 mills/kWh Power Credit (3)	1540	3.40
Selexol Gas Treating, 10 mills/kWh Power Credit (4)	1580	4.44
Benfield Gas Treating, 10 mills/kWh Power Credit (3) (4)	1540	4.34
BCR BI-GAS	1110	3.64
PERC Synthane	1270	3.94
Lurgi	1478	4.66

(1) Cost basis is January 1976.

(2) The power recovery section for the Steam-Iron process was designed for maximum power recovery using expanders and gas turbines projected to be available by 1985. The 10 mill cases were added to indicate sensitivity to power credit.

(3) These values were obtained by substituting a Benfield unit for the Selexol unit for acid gas removal. The sulfur recovery, effluent treating, and steam and water systems were revised as a result of the substitution.

(4) The capital requirements for these two cases are the same as those for the 25 mill power credit. The gas cost change is solely due to the change in by-product credit without the redesign of the power recovery section. Different gas costs would be obtained if the plant design was optimized for the 10 mill power credit.

(5) These gas costs are the numerical average calculated by the Utility Financing Method for the 20 year depreciation period. Details of this calculation are shown in Appendix A.

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APPENDIX A

FACTORED ESTIMATES FOR
EASTERN COAL
COMMERCIAL CONCEPTS

DESIGN AND GAS COST BASIS

C F BRAUN & CO

CONTENTS

I INTRODUCTION

Most of the guidelines for calculating gas cost for this report are the same as were given in Appendix A of Factored Estimates for Western Coal Commercial Concepts, Interim Report, FE-2240-5, October 1976.

The purpose of this appendix is to present the revised guidelines and to reflect changes which were required by the DOE-GRI operating committee for the comparison of gas costs for eastern coal. In some cases, the changes reflect variations in economic climate of eastern versus western locations. In other cases they are the result of review by the advisory committee. The changes from the previous guidelines are summarized below.

GUIDELINE CHANGES Maintenance is now segregated from the operating labor, supervision, and administration and general overhead, and only a total maintenance cost is given. The local taxes and insurance are reduced from 2.7 percent to 1.5 percent of the total plant investment. The average spending period is changed from 1.75 years to 1.875 years. Furthermore, the cooling system has been changed from maximum air cooling to mixed air and water cooling.

The credit for byproduct power has been changed. The previous credit of 1 cent per kilowatt hour represented the value to an electric utility of an "interruptible" source of power. The value only included energy costs. Braun was instructed to allow a byproduct power credit of 2.5 cents per kilowatt hour in the design basis for this study. The additional credit of 1.5 cents per kilowatt represents the 1976 value of incremental capital cost of additional installed capacity for a typical electric utility.

The appropriate value for this byproduct can only be determined in the final negotiation process and signing of a long term contract. Since the 1 cent per kilowatt represents a likely minimum credit, a separate gas cost calculation has been made for that case. Design changes appropriate to the lower credit have not been assessed, only the credit value has been changed.

The private investor financing method for calculating gas costs is deleted from this report. Only the average gas cost based as utility financing method is presented. The gas cost varies over the 20 year depreciation period, declining gradually from the highest cost which occurs in the first year. (See the sample calculation on page 19)

II BASIC ASSUMPTIONS

This section contains the basic assumptions that shall be used to develop the investment and operating costs needed for calculating the gas cost.

COAL AVAILABLE Pittsburgh Seam Number 8 coal is to be used for the plant design and economics.

RAW MATERIALS AND UTILITIES The only raw material supplied to the plant will be Pittsburgh Seam Number 8 coal. The only utility supplied will be untreated fresh water. Some natural gas and/or fuel oil is available at startup for critical needs, excluding steam generation. The exception is the Steam-Iron process which does not have separate coal firing capability, hence must be started up by using alternate fuels for steam generation.

UNIT COSTS AND PRICES The costs of fresh water and coal delivered to the plant site as of January 1, 1976 are shown in Table 1, along with unit costs for labor, ash disposal and plant by-products.

FRESH WATER COMPOSITION The design is to be based on the composition of untreated fresh waters for an Eastern location as tabulated below.

Total dissolved solids, ppm	412
Total hardness, ppm $CaCO_3$	220
Conductivity	698
Calcium, ppm $CaCO_3$	160
Magnesium, ppm $CaCO_3$	60
Sodium, ppm $CaCO_3$	116
Potassium, ppm $CaCO_3$	-
Iron, ppb Fe	1000
Carbonate, ppm $CaCO_3$	0
Bicarbonate, ppm $CaCO_3$	80
Sulfate, ppm $CaCO_3$	174
Chloride, ppm $CaCO_3$	64
Fluoride, ppm F	0.6
Nitrate, ppm $CaCO_3$	7.5
Color, cobalt platinum units	-
Turbidity, Jackson turbidity units	60
Temperature, °F Average, (Range)	55 (40-80)
pH	7.2
Silica, ppm SiO_2	8

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TABLE 1

UNIT COSTS AND PRICES AS OF JANUARY 1, 1976

ITEM	COST OR PRICE
Raw Water, Cents/Thousand Gallons	40
Pittsburgh Seam No 8 Coal, Dollars/Short Ton as Received	25.00
Pittsburgh Seam No 8 Coal, Cents/Million Btu as Received	100.7
Export Power Credit, Cents/KWH(1)	2.50
Sulfur, Dollars/Long Ton	25.00
Ammonia (Anhydrous), Dollars/Short Ton	170.00
Naphtha (120-320° F), Dollars/Gallon	0.38
Light Oil (300-700° F), Dollars/Gallon	0.40
Tar, Dollars/Gallon	0.20
Phenols, Dollars/Gallon	0.20
Operating Labor, Dollars/Hour	6.70
Construction Labor, Dollars/Hour	9.50
Ash Disposal, Dollars/Ton of Ash	1.00
Byproduct or Coal Fines or Char Cents/MM Btu	75.50
Limestone Dollars/Ton	15.00

(1) An alternate evaluation of gas cost for 1.00 Cents/KWH will be made to determine sensitivity.

II BASIC ASSUMPTIONS Continued

COAL PROPERTIES The plant design is to be based on the following properties of the feed coal.

Proximate Analysis, as received, Wt%

Moisture	6.0
Volatile Matter	31.9
Fixed Carbon	51.5
Ash	10.6
	100.0

Ultimate Analysis (dry), Wt%

Carbon	71.50
Hydrogen	5.02
Nitrogen	1.23
Oxygen	6.53
Sulfur	4.42
Ash	11.30
	100.00

Heating Value of Dry Coal Btu/lb (HHV)	13,190
Heating Value of Coal as Received Btu/lb (HHV)	12,400

II BASIC ASSUMPTIONS Continued

Hardgrove Grindability Index	59
Fusibility of Ash °F	
In Reducing Atmosphere	
Initial Deformation	2,020
Softening Temperature	2,140
Hemispherical Temperature	2,260
Fluid Temperature	2,360
In Oxidizing Atmosphere	
Initial Deformation	2,385
Softening Temperature	2,440
Hemispherical Temperature	2,480
Fluid Temperature	2,510
Chlorine Content, Wt%	0.05
Ash Analysis, Wt%	
SiO_2	44.86
Al_2O_3	21.60
TiO_2	0.92
Fe_2O_3	22.31
CaO	2.92
MgO	0.70
Na_2O	0.63
K_2O	1.90
P_2O_5	0.46
SO_3	2.73
Form of Sulfur as % of Total Sulfur	
Pyritic	35
Sulfate	2
Organic	63
	100

II BASIC ASSUMPTIONS Continued

Size Consist

Percent Below	
1 1/4 inch	99.0
3/4	86.0
3/8	59.0
1/8	26.0
28 mesh	10.0

ASH AND BY-PRODUCTS Ash and by-products from the plant shall be handled as follows.

DISPOSAL SOLID WASTE AND ASH Cost of plant will include facilities to dump waste in trucks or on a conveyor belt. The cost of ash disposal as of January 1, 1976, is shown in Table 1.

UTILIZATION OF CHAR AND FINES Char and fines are used to the maximum extent in the boilers. The char is used first and any fuel shortage is made up with fines. Any excess over boiler fuel needs is sold.

VALUE OF CHAR OR FINES The credit value assigned to by-product char or excess coal fines leaving the plant will be based upon the heating value, and will be 75 percent of the dollars per million Btu's for the plant feed coal as shown in Table 1.

II BASIC ASSUMPTIONS Continued

EXPORT POWER In the event that excess electricity is produced by the gasification plant and sold, the value assigned to such power as of January 1, 1976 is shown in Table. A comparison of the affect of an alternate lower value of power based solely on its energy cost will be included but no design specific to that case is to be added.

OTHER BY-PRODUCTS Other potential by-products are sulfur, ammonia, naphtha, light oil, tar and phenols. Their values as of January 1, 1976 are shown in Table 1.

ENVIRONMENTAL REQUIREMENTS The following environmental standards must be met.

WATER QUALITY STANDARDS All effluent water is treated and either returned to the process for reuse or discarded with solid waste disposal or used for dust control.

SOLIDS DISPOSAL Non-toxic solid wastes are returned to a land fill. Toxic solids must be treated to an acceptable limit prior to disposal.

AIR EMISSIONS Air emissions from a coal gasification complex fall into the categories of boiler plant emissions, process sulfur emissions, or fugitive emissions.

BOILER EMISSIONS A federal regulation exists for fossil fuel fired steam generators having a heat input of over 250 million Btu per hour. This regulation is listed as Part 60, Chapter 1, Title 40, Code of Federal Regulations and gives the following limitations:

COMPONENT	MAXIMUM EMISSION POUNDS PER MILLION BTU (HHV) HEAT INPUT (SOLID FUEL)
SO_2	1.2
NO_x	0.7 expressed as NO_2
Particulates	0.1

II BASIC ASSUMPTIONS Continued

PROCESS SULFUR EMISSIONS Sulfur recovery facilties shall be designed for a recovery of 99.8 percent of the sulfur in the fresh feed to the sulfur recovery units.

FUGITIVE EMISSIONS Fugitive emissions are of two types. One is dust emissions from solids handling equipment. The other is miscellaneous gas emissions containing sulfur compounds. Scrubbing devices shall be included on all gas streams containing particulates. The limit for sulfur compounds in miscellaneous gas streams is 500 parts per million by volume expressed as sulfur dioxide. And the gas stream shall contain no more than 10 parts per million by volume of hydrogen sulfide. These sulfur contents are representative of the limits now set by a number of states.

II BASIC ASSUMPTIONS Continued

EQUIPMENT DESIGN The plant equipment shall be designed to meet the following requirements.

PLANT SIZE The nominal design capacity of the commercial plant is 250 billion Btu/stream day (HHV) of synthetic natural gas.

PRODUCT GAS SPECIFICATION Limits for carbon monoxide and sulfur are as follows.

Carbon Monoxide	0.1 volume percent
Hydrogen Sulfide	0.25 grains/100 SCF
Total Sulfur	10 grains/100 SCF

The product gas shall be interchangeable with pure methane in accordance with procedures described in Appendix A, Factored Estimates for Western Coal Commercial Concepts, Braun Report FE-2240-5.

PRODUCT PRESSURE Nominal plant site delivery pressure of gas will be 1,000 psig.

SERVICE FACTOR Service factor of the total plant shall be 90 percent.

GRASS ROOTS FACILITY The plant will be self-contained, except for water and coal. It will have cold start capability. Natural gas is available at startup for critical needs, excluding steam generation.

The exception is the Steam-Iron HYGAS process which has no coal fired boiler and must therefore use either fuel oil or natural gas for steam generation during plant startup.

EQUIPMENT SELECTION The approach to be taken for equipment selection and sizing shall be on the conservative side. This means that wherever possible, proven equipment in the same or similar services shall be used. When this is not possible, because of size, pressure, temperature, or other service conditions, the vendor of similar equipment must be contacted to assist in establishing a reasonable extrapolation of current technology.

PLANT SITES The plant sites for Eastern coal will be in the following states- Alabama, Illinois, Indiana, Kentucky, Ohio, Pennsylvania, Tennessee, and West Virginia. In all cases, the plant will be located near the mine. No barge or other form of water transportation will be available to the plant sites.

SITE CONDITIONS The plant will be built on relatively level and dry land. The soil has a load bearing capacity of 4,000 pounds per square foot.

C F BRAUN & CO

DOE-GRI	DESIGN AND GAS COST BASIS	Project 4568-NW
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II BASIC ASSUMPTIONS Continued

SEISMIC CONDITIONS All plants are located in Seismic Zone 1.

CLIMATIC CONDITIONS The plant design is to be based on the following climatic conditions

Temperature, ^{o}F	
Summer dry bulb	95
Summer wet bulb	75
Winter dry bulb	5
Design for freeze protection, ^{o}F with 30 MPH wind	-15
Design frost line, feet below surface	4
Wind speed (miles per hour)	
Average	4
Peak Gust	113
Plant elevation, feet above sea level	650
Normal atmospheric pressure	14.4

CONSTRUCTION LABOR CONDITIONS Average construction labor rates for the plant sites are included in Table 1. Construction labor travel costs and living quarters should be added in addition to the normal indirect labor costs for fringe benefits, FICA, FUI, and SUI taxes, and Workmen's Compensation insurance. Labor productivity may vary widely over the eight states listed previously. For consistency in developing gas cost comparisons, a labor productivity factor of 1.0 shall be assumed.

II BASIC ASSUMPTIONS Continued

COAL FEED The coal will be received at plot edge on a conveyor belt. The coal will not require any on-plot beneficiation such as washing. It will be received on a six days per week and two shifts per day basis.

COAL STORAGE Storage and handling facilties will be provided for a 14 days supply of coal to the plant.

CHAR AND FINES STORAGE Storage and handling facilities will be provided for seven days production of by-product char and excess coal fines.

COAL FEED PREPARATION The number of mills required will depend upon the type of mill, which in turn depends upon the specific requirements for each process. Spare mills and classifying equipment will be provided in an amount equivalent to a minimum of 25 percent of total plant capacity. An intermediate coal storage time of eight hours shall be provided for temporary repair of elevators and conveyors. This requirement does not apply if the elevators or conveyors are part of a spare system or line.

WATER STORAGE A water storage pond containing seven days water needs shall be included.

LIMESTONE AND DOLOMITE Limestone to be used as flux to control slag viscosity will be received as ground rock with a maximum size of 3/8-inch. Dolomite or limestone to be used in gasification will be received as ground and screened rock suitable for direct use. Price will be based on delivery to the storage equipment on plot.

GASIFICATION A minimum of two gasifiers will be provided for all processes. For those processes requiring air for gasification, separate air compressors and hot gas expander drives will be provided for each gasifier. Similary, facilities for gas quench and solids removal will be separate for each gasifier.

II BASIC ASSUMPTIONS Continued

GAS TREATMENT Two trains, 50 percent each, will be provided for the following major process units. Fixed catalyst beds will be designed for 25 percent of plant capacity, two beds for each 50 percent train.

- Shift Conversion
- Acid-Gas Removal
- Methanation
- Product Gas Compression
- Product Gas Drying

OXYGEN The size of oxygen plants will be based on proven capacity. The total oxygen capacity to be provided will equal the total required without any spare capacity, however, 24 hours of liquid oxygen storage for one train will be provided.

LIQUID EFFLUENT Process liquid effluent treating will have two trains, 50 percent each. One common spare sour water stripper with its auxiliary equipment will be provided.

SOLID EFFLUENT Solid effluent treating will be one train with multiple equipment items. Spare equipment will be provided to maintain full plant capacity.

GAS EFFLUENT All gaseous effluents from the plant must meet the effluent standards described in this basis. Facilities for recovering sulfur from effluent gas streams may be provided in a single train or in multiple parallel trains. One spare train will be provided to maintain full plant capacity.

WATER WASTES No water may be discarded to surface runoff. All water wastes must be utilized in the plant. The only water discarded will be with solid waste disposal or for dust control.

BOILER PLANT AND COAL FIRED SUPERHEATERS To determine total installed capacity, two rules will be followed.

A Total installed capacity will be sufficient to handle start-up of second train with one train in operation.

B During normal operation of total plant, total boiler capacity will be sufficient to permit shut down of one boiler.

II BASIC ASSUMPTIONS Continued

BOILER FLUE GAS SCRUBBING Each boiler, if direct coal fired, will be equipped with a separate SO_2 absorber. Two regenerators, each 100 percent, will be installed.

BOILER SIZE LIMITATION Due to present-day limitations on the size of industrial coal-fired boilers, the maximum rated capacity of any coal-fired boiler shall be 1 million pounds per hour of super heated steam. Char-fired boilers, and boilers partly fired with low BTU waste gases, should be derated to a lower capacity.

POWER GENERATION The Power plant will consist of multiple generators with one spare.

EQUIPMENT SPARING

A Large centrifugal compressors and expanders will not be spared.

B Other rotating equipment will be spared. The spare may be either a complete spare or a 50 percent spare in cases where two pumps are normally operating.

C Spare rotors will be provided for centrifugal compressors and their turbine drivers. Spare rotors for turbine generators will not be included.

D Belt conveyors and bucket elevators will not be spared, unless failure of the equipment would cause immediate plant shutdown.

EQUIPMENT SPACING Equipment spacing shall be such as to satisfy insurance requirements.

DATA LOGGER A data logger will be included.

INSTRUMENTATION No computer controlled instrumentation will be used.

MAINTENANCE SHOP A shop capable of major maintenance will be included in capital cost of the plant.

COOLERS Water cooled exchangers shall be used for all steam turbine surface-condensers, and for all process cooling and condensing services below 160° F. Air fin coolers shall be used for other plant cooling services, where economical.

III PROCEDURE FOR CALCULATING GAS COST

This section outlines the procedure to be followed in calculating the gas cost, using utility financing methods. Private investor financing is described in Appendix A of Factored Estimates for Western Coal Commercial Concepts, Braun Report FE-2240-5.

DATA NEEDED In order to calculate a gas cost, the following data are needed. (1) Total capital requirement, (2) Gross operating costs, and (3) By-Product credits. The following three paragraphs discuss what is included in these items.

TOTAL CAPITAL REQUIREMENT Table 2 shows the components that make up the Total Capital Requirement. Included are (1) the estimated installed cost of both onsite and offsite facilities, (2) project contingency at 15 percent of the estimated installed cost of facilities, (3) initial charge of catalysts and chemicals, (4) paid-up royalties, (5) allowance for funds used during construction, (6) start-up costs, and (7) working capital.

ESTIMATE The installed cost estimate date of the plant shall be stated. No forward escalation shall be included. Construction labor costs as of January 1, 1976 are shown in Table 1.

OPERATING COSTS Table 3 shows the items that make up the gross operating costs. Net operating costs are calculated by deducting by-product credits from the gross operating costs. The direct cost of maintenance is calculated by summing contributions for each unit of the plant. The following table shows the rates to use for each plant section.

III PROCEDURE FOR CALCULATING GAS COST Continued

PLANT SECTION	MAINTENANCE COST PERCENT OF PLANT SECTION INVESTMENT
(1) Coal feed preparation, coal gasification, gas quench, and solids removal	6.0
(2) Shift conversion, acid gas removal, sulfur recovery, methanation, product gas compression and drying, oxygen plant, liquid and solid effluent treating, boiler flue gas treating, and water treating	3.0
(3) All other offsites	1.0

GAS COST BY UTILITY FINANCING METHOD Table 4 shows a sample case covering the development of the data needed and both the first year gas cost and the average gas cost over 20 years by the utility financing method. Only the average gas cost is presented in this report. The following parameters have been used.

1 20-year project life

2 20-year straight line depreciation on plant investment, allowance for funds used during construction, and capitalized portion of start-up costs.

3 Debt-equity ratio of 75/25

4 Percent interest on debt of nine percent

5 Percent return on equity of 15 percent

6 Federal income tax rate of 48 percent

TABLE 2
BASIS FOR CALCULATING TOTAL CAPITAL REQUIREMENT

TOTAL PLANT INVESTMENT	
Onsites	XXX
Offsites	XXX
Contractor's Overhead and Profit	XXX
Engineering and Design Costs	XXX
Subtotal	XXX
Project Contingency at 15 Percent of Subtotal	XXX
Total Plant Investment	XXX
INITIAL CHARGE OF CATALYSTS AND CHEMICALS	XXX
PAID-UP ROYALTIES	XXX
ALLOWANCE FOR FUNDS USED DURING CONSTRUCTION (Total Plant Investment x Average Spending Period in Years* x 0.09)	XXX
START-UP COSTS (20 Percent of Total Annual Gross Operating Costs)	XXX
WORKING CAPITAL (Sum of (1) Raw materials inventory of 14 days at full rate, (2) materials and supplies at 0.9 percent of Total Plant Investment, and (3) net receivables at 1/24 annual gas and by-products revenue at calculated sales price.	XXX
TOTAL CAPITAL REQUIREMENT	XXX

*Average Spending Period used for this report is 1.875 years.

TABLE 3
BASIS FOR CALCULATING GROSS AND NET OPERATING COST*

RAW MATERIALS	XXX
CATALYSTS AND CHEMICALS	XXX
PURCHASED WATER	XXX
LABOR	
Process Operating Labor (Men/shift x 8304 man-hours/year x dollars/man-hour)	XXX
Supervision (20 percent of process operating labor)	XXX
ADMINISTRATION AND GENERAL OVERHEAD (60 percent of Total Labor Including Supervision)	XXX
OPERATING SUPPLIES (30 percent of Process Operating Labor)	XXX
TOTAL MAINTENANCE	XXX
LOCAL TAXES AND INSURANCE (1.5 percent of Total Plant Investment)	XXX
ASH DISPOSAL	XXX
TOTAL GROSS OPERATING COST PER YEAR	XXX
BY-PRODUCT CREDITS	
Sulfur	(XXX)
Ammonia	(XXX)
Naphtha	(XXX)
Light Oil	(XXX)
Tar	(XXX)
Phenols	(XXX)
Char and Coal Fines	(XXX)
Surplus Electric Power	(XXX)
TOTAL BY-PRODUCT CREDITS	(XXX)
TOTAL NET OPERATING COST PER YEAR	XXX

*90 Percent Plant Service Factor

TABLE 4
GAS COST EQUATIONS, UTILITY FINANCING METHOD

BASIS

- 20-year project life
- 5 percent per year straight line depreciation on Total Capital Requirement excluding Working Capital
- 48 percent federal income tax rate

DEFINITION OF TERMS

C = Total Capital Requirement, Million Dollars
W = Working Capital, Million Dollars
N = Total Net Operating Cost in First Year, Million Dollars/Year
G = Annual Gas Production, Trillion Btu/Year

d = Fraction Debt
i = Interest on Debt, Percent Per Year
r = Return on Equity, Percent Per Year
p = Return on Rate Base, Percent Per Year

EQUATION FOR RETURN ON RATE BASE

$$p = (d)i + (1-d)r$$

GENERAL GAS COST EQUATION

First Year Gas Cost, \$/MM Btu =

$$\frac{N + 0.05\ (C-W) + 0.01\ [P + \frac{48}{52}\ (1-d)r][C-0.025(C-W)]}{G}$$

Average Gas Cost, \$/MM Btu =

$$\frac{N + 0.05\ (C-W) + 0.005\ [p + \frac{48}{52}\ (1-d)r]\ (C+W)}{G}$$

III PROCEDURE FOR CALCULATING GAS COST Continued

SAMPLE CALCULATION

C = 1000 Million Dollars
W = 25 Million Dollars
N = 110 Million Dollars
G = 82 Trillion Btu/Year

d = 0.75
i = 9 Percent Per Year
r = 15 Percent Per Year
$p = 0.75 \times 9 + (1 - 0.75) \times 15 = 10.5$ Percent Per Year

First Year Gas Cost =

$$\frac{(110)+0.05\ (1000-25) + 0.01\ (13.9615)\ [1000-0.025\ (1000-25)]}{82}$$

$$= \frac{110.0 + 48.7 + 136.0}{82} = \frac{294.7}{82} = \$3.60/\text{MM Btu}$$

Average Gas Cost =

$$\frac{(110) + 0.05\ (1000-25) + 0.005\ (13.9615)\ (1000+25)}{82}$$

$$= \frac{110.0 + 48.7 + 71.5}{82} = \frac{230.2}{82} = \$2.81/\text{MM Btu}$$