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ENERGY CONVERSION ALTERNATIVES STUDY

-ECAS-

GENERAL ELECTRIC PHASE I FINAL REPORT

VOLUME III, ENERGY CONVERSION SUBSYSTEMS AND COMPONENTS
Part 3, Gasification, Process Fuels, and Balance of Plant

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16. Abstract

A parametric study was performed to assist in the development of a data base for the comparison of advanced energy conversion systems for utility applications using coal or coal-derived fuels. Estimates of power plant performance (efficiency), capital cost, cost of electricity, natural resource requirements, and environmental intrusion characteristics were made for ten advanced conversion systems. Over 300 parametric points were analyzed to estimate the potential of these systems. Emphasis of the study was on the energy conversion system in the context of a base loaded utility power plant. Although cases employing transported coal-derived fuels were included in the study, the fuel processing step of converting coal to clean fuels was not investigated except for cases where a low-Btu gasifier was integrated with the power plant. All power plant concepts were premised on meeting emission standards requirements. The investigative approach focused on achieving consistency and comparability in the analysis of the various conversion systems. Recognized advocate organizations were employed to analyze their respective cycles and to present their analyses for power plant integration by the GE systems evaluation team. Wherever possible, common subsystems and components for the various systems were treated on a uniform basis. A steam power plant (3500 psig, 1000 F, 1000 F) with a conventional coal-burning furnace-boiler was analyzed as a basis for comparison. Combined cycle gas/steam turbine system results indicated competitive efficiency and a lower cost of electricity compared to the reference steam plant. The Open-Cycle MHD system results indicated the potential for significantly higher efficiency than the reference steam plant but with a higher cost of electricity. The information contained in this report constitutes results from the first phase of a two phase effort. In Phase II, a limited number of concepts will be investigated in more detail through preparation of conceptual designs and an implementation assessment including preparation of R&D plans estimating the resources and time required to bring the systems to commercial fruition.

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FOREWORD

The work described in this report is a part of the Energy Conversion Alternatives Study (ECAS)—a cooperative effort of the Energy Research and Development Administration, the National Science Foundation, and the National Aeronautics and Space Administration.

This General Electric contractor report for ECAS Phase I is contained in three volumes:

Volume I - Executive Summary

Volume II - Advanced Energy Conversion Systems

- Part 1 - Open-Cycle Gas Turbines
- Part 2 - Closed Turbine Cycles
- Part 3 - Direct Energy Conversion Cycles

Volume III - Energy Conversion and Subsystems and Components

- Part 1 - Bottoming Cycles and Materials of Construction
- Part 2 - Primary Heat Input Systems and Heat Exchangers
- Part 3 - Gasification, Process Fuels, and Balance of Plant

In addition to the principal authors listed, members of the technical staffs of the following subcontractor organizations developed information for the Phase I data base:

General Electric Company
- Advanced Energy Programs/Space Systems Department
- Direct Energy Conversion Programs
- Electric Utility Systems Engineering Department
- Gas Turbine Division
- Large Steam Turbine-Generator Department
- Medium Steam Turbine Department
- Projects Engineering Operation/I&SE Engineering Operation
- Space Sciences Laboratory

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Thermo Electron Corporation

This General Electric contractor report is one of a series of three reports discussing ECAS Phase I results. The other two reports are the following: Energy Conversion Alternatives Study (ECAS), Westinghouse Phase I Final Report (NASA CR-134941), and NASA Report (NASA TMX-71855).

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Summary

ENERGY CONVERSION SUBSYSTEMS AND COMPONENTS

The objective of Phase I of the Energy Conversion Alternatives Study (ECAS) for coal or coal-derived fuels was to develop a technical-economic information base on the ten energy conversion systems specified for investigation. Over 300 parametric variations were studied in an attempt to identify system and cycle conditions which indicate the best potential of the energy conversion concept. This information base provided a foundation for selection of energy conversion systems for more in-depth investigation in the conceptual design portion of the ECAS study. The systems for continued study were specified by the ECAS Interagency Steering Committee.

The major emphasis of this study was the evaluation of the prime cycle portion of the energy conversion system. The energy conversion subsystems and auxiliary systems are coupled to the prime cycle to produce a complete power plant. These subsystems were applied to each of the prime cycles on a consistent basis. Each of the subsystems, e.g., furnaces, bottoming cycles, balance of plant, was analyzed by its respective independent study team for each specific application to an energy conversion system.

The furnace systems included both direct combustion of coal and combustion of process fuels derived from coal. The furnaces with direct coal combustion employing fluidized beds with in-bed sulfur capture appear to be the most attractive options for the closed-cycle advanced energy conversion systems.

Both organic and steam cycles were studied for bottoming many of the prime cycles. The characteristics of the organic cycles made them most attractive in ratings up to 100 MWe and peak organic cycle temperature less than 500 F (533 K). Although the addition of an organic bottoming cycle to a prime cycle showed an efficiency improvement, a relatively high capital cost addition for the organic bottoming cycle and its related balance of plant was estimated. A steam bottoming cycle was an essential requirement for use with many of the prime cycles; e.g., Combined Cycle Gas Turbine, Liquid Metal Topping Cycle, MHD Systems, and High-Temperature Fuel Cells. The steam bottoming cycles were all analyzed by the same study team to assure a uniform assessment. Steam throttle conditions and feedwater heating chains were varied, however, to accommodate specific prime cycle requirements for improvement of the system efficiency.

In energy conversion systems which could utilize coal directly, the employment of clean fuels produced from coal did not appear to be economically attractive. In systems which require a fuel processing step, e.g., open-cycle gas turbines, the semi-clean liquid fuels produced from coal appeared to be an attractive alternative and were close to an economic standoff with the low-Btu integrated gasifier technique for producing an acceptable gas turbine fuel.

Introduction

ENERGY CONVERSION SUBSYSTEMS AND COMPONENTS

Many advanced energy conversion techniques which can use coal or coal-derived fuels have been advocated for power generation applications. Conversion systems advocated have included open- and closed-cycle gas turbine systems (including combined gas turbine-steam turbine systems), supercritical CO_2 cycle, liquid metal Rankine topping cycles, magnetohydrodynamics (MHD), and fuel cells. Advances have also been proposed for the steam systems which now form the backbone of our electric power industry. These advances include the use of new furnace concepts and higher steam turbine inlet temperatures and pressures. Integration of a power conversion system with a coal processing plant producing a clean low-Btu gas for use in the power plant is still another approach advocated for energy conserving, economical production of electric power. Studies of all these energy conversion techniques have been performed in the past. However, new studies performed on a common basis and in light of new national goals and current conditions are required to permit an assessment of the relative merits of these techniques and potential benefits to the nation.

The purpose of this contract is to assist in the development of an information base necessary for an assessment of various advanced energy conversion systems and for definition of the research and development required to bring these systems to fruition. Estimates of the performance, economics, natural resource requirements and environmental intrusion characteristics of these systems are being made on as comparable and consistent a basis as possible leading to an assessment of the commercial acceptability of the conversion systems and the research and development required to bring the systems to commercial reality. This is being accomplished in the following tasks:

Task I	Parametric Analysis (Phase I)	
Task II	Conceptual Designs	(Phase II)
Task III	Implementation Assessment	(Phase II)

This investigation is being conducted under the Energy Conversion Alternatives Study (ECAS) under the sponsorship of Energy Research and Development Administration (ERDA), National Science Foundation (NSF), and National Aeronautics and Space Administration (NASA). The control of the program is under the direction of an Interagency Steering Committee with participation of the supporting agencies. The NASA Lewis Research Center is responsible for project management of this study.

The information presented in this report describes the results produced in the Task I portion of this study. The emphasis in this task was placed upon developing an information base upon which comparisons of Advanced Energy Conversion Techniques using coal or coal-derived fuels can be made. The Task I portion of the study was directed at a parametric variation of the ten advanced energy conversion systems under investigation. The wide-ranging parametric study was performed in order to provide data for selection by the Interagency Steering Committee of the systems and specific configurations most appropriate for Task II and III studies.

The Task II effort will involve a more detailed evaluation of seven advanced energy conversion systems and result in a conceptual design of the major components and power plant layout. The Task III effort will produce the research and development plans which would be necessary to bring each of the seven Task II systems to a state of commercial reality and then to assess their potential for commercial acceptability.

A prime objective of this study was to produce results which had a cycle-to-cycle consistency. In order to accomplish this objective and still ensure that each system was properly advocated, an organization which is or had been a proponent of the prime cycle was selected to advocate the energy conversion system and to analyze the performance and economics of the prime cycle portion of the energy conversion system, i.e., the parts of the system which were novel or unique to the system. The remaining subsystems, e.g., fuel processing, furnaces, bottoming cycles, balance of plant, were analyzed by technology specialist organizations which presently have responsibility for supplying these subsystems for utility applications. The final plant configuration and performance were produced by the General Electric Corporate Research and Development study team and this group performed the critical integration of the final plant concept. This methodology was used to provide a system-to-system consistency while maintaining the influence of a cycle advocate.

The energy conversion subsystems and components which were applied on a common basis to each of the advanced energy conversion systems are described in this Volume. The discussion and results for each of the advanced systems is given in Volume II.

<u>Bottoming Cycles</u> are applied to most of the advanced energy conversion systems. To the maximum extent possible, the bottoming cycles were assumed to be composed of state-of-the-art components. Steam bottoming cycles are utilized for "high-temperature" applications bottoming with steam conditions being limited to 1000 F (811 K). Organic fluid bottoming cycles are employed for the low-temperature applications (temperatures less than 600 F [589 K]).

The <u>Materials of Construction</u> are defined for each of the energy conversion systems. This includes both the identification of the materials and the assumptions which were made with respect to design criteria.

Primary Heat Input Systems were employed for all closed-cycle applications. The heat exchanger equipment provides for the transport process to introduce thermal energy into the cycle working fluids. Advanced furnace techniques for direct combustion of coal and combustion of clean fuels were considered. The atmospheric fluidized bed with direct coal was utilized as a reference furnace for the closed-cycle parametric variations.

Heat Exchangers were employed in all advanced energy conversion systems. This fluid-to-fluid exchange equipment provided for transport processes within the cycles, e.g., the regeneration of thermal energy, heat rejection precoolers, and low temperature air preheaters.

Gasification and Process Fuels derived from coal were employed as clean fuel sources for combustion systems. The low-Btu gasifier employed for integrated plants was the fixed bed gasifier with low-temperature cleanup. The process fuels were considered as delivered to the plant boundary. The cost and conversion efficiency for these clean fuel production processes were directly related to the fixed bed gasifier. This gave a basis for cost comparison between the use of process fuels and integrated gasifier systems.

The Balance of Plant for the advanced energy conversion concepts considered the installation of the specific components of the energy conversion cycle and primary heat input heat exchangers and the supply and installation of the auxiliary plant equipment. The fuel supply and storage system and the heat rejection system were two of the major elements evaluated as balance-of-plant items.

COAL GASIFICATION AND OTHER CLEAN FUELS FROM COAL

INTRODUCTION

The technical effort on gasification and clean fuels from coal included derivation of expected coal and coal transportation costs, estimation of projected clean liquid and gas fuel process efficiencies and costs, and definition of cost, performance, and environmental intrusion elements of the integrated low-Btu coal gasification system with thirty-two specific cycles.

An initial screening, based on published data, narrowed the various liquid and solid clean (and semi-clean) fuels processes to be studied down to the representative number reported in this section. This report includes process analyses and cost projections for representative clean and semi-clean fuels from coal based on the three coals specified for this study: Illinois No. 6, Montana sub-bituminous, and North Dakota lignite as defined in Table 8-1. (Coal costs given in Table 8-1 are values subsequently assigned by NASA.)

In this Section, cost factors for the three coals will first be discussed, followed by transportation costs of the coal and the various coal products. Since many of the clean fuels options are either direct or derived products of coal gasification processes, performance of air and oxygen blown coal gasifiers are discussed next, followed by derivation of the various clean fuels. The final section will deal with the specifics of the integrated low-Btu gas plants used in the study.

COAL PARAMETERS AND COSTS

Characteristics of the three specified coals to be used in this study are defined in Table 8-1, which also includes the coal and coal transportation costs assigned by NASA during the study.

Costs for the coals are rapidly changing because of a number of diverse factors including:

- New market conditions created by OPEC oil price hikes
- Added capital costs and reduced output per man-hour due to OSHA requirements. (This effect has impacted deep mines in particular, where output per man-day has dropped from 15.6 tons in 1969 to 11 tons in 1973.)
- The 1974 United Mine Workers' (UMW) settlement, which raised the average daily wage and benefit package from $64.88 to $97.44

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Table 8-1

COAL SPECIFICATIONS

	Illinois No. 6	Montana Sub-Bituminous	North Dakota Lignite
Coal Proximate Analysis (%)			
H_2O (Water)	13.0	24.3	36.7
FC (Fixed Carbon)	40.7	39.6	30.5
Volatile	36.7	28.6	26.6
Ash	9.6	7.5	6.2
Coal Ultimate Analysis (%)			
Carbon	59.6	52.2	41.1
Hydrogen	5.9	6.1	6.9
Oxygen	20.0	32.6	44.5
Nitrogen	1.0	0.8	0.6
Sulfur	3.9	0.8	0.7
Coal HHV (Btu/lb)	10,788	8,944	6,890
Coal price at mine (per MM Btu)*	$ 0.70	$ 0.45	$ 0.40
Delivery cost (per MM Btu)*	$ 0.15	$ 0.40	$ 0.45
Delivered cost (per MM Btu)*	$ 0.85	$ 0.85	$ 0.85

*Assigned by NASA.

At the time of writing, data on coal costs were available from the Federal Power Commission (FPC) (ref. 1) for deliveries as late as September 1974, the month before the UMW settlement. It should be cautioned, however, that much of the coal reported by the FPC was delivered under long-term contracts at prices considerably lower than what could be negotiated now.

First, considering the impact of oil prices on coal prices, compare the national average oil and coal costs in September 1973 (pre-embargo) to those in September 1974 (ref. 1).

	Oil (¢/MM Btu)	Coal (¢/MM Btu)
September 1973	82.0	40.8
September 1974	195.4	79.1

In 1973, the average market price for coal on a Btu basis was approximately 50 percent of that for oil. If this traditional price relationship were to hold, the 1974 average price for coal should approach \$1.00/MM Btu. Assuming oil prices will remain fairly stable at \$1.95/MM Btu, this will represent a ceiling of about \$1.00/MM Btu on average coal prices, a level approximately 25 percent higher than September 1974 levels.

Next, the UMW settlement's impact is expected to result in a 20 percent increase in surface-mined coal costs and a 30 percent increase in the cost of underground-mined coal.

In light of these factors, the following f.o.b. mine costs were chosen for the three coals:

	Cost/Ton (Average)	¢/MM Btu	
		Range	Average
Illinois No. 6	\$14	60-70	65
Montana Sub-bituminous	8	40-50	45
North Dakota Lignite	5	20-50	35

These are close to the values subsequently assigned by NASA and reported in Table 8-1.

The September 1974 average FPC prices for coals in corresponding sulfur ranges f.o.b. plant in the above three states, with corresponding adders in anticipation of the UMW settlement, are:

State	¢/MM Btu FPC 9/74	% Adder for UMW	¢/MM Btu (with adder)
Illinois	49.0	30	63.7
Montana	37.7	20	45.2
North Dakota	17.4	20	20.9

The resulting numbers correlate well with the recommended f.o.b. mine costs, except for the North Dakota lignite, which is thought to be depressed by long-term contracts. A spot check of October 1974 prices shows North Dakota lignite having a 0.7 percent sulfur content was delivered to the Heskett Station of the Montana-Dakota Power Company for 28.1 ¢/MM Btu, which would add credence to the expectation that lignite is heading in a direction of equivalent cost per Btu compared to that of Montana sub-bituminous coal of similar sulfur content. This trend is expected to continue if more equipment comes on-line that is capable of using lignite.

As a final note, it is recognized that the FPC prices do contain transportation costs. Since they are costs delivered to power plants in the states noted, it is expected that these are primarily intrastate shipments. The FPC prices are primarily contract prices, many of which were negotiated without anticipation of the magnitude of cost increases even prior to the UMW settlement. These two effects tend to cancel each other.

A remaining uncertainty in the prices of surface-mined coal is the impact of forthcoming strip mining legislation. The cost of restoring land to its original contour is expected to be relatively minimal, but extensive restoration of vegetation could be a very high cost factor in arid regions of the West.

COAL TRANSPORTATION

TRANSPORATION DISTANCES

The central locations for the coals under study are:

Coal	Centers
Illinois No. 6	Paducah, Kentucky
Montana Sub-bituminous	Billings, Montana
North Dakota Lignite	Bismarck, North Dakota

The load centers and projected load centers surrounding these locations are shown in Figure 8-1. These data were taken from a 1970 FPC report.* The following transportation distances from the centers have been selected for use in the coal transportation costs.

- Montana Sub-bituminous—A 700-mile transportation distance was selected to the West Coast load centers of Washington and Oregon.

- North Dakota Lignite—A 700-mile transportation distance was selected to the north central load centers including Minneapolis, Minnesota, and Milwaukee, Wisconsin.

- Illinois No. 6—A 400-mile transportation distance was selected to cover the central portion of the United States including the load centers of Chicago, Illinois, and Atlanta, Georgia.

RAIL TRANSPORT OF COAL—COSTS

Appendix A, extracted from a General Electric Company Coal Refining Application Study, dated February 4, 1974, explains the methodology of deriving railroad costs for a fully committed coal-hauling railroad (including construction of the track) for distances of 50, 100, 200, 300, and 500 miles. Also given are cost factors for barge and slurry pipe-line transport.

*1970 National Power Survey—Part I (FPC).

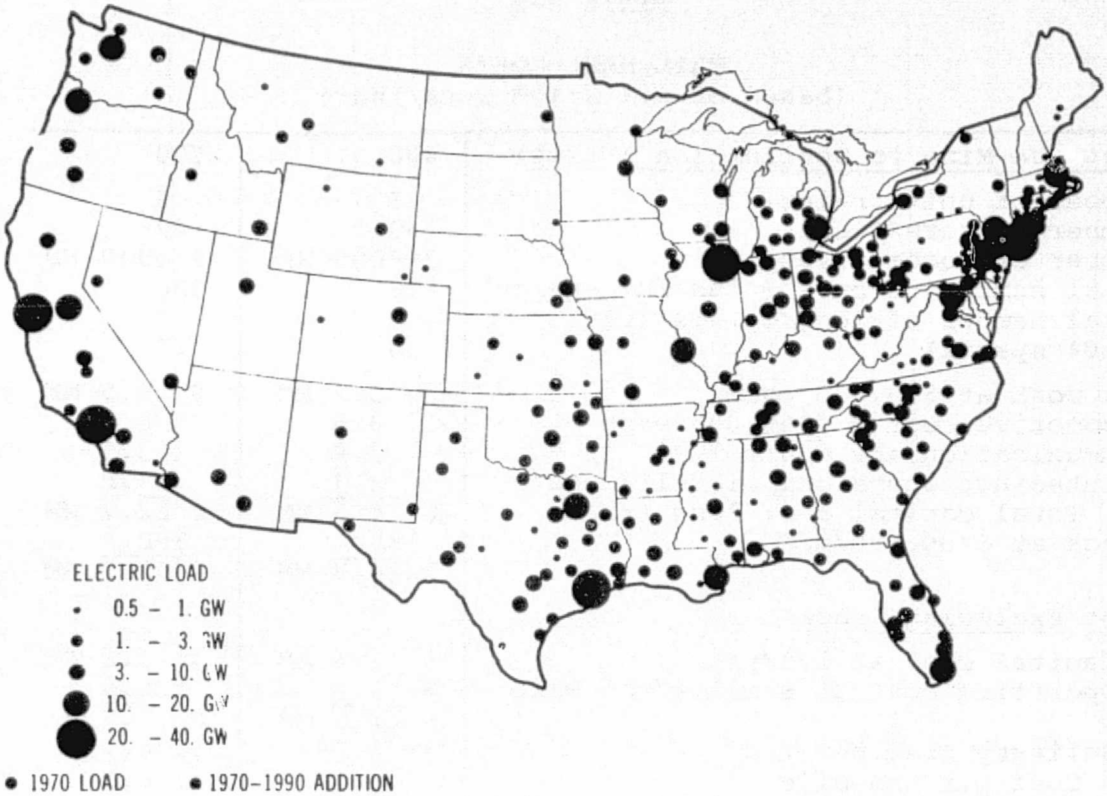


Figure 8-1. Major Electric Load Centers (1970-1990)

Table 8-2 shows derived costs for rail haul of coal without the cost of track (assuming it is fully written off) to be 0.7¢ per ton-mile for both the 400-mile and 700-mile distances. If new track is required, the cost rises to 1.76¢ per ton-mile. A generally accepted rule-of-thumb for unit train haulage of coal at current prices is 0.9¢ per ton-mile. Using this figure for existing trackage and 1.76¢/ton-mile for new, fully committed track, the following costs per million Btu of coal result:

Coal	Distance (miles)	Existing Track	New Track	Assigned NASA Values
Illinois No. 6	400	$0.17	$0.33	$0.15
Montana sub-bituminous	700	0.35	0.69	0.40
North Dakota lignite	700	0.46	0.89	0.45

SLURRY PIPELINE OF COAL

As noted in Appendix A, slurry pipelines become competitive with committed unit trains (including new track) only at distances greater than 800 to 900 miles and are therefore not considered.

Table 8-2

RAIL HAUL COSTS
(Based on 6.4×10^6 Tons/Year)

Distance–Mine to Destination (Miles)	400	700
Number of unit trains	3	5
Number of cars/train	69	69
Number of locomotives/train	3-6000 HP	3-6000 HP
Total number of cars (plus 10% spares)	228	380
Total number of locomotives (plus 10% spares)	10	17
Car cost at $25,000 each	$ 5.7 MM	$ 9.5 MM
Locomotive cost @ $350,000 each	3.5	6.0
Communication and control	2.8	3.5
Maintenance shops and miscellaneous	2.3	3.2
Total capital cost less track	$ 14.3 MM	$ 22.2 MM
Track at $400,000/mile	160.	280.
	$174.3 MM	$302.2 MM
Cost Excluding Track		
Capital cost at 17%/year	$ 2.4 MM	$ 3.8 MM
Operating cost at 6 mills/ton-mile	15.4	26.9
	$ 17.8 MM	$ 30.7 MM
Delivery cost per ton	$ 2.78	$ 4.79
Cost per ton-mile	0.7¢	0.7¢
Cost Including Track		
Capital cost at 17%/year	$ 29.6 MM	$ 51.4 MM
Operating cost at 6 mills/ton-mile	15.4	26.9
	$ 45.0 MM	$ 78.3 MM
Delivery cost per ton	$ 7.03	$ 12.23
Cost per ton-mile	1.76¢	1.76¢

RAIL HAUL OF SOLVENT REFINED COAL

Solvent refined coal having a heating value of 15,700 Btu/lb can be hauled by unit trains over existing track at an estimated cost of 1¢ per ton-mile. For a 400-mile distance this results in a delivery cost of 13¢/MM Btu, and 22¢/MM Btu will be required for 700 miles.

GAS PIPELINING OF PRODUCT GAS

From Reference 2, the average cost of natural gas pipelining is 1.8¢/100 miles/MM Btu. This figure will apply to substitute natural gas (SNG). Since intermediate-Btu gas and hydrogen have one-third the heat content of SNG, they will cost 5.4¢/100 miles/MM Btu, resulting in the following delivery costs:

Gas	400 Miles	700 Miles
SNG	$0.07	$0.13
H_2	0.22	0.38
IBtu	0.22	0.38

RAIL DELIVERY OF LIQUID PRODUCTS

Using existing tracks and unit trains, a rail haul cost of 1¢/ton-mile is expected. Using a HHV of 9750 Btu/lb for methanol* and assuming 18,000 Btu/lb for syncrude, the resulting costs are:

Liquid	400 Miles	700 Miles
Methanol	$0.21	$0.36
Syncrude	0.11	0.19

PIPELINE DELIVERY OF LIQUID PRODUCTS

Reference 2 cites a transport charge of approximately 1¢/100 miles/MM Btu for petroleum products. Syncrude would correspond to this, while, ratioing volumetrically, methanol will cost about twice this amount. As a result, costs will be:

Liquid	400 Miles	700 Miles
Methanol	$0.08	$0.14
Syncrude	0.04	0.07

GASIFIER PERFORMANCE ANALYSIS

Gasifier Types

Coal gasification processes can be categorized in a number of ways: air blown or oxygen blown; low, intermediate, or high pressure; slagging or nonslagging, etc. The most commonly accepted categorization, however, is between fixed bed, fluidized bed, and entrained flow. In the initial screening study, the characteristics of the latter three types were compared in the context of an integrated, air blown, low-Btu gas process, and the

*Methanol was not pursued further in the clean fuels study since the initial screening showed it to be among the higher cost fuels.

fixed bed type of gasifier was selected for integration with both the near- and long-term power systems to be integrated.

Fixed bed gasification is well established. At least one coal-fired power plant has been built using an integrated low-Btu fixed bed gasifier (ref. 3). Open literature data (ref. 4) gives a detailed breakdown of gasifier performance parameters as well as subsequent processing of the raw product gas to produce a synthetic, or substitute natural gas (SNG). Cost breakdowns are also available in Reference 4 that permit the development, on a consistent basis, of cost factors of alternative processing steps to produce clean fuels from the raw coal gas.

This report does no' presume to judge the superiority of one type of gasifier over another, but rather seeks to provide a comparison of coal-derived clean fuels on a consistent cost and performance basis. The availability of an excellent cost, performance, and experience base on commercial-scale units led to the choice of the fixed bed gasifier as the basic gasifier type for comparison of the clean fuels processes.

Air Blown Fixed Bed Gasifier Performance

Performance of the air blown, pressurized fixed bed gasifier has been developed using a semi-empirical approach developed on other General Electric Company programs.

Referring to Figure 8-2, the fixed bed gasifier itself is divided into four zones: the drying zone, the devolatilizing zone, the reduction zone, and the oxidation zone. Sized coal is fed via one or more lock-hoppers into the top of the gasifier, where the moisture is driven off by the heat of the gases rising through the raw coal. As the coal progresses downward through the bed, it enters the devolatilizing zone, where the volatile matter is driven off in the form of gas. Next, in the reduction zone, the basic chemical process of the gasifier takes place. Here the coke remaining from the devolatilizing zone combines with the hot gases and steam rising from the oxidation zone to produce the reduction gas. The reduction gas mixes with the volatiles and moisture as it rises through the gasifier to produce the raw gas exiting from the top of the gasifier. The remaining unreacted coke proceeds down the gasifier shaft, where it is burned in the presence of the air blast to produce the heat to support the process. The ash and the small amount of unburned carbon remaining is lock-hoppered out the bottom into a quench tank from which it is removed for disposal.

Several forms of energy recovery are utilized to assure reasonable efficiencies of operation. The gasifier wall in the oxidation and reduction zones is usually water-jacketed to limit the wall metal temperature. This provides a source of process steam which, in advanced fixed bed gasifiers, may entirely satisfy the gasifier steam demand. Also, the raw gas leaving the gasi-

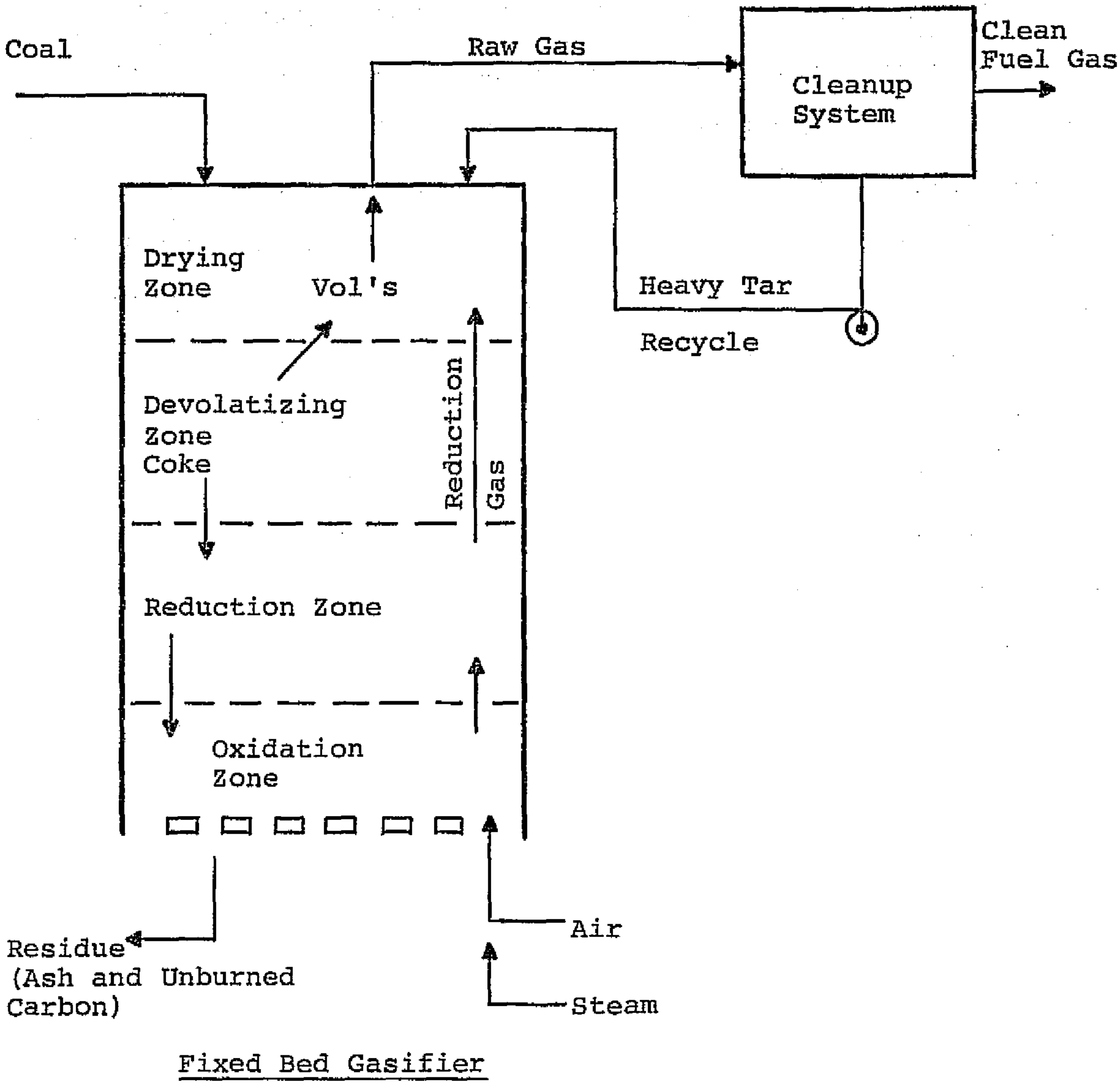


Figure 8-2. Elements of Fixed Bed Gasifier

fier will contain heavy tars and oils that represent a considerable heat content. Heavy tars can be recovered in the cleanup system and recycled to the gasifier where they are reintroduced onto the top of the gasifier bed to be cracked into lighter fractions as they circulate down through the gasifier.

Still other forms of energy recovery are obtained in the cleanup system. Figure 8-3 shows, in schematic form, one such gasifier/cleanup system. Two additional forms of energy recovery are shown here. The plant, as shown, has no liquid effluents, all waste products being destroyed in an incinerator equipped with a waste heat boiler. Energy is also recovered in the cleanup train by resaturating the product gas with a liquor containing light oils, tars, and phenols that have been removed from the raw gas stream in the initial quench as well as sensible heat received from the gas in the wash cooler and the secondary cooler. Resaturation in this manner can improve the gasifier efficiency by as much as 10 percent. However, it is limited to uses where the gasifier and power plant are adjacent to each other. Otherwise, condensation and heat losses in transit over any distance can nullify the gains from resaturation.

With this background, the basis for the semi-empirical gasifier analysis becomes more apparent. The procedure is as follows:

a. Starting with the particular coal's proximate and ultimate analyses and heating value, the products of the devolatilizing and drying zones are calculated. These include H_2S, ammonia, nitrogen, CH_4, C_2H_4, and oils, tars, and phenols.

b. The remaining coke is assumed to be all carbon and ash. Capacity of the gasifiers is scaled on the basis of a uniform coke loading in pounds coke per square foot of grate area. For caking coals, it is assumed that a stirrer will be used.

c. Products of the reaction zone and raw gas temperature are derived as a function of the ratio of pounds of steam per pound of reactive coke. The functions of reaction gas constituents are based on reported test results from a number of sources.

d. The required air to produce the reduction gas is calculated.

e. The raw gas composition is the sum of products from the reaction, devolatilization, and drying zones.

f. Lock-hopper losses are assigned equally to all gases.

g. The temperature from the washer cooler is then calculated.

h. Assumptions associated with the cleanup train analysis include:

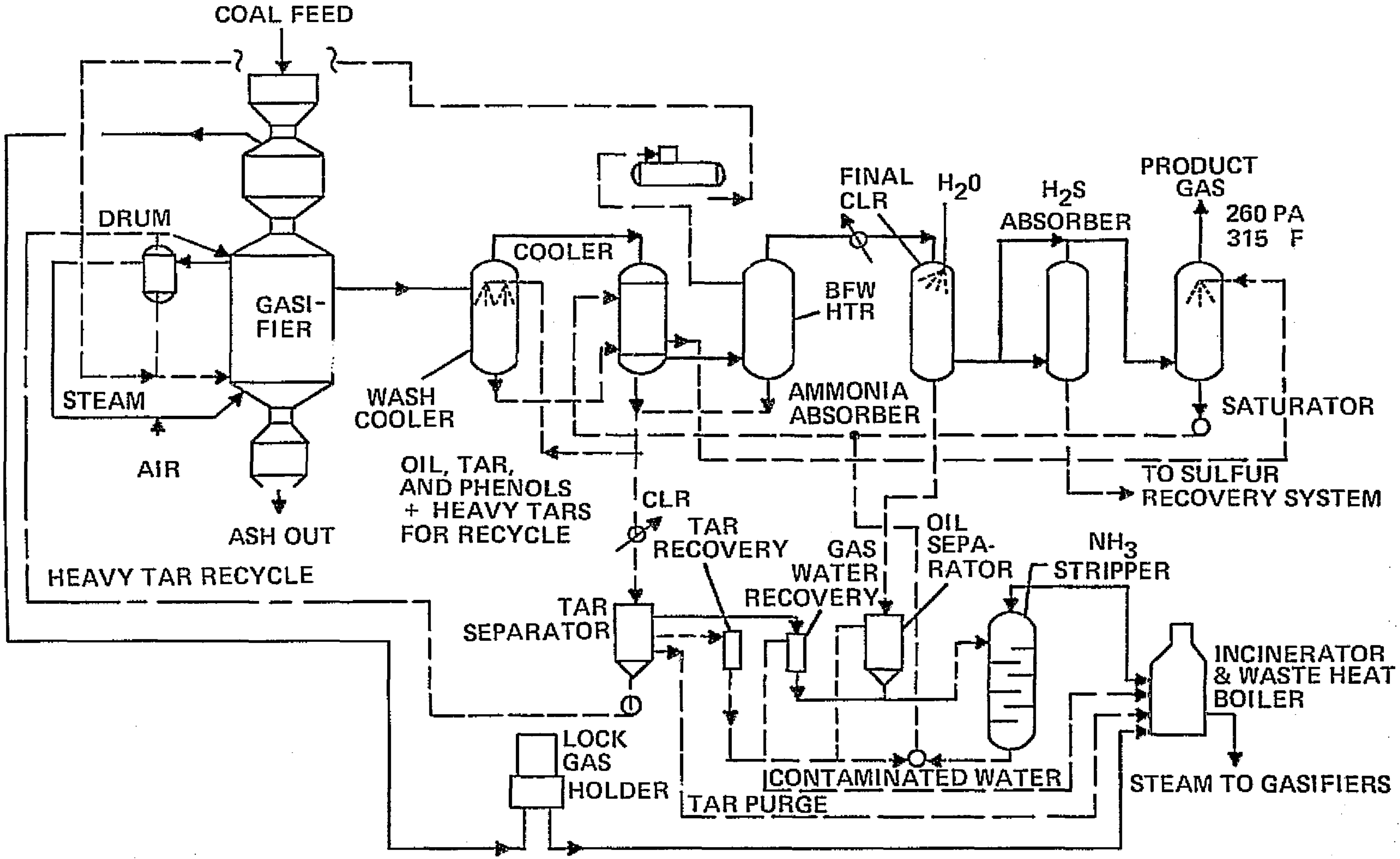


Figure 8-3. Fixed Bed Gasification System

- 90 percent of the NH_3 is removed.
- 85 percent of heavy tars are reinjected into the gasifier.
- The light oils, tars, and phenols are reinjected in the resaturator.
- The hot potassium carbonate H_2S removal system reduces H_2S content of the product gas to 50 ppm. In the process, 22 percent of the CO_2 is assumed to be removed from the product gas. (This represents a sizable energy loss.)

i. Knowing the clean product gas composition, the dry gas chemical heat prior to resaturation is calculated.

j. The moisture content of the resaturated clean product gas is calculated.

k. Sensible and chemical heat content of the wet, clean product gas is calculated.

Following this procedure, the resulting predicted gas compositions for the three coal feedstocks specified for this study are given in Table 8-3 for dry, low-Btu gas (without resaturation) and wet, low-Btu gas (saturated at 315 F, 265 psia). Wet gas composition will vary in moisture content as a function of delivery pressure.

Also shown on Table 8-3 are the predicted chemical conversion ratios based on the higher heating value of the gas produced by one pound of coal divided by the higher heating value of one pound of the coal feedstock. It should be recognized that this is not an efficiency *per se*, but is a convenient measure of gasifier performance for use in further process calculations.

Oxygen Blown Fixed Bed Gasifier Performance

Performance of the oxygen blown gasifier is calculated in a manner similar to the air blown case. Up to the start of the cleanup system, the gasifier streams will be identical whether the product gas is destined to become high-Btu SNG, intermediate-Btu gas, or hydrogen. The product gas analysis shown in Table 8-4 is for dry gas (without resaturation) cleaned up to the same level as that of the low-Btu gas case.

The gasifier conversion ratio is shown for both the dry gas case and the "wet" case where light tars, oils, and phenols are reinjected in the resaturator. Since this is strictly a measure of gasifier performance, it is not surprising that the oxygen blown case has a higher conversion ratio than an equivalent air blown gasifier, since this measure does not take into account the losses imposed by the oxygen plant.

Table 8-3

AIR BLOWN
FIXED BED GASIFIER ANALYSIS RESULTS

(Wet Gas Values at 315 F, 265 psia)

Gas Product (% by volume)	Illinois No. 6 Dry	Illinois No. 6 Wet	Montana Sub-Bituminous Dry	Montana Sub-Bituminous Wet	North Dakota Lignite Dry	North Dakota Lignite Wet
CO_2	15.64	10.28	15.71	10.46	15.71	10.47
H_2S (ppm)	50	50	50	50	50	50
C_2H_4	0.60	0.40	0.38	0.25	0.26	0.17
CO	11.40	7.49	11.58	7.71	11.72	7.81
H_2	24.96	16.71	25.37	16.89	25.37	16.93
CH_4	6.71	4.41	5.46	3.63	4.77	3.18
N_2	40.69	26.74	41.49	27.62	42.17	28.13
Tars/oils	--	2.78	--	1.95	--	1.82
H_2O	--	31.49	--	31.49	--	31.49
	100.00	100.00	100.00	100.00	100.00	100.00
HHV (Btu/SCF)	195	148	181	134	172	128
R_g, Gasifier Conversion Ratio (HHV Basis)						
(Btu chem. ht. in. gas) / (Btu chem. ht. in. coal)	0.759	0.866	0.792	0.875	0.794	0.875
Steam Requirements* (lb steam/lb coal)	1.14		1.08		0.879	
Air Requirements (lb air/lb coal)	1.66		1.58		1.30	

*Includes steam generated in jacket.

Table 8-4

OXYGEN BLOWN
FIXED BED GASIFIER ANALYSIS

Dry Gas Product (% by Volume)	Illinois No. 6	Montana Sub-Bituminous	North Dakota Lignite
CO_2	24.42	24.99	25.45
H_2S (PPM)	(50)	(50)	(50)
C_2H_4	0.32	0.26	0.18
C_2H_6	0.46	0.36	0.26
CO	21.43	21.71	21.98
H_2	41.80	42.35	42.89
CH_4	11.18	10.21	9.13
N_2	0.13	0.12	0.11
	100.00	100.00	100.00
HHV (Btu/SCF)	≈335	≈320	≈310
R_g, Gasifier Conversion Ratio (HHV Basis)			
$\frac{\text{(Btu chem. ht. in gas)}}{\text{(Btu chem. ht. in coal)}}$ Dry	0.769	0.817	0.817
Wet	0.875	0.906	0.906
Steam Requirement* (lb steam/lb coal)	1.284	1.18	0.956
Oxygen Requirement (lb air/lb coal)	0.331	0.304	0.246

* Includes steam generated in jacket.

CLEAN FUEL COSTS

General Approach

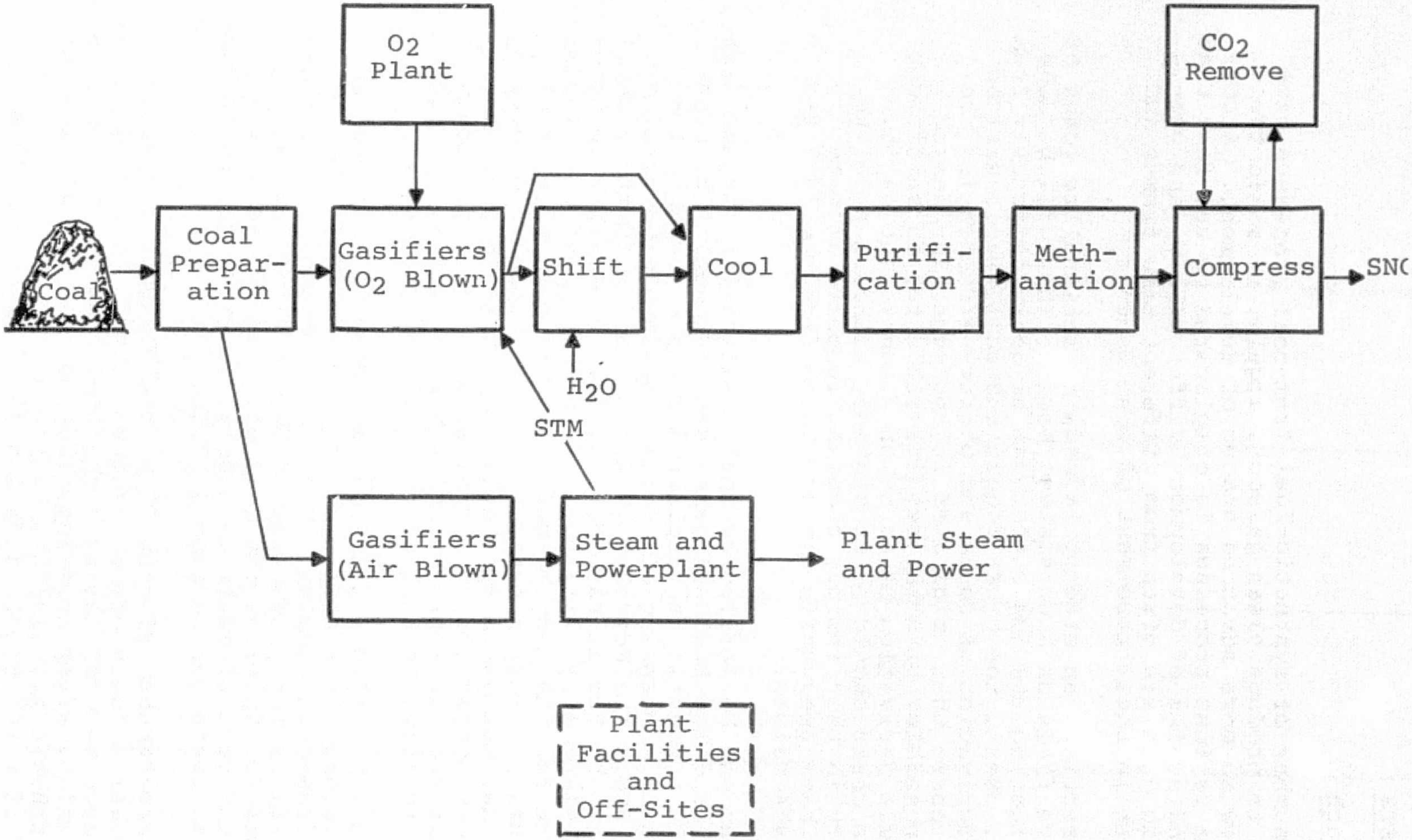
A large number of synthetic-fuel-from-coal processes have been proposed to produce clean gaseous, liquid, or solid fuels. Several are now in more advanced stages of development. A comparison of the various processes is complicated by the fact that the degrees and scales of development differ widely, and published economic data are often from different time frames and are not uniform in their treatment of cost factors.

In this section, an attempt is made to rationalize costs of the alternative fuels on a consistent basis. This will be done by first considering the fuels that can be derived directly from gasified coal. Next, the other liquid and solid fuels will be considered. Derivation of costs and process efficiencies are based on references that originated in the same time period (1972, where possible) with the results presented in sufficient detail to permit derivation of costs on a consistent basis. Thus, relative costs should be consistent, although absolute levels may vary in this rapidly changing economic climate. Capital costs have been uniformly escalated from the 1972 figures to mid-1974 values.

Fuels that can be derived by coal gasification include high-, intermediate-, and low-Btu coal gases and hydrogen. The high-Btu coal gas is a natural gas replacement and represents the highest degree of processing of coal to obtain a high-quality gas product: SNG. The November 1972 application to the Federal Power Commission by the El Paso Natural Gas Company for the proposed Burnham Plant (ref. 4) provides a breakdown of cost factors and performance for the many elements of this commercial-scale SNG plant. This provides a basis for a cost-by-function development of the other gas-based synthetic fuel costs in order to arrive at a cost comparison on a consistent basis. It should be recognized that such an approach is very approximate, but will be helpful in relative ranking of the costs of products.

Reference 4 provides a detailed breakdown of both cost and performance factors for a complete, self-sufficient, free-standing SNG-from-coal complex. The plant contains oxygen blown fixed bed gasifiers for production of SNG feedstock and air blown gasifiers for internal fuel, as shown in Figure 8-4. Grouping capital cost elements by function, the percentage breakdown of capital costs can be seen in Table 8-5.

The El Paso-Burnham plant will be the basis of comparison for the alternative fuels being studied. The El Paso product gas gasifiers produce raw gas having a chemical heat content of 12.5 x 10^9 Btu/hr which, after shifting, cleanup, and methanation results in a synthetic pipeline gas output having a chemical heat content of 10.15 x 10^9 Btu/hr (250.1 x 10^6 SCF/day of 972 Btu/



Output = 250 MMSCF/Day of 970 Btu/SCF Synthetic Pipeline Gas
(High Purity)
= 243.7×10^9 Btu/Day

Free Standing at Mine Mouth

Overall Plant Efficiency = 52.9 Percent Using Navajo Coal

Figure 8-4. Base Case SNG Plant

Table 8-5

CAPITAL COST BREAKDOWN OF EL PASO-BURNHAM PLANT

	Capital Cost (%)
Gasifiers (including coal preparation and ash handling)	24.3
Oxygen plant	13.2
Shift conversion and gas cooling	3.6
Methanation	5.1
Gas cleanup and pollution controls	17.7
Product gas compressor	1.9
Steam and power plant (including fuel gas supply)	19.6
Plant facilities and offsites	14.6
	100.0

SCF gas). All alternative gaseous, liquid, and solid fuel processes being considered are scaled up or down to a plant size producing the 10.15 x 10^9 Btu/hr output. For the gasification-based fuel processes, costs for each function are developed as a percentage of the El Paso plant total.

The processes to be compared in this manner will be high-, intermediate-, and low-Btu gasification, and hydrogen production. The high-Btu gasification and hydrogen plants will be treated as free-standing, mine-mouth plants having their own water supplies and steam and power plants. A high degree of gas cleanup representing 17.7 percent of total plant costs is found in the high-Btu plant since its product is sold as a premium fuel and extensive sulfur removal is needed to avoid catalyst poisoning. A similar degree of cleanup is expected in the hydrogen plant. A simpler, hot potassium carbonate based cleanup system is considered for intermediate- and low-Btu gas since these products will be used directly for power generation. Cost of these simpler gas cleanup and pollution controls is considerably less. The intermediate- and low-Btu gasification plants will be located at the power plant. The low-Btu gasification plant will be investigated on both a free-standing and integrated basis.

Costs of liquid and solid clean fuels from coal will not be as directly comparable, in that the commonality of basic process steps is not as strong. However, costs for the COED (ref. 5) and SRC based liquid fuels (ref. 6) were based on studies performed in the same time period (1972) as the El Paso study. These studies were presented in sufficient detail to permit direct comparison of capital costs and performance in a manner consistent with the gasification based processes. This permitted common·escalation to mid-1974 capital costs. The solid SRC fuel case was based on earlier data from ref. 6 which contained process data generated in 1969 and cost data generated in 1970. Due to uncertainty in these costs, capital cost of the solid SRC plant was based on a recent announcement (ref. 7) scaled and de-escalated to mid-1974 prices.

<u>High-Btu Gas (SNG)</u>

Simplifying the system schematic diagram of Figure 8-4, it can be seen that the basic processing units can be combined as shown in Figure 8-5 below:

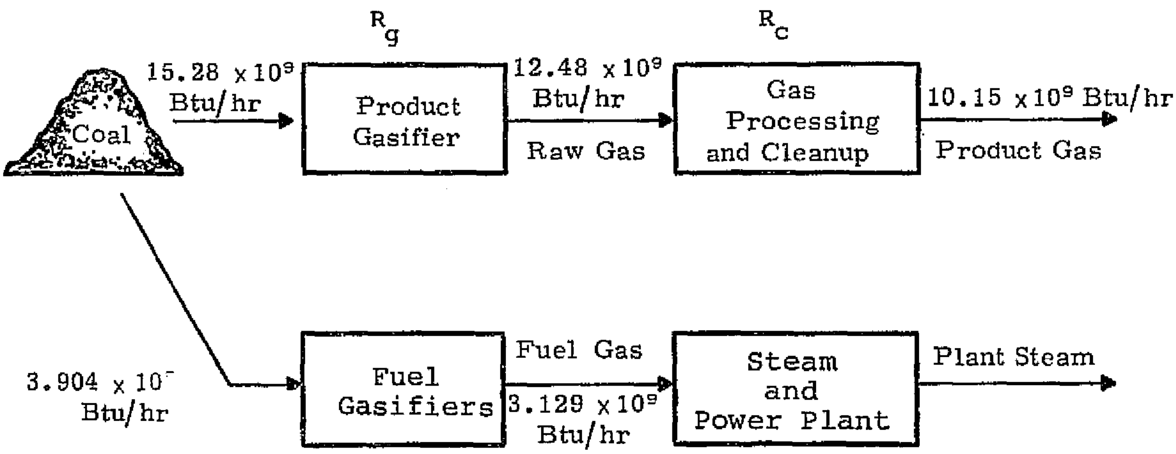


Figure 8-5. Simplified SNG Plant Diagram (coal flows are for El Paso Navajo coal)

The oxygen-blown product gas gasifiers conversion ratio (R_g) (output Btu/hr-input coal Btu/hr) is thus for the Navajo coal of the El Paso plant,

$$R_g = \frac{12.48 \times 10^9}{15.28 \times 10^9} = 0.8168.$$

The gas processing and cleanup conversion ratio is

$$R_c = \frac{10.15 \times 10^9}{12.48 \times 10^9} = 0.8133.$$

The overall chemical conversion efficiency (coal-pile-to-product-gas) of this free-standing plant is (using Navajo coal),

$$\eta_c = \frac{10.15 \times 10^9}{(15.28 + 3.904) \times 10^9} = 0.529.$$

To determine performance on Illinois No. 6 coal feedstock, the preceding section shows the gasifier conversion ratio, R_g, to be 0.769 for the dry gas product, as compared to 0.817 for Navajo coal. The coal feed must then be 16.23×10^9 Btu/hr to the product gasifier. Assuming the same power and steam plant requirements as in the El Paso case, 3.904×10^9 Btu/hr will go to the fuel gas plant. The overall chemical conversion efficiency using Illinois No. 6 coal is:

$$\eta_c = \frac{10.15 \times 10^9}{(16.23 + 3.904) \times 10^9} = 0.504.$$

Since the Illinois No. 6 coal results in a lower gasifier conversion ratio (R_g = 0.769 vs 0.8168 for the El Paso Navajo coal), more gasifiers would be expected to be needed to produce the same gas output. However, the greater heating value of the Illinois No. 6 coal more than offsets this, resulting in the need to process less coal overall by weight to produce the same gas output. The result is fewer gasifiers. A slightly higher oxygen requirement results in an increase in oxygen plant size; however, all other plant elements remain the same as the El Paso base case. Capital costs by function for the Illinois No. 6 case and the El Paso-Burnham plant base case are compared in Table 8-6, which shows a nominal capital cost decrease of 4 percent to use Illinois No. 6 coal, accompanied by a 2.5 percent decrease in process efficiency.

Composition of the high-Btu gas is not expected to vary significantly with coal feedstock. Table 8-7 shows the projected composition of the El Paso SNG which should be typical.

Intermediate-Btu Gas Cases

Free-standing intermediate-Btu gas plants were considered for all three coal feedstocks. Here the raw gas from the product gasifiers has impurities removed, but is not processed in any other manner. Basically, the product gas conversion ratio is

$$R_c = 1.0.$$

Table 8-6

CAPITAL COST RATIOED AS PERCENT OF TOTAL
HBtu GAS PLANT CAPITAL COST

(Output = 243.7 x 10^9 Btu/day)

	Base Case Burnham Plant Navajo Coal	Illinois No. 6
Gasifiers plus coal preparation plus ash	24.3	19.5
Oxygen plant and compressor	13.2	14.0
Shift conversion and gas cool	3.6	3.6
Methanation	5.1	5.1
Gas cleanup and pollution controls	17.7	17.7
Product gas compressor	1.9	1.9
Plant facilities and offsites	14.6	14.6
Fuel gas, steam, and power plant	19.6	19.6
TOTAL	100.0	96.0
Process efficiency	0.529	0.504

Table 8-7

PROJECTED HIGH-Btu (SNG) GAS COMPOSITION

	Volume (%)
CH_4	95.95
CO_2	2.01
N_2, Ar	1.16
H_2	0.75
CO	0.12
	100.00

Data source: Reference 4.

For the various coals, Table 8-4 lists the values of gasifier conversion ratio, R_g, for both the dry gas and the resaturated gas for each of the three coals. Using these values, and the heating content and coke content (assumed to be fixed carbon plus ash) of the coal, the gasifier costs can be established as a percentage of the El Paso-Burnham base-case plant cost as in the previous section. This implies the assumption that a given gasifier can process the same quantity of coke per hour from any feedstock.

Similarly, the oxygen plant cost is scaled directly with oxygen consumption.

Gas cleanup and air pollution control costs for the intermediate-Btu gas case will be drastically lower since gas cleanup need only be that needed to assure that the powerplant emissions fall within specifications. Based on observations of several cleanup plant designs for coal and oil gasification plants, cleanup costs as a function of gas flow quantities and sulfur content of the coal were developed. Table 8-8, which summarizes the capital cost factors for the various intermediate-Btu cases, shows a higher gas cleanup cost for Illinois No. 6 vs the other two coals, primarily because of its higher sulfur content. Table 8-8 also shows a gas cooling and resaturator cost for the "wet" cases for each coal which is scaled directly to the gasifier cost. Plant facilities and offsites are assumed to be the same as in the base case.

An analysis of the power requirements shows that elimination of the shift and methanation steps, a smaller oxygen plant, and simpler pollution controls permit reduction of the fuel gas, steam, and power plant to 14 to 16 percent of the base case total, depending on the coal and process used.

Coal consumption based on gasifier conversion ratio for product gas and on the fuel gas feed requirements are also tabulated in Table 8-8. These values lead to a process efficiency, which is also tabulated.

Table 8-8 shows the "wet" process, where the fuel gas is resaturated with light tars, oils, and phenols, to have both a capital cost and a process efficiency advantage in the case of any of the three coals.

The composition of the dry process intermediate-Btu gas used in the study is given in Table 8-4.

Low-Btu Gas

Of the various cases considered, all gasification processes except the low-Btu case use oxygen blown product gasifiers. The low-Btu system uses air blown gasifiers similar to the fuel gasi-

Table 8-8

CAPITAL COSTS OF FREE STANDING INTERMEDIATE BTU GAS PLANTS
(AS PERCENT OF TOTAL HBtu EL PASO PLANT CAPITAL COST)
(243.7×10^9 Btu/Day Output)

	Illinois No. 6		Montana Sub-bituminous		North Dakota Lignite	
	Dry	Wet	Dry	Wet	Dry	Wet
Gasifiers + coal prep + ash	16.60	14.59	17.65	15.92	17.85	16.10
Oxygen plant & compressor	11.37	10.00	11.90	10.73	12.50	11.27
Gas cleanup & pollution controls	8.44	7.56	4.30	3.97	4.59	4.24
Gas cooling & resaturation	--	3.60	--	3.92	--	3.97
Plant facilities & off-sites	14.60	14.60	14.60	14.60	14.60	14.60
Fuel gas, steam, & power plant	15.62	14.24	15.64	14.78	16.08	15.17
TOTAL	66.63	64.59	64.09	63.92	65.62	65.35
Coal for product gas (10^9 Btu/hr)	13.189	11.608	12.425	11.198	12.421	11.196
Coal for fuel gas (10^9 Btu/hr)	3.112	2.837	3.116	2.945	3.204	3.022
TOTAL COAL FEED (10^9 Btu/hr)	16.301	14.445	15.541	14.143	15.625	14.218
Process efficiency	0.623	0.700	0.653	0.718	0.649	0.714

fiers in the base-case El Paso plant which had a conversion ratio of 0.802. As indicated in the preceding section, resaturation of the product gas with light oils, tars, and phenols can produce an improvement in performance on the order of 10 percent, bringing the gasifier conversion ratio up to 88 percent. In the El Paso base case, each oxygen blown gasifier produced 460 MM Btu/hr of raw gas resulting in an end product of 374 MM Btu/hr of product gas after shift, cleanup, and methanation. One air blown gasifier at 80 percent conversion ratio produces 347 MM Btu/hr of raw gas, which with the 10 percent improvement gained by resaturation can be increased to 382 MM Btu/hr. Since only a simplified hot potassium carbonate cleanup system is used in the air blown gasifier (as in the intermediate-Btu oxygen blown case), the product gas conversion ratio, R_C, is basically unity. Therefore, the product gas output per air blown gasifier at a nominal 380 MM Btu/hr with resaturation is virtually identical with that of an oxygen blown gasifier in a high-Btu gas plant—374 MM Btu/hr. The starting point in costing the low-Btu gas plant, therefore, is to apply the same gasifier cost to the low-Btu gas plant as that used for a high-Btu gas plant of the same output capacity and using the Navajo coal of the El Paso plant. In addition, a gas cooling resaturation system must be added, as in the "wet" intermediate-Btu gas case. However, because of the smaller heating value of the gas, the volumetric flow that must be handled is two-to-three times greater for the same Btu output, and the resaturator cost must be scaled up accordingly.

Since an oxygen plant is not used in the air blown case, some means for pressurizing the gasifier air must be provided. In the case of a free-standing, self-sufficient plant, the air compression equipment must compress atmospheric air up to 285 psi gasifier pressure, and a steam and power plant must be provided to supply the steam needs of the gasifier as well as the steam and power needs of the plant.

For simplicity of calculations, the steam and power plant was assumed to contain its own fuel gas gasifiers as in the El Paso plant. In an actual free-standing low-Btu gas plant, product gas would be burned in the steam and power plant. A spot check showed that costs figured on this basis of an expanded gasifier facility providing gas to a steam and power plant agreed very closely with the simpler approach of lumping the fuel gas, steam, and powerplant costs and rat'oing up and down according to process steam and power needs.

Also considered was an integrated low-Btu plant, Figure 8-6, where the gasification plant and the combined cycle power plant are closely integrated. Configurations similar to that in Figure 8-7 were used for both the combined open-cycle gas turbine-steam turbine cycles and the closed-cycle conversion systems which were integrated with a low-Btu gasifier. Here, the gasifier air is supplied by extraction air from the gas turbine compressor which must be compressed from about 130 psi up to

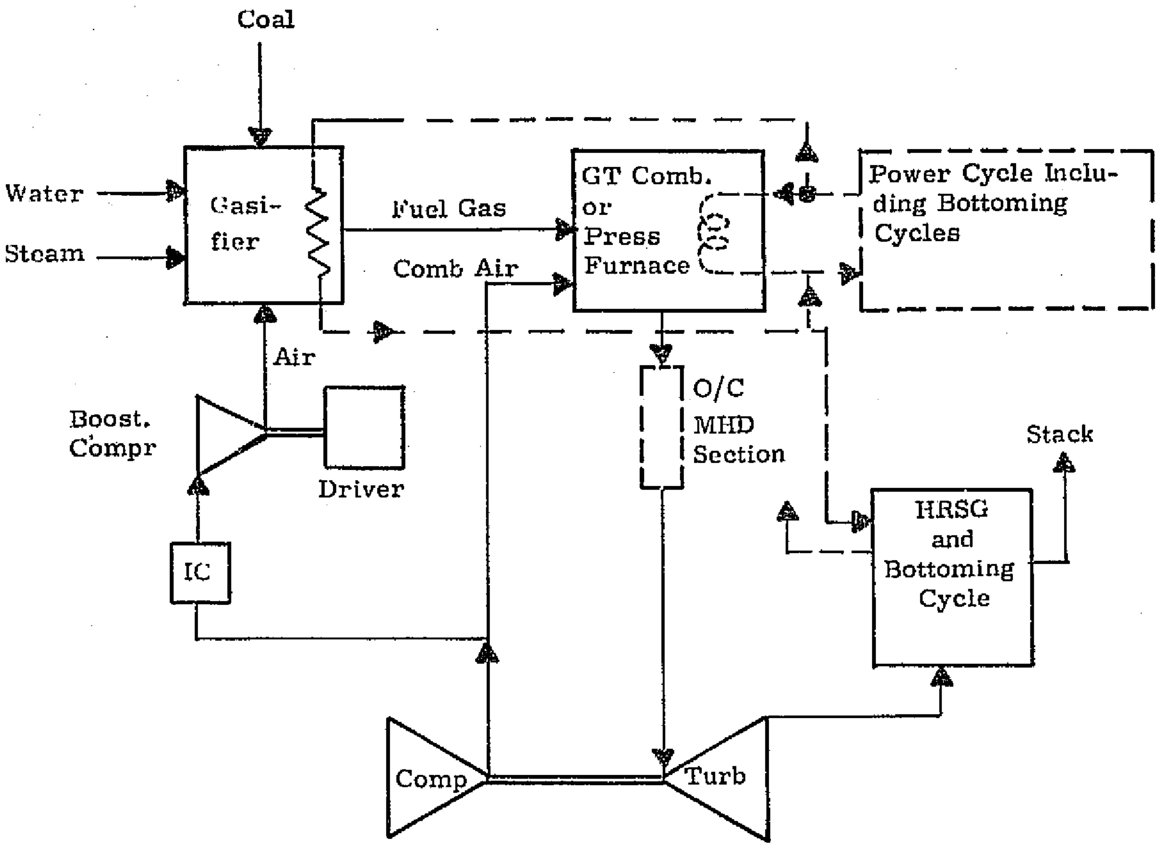
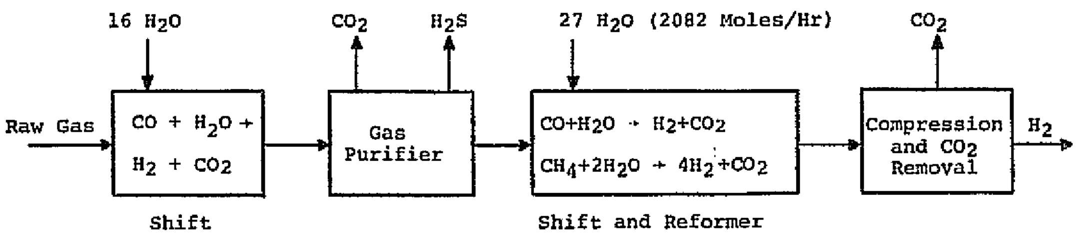


Figure 8-6. Generalized Low-Btu Gas System



CO_2	25	41	0	16	0
CO	21	5	5	0	0
H_2	42	58	58	107	107
CH_4	11	11	11	0	0
Other	1	1	0	0	0
	100 Moles	116 Moles	74 Moles	123 Moles	107 Moles
	77,120	89,460	57,070	94,860	82,520

Dry Gas Moles/Hr for 10.15×10^9 Btu/hr Output

Figure 8-7. Idealized Hydrogen Conversion Process the gasifier pressure. Process steam is supplied to the gasifier from the power plant steam system, and electric power is received from the power plant. The integrated gas plant requirements for facilities and off-sites are greatly reduced compared to a free-standing plant.

The resulting breakdown of capital cost elements for both the free standing and integrated low-Btu gasification plants are given in Table 8-9 for the three coal feedstocks studied. Coal consumption and the resulting process efficiencies are also tabulated. The integrated low-Btu plant offers substantial capital cost savings and an improved process efficiency. Some of these gains are offset by added costs and energy usage that must be charged to the power plant, but the integrated low-Btu gasification plant remains the lowest cost source of energy in gaseous form.

Hydrogen Gas

Hydrogen generation from coal was considered only for the Illinois No. 6 feedstock. Taking the same general approach as in Reference 1, start at the raw gas from the oxygen blown gasifier which has the following composition by volume:

CO_2	25%
CO	21%
H_2	42%
CH_4	11%
Other	1%

Consider 100 moles of this gas and observe its processing through a hypothetical series of steps to produce hydrogen as in Figure 8-7. The process conversion ratio R_c is

$$R_c = \frac{107 \text{ Moles } H_2 \times 123{,}000 \text{ Btu/Mole}}{\underset{CO}{(21 \times 121{,}800)} + \underset{H_2}{(42 \times 123{,}000)} + \underset{CH_4}{(11 \times 383{,}000)}} = 1.102$$

This does not imply efficiency greater than 100 percent since the shift reforming process is highly endothermic, a fact reflected in larger steam plant requirements. To produce 10.15×10^9 Btu/hr of product gas, the raw gas content must be 9.21×10^9 Btu/hr which, at a gasifier conversion ratio of 0.769, corresponds to a product gasifier feed of 11.98×10^9 Btu/hr. For Illinois No. 6 coal, this corresponds to 555 tons/hr of coal feed or 279 tons/hr of coke feed which is 62 percent of that in the El Paso plant. The oxygen requirement is 0.33 lb of O_2 per lb of coal or 183 tons/hr of oxygen is 78.2 percent of that in the El Paso plant.

Table 8-9

CAPITAL COSTS OF LOW-BTU GAS PLANTS
AS PERCENT OF TOTAL HBTU EL PASO PLANT COST

(243.7×10^9 Btu/Day Output Capacity)

	FREE STANDING PLANTS			INTEGRATED PLANTS		
	ILLINOIS NO. 6	MONTANA SUBBITUMINOUS	N. DAKOTA LIGNITE	ILLINOIS NO. 6	MONTANA SUBBITUMINOUS	N. DAKOTA LIGNITE
Gasifiers + Coal Prep + Ash	19.54	21.85	22.09	19.54	21.85	22.09
Air Compression	3.12	3.54	3.78	2.29	2.60	2.77
Gas Cleanup & Pollution Controls	7.96	4.77	5.13	7.96	4.77	5.13
Gas Cooling & Resaturation	9.04	9.74	10.25	9.04	9.74	10.25
Plant Facilities & Offsites	14.60	14.60	14.60	4.30	4.30	4.30
Fuel Gas, Steam & Power Plant	16.62	18.48	19.40	--	--	--
TOTAL	70.88	72.98	75.25	43.13	43.26	44.54
Coal for Product Gas (10^9 Btu/Hr)	11.726	11.604	11.603	11.726	11.604	11.603
Coal for Fuel Gas (10^9 Btu/Hr)	3.239	3.565	3.741	--	--	--
TOTAL COAL FEED (10^9 Btu/Hr)	14.965	15.169	15.344	11.726	11.604	11.603
Process Efficiency*	.678	.669	.661	.866**	.875**	.875 **

*Btu product gas/Btu in coal feed

**Not adjusted for energy received from power plant

Using these values:

$$\text{Gasifier cost} = 0.620 \times 24.3\% = 15.1\%$$

$$\text{Oxygen plant cost} = 0.782 \times 13.2\% = 10.3\%$$

$$\text{Cleanup cost} = \frac{0.8133}{1.102} \times 17.7\% = 13.0\%$$

The cleanup cost is ratioed directly to gas flow. In the base case El Paso plant, 46 percent of the raw gas flow went to the shift process. In the hydrogen process, the total raw gas flow is

$$\frac{0.8133}{1.102} = 0.738 \times \text{base case raw gas flow.}$$

Therefore, the shift cost is

$$\frac{0.738}{0.46} \times 3.6\% = 5.8\%$$

Assume the reformer/shift following the gas purification has the same cost per total moles as the El Paso methanator. Scaling per mole flow, noting that El Paso's methanator handled 75,518 moles/hr of dry gas:

$$\text{Reformer/shift cost} = \frac{(57070 + 20820)}{75{,}518} \times 5.1\% = 5.2\%$$

Scaling the product gas compression costs by mole flow for the same heat output

$$\text{Mole flow ratio} = \frac{\text{Methane Btu/mole} = 383{,}000}{\text{Hydrogen Btu/mole} = 123{,}000} = 3.114$$

$$\text{Product gas compressor cost} = 3.114 \times 1.9\% = 5.9\%$$

Power and steam requirements are higher than those of the base-case plant, resulting in a power, steam, and fuel gas plant cost that is 23.7 percent of the base-case total.

Therefore, the coal requirements are:

$$\text{Product gasifiers} = \frac{10.15 \times 10^9}{1.102} \times 0.769 = 11.98 \times 10^9 \text{ Btu/hr}$$

$$\text{Fuel gasifiers} = \frac{23.7}{19.6} \times 3.904 \times 10^9 = 4.72 \times 10^9 \text{ Btu/hr}$$

$$\text{Total} \quad 16.70 \times 10^9 \text{ Btu/hr}$$

Process efficiency = 0.608

This compares closely with a process efficiency of 60.2 percent deduced for the SRC filter cake-to-hydrogen portion of the process of Reference 5. The cost breakdown for the hydrogen plant (as a percentage of the base case El Paso-Burnham plant) is included in the summary of Table 8-10. The total 93.6 percent is slightly more conservative than the 89.0 percent which can be deduced by scaling hydrogen plant elements from selected portions of the coal processing plant of Reference 6.

The composition of the product gas is not expected to be strongly affected by coal feedstock. A typical gas composition to be expected is given in Table 8-11. That composition is based on a hydrogen plant fed by SNG.

COED Liquid Fuel

Generation of liquid fuel from coal essentially involves the addition of hydrogen to the coal to raise the H/C ratio so that the product is a liquid. In most processes (including the SRC process of the next section), the entire coal is hydrogenated. In the COED process, the coal is first pyrolized to yield a solid char, a gas, and a liquid. The liquid is then hydrogenated to produce a synthetic crude oil. The COED process can take many forms in its treatment of the char and the gas. For purposes of this study, the process described in Reference 5 is used because of its complete documentation and its costing in a time period (1972) compatible with the other processes studied. In this form of the COED process, the char is gasified by the molten salt process and, after shift conversion, is mixed with the pyrolysis gas, and purified, and methanated. The process, as outlined in Reference 5, produces 250 MM SCF per day of pipeline gas (921 Btu/SCF). The process also produces 27,275 bbl/day of synthetic crude, 1900 bbl/day of light hydrocarbons, 1035 tons/day of sulfur, and 40 tons/day of phenol. Crediting only the synthetic pipeline gas, the synthetic crude and the light hydrocarbons as energy products, the yield in energy is 56.3 percent of the energy of the coal entering the plant. Output in Btu terms breaks down as follows:

SNG	57.7%
Syncrude	39.6
Light oil	2.7
	100.0%

Table 8-12 lists the composition of these three products. Trace element analysis was not available, but independent tests show that COED syncrude has the potential for being a clean liquid fuel.

Table 8-10

CAPITAL COST OF GAS BASED CLEAN FUELS PLANTS
RATIOED AS PERCENT OF TOTAL EL PASO-BURNHAM HBtu GAS PLANT CAPITAL COST

(Illinois No. 6 Feedstock, 244 x 10^9 Btu/Day Output)

	Free Standing Oxygen Blown Cases				Air Blown Cases	
	HBtu Gasification	LBtu Gasification Dry Gas	LBtu Gasification Wet Gas	Hydrogen	Free Standing LBtu	Integrated LBtu
Gasifiers + coal preparation + ash	19.5	16.6	14.6	15.1	19.5	19.5
Oxygen plant and compressor	14.0	11.4	10.0	10.3	—	—
Booster air compressor	—	—	—	—	3.1	2.3
Shift conversion and gas cool	3.6	—	—	5.8	—	—
Reformer	—	—	—	5.2	—	—
Methanation	5.1	—	—	—	—	—
Gas cleanup and pollution controls	17.7	8.4	7.6	13.0	8.0	8.0
Gas cooling and resaturation	—	—	3.6	—	9.0	9.0
Product gas compression	1.9	—	—	5.9	—	—
Plant facilities and offsites	14.6	14.6	14.6	14.6	14.6	4.3
Fuel gas, steam, and power plant	19.6	15.6	14.2	23.7	16.6	—
TOTAL	96.0	66.6	64.6	93.6	70.9	43.1
Process efficiency	0.50	0.62	0.70	0.61	0.68	0.87*

*Basis η = HHV LBtu Gas/HHV Coal.

Table 8-11

APPROXIMATE HYDROGEN FUEL COMPOSITION
(Based on SNG Feedstock)

	Volume (%)
H_2	98.0
CH_4	1.6
N_2	0.4
	100.0

Scaling the plant of Reference 5 to a total output of 243.7 x 10^9 Btu/day and applying adders consistent with those of the SNG base case, a plant cost of $380 million results.

Solvent Refined Coal (SRC)

Reference 8 defines a solvent refined coal process which produces a de-ashed coal (0.1 percent ash, 0.78 percent sulfur) from Illinois No. 6 coal. In this process, the coal is hydrogenated directly under high pressure and temperature (1000 psi, 825 F), producing a liquid from which the ash is extracted by filtration. At temperatures below 300 F, the product is solid, having a higher heating value of 15,680 Btu/lb and a composition as outlined in Table 8-13. The composition of Table 8-13 does not include trace element analysis. Indications from preliminary tests are that alkali metal carryover from the coal to the SRC is quite high—a fact that will be particularly troublesome to equipment having high metal temperatures. In addition, the nitrogen content of the SRC in its present form can be a serious emission limitation. For this reason, the SRC must be considered a semi-clean fuel.

A process efficiency of 78 percent reported in the initial screening study did not factor in the feedstock requirements of the hydrogen plant. A more detailed review of the background references of Reference 8 shows that the plant used natural gas as a feedstock to produce hydrogen, and also produced a light oil and a small amount of surplus electric energy. Since natural gas is not a realistic feedstock in the future, the process was reanalyzed assuming hydrogen-from-coal (previous section) derived at 60.8 percent process efficiency provided the hydrogen feed. Using these values, the overall coal-pile-to-product efficiency was calculated to be 74.3 percent and the product mixture broke down as follows (on a Btu output basis):

SRC product	88.7%
Light oil	9.1
Surplus electricity	2.2
	100.0%

Table 8-12

COED PROCESS PRODUCTS
(Illinois No. 6 Feedstock)

Synthetic Pipeline Gas (57.7% of Total Btu Output)

Composition, Mole %	
Methane	88.9
Hydrogen	6.5
Carbon monoxide	0.1
Carbon dioxide	2.9
Nitrogen	1.6
	100.0

Higher heating value, Btu/SCF 921

Synthetic Crude (39.6% of Total Btu Output)

Composition, Wt %	
Carbon	87.55
Hydrogen	11.14
Oxygen	0.91
Nitrogen	0.32
Sulfur	0.08

ASTM Distillation, °F	
IBP	168
5%	280
10%	324
30%	489
50%	573
70%	676
90%	839
EP	871
Rec. %	93
Res. %	7

°API	22
Pour, °F	40
Viscosity, SSU @ 100 F	44.0
Viscosity, SSU @ 122 F	39.2
Ramsbottom Carbon, Wt %	0.6

Light Hydrocarbon (2.7% of Total Btu Output)

Composition, Vol %	
C_3	40
C_4	43
C_5	17
	100

Source: Reference 5.

Table 8-13

SOLVENT REFINED COAL PROCESS
(Based on Illinois No. 6 Feedstock)

SRC Product	Weight (%)
C	88.41
H	5.15
O	3.72
N	1.84
S	0.78
Moisture	0
Ash	0.1
	100.00

HHV = 15,682 Btu/lb

Source: Reference 8, Appendix B.

Capital costs in Reference 8 were based on a 1969 study. A more up-to-date capital cost figure (ref. 7) report in November 1974 for a commercial SRC plant is the basis for the estimated capital cost of $270 million used in this report. Since it was not possible to develop capital costs for SRC plants on a basis consistent with the other clean and semi-clean fuels processes, the costs derived for SRC fuel should be recognized as being the least consistent and considerably less reliable for comparison with the other fuels. As more recent data becomes public, it is essential that these efficiency and cost figures be updated.

Fuels Cost Comparison

Capital costs of all gasification-based processes have been expressed up to this point as a percentage of the cost of the proposed Burnham Plant of the El Paso Corporation (ref. 4). This cost, escalated 7 percent from late 1972 to early 1974, and with allowances added for contingency (10 percent), interest during construction (15 percent), and startup (10 percent), works out to $393,000,000 (rounded off to $390 x 10^6). In retrospect, the escalation rate used was low for this time period.

Recent reports place projected costs for this project at numbers as high as $700 million+, including mine development and community and road complexes, which are not included in the $393,000,000 figure. Escalation is on the order of $200,000 per day due to inflation (ref. 9). The base capital cost figure of $\$390 \times 10^6$ is therefore a moving target. However, since all gasification-based processes in this section are ratioed to this same value, the relative capital cost rankings should be valid, although absolute levels may be open to argument. Therefore, the $393,000,000 figure will be used here as representative of the first half of 1974 costs.

Capital cost of the COED plant was based on values from Reference 5 after scaling and adjustment to put the numbers on a basis comparable to those of the gas plants. (Reference 5 originated also in late 1972, so that it received identical escalation treatment as the base-case gas plant.) As already noted, the $270 million capital cost for the SRC plant is a very rough figure which may not be as directly comparable, and bears further investigation if SRC is to be considered as a serious economic contender.

In deriving fuels costs, all plants were appraised on a common basis. It was assumed that the plants operated 8000 hours per year, a yearly fixed charge rate of 18 percent was applied, and yearly operating and maintenance costs were assumed to be 6 percent of capital cost of the plant. This includes the integrated as well as the nonintegrated fuels plants reported in this section, so that a direct fuels cost comparison on a process-by-process basis could be made. Elsewhere in the Task I Study, where total cost of electricity is calculated, the integrated gasifier plants are operated at the same 65 percent capacity factor (5694 equivalent hours per year) as their associated power plants.

Table 8-14 compares the resulting fuels costs per million Btu of product fuel for the various processes using Illinois No. 6 coal as the feedstock. In general, the groupings seem to place the higher quality fuels (SNG, hydrogen, and COED syncrude) in the $2.50/MM Btu area, the free-standing IBtu and LBtu gases in the $2.00/MM Btu area, and the integrated low-Btu gas comes out at a cost of approximately $1.50/MM Btu. Although the latter has the lowest cost, it will involve some penalties in use since the powerplant with which it is integrated will be penalized for extracting air, steam, and electrical energy. Also, the penalty for lower utilization resulting from integration with the power plant will apply in actual use.

The SRC costs noted list the value using the 78 percent process efficiency used in the study and, in parenthesis, the 74 percent process efficiency developed later. In the case of both the COED and SRC fuels, the fuels plant produces a mix of energy products which may bear different values per million Btu in the

Table 8-14

FUEL COST COMPARISONS USING ILLINOIS NO. 6 COAL

(244×10^9 Btu/Day Output)

	HBtu	IBtu (Dry)	IBtu (Wet)	LBtu (Free)	LBtu (Int.)	H_2	COED	SRC
Process efficiency	0.50	0.62	0.70	0.68	0.87	0.61	0.56	0.78(.74)
Plant location	Mine mouth	Power plant	Power plant	Power plant	Power plant	Mine mouth	Mine mouth	Mine mouth
Plant capital cost ($MM)	380	260	250	280	170	370	380	270
Fuel product cost ($/MM Btu)								
Coal at 70¢/MM Btu	1.39	1.12	1.00	1.03	0.81	1.15	1.24	0.90(.95)
Coal transport at 15¢/MM Btu	—	0.24	0.21	0.22	0.17	—	—	—
Plant at 18%/year	0.84	0.58	0.56	0.62	0.38	0.82	0.86	0.60
Operation & maintenance at 6%/year	0.28	0.19	0.19	0.21	0.13	0.27	0.29	0.20
Product transport	0.07	—	—	—	—	0.22	0.06	0.13
Calculated Total ($/MM Btu)	2.58	2.13	1.96	2.08	1.49	2.46	2.45	1.83 (1.88)
Costs used in study*	2.60	2.00		2.08		2.50	2.60	1.80

* Final clean fuel cost used in study were specified.

real marketplace. Noting Table 8-12, the COED process's major product (57.7 percent by Btu content) is pipeline gas, the syncrude making up 39.6 percent of total output. Assuming the market place could support a price of $2.58/MM Btu for high Btu SNG, and $3.00/MM Btu for the light hydrocarbon, a case could be made that the COED syncrude could have a cost of $2.27/MM Btu. However, such market determinations are beyond the scope of this study, and the total calculated costs shown are the cost per million Btu of the total product mix.

The impact of coal type on clean fuels costs was also determined for two representative processes reported in Table 8-15. In the case of the free-standing dry intermediate Btu gas process, the calculated costs ranged from $2.05 to $2.13/MM Btu. The spread was even less for the integrated low-Btu process with resaturation, the spread was even less: $1.48 to $1.50 per MM Btu.

INTEGRATED LOW-Btu GASIFICATION PLANT

As part of the study, low-Btu gas plants were considered for integration with a number of the cycles investigated. In two of the cases (air-cooled and water-cooled open cycle gas turbines), the system was a base-case system where detailed information on the fuels plant was required. In this section, the detailed information on the base case plant will be developed and then the general approach for costing the many integrated plants will be presented.

Environmental Impact

The base-case fuels plant for integration is delineated in Figure 8-3. This plant (described in ref. 10) produces the following output streams:

a. Clean fuel gas for power generation

b. Elemental sulfur for sale as a byproduct

c. Emissions from the incinerator

d. Ash for disposal

All undesirable waste products, including the tar purge, ammonia, sulfur plant tail gas, lock gas, and contaminated water, are delivered to the incinerator for disposal. A waste-heat boiler on the incinerator generates steam for use in the gasifiers. Using data generated for Reference 10 and applying appropriate scaling factors, the emissions from the incinerator will be as indicated in Table 8-16. The basic layout for an 875 MW integrated gas plant/power plant reported in Reference 10 is given in Figure 8-8. Factoring elements from this layout resulted in the projected land area requirements of Table 8-16.

Table 8-15

EFFECT OF COAL TYPE ON CLEAN FUELS COSTS

(244×10^9 Btu/Day Output)

	Free-Standing Dry Gas Intermediate-Btu Gas Plant			Integrated Wet Gas Low-Btu Gas Plant		
	Illinois No. 6	Montana Sub-bituminous	North Dakota Lignite	Illinois No. 6	Montana Sub-bituminous	North Dakota Lignite
Process efficiency	0.62	0.65	0.65	0.87*	0.87*	0.87*
Plant capacity cost ($MM)	260	250	260	170	170	175
Coal cost ($/MM Btu of coal)	0.70	0.45	0.40	0.70	0.45	0.40
Coal transport ($/MM Btu of coal)	0.15	0.40	0.45	0.15	0.40	0.45
Fuel product cost ($/MM Btu of product)						
Coal	1.12	0.69	0.62	0.81	0.51	0.46
Coal transport	0.24	0.61	0.69	0.17	0.46	0.51
Plant at 18%/year	0.58	0.56	0.57	0.38	0.38	0.40
Operation and maintenance at 6%/year	0.19	0.19	0.19	0.13	0.13	0.13
TOTAL	2.13	2.05	2.07	1.49	1.48	1.50

* Basis $\eta = \frac{\text{HHV LBtu Fuel}}{\text{HHV Coal}}$.

Table 8-16

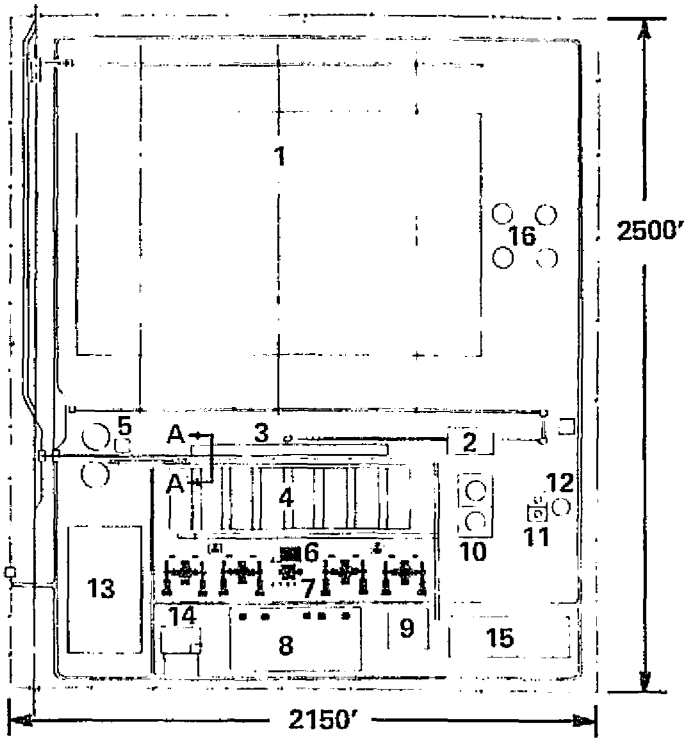
ENVIRONMENTAL IMPACT

(Illinois No. 6 Coal)

	Air-Cooled Open-Cycle Gas Turbine Base Case	Water-Cooled Open-Cycle Gas Turbine Base Case
Coal Feed (tons/hr)	256.25	385.88
Incinerator Emissions (lb/hr)		
SO_2	1,100	1,650
CO_2	201,000	303,000
NO_X	Nil	Nil
N_2	165,000	249,000
O_2	8,300	12,500
H_2O	58,800	88,500
TOTAL	434,200	654,650
Ash for Disposal (tons/hr) (9.6% moisture)	28.9	43.5
Elemental Sulfur for Sale (tons/hr)	9.7	14.6
Total Land Area (acres)	61	92
Land Area Excluding Coal Pile (acres)	21	32

Balance-of-Plant Requirements

Balance-of-plant and feed requirements for the fuels plant were also derived from information prepared for Reference 10. Most are lreatively straightforward. However, a farily complex steam balance does exist inside the fuels plant-in that steam is both generated and consumed by the fuels plant. For instance, in the air-cooled base case, the gasifiers require 586,400 PPH of steam, but generate 92,900 PPH of this requirement in their water jackets, leaving a net requirement of 493,500 PPH. Internal steam generation in the Claus Plant and the incinerator waste heat boiler have similarly been considered in deriving the net steam requirements for the fuels plant. Balance-of-plant requirements are summarized in Table 8-17 for two base cases.



1 Coal handling and storage
2 Briquetting
3 Gasifiers
4 Gas treatment and tar facility
5 Ash handling
6 Control room
7 Power plant
8 Substation
9 BFW treatment
10 Lock gas storage
11 Incinerators
12 Gas Flare
13 Sulfur removal
14 Maintenance and firehouse
15 Cooling tower
16 Fuel oil storage tanks

Figure 8-8. Gasification/Combined Cycle Plant Layout (Nominal capacity—875 MW)

Table 8-17

FUELS PLANT REQUIREMENTS

	Air-Cooled Open-Cycle Gas Turbine Base Case	Water-Cooled Open-Cycle Gas Turbine Base Case
Gasifier pressure (psia)	263	351
Coal feed (tons/hr)	256.25	385.88
Cooling water (gal/min) (Δ T = 22 F)	29,000	43,500
Total Boiler FW (lb/hr) (excluding power plant)	474,000	717,800
Fuels Plant Electrical (kW)	5,960	8,980
Booster Driver Steam (lb/hr) (325 psia, 630 F)	114,500	163,400
Net Fuels Plant Steam Requirements (lb/hr) (Excluding Booster Drive Turbine)		
Gasifier steam		
Pressure (psig)	315	400
Net flow (lb/hr)	493,500	743,000
Claus plant		
Pressure (psig)	400	400
Net flow (lb/hr)	259,900	395,000
Hot carbonate process		
Pressure (psig)	50	50
Net flow (lb/hr)	19,000	24,000
Sulfur to storage for sale (tons/hr)	9.72	14.63

Capital Cost Scaling Parameters

In the preceding section, the cost breakdowns for a number of gasification based clean fuels plants were derived. All of the plants were sized to produce a total output of 243.7 billion Btu's per day of energy product. For the integrated low-Btu fuels plant, a large number of applications are involved in this study each of which has a different energy throughout. In addition, each of the three coal feedstocks must be handled.

To develop costs for this large variety of cases, a factoring method was developed which is summarized in Table 8-18. Briefly, the approach is to start with the cost factor breakdown for integrated low Btu gasification plants listed in Table 8-9. The El Paso-Burnham plant cost of $393 million was the cost basis, and all cost factors were developed as a percentage of base-case cost to permit ratioing costs up with future escalation. The computer programs used to calculate capital costs required only one input change to generate all costs on a different cost basis.

The other common basic inputs to the calculations include coal flow, coal type, and booster power requirement. Knowing coal type and flow establishes coke, ash, and sulfur throughputs.

In the gasification plant, most items show some economy of scale in their costing.

The major exception is the cost of gasifiers and gas cooling and resaturation equipment. Since the gasifiers are fixed size modules, capacity is increased by adding more modules rather than making them larger. The major expense in the gas cooling and resaturation system consists of vessels trained on a one-for-one basis with each gasifier. Therefore, the gas cooling/resaturation system also is treated as a modular unit with no economy of scale—its cost being in direct proportion to the gasifier costs. All other units of the fuels plant will be treated as having economy of scale. Unless experience has shown otherwise, all elements having economy of scale are to be scaled to the 0.7 power of the applicable throughput parameter.

Now, referring to Table 8-18, it is seen that the three elements of the coal prep-gasifier-ash handling system must be considered separately for scaling purposes rather than as a unit in the earlier studies for the plants having a uniform output of 243.7 x 10^9 Btu/day. Again, the El Paso-Burnham plant was the starting point for calculations. The coal preparation system (coal handling and briquetting of fines) is scaled using the coal throughput as the scale factor and the ash handling system is scaled to ash throughput. Both scale to the 0.7 power. The gasifier capacity varies as the square root of pressure. It is also generally accepted that, at a given pressure, the factor governing gasifier capacity is the coke handling capacity of the

Table 8-18

LBtu FUELS PLANT COST ELEMENTS
SCALING PARAMETERS

Element	Scaling Parameter
Gasifiers/Coal Preparation/Ash	
Coal preparation	$(\text{Coal throughput})^{0.7}$
Gasifier	$(\text{Coke throughput})^{1.0} \div \sqrt{\text{Pressure}}$
Ash handling	$(\text{Ash throughput})^{0.7}$
Booster air compressor	$(\text{Booster MW})^{0.52}$
Gas cooling and saturation	$(\text{Coke throughput})^{1.0} \div \sqrt{\text{Pressure}}$
Gas cleaning and pollution Controls*	
Gas cleaning	$(\text{Gas flow})^{0.7} \times f(P)$
Sulfur removal	$(\text{Sulfur throughput})^{0.7}$
Plant Facilities and Offsites	$(\text{Coal throughput})^{0.7}$

*Assumes hot potassium carbonate/Claus cleanup for all coals.

gasifier grate. Therefore, the number of gasifiers will vary directly as the coke throughput and inversely with the square root of gasifier pressure. Unit cost per gasifier is assumed constant and will not vary with quantity.

Costs for the steam turbine driven booster compressor have been found to vary as the 0.52 power of the booster compressor driver power requirement. Since this power requirement has been specified in megawatts elsewhere in the program, this unit is used in the cost estimate. Unless indicated otherwise, the booster compressor is driven by a condensing steam turbine.

The gas cooling and resaturator costs, being proporational to the gasifier cost, are scaled in the same manner.

Costs of the cleanup system are broken down into the gas cleaning and sulfur plant components. The basic scale factor in the gas cleaning cost is volumetric flow of the gases—a function of heating value and gas density. Since the pressure vessel and piping costs will be sensitive to pressure, a multiplier because of pressure is also applied to this cost (ref. 11).

The sulfur removal system costs are assumed to vary as the 0.7 power of the sulfur processed.

The plant facility and offsite costs are assumed to simply vary as the 0.7 power of coal flow.

Capital Cost Results

Applying the rationale of the previous section to the air cooled open cycle gas turbine cases, the integrated fuels plant costs work out as shown in Table 8-19. All cost figures ratio back to the base case El Paso-Burnham plant. The capital costs shown here have not included contingency, interest during construction, or escalation from 1974. (On this basis, the base-case El Paso plant capital cost would be $320,000,000.) Cases 18 and 34 differ from the other cases in that the booster compressor drive turbine is the more expensive back-pressure type of steam turbine supplied by 1800 psig, 950 F steam with 325 psig back pressure. (Exhaust steam from the booster drive turbine supplies a portion of the gasifier steam requirements.) Cases 20 and 21 differ from the other cases in that the gas turbine uses a 20:1 pressure ratio compressor. The delivery pressure from the fuels plant (which uses a 351 psi gasifier) is insufficient to supply the gas turbine. As a result, a fuel gas compressor was added in the fuel line from the fuels plant to the gas turbine, resulting in some net cost increase. (The added cost of the fuel compressor was partially offset by a reduction in booster air compressor cost since the air pressure rise from the gas turbine compressor discharge to the gasifier was correspondingly less.)

The fuels plant capital costs associated with the water cooled open cycle gas turbine cases are listed in Table 8-20. Here, cases 12, 13, 14, 17, 27, and 28 use the higher cost back-pressure steam turbine drivers for the booster compressor. Case 11 has a high-pressure ratio gas turbine compressor requiring the fuel gas compressor between the fuels plant and the gas turbine.

The fuels plant capital costs associated with the pressurized furnace cases are listed in Table 8-21 and were derived in a manner identical to the conventional integrated plant of Figure 8-6.

The low-Btu fuel gas plant for the high-temperature fuel cell cases differs considerably from the plant of Figure 8-6 in that it is a free-standing low-Btu plant having its own air supply and steam supply for the gasifier, as shown in Figure 8-9. In addition, since gas is to be delivered to the fuel cell at only 5 psig, 80 F, it will have an expander turbine generator to reduce the output pressure and recover some power. To assure an 80 F delivery temperature of the fuel gas leaving the turbo-expander, a fuel gas heater upstream of the turbo expander was

Table 8-19

FUELS PLANT CAPITAL COSTS
AIR-COOLED OPEN CYCLE-GAS TURBINE CASES

Case	Gasifier Pressure (psi)	Coal	Coal Flow (lb/s)	Booster Power (MW)	Capital Cost** ($ MM)
1	263	Ill. #6	142.36	11.01	71
3	263	N. Dakota lignite	230.68	13.98	84
4	263	Montana	175.08	12.89	77
11	263	Ill. No. 6	71.18	5.51	41
12	263	Ill. No. 6	284.72	22.02	128
13	263	Ill. No. 6	120.96	9.37	62
14	263	Ill. No. 6	164.16	12.70	80
15	263	Ill. No. 6	186.28	14.41	89
16	351	Ill. No. 6	162.16	12.85	74
17	263	Ill. No. 6	196.96	27.62	95
18	263	Ill. No. 6	196.96	27.62*	96
19	351	Ill. No. 6	125.12	9.91	60
20	351	Ill. No. 6	171.88	17.97†	84
21	351	Ill. No. 6	141.16	16.23†	72
24	263	Ill. No. 6	142.36	11.01	71
25	263	Ill. No. 6	142.36	11.01	71
32	263	Ill. No. 6	168.7	13.05	82
34	263	Ill. No. 6	142.36	13.05*	73

* Back-pressure steam turbine driver for booster (reheat case)

† High-pressure case—uses fuel gas compressor

** Excludes contingency, interest during construction, and escalation from 1974.

included. The fuel gas requirements of the heater, of course, were subtracted from the plant output. Table 8-22 lists the resulting capital costs for the low-Btu fuels plant for the four fuel cell cases using that source of fuel.

Table 8-20

FUELS PLANT CAPITAL COSTS

WATER-COOLED OPEN-CYCLE GAS TURBINE CASES

Case	Gasifier Pressure	Coal	Coal Flow (lb/s)	Booster Power (MW)	Capital Cost** ($ MM)
1	351	Ill. No. 6	214.38	16.99	93
2	351	N. Dakota lignite	351.42	21.83	111
3	351	Montana	263.88	19.90	100
7	351	Ill. No. 6	142.92	11.33	67
8	351	Ill. No. 6	285.84	22.65	118
9	351	Ill. No. 6	248.04	19.66	105
10	263	Ill. No. 6	211.71	16.38	99
11	351	Ill. No. 6	203.37	9.69†	92
12	351	Ill. No. 6	214.38	16.99*	94
13	263	Ill. No. 6	249.18	19.28*	115
14	351	Ill. No. 6	202.80	16.07*	90
17	351	Ill. No. 6	214.38	16.99	93
27	351	Ill. No. 6	214.38	16.99*	95
28	351	Ill. No. 6	214.38	16.99*	95

* Back-pressure steam turbine driver used for booster (reheat case):

Case	Booster Turbine Inlet Press.	Exhaust Pressure
12	1450	410
13	1450	325
14	1450	410
27	1800	410
28	2400	410

† High-pressure case; uses fuel gas compressor.

** Excludes contingency, interest during construction, and escalation from 1974.

Table 8-21

LOW-BTU FUELS PLANT CAPITAL COSTS

PRESSURIZED FURNACE CASES

Case	Gasifier Pressure (psi)	Coal	Coal Flow (lb/s)	Booster (MW)	Capital Cost* ($ MM)
1	185	Ill. No. 6	47.57	2.37	32
2	185	Montana	59.37	2.82	34
3	185	N. Dakota lignite	76.15	2.96	37

* Excludes contingency, interest during construction, and escalation from 1974.

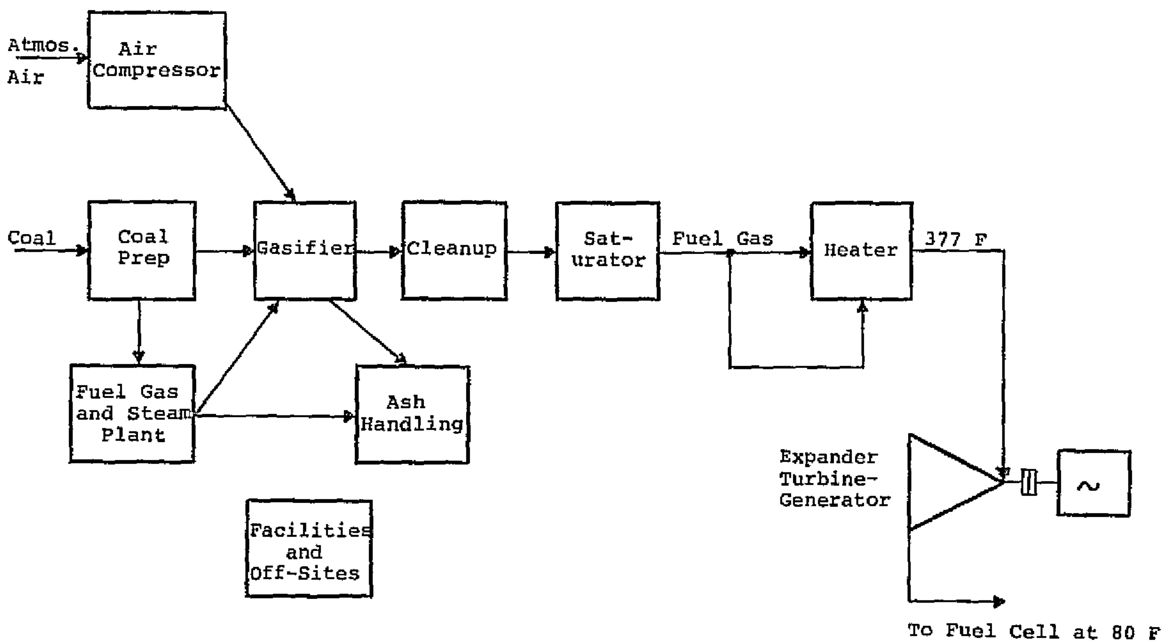


Figure 8-9. Free-Standing Low-Btu Fuel Gas Plant for Fuel Cell Applications

Table 8-22

LOW-BTU FUELS PLANT CAPITAL COSTS

FUEL CELL CASES

Case	Gasifier Pressure (psi)	Coal	Coal Flow (lb/s)	Air Compressor Power Input (MW)	Expander Power Output (MW)	Capital Cost* ($MM)
1	351	Illinois No. 6	310.30	106.51	80.8	202
2	351	Montana	343.84	112.33	80.8	204
3	351	Illinois No. 6	226.55	77.76	58.99	157
4	351	Illinois No. 6	260.13	89.29	67.73	175

* Excludes contingency, interest during construction, and escalation from 1974.

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Section 9

BALANCE OF PLANT

INTRODUCTION

This Section defines the systems and summarizes the pre-conceptual cost estimates for the balance-of-plant (BOP) requirements associated with advanced energy conversion systems utilizing coal or coal-derived fuels. The work described herein was preparatory to estimating the BOP capital costs associated with each energy conversion system and the effects resulting from those parametric variations of these systems that would significantly affect the BOP costs. Because of the short Task I time schedule, relative to the rather extensive scope, it was necessary to limit the effort devoted to each energy conversion system to a pre-conceptual level in order to accomplish the task. Therefore, plant definitions have been limited to informal sketches and supporting calculations that estimate required subsystem component capacities based on the architect-engineer's background.

Each of the advanced energy conversion systems treated in this study is divisible into general functional elements. The major components were assumed to be delivered to the site for installation and the capital costs of these items were not part of the BOP costs. The primary energy conversion systems consisted of a combustor or fuel processing system and an energy conversion system. Some form of these elements existed in each advanced energy plant concept studied. Estimating the costs for erection of the combustor and energy conversion systems at the plant site were BOP items, thus the responsibility of the architect-engineer.

To support the primary energy conversion systems, each plant had BOP systems to serve the following functions:

- Fuel—receiving, storage and recovery
- Oxidizer—ducting to the combustor
- Energy Delivery—voltage transformation and connection to switch yard
- Gaseous Wastes—stack gas cleanup and ducting
- Solid Wastes—collection for disposal
- Thermal Wastes—heat rejection cooling towers

Specifying and cost estimating through erection of all of these BOP systems were the responsibility of the architect-engineer.

BALANCE-OF-PLANT ITEMS

The BOP requirements for these advanced plant concepts in most respects are similar to those for today's conventional power plants. These requirements can be grouped into a few items that summarize the basic BOP responsibilities. These items are:

- Fuel Storage and Handling—involves the receiving, storage, and delivery to the combustion system of either the coal and its limestone additives, where required, or of the coal derived liquid or gaseous fuels.
- Equipment Installation—includes installation of the combustion and primary energy conversion equipment as well as erection of the entire plant facility.
- Thermal Cycle Heat Rejection—includes cooling towers, circulating water pumps, and piping.
- Plant Enclosure—includes buildings for plant administration, control, turbomachinery, and conventional boiler systems. (The geographic locations of the plants in this study are such that they require enclosure of most of the plant equipment.)
- Electric Energy Output Provisions—include bus bar, switchgear, transformers, and wire to conduct the generated electric energy to the plant high voltage switchyard.
- Plant Control—includes instruments, recorders, computers, and all other equipment necessary to monitor and control the power plant.
- Site Preparation—includes excavation, roads, fences, and landscaping.

The variety of energy conversion systems included in this study resulted in the need for definition and cost estimating of many plant support systems and subsystems. Some of the plant support systems are unique to a particular energy conversion cycle. However, the majority are common to two or more conversion cycles, except for capacity differences, and have been commonly defined and cost estimated with scaling factors applied to adjust for the capacity differences.

This approach is essential to accomplishing consistent treatment of the many subsystems with the multiple base cases and parametric variations. Identification of the plant systems and subsystems considered under the BOP responsibility follows.

Fuel Systems. An essential first step system for all of the plants is that for the receiving and processing of the fuel to be consumed by the plant energy conversion cycle. Fuels included in this study consist of coal or coal-derived fuels. The coals include Illinois No. 6, Montana Sub-bituminous and North Dakota Lignite. In this study, all coal was assumed to be delivered by unit trains to the plant. The plant coal handling system must unload the trains, move the coal to outside coal storage piles, reclaim the coal from storage as needed by the plant, and deliver the reclaimed coal to hoppers at the combustor feed system. Coal storage capacity of each plant is sixty days at rated energy output.

For plants using direct combustion of coal in fluidized beds, dolomite or limestone fuel additive for absorbing sulfur is mixed and injected with the coal. Thus a receiving, storage, and handling system similar to that for coal was provided for the additive material. This also requires provision for sixty days of storage capacity.

Liquid fuels derived from coal were specified for use in some of the cycles. Those plants using a liquid fuel incorporate a fuel handling system that receives oil from a pipeline, stores the fuel in insulated and heated tanks, and pumps the oil to the plant combustion system. The storage capacity requirement for oil is also sixty days.

Some of the plants were specified to use coal-derived gaseous fuels. For these plants no on-site storage capacity is required. The gaseous fuels are piped to the fence-line from a remote gasification plant for the intermediate-Btu and high-Btu gas fueled plants, thus requiring very little in-plant fuel piping. In general for the plants burning low-Btu gas, the gasification plant is considered integrated with the primary power plant. These integrated plants include coal handling and sixty-day storage facilities in their BOP.

Cooling Towers. The baseline cooling towers used throughout this study were mechanical draft evaporative towers. The rationale for use of these towers is covered in more detail later in this Section. Dry mechanical draft towers were included as at least one parametric variation in each base case. Specification, purchase, and erection of cooling towers were included in the BOP responsibilities as reported herein.

COSTING PROCEDURES

The primary objective of the cost estimate in Task I was to compare various systems on a consistent basis and therefore establish cycle-to-cycle comparability. The absolute costs represent a best effort commensurate with limited engineering definition accomplished within the limited schedule. Table 9-1 gives a summary comparison of the BOP costs for the energy comparison system base cases.

COST ESTIMATE BASIS

The cost estimates rely heavily on unit cost factors from recent power plant experience applied to the subsystems and components for each plant, as defined by informal engineering calculations, equipment lists and "sketches." The resulting estimates, though not accompanied by formal drawings and equipment lists, are founded on direct recent construction experience and sound estimating techniques.

The energy comparison systems under consideration involved vast differences in direct supporting experience. Some cases

Table 9-1

COMPARISON OF BASE CASE BOP COSTS*

SYSTEM NAME	1 OCGT	2 OCGT W/R	3 OCGT-OB	4 CC-AC	5 CC-WC	6 CCGT	7 SC-CO_2	8 ASC	9 PLMTC	10 CLMTC	11 OC-MHD-C	12 OC-MHD SRC	13 IG-MHD CF	14 IG MHD-C	15 LM-MHD	16 LTFC	17 HTFC
Estimated Construction Time-Years	1.5	1.5	2	3	4	4	5	5	6	6	7	7	6	7	6	2	6
Land Required - Acres	2.5	2.5	5	31	47	33	40	35	50	50	70	70	35	55	44	4	50
	BASE CASE CAPITAL COSTS : $1000																
INSTALLATION ONLY																	
1. Furnace						1,450	2,600	3,400	4,790	4,790			1,650	29,400	5,500		
2. Primary Generating Unit	90	90	90	360	450	800	1,600	1,900	800	800	26,400	26,400	4,200	8,400	7,150	20	1,570
3. Waste Heat Boiler			150	140	210				100	100	5,500	5,500	600	1,200	650		400
4. Bottoming Cycle Turbine Generator			20	70	100				2,320	2,320	1,900	1,900	900	1,800	1,000		990
SUPPLY AND INSTALLATION																	
5. Cooling Tower System			1,360	590	1,380	2,300	1,900	5,000	6,160	6,160	8,200	8,200	4,050	8,000	4,300		3,490
6. Other Mechanical Equipment	130	135	580	3,316	5,095	6,820	13,500	27,900	64,500	71,850	59,100	38,100	16,500	49,300	26,100	240	19,910
7. Electrical	650	650	1,170	4,316	6,319	2,080	7,100	8,700	15,360	15,670	34,000	32,100	12,500	26,500	19,800	300	17,580
8. Civil and Structural	100	100	676	3,872	5,744	3,500	17,000	23,700	29,000	30,200	49,400	41,100	17,900	42,000	45,500	640	18,440
9. Piping and Instrumentation	80	80	402	2,252	3,214	2,550	19,400	10,500	20,500	20,800	80,100	78,400	44,000	89,200	63,400	50	18,180
10. Miscellaneous and Yardwork	30	30	140	430	640	970	6,100	7,300	12,700	12,700	26,400	26,400	11,000	22,000	11,000	30	6,510
Direct Labor	265	290	3,[illegible]68	11,704	17,298	12,990	32,100	37,200	73,390	77,170	178,000	158,500	58,500	135,900	85,000	380	46,930
PARTIAL DIRECT FIELD COST	1,345	1,375	8,276	27,050	40,450	33,460	101,300	125,600	229,700	242,560	469,000	416,600	171,800	413,700	269,400	1,660	136,000
Distributable Field Cost	240	260	3,301	10,530	15,570	11,630	28,900	33,400	66,050	69,450	160,000	142,700	52,700	122,300	76,600	340	44,000
TOTAL FIELD COST	1,583	1,635	11,577	37,580	56,020	45,1[illegible]0	130,200	159,000	295,780	312,010	629,000	559,300	224,500	536,000	346,000	2,000	180,000
Engineering, Home Office & Fee	240	245	1,740	5,640	8,400	6,770	19,800	24,000	44,350	46,820	94,400	84,000	33,500	84,000	54,000	300	27,000
Contingency	365	375	2,663	8,640	12,880	10,3[illegible]0	30,000	37,000	68,000	71,770	144,600	126,700	52,000	120,000	80,000	460	41,000
PARTIAL CONSTRUCTION COST AT MID-1974 MATERIAL PRICES	2,190	2,255	15,980	51,860	77,300	62,3[illegible]0	180,000	220,000	408,100	430,6[illegible]	868,000	772,000	310,000	740,000	480,000	2,760	248,000
MWe	100	100	125	533	920	300	600	800	1,200	1,200	2,000	2,000	600	1,200	600	50	1,050
$/KW (BOP only)	22	23	128	97	84	208	300	275	340	359	434	386	517	617	800	55	236

*Data shown for each base case

Note:
- OCGT = open-cycle gas turbine
- OCGT W/R = open-cycle gas turbine with recuperator
- OCGT-OB = open-cycle gas turbine, organic bottoming
- CC-AC = combined cycle - air cooled
- CC-WC = combined cycle - water cooled
- CCGT = closed-cycle gas turbine
- SC-CO_2 = supercritical CO_2
- ASC = advanced steam cycle
- PLMTC = potassium liquid metal topping cycle
- CLMTC = cesium liquid metal topping cycle
- OC-MHD-C = open-cycle MHD with coal
- OC-MHD-SRC = open-cycle MHD with solvent refined coal
- IG-MHD CF = inert gas MHD with conventional furnace
- IG-MHD-C = inert gas MHD with coal
- LM-MHD = liquid metal MHD
- LTFC = low temperature fuel cell
- HTFC = high temperature fuel cell

were well within the state of the practice but others were at the limits of technology. In the absence of specific engineering resolution of problem elements into design drawings and specifications, the estimate is an extrapolation of cost experience on standard plants. The extent of this extrapolation is considerable in a number of cases.

The emphasis should therefore be placed on the relative values for the cycles rather than absolute value. In particular, the parametric variation estimates were extrapolations of a base case which had already been developed from extrapolated BOP experience.

Consistency

Although all the plants studied were technically advanced energy conversion systems, some, such as the simple cycle gas turbine and steam cycle, were relatively mature while others, such as MHD, are only in the experimental stage of development.

To maintain consistency in the results, more time was allocated to determining the costs of those plants on which comparatively little information is available (such as MHD) and less time devoted to the more standard cycles where the BOP component is relatively small.

To further ensure consistency, costs of a standard coal-fired steam plant were developed to obtain a base reference point for the four major BOP cost category accounts: civil/structural, mechanical, electrical, and piping/instrumentation. Major subsystems were also priced separately and utilized for all appropriate energy conversion systems.

Approach

In a definitive estimate, which is based on final engineering design, it is possible to derive an estimate by building up the cost piece by piece. In a conceptual estimate, not more than 60 percent of the equipment is likely to be defined. This means that a large portion of the cost is based on allowances or factoring. In a pre-conceptual estimate, such as this, where even less definition is available, another approach is necessary. The method used is to break down each of the advanced energy systems into its component subsystems, and to compare these subsystems with known references. In a liquid metal topping cycle for instance, the piping system for the liquid metal cycle was deemed to be similar to that of a steam plant in extent and complexity. However the materials for the liquid metal plant are more exotic, and the piping cost was therefore derived by taking a steam plant piping estimate and adjusting it by appropriate factors for liquid metal service, hence the necessity for developing standard reference costs such as a conventional steam plant. Where no analogous system exists, for example in MHD piping, an estimate was made on a "piece by piece" basis.

Pre-conceptual engineering flow diagrams, sketches, outline specifications and preliminary lists provide an estimate basis.

The estimate scope includes material and installation costs for all BOP mechanical and electrical equipment, piping, wiring, instrumentation, site preparation, and structures. Material costs of major plant components (e.g., furnaces, turbine/generators, MHD generators, waste heat boilers were estimated. Only installation costs for these major components are included in this estimate. Where on-site coal gasification plants have been specified, the entire gasification plant estimated cost, including material and installation costs, was specified as other than BOP costs. Switchyard costs beyond the transmission voltage transformer are excluded from the estimate scope.

In reviewing the results no detailed subsystem-by-subsystem comparison has been made for each cycle, but a check has been made for each cycle on the proportional relationship between the civil, mechanical, electrical, and piping categories. The architect-engineers' experience was utilized to ensure a consistent relationship between these categories for all energy conversion systems.

COMMON MAJOR SUBSYSTEMS

The common major subsystems for which estimated costs are developed are:

- Coal handling
- Liquid fuel system
- Bottoming cycles
- Furnaces and stacks
- Cooling towers
- High-temperature piping

Coal Handling

The basis of the estimate for the coal and dolomite handling systems was provided by graphic sketches which diagrammatically show the equipment required, such as silos, conveyors, crushers, and hoppers. The frame of reference to determine the estimated costs is a standard coal handling system for a conventional coal-fired power plant. Three plants were evaluated from historical records to arrive at the base dollars-per-ton-per-hour capacity reference point. To reflect the economies of scale in the cost of coal handling plants (as a function of capacity), an exponential curve was drawn through the reference point. The curve is shown in Figure 9-1.

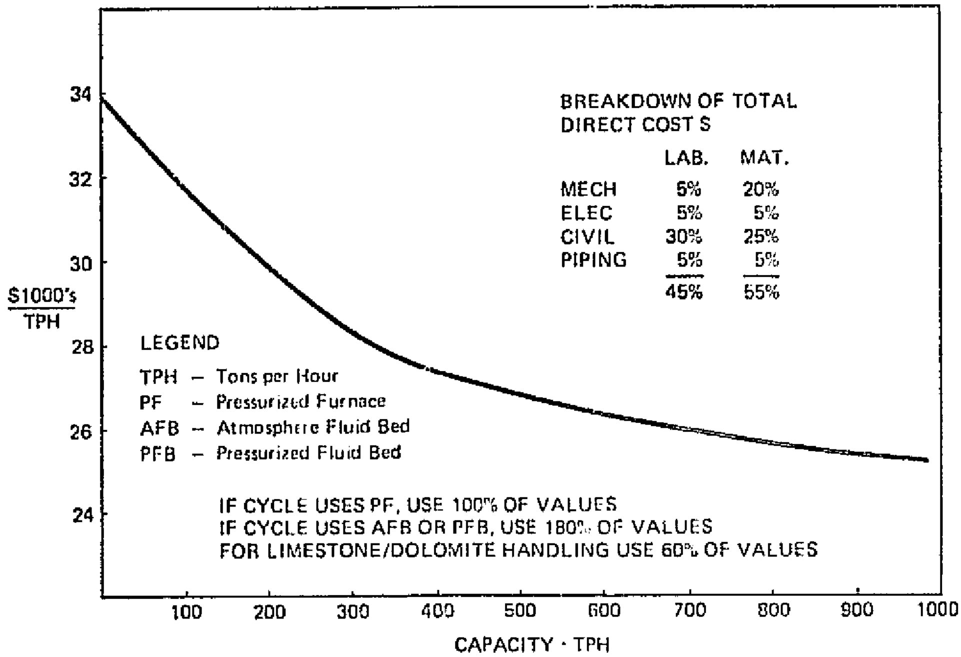


Figure 9-1. Coal Handling System Estimated Costs

It is estimated that the additional coal handling cost for atmospheric and pressurized fluidized bed furnaces will be equivalent to the cost of the equipment required to unload, break, sample, stack, and reclaim coal in conventional power plant coal handling which, in turn, is estimated to be 80 percent of the total coal handling cost. Where an integrated gasification plant is specified, only the coal handling to the plant is estimated in the BOP, and the cost is assessed to be the same as for a conventional coal plant. The dolomite/limestone handling system is assumed to be similar to the coal handling system, but its cost will vary as a function of volume handled rather than weight. Therefore for a given tons-per-hour capacity, the additive handling is estimated to be approximately half that of coal, since dolomite and limestone are approximately twice the density of coal.

The total estimated cost of a coal and additive handling system is not presented separately, but subdivided into materials and labor and accounted for in the four categories comprising it; mechanical, electrical, civil structural, and piping/instrumentation.

Liquid Fuel System

The bulk of the cost of a liquid fuel handling system is associated with the provision of a sixty-day storage capacity, the cost of which is linear for the ranges considered. The figure used is $157/bbl/day capacity, broken down into 85 percent materials and 15 percent labor in the mechanical category.

Bottoming Cycles

A steam bottoming cycle is considered to be analogous to a gas-fired steam power plant except that the boiler is replaced by a heat recovery steam generator (HRSG). Since the cost of a gas-fired power plant and its composition is significantly different from that of a coal-fired plant, the standard coal plant base is not used. Instead, historical costs for a high-pressure and an intermediate-pressure gas-fired power plant are used to derive a family of estimated costs for different megawatt ratings. These are shown in Tables 9-2 and 9-3.

Furnaces and Stacks

The bases for the furnace system cost estimates are typical furnace drawings and diagrammatic sketches of the supporting systems.

Specifications for stacks are not established; so estimated costs, based on those of a typical plant and shown in Figure 9-2, are assumed.

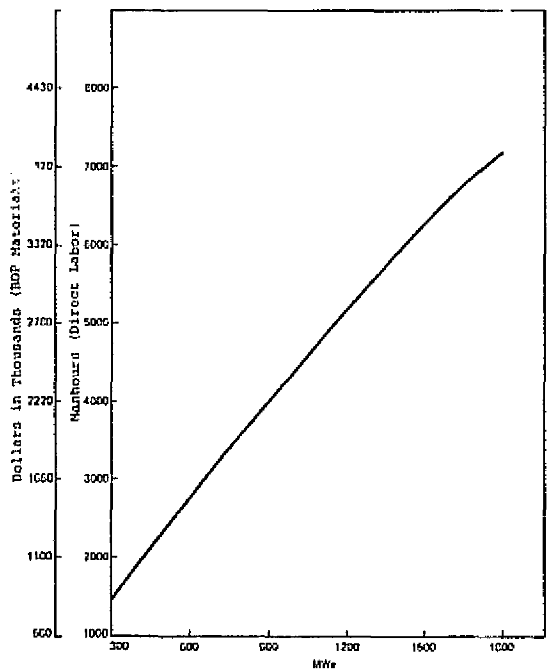


Figure 9-2. Exhaust Stack Costs

Although in most cases the estimated procurement costs of electrostatic precipitators and other emission control equipment were supplied as major components, the erection is estimated by the architect-engineer (AE). With the addition of peripheral equipment and materials, these estimated costs are substantial. (See Table 9-4.)

Table 9-2

BOP COST ESTIMATE FOR STEAM BOTTOMING CYCLES
(High Pressure: 3500 psig, 1000 F)

	100 MW		250 MW		500 MW		750 MW		900 MW	
	MH* 1000	$** 1000	MH 1000	$ 1000	MH 1000	$ 1000	MH 1000	$ 1000	MH 1000	$ 1000
Boiler installation	20	20	30	40	50	60	70	80	86	100
Turbine installation	30	30	60	60	100	100	130	130	160	160
Mechanical	40	2860	70	5430	120	8830	160	11720	205	14380
Electrical	80	2100	150	3980	250	6470	320	8590	400	10560
Civil/structural	170	1030	320	1960	510	3180	680	4240	820	5200
Piping & instruments	170	2790	330	5300	540	8610	710	11430	875	14040

*Direct man hours
**BOP materials

Table 9-3

BOP COST ESTIMATE FOR STEAM BOTTOMING CYCLES
(Low Pressure: 1500 psig, 1000 F)

	25 MW		75 MW		150 MW		300 MW		500 MW	
	MH* 1000	$** 1000	MH 1000	$ 1000	MH 1000	$ 1000	MH 1000	$ 1000	MH 1000	$ 1000
Boiler installation	30	50	50	100	90	150	140	250	200	360
Turbine installation	20	20	40	50	70	80	120	120	160	170
Mechanical	10	450	20	960	30	1560	50	2530	80	3610
Electrical	40	520	90	1130	140	1850	230	3000	330	4300
Civil/structural	60	570	120	1230	200	1990	330	3250	480	4640
Piping & instruments	30	460	90	990	140	1630	220	2640	310	3780
Yardwork & misc.	10	110	20	240	40	380	60	620	80	890
For reheat add to piping		50		100		170		280		390
Low-Btu gas add to piping		0		10		10		20		30
Water treatment add to mech.		60		120		200		320		460

*Direct labor man hours
**BOP materials

Table 9-4

GAS CLEANUP SYSTEM INSTALLATION COSTS

Category	Electrostatic Precipatator ($/kW)		SO_2 Absorber ($/kW)	
	Labor	Material	Labor	Material
Furnace	4.00	GE*	4.30	GE*
Mechanical	0.90	11.80	1.10	0.80
Electrical	0.25	0.45	0.25	0.55
Civil	0.60	1.80	0.75	2.15
Piping	0.35	0.35	0.40	0.40

*Equipment cost supplied except for conventional furnace case and inert gas MHD parallel cycle.

Cooling Towers

An evaluation of cooling towers showed that hyperbolic, natural draft, cooling towers have no cost advantage over mechanical draft cooling towers. Thus, for purposes of consistency, all wet cooling towers are assumed to be the mechanical forced draft type.

Vendor data indicate that heat rejection costs are a linear function of heat rejection rates, so it has been assumed that all the costs of wet mechanical draft towers follow this principle. The unit rates used come from informal quotes corroborated by the AE experience. The costs developed include the cooling tower basins and associated structures.

High-Temperature Piping

All of the piping estimated is considered to be commercially available, but the temperatures and sizes involved make the applications rather exotic, and the sheer magnitude of the costs involved necessitated a separate study. Table 9-5 shows the resulting selection chart.

Although some estimated costs are extremely high (material only costs of $17,000/linear ft for a refractory lined 25 ft (7.62 m) diameter duct operating at 3200 F (2033 K), no optimization of layouts was possible in Task I.

MAJOR VARIATIONS AFFECTING BALANCE OF PLANT

Fuel Changes

The substitution of other fuels for the Illinois No. 6 coal used in the base cases affects the coal handling and also the furnace costs.

Table 9-5

HIGH-TEMPERATURE PIPING

Temperature Range	Material
To 850 F	Carbon steel A106
850 F to 1000 F	Chrome Molybdenum
1000 F to 1200 F	Stainless steel 316
1200 F to 1500 F	Incoloy 800
Over 1500 F	Refractory lined pipe

Coals. The quantities of coal and limestone/dolomite consumed as a multiple of the quantity used for the atmospheric fluidized bed are shown in Table 9-6. The limestone/dolomite required is a function of the coal's sulfur content, except in the case of the pressurized furnace where a gasification plant is required and the sulfur removal is an integral part of the gasification process.

Liquids. In parametric variations where coal liquids are employed, the fuel supply is treated as an over-the-fence item. The only provision in the estimate is for a sixty-day capacity storage vessel and piping to the furnace.

Gases. In cases where gas fuel is used, the gas is treated as an over-the-fence item supplied by others. Provision is made in the cost estimate for a steam turbine compressor drive installation if pressurization is required. In free-standing low-Btu gasification, the supply of coal to a hopper at the gasification plant is provided.

Table 9-6

FUEL CONSUMPTION AS A FUNCTION OF BASE CASE

	AFB		PFB		PF	
Coal Type	Coal	Limestone	Coal	Dolomite	Coal	Limestone
Illinois No. 6	1	1	1.36	2.42	2.4	N/A
Montana Sub-bituminous	1.22	0.25	1.70	0.13	2.88	N/A
North Dakota Lignite	1.65	0.29	2.42	0.14	3.76	N/A

Note: AFB = atmospheric fluidized bed
PFB = pressurized fluidized bed
PF = pressurized furnace

Furnace Changes

The base case furnace, except where gas or liquid fuel is provided, is an atmospheric fluidized bed furnace. In the parametric variations a conventional furnace, pressurized fluidized bed furnaces (PFB), and pressurized furnaces (PF) are considered.

Atmospheric Fluidized Bed Furnace. The estimated installation cost per module is determined on the basis of drawings of the furnace, estimated weights, and guidelines from the supplier of the furnace estimate. Also included is the estimated erection cost of spent stone cooling and handling equipment. The number of modules required is not affected by the coal type.

Pressurized Fluidized Bed Furnace. The module installation estimated costs are determined in the same way as for the atmospheric fluidized bed furnace.

In addition to the spent stone handling, the estimated costs of installing hot gas treatment and fines removal equipment and a pressurizing gas turbine with or without a regenerator are included. The number of modules required is dependent on the coal type, about 13 percent more being required for low heating value coals.

Pressurized Furnace. The estimated erection cost includes the furnace and gas turbogenerator installation costs as determined for the PFB furnace. In addition, a steam bottoming cycle is included as is the installation of a steam turbine for the gasifier air compressor. The number of furnace modules required increases by approximately 30 percent for the low heating value Btu coals. The pressurized furnaces operating on over-the-fence gas fuel involved only the erection of the furnace module and the pressurizing gas turbine.

Conventional Furnace. The estimated erection cost includes the supply and erection of all equipment except the furnace. This includes an electrostatic precipitator and stack gas clean-up system where required.

Bottoming Cycles

Steam Bottoming Cycles. Steam bottoming cycle estimated costs are shown in Table 9-2 and Table 9-3. Appropriate adjustments were included for reheat and treated water.

Organic Bottoming Cycles. Organic bottoming cycles are assumed to be functionally similar to steam bottoming cycles, but the estimated costs should be adjusted as specified in Table 9-7. The underlying assumptions are that an organic fluid has poor heat transfer coefficients (necessitating greater heat exchanger surfaces) but a higher specific volume, which in conjunction with other factors resulted in the piping materials being reduced, but the weight, and hence installation of the turbine, were assumed unchanged.

Table 9-7

ORGANIC BOTTOMING CYCLE COST ESTIMATING
FACTORS APPLIED TO STEAM BOTTOMING CYCLES

Major Category	Adjustment
Waste heat boiler	Multiply installation by 3
Bottoming cycle turbogenerator	Installation—unchanged
Other mechanical equipment	Unchanged
Electrical	Unchanged
Civil/structural	Increase by $500/MWe
Piping/instrumentation	Installation—unchanged Materials—reduce to 70% of steam values

Cooling Towers

The method of estimating wet cooling towers is described earlier in this section. Parametric variations include dry cooling towers which are sized to achieve 3.45 in. (87.6 mm) of mercury and 1.9 in. (48.3 mm of mercury condenser absolute pressures.

The estimated costs of the dry cooling towers for the less severe duty (3.45 in. [87.6 mm]) were determined to be 2.7 times greater than an equivalent duty wet cooling tower, and 4 times greater for the more stringent requirements (1.9 in. [48.3 mm]).

INDIRECT CHARGES AND CONTINGENCY

The estimated costs consist of material costs and labor costs priced at $10.60 per manhour, an average craft rate which includes associated payroll costs and foreman supervision. The indirect charges and contingency which must be added to the direct costs to arrive at a total estimated construction cost are a function of the direct costs, and are described below.

Indirect Costs

Indirect or distributable costs are largely a function of direct manhours, and for this study are taken as 90 percent of estimated direct labor costs. The main categories and their rough respective percentage of the distributable costs are:

- Temporary construction facilities (15%)
- Miscellaneous construction services (cleanup, guards, welders' tents, etc.) (18%)

- Construction equipment and supplies (19%)
- Field office costs (42%)
  (supervision, engineering, administration, warehousing, field purchasing, medical, and overhead)
- Other (6%)

Engineering, Home Office and Fee

The estimated engineering manhours required to produce preliminary and final designs for a project are usually calculated on a manhours-per-working-drawing or some other tangible basis. Home office costs, which comprise engineering services, procurement, startup, quality assurance, and project management, are about 50 percent to 60 percent of the engineering cost. Fee is normally a function of the total project cost, and there are commonly accepted guidelines on acceptable schedules. The sum of these three categories falls into historically consistent percentages, and for this study a figure of 15 percent of total field costs was used.

Contingency

Contingency is the amount of money, manhours, and time which must be added to an estimate to provide for uncertainties within the detail—in quantity, pricing, and productivity. Contingency minimizes the risk of these uncertainties. The magnitude of the contingency is directly related to the probability of the occurrence of these uncertainties and reflects a selected risk of overrun.

Contingency is applied to the estimates to reflect a level of confidence. Generally, a contingency should be selected to yield the most probable total project cost and schedule. The contingency selected is expected to be used. Contingency is not a separate allowance fund to be used as a drawdown account to compensate for overruns as they are encountered.

The cost estimates do not cover all of the eventualities which may occur during the design and construction phases of a project. Rather they provide the best judgment of cost and schedule if the defined scope is maintained and assumed events occur. Contingency does not provide for changes in the defined scope of a project, or for unforeseeable circumstances beyond normal experience or control.

Design Allowance

The probability of error in the cost estimate is greater for the more advanced systems than for the simple ones. The potential error lies more within the design than in the cost estimate of a plant. The contingency has therefore not been increased, but a design allowance has been added to the BOP costs. For example in the case of the MHD plants and the high-temperature fuel cells, there is a 10 percent allowance added to all BOP costs.

ENERGY CONVERSION SYSTEM EVALUATIONS

This subsection contains a description of the energy conversion system and an itemization of the elements which were included in the BOP capital cost estimate. A cost estimate summary is also provided for each of the base cases. The BOP plant requirements and cost estimates for the other parametric point variations are given in Appendix B.

Open-Cycle Gas Turbine

The open-cycle gas turbine plants involve the least complex BOP systems of all plant concepts considered in this study. This results from the gas turbines being assembled at a factory into modules that can be readily installed at the plant site. These modules generally include even the weather protective enclosure for the turbine and its generator. Thus the BOP for the gas turbines involves only installation onto simple foundation pads, connection of air and gas ducting, interconnection of fuel supply and control modules, provision for power connection to the distribution grid, and plant buildings to function as central control and maintenance facilities for those plants with multiple gas turbine units.

Definitions of the base case cycles and the parametric variations from the base cases are listed in Volume II. Three base cases are identified. The first base case (Case 1) is a single turbine unit, simple cycle, of 100 MWe nominal output. The second base case (Case 6) involves the addition of a recuperator to the Case 1 turbine for improvement of cycle efficiency. The third base case (Case 30) incorporates an organic fluid closed-cycle turbine system as a bottoming cycle to the recuperated gas turbine.

The BOP elements required for these gas turbine base cases are summarized in Table 9-8. This table outlines the elements considered in estimating the BOP costs associated with each base case. Each of the three base cases uses the same gas turbine. Therefore the site preparation, equipment installation, ducting, electrical, cooling hydrogen, and combustor injection water requirements associated with the gas turbine are comparable for the three cases. Adding a recuperator increases slightly the cost of equipment installation but imposes no significant BOP cost penalties on the gas turbine plant.

Adding the organic fluid bottoming cycle does increase the complexity of the BOP. An additional turbine and generator, along with a heat recovery steam generator (HRSG) and a condenser, increase the equipment installation effort. Another piping system for the closed organic fluid loop is required. Additional electrical work is needed for the second generator. Dry cooling

Table 9-8

BOP ELEMENTS FOR OPEN-CYCLE GAS TURBINE

Element	Comments	Base Case Identification		
		No. 1*	No. 6*	No. 30*
Site preparation	conventional gas turbine installations, modular components	X	X	X
Equipment installation		X	X	X
Piping		X	X	X
Electrical		X	X	X
Hydrogen	generator cooling	X	X	X
Water	combustor injection	X	X	X
Recuperator installation	conventional		X	X
Organic cycle	equipment installation			X
Dry cooling tower	4 cells, 830 kWe demand			X
Cooling water	piping and pump, 170 kWe demand			X

Note: 100 MWe nominal output per unit with HBtu gas fuel

* An X indicates applicable elements.

towers and the closed-loop cooling water system interconnecting the towers with the organic condenser are also additional BOP requirements imposed by the bottoming cycle.

The estimated BOP costs of the three open-cycle gas turbine base cases are summarized in Tables 9-9 through 9-11. Table 9-9 is data for the open-cycle gas turbine. Table 9-10 is for the recuperated open-cycle gas turbine. Table 9-11 is for the recuperated open-cycle gas turbine with exhaust heat rejection to an organic bottoming cycle.

Open-Cycle Gas Turbine—Combined Cycle

By adding an HRSG to recover the exhaust heat from a gas turbine and using the steam to drive a turbine/generator, additional electric energy can be produced. Two such combined cycle

Table 9-9

OPEN-CYCLE GAS TURBINE, CASE 1

COST ESTIMATE SUMMARY: BASE CASE BOP CAPITAL COSTS

	Direct Manual Field Labor (MH 1000's)	Direct Materials ($1000's)	Total Cost ($1000's)
INSTALLATION ONLY			
1. Furnace	NA	NA	
2. Primary Generating Unit*	15.0	90	
3. Heat Recovery Steam Generator	NA	NA	
4. Bottoming Cycle Turbine/Generator	NA	NA	
SUPPLY & INSTALLATION			
5. COOLING TOWER SYSTEM	NA	NA	
6. OTHER MECHANICAL EQUIPMENT	1.2	130	
7. ELECTRICAL	7.5	650	
8. CIVIL AND STRUCTURAL	0.5	100	
9. PIPING AND INSTRUMENTATION	0.7	80	
10. MISCELLANEOUS AND YARDWORK	0.1	30	
		1,080	1,080
Direct Labor	25.0	@$10.60	265
Direct Field Cost			1,345
Distributable Field Cost @ 90% of direct labor			240
Field Cost			1,585
Engineering, Home Office and Fee		@15%	240
			1,825
Contingency		@20%	365
ESTIMATED BALANCE-OF-PLANT CONSTRUCTION COSTS:			2,190
MID-1974 DOLLARS (1000's)			

*Turbine/Generator, MHD Generator, or Fuel Cells

Table 9-10

OPEN-CYCLE GAS TURBINE, CASE 6

COST ESTIMATE SUMMARY: BASE CASE BOP CAPITAL COSTS

	Direct Manual Field Labor (MH 1000's)	Direct Materials ($1000's)	Total Cost ($1000's)
INSTALLATION ONLY			
1. Furnace	NA	NA	
2. Primary Generating Unit*	15.0	90	
3. Heat Recovery Steam Generator	NA	NA	
4. Bottoming Cycle Turbine/Generator	NA	NA	
SUPPLY & INSTALLATION			
5. COOLING TOWER SYSTEM	NA	NA	
6. OTHER MECHANICAL EQUIPMENT	2.7	135	
7. ELECTRICAL	7.5	650	
8. CIVIL AND STRUCTURAL	1.0	100	
9. PIPING AND INSTRUMENTATION	0.7	80	
10. MISCELLANEOUS AND YARDWORK	0.2	30	
		1,085	1,085
Direct Labor	27.1	@$10.60	290
Direct Field Cost			1,375
Distributable Field Cost @ 90% of direct labor			260
Field Cost			1,635
Engineering, Home Office and Fee		@15%	245
			1,880
Contingency		@20%	375
ESTIMATED BALANCE-OF-PLANT CONSTRUCTION COSTS:			2,255
MID-1974 DOLLARS (1000's)			

* Turbine/Generator, MHD Generator, or Fuel Cells

Table 9-11

OPEN-CYCLE GAS TURBINE, CASE 30

COST ESTIMATE SUMMARY: BASE CASE BOP CAPITAL COSTS

	Direct Manual Field Labor (MH 1000's)	Direct Materials ($1000's)	Total Cost ($1000's)
INSTALLATION ONLY			
1. Furnace	NA	NA	
2. Primary Generating Unit *	15	90	
3. Heat Recovery Steam Generator	90	150	
4. Bottoming Cycle Turbine/Generator	20	20	
SUPPLY & INSTALLATION			
5. COOLING TOWER SYSTEM	60	1,380	
6. OTHER MECHANICAL EQUIPMENT	10	580	
7. ELECTRICAL	49	1,170	
8. CIVIL AND STRUCTURAL	61	676	
9. PIPING AND INSTRUMENTATION	31	402	
10. MISCELLANEOUS AND YARDWORK	10	140	
		4,608	4,608
Direct Labor	346	@$10.60	3,668
Direct Field Cost			8,276
Distributable Field Cost @ 90% of direct labor			3,301
Field Cost			11,577
Engineering, Home Office and Fee		@15%	1,740
			13,317
Contingency		@20%	2,663
ESTIMATED BALANCE-OF-PLANT CONSTRUCTION COSTS:			15,980
MID-1974 DOLLARS (1000's)			

* Turbine/Generator, MHD Generator, or Fuel Cells

base cases are included in this study. One utilizes air-cooled gas turbines operating at 2200 F (1478 K) base case turbine inlet temperature, whereas the second involves water-cooled gas turbine operating at 2800 F (1811 K) base case turbine inlet temperature.

Air-Cooled Gas Turbine

The base case plant employed four gas turbine modules of 100 MWe nominal output. Each turbine module included a weather protective enclosure and was installed on an outdoor concrete pad. An HRSG was connected to each of the four turbines. This arrangement provided four separate and parallel turbine gas flow paths, which permitted independent operation of each turbine. The steam generated by the heat recovery boilers was collected in a common steam manifold pipe that supplied a single steam turbine/generator of about 130 MWe nominal output. Condenser cooling water was provided by a five-cell mechanical draft wet cooling tower installation. Land area required for this plant equipment is approximately 31 acres, not including area for the coal gasification plant supplying low-Btu fuel for the gas turbines.

The BOP elements required for this plant are summarized in Table 9-12. This table outlines the elements considered in estimating the BOP costs for this combined cycle plant. No unusual or particularly high cost BOP elements are required in this plant. Equipment and subsystems are conventional. Equipment supplied by others, but installed as BOP, includes the gas turbines, heat recovery steam generators, exhaust gas bypass system, and steam turbine. The remainder of BOP equipment was assumed to be procured and erected by the AE. This includes: 1) the condenser and pumps sized to provide 1.5 in. Hga (38.1×10^{-3} m) back pressure for the steam turbine; 2) a condensate return system, including one regenerative feedwater heater and one deaerator; 3) a five cell mechanical draft cooling tower with necessary water pumps and piping installed to provide cooling water to the condenser; and 4) coal receiving, storage, and recovery equipment installed to provide the fuel required by the integrated gasification system. This system provides for 60 days of coal storage and off-loading from unit trains. To provide electric power to the distribution grid at 500 kV, transformers and bus bar connecting from the generators to the transformers are included in the cost estimate. Buildings included for this plant are a steam turbine hall and a single story building to serve for plant control and service.

The estimated BOP costs for this combined cycle plant base case are summarized in Table 9-13.

Water-Cooled Gas Turbine

The base case plant with water-cooled gas turbines was very similar to the plant using air-cooled gas turbines. The primary difference was that water cooling permitted a higher operating temperature in the gas turbine, which in turn provided a higher

Table 9-12

BOP ELEMENTS FOR OPEN-CYCLE GAS TURBINE COMBINED CYCLE
AIR COOLED

Elements	Comments
Site preparation	
Equipment installation	Conventional gas turbine components
• HRSG and ducting	erection of boiler and gas ducting
• Steam turbine installation	1 HP + 1 LP turbine, no reheat, ≈ 130 MWe
Condenser and pumps	1.5 in. Hga
Feedwater heaters	1 reheater and 1 deaerator
Coal handling equipment	receiving, storage and recovery for LBtu plant
Wet cooling tower	mechanical draft, 5 cells, 900 kWe demand
Transformers and bus	69/500 kV
Buildings	1 steam turbine and 1 plant control

Note: 400 MWe nominal output gas turbine output from four 2200 F units using LBtu gas fuel. 130 MWe nominal output steam bottoming cycle, 1250 psi and 950 F, 1.5 in. Hga condenser.

temperature exhaust gas for a more efficient steam cycle. The net effect was to increase the output and efficiency of both the gas and steam turbines. Thus this plant used three gas turbine modules of 230 MWe nominal output each. Steam was gathered from three HRSGs, one installed on each of the three gas turbines, to supply a single steam turbine/generator of 230 MWe nominal output. This plant had a greater cooling load, requiring seven cells in the mechanical draft evaporative cooling tower installation. Land area required for this plant is approximately 47 acres, not including area for the coal gasification plant.

The BOP elements required for this plant are summarized in Table 9-14, which outlines the elements considered in estimating the BOP costs. These elements are similar to those for the air-cooled gas turbine plant, with some increase in BOB subsystem capacities to accommodate the increase in plant energy output.

Table 9-13

OPEN-CYCLE GAS TURBINE, COMBINED CYCLE
AIR COOLED
COST ESTIMATE SUMMARY: BASE CASE BOP CAPITAL COSTS

		Direct Manual Field Labor (MH 1000's)	Direct Materials ($1000's)	Total Cost ($1000's)
INSTALLATION ONLY				
1.	Furnace	NA	NA	
2.	Primary Generating Unit*	60	360	
3.	Heat Recovery Steam Generator	80	140	
4.	Bottoming Cycle Turbine/Generator	64	70	
SUPPLY & INSTALLATION				
5.	COOLING TOWER SYSTEM	56	590	
6.	OTHER MECHANICAL EQUIPMENT	62.1	3,316	
7.	ELECTRICAL	192.6	4,316	
8.	CIVIL AND STRUCTURAL	387	3,872	
9.	PIPING AND INSTRUMENTATION	164.6	2,252	
10.	MISCELLANEOUS AND YARDWORK	37.5	430	
			15,346	15,346
	Direct Labor	1103.8	@$10.60	11,704
	Direct Field Cost			27,050
	Distributable Field Cost @ 90% of direct labor			10,530
	Field Cost			37,580
	Engineering, Home Office and Fee		@15%	5,640
				43,220
	Contingency		@20%	8,640
	ESTIMATED BALANCE-OF-PLANT CONSTRUCTION COSTS:			51,860

MID-1974 DOLLARS (1000's)

*Turbine/Generator, MHD Generator, or Fuel Cells

Table 9-14

BOP ELEMENTS FOR OPEN-CYCLE GAS TURBINE COMBINED CYCLE
WATER COOLED

Elements	Comments
Site preparation	
Equipment installation	Water-cooled gas turbine components
• HRSG and ducting	erection of boiler and gas ducting
• Steam turbine installation	1 HP + 2 LP turbines, no reheat, 230 MWe
Condenser and pumps	1.5 in. Hga
Feedwater heaters	1 reheater and 1 deaerator
Coal handling equipment	receiving, storage and recovery for LBtu plant
Wet cooling tower	mechanical draft, 7 cells, 1230 kWe demand
Transformers and bus	69/500 kV
Buildings	1 steam turbine and 1 plant control

Note: 690 MWe nominal output gas turbine from three 2800 F units using LBtu gas fuel. 230 MWe nominal output steam bottoming cycle, 1450 psi and 1000 F, 1.5 in. Hga condenser.

The one additional subsystem requirement is for a demineralized water supply to provide cooling water to the gas turbines. The estimated BOP costs for this combined cycle plant base case are summarized in Table 9-15.

CLOSED-CYCLE GAS TURBINE

The closed-cycle gas turbine plant uses a single 300 MWe nominal output gas turbine with helium as the working fluid. Input energy is from the burning of coal in two atmospheric fluidized bed (AFB) combustors with heat transfer tubes in and above the beds. Helium is heated to 1500 F (1089 K) turbine inlet temperature. Since this is a closed cycle, additional heat exchangers are used to improve efficiency and reject heat. Regenerative heat exchange from the turbine exit gas to the colder compressor outlet gas is incorporated to reduce the heat rejected.

Table 9-15

OPEN-CYCLE GAS TURBINE COMBINED CYCLE
WATER COOLED
COST ESTIMATE SUMMARY: BASE CASE BOP CAPITAL COSTS

	Direct Manual Field Labor (MH 1000's)	Direct Materials ($1000's)	Total Cost ($1000's)
INSTALLATION ONLY			
1. Furnace	NA	NA	
2. Primary Generating Unit*	81	450	
3. Heat Recovery Steam Generator	116	210	
4. Bottoming Cycle Turbine/Generator	100	100	
SUPPLY & INSTALLATION			
5. COOLING TOWER SYSTEM	96	1,380	
6. OTHER MECHANICAL EQUIPMENT	92.5	5,095	
7. ELECTRICAL	284	6,319	
8. CIVIL AND STRUCTURAL	576	5,744	
9. PIPING AND INSTRUMENTATION	236	3,214	
10. MISCELLANEOUS AND YARDWORK	50.5	640	
		23,152	23,152
Direct Labor	1,632	@$10.60	17,298
Direct Field Cost			40,450
Distributable Field Cost @ 90% of direct labor			15,570
Field Cost			56,020
Engineering, Home Office and Fee		@15%	8,400
			64,420
Contingency		@20%	12,880
ESTIMATED BALANCE-OF-PLANT CONSTRUCTION COSTS:			77,300
MID-1974 DOLLARS (1000's)			

*Turbine/Generator, MHD Generator, or Fuel Cells

The low-pressure gas is then further cooled by heat exchange with the cooling water (in a precooler) prior to its return to the compressor inlet. About 33 acres of land area are required to accommodate the equipment involved in this plant.

The BOP elements required for this plant are summarized in Table 9-16. This outlines the elements considered in estimating the BOP costs for this closed-cycle plant. This plant, with coal and limestone handling equipment, two fluid bed combustors, heat exchangers, and closed-cycle piping, involves a significant amount of field erection work. The BOP costs for this system were rather low because of the common nature of the subsystems and components involved.

The one element involved in this plant that extends beyond conventional or standard practice, thus contributing a higher than normal cost factor, is the high-temperature piping needed to duct 1500 F (1089 K) helium from the furnaces to the turbine. This piping is 50-in. (1.27 m) inside diameter, internally lined with Incoloy 800 backed with refractory insulation. It is estimated that 200 ft (61 m) of this piping is required at an approximate cost of $3800 per foot installed.

The estimated BOP costs for the closed-cycle helium gas turbine plant base case are summarized in Table 9-17.

Supercritical CO_2

The supercritical CO_2 plant cycle equipment is complicated and relatively expensive to install because of the combination of high pressures and temperatures and the use of multiple components. Three AFB furnaces are used to provide 1350 F (1005 K), 3800 psia (26,200 kN/m^2) CO_2 to drive two turbines in series. The first expansion turbine drives a CO_2 compressor and pump. The second expansion turbine drives the 600 MWe generator. The hot, expanded CO_2 then flows through two series sets of recuperative heat exchangers. The first set consists of high-temperature multiple heat exchange units with multiple tube-in-shell heat exchangers in series per each unit and multiple parallel units. The second set consists of the low-temperature recuperator and employs multiple parallel tube-in-shell heat exchangers. Another heat exchanger set is also installed for heat rejection to the cooling water. All of these fluid cycle components are interconnected with piping to complete the closed circuit. The complexity and quantities of piping at high-pressure and temperature contribute significantly to the plant costs. Land area required for the fluid cycle components plus the coal and limestone receiving and handling equipment are about 40 acres.

The BOP elements required for this plant are summarized in Table 9-18. This outlines the elements considered in estimating the BOP costs for this closed cycle plant. As stated above, the special piping in this plant is a major cost factor. To illus-

Table 9-16

BOP ELEMENTS FOR CLOSED-CYCLE GAS TURBINE

Elements	Comments
Site preparation	
Equipment installation	helium cycle components
• Turbine and generator	300 MWe, 1500 F inlet temperature
• Regenerators	shell: 1000 psia, 875 F, 993 lb/sec helium
• Precoolers	1031 lb/sec, 390 psia helium
Coal handling equipment	147 tons/hr, 212,000 tons storage
Limestone handling equipment	37 tons/hr, 53,200 tons storage
AFB installation	2 units, 12 ft dia x 200 ft high, plus peripherals
Stack	27 ft ID x 800 ft high
Wet cooling towers	mechanical draft, 12 cells, 2100 kWe demand
Transformer and bus	13.8/500 kV
Buildings	1 turbine and 1 plant control
Special piping	50 in. ID refractory lined, 1500 F, 960 psia

Note: 300 MWe nominal output from single helium turbine using coal fuel atmospheric fluidized bed combustors.

trate this, a brief list of the more costly CO_2 piping runs is presented below.

- To furnace, 1300 ft (396 m) of 32-in. (0.813 m) I.D., at $6,650/ft installed
- To high-pressure turbine, 700 ft (213 m) of 48-in. (1.22 m) I.D., refractory and Incoloy 800 lined at $7,325/ft installed
- To high-temperature regenerator, 300 ft (91 m) of 48-in. (1.22 m) I.D., 316 stainless steel at $11,000/ft installed

Table 9-17

CLOSED-CYCLE GAS TURBINE, CASE 1

COST ESTIMATE SUMMARY: BASE CASE BOP CAPITAL COSTS

	Direct Manual Field Labor (MH 1000's)	Direct Materials ($1000's)	Total Cost ($1000's)
INSTALLATION ONLY			
1. Furnace	335	1,450	
2. Primary Generating Unit *	45	800	
3. Heat Recovery Steam Generator	NA	NA	
4. Bottoming Cycle Turbine/Generator	NA	NA	
SUPPLY & INSTALLATION			
5. COOLING TOWER SYSTEM	160	2,300	
6. OTHER MECHANICAL EQUIPMENT	65	6,820	
7. ELECTRICAL	110	2,080	
8. CIVIL AND STRUCTURAL	350	3,500	
9. PIPING AND INSTRUMENTATION	130	2,550	
10. MISCELLANEOUS AND YARDWORK	30	970	
		20,470	20,470
Direct Labor	1,225	@$10.60	12,990
Direct Field Cost			33,460
Distributable Field Cost @ 90% of direct labor			11,690
Field Cost			45,150
Engineering, Home Office and Fee		@15%	6,770
			51,920
Contingency		@20%	10,380
ESTIMATED BALANCE-OF-PLANT CONSTRUCTION COSTS:			62,300
MID-1974 DOLLARS (1000's)			

* Turbine/Generator, MHD Generator, or Fuel Cells

Table 9-18

BOP ELEMENTS FOR SUPERCRITICAL CO_2 CYCLE

Elements	Comments
Site preparation	
Equipment installation	CO_2 cycle components
• Turbine and generator	600 MWe, 10700 lb/s, 1400 psia, 1100 F
• Turbine and compressor	10700 lb/s, 3780 psia, 1350 F
• HT regenerators	160 heat exchanger units
• LT regenerators	16 heat exchanger units
• Pump precooler	7500 lb/s, 1330 psia
Coal handling equipment	225 tons/hr, 324000 tons storage
Limestone handling equipment	57 tons/hr, 81,500 tons storage
AFB installation	3 units, 12 ft dia × 200 ft high, plus peripherals
Stack	33 ft ID x 800 ft high
Wet cooling towers	mechanical draft, 14 cells, 1450 kWe demand
Transformer and bus	13.8/500 kV
Buildings	1 turbine, 1 plant control
Special piping	47 in. ID, Incoloy and refractory lined, 10,700 lb/s, 3780 psia, 1350 F

Note: 600 MWe nominal output from two-shaft turbine
1st shaft, HP turbine driving compressor and pump
2nd shaft, LP turbine driving generator
Coal-fueled atmospheric fluidized bed furnace

- To low-temperature regenerator, 200 ft (61 m) of 48-in. (1.22 m) I.D., A106 steel at $1,983/ft installed

The estimated BOP costs for the supercritical CO_2 plant base case are summarized in Table 9-19.

Table 9-19

SUPERCRITICAL CO_2 CYCLE, CASE 1

COST ESTIMATE SUMMARY: BASE CASE BOP CAPITAL COSTS

	Direct Manual Field Labor (MH 1000's)	Direct Materials ($1000's)	Total Cost ($1000's)
INSTALLATION ONLY			
1. Furnace	625	2,600	
2. Primary Generating Unit *	85	1,600	
3. Heat Recovery Steam Generator	NA	NA	
4. Bottoming Cycle Turbine/Generator	NA	NA	
SUPPLY & INSTALLATION			
5. COOLING TOWER SYSTEM	142	1,900	
6. OTHER MECHANICAL EQUIPMENT	158	13,500	
7. ELECTRICAL	325	7,100	
8. CIVIL AND STRUCTURAL	710	17,000	
9. PIPING AND INSTRUMENTATION	900	19,400	
10. MISCELLANEOUS AND YARDWORK	80	6,100	
		69,200	69,200
Direct Labor	3,025	@$10.60	32,100
Direct Field Cost			101,300
Distributable Field Cost @ 90% of direct labor			28,900
Field Cost			130,200
Engineering, Home Office and Fee		@15%	19,800
			150,000
Contingency		@20%	30,000
ESTIMATED BALANCE-OF-PLANT CONSTRUCTION COSTS:			180,000
MID-1974 DOLLARS (1000's)			

*Turbine/Generator, MHD Generator, or Fuel Cells

Advanced Steam

The advanced steam plant base case varies from conventional steam plants in two areas that affect BOP. One is the steam turbine inlet temperature increase to 1200 F (922 K). The second is the use of multiple AFB boilers. The remainder of the plant follows conventional practice. Land area required for the plant is approximately 35 acres.

The BOP elements required for this plant are summarized in Table 9-20, which outlines the elements considered in estimating the BOP costs for this steam plant. The estimated costs for the base case plant are summarized in Table 9-21.

Liquid Metal Topping Cycle

This cycle uses two closed-cycle turbine systems in series. The topping cycle receives heat energy in the coal-fired furnaces and rejects heat to a steam bottoming cycle, which in turn rejects heat to cooling water in a condenser. The topping cycle working fluid is liquid metal which is heated and vaporized in six parallel AFB furnaces that are fueled with coal. Vaporized liquid metal is manifolded from two groups of three furnaces to supply two separate metal vapor turbine driven generators of 150 MWe output each. Three metal vapor turbines are connected to each electric energy generator. Heat is transferred from the turbine exhaust to the steam cycle by a heat recovery boiler attached to each metal vapor turbine. The steam from the six heat recovery boilers is piped to a single conventional steam turbine of 900 MWe nominal output.

The BOP effort involved in installation and interconnection of the multiple parallel components used in the two fluid systems of this plant is extensive. Six parallel metal vapor units are required along with the conventional closed steam cycle system. The list of BOP elements is presented in Table 9-22. The power cycle equipment along with the coal fuel and limestone receiving and storage system requires about 50 acres of land area.

The estimated BOP costs for the two base case plants are summarized in Tables 9-23 and 9-24. Table 9-23 is for a plant using potassium in the topping cycle, whereas, Table 9-24 is the estimated cost for use of cesium as a working fluid.

Open-Cycle MHD

MHD systems require the ducting of, and heat extraction from, a very hot gas stream at temperatures greater than 3000 F (1922 K). To accommodate the piping and flow control of such high temperature gases requires costly and technically unproven piping designs in the BOP systems. Large diameter piping with internal refractory lining to protect the external metal pipe from temperatures near or above its melting point is required. Any valving required must incorporate some water-cooling of

Table 9-20

BOP ELEMENTS FOR ADVANCED STEAM CYCLE

Elements	Comments
Site preparation	
Equipment installation	steam cycle components
• Turbine and generator	800 MWe, 1 HP + 1 IP + 2 LP
Condensers	1.5 in. Hga
Reheaters	7 reheat stages
Condensate pumps and pipe	
Coal handling equipment	316 tons/hr, 455,000 tons storage
Limestone handling equipment	79 tons/hr, 114,000 tons storage
AFB installation	4 units, 12 ft dia × 200 ft high, plus peripherals
Stack	39 ft ID x 800 ft high
Wet cooling towers	mechanical draft, 40 cells, 7000 kWe demand
Transformer and bus	13.8/500 kV
Buildings	1 turbine, 1 plant control
Special piping	26 in. ID, 316 SS, 3500 psia, 1200 F

Note: 800 MWe nominal output from increased temperature steam turbine cycle, single reheat, 3500 psia/1200 F/1000 F. Coal-fueled atmospheric fluidized bed boiler.

internal parts. Such service conditions have not been met by a utility energy conversion system to date.

The open-cycle MHD system in the first base case burns pulverized coal in a combustor. The hot gas flows through an MHD channel generator and diffuser into a radiant furnace where secondary air injection completes the combustion reaction. Additional heat is then extracted in ceramic core mass heat exchangers which are cycled from this heat-up phase to combustor air preheating. Six of these heat exchangers are manifolded into

Table 9-21

ADVANCED STEAM CYCLE, CASE 1

COST ESTIMATE SUMMARY: BASE CASE BOP CAPITAL COSTS

	Direct Manual Field Labor (MH 1000's)	Direct Materials ($1000's)	Total Cost ($1000's)
INSTALLATION ONLY			
1. Furnace	835	3,400*	
2. Primary Generating Unit †	110	1,900*	
3. Heat Recovery Steam Generator	NA	NA	
4. Bottoming Cycle Turbine/Generator	NA	NA	
SUPPLY & INSTALLATION			
5. COOLING TOWER SYSTEM	355	5,000	
6. OTHER MECHANICAL EQUIPMENT	175	27,900	
7. ELECTRICAL	500	8,700	
8. CIVIL AND STRUCTURAL	920	23,700	
9. PIPING AND INSTRUMENTATION	505	10,500	
10. MISCELLANEOUS AND YARDWORK	110	7,300	
		88,400	88,400
Direct Labor	3,510	@$10.60	37,200
Direct Field Cost			125,600
Distributable Field Cost @ 90% of direct labor			33,400
Field Cost			159,000
Engineering, Home Office and Fee		@15%	24,000
			183,000
Contingency		@20%	37,000
ESTIMATED BALANCE-OF-PLANT CONSTRUCTION COSTS:			220,000
MID-1974 DOLLARS (1000's)			

* Major equipment costs supplied by others.

† Turbine/Generator, MHD Generator, or Fuel Cells

Table 9-22

BOP ELEMENTS FOR LIQUID METAL TOPPING CYCLE

Elements	Comment
Site preparation	
Equipment installation	potassium cycle components
• Turbines and generators	2 units of 3 turbines + 1 generator (150 MWe)
• K/H_2O heat exchangers	6 H/X*, 6 parallel flows
• Liquid K pumps and pipe	6 pumps, 6 parallel flows
Equipment installation	Steam cycle components
• Turbine and generator	900 MWe, 1 HP + 1 IP + 2 LP
Steam condensers	1.5 in. Hga
Reheaters	7 reheat stages
Condensate pumps and pipe	
Coal handling equipment	380 tons/hr, 547,000 tons storage
Limestone handling equipment	95 tons/hr, 137,000 tons storage
AFB installation	6 units, 12 ft dia × 200 ft high, plus peripherals
Stacks	3 at 22.5 ft ID × 800 ft high
Wet cooling towers	mechanical draft, 48 cells, 8400 kWe demand
Transformer and bus	13.8/500 kV
Buildings	2 turbine, 1 plant control
Special piping	79 in. ID, Incoloy and refractory lined pipe 2 psia, 1490 F

*H/X = Heat Exchanger

Note: 300 MWe nominal output from two potassium vapor turbine generator sets.
900 MWe nominal output from 3500 psia/1000 F/1000 F steam turbine generator.
Coal-fueled atmospheric fluidized bed boilers.

Table 9-23

POTASSIUM LIQUID METAL TOPPING CYCLE, CASE 1

COST ESTIMATE SUMMARY: BASE CASE BOP CAPITAL COSTS

	Direct Manual Field Labor (MH 1000's)	Direct Materials ($1000's)	Total Cost ($1000's)
INSTALLATION ONLY			
1. Furnace	1,260	4,790	
2. Primary Generating Unit *	58	800	
3. Heat Recovery Steam Generator	86	100	
4. Bottoming Cycle Turbine/Generator	160	2,320	
SUPPLY & INSTALLATION			
5. COOLING TOWER SYSTEM	440	6,160	
6. OTHER MECHANICAL EQUIPMENT	530	64,500	
7. ELECTRICAL	660	15,360	
8. CIVIL AND STRUCTURAL	2,200	29,000	
9. PIPING AND INSTRUMENTATION	1,190	20,580	
10. MISCELLANEOUS AND YARDWORK	340	12,700	
		156,310	156,310
Direct Labor	6,924	@$10.60	73,390
Direct Field Cost			229,700
Distributable Field Cost @ 90% of direct labor			66,050
Field Cost			295,750
Engineering, Home Office and Fee		@15%	44,350
			340,100
Contingency		@20%	68,000
ESTIMATED BALANCE-OF-PLANT CONSTRUCTION COSTS:			408,100
MID-1974 DOLLARS (1000's)			

*Turbine/Generator, MHD Generator, or Fuel Cells

Table 9-24

CESIUM LIQUID METAL TOPPING CYCLE, CASE 17

COST ESTIMATE SUMMARY: BASE CASE BOP CAPITAL COSTS

	Direct Manual Field Labor (MH 1000's)	Direct Materials ($1000's)	Total Cost ($1000's)
INSTALLATION ONLY			
1. Furnace	1,260	4,790	
2. Primary Generating Unit*	58	800	
3. Heat Recovery Steam Generator	86	100	
4. Bottoming Cycle Turbine/Generator	160	2,320	
SUPPLY & INSTALLATION			
5. COOLING TOWER SYSTEM	440	6,160	
6. OTHER MECHANICAL EQUIPMENT	813	71,850	
7. ELECTRICAL	673	15,670	
8. CIVIL AND STRUCTURAL	2,240	30,200	
9. PIPING AND INSTRUMENTATION	1,210	20,800	
10. MISCELLANEOUS AND YARDWORK	340	12,700	
		165,390	165,390
Direct Labor	7,280	@$10.60	77,170
Direct Field Cost			242,560
Distributable Field Cost @ 90% of direct labor			69,450
Field Cost			312,010
Engineering, Home Office and Fee		@15%	46,820
			358,830
Contingency		@20%	71,770
ESTIMATED BALANCE-OF-PLANT CONSTRUCTION COSTS:			430,600
MID-1974 DOLLARS (1000's)			

* Turbine/Generator, MHD Generator, or Fuel Cells

the system with valving to permit their being cycled selectively from heat absorption to heat release. Each exchanger is 30 ft (9.14 m) in diameter by 75 ft (22.9 m) high with refractory lining and is porous ceramic filled. The hot gases from the heat exchangers then flow through a water walled steam generator. The steam is used to drive two condensing turbines. One drives the primary air compressor for the combustion system. The second drives a generator.

The BOP elements involved in this plant are summarized in Table 9-25. The field effort needed to install all of the MHD, heat exchange, boiler and steam turbine components, as well as providing the piping and valves to interconnect the components, results in a major and costly plant that covers about 70 acres. The estimated BOP costs for the two base cases are summarized in Table 9-26, for the coal-fired case, and in Table 9-27, for the solvent refined coal-fueled case.

Closed-Cycle Inert Gas MHD

This closed-cycle MHD plant uses argon as the working fluid with cesium seed injected upstream of the MHD generator. This plant functions like the open-cycle MHD system with the added requirements of returning the argon in a closed piping loop and recovering the cesium seed for reinjection. Eight ceramic filled heat exchange pressure vessels are used in this system to supply thermal energy to the working fluid. High-temperature piping and valves permit cycling from fired-heat-up to heat-input functions. An HRSG is used in this cycle to extract heat from the gas stream and drive a steam turbine of 350 MWe nominal output. This plant using solvent refined coal (SRC) fuel requires about 35 acres of land.

The BOP elements included in this plant are summarized in Table 9-28. This listing illustrates the extent of BOP considered in estimating the capital costs. These estimated costs for the two base cases are summarized in Tables 9-29 and 9-30. Table 9-29 is for the SRC case. Table 9-30 is for the direct-fired coal-fueled combustor case.

Closed-Cycle Liquid Metal MHD

This cycle uses helium as the working fluid with liquid metal addition. The system is in a closed cycle that receives heat from three parallel atmospheric fluid bed combustors, then expands through 13 parallel MHD generators, each with a separator to extract liquid metal for reinjection. The helium from the 13 MHD generators is then collected in manifold ducting and flows through a water walled steam generator followed by heat rejection cooling and compression for delivery back to the fluid bed furnaces. The 13 MHD generators and three furnaces result in an extensive 1300 F (978 K) helium/liquid metal fluid piping system which, in combination with a steam turbine generator system, requires complex and costly BOP piping systems. Multiple parallel

Table 9-25

BOP ELEMENTS FOR OPEN-CYCLE MHD

Elements	Comment
Site preparation	
Equipment installation	MHD cycle components
• Combustor	9 ft dia × 30 ft long
• MHD generator	5 ft × 5 ft × 82 ft long
• Diffuser	12 ft × 12 ft × 95 ft long
• Radiant furnace	110 ft long
• HT air heaters	6 units, 30 ft dia × 75 ft high
• Boilers	
• Seed recovery	
Equipment installation	steam cycle components
• Turbine and compressor	369 MWm, 1 HP + 1 IP + 2 LP
• Turbine and generator	550 MWe, 1 HP + 1 IP + 2 LP
Steam condensers	1.5 in. Hga
Reheaters	1 deaerator stage
Condensate pumps and pipe	
Coal handling Equipment	595 tons/hr, 857,000 tons storage
Coal pulverizers	14 units
Stacks	2 at 34 ft ID × 800 ft high
Wet cooling towers	48 cells, mechanical draft, 8400 kWe demand
Transformer and bus	13.8/500 kV
Buildings	1-MHD, 1-turbine, 1-plant control
Special piping	9.5 ft ID, refractory lined, 145 psig, 2550 F
	22.5 ft ID, refractory lined, 1.5 psig, 2950 F
	21.7 ft ID, refractory lined, 1 psig, 2700 F
	5.9 ft ID, refractory lined, 1 psig, 2200 F

Note: 1450 MWe nominal output from MHD generator
550 MWe nominal output from 3500 psia/1000 F/1000 F steam turbine generator. Direct pulverized coal combustor.

Table 9-26

OPEN-CYCLE MHD WITH DIRECT COAL, CASE 1

COST ESTIMATE SUMMARY: BASE CASE BOP CAPITAL COSTS

	Direct Manual Field Labor (MH 1000's)	Direct Materials ($1000's)	Total Cost ($1000's)
INSTALLATION ONLY			
1. Furnace	NA	NA	
2. Primary Generating Unit *	1,760	26,400	
3. Heat Recovery Steam Generator	1,540	5,500	
4. Bottoming Cycle Turbine/Generator	180	1,900	
SUPPLY & INSTALLATION			
5. COOLING TOWER SYSTEM	590	8,200	
6. OTHER MECHANICAL EQUIPMENT	1,740	59,100	
7. ELECTRICAL	2,380	34,000	
8. CIVIL AND STRUCTURAL	3,460	49,400	
9. PIPING AND INSTRUMENTATION	4,420	80,100	
10. MISCELLANEOUS AND YARDWORK	730	26,400	
		291,000	291,000
Direct Labor	16,800	@$10.60	178,000
Direct Field Cost			469,000
Distributable Field Cost @ 90% of direct labor			160,000
Field Cost			629,000
Engineering, Home Office and Fee		@15%	94,400
			723,400
Contingency		@20%	144,600
ESTIMATED BALANCE-OF-PLANT CONSTRUCTION COSTS:			868,000
MID-1974 DOLLARS (1000's)			

* Turbine/Generator, MHD Generator, or Fuel Cells

Table 9-27

OPEN-CYCLE MHD WITH SRC FUEL, CASE 24

COST ESTIMATE SUMMARY: BASE CASE BOP CAPITAL COSTS

	Direct Manual Field Labor (MH 1000's)	Direct Materials ($1000's)	Total Cost ($1000's)
INSTALLATION ONLY			
1. Furnace	NA	NA	
2. Primary Generating Unit*	1,760	26,400	
3. Heat Recovery Steam Generator	790	5,500	
4. Bottoming Cycle Turbine/Generator	180	1,900	
SUPPLY & INSTALLATION			
5. COOLING TOWER SYSTEM	590	8,200	
6. OTHER MECHANICAL EQUIPMENT	1,590	38,100	
7. ELECTRICAL	2,240	32,100	
8. CIVIL AND STRUCTURAL	2,810	41,100	
9. PIPING AND INSTRUMENTATION	4,260	78,400	
10. MISCELLANEOUS AND YARDWORK	730	26,400	
		258,100	258,100
Direct Labor	14,950	@$10.60	158,500
Direct Field Cost			416,600
Distributable Field Cost @ 90% of direct labor			142,700
Field Cost			559,300
Engineering, Home Office and Fee		@15%	84,000
			643,300
Contingency		@20%	128,700
ESTIMATED BALANCE-OF-PLANT CONSTRUCTION COSTS:			772,000
MID-1974 DOLLARS (1000's)			

*Turbine/Generator, MHD Generator, or Fuel Cells

Table 9-28

BOP ELEMENTS FOR CLOSED CYCLE INERT GAS MHD

Elements	Comment
Site preparation	
Equipment installation	MHD cycle components
• MHD generator	5.2 ft × 5.2 ft × 50 ft long
• Diffuser	21.8 ft × 21.8 ft × 180 ft long
• Steam generator	2 million lb/hr, 3500 psia/ 1000 F/1000 F
• Gas cooler	379 million Btu/hr
• Cesium recovery system	26 gal/min liquid metal
• Argon recovery system	
Equipment installation	steam cycle components
• Turbine and generator	350 MWe, 1 HP + 1 IP + 1 LP
Steam condenser	1.5 in. Hga
Reheater	1 deaerator stage
Condensate pump and pipe	
SRC handling system	288,000 lb/hr, five 200 ft dia. tanks
Combustor	4520 million Btu/hr, solvent refined coal
High temperature heaters	8 at 28 ft dia. × 43 ft high
Stack	39 ft ID × 800 ft high
Wet cooling towers	mechanical draft, 20 cells, 3500 kWe demand
Transformer and bus	13.8/500 kV
Buildings	1-MHD, 1-turbine, 1-plant control
Special piping	15 ft ID, refractory lined, 130 psig, 3000 F
	18.5 ft ID, refractory lined, 6 psig, 3200 F
	48 valves, 10 ft ID, water cooled

Note: 250 MWe nominal output from MHD generator
350 MWe nominal output from 3500 psia/1000 F/1000 F steam turbine generator
Direct combustion of solvent refined coal liquid fuel

Table 9-29

CLOSED-CYCLE INERT GAS MHD WITH CLEAN FUEL, CASE 1

COST ESTIMATE SUMMARY: BASE CASE BOP CAPITAL COSTS

	Direct Manual Field Labor (MH 1000's)	Direct Materials ($1000's)	Total Cost ($1000's)
INSTALLATION ONLY			
1. Furnace	330	1,650*	
2. Primary Generating Unit †	280	4,200*	
3. Heat Recovery Steam Generator	110	600*	
4. Bottoming Cycle Turbine/Generator	90	900*	
SUPPLY & INSTALLATION			
5. COOLING TOWER SYSTEM	290	4,050	
6. OTHER MECHANICAL EQUIPMENT	640	16,500*	
7. ELECTRICAL	700	12,500	
8. CIVIL AND STRUCTURAL	1,100	17,900	
9. PIPING AND INSTRUMENTATION	1,640	44,000	
10. MISCELLANEOUS AND YARDWORK	340	11,000	
		113,300	113,300
Direct Labor	5,520	@$10.60	58,500
Direct Field Cost			171,800
Distributable Field Cost @ 90% of direct labor			52,700
Field Cost			224,500
Engineering, Home Office and Fee		@15%	33,500
			258,000
Contingency		@20%	52,000
ESTIMATED BALANCE-OF-PLANT CONSTRUCTION COSTS:			310,000
MID-1974 DOLLARS (1000's)			

* Major equipment costs supplied by others.

† Turbine/Generator, MHD Generator, or Fuel Cells

Table 9-30

CLOSED-CYCLE INERT GAS MHD WITH DIRECT COAL, CASE 16

COST ESTIMATE SUMMARY: BASE CASE BOP CAPITAL COSTS

	Direct Manual Field Labor (MH 1000's)	Direct Materials ($1000's)	Total Cost ($1000's)
INSTALLATION ONLY			
1. Furnace	1,610	29,400 *	
2. Primary Generating Unit †	560	8,400 *	
3. Heat Recovery Steam Generator	220	1,200 *	
4. Bottoming Cycle Turbine/Generator	180	1,800 *	
SUPPLY & INSTALLATION			
5. COOLING TOWER SYSTEM	580	8,000	
6. OTHER MECHANICAL EQUIPMENT	1,550	49,300	
7. ELECTRICAL	1,500	26,500	
8. CIVIL AND STRUCTURAL	2,540	42,000	
9. PIPING AND INSTRUMENTATION	3,400	89,200	
10. MISCELLANEOUS AND YARDWORK	680	22,000	
		277,800	277,800
Direct Labor	12,820	@$10.60	135,900
Direct Field Cost			413,700
Distributable Field Cost @ 90% of direct labor			122,300
Field Cost			536,000
Engineering, Home Office and Fee		@15%	84,000
			620,000
Contingency		@20%	120,000
ESTIMATED BALANCE-OF-PLANT CONSTRUCTION COSTS: MID-1974 DOLLARS (1000's)			740,000

* Major equipment costs supplied by others.

† Turbine/Generator, MHD Generator, or Fuel Cells

flow path energy conversion equipment, coal handling and storage system, and other plant support systems require approximately 44 acres of land.

The BOP elements included in this plant are summarized in Table 9-31. This listing illustrates the extent of BOP considered in estimating the capital costs. The estimated costs for the base case are summarized in Table 9-32.

Fuel Cells

Two fuel cell systems are included in this study. The first is a low-temperature system of 50 MWe nominal output. The second is a high-temperature, low-Btu gas-fueled system of 1000 MWe nominal output.

Low-Temperature Fuel Cells. The low-temperature fuel cells and much of the associated equipment are delivered at plant site as prepackaged modular units. Thus, as with open-cycle gas turbine units, BOP requirements are reduced relative to other advanced energy conversion systems in this study. The BOP consists of equipment installation, minor buildings for weather protection, control and maintenance, system water treatment, and minor piping requirements. Land area required is 4 acres for this installation. The BOP elements for the low-temperature fuel cell are shown in Table 9-33. Estimated costs of the BOP for this low-temperature fuel cell plant installation are summarized in Table 9-34.

High-Temperature Fuel Cells. The high-temperature fuel cell plant installation is far more complex than for the low-temperature fuel cells. This plant incorporates an on-site gasification plant that receives coal and converts it to low-Btu gas for the fuel cell system boilers. Four parallel boilers provide steam to a turbine/generator and deliver hot gases at 1870 F (1294 K) to the fuel cells. The fuel cells have a hot gas total frontal flow area of 87,900 ft^2 (8,166 m^2), which is accomplished by using 24 parallel units of 60 by 60 ft (18.3 m) frontal dimensions. Refractory lined ducting for parallel hot gas flow to each of these units is provided. This plant requires about 50 acres of land for the coal system and the energy conversion equipment. Additional land area is required for the gasification plant, which is not included in this BOP scope.

The BOP elements included in the high-temperature fuel cell plant are summarized in Table 9-35. This listing outlines the extent of BOP considered in estimating the capital costs that are summarized in Table 9-36.

Table 9-31

BOP ELEMENTS FOR CLOSED-CYCLE LIQUID METAL MHD

Elements	Comment
Site preparation	
Equipment installation	MHD cycle components
• MHD generators	13 units, 6.5 ft × 6.5 ft × 34 ft long
• Sodium separators and pumps	13 units, 41.5 million lb/hr each
• Steam generator	2.4 million lb steam/hr 3500 psia/1000 F
• Helium cooler and compressor	2.4 million lb helium/hr
Equipment installation	steam cycle components
• Turbine and generator	420 MWe, 1 HP + 1 IP + 1 LP
Steam condenser	1.5 in. Hga
Reheater	1 deaerator stage
Condensate pump and pipe	
Coal handling equipment	260 tons/hr, 374,000 tons storage
Limestone handling equipment	65 tons/hr, 94,000 tons storage
AFB installation	3 units, 12 ft dia × 200 ft high
Stack	34 ft ID × 800 ft high
Wet cooling towers	mechanical draft, 28 cells, 4900 kWe demand
Transformer and bus	13.8/500 kV
Buildings	1-MHD, 1-turbine, 1-plant control
Special piping	5.5 ft ID, refractory lined, 720 psia, 1300 F
	11.4 ft ID, refractory lined, 720 psia, 1300 F

Note: 600 MWe nominal output from 13 MHD generators
420 MWe nominal output from 3500 psia/1000 F/1000 F steam turbine generator. Coal-fired atmospheric fluidized bed boilers.

Table 9-32

CLOSED-CYCLE LIQUID METAL MHD, CASE 1

COST ESTIMATE SUMMARY: BASE CASE BOP CAPITAL COSTS

	Direct Manual Field Labor (MH 1000's)	Direct Materials ($1000's)	Total Cost ($1000's)
INSTALLATION ONLY			
1. Furnace	1,210	5,500*	
2. Primary Generating Unit†	430	7,150*	
3. Heat Recovery Steam Generator	130	650*	
4. Bottoming Cycle Turbine/Generator	100	1,000*	
SUPPLY & INSTALLATION			
5. COOLING TOWER SYSTEM	310	4,300	
6. OTHER MECHANICAL EQUIPMENT	460	26,100*	
7. ELECTRICAL	950	19,800	
8. CIVIL AND STRUCTURAL	2,020	45,500	
9. PIPING AND INSTRUMENTATION	2,070	63,400	
10. MISCELLANEOUS AND YARDWORK	340	11,000	
		184,400	184,400
Direct Labor	8,020	@$10.60	85,000
Direct Field Cost			269,400
Distributable Field Cost @ 90% of direct labor			76,600
			346,000
Field Cost			
Engineering, Home Office and Fee		@15%	54,000
			400,000
Contingency		@20%	80,000
ESTIMATED BALANCE-OF-PLANT CONSTRUCTION COSTS:			480,000
MID-1974 DOLLARS (1000's)			

* Major equipment costs supplied by others.

† Turbine/Generator, MHD Generator, or Fuel Cells

Table 9-33

BOP ELEMENTS FOR LOW-TEMPERATURE FUEL CELLS

Elements	Comment
Site preparation	
Fuel cell installation	One unit, 150 ft × 80 ft × 30 ft high
Cooling water system installation	24,000 gal/min, 150 ft head, 224,000 gal storage
Cooling air system installation	7,300,000 ft^3/min, 15 in. water gage
Transformer and bus	1/69 kV
Buildings	1-fuel cell, 1-plant control

Note: 50 MWe nominal output from one fuel cell unit.

COMMON ELEMENTS

A number of elements of the BOP are common to several of the plants. This commonality was used in defining and cost estimating the BOP requirements for the various power plants involved in this study.

The methods for evaluating these common elements were established, then applied to each particular plant situation. This technique was employed as a means of providing consistent treatment of these elements while maintaining the flexibility to adjust to the various capacities and particular requirements of each plant.

The significant elements that received common evaluations, as defined herein, were:

- Auxiliary power requirements
- High-temperature piping
- Construction time estimate
- Wet cooling tower
- Exhaust gas emission control equipment

AUXILIARY POWER REQUIREMENTS

Auxiliary power estimates for the plant cycles involved in this parametric study were obtained by adding the power requirements for major identifiable energy consuming components in each

Table 9-34

LOW-TEMPERATURE FUEL CELLS, CASE 1

COST ESTIMATE SUMMARY: BASE CASE BOP CAPITAL COSTS

	Direct Manual Field Labor (MH 1000's)	Direct Materials ($1000's)	Total Cost ($1000's)
INSTALLATION ONLY			
1. Furnace	NA	NA	
2. Primary Generating Unit *	5.0	20	
3. Heat Recovery Steam Generator	NA	NA	
4. Bottoming Cycle Turbine/Generator	NA	NA	
SUPPLY & INSTALLATION			
5. COOLING TOWER SYSTEM	NA	NA	
6. OTHER MECHANICAL EQUIPMENT	4.0	240	
7. ELECTRICAL	5.0	300	
8. CIVIL AND STRUCTURAL	18.0	640	
9. PIPING AND INSTRUMENTATION	3.0	50	
10. MISCELLANEOUS AND YARDWORK	1.0	30	
		1,280	1,280
Direct Labor	36.0	@$10.60	380
Direct Field Cost			1,660
Distributable Field Cost @ 90% of direct labor			340
Field Cost			2,000
Engineering, Home Office and Fee		@15%	300
			2,300
Contingency		@20%	460
ESTIMATED BALANCE-OF-PLANT CONSTRUCTION COSTS:			2,760
MID-1974 DOLLARS (1000's)			

*Turbine/Generator, MHD Generator, or Fuel Cells

Table 9-35

BOP ELEMENTS FOR HIGH TEMPERATURE FUEL CELLS

Elements	Comment
Site preparation	
Fuel cells installation	24 units, 25 ft × 60 ft × 65 ft high
Ducting—high temperature	8 lines, 13.2 ft ID, refractory lined, 0.5 psig, 1870 F 24 shrouds, 8700 ft^2 of refractory lining on each cell unit
Steam turbine and generator installation	500 MWe, 1 HP + 1 IP + 2 LP
Steam condenser	1.5 in. Hga
Reheaters	7 reheater stages
Condensate pump and pipe	
Coal handling equipment	400 tons/hr, 582,000 tons storage
Boilers—gas fired	4 units, 850,000 lb steam/hr each
Stacks	4 at 25 ft ID × 200 ft high
Wet cooling towers	32 cells, mechanical draft, 5600 kWe demand
Transformer and bus	13.8/500 kV
Buildings	1-fuel cells, 1-turbine, 1-plant control

Note: 550 MWe nominal output from 24 fuel cell units
500 MWe nominal output from 3500 psia/1000 F/1000 F steam turbine generator. Low-Btu gas fired boilers (4).

cycle to a nominal allowance for plant housekeeping loads. The nominal allowance covers heating and ventilating, plant controls, and minor energy consuming components, and is assumed to be 1 percent of the plant gross power rating. Major power consuming components, for which auxiliary power requirements were computed and added to the nominal allowance, were the following:

Table 9-36

HIGH-TEMPERATURE FUEL CELLS, CASE 1

COST ESTIMATE SUMMARY: BASE CASE BOP CAPITAL COSTS

	Direct Manual Field Labor (MH 1000's)	Direct Materials ($1000's)	Total Cost ($1000's)
INSTALLATION ONLY			
1. Furnace	NA	NA	
2. Primary Generating Unit*	500	1,570	
3. Heat Recovery Steam Generator	140	400	
4. Bottoming Cycle Turbine/Generator	70	990	
SUPPLY & INSTALLATION			
5. COOLING TOWER SYSTEM	240	3,490	
6. OTHER MECHANICAL EQUIPMENT	260	19,910	
7. ELECTRICAL	790	17,580	
8. CIVIL AND STRUCTURAL	1,650	18,440	
9. PIPING AND INSTRUMENTATION	880	18,180	
10. MISCELLANEOUS AND YARDWORK	90	6,510	
		87,070	87,070
Direct Labor	4,620	@$10.60	48,930
Direct Field Cost			136,000
Distributable Field Cost @ 90% of direct labor			44,000
Field Cost			180,000
Engineering, Home Office and Fee		@15%	27,000
			207,000
Contingency		@20%	41,000
ESTIMATED BALANCE-OF-PLANT CONSTRUCTION COSTS:			248,000
MID-1974 DOLLARS (1000's)			

*Turbine/Generator, MHD Generator, or Fuel Cells

- Large Fans and Blowers: Electric motor drives for primary air and exhaust gas circulation, pneumatic transport air, or any other functions defined for a particular plant, are included in this category.

- Cooling Tower Fans: The allowance for fan motor drive is 175 kWe per wet cooling tower cell and 250 kWe per dry cooling tower cell.

- Cooling Water Pumps: The pump motor energy consumption for circulating the cooling water from the tower basins, through the condensers, and back to the cooling towers is included based on each plant's estimated water flow requirements. The factor applied is 13 pump horsepower (9.69 kWm) per 1000 gal/min (0.0631 m^3/s).

- Condensate Pumps: Pump motor energy requirements for condensate pumps used in the study cycles are included for each plant involving such pumps. These energy requirements are based on condensate flow rates and head pressures as defined by the plant flow schematic diagrams.

- Solid Fuel and Residue Handling: A variety of bulk material handling equipment is required for the coal burning plants in this study. Handling equipment is needed not only for the coal fuel, but also for additive materials, combustor residue ash, and collected fly ash. Energy requirements for the motors to drive the conveyors, elevators, etc., have been estimated and are included for each plant requiring such bulk handling systems.

HIGH-TEMPERATURE PIPING

Some of the BOP subsystems require the application of high-temperature ducting or pressure piping. These applications range from compressor exit piping at less than 300 F (422 K) to MHD channels containing high velocity combustion products at temperatures as high as 3500 F (2200 K). To contain such high temperature fluids, piping installations can become complex and expensive. Insulation must be used to reduce heat losses; the design must allow for piping expansion by the use of long flexible pipe runs or expansion joints; pipe supports must be sufficiently sturdy to support design loads yet not provide a large heat conduction loss from the pipe. Meeting the design constraints imposed by the advanced systems in this study, which involve complex runs of high-temperature piping, can become the major capital cost item in a plant.

Two approaches to high-temperature piping design have been applied in this study. First is to have the piping metal work at the temperature of the fluid with external insulation. This approach is used where fluid temperatures are less than working temperature limits of available piping metals. The second approach is to use low-temperature, low-cost pipe with refractory insulation installed internally. This approach is used where fluid temperatures are greater than allowable pipe metal temperatures, with the high-temperature refractory exposed to the hot fluid and the outer pipe nearer the ambient temperature as a result of the refractory insulation effect.

The temperature range and relative pipe costs for the pipe and the refractory lining material considered in this study are shown in Table 9-37. Installed costs per linear foot as a function of material and pipe diameter are estimated to be as shown in Figure 9-3. As shown, high alloy piping can be applied at temperatures up to 1500 F (1089 K). Because of reduced allowable stress at higher temperatures, wall thicknesses and weight per linear foot of pipe increase, causing rapid cost increase with increasing temperature and increasing piping inside diameter. Also, for fluid temperatures greater than 1500 F (1089 K), no metal alloy piping is available that can reliably contain the pressurized fluid without reducing metal temperatures by external cooling or insulation from the fluid heat source. Thus for temperatures greater than 1500 F (1089 K), and for larger diameter pipes, refractory lined low-alloy piping becomes a necessary economic choice.

To illustrate the relative costs of high-alloy and refractory lined carbon steel piping, four refractory lined piping systems are estimated and plotted as dashed lines on Figure 9-3. These four piping systems contain various thicknesses of internal refractory insulation which permits application to various high-temperature zones. The estimates include allowances for increased piping diameters needed to achieve the same inside diameters for refractory lined as for unlined pipe, as well as allowances for the cost of refractory linings.

To allow use of carbon steel pipe with fluids at 850 to 1200 F (454 to 922 K), a piping system with an internal refractory lining of 5-in. (12.7×10^{-2} m) thickness is needed. This lining is a composite with 3 in. (7.6×10^{-2} m) of medium density cast aluminum oxide against the interior of the pipe, followed with 2 in. (5.1×10^{-2} m) of high density, high abrasion resistant aluminum oxide in contact with the flowing fluid. Both refractories are estimated on the basis of $660 per ton ($0.73/1000 grams) with an installation cost factor of 67 percent applied. These approximate cost factors are recommended typical values from vendor quotes and represent the experience from recent vendor installations. This lined piping system offers significant cost reduction potential compared to 316 stainless steel for inside diameters greater than 20 in. (51.0×10^{-2} m) (see Figure 9-3).

Refractory lined piping for fluid temperatures from 1200 to 1500 F (922 to 1089 K) require increased refractory thicknesses. For this temperature range a composite insulation system of 6 in. (15.2×10^{-2} m) of medium density cast aluminum oxide against the pipe interior, followed with 2 in. (5.1×10^{-2} m) of high density

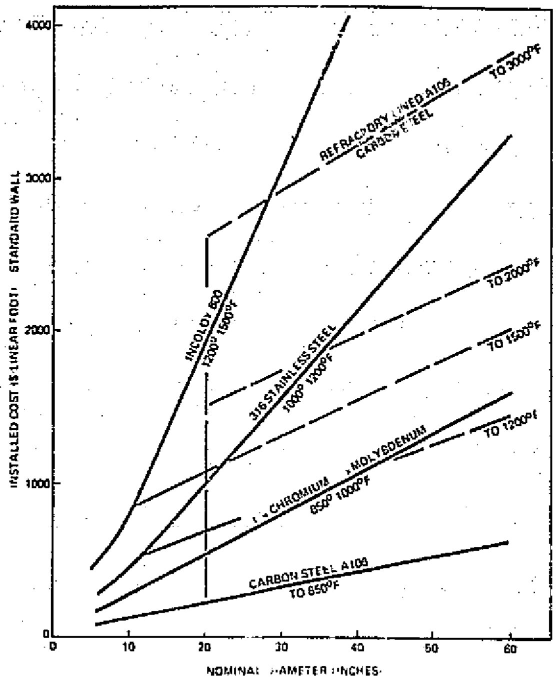


Figure 9-3. High-Temperature Piping Estimated Installed Costs

Table 9-37

HIGH-TEMPERATURE PIPING

Temperature Range (°F)	Material	Fabricated Material Cost ($/lb)
To 850	Carbon steel A105	1.05
850-1000	1 1/4 Chromium 1/2 Molybdenum	2.60
1000-1200	316 Stainless Steel	7.25
1200-1500	Incoloy 800	16.00
To 3400	Refractory linings (≈ $27/ft^2 of wall for 3-in. thick refractory)	Varies

cast aluminum oxide in contact with the fluid is estimated. This insulation system offers significant cost reductions compared to the use of Incoloy 800 pipe for inside diameters greater than about 14 in. (36.0×10^{-2} m) (see Figure 9-3).

As fluid temperatures increase above 1500 F (1089 K), refractory lined piping becomes the only practical method available. For the fluid temperature range of 1500 to 2000 F (1089 to 1366 K), piping cost estimates are based on a 12-in. (30.5×10^{-2} m) thick composite lining that uses 9-in. (22.9×10^{-2} m) thick pre-cast furnace brick, of lower thermal conductivity than cast aluminum oxide, against the pipe wall followed by 3 in. (7.6×10^{-2} m) of high density aluminum oxide. For temperatures of from 2000 to 3000 F (1366 to 1922K), the lining estimated is 18 in. (45.7×10^{-2} m) total thickness with the 9-in. (22.9×10^{-2} m) outer layer of brick followed internally by 9 in. (22.9×10^{-2} m) of aluminum oxide which can be either pre-cast brick or cast in place.

CONSTRUCTION TIME ESTIMATE

Years required for construction of each plant are estimated based on recent AE experience in design and construction of coal-fueled power plants of about 800 MWe capacity. This provides a direct recent experience basis for the advanced steam cycle, with the other plants' construction times being estimated relative to the advanced steam cycle by allowances for capacity and complexity differences. Thus, the gas turbine cycles, being smaller in capacity as well as readily erected from modular units, result in shorter construction times. Long construction periods are associated with the large capacity plants involving combinations of basic energy conversion cycles, e.g., metal vapor topping with steam bottoming and MHD in combination with steam. These combination cycles at large gross electric energy capacities tend to require more field erection effort because of large component physical size and the need for simultaneous erection of multiple component systems. The result is longer construction periods for such plants.

COOLING TOWER SYSTEMS

For this study, the base cases and parametric variations use cooling systems employing wet or dry cooling towers. Combinations of these cooling methods are excluded as beyond the study scope.

Two atmospheric days have been defined for the Middletown, U.S.A., site. These two days define the design conditions for sizing and costing of the study cooling systems.

Standard Day:

- Wet bulb temperature - 51.5 F
- Dry bulb temperature - 59 F
- Relative humidity - 60 %

Hot Day:

- Wet bulb temperature - 76 F
- Dry bulb temperature - 94 F
- Relative humidity - 44%

The Middletown site is near a river adequate for supplying cooling system makeup as well as receiving treated blowdown water.

The base, or reference, cooling method for this study is the mechanical draft wet cooling tower.

Mechanical Draft Wet Towers

These are the most widely used and least expensive of evaporative cooling towers (refs. 1 through 5). Their advantages are:

- Low capital cost to install
- Low silhouette

Their disadvantages are:

- Power required to drive fans
- Maintenance of fans and fan drives
- Land requirements in large installations in order to disperse towers to prevent mutual interference

Nominal design conditions for 85 recent mechanical draft towers (ref. 5) are given in Table 9-38.

Table 9-38

NOMINAL COOLING TOWER DESIGN CONDITIONS

Item	Avg.	Low	High
Water flow rate, (gal/min)/kW	0.4	0.25	0.97
Design wet bulb temperature, (°F)	73.8	55	80
Approach to wet bulb temperature, (°F)	13.9	7	29
Range (°F)	22.5	12.8	40.4

Note: The above averages result in a steam condenser saturation temperature of 115 F (≈ 3 in. Hga).

In this study, the controlling design condition will be the more stringent of providing near 3 in. Hga (76.2×10^{-3} m) condenser pressure on the hot day or 1.5 in. Hga (38.1×10^{-3} m) on the standard day. Using the "tower unit" design approach of Reference 2, the requirements for a one million Btu per minute cooling capacity follow.

Hot Day Design:

Range = 22.5 F, Approach = 14 F, Terminal temperature difference (TTD) = 5 F

Condensate temperature = Hot day wet bulb + approach + range + TTD

Condensate temperature = 117.5 F

$$\text{Water flow} = \frac{\text{Q Btu/min}}{\text{Cp} \times 8.33 \text{ lb/gal} \times \text{Range}} = 5375 \text{ gal/min}$$

$$\text{Maximum evaporation} = \frac{Q}{8.33\Delta h} = 123.7 \text{ gal/min (2.3\%)}$$

Makeup rate; assume ≈ 0.7%

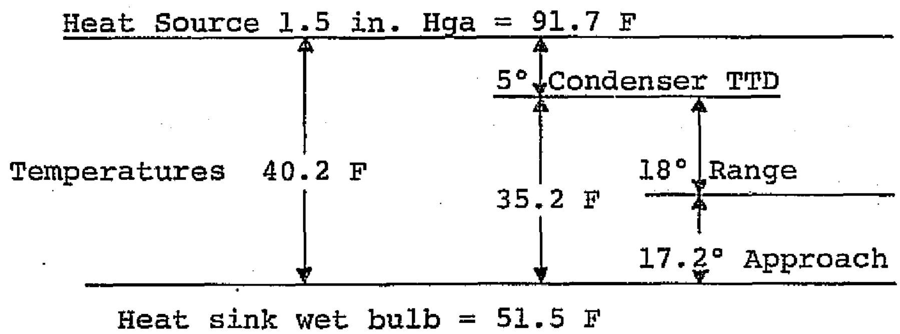
Total water requirement ≈ 3% of flow capacity

Rating factor from Reference 2 = 0.94

Number of tower units = 0.94 × 5335 gal/min = 5015 T.U.

A standard mechanical draft tower cell, 51' × 36' × 39' high, with a 200 HP fan, will provide 17,500 T.U. cooling capacity.

Standard Day Design:



Rating factor from Reference 2 = 1.22

Water flow = 6669 gal/min

Number of tower units = 1.22 × 6669 = 8136 T.U.

The more stringent case is the standard day case, for which the following study parameters were established for steam condensing systems.

5 F (2.78 K) Terminal temperature difference

17.2 F (9.56 K) Approach temperature difference

18 F (10 K) Range (temperature difference)

6670 Gal/min per million Btu/min (23.946 m^3/s per kW) water circulation rate

3% Water makeup requirement

One cooling tower cell is needed for each 10,800 gal/min (0.68 m^3/s), and is 51' × 36' × 47' high (15.5 × 11 × 19.3 m) with a 200 HP (149 kW) fan.

Use 13 Pump Horsepower (9.69 kW) per 1000 gal/min (0.0631 m^3/s) (ref. 5).

Natural Draft Wet Towers

Concrete natural draft towers may be preferable for a plant as cooling water flows become greater than about 400,000 gal/min (25.2 m^3/s). However, initial capital cost alone does not favor the natural draft tower. They are usually selected by site considerations of land scarcity or environmental conditions. (ref. 3). As electrical costs increase for fan motors, and as construction techniques for natural draft towers improve their costs relative to forced draft towers, more plants may be selecting natural draft towers as the economic choice. Advantages of natural draft towers are:

- No fan power required
- Less maintenance
- Less land area required
- Less piping required than for multiple cells

Disadvantages are:

- Higher capital costs
- Minor increase in pumping head

For this study, wet natural draft tower costs are not incorporated into any of the cases for the following reasons:

1. Very few of the cases require cooling water flows greater than 400,000 gal/min (25.2 m^3/s).

2. No apparent cost advantage exists for hyperbolic towers at the Middletown site.

3. Consistency of costs between parametric cases favor a standardized tower module.

4. Cooling tower costs for the largest capacity power plants tend to be a very small portion of the total plant costs.

Dry Cooling Towers

Dry cooling towers increase the cost of electric energy by increasing capital costs and by reducing the net energy delivered from the plant (refs. 1, 5, and 6). Dry towers cost more per unit heat rejection to buy and install. The ratio of dry tower to wet tower costs for condensing and noncondensing energy conversion systems for equal heat capacity at Middletown standard day conditions used in this study, including labor and materials, is 4. Dry towers reduce net electric energy by consuming about 3 times more fan power than equivalent mechanical draft wet towers. Dry towers also cause an increase in condenser pressures commensurate with higher temperature cooling water from dry towers. This causes the condensing turbines to operate at reduced pressure ratios, thus producing less power. The total effect of increased dry tower cost and reduced heat rate is to increase the capital cost per kilowatt to about 5 times that obtainable from a wet tower.

The dry tower cell used as a standard in this study permitted direct substitution for the standard wet mechanical draft tower. These dry cooling tower parameters are given in Table 9-39.

Table 9-39

DRY COOLING TOWER PARAMETERS

Parameter	Wet Tower	Dry Tower	Ratio Dry/Wet
Size L × W × H	36' × 75' × 47'	30' × 30' × 25'	—
No. Required	1	2	2
Power Consumption	175 kW	250 kW × 2	2.86
Water Consumption	300 gal/min	Nil	0
Cost	$219,000	$434,500 × 2	4.0
Capacity	97×10^6 Btu/hr	97×10^6 Btu/hr	1

Air Emission Control Equipment

To facilitate cost estimating, the same pollution control system types are used for all coal fuels, namely, electrostatic precipitator (ESP) for bulk dust removal (90 percent) followed by alkaline wet scrubbing for SO_2 and residual dust removal. For the solvent refined coal liquid (SRCL) fuel, SO_2 removal (20 percent) is accomplished in a single-stage Venturi scrubber with a recirculating lime slurry. Stack gas reheat is needed in each case.

Dry precipitator ash is assumed to be transported off-site. Spent scrubber solids are deposited in a pond with decant water being recycled.

A summary of control systems and estimated emissions for the advanced steam cycle with a conventional furnace and the closed-cycle MHD parallel cycle is presented as Table 9-40. Emission control for the other plant cycles is accomplished by cleanup equipment that is an integral part of the combustion system, thus, not part of the BOP.

For conventional furnace of the advanced steam cycle, the emission control equipment sizing basis is detailed in Table 9-41. The sizing basis for the closed inert gas MHD cycle is similarly detailed in Table 9-42. A schematic showing the emission control equipment involved in the coal-burning furnaces is Figure 9-4. The Venturi-scrubber required by the solvent refined coal liquid furnace is shown schematically in Figure 9-5. Both of these systems use a pressurized hot water system to extract heat from the main exhaust stream ahead of the Venturi scrubber and transfer it to reheat the stack gas after the scrubber. Resulting estimated gas stream conditions for both the advanced steam and MHD plants, incorporating the emission control equipment as defined, are shown in Table 9-43.

MAJOR TECHNICAL UNCERTAINTIES FOR BOP SYSTEMS

For the plants considered in this study the majority of BOP systems and equipment are based on conventional technology, involving well-established machinery and system techniques. Providing foundations, structures, buildings, cooling towers, piping, controls, fuel handling systems, landscaping, and almost all other BOP systems are routine work for the architect-engineer, with the costs being commensurate with the size and complexity of a particular plant. This conventional technology applies to most of the advanced energy conversion systems included in this study. The technical uncertainties that do exist are associated with the increased working fluid temperatures needed in many of these advanced systems to improve overall conversion efficiencies. Methods for ducting and controlling hot fluids must therefore be accomplished at a cost that is not prohibitive in order to make these systems viable.

Today's utility plants are designed for maximum reliability and minimum maintenance over 30 to 40 year lifetimes and limit primary piping material temperatures to approximately 1100 F (866 K). Higher temperature operations have been attempted but were found to be economically disadvantageous because of increased maintenance and reduced reliability. In fired boilers, present steam tube material temperatures are limited to less than 1500 F (1089 K). Yet, even with this design limit, boiler tube maintenance is a major operating cost and a significant cause of down time for utility steam power plants.

Obviously then, a major technical uncertainty in advanced concept high operating temperature plants, is how to contain and control fluids greater than 1500 F (1089 K) while sustaining high levels of reliability for the ducting system.

Table 9-40

SUMMARY OF CONTROL SYSTEMS AND ESTIMATED EMISSIONS

Case Number	Advanced Steam Cycle 17	Advanced Steam Cycle 18	Advanced Steam Cycle 19	Advanced Steam Cycle 20	Closed Cycle Inert Gas MHD Parallel Cycle		
Combustor	CF	CF	CF	CF	Dir.	Dir.	Dir.
Fuel	Ill #6	NDL	MSB	SRCL	Il #6	NDL	MSB
Heat Input (10^9 Btu/hr)	6.814	7.529	6.949	6.814	10.902	12.045	11.117
Control Systems & Performance (removal)	ESP (90%dust) Alkali Scrubber (90%SO_2, 95%dust)	ESP (90%dust) Alkali Scrubber (60%SO_2, 95%dust)	ESP (90%dust) Alkali Scrubber (60%SO_2, 95%dust)	— Venturi Scrubber (20%SO_2, 50%dust)	ESP (90%dust) Alkali Scrubber (90%SO_2, 95%dust)	ESP (90%dust) Alkali Scrubber (60%SO_2, 95%dust)	ESP (90%dust) Alkali Scrubber (60%SO_2, 95%dust)
Estimated Emissions							
SO_2 (lb/hr)	4910	6110	4980	4850	7850	9780	7960
NO_x (lb/hr)	4770	5270	4860	2040	7630	8430	7780
HC (lb/hr)	—	—	—	—	—	—	—
Particulates (lb/hr)	240	250	220	160	380	400	360
Stack Gas Temp, ^oF (min.)	250	250	250	250	250	250	250

Table 9-41

AIR EMISSION CONTROL EQUIPMENT
SIZING BASIS--ADVANCED STEAM CYCLE

Case Number	Conventional Furnace 17	18	19	20	Emiss. Reg's Solid	Liq.
Fuel	Ill. #6	NDL	MSB	SRC		
Flow, 10^3 lb/hr	631.6	1,092.7	776.9	434.5		
HHV, Btu/lb	10,788	6,890	8,944	15,682		
Emissions						
Gas, 10^6 lb/hr	7.114	7.811	7.172	6.642		
Temp., °F	300	300	300	300		
SO_2 (lb/10^6 Btu)	7.2	2.03	1.79	0.89	1.2	0.8
NO_2 (lb/10^6 Btu)	0.70	0.70	0.70	0.30	0.7	0.3
Dust (lb/10^6 Btu)	6.926	6.642	6.381	0.047	0.1	0.1
(lb/hr)*	47,190	50,010	44,340	321		
Pollutant Removals Required						
SO_2 (%)	83.3	40.9	33	10		
NO_2 (%)	0	0	0	0		
Dust (%)*	98.5	98.5	98.4	0		
Control Systems	ESP - Alkali Scrubber Reheat	ESP - Alkali Injection Reheat	ESP - Alkali Scrubber Reheat	Venturi Scrubber (lime slurry) Reheat		
Sizing Basis						
Dust	99.5% removal	99.5%	99.5%	50+% (overall)		
SO_2	90% removal	60%	60%	20%		

*75% Total Dust Load

Table 9-42

AIR EMISSION CONTROL EQUIPMENT

SIZING BASIS—CLOSED-CYCLE INERT GAS MHD

Case Number	Direct Coal Combustor 16	17	18	Emiss. Reg's
Fuel	Ill. #6	NDL	MSB	Solid
Flow, 10^3 lb/hr	1,010.6	1,748.3	1,243.0	
HHV, Btu/lb	10,788	6,890	8,944	
Emissions				
Gas, 10^6 lb/hr	11.382	12.498	11.475	
Temp, ^oF	300	300	300	
SO_2 (lb/10^6 Btu)	7.2	2.03	1.79	1.2
NO_2(lb/10^6 Btu)	0.70	0.70	0. 0	0.7
Dust (lb/10^6 Btu)	6.926	6.642	6.381	0.1
(lb/hr)*	75,500	80,020	70,940	
Pollutant Removals Required				
SO_2 (%)	83.3	40.9	33	
NO_2 (%)	0	0	0	
Dust (%)*	98.5	98.5	98.4	
Control Systems				
	ESP - Alkali Scrub-ber Re-heat	ESP - Alkali Scrub-ber Re-heat	ESP - Alkali Scrub-ber Re-heat	
Sizing Basis				
Dust	99.5% removal	99.5%	99.5%	
SO_2	90% removal	60%	60%	

*75% of Total Dust Load

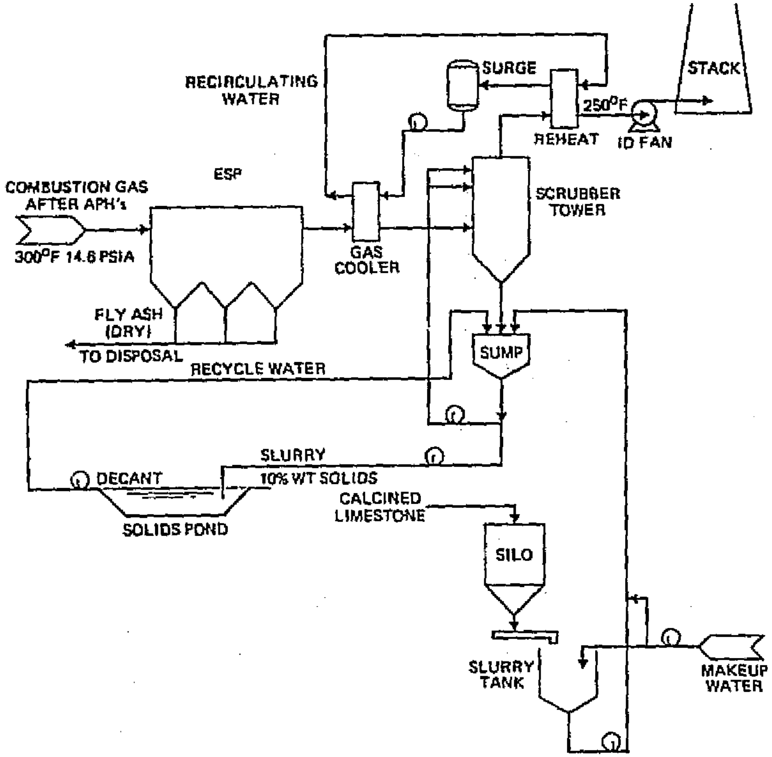


Figure 9-4. Air Emmission Control System Schematic--Coal Fueled Furnace

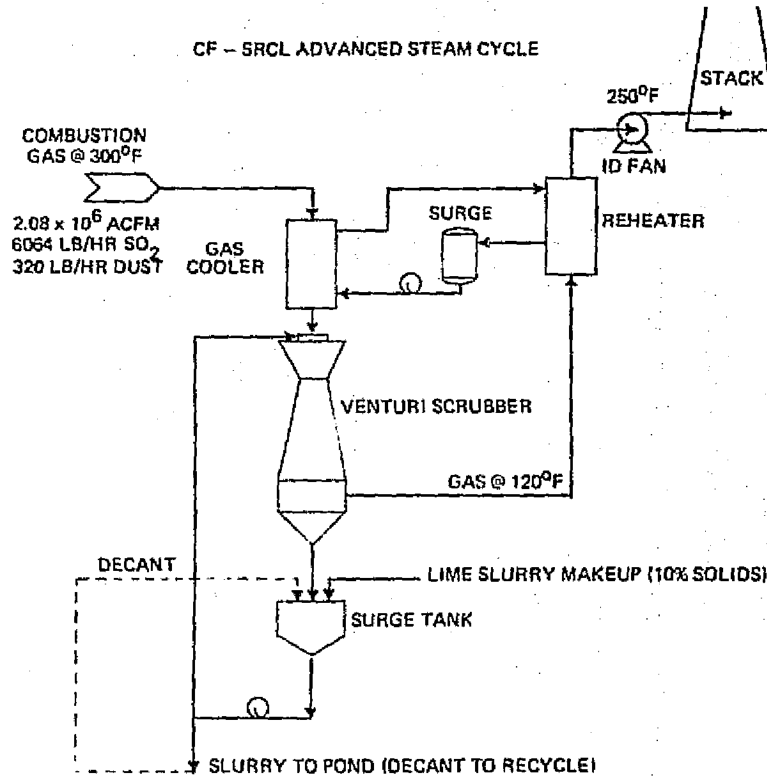


Figure 9-5. Venturi Scrubber System Schematic Solvent Refined Coal Liquid Furnace

Table 9-43

RESULTING ESTIMATED GAS STREAM CONDITONS

AFTER PREHEATERS	Advanced Stream CONVENTIONAL FURNACE			Closed Cycle Inert Gas MHD (Parallel Cycle) DIRECT COMBUSTION		
	Ill #6	NDL	MSB	Ill#6	NDL	MSB
Wt. Rate, 10^6 lb/hr	7.114	7.811	7.172	11.382	12.498	11.475
*Vol. 10^6 ACFM	2.23	2.44	2.25	3.57	3.92	3.60
* " 10^6 SCFM	1.53	1.67	1.54	2.44	2.68	2.46
Temp, F	300	300	300	300	300	300
Press psia	14.6	14.6	14.6	14.6	14.6	14.6
Dust, lb/hr	47,190	50,010	44,340	75,500	80,020	70,940
" gr/ACF	2.47	2.38	2.30	2.47	2.38	2.30
SO_2 lb/hr	49,060	15,280	12,440	78,500	24,450	19,900
" gr/ACF	2.57	0.73	0.645	2.57	0.73	0.645
AFTER ESP'S						
Temp F	300	300	300	300	300	300
Press psia	14.6	14.6	14.6	14.6	14.6	(ΔP~.5 in. Hg)
Dust, lb/hr	4720	5000	4430	7550	8000	7090
" gr/ACF	0.25	0.24	0.23	0.25	0.24	0.23
AFTER COOLERS						
Temp. F	170	170	170	170	170	170
Press. psia	14.4	14.4	14.4	14.4	14.4	14.4
AFTER SCRUBBERS						
Approx. 10^6 ACFH	1.78	1.94	1.79	2.84	3.12	2.86
Temp. F	120	120	120	120	120	120
Press. psia	14.0	14.0	14.0	14.0	14.0	14.0
Dust, lb/hr	240	250	220	380	400	360
" gr/ACF	0.016	0.015	0.014	0.016	0.015	0.015
SO_2, lb/hr	4910	6110	4980	7850	9780	7960
" gr/ACF	0.32	0.37	0.20	0.32	0.37	0.32

REHEAT to 250 F & Boost to 14.8 psia ⟶ Stack

*Assumed Molecular Weight = 29.5 all cases

PIPING AND DUCTING

Pressure piping and near ambient pressure ducting of fluids greater than 1000 F (811 K) must be insulated to prevent excessive heat losses. Where the pressure containing pipe metal can work at the fluid temperature, external insulation materials can be applied. At fluid temperatures greater than about 1200 F (922 K), the external pressure containing metal pipe must be internally insulated to maintain the pipe wall at temperatures below the fluid temperature, in order to permit reasonable allowable stress in the pipe. This can be done by using internal high alloy liners with a cooling fluid flow between the liner and the external pressure containing wall, as is usually done in high-temperature zones of gas turbine ducting. Or, alternatively, refractory insulation materials can be applied internally to the pressure containing metal wall. For the BOP piping between major components of the plants in this study, the latter alternative is applied for estimating purposes. This technique is discussed earlier in this Section. Design problems that must be solved in order to use refractory lined piping successfully are as follows.

- Refractory Spalling: Small particles of refractory material that become entrained in the fluid flow stream cause abrasive wear downstream. And for those systems containing high speed rotary compressors or turbines, abrasive impingement can result in rapid failure. Thus high alloy, nonpressure containing, internal liners may be needed in closed-cycle systems. In open-cycle systems, highly stable abrasion resistant refractory is required on the internal surface.

- Pipe Expansion: Thermal gradients within a refractory lined pressurized pipe, where the internal surface is at the fluid's high temperature while the external pipe wall is nearer ambient, result in refractory growth that is greater than the pipe growth. Thus the refractory is compressed at working conditions, and at ambient shutdown conditions shrinks, causing small cracks throughout the refractory. These dimensional changes must be accommodated in the piping design as well as normal exterior piping growth from temperature and pressure loads.

- Liner or Refractory Collapse: The high-temperature internally insulated pipe that cycles between high- and low-pressure levels must be designed to vent to the flow passage any fluid contained between the lining and the external pipe. Otherwise the lining, whether high alloy metal or refractory, can collapse from the external pressure load.

HIGH-TEMPERATURE VALVING

Some of the plants evaluated in this study not only require pressure piping systems for fluids greater than 1500 F (1089 K), but also cycle some of the fluid systems through frequent pressure and temperature excursions by off and on operation of valves. Obtaining or developing valves to reliably function as active cyclical control elements in such a demanding environment will be a major technical achievement.

An application of high-temperature valves similar to that required here is presently being accomplished with blast furnace systems in the steel industry. Both "goggle" and "gate" type valves rated at 2800 F (1811 K) and 50 psig (345×10^3 N/m^2) are offered by one manufacture (ref. 7). These valves use water cooling that introduces a heat loss in the energy conversion system, are designed for low pressure use, and are not designed for continuous cyclical operation. Thus this available valving would have to be evaluated in detail and perhaps significantly modified for use in certain of the systems studied herein.

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Section 10

SUMMARY OF RESULTS FOR ENERGY CONVERSION SUBSYSTEMS AND COMPONENTS

The objective of the Task I Study of Advanced Energy Conversion Techniques for coal or coal-derived fuels was to develop a technical-economic information base on the ten conversion systems under investigation. A large number of parametric variations were studied in order to select the systems and cycle conditions which demonstrated the potential of the conversion concept.

The major emphasis of this study was the evaluation of the prime cycles. The auxiliary systems were selected and coupled to each cycle in ways which were aimed at showing the potential of the basic energy conversion system. The common systems, i.e., furnaces, bottoming cycles, balance of plant, were evaluated by the same study team for each cycle concept. This approach maintained a commonality of analysis through the ten conversion systems.

A summary of comparative results of furnace types, bottoming cycles, and clean fuels is presented in this section. These comparisons are made to give additional insight into the results for the conversion systems. The summary of results for the total energy conversions system is found in Part 3 of Volume II.

COMMON SUBSYSTEMS

Furnace Types

In the closed-cycle systems, energy has to be introduced into the cycle through an input heat exchanger. Several furnace concepts were explored for utilizing coal in an environmentally acceptable manner:

1. Direct Combustion of Coal

   a. Atmospheric fluidized beds
   b. Pressurized fluidized beds
   c. Conventional furnace with stack gas cleanup

2. Clean Fuels

   a. Conventional furnace with semi-clean fuel (solvent refined coal)

   b. Pressurized furnace with integrated low-Btu gasifier or high-Btu gas

Although these furnace systems were applied to each energy conversion system, the advanced steam cycle offers a convenient basis for furnace comparison. This comparison is shown in Figure 10-1 for the four furnace types. The pressurized fluidized bed is seen to have the potential for producing highest cycle effi-

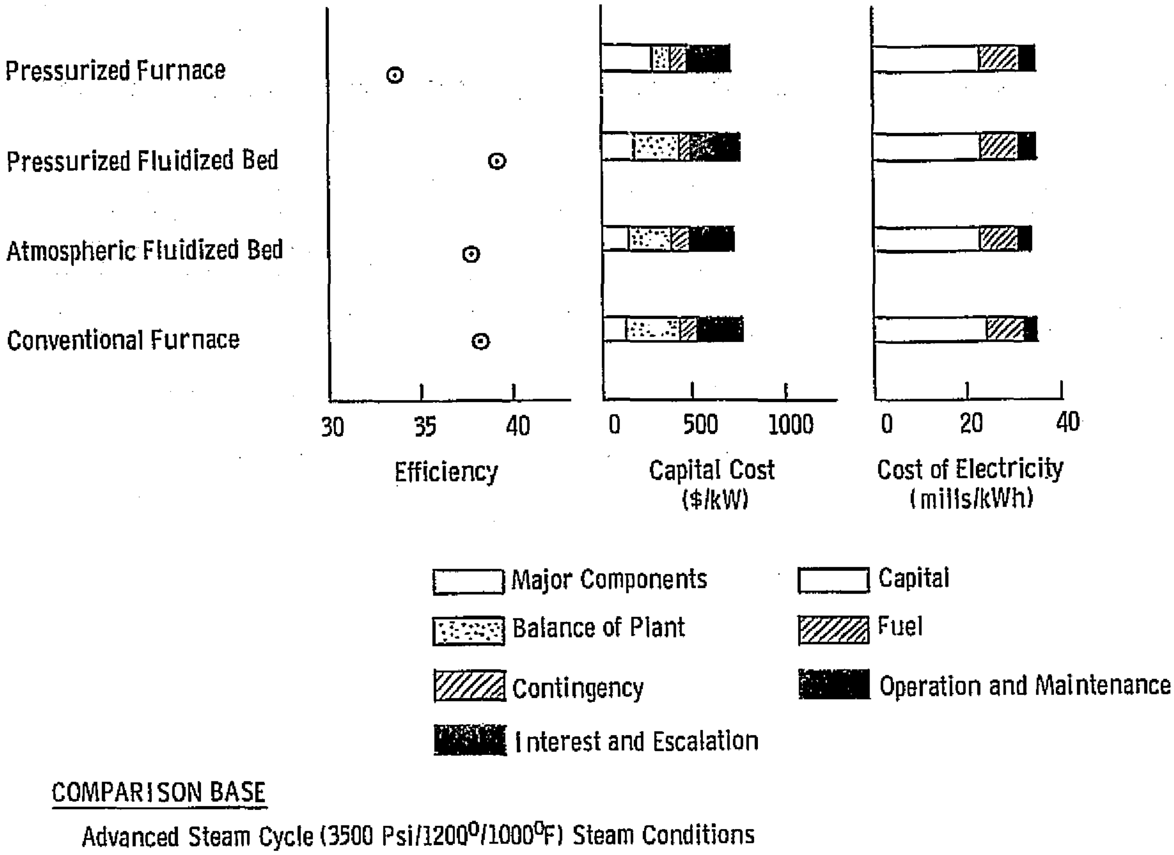

Figure 10-1. Variations in Furnace Types

ciencies. However, the lowest cost of electricity was achieved with the atmospheric fluidized bed.

The major component cost elements for these furnaces are shown in Table 10-1. The stack gas cleanup system in the conventional furnace is a major cost item. In the pressurized fluidized bed, the cost of the high-pressure coal and dolomite feed system and the high-temperature exhaust gas cleanup system, which is required before the furnace gases enter the pressurizing gas turbine, produces a higher capital cost for this system than for the atmospheric fluidized bed system. These costs are included in the furnace module costs. The major element of cost in the pressurized furnace is the gasifier, which produces an acceptable fuel.

In summary, the results presented for the advanced steam cycle indicate that the atmospheric fluidized bed is the most economical approach to direct combustion of coal. In both pressurized systems, a significant portion of the total plant output was derived from the pressurizing gas turbines, e.g., 55 percent in the pressurized furnace and 23 percent in the pressurized fluidized bed. This places a gas turbine system in a parallel cycle configuration with the prime cycle. For these systems to

Table 10-1

PRIMARY HEAT INPUT HEAT EXCHANGER COSTS

Components	Conventional Furnace	Atmospheric Fluidized Bed	Pressurized Fluidized Bed	Pressurized Furnace
Furnace module	$ 42/kW	$54/kW	$71/kW	$ 7/kW
Low-temperature air preheat	3	4	--	--
Pressurizing gas turbine	--	--	28	52
Gasifier	--	--	--	171
Stack gas cleanup	42	--	--	--
Totals	$ 87/kW	$58/kW	$99/kW	$230/kW

be successful, the reliability of gas turbines under base load conditions must be demonstrated.

In order to evaluate the pressurized fluidized bed on an equal basis for all closed-cycle systems, the pressurized fluidized bed with recuperator (PFB_R) applied to the pressurizing gas turbine was evaluated. In many of the closed-cycle systems, the PFB_R furnace system resulted in a configuration which had lower cost of electricity than the equivalent cycle configuration with an AFB. This was due in part to the higher average temperature differences in the PFB_R cases and subsequent reduction in furnace module cost. However a more critical element was the fact that substantial amounts of electricity were being generated at a rather low capital cost in the pressurizing gas turbines thus reducing the total $/kW of the combined furnace prime cycle system.

The pressurized furnace does offer a potential for integration of the furnace with the prime cycle in cases where a steam turbine is being employed as part of the conversion system. This close integration of the gasifier and steam cycle was not done in this Task I effort. Nevertheless, the resultant plant would still be a complex chemical-thermal conversion system. From thermodynamic considerations, the paralleling feature of the prime cycle and furnace cycle will probably result in lower overall efficiency than the prime cycle standing alone. However, when steam cycles are employed as part of the prime energy conversion system, integration with the feedwater heating train can result in lowering of the exhaust gas temperature and improvements in the overall plant efficiency.

For the particular case compared in Figure 10-1, the pressurized fluidized bed exhibited a higher overall efficiency. There is, however, a major uncertainty in the hot gas cleanup system. A difficult technology and equipment development are prerequisite to demonstrating that the exhaust from direct coal combustion can be cleaned up to a state acceptable to a high-temperature (in excess of 1500 F [1089 K]) gas turbine.

BOTTOMING CYCLES

Two different types of bottoming cycles were employed in this study: steam and organic. Although an attempt was made in all bottoming cycles to utilize state-of-the-art equipment, the steam cycle is a developed technology and the organic cycle is a developing technology. Thus the comparison of steam vs organic bottoming cycles cannot be truly made on a one-to-one basis.

The characteristics of organic cycles make them most attractive in the low power range (less than 100 MW) and at low cycle temperatures (~500 F [533 K]). At present there is a temperature limit on organic fluids which excludes their operation above 600 F (589 K). Therefore, all prime cycles which had the potential for producing bottoming cycle temperatures greater than 600 F (589 K) featured steam bottoming cycles.

The open-cycle gas turbine with recuperative heat exchanger was evaluated with an organic bottoming cycle. The comparison of the bottoming vs the nonbottoming cases are shown in Table 10-2 for the same gas turbine conditions. The overall efficiency of the conversion systems was increased by approximately 25 percent by the addition of the bottoming cycle. However, the added equipment and balance-of-plant capital cost of the organic cycle produced a slightly higher total cost of electricity for the bottomed case even though this cycle employed over-the-fence clean fuels at greater than $\$2/10^6$ Btu ($\$1.90/10^9$ J). The bottoming cycle added approximately 20 MW to the plant output. The incremental cost attributed to the bottoming cycle was $\$200/kW_{incr}$ for major components and $\$485/kW_{incr}$ for balance of plant.

Table 10-2

OPEN-CYCLE GAS TURBINE: RECUPERATIVE

Performance Factors	Nonbottomed	Organic Bottomed with OCT
Efficiency (percent)		
Power plant	34.4	42.6
Overall	17.3	21.5
Capital cost ($/kW)	166	338
Cost of electricity (mills/kWh)		
Capital	5.3	10.7
Fuel	25.8	20.8
Total	33.2	34.1

The only concept in which both organic and steam bottoming cycles were compared on a one-to-one basis was with the closed gas turbine cycle. This comparison is shown in Table 10-3. For these particular cases, the organic bottoming cycle was attractive both on an efficiency and a cost of electricity basis compared to the steam bottomed cycle. The steam cycle did not compare favorably at low cycle temperatures (500 F [533 K]). The higher efficiency of the closed gas turbine with organic bottoming resulted from the ability of the organic fluid to extract more energy from the prime cycle working fluid before it entered the precooler. This larger percentage of energy extraction resulted in higher bottoming cycle output.

In summary, the limit on organic fluid operating temperature curtails the employment of this bottoming cycle concept for many of the prime cycles. At low-temperature operation, the organic bottoming cycle is more attractive than steam because of its ability to match more closely the sensible heat rejection characteristics of the prime cycle working fluid and thus achieve a higher output from the bottoming cycle. The high capital costs which were incurred with the addition of an organic bottoming cycle to the open-cycle gas turbine recuperative resulted in an increase in the cost of electricity even though the efficiency increased significantly. A major item of this increased capital cost was in balance-of-plant considerations. A trend toward "skid" mounted major components in the small power ranges for this cycle would help reduce both the balance-of-plant costs and the time for construction.

Table 10-3

CLOSED-CYCLE GAS TURBINE BOTTOMING CYCLES

Performance Factors	Nonbottomed	Organic Bottomed	Steam Bottomed*
Efficiency (percent)			
Overall	29.5	36.8	33.3
Capital cost	814	947	924
Cost of electricity (mills/kWh)			
Capital	25.7	29.9	29.2
Fuel	9.8	7.9	8.7
Total	38.8	40.8	41.3

*Best steam bottomed cycles occur with no recuperator and have a cost of electricity of 37.0 mills/kWh. This condition is not suited for organics, due to high temperatures.

CLEAN FUELS FROM COAL

Semi-Clean Fuel

The potential exists for producing a semi-clean liquid fuel from coal at a lower price and higher processing efficiency than "clean" fuels. Semi-clean fuels could exhibit characteristics similar to residual oil, which is presently used by the utility industry. In this study, solvent refined coal (SRC) was evaluated as an example of this fuel class.

The semi-clean fuel was employed in the closed-cycle case as a fuel for a conventional furnace and in the open-cycle cases directly in the combustors.

Residual oils are presently used in the open-cycle gas turbines. With the use of an on-site fuel processing skid similar to that employed for residual oils, the semi-clean fuel was evaluated in open-cycle gas turbine combined cycle applications. A comparison of the semi-clean fuel and integrated-low Btu gasifier cases is shown in Table 10-4. Even with the less than 80 percent semi-clean fuel processing efficiency and the over-the-fence fuel cost of \$180/10^6 Btu (\$1.71/10^9 J), the overall efficiency and cost of electricity is slightly better for the semi-clean fuel case than for the integrated gasifier case. The employment of the over-the-fence fuel eliminates the requirement for operation of an on-site gasifier for fuel production. This application raises several major questions. The semi-clean fuel as specified from the solvent refined coal process has too high a fuel bound nitrogen content to permit adherence to the environmental standards. Further fuel processing would have to be accomplished before the NO_x criteria can be met. The on-site fuel processing skid currently employed for gas turbines would also have to be redesigned to accommodate the semi-clean fuel characteristics e.g., specific gravity, electrical conductivity, water solubility of alkaline metal salts. The heat recovery-heat exchange equipment would be susceptible to fouling, and tube cleaning provisions must be made. (A soot-blowing capital cost was included in all open-cycle gas turbine combined cycle cases employing SRC fuel.)

Table 10-4

SEMI-CLEAN FUELS
OPEN-CYCLE GAS TURBINE COMBINED CYCLE WATER-COOLED

Performance Factors	Low-Btu Fuel	Semi-Clean Fuels
Efficiency (percent)		
Plant	35.5	47.0
Overall	35.5	36.7
Cost of electricity (mills/kWh)		
Fuel	8.2	13.1
Total	25.2	23.6

In energy conversion systems in which coal is directly combusted, the employment of semi-clean fuels was shown not to be economically attractive. Table 10-5 makes a comparison for both

Table 10-5

DIRECT COAL-FIRED CYCLES WITH SEMI-CLEAN FUELS

Cycle	Ill. No. 6 Coal	Semi-Clean Fuel
Advanced Steam	Atmospheric Fluidized Bed	Conventional Furnace
Efficiency (percent)		
Plant	37.7	40.1
Overall	37.7	31.2
Cost of electricity (mills/kWh)		
Fuel	7.7	15.3
Total	33.1	38.6
Open-Cycle MHD	Direct Combustion	Direct Combustion
Efficiency (percent)		
Plant	49.2	51.6
Overall	48.3	40.2
Cost of electricity (mills/kWh)		
Capital	34.9	32.1
Fuel	6.2	11.9
Total	43.9	47.0

the advanced steam and open-cycle MHD concepts with direct combustion of coal as compared with semi-clean fuels. The employment of the semi-clean fuel did not result in either a higher overall efficiency or a lower cost of electricity for these concepts.

In summary, the semi-clean fuel appears to be an attractive alternative for cycles which require a clean fuel in order to meet the environmental specifications, e.g., open-cycle gas turbines. This is particularly true in the case of the water-cooled gas turbine. In this concept, high firing temperatures are obtained without the employment of transpiration cooling of the turbine blades which would introduce cooling passages that could be reduced in efficiency because of particulates in the combustion gas stream. Also, the water-cooled gas turbine has the potential of maintaining low enough metal temperatures so that hot corrosion problems produced by contaminants in the fuel might be reduced. In energy conversion concepts in which coal can be used directly, there seems to be no advantage in cost of electricity or overall energy efficiency for the semi-clean fuels. The one possible exception is the reduction of on-site capital expense and its replacement with higher fuel costs and subsequent off-site fuel processing capital costs.

Low-Btu Gasification

A fixed bed, low-Btu gasification system was employed in this study. Since fixed bed concepts are the closest systems to commercial application, this approach permits as realistic a cost estimation as possible for the gasification systems.

The low-Btu gasifier was employed as a fuel supply for both the open-cycle gas turbine combined cycle and the pressurized furnaces for the closed cycles.

In both instances, the gasifier was integrated with the conversion system. In order to achieve capital cost advantage, the gasifier and its cleanup system must operate at pressure. This requires a gas turbine compressor as an air supply and a gas turbine expander to recover the energy of compression. The presence of a steam cycle is also advantageous since the low-Btu gasifier has a significant steam demand and opportunities exist for thermodynamically coupling the gasifier and the power cycle.

The state-of-the-art fixed bed gasifier employed in this study had an efficiency of 88 percent* and a steam-to-coal ratio of 1.2. It is conceivable that advanced gasifier concepts could achieve 90 percent efficiency through improvements in the cleanup system, lower "feed" losses and thermally integrated subsystems. Test data have also been obtained on low steam-to-coal ratios ($\sim$0.4). This improvement might permit the gasifier to operate only on steam generated in the gasifier water jacket. Both of these improvements would have substantial impact on the conversion efficiency. For example, the open-cycle gas turbine combined cycle-water cooled could achieve an overall efficiency of 40 to 44 percent. Similar gains could be projected for the open-cycle gas turbine combined cycle-air cooled. Gains could also be projected for the closed cycles from gasifier improvements and other integration schemes.

In summary, the low-Btu gasifier is an attractive approach to producing clean fuel for cycles which demand this degree of fuel quality. This fuel supply system is most attractive with energy conversion concepts which have a compressed air supply, a combustion gas expansion turbine and a steam cycle. If these cycle components exist, advantages accrue from integration of the gasifier and conversion system.

*Defined as higher heating value of low-Btu gas output divided by HHV of coal input.

Appendix A

COAL TRANSPORTATION COST ESTIMATES

This Appendix records some representative coal transportation investment and operating cost estimates for railroad, waterway, and slurry pipelines. This is by no means a comprehensive assessment of coal transportation means. For example, a significant amount of the short haul transportation is by truck, which was not reviewed at all in this study. Furthermore, only the dedicated form of unit-train rail transportation was evaluated. Wherever practical, costs are presented on a per-unit basis, for the supply to a 250 x 10^9 Btu/day output coal refinery.

A. Railroad Unit Trains

Construction and operating costs have been calculated for dedicated unit trains for mine to refinery distances of 50, 100, 200, 300, and 500 miles. These costs are summarized below:

Unit Train and Dedicated Railroad Costs
(17,500 tons/day, or 6.4 X 10^6 tons of coal/year)

	(Costs in Millions)				
Construction	50 mi	100 mi	200 mi	300 mi	500 mi
a. Cars & locomotives	\$ 1.7	\$ 2.6	\$ 4.7	\$ 6.6	\$ 12.1
b. Single track @ \$400,000/mile	20.0	40.0	80.0	120.0	200.0
c. Communication & control equip.	0.5	0.5	2.0	2.5	3.0
d. Maintenance shops & misc. (est.)	1.0	1.2	1.5	2.0	2.6
Total Construction Costs	\$23.2	\$44.3	\$88.2	\$131.1	\$217.7
Operation					
a. No. of ton-miles/ year	3.2×10^8	6.4×10^8	1.28×10^9	1.92×10^9	3.2×10^9
b. Annual operating cost @ 6 mills/ ton-mile	\$ 1.9	\$ 3.8	\$ 7.7	\$ 11.5	\$ 19.2
c. No. of people (est.)	50	75	125	175	250

The following data on the Black Mesa and Lake Powell railroad were used as a guide in developing the equipment and operating estimates:

Distance - 80 miles 8×10^6 tons coal/year

1 Train:
3 - 6000 hp electric locomotives
78 - 120-ton hoppers
35 mph average - 55 mph maximum

1 round trip/8 hour shift
3 shifts/day, 6 days/week
Sunday used for maintenance and buffer

Loading at 0.5 to 0.8 mph
Dumping at 4 mph

Total investment (track and train) $57 million.

This Black Mesa system is completely automated; therefore, total investment is high as compared to the 100-mile column, above, which is based on operation by train crews with standard communication and control equipment. Although the 50- and 100-mile systems would lend themselves to automation, it is assumed that the longer distances would not; therefore, cost and personnel estimates are based on manning all systems in the 50-to-500-mile table.

The following explanatory notes cover sources and calculations:

1. Construction Costs—Cars and Locomotives

	(Costs are in Millions) Mine to Refinery Distance, Miles				
	50	100	200	300	500
Time per round trip at 35 mph (avg)	2.86 hr	5.71 hr	11.43 hr	17.14 hr	28.57 hr
Time for loading and unloading	1.14	1.29	1.57	1.86	2.43
Total time/round trip	4.00 hr	7.00 hr	13.00 hr	19.00 hr	31.00 hr
No. of round trips/ Week/train (1)	36	20	11	7	4
No. of round trips/ year/train (2)	1872	1040	572	364	208
No. of 120-Ton hopper cars req'd (3)	29	52	94	148	260
No. of unit trains req'd (80 cars max.)	1	1	2	2	4
No. of 120-ton cars/ train	29	52	47	74	65
No. of locomotives/ train	2-5000 hp	3-5000 hp	3-5000 hp	3-6000 hp	3-6000 hp

(Costs are in Millions) Mine to Refinery Distance, Miles	50	100	200	300	500
Cost of cars @ $25,000 each(4)	$ 0.8	$1.4	$2.6	$4.1	$7.2
Cost of locomotives(5)	0.9	1.2	2.1	2.5	4.9
Total cost - cars & locomotives	$ 1.7	$2.6	$4.7	$6.6	$12.1

Notes: (1) Assumes 3 shifts/day, 6 day week. Sundays for maintenance and buffer

(2) Assumes 52 weeks per year operation

(3) (6.4×10^6 - No. of round trips/year) - 120

(4) Including 10 percent spares

(5) Including spares: 5000 hp @ $300,000 ea.; 6000 hp @ $350,000 each

2. Cost of Track

Estimates include sidings for passing at the midpoint of the 200-and 300-mile systems and at the midpoint and quarter points for the 500-mile system. The Montana Burlington-Northern coal train track being built from Hysham to a new coal mine 38 miles away in the Sarpy Creek area will have a total cost of $11 MM or $290,000/mile for single track. (Reference: Burlington Northern NEWS, Vol. 3, No. 4, April 1973, pp. 12-13); Richard A. Rice, in "How to Reach that North Slope Oil: Some Alternatives and Their Economics," Technology Review, June, 1973, p. 14, quotes figures for double-track resource railways of $800,000 to $1,000,000 per mile in temperature climates. For single-track dedicated systems, $400,000 per mile is assumed to be a good average for the U.S.A.

3. Total Construction Costs

Loading and unloading facilities for coal are not included in these figures. It is assumed, however, that loading and unloading are done "on the fly" at speeds approximating those of the Black Mesa and Lake Powell railroad, which load at 0.5 and 0.8 mph and unload at 4 mph.

4. Operating Cost/Ton-Mile

Unit Train operating cost = 6 mills/ton-mile.

(Reference E.J. Wasp and T.L. Thompson, "Slurry Pipelines," The Oil and Gas Journal, Dec. 24, 1973, page 44, Figure 3.)

5. Number of People

Railroad union rules are assumed to apply. Train crews can work up to 12 hours/day, 7 days per week. 100 miles = 1 day's pay. This is assumed to be accounted for in the rate of 6 mills/ton-mile assumed in #4, above. Crews are assumed to consist of 2 in the front locomotive and 2 in the caboose per union rules, even though a crew of 2 can run a train.

Calculation of operating crews:

	Distance, Miles				
	50	100	200	300	500
No. of trains	1	1	2	2	4
No. of crews/train	3	3	3	3	4
No. of people at 4/crew	12	12	24	24	64
Plus extras for vacations, etc.	2	2	4	4	8
Total people for crews	14	14	28	28	72
Maintenance & other personnel*	36	61	97	147	178
Total no. of people	50	75	125	175	250

*Based on D&H experience per J.D. Thompson.

B. Waterborne Transport of Coal

In 1969, domestic waterborne haulage of bituminous coal was 153 million tons or 30.2 percent of such coal transported in the U.S. About two-thirds of this, 103.4 million tons, was carried by internal waterways (rivers and canals) which are the fastest rising segment of waterborne transportation. This 103.4 million tons is 20.4 percent of the total bituminous coal transported in the U.S. The remaining waterborne coal was carried by coastwise, lakewise, and local harbor movements.

Joint rail-water movement is also significant. In 1969, 63.4 million tons of coal or 18.5 percent of the railborne total destined for domestic consumption was joint rail-water movement. This excludes tidewater and lake exports.

Costs for water transportation of coal are much less than for rail or truck. The 1965 average rail charge was 9.9 mills per ton-mile.* By contrast, large volume, steady movements on the

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* U.S. Department of the Interior, Bureau of Mines, Transportation of Mineral Commodities on the Inland Waterways of the South-Central States, IC 8431 (1969), page 18.

inland rivers commonly cost 2.5 mills per ton-mile, and the average is probably 3.0 mills.†

The service characteristics of water transportation are well suited to bulk commodities, such as coal; and many U.S. waterways are navigable the year 'round (some winter shutdown on the Mississippi River north of Alton, Illinois, the Missouri River and the Greak Lakes). If coal refineries are located on these navigable waterways, transport of coal from the mines by joint water and other means will usually result in lowest transportation costs.

C. Slurry Pipelines

Construction and operating costs for coal slurry pipelines have been calculated for mine-to-refinery distances of 100, 300 500, 750, and 1000 miles. To arrive at an estimate of the corresponding electrical equipment content, a specific example, Black Mesa, may be cited. This line is 273 miles long, and has a capacity of 6,100,000 tons per year (about the same as the 6,400,000 tons/year of the "unit plant"). The 23,000 hp of motors, starters, switchgear, and transformers required amount to approximately $900,000 or $330,000/100 miles. However, there is a 6000-foot gradient (drop) over the length of this pipeline. It is estimated that, had the gradient been zero, approximately 50 percent more power would have been required making the cost approximately $500,000/100 miles.

These costs and other data are summarized below:

Slurry Pipeline (17,500 tons/day; 6.4×10^6 tons/year)

	Costs in Millions				
	100 mi	300 mi	500 mi	750 mi	1000 mi
Construction @ $350,000	$35.0	$105.0	$175.0	$262.5	$350.0
Electrical equip. content	0.5	1.5	2.5	3.8	5.0
Operation					
No. of ton-miles/year	6.4×10^8	1.92×10^9	3.2×10^9	4.8×10^9	6.4×10^9
Operating cost/ton-mile (mills)	1.3	7.5	6.8	6.2	5.8
Annual operating cost (including slurry preparation)	$ 8.3	$ 14.4	$ 21.8	$ 29.8	$ 37.1
No. of people (est.)	5	8	13	18	25

† The charges for barging coal on certain tributary rivers where congestion in obsolete navigation facilities is serious are privately reported to be as high as 7.0 mills per ton-mile, the highest reported. These charges may be expected to decline substantially as modern navigation facilities are brought into service.

For a volume of 6.4 million tons of coal per year, slurry pipeline operating costs become competitive with railroad unit trains above distances of 800 to 900 miles. For the longer and higher volume systems for which slurry pipelines become practical, they also have other advantages: (1) they are less sensitive to inflation, since few people are required for operation and maintenance and (2) they are placed underground where they have the least impact on the environment.

The following explanatory notes cover sources and calculations for summary above:

1. Construction Cost—Slurry Pipeline

The Black Mesa Coal Slurry Pipeline, which began operation in 1970, is an 18-inch-diameter pipeline 273 miles long, capable of transporting 5.5 million tons of coal annually. Assuming that for a given length, capacity is approximately proportional to the square of the diameter; a pipeline 20 inches in diameter would be required for 6.4 million tons/year.

A paper by Richard A. Rice, "How to Reach That North Slope Oil: Some Alternatives and their Economics," in *Technology Review*, June 1973, gives per-mile pipeline costs for oil and gas pipelines in a table on page 16. A 36-inch oil pipeline in the U.S. costs from $300,000 to $500,000 per mile, depending on terrain. An average cost of $350,000 appears reasonable for a 20-inch slurry pipeline. These costs do not include construction of facilities for slurry preparation.

2. Slurry Pipeline Cost/Ton-Mile

E. J. Wasp and T. L. Thompson in "Slurry Pipelines," *The Oil and Gas Journal*, December 24, 1973, give updated annual transportation costs for coal-slurry-pipelines as a function of throughput and distance in Figure 5, page 45. The operating costs per ton-mile were obtained from that graph for 6.4 million tons throughput per year. These figures include the operating cost of slurry preparation.

3. Number of People

These estimates were based on employment data for railroads and pipelines given in Table 875, page 537, U.S. Statistical Abstract—1972. Employment for pipelines is approximately 1/30 of that for railroads overall. Since unit trains use far fewer people than the average railroad, it is assumed that manpower required for slurry pipelines is 1/10 that of unit trains.

Appendix B

BALANCE-OF-PLANT ESTIMATE RESULTS FOR PARAMETRIC POINT VARIATIONS

This Appendix contains the tabulated results of the balance-of-plant requirements and cost estimates for all parametric points in the Task I Study. The column heading numbers correspond to the "case number" headings on the Parametric Point Definition tables given for each energy conversion system in Volume II of this report.

LIST OF TABLES

LIST OF TABLES (Cont'd)

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OPEN-CYCLE GAS TURBINE: BOP INFORMATION SUMMARY

ITEM	CASE NO. 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
ESTIMATED CONSTRUCTION TIME - YEARS	1.5	←								→	1.5	2	2	1.5	←	→	1.5
LAND REQUIRED - ACRES	2.5	←					→	2.5	16.5	17	2.1	4.5	3.1	2.5	←	→	2.5
COOLING TOWERS - NO. UNITS	NONE	←														→	NONE
UNIT SIZE - LENGTH - FT																	
- WIDTH - FT																	
HEIGHT FT																	
AUXILIARY POWER REQUIRED																	
AT COOLING TOWER - KWe	NONE	←														→	NONE
REST OF PLANT AUX. - KWe	1000	←					→	1000	3500(1)	3600(1)	250	4000	4000	1000	←	→	1000
CAPITAL COSTS TOTAL Millions $	2.19	←		→	2.19	2.26	←		→	2.26	.52	5.5	4.4	2.26	←	→	2.26
SITE LABOR - Millions $	.26	←		→	.26	.29	←		→	.29	.11	1.1	0.5	.29	←	→	.29
COOLING TOWERS - Millions $	NONE	←														→	NONE
ALL OTHER - Millions $	1.93	←		→	1.93	1.97	←		→	1.97	.41	4.4	3.9	1.97	←	→	1.97
OPERATING & MAINT. COST - Millions $ / Year	0.5	←					→	0.5	0.55	0.55	0.2	1.5	1.5	0.5	←	→	0.5
NET WATER CONSUMPTION - gpm	23	←					→	23	28	28	10	82	82	23	←	→	23

(1) Includes steam generation for heating oil.

Table B-1 (Page 2 of 2)

OPEN-CYCLE GAS TURBINE: BOP INFORMATION SUMMARY

ITEM	CASE NO. 18	19	20	21	22	23	24	25	26	27	28	29	30	31	34	35	36
ESTIMATED CONSTRUCTION TIME - YEARS	1.5											1.5	2				2
LAND REQUIRED - ACRES	2.5											2.5	5				5
COOLING TOWERS - NO. UNITS	NONE											NONE	4			4	2
UNIT SIZE - LENGTH - FT													30			30	36
- WIDTH - FT													30			30	75
- HEIGHT - FT													25			25	47
AUXILIARY POWER REQUIRED													3280			3280	2900
AT COOLING TOWER - KWe	NONE											NONE	830			830	350
REST OF PLANT AUX. KWe	1000											1000	2450			2450	2550
CAPITAL COSTS TOTAL - Millions $	2.26											2.26	16.0			16.0	14.3
SITE LABOR - Millions $	.29											.29	3.7			3.7	3.3
COOLING TOWERS - Millions $	NONE											NONE	1.4			1.4	2.9
ALL OTHER - Millions $	1.97											1.97	10.9			10.9	10.71
OPERATING & MAINT. COST - Millions $ / Year	0.5											0.5	1.0				1.0
NET WATER CONSUMPTION - gpm	23											23	26			26	650

Table B-2a

OPEN-CYCLE GAS TURBINE

COST ESTIMATE SUMMARY: PARAMETRIC VARIATION BOP CAPITAL COSTS

	All Costs in Dollars (Millions)						
	Case #	Site Labor	Cooling Tower System	Emission Control Equip.	Seed Recovery Equip.	All Other	BOP Const. Cost
Base Case	1	0.26	-	-	-	1.93	2.19
Parametric Variations:	2-5	same as base					

Table B-2b

OPEN-CYCLE GAS TURBINE WITH RECUPERATION

COST ESTIMATE SUMMARY: PARAMETRIC VARIATION BOP CAPITAL COSTS

	All Costs in Dollars (Millions)						
	Case #	Site Labor	Cooling Tower System	Emission Control Equip.	Seed Recovery Equip.	All Other	BOP Const. Cost
Base Case	6	0.29	-	-	-	1.97	2.26
Parametric Variations:	7-10	same as base					
	11	0.11	-	-	-	0.41	0.52
	12	1.1	-	-	-	4.4	5.5
	13	0.5	-	-	-	3.9	4.4
	14-29	same as above					

Table B-2c

OPEN-CYCLE GAS TURBINE WITH RECUPERATION AND ORGANIC BOTTOMING CYCLE

COST ESTIMATE SUMMARY: PARAMETRIC VARIATION BOP CAPITAL COSTS

	All Costs in Dollars (Millions)						
	Case #	Site Labor	Cooling Tower System	Emission Control Equip.	Seed Recovery Equip.	All Other	BOP Const. Cost
Base Case	30	3.7	1.4	-	-	10.9	16.0
Parametric Variations:	31-35	same as base					
	36	3.3	0.29	-	-	10.71	14.3

Table B-3 (Page 1 of 2)

OPEN-CYCLE GAS TURBINE COMBINED CYCLE-AIR COOLED

BOP INFORMATION SUMMARY

ITEM	CASE NO.																
	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
ESTIMATED CONSTRUCTION TIME - YEARS	3	←	→	3	2.9	←	→	2.9	3	3	3	4	3	←		→	3
LAND REQUIRED - ACRES	31 (1)	31 (1)	42 (1)	35 (1)	8	←	→	8	28	26	18 (1)	56 (1)	31 (1)	←		→	31 (1)
COOLING TOWERS - NO. UNITS	5	←							→	5	2	10	4	6	7	6	8
UNIT SIZE - LENGTH - FT	36	←														→	36
- WIDTH - FT	75	←														→	75
- HEIGHT - FT	47	←														→	47
AUXILIARY POWER REQUIRED	13500	←	→	13300	13100	←	→	13100	18300	18100	7550	29350	13300	13660	13830	13660	14010
AT COOLING TOWER - KWe	900									900	350	1750	700	1060	1230	1060	1410
REST OF PLANT AUX. - KWe	126·0	←	→	12600	12200	←	→	12200	17400 (3)	17200 (3)	7200	22600	12600	←		→	12600
CAPITAL COSTS TOTAL - Millions $	51.9	51.9	58.5	54.1	←	→	54.1	37.0	41.0	41.0	26.5	102 5	51.9	←		→	51.9
SITE LABOR - Millions $	11.7	11.7	13.3	12.3	←	→	12.3	8.5	8.8	8.8	5.9	23.0	11.7	←		→	11.7
COOLING TOWERS - Millions $	.6	.6	.6	.6	←	→	.6	.6	.6	.6	.3	1.2	.6	.7	.9	.7	0.6
ALL OTHER - Millions $	39.6	39.6	44.6	41.2		→	41.2	27.9	31.6	31.6	20.3	78.3	39.6	←		→	39.6
OPERATING & MAINT. COST - Millions $ / Year	3.0 (2)	←	→	3.0 (2)	2.5	←	→	2.5	2.6	2.6	1.8 (2)	5.0 (2)	3.0 (2)	←		→	3.0 (2)
NET WATER CONSUMPTION - 1000 gpm	3.9	3.9	4	4	2.9	←			→	2.9	1.95	7.7	3.0	4.6	6.5	5.8	7.1

(3) Includes steam generation for heating oil.
(2) Does not include O&M for LBTU Gas plant.
(1) Does not include acreage for LBTU Gas plant process equip.

Table B-3 (Page 2 of 2)

OPEN-CYCLE GAS TURBINE COMBINED CYCLE-AIR COOLED

BOP INFORMATION SUMMARY

ITEM	CASE NO. 18	19	20	21	22	23	24	25	26	27	29	30	31	32	33	34	35
ESTIMATED CONSTRUCTION TIME - YEARS	3	←														→	3
LAND REQUIRED - ACRES	31 (1)	←											→	31 (1)	32 (1)	31 (1)	31 (1)
COOLING TOWERS - NO. UNITS	8	4	4	4	5	←							→	5	10	5	5
UNIT SIZE - LENGTH - FT	36	←											→	36	30	36	36
· WIDTH - FT	75	←											→	75	30	75	75
· HEIGHT - FT	47	←											→	47	25	47	47
AUXILIARY POWER REQUIRED	14400	13300	13300	13300	13500	←							→	13500	25100	13900	13500
AT COOLING TOWER - KWe	1400	700	700	700	900	←							→	900	2500	900	900
REST OF PLANT AUX. - KWe	13000	12600	←											→	12600	13000	12600
CAPITAL COSTS TOTAL Millions $	51.9	←											→	51.9	55.7	51.9	51.9
SITE LABOR - Millions $	11.7	←											→	11.7	12.5	11.7	11.7
COOLING TOWERS - Millions $	0.6	.6	←										→	.6	1.8	.6	.6
ALL OTHER - Millions $	39.6	←											→	39.6	41.4	39.6	39.6
OPERATING & MAINT. COST - Millions $ / Year	3.1 (2)	3.0 (2)	←											→	3.0 (2)	3.1 (2)	3.0 (2)
NET WATER CONSUMPTION - 1000 gpm	7.1	3.1	3.6	3.5	3.9	←						→	3.9	4.1	1.2	3.9	3.9

(2) Does not include O&M for LBTU Gas Plant.

(1) Does not include acreage for LBTU Gas Plant process equip.

Table B-4

OPEN-CYCLE GAS TURBINE, COMBINED CYCLE AIR COOLED

COST ESTIMATE SUMMARY: PARAMETRIC VARIATION BOP CAPITAL COSTS

	Case #	All Costs in Dollars (Millions) Site Labor	Cooling Tower System	Emission Control Equip.	Seed Recovery Equip.	All Other	BOP Const. Cost
Base Case	1	11.7	.6	-	-	39.6	51.9
Parametric Variations:	2	11.7	.6	-	-	39.6	51.9
	3	13.3	.6	-	-	44.6	58.5
	4-7	12.3	.6	-	-	41.2	54.1
	8	8.5	.6	-	-	27.9	37.0
	9-10	8.8	.6	-	-	31.6	41.0
	11	5.9	.3	-	-	20.3	26.5
	12	23.0	1.2	-	-	78.3	102.5
	13-32	same as base					
	33	12.5	1.8	-	-	41.4	55.7
	34-35	same as base					

Table B-5 (Page 1 of 2)

OPEN-CYCLE GAS TURBINE COMBINED CYCLE-WATER COOLED

BOP INFORMATION SUMMARY

ITEM	CASE NO. 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
ESTIMATED CONSTRUCTION TIME - YEARS	4	←→	4	3	3	3	4	5	4	←						→	4
LAND REQUIRED - ACRES	47 (1)	58 (1)	51 (1)	12	98	93	27 (1)	58 (1)	47 (1)	←						→	47 (1)
COOLING TOWERS - NO. UNITS	7	←→	7	8	←→	8	5	9	8	8	7	5	7	5	7	←→	7
UNIT SIZE - LENGTH - FT	36	←														→	36
- WIDTH - FT	75	←														→	75
- HEIGHT - FT	47	←														→	47
AUXILIARY POWER REQUIRED	20230	20480	20330	19900	27700	27400	10900	28580	20400	20400	20330	19900	20330	19900	20330	←→	20330
AT COOLING TOWER - KWe	1230	1230	1230	1400	←→	1400	900	1580	1400	1400	1230	900	1230	900	1230	←→	1230
REST OF PLANT AUX. - KWe	19000	19250	19100	18500	26300 (3)	26000 (3)	10000	27000	19000	19000	19000	19000	19000	19000	←	→	19000
CAPITAL COSTS TOTAL - Millions $	77.0	87.1	80.8	55.2	60.6	61.7	51.5	103.1	77.0	←						→	77.0
SITE LABOR - Millions $	17.3	19.7	18.2	12.5	13.0	13.0	11.5	23.1	17.3	←						→	17.3
COOLING TOWERS - Millions $	1.4	1.4	1.4	1.4	1.4	1.4	0.9	1.8	1.4	←						→	1.4
ALL OTHER - Millions $	58.3	66.0	61.2	41.3	46.2	47.3	39.1	78.2	58.3	←						→	58.3
OPERATING & MAINT. COST - Millions $ / Year	5 (2)	←→	5 (2)	4	←→	4	3 (2)	6 (2)	5 (2)	←						→	5 (2)
NET WATER CONSUMPTION - 1000 gpm	6.5	6.8	6.6	5.5	←→	5.5	4.3	8.7	7.4	6.8	6.5	5.6	6.8	5.4	6.4	6.5	6.6

(3) Includes steam generation for heating oil.

(2) Does not include O&M for LBTU Gas Plant.

(1) Does not include acreage for LBTU Gas plant process equipment.

Table B-5 (Page 2 of 2)

OPEN-CYCLE GAS TURBINE COMBINED CYCLE-WATER COOLED

BOP INFORMATION SUMMARY

ITEM	CASE NO. 18&19	20	21&22	23	24	25	26	27	28
ESTIMATED CONSTRUCTION TIME - YEARS	DELETED	4	DELETED	4	←			→	4
LAND REQUIRED - ACRES		47 (1)		47 (1)	←			→	47 (1)
COOLING TOWERS - NO. UNITS		7		14	14	7	7	6	6
UNIT SIZE - LENGTH - FT		36		30	30	36	←	→	36
- WIDTH - FT		75		30	30	75	←	→	75
- HEIGHT - FT		47		25	25	47	←	→	47
AUXILIARY POWER REQUIRED		20230		22500	22500	20230	20230	20060	20060
AT COOLING TOWER - KWe		1230		3500	3500	1230	1230	1060	1060
REST OF PLANT AUX. - KWe		19000		19000	←			→	19000
CAPITAL COSTS TOTAL - Millions $		77.0		91.0	95.1	77.0	←	→	77.0
SITE LABOR - Millions $		17.3		20.4	19.0	17.3	←	→	17.3
COOLING TOWERS - Millions $		1.4		5.5	3.7	1.4	←	→	1.4
ALL OTHER - Millions $		58.3		65.1	62.4	58.3	←	→	58.3
OPERATING & MAINT. COST - Millions $ / Year		6 (2)		5 (2)	4.5 (2)	4.5 (2)	5 (2)	← →	5 (2)
NET WATER CONSUMPTION - 1000 gpm		6.5		2.6	2.6	6.8	6.6	5.6	5.7

(2) Does not include O&M for LBTU Gas plant.

(1) Does not include acreage for LBTU Gas plant process equipment.

Table B-6

OPEN-CYCLE GAS TURBINE, COMBINED CYCLE WATER COOLED
COST ESTIMATE SUMMARY: PARAMETRIC VARIATION BOP CAPITAL COSTS

	Case #	Site Labor	Cooling Tower System	Emission Control Equip.	Seed Recovery Equip.	All Other	BOP Const. Cost
		All Costs in Dollars (Millions)					
Base Case	1	17.3	1.4	-	-	58.3	77.0
Parametric Variations:	2	19.7	1.4	-	-	66.0	87.1
	3	18.2	1.4	-	-	61.2	80.8
	4	12.5	1.4	-	-	41.3	55.2
	5	13.0	1.4	-	-	46.2	60.6
	6	13.0	1.4	-	-	47.3	61.7
	7	11.5	.9	-	-	39.1	51.5
	8	23.1	1.8	-	-	78.2	103.1
	9-17, 20	17.3	1.4	-	-	58.3	77.0
	23	20.4	5.5	-	-	65.1	91.0
	24	19.0	3.7	-	-	62.4	85.1
	18-19, 21-22	Deleted					

Table B-7 (Page 1 of 3)

CLOSED-CYCLE GAS TURBINE

BOP INFORMATION SUMMARY

ITEM	CASE NO. 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
ESTIMATED CONSTRUCTION TIME - YEARS	4	←			→	4	3	4	5	6	4	3	4	←		→	4
LAND REQUIRED - ACRES	33	41	36	33 (1)	41 (1)	36 (1)	16	35	50	86	33	16	33	←		→	33
COOLING TOWERS - NO. UNITS	12	←					→	12	24	48	11	13	11	13	12	←→	12
UNIT SIZE - LENGTH - FT	36	←														→	36
- WIDTH FT	75	←														→	75
- HEIGHT FT	47	←														→	47
AUXILIARY POWER REQUIRED	4350	4450	4400	4100	←	→	4100	4350	8200	15900	4175	4275	4175	4525	4350	←→	4350
AT COOLING TOWER - KWe	2100	←					→	2100	4200	8400	1925	2275	1925	2275	2100	←→	2100
REST OF PLANT AUX. - KWe	2250	2350	2300	2000	←	→	2000	2250	4000	7500	2250	2000	2250	←		→	2250
CAPITAL COSTS TOTAL - Millions $	62.3	64.0	62.3	72.6	79.6	62.3	34.7	63.1	118.2	226.4	62.3	←				→	62.3
SITE LABOR - Millions $	13.0	13.4	13.0	16.0	17.9	13.0	7.3	13.2	24.8	47.6	13.0	←				→	13.0
COOLING TOWERS - Millions $	2.3	2.3	2.3	2.3	2.3	2.3	2.3	2.3	4.4	8.6	2.3	←				→	2.3
ALL OTHER - Millions $	47.0	48.3	47.0	54.3	57.4	47.0	25.1	47.6	89.0	170.2	47.0	←				→	47.0
OPERATING & MAINT. COST - Millions $ / Year	3.0	←			→	3.0	2.5	3.0	←	→	3.0	2.5	3.0	←		→	3.0
NET WATER CONSUMPTION - 1000 gpm	3.6	←					→	3.6	7.2	14.4	3.3	3.9	3.3	3.9	3.6	←→	3.6

(1) Does not include acreage for LBTU Gas plant process equipment.

Table B-7 (Page 2 of 3)

CLOSED-CYCLE GAS TURBINE

BOP INFORMATION SUMMARY

ITEM	CASE NO. 18	19	20	21	22	23	24	25	26	27	28	29	30	31	32	33
ESTIMATED CONSTRUCTION TIME - YEARS	4	←			→	4	3	3	4	←		→	4	3	←→	3
LAND REQUIRED - ACRES	33	←			→	33	16	16	33	←		→	33	16	←→	16
COOLING TOWERS - NO. UNITS	12	12	15	18	24	10	14	12	10	13	9	11	13	11	12	14
UNIT SIZE - LENGTH - FT	36	←	→	36	30	36	←								→	36
- WIDTH - FT	75	←	→	75	30	75	←								→	75
- HEIGHT - FT	47	←	→	47	25	47	←								→	47
AUXILIARY POWER REQUIRED	4350	4350	4875	5400	8250	4000	4450	4100	4000	4525	3825	4175	4525	3925	4100	4450
AT COOLING TOWER - KWe	2100	2100	2625	3150	6000	1750	2450	2100	1750	2275	1575	1925	2275	1925	2100	2450
REST OF PLANT AUX. - KWe	2250	←			→	2250	2000	2000	2250	←		→	2250	2000	2000	2000
CAPITAL COSTS TOTAL - Millions $	62.3	←	→	62.3	84.7	62.3	←								→	62.3
SITE LABOR - Millions $	13.0	←	→	13.0	18.1	13.0	←								→	13.0
COOLING TOWERS - Millions $	2.3	←	→	2.3	9.2	2.3	←								→	2.3
ALL OTHER - Millions $	47.0	←	→	47.0	57.4	48.3	←								→	48.3
OPERATING & MAINT. COST - Millions $ / Year	3.0	←			→	3.0	2.5	2.5	3.0	←		→	3.0	2.5	←→	2.5
NET WATER CONSUMPTION - 1000 gpm	3.6	3.6	4.5	5.4	NIL	3.0	4.2	3.6	3.0	3.9	2.7	3.3	3.9	3.3	3.6	4.2

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CLOSED-CYCLE GAS TURBINE

BOP INFORMATION SUMMARY

ITEM	Case No. 34	35	36	37	38	39	40	41	42	43	44	45
ESTIMATED CONSTRUCTION TIME - YEARS	5					5		5				5
LAND REQUIRED - ACRES	35					35		35				35
COOLING TOWERS - NO. UNITS	7					7	DELETED	6	9	18	11	8
UNIT SIZE - LENGTH - FT	36					36		36	36	30	36	36
- WIDTH - FT	75					75		75	75	30	75	75
- HEIGHT - FT	47					47		47	47	25	47	47
AUXILIARY POWER REQUIRED	3725					3725		3550	4075	7000	4425	3900
AT COOLING TOWER - KWe	1225					1225		1050	1575	4500	1925	1400
REST OF PLANT AUX. - KWe	2500					2500		2500				2500
CAPITAL COSTS TOTAL - Millions $	95.4				95.4	102.7		95.4	80.7	105.7	80.7	80.7
SITE LABOR - Millions $	23.2				23.2	24.9		23.2	17.8	25.6	17.8	17.8
COOLING TOWERS - Millions $	1.3				1.3	5.2		1.3	1.7	~~6.8~~	1.7	1.7
ALL OTHER - Millions $	70.9				70.9	72.6		70.9	61.2	73.3	61.2	61.2
OPERATING & MAINT. COST - Millions $ / Year	3.5					3.5		3.5				3.5
NET WATER CONSUMPTION - 1000 gpm	2.1					2.1		1.8	2.7	NIL	3.3	2.4

Table B-8

CLOSED-CYCLE GAS TURBINE

COST ESTIMATE SUMMARY: PARAMETRIC VARIATION BOP CAPITAL COSTS

		All Costs in Dollars (Millions)					
	Case #	Site Labor	Cooling Tower System	Emission Control Equip.	Seed Recovery Equip.	All Other	BOP Const. Cost
Base Case	1	13.0	2.3	-	-	47.0	62.3
Parametric Variations:	2	13.4	2.3	-	-	48.3	64.0
	3	same as base					
	4	16.0	2.3	-	-	54.3	72.6
	5	17.9	2.3	-	-	59.4	79.6
	6	same as base					
	7	7.3	2.3	-	-	25.1	34.7
	8	13.2	2.3	-	-	47.6	63.1
	9	24.8	4.4	-	-	89.0	118.2
	10	47.6	8.6	-	-	170.2	226.4
	11-21	same as base					
	22	18.1	9.2	-	-	57.4	84.7
	23-33	same as base					
	34-38	23.2	1.3	-	-	70.9	95.4
	39	24.9	5.2	-	-	72.6	102.7
	40	deleted					
	41	23.2	1.3	-	-	70.9	95.4
	42	17.8	1.7	-	-	61.2	80.7
	43	25.6	6.8	-	-	73.3	105.7
	44-45	17.8	1.7	-	-	61.2	80.7

Table B-9

SUPERCRITICAL CO_2

BOP INFORMATION SUMMARY

ITEM	CASE NO. 1	2	3	4	5	6	7	8	9	10	11→26	27	28→32
ESTIMATED CONSTRUCTION TIME - YEARS	5	6	5	←			→	5	4	4	5	5	5
LAND REQUIRED - ACRES	40	55	44	49	42	40 (1)	44 (1)	49 (1)	18	18	40	40	40
COOLING TOWERS - NO. UNITS	14	28	14	←						→	14	28	14
UNIT SIZE - LENGTH - FT	36	←								→	36	25	36
- WIDTH - FT	75	←								→	75	25	75
- HEIGHT - FT	47	←								→	47	30	47
AUXILIARY POWER REQUIRED	5550	10500	5650	5750	5550	5350	5450	5550	5250	5250	5550	10100	5550
AT COOLING TOWER - KWe	2450	4900	2450	←						→	2450	7000	2450
REST OF PLANT AUX. - KWe	3100	5600	3200	3300	3100	2900	3000	3100	2800	2800	3100	3100	3100
CAPITAL COSTS TOTAL - Millions $	180	360	182.5	182.5	182.6	201.9	206.6	214.8	165.0	165.0	180	190.3	180
SITE LABOR - Millions $	32.1	64.2	32.7	32.7	32.5	39.3	40.5	42.6	29.6	29.6	32.1	34.5	32.1
COOLING TOWERS - Millions $	1.9	3.8	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	1.9	5.2	1.9
ALL OTHER - Millions $	146	292	147.9	147.9	148.2	160.7	164.2	170.3	133.5	133.5	146	150.6	146
OPERATING & MAINT. COST - Millions $ / Year	4	7	4	←				→	3.5	3.5	4	4	4
NET WATER CONSUMPTION - 1000 gpm	4.2	8.4	4.2	←						→	4.2	NIL	4.2

(1) Does not include acreage for LBTU Gas plant process equip.

SUPERCRITICAL CO_2 CYCLE

COST ESTIMATE SUMMARY: PARAMETRIC VARIATION BOP CAPITAL COSTS

		All Costs in Dollars (Millions)					
	Case #	Site Labor	Cooling Tower System	Emission Control Equip.	Seed Recovery Equip.	All Other	BOP Const. Cost
Base Case	1	32.1	1.9	-	-	146.0	180.0
Parametric Variations:	2	64.2	3.8	-	-	292.0	360.0
	3&4	32.7	1.9	-	-	147.9	182.5
	5	32.5	1.9	-	-	148.2	182.6
	6	39.3	1.9	-	-	160.7	201.9
	7	40.5	1.9	-	-	164.2	206.6
	8	42.6	1.9	-	-	170.3	214.8
	9-10	29.6	1.9	-	-	133.5	165.0
	11-26	same as base					
	27	34.5	5.2	-	-	150.6	190.3
	28-32	same as base					

Table B-11 (Page 1 of 2)

ADVANCED STEAM

BOP INFORMATION SUMMARY

ITEM	CASE NO. 1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17
ESTIMATED CONSTRUCTION TIME - YEARS	5	5	6	5	5	←—→											5
LAND REQUIRED - ACRES	35	28	50	63	35	←—→								35	40	37	35
COOLING TOWERS - NO. UNITS	40 cells	30 cells	60 cells	80 cells	40 cells	38 cells	34 cells	40 cells	80 cells	40 cells	←—→		40 cells	37 cells	40 cells	←—→	40 cells
UNIT SIZE - LENGTH - FT	[illegible]6	←—→						36	30	36	←—→						36
- WIDTH - FT	[illegible]	←—→						75	30	75	←—→						75
- HEIGHT - FT	47	←—→						47	25	47	←—→						47
AUXILIARY POWER REQUIRED	19000	14650	27500	44000	19000	18650	17950	19000	19000	29000	←—→		19000	18475	19000	19000	20000
AT COOLING TOWER - KWe	7000	5250	10500	14000	7000	6650	5950	7000	7000	7000	←—→		7000	6475	1000	7000	[illegible]
REST OF PLANT AUX. - KWe	12000	9400	17000	30000	12000	←—→										12000	13000
CAPITAL COSTS TOTAL - Millions $	220	170	330	440	220	←—→		220	246.0	220	←—→			220	233	220	232.2
SITE LABOR - Millions $	37.2	28.7	55.8	74.4	37.2	(2)	(2)	37.2	43.6	37.2	←—→		37.2	(2)	43	37.2	43
COOLING TOWERS - Millions $	5	3.8	7.5	10.	5	(2)	(2)	5	13.5	5	←—→		5	(2)	5	5	5
ALL OTHER - Millions $	177.8	137.5	266.7	355.6	177.8	(2)	(2)	177.8	188.9	177.8	←—→		177.8	(2)	185	177.8	185.2
OPERATING & MAINT. COST - Millions $ / Year	9.0	7.3	12.2	15	9.0	←—→											9.0
NET WATER CONSUMPTION - 1000 gpm	12	9	18	24	12	11.4	10.2	12	0.4	12	←—→		12	11.1	12	←—→	12
ENVIRONMENTAL INTRUSION	NA ←—→																
SO_2 - 1000 lb/Hr.	↓																4.9
NO_x - 1000 lb/Hr.																	4.8
HC - 1000 lb/Hr.																	Nil
PARTICULATES - 1000 lb/Hr.																	.24
															EMISSION CONTROL COST		
															Labor		10.3
															Material		32.4
															Total		42.7

(2) Minor Variations, Negligible.

Table B-11 (Page 2 of 2)

ADVANCED STEAM

BOP INFORMATION SUMMARY

ITEM	CASE NO. 18	19	20	21	22	23	24	25	26	27	28
ESTIMATED CONSTRUCTION TIME - YEARS	5	←								→	5
LAND REQUIRED - ACRES	35	35	95	37(1)	37(1)	37(1)	37	←		→	37
COOLING TOWERS - NO. UNITS	40 cells	←							→	40 cells	80 cells
UNIT SIZE - LENGTH - FT	36	←							→	36	30
- WIDTH - FT	75	←							→	75	30
- HEIGHT - FT	47	←							→	47	25
AUXILIARY POWER REQUIRED	20000	20000	33000	19000	←				→	19000	20900
AT COOLING TOWER - KWe	7000	←							→	7000	8900
REST OF PLANT AUX. - KWe	13000	13000	26000	12000	←					→	12000
CAPITAL COSTS TOTAL - Millions $	240.2	235.2	203.2	249.0	266.7	258.4	220.0	244.0	244.0	223.6	266
SITE LABOR - Millions $	45.8	43.9	33.4	46.8	51.4	49.3	35.6	41.5	36.1	37.8	48.5
COOLING TOWERS - Millions $	5	5	5	6	6	6	6	6	6	6	20
ALL OTHER - Millions $	189.4	186.3	164.8	196.2	205.3	203.1	178.4	196.5	182.2	179.8	197.5
OPERATING & MAINT. COST - Millions $ / Year	9.0	9.0	10.0	10.0	10.7	10.7	11.0	11.0	11.0	11.0	9.0
NET WATER CONSUMPTION - 1000 gpm	12	←		(3)	(3)	(3)			→	12	0.4
ENVIRONMENTAL INTRUSION											
SO_2 - 1000 lb/Hr.	6.1	5.0	4.8								
NO_x - 1000 lb/Hr.	5.3	4.9	2.0								
HC - 1000 lb/Hr.	Nil	Nil	Nil								
PARTICULATES - 1000 lb/Hr.	.25	.22	.16								
	EMISSION CONTROLS COST:										
	10.3	10.3	5.4	Labor: Millions $							
	32.4	32.4	13.0	Materials: Millions $							
	42.7	42.7	18.4	Total: Millions $							

(1) Does not include acreage for LBTU Gas Plant Process Equip.

(3) Does not include water to the LBTU Gas Plant Process Equipment.

Table B-12

ADVANCED STEAM CYCLE

COST ESTIMATE SUMMARY: PARAMETRIC VARIATION BOP CAPITAL COSTS

		All Costs in Dollars (Millions)					
	Case #	Site Labor	Cooling Tower System	Emission Control Equip.	Seed Recovery Equip.	All Other	BOP Const. Cost
Base Case	1	37.2	5.0	-	-	177.8	220.0
Parametric Variations:	2	28.7	3.8	-	-	137.5	170.0
	3	55.8	7.5	-	-	266.7	330.0
	4	74.4	10.0	-	-	355.6	440.0
	5-8	same as base					
	9	43.6	13.5	-	-	188.9	246.0
	10-14	same as base					
	15	43.0	5.0	-	-	185.0	233.0
	16	same as base					
	17	39.7	5.0	32.4	-	183.3	260.4
	18	42.7	5.0	32.4	-	192.3	272.0
	19	40.8	5.0	32.4	-	186.6	264.8
	20	29.5	5.0	13.0	-	163.7	211.0
	21	46.8	6.0	-	-	196.2	249.0
	22	51.4	6.0	-	-	209.3	266.7
	23	49.3	6.0	-	-	203.1	258.4
	24	31.1	6.0	-	-	163.7	200.8
	25	36.3	6.0	-	-	181.2	223.5
	26	31.5	6.0	-	-	170.3	207.8
	27	37.8	6.0	-	-	179.8	223.6
	28	48.5	20	-	-	197.5	266.0

Table B-13

LIQUID METAL TOPPING CYCLE

BOP INFORMATION SUMMARY

ITEM	CASE NO. 1	2	3	4	5	6	7	8	9	10	11–13	16	17	18
ESTIMATED CONSTRUCTION TIME - YEARS	6	←				→	6	7	6	←			→	6
LAND REQUIRED - ACRES	50	54	58	52(1)	56(1)	60(1)	30	61	52	30	50	←	→	50
COOLING TOWERS - NO. UNITS	48	←				→	48	72	48	48	48	96	48	48
UNIT SIZE - LENGTH - FT	36	←								→	36	30	36	36
- WIDTH - FT	75	←								→	75	30	75	75
- HEIGHT - FT	47	←								→	47	25	47	47
AUXILIARY POWER REQUIRED	29000	29200	29400	29000	29200	29400	28400	42600	29000	28400	29000	44600	29000	29000
AT COOLING TOWER - KWe	8400	←				→	8400	12600	8400	8400	8400	24000	8400	8400
REST OF PLANT AUX. - KWe	20600	20800	21000	20600	20800	21000	20000	30000	20600	20000	20600	20600	20600	20600
CAPITAL COSTS TOTAL - Millions $	408.1	413.3	413.3	452.7	460.3	476.4	379.1	602.6	413.4	379.1	408.1	465.9	430.6	430.6
SITE LABOR - Millions $	73.4	74.7	74.7	87.4	89.9	93.9	66.7	108.6	74.2	66.7	73.4	87.3	77.2	77.2
COOLING TOWERS - Millions $	6.2	6.2	6.2	6.2	6.2	6.2	6.2	4.3	6.2	6.2	6.2	24.7	6.2	6.2
ALL OTHER - Millions $	328.5	332.4	332.4	358.6	364.2	376.3	306.2	489.7	333.0	306.2	328.5	353.9	347.2	347.2
OPERATING & MAINT. COST - Millions $/Year	15	←			→	15	14	15	15	14	15	←	→	15
NET WATER CONSUMPTION - 1000 gpm	14.4	←				→	14.4	21.6	14.4	14.4	14.4	0.4	14.4	14.4

(1) Does not include acreage for LBTU Gas plant : misc equip.

Table B-14a

POTASSIUM LIQUID METAL TOPPING CYCLE

COST ESTIMATE SUMMARY: PARAMETRIC VARIATION BOP CAPITAL COSTS

	Case #	All Costs in Dollars (Millions) Site Labor	Cooling Tower System	Emission Control Equip.	Seed Recovery Equip.	All Other	BOP Const. Cost
Base Case	1	73.4	6.2	-	-	328.5	408.1
Parametric Variations:	2-3	74.7	6.2	-	-	332.4	413.3
	4	87.4	6.2	-	-	358.6	452.7
	5	89.9	6.2	-	-	364.2	460.3
	6	93.9	6.2	-	-	376.3	476.4
	7	66.7	6.2	-	-	306.2	379.1
	8	108.6	9.3	-	-	484.7	602.6
	9	74.2	6.2	-	-	333.0	413.4
	10	66.7	6.2	-	-	306.2	379.1
	11-13	same as base					
	16	87.3	24.7	-	-	353.9	465.9

Table B-14b

CESIUM LIQUID METAL TOPPING CYCLE

COST ESTIMATE SUMMARY: PARAMETRIC VARIATION BOP CAPITAL COSTS

	Case #	All Costs in Dollars (Millions) Site Labor	Cooling Tower System	Emission Control Equip.	Seed Recovery Equip.	All Other	BOP Const. Cost
Base Case	17	77.2	6.2		not determined	347.2	430.6
Parametric Variations:	18	same as base					

Table B-15

OPEN-CYCLE MHD

BOP INFORMATION SUMMARY

ITEM	CASE NO. 1	2	3	4	5	6→21	22	23	24-30
ESTIMATED CONSTRUCTION TIME - YEARS	7	6.5	6	7	⟶				7
LAND REQUIRED - ACRES	70	48	30	74	78	70	UNDEFINED	70	70
COOLING TOWERS - NO. UNITS	48	29	14	48	48	48		56	48
UNIT SIZE - LENGTH - FT	36	⟵			⟶	36		30	36
- WIDTH - FT	75	⟵			⟶	75		30	75
- HEIGHT - FT	47	⟵			⟶	47		25	47
AUXILIARY POWER REQUIRED	40500	25075	12700	40750	40950	40500		46100	41200
AT COOLING TOWER - KWe	8400	5075	2450	8400	8400	8400		14000	8400
REST OF PLANT AUX. - KWe	32100	20000	10250	32350	32550	32100		32100	32800
CAPITAL COSTS TOTAL - Millions $	868.0	534.0	294.0	875.0	889.0	868.0		913.5	772.0
SITE LABOR - Millions $	178.0	109.5	60.2	179.7	182.8	178.0		188.5	158.5
COOLING TOWERS - Millions $	8.2	5.0	2.8	8.2	8.2	8.2		22.2	8.2
ALL OTHER - Millions $	681.8	419.5	231.0	687.1	698.0	681.8		702.8	605.3
OPERATING & MAINT. COST - Millions $ / Year	23	14.5	8	23	23	23		23	23
NET WATER CONSUMPTION - 1000 gpm	14	8.7	4.2	14	14	14		0.4	14

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Table B-16a

OPEN-CYCLE MHD WITH DIRECT COAL

COST ESTIMATE SUMMARY: PARAMETRIC VARIATION BOP CAPITAL COSTS

	Case #	All Costs in Dollars (Millions) Site Labor	Cooling Tower System	Emission Control Equip.	Seed Recovery Equip.	All Other	BOP Const. Cost
Base Case	1	178.0	8.2	-	-	681.8	868.0
Parametric Variations:	2	109.5	5.0	-	-	419.5	534.0
	3	60.2	2.8	-	-	231.0	294.0
	4	179.7	8.2	-	-	687.1	875.0
	5	182.8	8.2	-	-	698.0	889.0
	6-21	same as base					
	22	undefined					
	23	188.5	22.2	-	-	702.8	913.5

Table B-16b

OPEN-CYCLE MHD WITH SRC FUEL

COST ESTIMATE SUMMARY: PARAMETRIC VARIATION BOP CAPITAL COSTS

	Case #	All Costs in Dollars (Millions) Site Labor	Cooling Tower System	Emission Control Equip.	Seed Recovery Equip.	All Other	BOP Const. Cost
Base Case	24	158.5	8.2	-	-	605.3	772.0
Parametric Variations:	25-30	158.5	8.2	-	-	605.3	772.0

Table B-17

INERT GAS MHD CLOSED-CYCLE
BOP INFORMATION SUMMARY

ITEM	CASE NO. 1	2	3	4,5 & 6	7→14	15	16	17	18	19,20&21	22
ESTIMATED CONSTRUCTION TIME - YEARS	6	7	4	6	6	6	7	←		→	7
LAND REQUIRED - ACRES	35	65	10	10	35	35	55	58	61	55	55
COOLING TOWERS - NO. UNITS	20	40	12	20	20	40	40	←	→	40	80
UNIT SIZE - LENGTH - FT	36	36	30	36	36	30	36	←	→	36	30
- WIDTH - FT	75	75	30	75	75	30	75	←	→	75	30
- HEIGHT - FT	47	47	25	47	47	25	47	←	→	47	25
AUXILIARY POWER REQUIRED	20500	39000	5500	19900	20500	27000	40700	40800	40700	40700	40700
AT COOLING TOWER - KWe	3500	7000	3000	3500	3500	10000	7000	←	→	7000	20000
REST OF PLANT AUX. - KWe	17000	32000	2500	16400	17000	17000	32000	32000	32000	32000	32000
EMISSION CONTROL - KWe	NONE	←			→	NONE	1700	1800	1700	1700	1700
CAPITAL COSTS TOTAL - Millions $	310	620	34.4	304	310	331.9	740	742	746	740	748
SITE LABOR - Millions $	58.5	117	11.3	57.9	58.5	63.7	135.9	136.5	137.3	135.9	137.7
COOLING TOWERS - Millions $	4	8	3.6	4	4	11.0	8	8	8	8	10.4
ALL OTHER - Millions $	247.5	495	19.5	242.1	247.5	257.2	542.6	544	547.2	542.6	546.4
EMISSION CONTROL - Millions $	NONE	←			→	NONE	53.5	53.5	53.5	53.5	53.5
OPERATING & MAINT. COST - Millions $ / Year	9	15	2	9	9	9	17	←		→	17
NET WATER CONSUMPTION - 1000 gpm	6	12	NIL	6	6	.15	13	←	→	13	.5
ENVIRONMENTAL INTRUSION											
SO_2 - 1000 lb/Hr.							7.85	9.78	7.96	7.85	7.85
NO_x - 1000 lb/Hr.							7.63	8.43	7.78	7.63	7.63
HC - 1000 lb/Hr.							—	—	—	—	—
PARTICULATES - 1000 lb/Hr.							0.38	0.40	0.36	0.38	0.38

Table B-18a

CLOSED-CYCLE INERT GAS MHD WITH CLEAN FUEL

COST ESTIMATE SUMMARY: PARAMETRIC VARIATION BOP CAPITAL COSTS

	All Costs in Dollars (Millions)						
	Case #	Site Labor	Cooling Tower System	Emission Control Equip.	Seed Recovery Equip.	All Other	BOP Const. Cost
Base Case	1	58.5	4.0	-		247.5	310.0
Parametric Variations:	2	117.0	8.0	-	-	495.0	620.0
	3	11.3	3.6	-	-	19.5	34.4
	4-6	57.9	4.0	-	-	242.1	304.0
	7-14	same as base					
	15	63.7	11.0	-	-	257.2	331.9

Table B-18b

CLOSED-CYCLE INERT GAS MHD WITH DIRECT COAL

COST ESTIMATE SUMMARY: PARAMETRIC VARIATION BOP CAPITAL COSTS

	All Costs in Dollars (Millions)						
	Case #	Site Labor	Cooling Tower System	Emission Control Equip.	Seed Recovery Equip.	All Other	BOP Const. Cost
Base Case	16	135.9	8.0	53.5	-	542.6	740.0
Parametric Variations:	17	136.5	8.0	53.5	-	544.0	742.0
	18	137.3	8.0	53.5	-	547.2	746.0
	19-21	same as base					
	22	137.7	10.4	53.5	-	546.4	748.0

Table B-19

LIQUID METAL MHD CLOSED-CYCLE
BOP INFORMATION SUMMARY

ITEM	CASE NO. 1	2	3	4	5	6	7	8	9	10	11→15	16	17
ESTIMATED CONSTRUCTION TIME - YEARS	6	5	7	6	←		→	6	5	6	←	→	6
LAND REQUIRED - ACRES	44	26	74	46	49	46 (1)	48 (1)	51 (1)	27	48	44	44	44
COOLING TOWERS - NO. UNITS	28	14	56	28	←					→	28	56	28
UNIT SIZE - LENGTH - FT	36	←								→	36	30	36
- WIDTH - FT	75	←								→	75	30	75
- HEIGHT - FT	47	←								→	47	25	47
AUXILIARY POWER REQUIRED	11100	5750	21800	11200	10300	11100	11200	11300	10900	11100	11100	20200	11100
AT COOLING TOWER - KWe	4900	2450	9800	4900	←					→	4900	14000	4900
REST OF PLANT AUX. - KWe	6200	3300	12000	6300	6400	6200	6300	6400	6000	6200	6200	6200	6200
CAPITAL COSTS TOTAL - Millions $	480	257	960	481.6	481.6	517.2	525.6	539.4	451.2	486.3	480	503	489
SITE LABOR - Millions $	85	45.6	170	85.4	85.4	97.1	99.2	102.7	79.9	86.2	85	90.5	87
COOLING TOWERS - Millions $	4.3	2.2	8.6	4.3	4.3	4.3	4.3	4.3	4.3	4.3	4.3	11.7	6.9
ALL OTHER - Millions $	390.7	209.2	781.4	391.9	391.9	415.8	422.1	432.4	367.0	395.8	390.7	406.8	395.1
OPERATING & MAINT. COST - Millions $ / Year	9	7.5	16	9	←		→	9	8	9	←	→	9
NET WATER CONSUMPTION - 1000 gpm	8.4	4.2	16.8	8.4	←					→	8.4	0.2	8.4

(1) Does not include acreage for LBTU Gas Plant Process Equipment

Table B-20

CLOSED-CYCLE LIQUID METAL MHD

COST ESTIMATE SUMMARY: PARAMETRIC VARIATION BOP CAPITAL COSTS

	Case #	Site Labor	Cooling Tower System	Emission Control Equip.	Seed Recovery Equip.	All Other	BOP Const. Cost
		All Costs in Dollars (Millions)					
Base Case	1	85	4.3			390.7	480.0
Parametric Variations:	2	45.6	2.2			209.2	257.0
	3	170	8.6			781.4	960.0
	4-5	85.4	4.3			391.9	481.6
	6	97.1	4.3			415.8	517.2
	7	99.2	4.3			422.1	525.6
	8	102.7	4.3			432.4	539.4
	9	79.9	4.3			367.0	451.2
	10	86.2	4.3			395.8	486.3
	11-15	same as base case					
	16	90.5	11.7			400.8	503.0
	17	87.0	6.9			395.1	489.0

Table B-21

FUEL CELLS

BOP INFORMATION SUMMARY

ITEM	LOW TEMPERATURE CASE NO.													HIGH TEMPERATURE			
	1	2	4,5&6	7	8	9	10	11	12	13	14	15		1	2	3	4
ESTIMATED CONSTRUCTION TIME - YEARS	2	1.5	2	2	3	2	←				→	2		6	6	5	5
LAND REQUIRED - ACRES	4	3	4	3.5	10	5	4	4	4	4	5.5	4		50	55	47	48
COOLING TOWERS - NO. UNITS	NONE	←									→	NONE		32	←	→	32
UNIT SIZE - LENGTH - FT														36	←	→	36
- WIDTH - FT														75	←	→	75
- HEIGHT - FT														47	←	→	47
AUXILIARY POWER REQUIRED														63300	63400	53300	57300
AT COOLING TOWER - KWe	NONE	←									→	NONE		5600	5600	5600	5600
REST OF PLANT AUX. - KWe	3400	1750	3400	3600	4650	3200	3300	3600	3800	3800	3800	3800		57700	57800	47700	51700
CAPITAL COSTS TOTAL - Millions $	2.76	1.38	2.76	2.76	10.49	3.37	2.95	2.95	3.01	3.01	3.42	3.01		248.00	248.00	126.00	175.00
SITE LABOR - Millions $	0.38	0.19	0.38	0.38	1.44	0.51	0.45	0.45	0.47	0.47	0.52	0.47		48.93	48.93	25.90	35.20
COOLING TOWERS - Millions $	NONE	←									→	NONE		3.49	3.49	3.49	3.49
ALL OTHER - Millions $	2.38	1.19	2.38	2.38	9.05	2.86	2.50	2.50	2.54	2.54	2.90	2.54		195.58	195.58	96.61	136.31
OPERATING & MAINT. COST - Millions $/Year	0.7	0.4	0.7	0.7	2.5	0.7	←				→	0.7		12	12	7	10
NET WATER CONSUMPTION - 1000 gpm	0.3	0.15	0.30	0.36	0.68	0.25	0.29	0.32	0.25	0.21	0.30	0.30		10	←	→	10

Table B-22a

LOW-TEMPERATURE FUEL CELLS

COST ESTIMATE SUMMARY: PARAMETRIC VARIATION BOP CAPITAL COSTS

	Case #	All Costs in Dollars (Millions): Site Labor	Cooling Tower System	Emission Control Equip.	Seed Recovery Equip.	All Other	BOP Const. Cost
Base Case	1	0.38				2.38	2.76
Parametric Variations:	2	0.19				1.19	1.38
	4-7	same as base case					
	8	1.44				9.05	10.49
	9	0.51				2.86	3.37
	10-11	0.45				2.50	2.95
	12-13	0.47				2.54	3.01
	14	0.52				2.90	3.42
	15	0.47				2.54	3.01

Table B-22b

HIGH-TEMPERATURE FUEL CELLS

COST ESTIMATE SUMMARY: PARAMETRIC VARIATION BOP CAPITAL COSTS

	Case #	All Costs in Dollars (Millions): Site Labor	Cooling Tower System	Emission Control Equip.	Seed Recovery Equip.	All Other	BOP Const. Cost
Base Case	1	48.93	3.49			195.58	248.0
Parametric Variations:	2	48.93	3.49			195.58	248.0
	3	25.90	3.49			96.61	126.0
	4	35.2	3.49			136.31	175.0

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