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HYDROGEN FROM COAL
COST ESTIMATION GUIDEBOOK

Billings
Energy
Corporation

HYDROGEN FROM COAL

COST ESTIMATION GUIDEBOOK

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This publication is designed to provide accurate and authoritative information in regard to the Subject Matter covered. Detailed documentation of baseline assumptions and extensive Sensitivity Analyses have been provided thereby allowing the user extensive flexibility in applying this information to specific projects in an accurate and meaningful manner.

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PREFACE

As the world energy shortage becomes more critical, alternative fuels must begin to receive more attention. Although several alternative fuel schemes are technically feasible, ultimate fuel selection criteria will eventually be based on economics. Unfortunately, it is very difficult to make meaningful cost comparisons of the diverse feedstocks and complex conversion processes involved in alternate fuel production systems, especially in an inflationary economy.

Perhaps the most interesting and least understood synthetic fuel alternative is hydrogen energy. It has been demonstrated that hydrogen can be synthesized, on a commercial scale, utilizing various coal gasification technologies. Traditionally, these processes have been used to generate hydrogen as a chemical feedstock. In many parts of the world ammonia is commercially synthesized utilizing feedstock hydrogen produced by coal gasification. To understand the production cost economics of producing hydrogen from coal requires a simultaneous evaluation of several independent variables which differ from site to site and project to project. The confusion and resulting disagreement among professionals on the cost of producing hydrogen from coal has been a serious deterrent to would-be hydrogen energy programs.

In an effort to establish baseline information whereby specific projects can be evaluated, on at least a preliminary basis, the United States Department of Energy, through the Jet Propulsion Laboratory, awarded a contract to the Billings Energy Corporation to organize a seminar of industrial specialists and collect a current set of parameters which are typical of coal gasification applications. Using these parameters a computer model has been developed which allows researchers to interrelate cost components in a sensitivity analysis. The results make possible an approximate estimation of hydrogen energy economics from coal, under a variety of circumstances. This is done by selecting the base case model most closely resembling the project under consideration and thereby modifying the base case assumptions utilizing the sensitivity analyses.

This report will provide the user with ready reference information which can be utilized to make a preliminary evaluation of a specific project. Additionally, it will provide resource information which will be useful during a more definitive evaluation phase.

The most significant reason why hydrogen energy systems will undergo commercial scale application in the near future is a result of the increased utilization efficiencies associated with hydrogen. It is possible to synthesize numerous hydrocarbon fuels from coal including methane, methanol, gasoline, and synthetic petroleum. In all of the above cases, hydrogen can be generated more efficiently and more economically from coal than can the other synthetic fuels. This advantage is modest in the case of methane, and it might be argued that the hydrogen advantage is more than offset by the increased difficulties associated with building an infrastructure for a new fuel. However, when the utilization efficiency advantages for hydrogen are included in the comparison, the conservation of resource and price advantage become substantial in favor of the pollution-free hydrogen system.

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CHAPTER I - HYDROGEN ENERGY TECHNOLOGY

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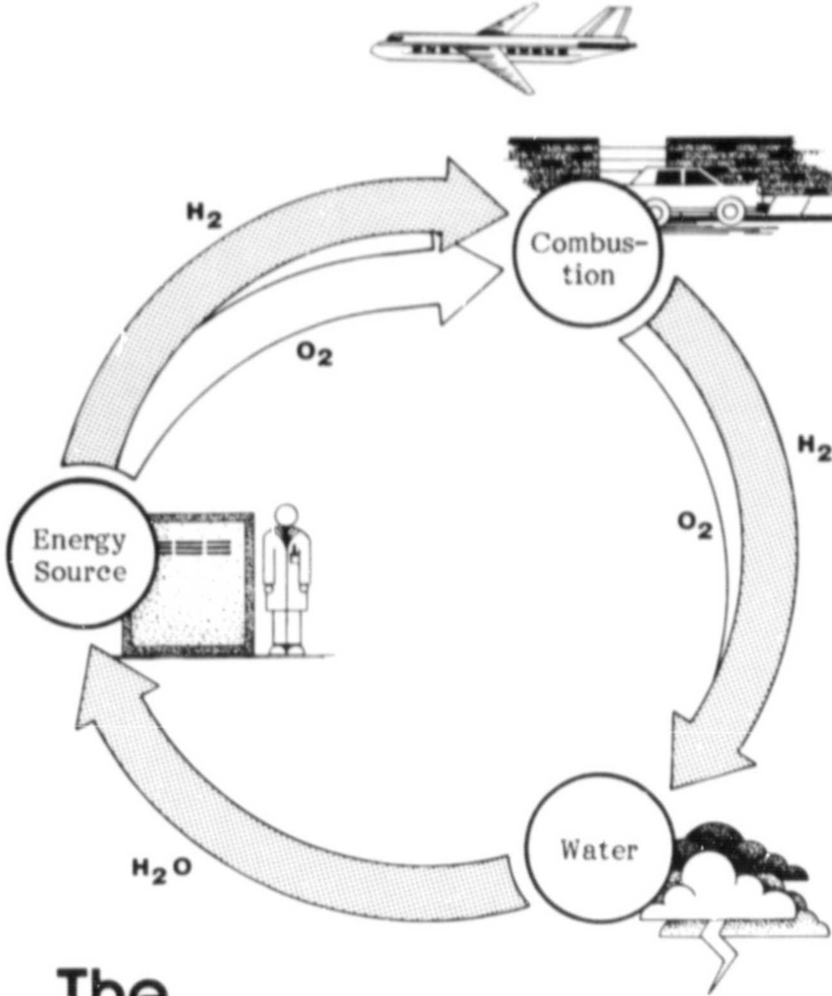
Hydrogen, the most abundant element in the universe, has the potential to supply mankind with an inexhaustible energy cycle provided that cycle can be fed by some energy source. In the cycle, hydrogen is produced by dissociating water into its component parts, hydrogen and oxygen. The oxygen can be stored or released to the atmosphere where it is available during the hydrogen combustion process. Hydrogen energy, taking the form of an odorless, non-toxic, colorless gas, can then be stored, transported, and converted via non-polluting means to desirable electrical or mechanical forms. (See Figure 1.)

Hydrogen Automotive Systems

Researchers have successfully demonstrated that hydrogen can be used as a vehicular fuel.[1] With a simple conversion, gasoline or hydrocarbon burning engines can be retrofitted with equipment to properly mix hydrogen and air. From this equipment, a combustible mixture enters the combustion chamber where it is ignited to provide energy during expansion to accelerate a piston and propel the vehicle in a conventional manner. Due to the unique chemical properties of hydrogen combustion, it is possible to eliminate all exhaust pollution from a hydrogen engine with the only by-product of combustion being pure water vapor.[2] Additionally, laboratory tests document a substantial increase in engine efficiency as compared with hydrocarbon fuels.[3] This increase in efficiency is attributable to the differences in chemical properties between hydrogen and the conventional hydrocarbon fuels. One difference is the flame speed of hydrogen which is an order of magnitude faster than the other fuels. This



The Hydrogen-Water Cycle

Figure 1:

As shown here, the total hydrogen energy concept can be viewed as a hydrogen-water cycle. The naturally occuring water molecule is split apart at the energy source forming hydrogen and oxygen. These two elements are then rejoined during combustion. After combustion, the water molecule reenters the environment as water vapor and is acted upon by the forces of nature eventually becoming liquid thereby completing the cycle.

allows engine designers to ignite the fuel charge later in the compression stroke. In this way more of the energy of combustion is released during the engine power stroke causing an Otto Cycle engine to more closly approximate the ideal Carnot Cycle.

Another major contributor to higher efficiencies from hydrogen engines is the fact that no air throttle is necessary in such engines. Power can be regulated by variances in the fuel equivalence ratio. This arrangement takes full advantage of higher engine efficiencies resulting from complete combustion of lean mixtures. It also eliminates normal pumping losses and lower volumetric efficiencies normally encountered in hydrocarbon engines operating at part throttle conditions.

Although the amount of efficiency increase of hydrogen over conventional fuels varies from engine to engine and from load to load, a conservative estimate of the efficiency gain under all types of driving is 25 percent. (See Figures 2 and 3.)

<u>Metal Hydride Storage Systems</u>

Traditionally, the major problem which has precluded the application of hydrogen fuel to vehicles was hydrogen storage on board the vehicle.

A new alternative hydrogen storage system for vehicular applications involves the reaction of hydrogen with certain intermetallic compounds to form metal hydrides.[4] In a metal hydride storage system, gaseous hydrogen is supplied under pressure to the vessel containing the hydriding material. The gaseous hydrogen reacts exothermically with the product metal alloy to form a hydride material. Utilizing heat from the engine cooling system or exhaust gases this process is reversible, and can supply sufficient hydrogen gas to service engine

Figure 2: Riverside Hydrogen Bus

This 19-passenger bus was test operated in passenger service by the City of Riverside, California in 1978. This test examined the concept of hydrogen fuel for transit systems. The pictured bus was the first hydrogen vehicle to be operated and maintained by a transit authority. It was converted to hydrogen by the Billings Energy Corporation. The bus is presently in use on a non-scheduled basis in Independence, Missouri, which is the location of the headquarters for Billings Energy Corporation.

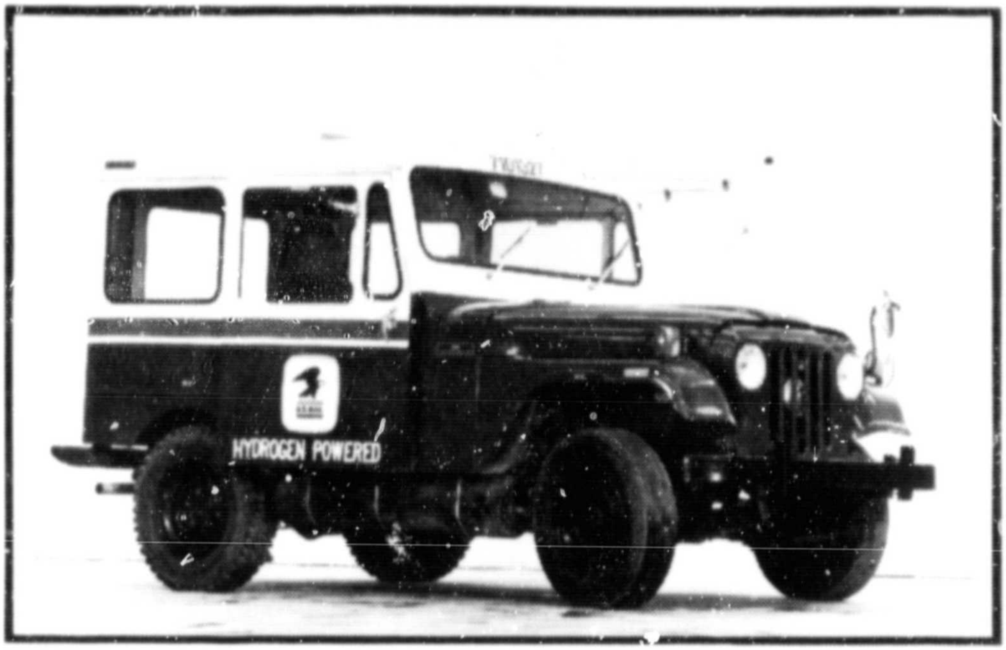


Figure 3: Postal Jeep

Pictured is a United States Postal Service delivery vehicle (1/4 ton Jeep DJ-5F) which has been converted by the Billings Energy Corporation to operate on hydrogen fuel. Included in the conversion design is gaseous fuel carburetion, engine water induction, and ignition system modifications. Originally converted to hydrogen in 1978, this Jeep will soon be operated on a delivery schedule by the Independence, Missouri Post Office under contract with the Billings Energy Corporation.

demand requirements.[5] This provides an exciting, safe, and compact method of storing hydrogen on board a vehicle.

The first hydrogen vehicle to successfully employ a metal hydride storage vessel was a Pontiac Grandville.[6] (See Figure 4.) Since this prototype, metal hydride storage vessels have been successfully tested in numerous vehicles.[7] The hydride storage vessels have undergone extensive safety testing and have been found to be substantially safer than conventional gasoline fuel tanks.[8]

Early metal hydride vessels suffered from severe weight penalties. New technology reduces the weight penalty of hydride storage systems to the extent necessary for successful vehicle application.

<u>Hydrogen Homestead</u>

For two and one-half years hydrogen has been successfully demonstrated as a fuel for domestic natural gas or propane replacement. In the hydrogen homestead project natural gas appliances were retrofitted for hydrogen service.[9] (See Figures 5 and 6.) Since hydrogen combustion generates no harmful pollution (except NO_x which is easily controlled in hydrogen combustion systems) it is not necessary to vent harmful exhaust fumes out of doors.[10] This factor provides the opportunity for a 30 to 40 percent increase in energy utilization efficiency for hydrogen. Additionally, tests of stove top burners indicate that 24 percent less energy is required to heat a pan with a hydrogen flame than with natural gas.[11] This is possible since the pan is placed directly in the flame, without fear of incomplete combustion or carbon buildup.

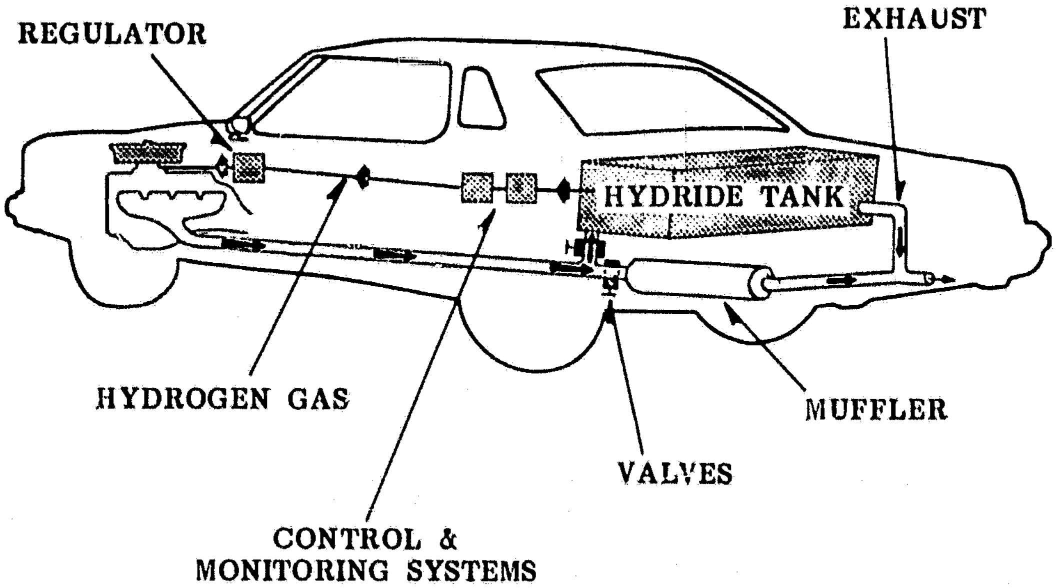


Figure 4: 1975 Pontiac Grandville

This figure is a schematic showing on-board locations of all of the basic components of a prototype hydrogen-powered automobile utilizing a metal hydride storage system. Engine modifications include increased compression ratio, carburetor water induction, and ignition system changes. Waste heat from the engine exhaust is circulated through the hydride tank to drive off stored hydrogen. Work was completed on the vehicle in 1976 by the Billings Energy Corporation.

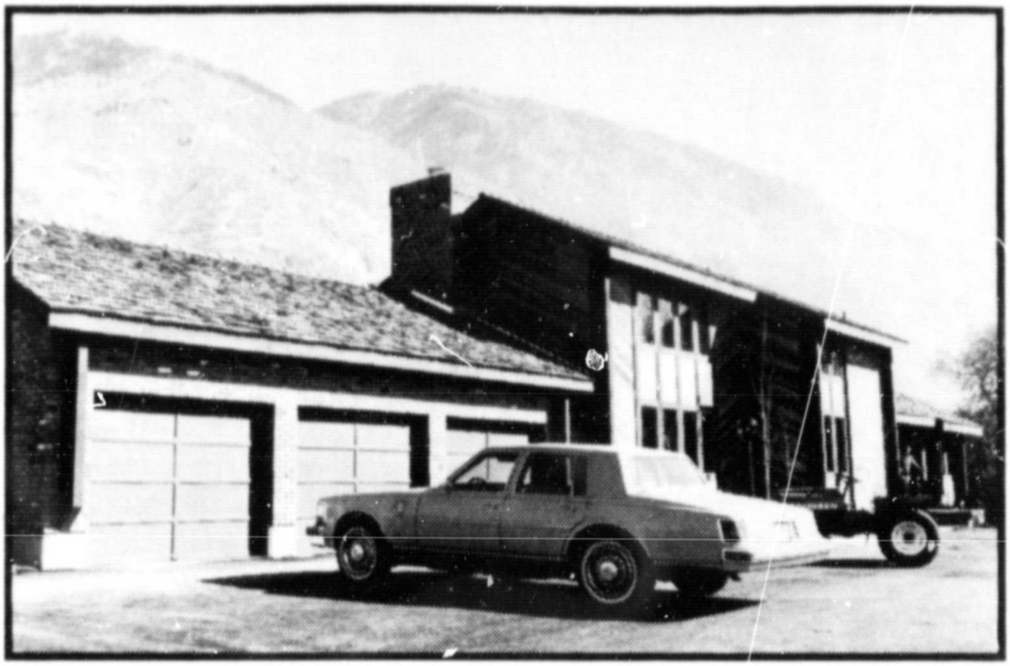


Figure 5: Hydrogen Homestead

This project, completed in 1977 in Provo, Utah, was a first step of plans moving towards the commercial implementation of hydrogen energy. In the Homestead, a complete domestic setting for the utilization of hydrogen was established. Data gathered from this application will help establish a baseline for expansion to a Hydrogen Village concept. Natural gas appliances in this home have been converted to operate with hydrogen.

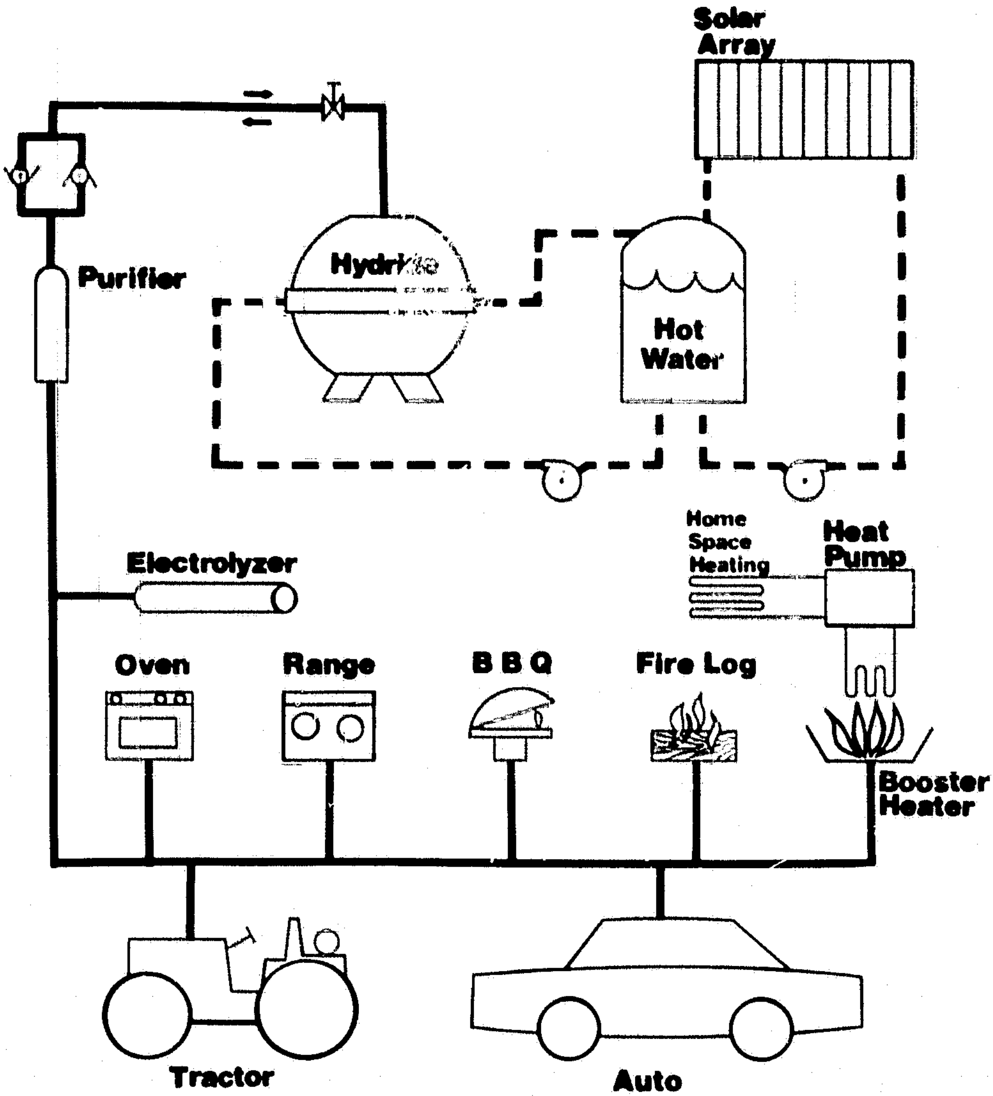


Figure 6: Hydrogen Homestead Energy System

The hydrogen system shown schematically in this figure was installed in the Hydrogen Homestead. Hydrogen, produced using a Billings Energy Corporation solid polymer electrolyzer, was utilized in five different natural gas appliances. Also supplied hydrogen was a 1977 Cadillac Seville and a Jacobsen garden tractor - both converted to hydrogen by the Billings Energy Corporation. When the system demand for hydrogen was low, it was storec in the metal hydride storage vessel as shown. A Billings Computer monitoring system provided instrumentation control and data collection functions.

Hydrogen Aircraft

When hydrogen is cooled to 423° below zero it condenses into its liquid form. It has been proposed that cryogenic liquid hydrogen would be an ideal fuel for aircraft applications.[12] As much as one-third of the gross weight of an aircraft on takeoff is jet fuel. Since hydrogen is the lightest of all chemical fuels, an equal amount of energy can be loaded on board an aircraft resulting in a substantial reduction in the gross aircraft weight. This reduction in weight provides an opportunity for the redesign of the aircraft to reduce the size of the engines, the landing gear and the wings to take advantage of the lighter weight. By making these reductions in the aircraft components, the weight is further reduced thereby requiring less hydrogen. The final result is an aircraft substantially lighter than in commercial service today, or alternatively, aircraft could be designed with a dramatic increase in payload or range.

Although hydrogen is a very light fuel, even in its liquid form, it is voluminous. Consequently, additional hydrogen storage space would be required as compared to the hydrocarbon fuels. It has been proposed that this storage be accommodated by enlarging the fuselage or by adding wing tip tanks. Extensive paper studies have considered the potential of hydrogen aircraft, including an analysis of the potential reduction in drag possible by circulating cryogenic liquids over the leading edges of the aircraft wings. Because of the extreme desirability of these advantages and the significant reduction in fuel consumption per payload mile, an important project is in the latter stages of planning which, if completed, will evaluate in actual operation the feasibility of this technology.[13] (See Figure 7.)

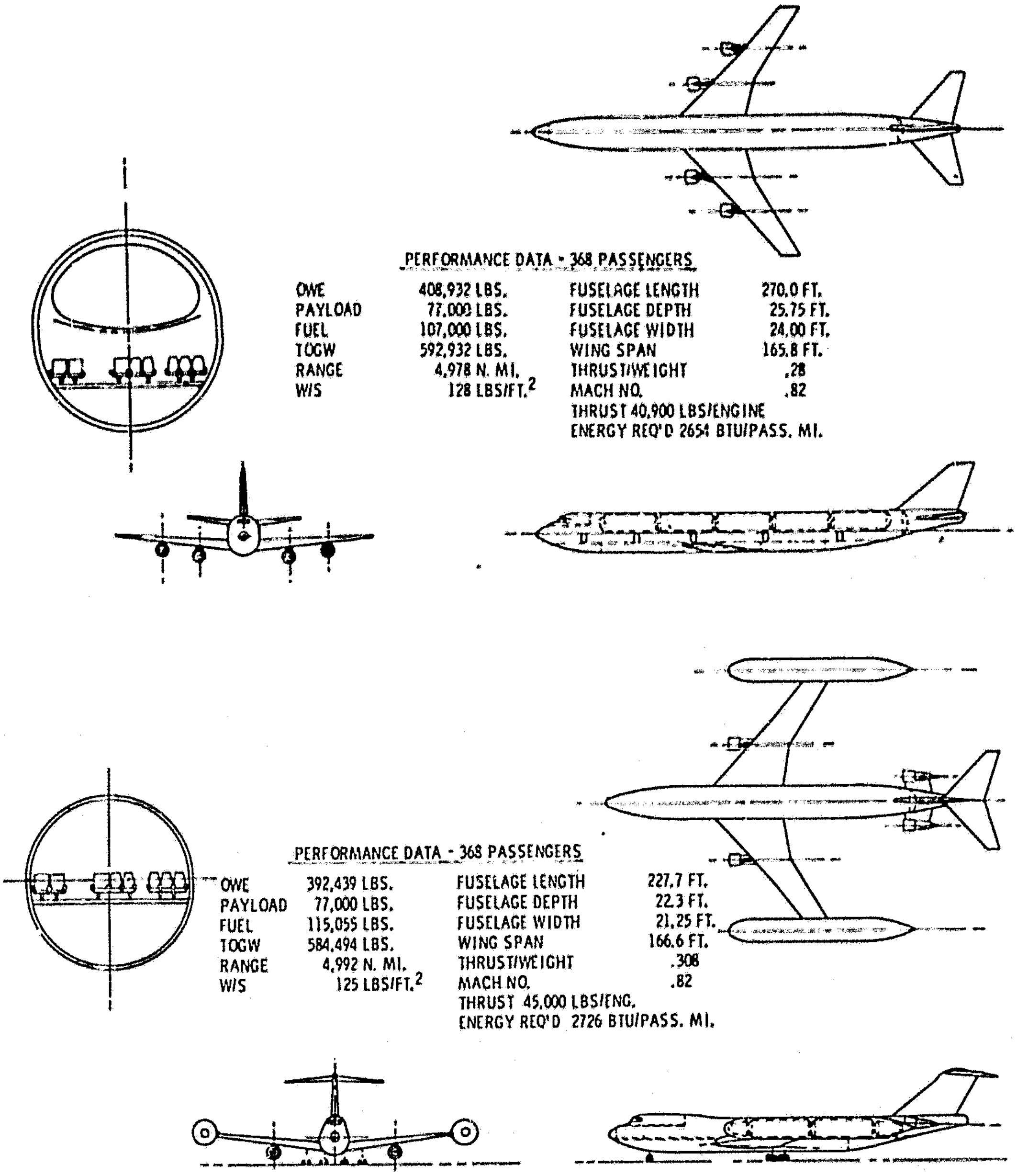


Figure 7: Hydrogen Aircraft

The top illustration shows a configuration for subsonic aircraft fueled with liquid hydrogen where the fuel tanks are placed in the fuselage. The bottom illustration shows a configuration for the same type of aircraft where the fuel tanks are located in nacelles over wing panels. (Reprinted with permission.)

Fuel Cells

Hydrogen has been demonstrated as an excellent fuel for electric power generation. Commercial gas turbines and diesel generators are readily available for hydrogen service. The most interesting way, however, to convert hydrogen into electrical energy is through a direct chemical process in equipment known as a fuel cell.

A fuel cell consists of a series of electrodes situated in such a way so as to enable the catalytic combination of hydrogen and oxygen to form water.[14] This electrochemical process generates an electric potential with an energy conversion efficiency of between 60 and 80 percent.

Fuel cells have been used extensively in the space program as a source of electricity. More recently development has been undertaken to develop commercial scale fuel cells utilizing feedstocks of ammonia, natural gas, methanol and petroleum. To utilize fuels other than hydrogen in a conventional fuel cell application, requires the converting of the fuels to a hydrogen rich gas which is acceptable to the fuel cell. The major problems with today's commercial scale fuel cell programs involve the conversion of the hydrocarbon fuel stock into hydrogen of a sufficient purity to maintain catalysts integrity within the fuel cell and to achieve efficient operation.[15] The problems in developing a commercial fuel cell are simplified substantially if pure hydrogen is available at the fuel cell feedstock.

Hydrogen Distribution and Storage

A major consideration regarding the technical feasibility of implementing a hydrogen energy system involves the ability to distribute and store hydrogen. The most efficient and economical method for transporting hydrogen is via underground pipeline. Extensive information is available regarding underground pipeline distribution of natural gas. Recent studies have evaluated the problems of converting existing natural gas equipment to hydrogen service.[16] Of major concern in the studies is the effect of hydrogen on the materials utilized in a natural gas system.[17] Specifically, the tendency of some alloys to become embrittled in the presence of hydrogen has been carefully evaluated.

Both studies have concluded that hydrogen can be safely utilized in existing natural gas distribution systems. Although hydrogen is a low BTU gas containing approximately one-third of the energy per unit volume as does natural gas, its low viscosity and light mass cause hydrogen to flow through a pipeline, a valve or an orifice at a rate three times faster than natural gas. Consequently, the energy carrying capacity of a pipeline is approximately equivalent for hydrogen or natural gas at a constant pressure. This factor is extremely important when considering conversion of major existing natural gas installations to utilization of hydrogen because major plant retrofitting of gaslines, control valves and orifices will not be required as with other low BTU gases.

Hydrogen can be successfully stored underground in depleted natural gas fields or in aquifers as is commonly done with propane and natural gas.[18] Additionally, hydrogen can be stored economically in stationary pressure vessels fabricated of low grade steels or concrete. For mobile storage systems, the metal hydride storage method is preferred since it is substantially lighter and more compact.

Utilization Feasibility

An evaluation of attempts to utilize hydrogen as a hydrocarbon fuel replacement reveals that adequate technology is available to safely and efficiently utilize hydrogen. In most applications the hydrogen alternative promises lower pollution levels and higher end use energy utilization efficiencies. The major problem with hydrogen distribution stems from the fact that an infrastructure is not presently in place and must be developed before large scale hydrogen implementation could be achieved. The technology for building such a infrastructure is presently available.

Since end use applications of hydrogen are almost universally more efficient than conventional fuel systems, any attempt to evaluate the feasibility of a hydrogen energy project must take efficiency into account as a significant factor to obtain meaningful results. Where possible, the specific utilization efficiency for the proposed application should be used. In general studies, a 25 percent average increase in efficiency for hydrogen over hydrocarbon fuels will provide a meaningful basis for making estimates.

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CHAPTER II - COAL GASIFICATION - FOREST CITY MODEL

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Introduction

Several coal gasification technologies have been evaluated for application at Forest City, Iowa.[1] These facilities have been designed to produce 4.1 billion BTU's per day of hydrogen from Iowa coal of the following analysis:[2]

Proximate	As Received
% Moisture	13.46
% Ash	9.74
% Volatile Matter	38.84
% Fixed Carbon	37.96
% Sulfur	4.69
TOTAL	
BTU/lb	10,895
Moisture and Ash free BTU/lb	14,187
Ultimate	
% Carbon	59.97
% Hydrogen	4.35
% Nitrogen	1.05
% Oxygen	6.74
% Sulfur	4.69
% Ash	9.74
TOTAL	

Fusibility of Ash °F	Reducing Atmosphere	Oxidizing Atmosphere
Initial Deformation Temperature	2280	2290
Softening Temperature	2450	2340
Hemispherical Temperature	2470	2370
Fluid Temperature	2480	2380

Hydrogen from the gasification plant would be transported via underground pipeline to a mined underground storage cavern and then distributed throughout the city utilizing the existing natural gas grid system.[3]

Utilizing the real world, base case assumptions associated with the proposed Forest City hydrogen project, plant designs were considered employing the coal gasification technologies; the Black, Sivalls & Bryson two-stage, fixed-bed gasifier; the Texaco gasifier; and the Davy McKee Winkler gasifier. In the case of the Texaco gasifier, two independent cost studies were provided: one furnished by Brown & Root, and the second by Davy McKee.

Utilizing technical and economics data provided by the prospective engineering and construction company, a computer model was developed to estimate the cost of hydrogen for each gasification technology (see Appendix A).

2.1 BLACK, SIVALLS, & BRYSON, INCORPORATED
Two-Stage, Fixed-Bed Gasifier[4]
Forest City Model

The system proposed herein is properly defined as a predistillation, two-stage gas producer. It is marketed by Black, Sivalls, & Bryson, Incorporated of Houston, Texas. It is a low-pressure system, operating at a few inches of water.

The first stage or gasifier phase occurs in the lower section of the retort and it is here that coal/coke is gasified by injection of a steam saturated air blast through the grate section at the bottom of the gasifier.

A low BTU producer gas is formed by the contact of water saturated air with the carbonaceous feedstock in the incandescent zone of a fixed-bed gasifier. Basic chemical reactions for the formation of the producer gas include the following:

1) In the combustion zone of the incandescent bed:

$$C + O_2 \text{ --> } CO_2$$

2) Passing through the reduction section of the incandescent bed

$$CO_2 + C \text{ --> } 2CO$$

3) Water vapor in steam saturated air reacts with hot carbon

$$H_2O + C \text{ --> } CO + H_2$$

Based on the preceding reactions, the chief combustible species in the producer gas are hydrogen, carbon monoxide, and perhaps some additional hydrocarbons such as methane. The thermal energy capacity of the producer gas can vary between 160 and 180 BTU's per standard cubic foot, depending on the feedstock. This producer gas, at 1,100°F, is bottom gas and rises through vertical passages behind the refractory walls to exit the retort shell. A portion of the hot bottom gas rises in the center of the retort countercurrent to the falling coal/coke. This gas "semi-cokes" the coal on its way to the incandescent stage as it rises to the distillation stage.

The second or distillation stage occurs in the upper section of the retort at comparatively low temperatures. The heat carried by the rising bottom gas, plus the heat reflected from the refractory walls, distills the coal. The coal releases volatiles such as methane, ethane, oils and tars. These volatiles combine with the rising gases and exit through the top gas off-take. The gases from both stages are combined after flowing through clean-up systems to improve their quality.

Module Description

In order to provide the optimum balance between reliability and equipment costs B,S&B proposes a module concept. Each gasifier will consist of two producer assemblies, three air fans (one for each producer assembly, plus one installed as a common spare), bottom gas wash column, top gas hydraulic seal drum, top gas electrostatic de-tarrer, shell-and-tube gas cooler, and de-oiler. There will be a two-compartment settling tank and two pumps (one spare) per module for recirculating scrubbing water.

Each module also has an oil-water separator and blowdown drum. Items shared by two modules are tar tank, oil tank, waste liquor tank, and associated pumps.

Coal Storage and Handling

The coal handling system for the Forest City gasifier will be a bucket elevator type since all coal receiving, storage and gasification facilities will be in close proximity.

Coal Feed

The coal is held in a bunker above the gasifier and supplies it with an automatic, inert gas purged, drum-type, rotary coal feeder. The gear motor which drives the feeder is activated by a dipstick and limit switch mechanism which monitors the level of the coal in a retort. As the coal level falls within the retort, the charged drum rotates discharging the coal through its open port. At the same time, the gasifier is sealed so gas will not escape during coal charging. The drum then resets to take another charge from the coal bunker. An isolating gate valve on the discharge chute of the coal bunker is provided to shift off coal supply.

Once entering the retort, the coal moves slowly downwards and is gradually heated by hot gases rising through the coal from the gasifying stage allowing the distillation gas (tars and volatile matter) to be liberated. This distillation gas at approximately 260^{o}F, moves to the gas space at the top of the retort and leaves through the top gas off-take at 212^{o}F to 303^{o}F. Coal also receives heat by radiation from the gasifier refractory lining and by convection segmental walls which contain vertical gas passages through which the hot gases pass in exiting the retort. By the time the coal arrives at the lower end of the retort it is in semi-coke form and the gasification process begins. Air and steam are fed through the bottom of the gasifier and react with the semi-coke to generate producer gas.

The carbon in the coke in the second stage reacts with the steam to produce carbon monoxide, methane and hydrogen. The resulting gas at temperatures around 1100^{O}F, rises through vertical passes behind the gasifier refractory walls to a horizontal, rectangular refractory-lined duct at the top of the retort shell.

The majority of the gasifier steam will be provided by a boiler plant. Additional steam at 25 psig is generated in a water jacket which envelopes the combustion zone of the retort. Heat from combustion inside the gasifier turns feed water to steam which is added to bottom air feed. A skirt is attached to the lower edge of the retort steam jacket and extends down into a water seal formed in an ash pan.

The ash pan collects ash removal by stationary ploughs which extend down into the pan to scoop up and dump the ash into chutes at the side of the pan. The ash pan is now rotated by hydraulic drive and ratchet mechanism allowing ash to drop from a hopper periodically onto a continuously running conveyor belt.

Tar and Oil Handling

The tar, being almost moisture and dust free and low in carbon content, is fluid-like in nature at ambient temperatures which facilitates pumping. It has been found readily interchangeable with medium-viscosity coal tar fuel.

The valuable light oils are recovered separately by decantation.

Ash Removal

B,S&B two-stage fixed-bed gasifiers use an automatic wet ash withdrawal system. The ash, withdrawn from the gasifier bottom section through a water-sealed ash pan equipped with a mechanically operated plow assembly, is conveyed from the gasifier facility for subsequent disposal. Considered as a by-product, the ash can be used in road construction or cinder block manufacture.

Automatic Poking

B,S&B has devised an automatic poking system which increases the number of Iowa coal types that can be satisfactorily gasified, eliminates the escape of producer gas with its carbon monoxide content, and eliminates manual poking. Automatic pokers are installed on two-stage gasifiers presently in operation at Caterpillar Tractor Company, York, Pennsylvania.

BASE CASE ASSUMPTIONS
BLACK, SIVALLS & BRYSON COAL GASIFIER
Municipal Financing
Forest City Model

Total Plant Investment

ITEM	CAPITAL COST ($1978)
Coal Handling and Preparation	$ 1,040,000
Gasifier Units	13,000,000
Desulfurization	5,956,000
General Facilities*	2,399,520
Total Plant Investment	$22,395,520

NOTES: 4-12 foot diameter gasification units needed to generate 4,120 MMBTU (HHV) H_2 per day.

* 12% of onsite capital costs.

BASE CASE ASSUMPTIONS
BLACK, SIVALLS & BRYSON COAL GASIFIER
Municipal Financing
Forest City Model

Fixed Operating and Maintenance Costs ($1978)

ITEM	AMOUNT	COST PER UNIT	ANNUAL COST
Process Labor (96 Jobs)	279,552 Hr/Yr	12.50 $/Hr	$3,494,400
Technical Labor (12 Jobs)	34,944 Hr/Yr	15.55 $/Hr	543,379
Maintenance (6 Jobs)	17,472 Hr/Yr	12.50 $/Hr	218,400
Overhead	1,276,853 $/Yr	-	1,276,853
Total Fixed Operating & Maintenance Costs			$5,533,032

NOTES: Labor rates include 35% payroll burden and are based on 364 paid days per year.

Cost of overhead is 30% of total labor costs.

BASE CASE ASSUMPTIONS
BLACK, SIVALLS & BRYSON COAL GASIFIER
Municipal Financing
Forest City Model

Variable Operating and Maintenance Costs ($1978)

ITEM	AMOUNT	COST PER UNIT	ANNUAL COST
Power	119,958 MMH/Yr	25.00 $/MWH	$2,998,960
Boiler Feedwater	8,173 KGAL/Yr	.85 $/KGAL	6,947
Make-Up Water	19,008 KGAL/Yr	.50 $/KGAL	9,504
Steam	84,269 KGAL/Yr	1.75 $/KGAL	147,470
Chemicals	111,758 $/Yr	-	111,758
Maintenance Supplies	22,396 $/Yr	-	22,396
Operating Supplies	167,966 $/Yr	-	167,966
Sulfur	7,590 Tn/Yr	(80.00) $/Tn	(607,200)
Total Variable Operating and Maintenance Costs			$2,857,801

NOTES: Costs calculated for four gasifiers generating a total of 4,120 MMBTU (HHV) H_2 per day.

Maintenance Supplies = .1% TPI; Operating Supplies = .75% TPI.

BASE CASE ASSUMPTIONS
BLACK, SIVALLS & BRYSON COAL GASIFIER
Municipal Financing
Forest City Model

Capital Requirement

ITEM	CAPITAL COST ($1978)
Total Plant Investment	$22,395,520
Pre-production Costs	989,484
Inventory Capital	105,738
Allowance for Funds During Construction	1,567,686
Total Capital Requirement	$25,058,428

NOTES: Construction Period: Three Years

Plant Capacity: 4,120 MMBTU (HHV) H_2 per day.

Capacity Factor: .904 = 330 days per year.

Annual Production: 1,359,435 MMBTU (HHV) H_2 per year.

BASE CASE ASSUMPTIONS
BLACK, SIVALLS & BRYSON COAL GASIFIER
Municipal Financing
Forest City Model

Financial Data

Debt Ratio: 100% (% of capital cost financed)

Debt Cost: 7% (% interest on borrowed capital)

Income Tax (Federal + State): Not applicable

Investment Tax Credit: Not applicable

Facility Life: 20 Years

Tax Life: 16 Years

Accounting Method: Straight Line

Tax Preference Allowance: Not applicable

Total Return (weighted cost of capital):	7.00%
Book Depreciation (Sinking Fund):	2.44%
Property Taxes + Insurance:	1.20%
Levelized Annual Fixed Charge Rate:	10.64%
Capital Recovery Factor:	9.44%

NOTE: Accelerated depreciation and investment tax credit decrease the fixed charge rate.

BASE CASE ASSUMPTIONS
BLACK, SIVALLS & BRYSON COAL GASIFIER
Municipal Financing
Forest City Model

Fuel Cost Data ($1978)

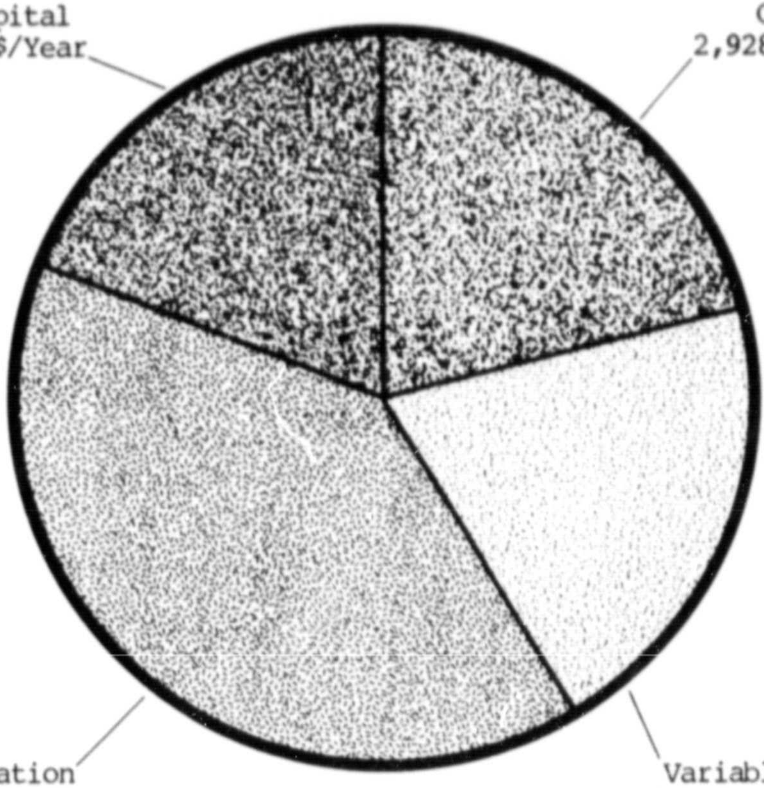
Coal Input	Cost Per Unit	Annual Cost
136,244 Tn/Yr	21.50 $/Tn	$2,928,316

First Year Cost of Hydrogen

	$1978/MMBTU H_2 (HHV)
Levelized Annual Capital Cost	$ 1.96
Levelized FOM & VOM Costs	6.18
Levelized Annual Coal Cost	2.16
Total Cost of Hydrogen	$10.30

HYDROGEN COST FACTORS

Black, Sivalls, and Bryson Gasifier
Forest City Model
Cost of Hydrogen: \$10.30*

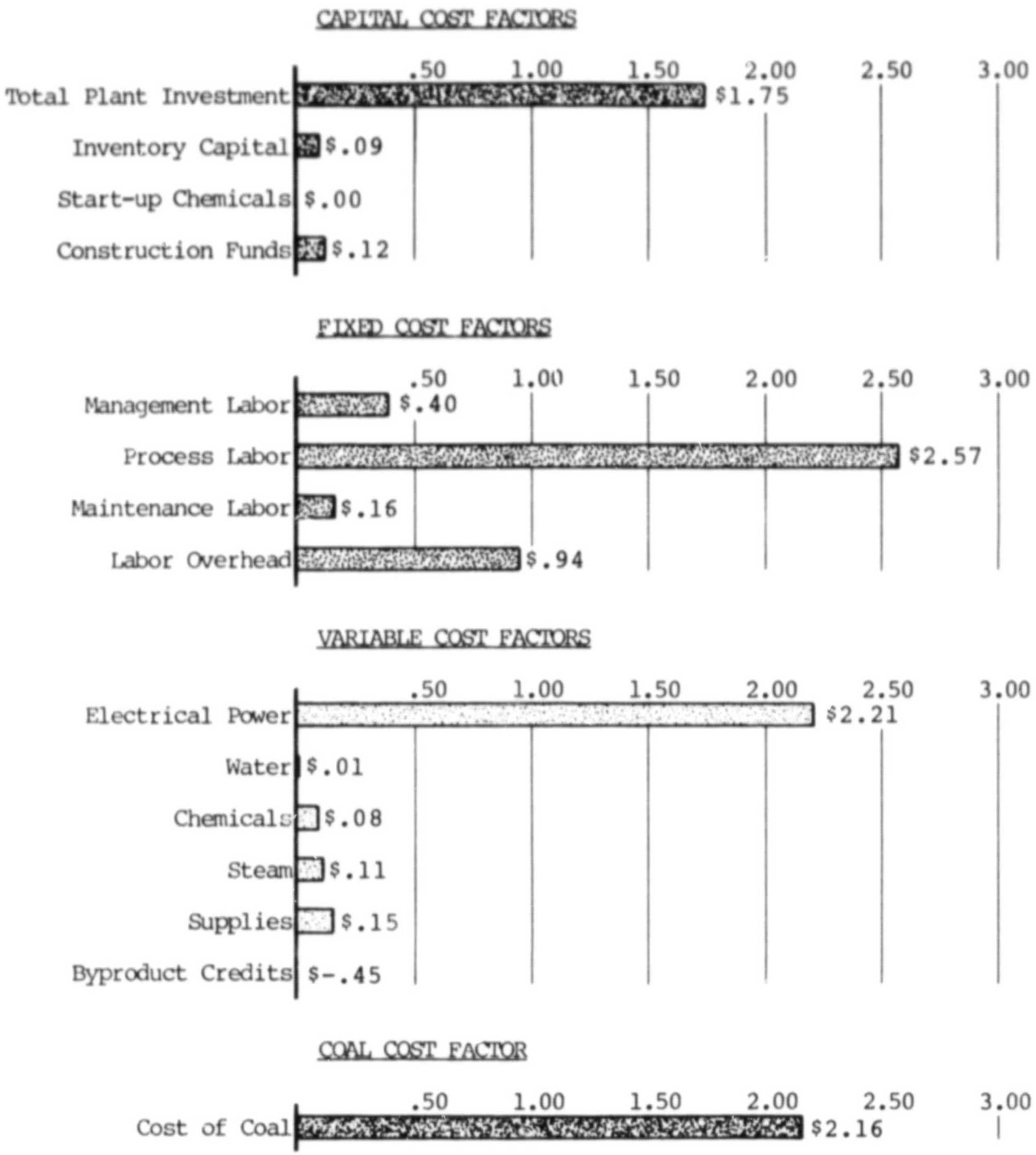


Base Case Summary Information - Municipal Finance

1. Total Plant Investment: \$22,395,520 (\$ 1978)
2. Plant Utilization Factor: .904 (330 Days/Year)
3. Plant Capacity: 4120 MMBTU H_2 (HHV/Day)
4. Debt Ratio (% of Capital Cost Financed): 100%
5. Debt Cost (Interest on Borowed Capital): 7%
6. Accounting Method: Straight Line
7. Income Taxes (Fed. + State): Not Applicable
8. Property Taxes + Insurance: 1.20%
9. Investment Tax Credit: Not Applicable
10. Facility Life: 20 Years
11. Tax Life: 16 Years
12. Tax Preference Allowance: Not Applicable
13. Fuel (Coal) Input: 136,224 Tons/Year
14. Coal Unit Cost: \$21.50/Ton (\$ 1978)

*1978 dollars/million BTU's higher heating value.

Cost of Hydrogen - $ 1978/MMBTU



BASE CASE ASSUMPTIONS
BLACK, SIVALLS & BRYSON COAL GASIFIER
Commercial Financing
Forest City Model

Total Plant Investment

ITEM	CAPITAL COST ($1978)
Coal Handling and Preparation	$ 1,040,000
Gasifier Units	13,000,000
Desulfurization	5,956,000
General Facilities*	2,399,520
Total Plant Investment	$22,395,520

NOTES: 4-12 foot diameter gasification units needed to generate 4,120 MMBTU (HHV) H_2 per day.

* 12% of onsite capital costs.

BASE CASE ASSUMPTIONS
BLACK, SIVALLS & BRYSON COAL GASIFIER
Commercial Financing
Forest City Model

__Fixed Operating and Maintenance Costs ($1978)__

ITEM	AMOUNT	COST PER UNIT	ANNUAL COST
Process Labor (96 Jobs)	279,552 Hr/Yr	12.50 $/Hr	$3,494,400
Technical Labor (12 Jobs)	34,944 Hr/Yr	15.55 $/Hr	543,379
Maintenance (6 Jobs)	17,472 Hr/Yr	12.50 $/Hr	218,400
Overhead	1,276,853 $/Yr	-	1,276,853
Total Fixed Operating & Maintenance Costs			$5,533,032

NOTES: Labor rates include 35% payroll burden and are based on 364 paid days per year.

Cost of overhead is 30% of total labor costs.

BASE CASE ASSUMPTIONS
BLACK, SIVALLS & BRYSON COAL GASIFIER
Commercial Financing
Forest City Model

Variable Operating and Maintenance Costs ($1978)

ITEM	AMOUNT		COST PER HOUR		ANNUAL COST
Power	119,958	MWH/Yr	25.00	$/MWH	$2,998,960
Boiler Feedwater	8,173	KGAL/Yr	.85	$/KGAL	6,947
Make-Up Water	19,008	KGAL/Yr	.50	$/KGAL	9,504
Steam	84,269	KGAL/Yr	1.75	$/KGAL	147,470
Chemicals	111,758	$/Yr	-		111,758
Maintenance Supplies	22,396	$/Yr	-		22,396
Operating Supplies	167,966	$/Yr	-		167,966
Sulfur	7,590	$/Yr	(80.00)	$/Tn	(607,200)
Total Variable Operating and Maintenance Costs					$2,857,801

NOTES: Costs calculated for four gasifiers generating a total of 4,120 MMBTU (HHV) H_2 per day.

Maintenance Supplies = .1% TPI; Operating Supplies = .75% TPI.

BASE CASE ASSUMPTIONS
BLACK, SIVALLS & BRYSON COAL GASIFIER
Commercial Financing
Forest City Model

Capital Requirement

ITEM	CAPITAL COST ($1978)
Total Plant Investment	$22,395,520
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Total Capital Requirement	$25,058,428

NOTES: Construction Period: Three Years

Plant Capacity: 4,120 MMBTU (HHV) H_2 per day.

Capacity Factor: .904 = 330 days per year.

Annual Production: 1,359,435 MMBTU (HHV) H_2 per year.

BASE CASE ASSUMPTIONS
BLACK, SIVALLS & BRYSON COAL GASIFIER
Commercial Financing
Forest City Model

Financial Data

Debt Ratio: 75% (% of capital cost financed)

Debt Cost: 10% (% interest on borrowed capital)

Preferred Stock Ratio: 8%

Preferred Stock Cost: 15%/Yr

Common Stock Ratio: 17%

Common Stock Cost: 15%/Yr

Income Tax (Federal + State): 50%

Investment Tax Credit: 10%

Facility Life: 20 Years

Tax Life: 16 Years

Accounting Method: Flow Through

Tax Preference Allowance: Accelerated Depreciation (Sum-of-the-years-digits)

Total Return (weighted cost of capital):	11.25%
Book Depreciation (Sinking Fund)	1.51%
Levelized Annual Income Tax	2.59%
Levelized Annual Accelerated Depreciation Allowance	(2.28%)
Levelized Annual Investment Tax Credit Allowance	(2.29%)
Property Taxes + Insurance	2.70%
Levelized Annual Fixed Charge Rate:	13.48%
Capital Recovery Factor:	12.76%

NOTE: Accelerated depreciation and investment tax credit decrease the fixed charge rate.

BASE CASE ASSUMPTIONS
BLACK, SIVALLS & BRYSON COAL GASIFIER
Commercial Financing
Forest City Model

Fuel Cost Data ($1978)

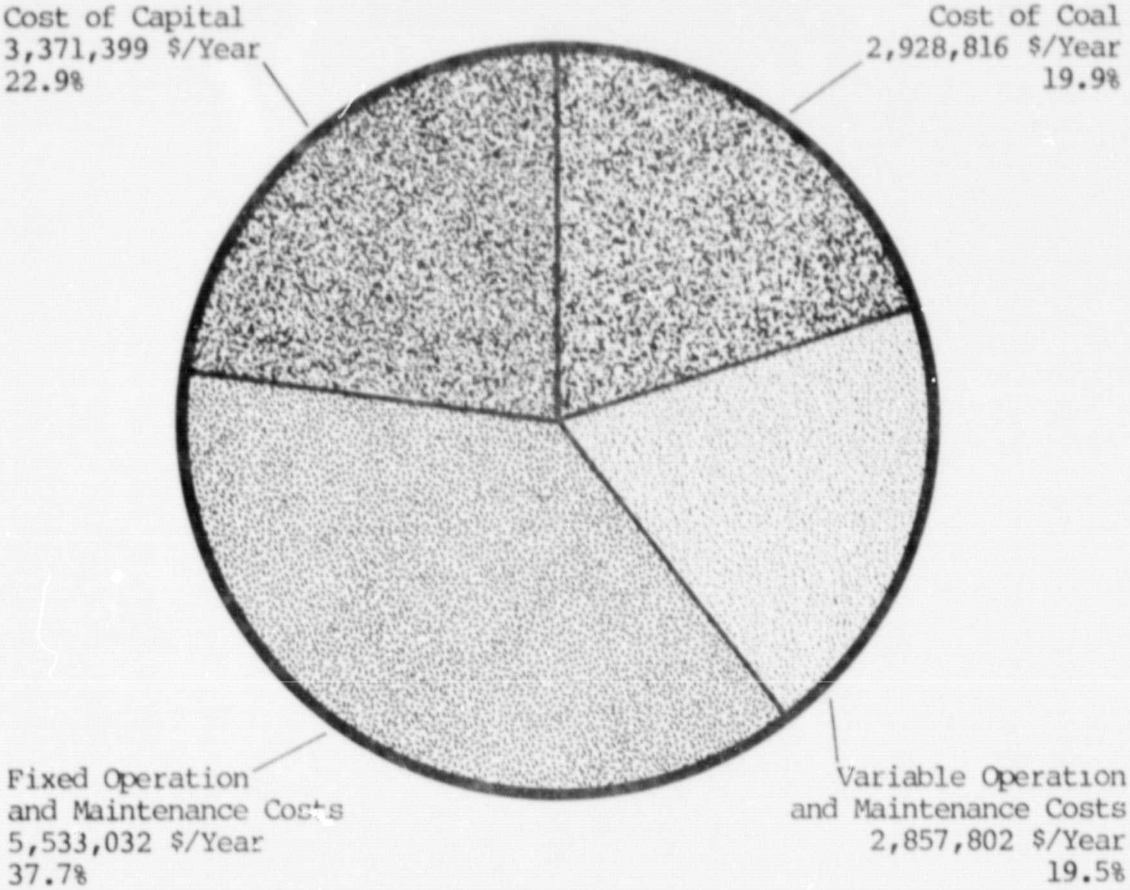
Coal Input	Cost Per Unit	Annual Cost
136,244 Tn/Yr	21.50 $/Tn	$2,928,816

First Year Cost of Hydrogen

	$1978/MMBTU H_2 (HHV)
Levelized Annual Capital Cost	$ 2.46
Levelized FOM & VOM Costs	6.18
Levelized Annual Coal Cost	2.16
Total Cost of Hydrogen	$10.80

HYDROGEN COST FACTORS

Black, Sivalls, and Bryson Gasifier
Forest City Model
Cost of Hydrogen: $10.80*

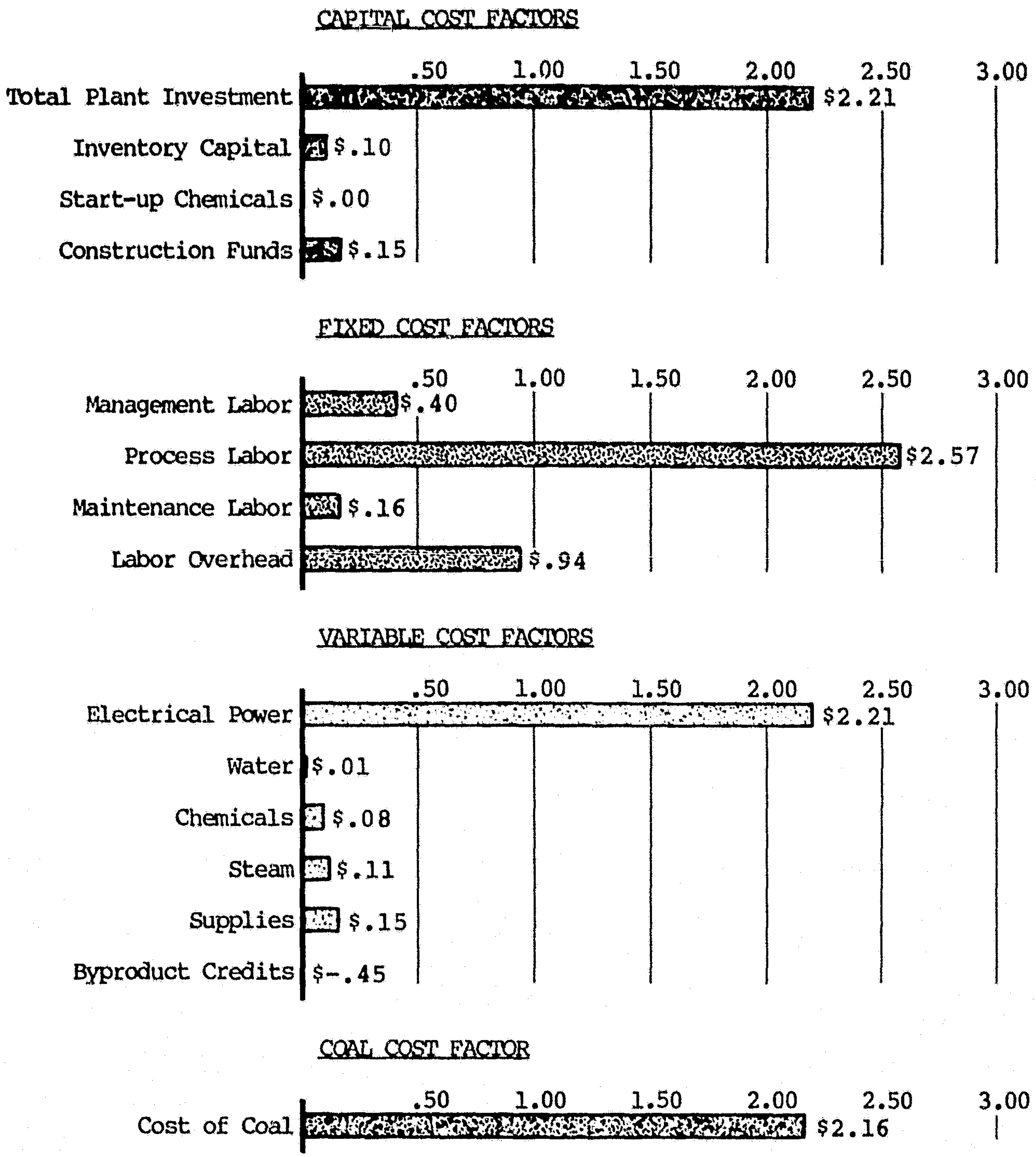


Base Case Summary Information - Commercial Finance

1. Total Plant Investment: $22,395,520 ($ 1978)
2. Plant Utilization Factor: .904 (330 Days/Year)
3. Plant Capacity: 4120 MMBTU H_2 (HHV/Day)
4. Debt Ratio (% of Capital Cost Financed): 75%
5. Debt Cost (Interest on Borrowed Capital): 10%
6. Accounting Method: Flow Through
7. Income Taxes (Fed. + State): 50%
8. Property Taxes + Insurance: 2.70%
9. Investment Tax Credit: 10%
10. Facility Life: 20 Years
11. Tax Life: 16 Years
12. Tax Preference Allowance: Accelerated Depreciation--Sum-of-the-Years-Digits
13. Fuel (Coal) Input: 136,224 Tons/Year
14. Coal Unit Cost: $21.50/Ton ($ 1978)

*1978 dollars/million BTU's higher heating value.

Cost of Hydrogen – $ 1978/MMBTU



2.2 Texaco Gasifier[5]

Forest City Model

The Texaco partial oxidation process was developed by the Texaco Development Corporation.[6] The major processing steps in the process include coal gasification, CO shift conversion, CO_2-H_2S removal, and sulfur recovery. A simplified flow diagram is attached.

Coal is received by rail and either sent directly to open storage or sized in a primary crusher to 1/2 inch or less. The coal can be conveyed directly from the crusher to the coal slurry preparation area. Coal is reclaimed from the storage area by front-end loaders and sent to the coal slurry preparation area.

Coal from the receiving and storage area is pulverized in a wet pulverizer to minus 40 mesh as required by the gasifier operation. The pulverizer discharge is partially dewatered and pumped to a mix tank where the solids content of the slurry is adjusted to about 55% solids. The slurry is pumped to one of two agitated 10-hour capacity feed tanks and then metered to the reactor (gasifier) at the process rate of about 8 tons (7 metric tons) of coal per hour. Gaseous oxygen from the air separation plant is fed to the reactor at about 8 tons per hour through a metering system interlocked with the coal slurry feed system.

The gasification process takes place in the Texaco-developed reactor at a pressure of about 510 psig and at a temperature in excess of 2,200^{o}F. The gasification reaction is represented by the equation:

$$C + H_2O \dashrightarrow CO + H_2$$

Oxygen is injected to burn a part of the coal to provide heat for this endothermic reaction. In addition to the gasification reaction and coal combustion to CO_2, sulfur compounds in the coal are gasified in the reducing atmosphere of the reactor to produce primarily H_2S and some carbonyl sulfide (COS). Small quantities of other compounds such as ammonia and methane also are formed. According to Texaco's pilot-plant experience, essentially no long-chain or aromatic hydrocarbons are formed.

Slag produced from the ash content of the coal is removed from the reactor through a lock hopper system. The slag is glassy in appearance and is very similar to the bottom produced in a coal-fired power plant boiler. The slag is washed and screened, and the oversize is crushed to a size suitable for slurrying and pumping to a disposal area. Initially, a front-end loader and dump truck arrangement will be used to transport the solids to the disposal area. A system may be installed later to handle the slag and transport it to the disposal area as a slurry.

The gases exiting the reactor are water-quenched, and particulate matter (fly ash) is removed in a quench scrubber. A blowdown stream is taken from the quench water recirculating loop and pumped to a wastewater treatment facility. The purge steam is chemically treated by addition of ferrous sulfate and hydrated lime and then sent to a clarifier. The clarifier underflow is sent to a filter press, and the recovered wet filter cake is available for disposal. A scheme is being developed to return the solids to the reactor through the coal slurry fed preparation system, where they will be tied up in glass-like slag and discarded as an innocuous landfill.

The liquid fraction from the solids separation step is steam stripped (or nitrogen stripped) to remove ammonia. The ammonia is recovered and routed to the coal slurry preparation area to neutralize the acidic slurry. The stripped aqueous material containing some organic material, primarily as formates and cyanates, along with water from washdown operations in the gasifier, is sent to an equalization-cooling basin for pH control, mixing and cooling. The combined waste then flows to an activated sludge unit to remove the organic material. The sludge solids are settled and removed by filtration for disposal. The water from the unit is metered and sampled on its way to discharge.

The process gas from the quench scrubber flows to the CO shift converter. The converter is charged with two beds of sulfur-activated colbalt-molybdenum catalyst with an expected life of two years. The CO content of the gas entering the converter will be about 11%. After full shift, the CO content of the gas will be about 2%.

The COS (Carbonyl Sulfide) produced during the gasification process is much more difficult to remove and recover from the process gas stream than H_2S. This is because the solubility of COS in solvents used to remove H_2S and CO_2 is very similar to that of CO_2. Thus, the COS remains with the CO_2 stream through much of the sulfur-recovery equipment. To decrease the quantity of COS, a hydrolysis unit is provided between the CO converter and the acid-gas removal (AGR) system to effect the reaction.

$$COS + H_2O \dashrightarrow CO_2 + H_2S$$

The process gas from the COS hydrolysis unit flows to the AGR system. The AGR system removes the CO_2, H_2S, and COS from the process gas. This system is capable of decreasing the total sulfur in the gas stream to less than 1 ppm. Two reject acid-gas streams are produced during regeneration of the solvent. One is a sulfur-rich stream containing up to 4% H_2S which is sent to a Stretford sulfur-recovery system.

The Stretford system uses Brown & Root proprietary solution containing an oxidized form of vanadium salts. The H_2S is oxidized in the solution to produce elemental sulfur:

$$H_2S + RO_5 \dashrightarrow S + H_2O + RO_4$$

where R = a salt of vanadium.

The reduced metal salt is regenerated by blowing air through the solution. This operation also floats the elemental sulfur to the surface. The sulfur is skimmed off and filtered to produce a wet granular cake. The tail gas from the Stretford system contains less than 150 ppm H_2S by volume, less than 12 ppm COS, and less than 500 ppm CO.

The second stream from the AGR solution regeneration system is high-purity CO_2. The gas is also sent to a Stretford unit and then to a sulfur guard (zinc oxide) bed to decrease the sulfur content to less than 0.5 ppm.

The process gas from the AGR system flows through two beds of sulfur guard to decrease the sulfur content of the gas to less than 0.1 ppm. The gas then passes through a Linde pressure swing adsorption unit which increases hydrogen concentrations to levels required for metal hydride storage.

<u>Air Separation Plant</u>

The air separation plant produces gaseous oxygen (99.5%) which is used to operate the coal gasifier. The plant will use a standard cryogenic process with reversing flow heat exchangers. The capacity of the plant is rated 210 tons per day of gaseous oxygen and

180 tons per day of gaseous nitrogen. In addition, up to 3 tons per day of liquid nitrogen will be produced and stored for use in startups of the air separation plant.

A centrifugal compressor discharges air at 82 psig to the reversing-flow exchangers in the "cold box" where it is cooled to $-270^{\circ}F$. Water vapor and carbon dioxide are removed by freezing on the heat-exchanger surfaces. The flow passages for the incoming air and waste nitrogen from the process are switched every few minutes so that the water and carbon dioxide are carried out by the waste nitrogen stream and vented. The cold air from the reversing exchangers then feeds into a sieve-tray distillation column system operating at about $-290^{\circ}F$ ($-179^{\circ}C$) where the air liquefies and is separated into oxygen and nitrogen. Refrigeration for the process is provided by expanding part of the product nitrogen through an expansion turbine. The oxygen and nitrogen product streams are both used to cool the incoming air. A reciprocating compressor boosts the oxygen pressure to 665 psig. The nitrogen is not compressed and is available for miscellaneous uses.

The main process safety problem in air separation plants is the buildup of hydrocarbons, such as acetylene and ethylene, which are present in trace quantities in ambient air. The hydrocarbons are an explosion hazard where present in liquid oxygen. The hydrocarbons are removed from the process by adsorption on silica gel.

Davy McKee Estimates[7]

BASE CASE ASSUMPTIONS
TEXACO COAL GASIFIER
Municipal Financing
Forest City Model

Total Plant Investment

ITEM	CAPITAL COST ($1978)
Coal Storage & Handling	-
Texaco Gasifier Unit	-
Waste Heat Recovery #1	-
Particulate Removal	-
Shift Conversion	-
Waste Heat Recovery #2	-
Rectisol System	-
Claus Plant	-
O_2 Plant W/Compression	-
Miscellaneous Offsites	
Total Davy-McKee Plant Investment	$43,500,000

NOTES: Turn-key price. Miscellaneous Offsites: Flare, Cooling Towers and Fresh Water Treatment.

Davy McKee Estimates

BASE CASE ASSUMPTIONS
TEXACO COAL GASIFIER
Municipal Financing
Forest City Model

Fixed Operating and Maintenance Costs ($1978)

ITEM	AMOUNT	COST PER UNIT	ANNUAL COST
Operators (5 per shift)	43,800 Hr/Yr	12.50 $/Hr	$ 547,500
Supervisors (1 per shift)	8,760 Hr/Yr	15.55 $/Hr	136,218
Maintenance (10 Jobs)	20,800 Hr/Yr	12.50 $/Hr	260,000
Admin & Support (13 Jobs)	27,040 Hr/Yr	10.80 $/Hr	292,032
Total Fixed Operating & Maintenance Costs			$1,235,750

NOTES: 365 x 24 = 8,760 hours per year for operator and supervisory jobs. 52 x 40 = 2,080 hours per year for administrative, support and maintenance jobs.

Davy McKee Estimates

BASE CASE ASSUMPTIONS
TEXACO COAL GASIFIER
Municipal Financing
Forest City Model

Fixed Operating and Maintenance Costs ($1978)

ITEM	AMOUNT		COST PER UNIT		ANNUAL COST
Power	16,286	MWH/Yr	25.00	$/MWH	$ 407,150
Water Makeup	91,728	KGAL/Yr	.85	$/KGAL	77,968
Chemicals & Catalysts	350,000	$/Yr	1.00		350,000
Maintenance Supplies	390,000	$/Yr	1.00		390,000
Waste Water Treatment	27,800	KGAL/Yr	1.25	$/KGAL	34,750
Ash Disposal	21,400	Tn/Yr	4.00	$/Tn	85,600
Sulfur	4,312	Tn/Yr	(80.00)	$/Tn	(344,960)
Total Variable Operating and Maintenance Costs					$1,000,508

Davy McKee Estimates

BASE CASE ASSUMPTIONS
TEXACO COAL GASIFIER
Municipal Financing
Forest City Model

Capital Requirement

ITEM	CAPITAL COST ($1978)
Total Plant Investment	$43,500,000
Pre-production Costs	1,164,800
Inventory Capital	389,000
Initial Catalyst & Chemicals	30,000
Allowance for Funds During Construction	3,045,000
Total Capital Requirement	$48,128,800

NOTES: Construction Period: Three Years

Plant Capacity: 4,900 MMBTU per day.

Capacity Factor: .904 = 330 days per year.

Annual Production: 1,616,804 MMBTU per year.

BASE CASE ASSUMPTIONS
TEXACO COAL GASIFIER
Municipal Financing
Forest City Model
Davy McKee Estimates

Financial Data

Debt Ratio: 100% (% of capital cost financed)

Debt Cost: 7% (% interest on borrowed capital)

Income Tax (Federal + State): Not applicable

Investment Tax Credit: Not applicable

Facility Life: 20 Years

Tax Life: 16 Years

Accounting Method: Straight Line

Tax Preference Allowance: Not applicable

Total Return (weighted cost of capital):	7.00%
Book Depreciation (Sinking Fund):	2.44%
Property Taxes + Insurance:	1.20%
Levelized Annual Fixed Charge Rate:	10.64%
Capital Recovery Factor:	9.44%

NOTE: Accelerated depreciation and investment tax credit decrease the fixed charge rate.

Davy McKee Estimates

BASE CASE ASSUMPTIONS
TEXACO COAL GASIFIER
Municipal Financing
Forest City Model

Fuel Cost Data ($1978)

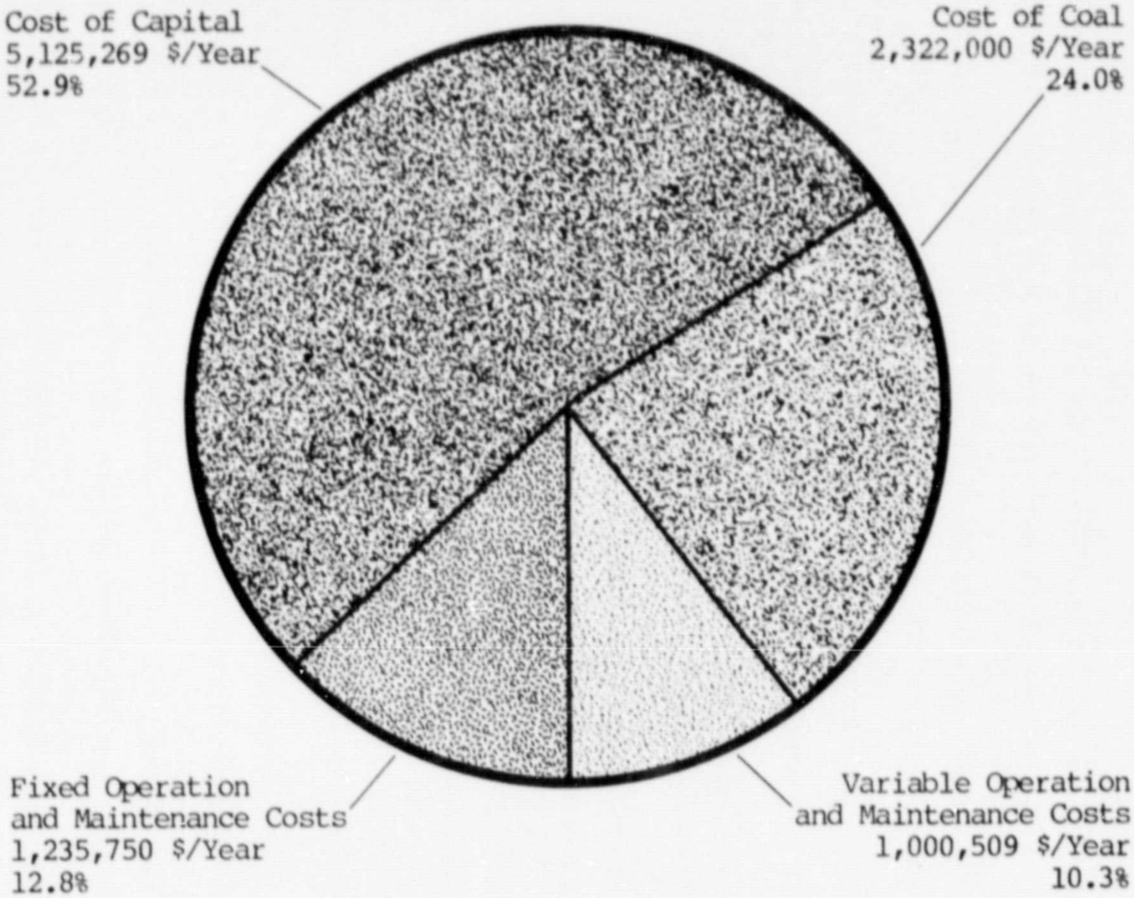
Coal Input	Cost Per Unit	Annual Cost
108,000 Tn/Yr	21.50 $/Tn	$2,322,000

First Year Cost of Hydrogen

	$1978/MMBTU H_2 (HHV)
Levelized Annual Capital Cost	$3.17
Levelized FOM & VOM Costs	1.38
Levelized Annual Coal Cost	1.44
Total Cost of Hydrogen	$5.99

HYDROGEN COST FACTORS

Texaco (Davy-McKee) Gasifier
Forest City Model
Cost of Hydrogen: \$5.99*

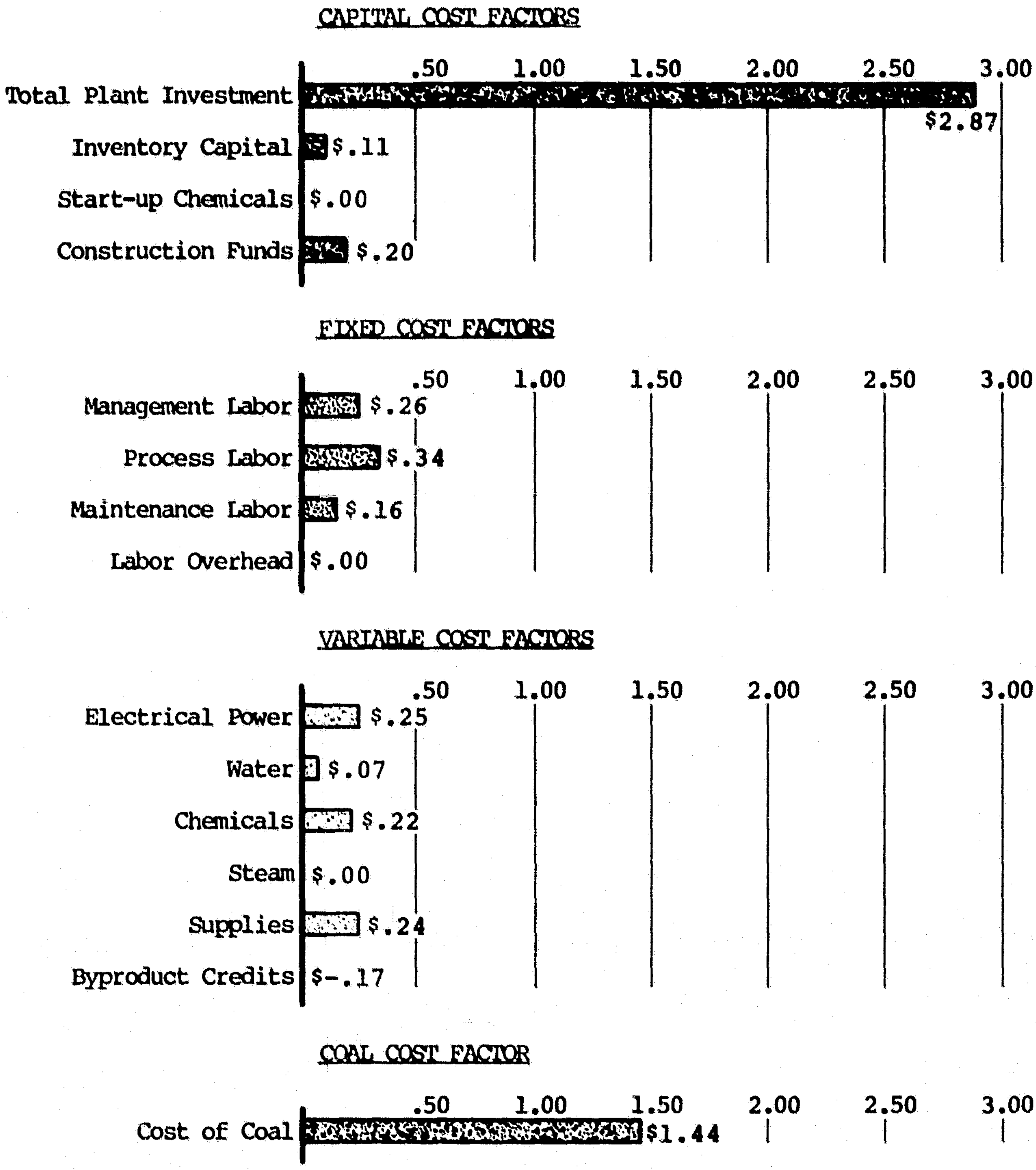


Base Case Summary Information - Municipal Finance

1. Total Plant Investment: \$43,500,000 (\$ 1978)
2. Plant Utilization Factor: .904 (330 Days/Year)
3. Plant Capacity: 4900 MMBTU H_2 (HHV/Day)
4. Debt Ratio (% of Capital Cost Financed): 100%
5. Debt Cost (Interest on Borrowed Capital): 7%
6. Accounting Method: Straight Line
7. Income Taxes (Fed. + State): Not Applicable
8. Property Taxes + Insurance: 1.20%
9. Investment Tax Credit: Not Applicable
10. Facility Life: 20 Years
11. Tax Life: 16 Years
12. Tax Preference Allowance: Not Applicable
13. Fuel (Coal) Input: 108,000 Tons/Year
14. Coal Unit Cost: \$21.50/Ton (\$ 1978)

*1978 dollars/million BTU's higher heating value.

Cost of Hydrogen - $ 1978/MMBTU



Davy McKee Estimates

BASE CASE ASSUMPTIONS
TEXACO COAL GASIFIER
Commercial Financing
Forest City Model

Total Plant Investment

ITEM	CAPITAL COST ($1978)
Coal Storage & Handling	-
Texaco Gasifier Unit	-
Waste Heat Recovery #1	-
Particulate Removal	-
Shift Conversion	-
Waste Heat Recovery #2	-
Rectisol System	-
Claus Plant	-
O_2 Plant W/Compression	-
Miscellaneous Offsites	
Total Davy-McKee Plant Estimate	$43,500,000

NOTES: Turn-key price. Miscellaneous offsites: Flare, Cooling Towers and Fresh Water Treatment.

Davy McKee Estimates

BASE CASE ASSUMPTIONS
TEXACO COAL GASIFIER
Commercial Financing
Forest City Model

Fixed Operating and Maintenance Costs ($1978)

ITEM	AMOUNT	COST PER UNIT	ANNUAL COST
Operators (5 per shift)	43,800 Hr/Yr	12.50 $/Hr	$ 547,500
Supervisor (1 per shift)	8,760 Hr/Yr	15.55 $/Hr	136,218
Maintenance (10 Jobs)	20,800 Hr/Yr	12.50 $/Hr	260,000
Admin & Support (13 Jobs)	27,040 Hr/Yr	10.80 $/Hr	292,032
Total Fixed Operating & Maintenance Costs			$1,235,750

NOTES: 365 x 24 = 8,760 hours per year for operation and supervisory jobs. 52 x 40 = 2,080 hours per year for administration, support, and maintenance jobs.

Davy McKee Estimates

BASE CASE ASSUMPTIONS
TEXACO COAL GASIFIER
Commercial Financing
Forest City Model

Variable Operating and Maintenance Costs ($1978)

ITEM	AMOUNT		COST PER HOUR		ANNUAL COST
Power	16,286	MWH/Yr	25.00	$/MWH	$ 407,150
Water Makeup	91,728	KGAL/Yr	.85	$/KGAL	77,968
Chemicals & Catalysts	350,000	$/Yr	1.00		350,000
Maintenance Supplies	390,000	$/Yr	1.00		390,000
Waste Water Treatment	27,800	KGAL/Yr	1.25	$/KGAL	34,750
Ash Disposal	21,400	Tn/Yr	4.00	Tn/Yr	85,600
Sulfur	4,312	Tn/Yr	(80.00)	$/Tn	(344,960)
Total Variable Operating and Maintenance Costs					$1,000,508

Davy McKee Estimates

BASE CASE ASSUMPTIONS
TEXACO COAL GASIFIER
Commercial Financing
Forest City Model

Capital Requirement

ITEM	CAPITAL COST ($1978)
Total Investment	$43,500,000
Pre-production Costs	1,164,800
Inventory Capital	389,000
Initial Catalyst & Chemicals	30,000
Allowance for Funds During Construction	3,045,000
Total Capital Requirement	$48,128,800

NOTES: Construction Period: Three Years

Plant Capacity: 4,900 MMBTU per day.

Capacity Factor: .904 = 330 days per year.

Annual Production: 1,616,804 MMBTU (HHV) H_2 per year.

BASE CASE ASSUMPTIONS
TEXACO COAL GASIFIER
Commercial Financing
Forest City Model
Davy-McKee Estimates

Financial Data

Debt Ratio: 75% (% of capital cost financed)

Debt Cost: 10% (% interest on borrowed capital)

Preferred Stock Ratio: 8%

Preferred Stock Cost: 15%/Yr

Common Stock Ratio: 17%

Common Stock Cost: 15%/Yr

Income Tax (Federal + State): 50%

Investment Tax Credit: 10%

Facility Life: 20 Years

Tax Life: 16 Years

Accounting Method: Flow Through

Tax Preference Allowance: Accelerated Depreciation (Sum-of-the-years-digits)

Total Return (weighted cost of capital):	11.25%
Book Depreciation (Sinking Fund)	1.51%
Levelized Annual Income Tax	2.59%
Levelized Annual Accelerated Depreciation Allowance	(2.28%)
Levelized Annual Investment Tax Credit Allowance	(2.29%)
Property Taxes + Insurance	2.70%
Levelized Annual Fixed Charge Rate:	13.48%
Capital Recovery Factor:	12.76%

NOTE: Accelerated depreciation and investment tax credit decrease the fixed charge rate.

Davy McKee Estimates

BASE CASE ASSUMPTIONS
TEXACO COAL GASIFIER
Commercial Financing
Forest City Model

Fuel Cost Data ($1978)

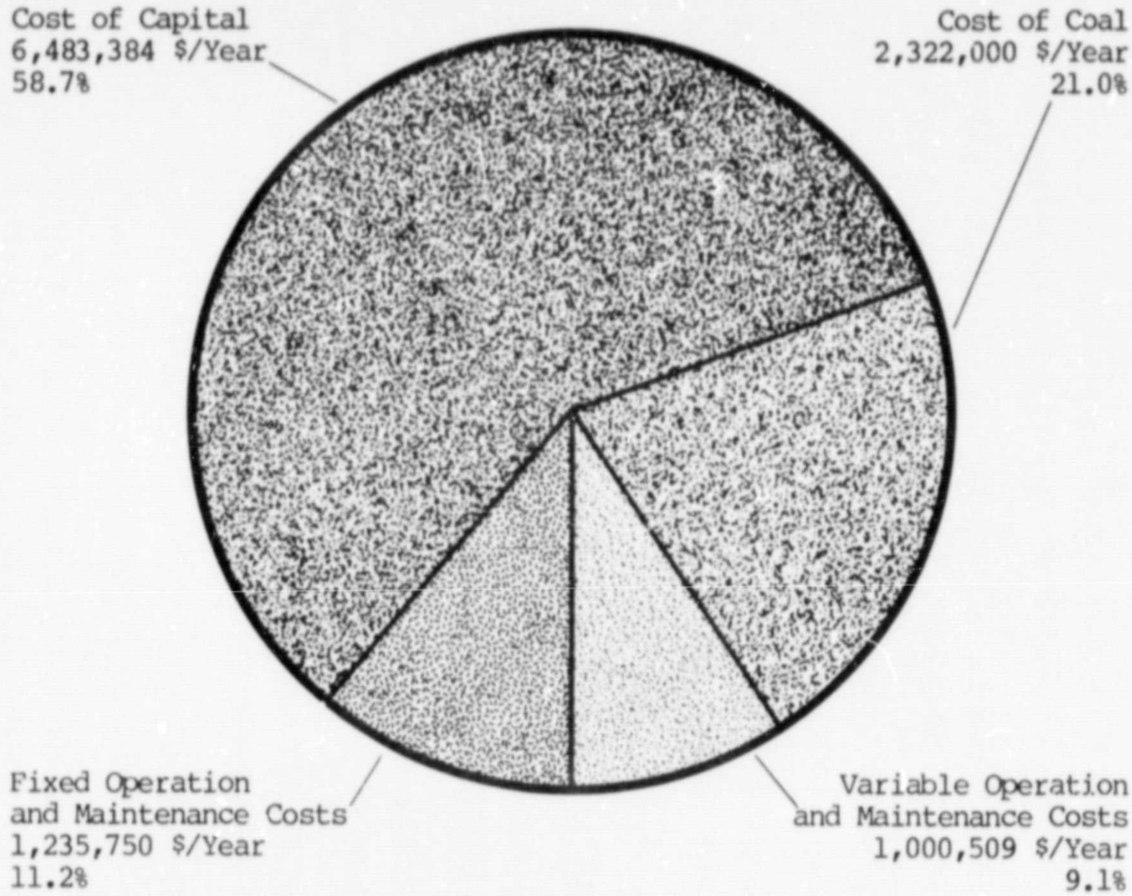
Coal Input	Cost Per Unit	Annual Cost
108,000 Tn/Yr	21.50 $/Tn	$2,322,000

First Year Cost of Hydrogen

	$1978/MMBTU H_2 (HHV)
Levelized Annual Capital Cost	$4.01
Levelized FOM & VOM Costs	1.38
Levelized Annual Coal Cost	1.44
Total Cost of Hydrogen	$6.83

HYDROGEN COST FACTORS

Texaco (Davy-McKee) Gasifier
Forest City Model
Cost of Hydrogen: $6.83*

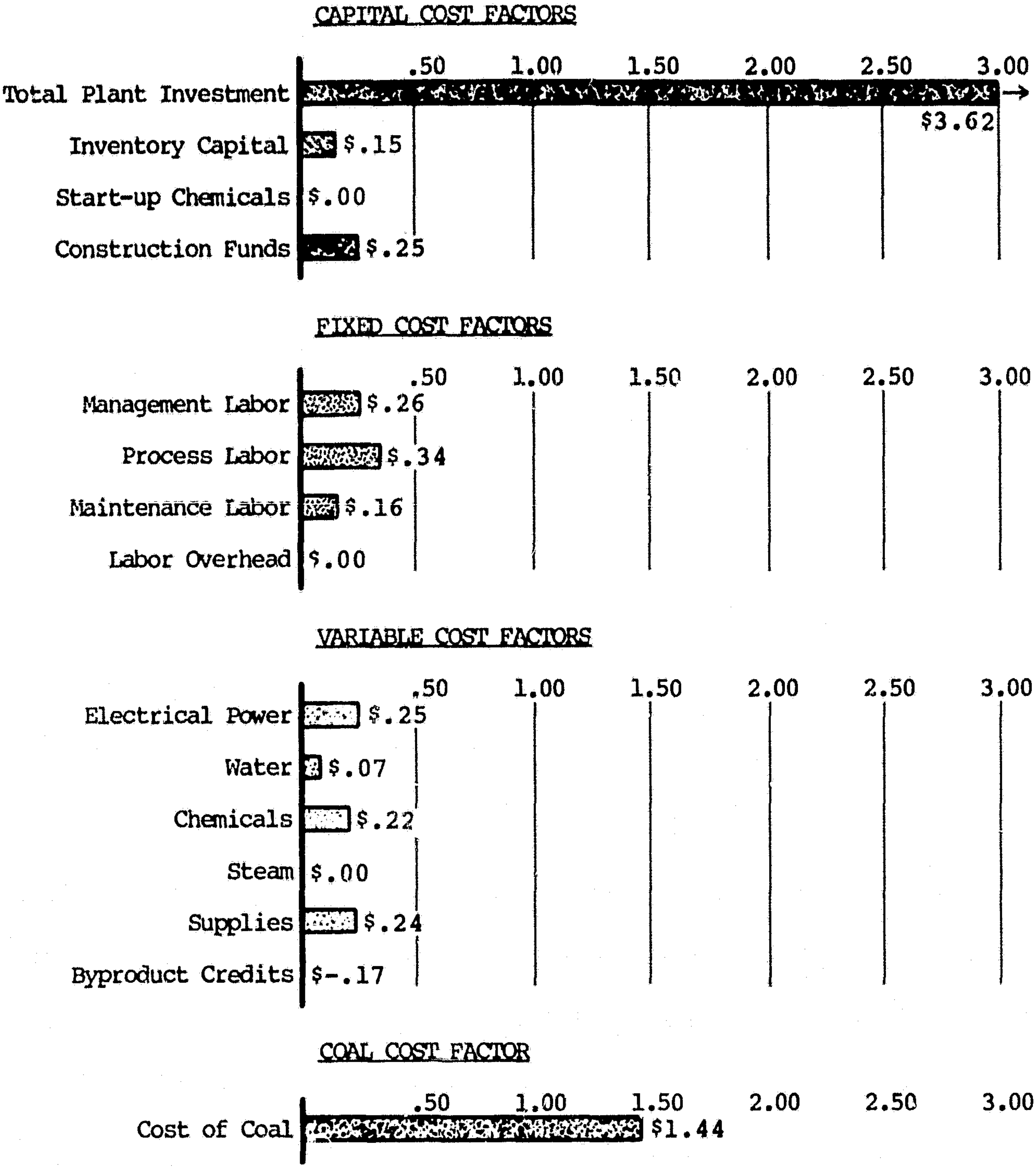


Base Case Summary Information - Commercial Finance

1. Total Plant Investment: $43,500,000 ($ 1978)
2. Plant Utilization Factor: .904 (330 Days/Year)
3. Plant Capacity: 4900 MMBTU H_2 (HHV/Day)
4. Debt Ratio (% of Capital Cost Financed): 75%
5. Debt Cost (Interest on Borrowed Capital): 10%
6. Accounting Method: Flow Through
7. Income Taxes (Fed. + State): 50%
8. Property Taxes + Insurance: 2.70%
9. Investment Tax Credit: 10%
10. Facility Life: 20 Years
11. Tax Life: 16 Years
12. Tax Preference Allowance: Accelerated Depreciation--Sum-of-the-Years-Digits
13. Fuel (Coal) Input: 108,000 Tons/Year
14. Coal Unit Cost: $21.50/Ton ($ 1978)

*1978 dollars/million BTU's higher heating value.

Cost of Hydrogen - $ 1978/MMBTU



Brown & Root Estimates[8]

BASE CASE ASSUMPTIONS
TEXACO COAL GASIFIER
Municipal Financing
Forest City Model

Total Plant Investment

ITEM	CAPITAL COST ($1978)
Coal Storage and Handling	-
Texaco Gasifier Unit	-
Waste Heat Recovery #1	-
Particulate Removal	-
Shift Conversion	-
Waste Heat Recovery #2	-
Rectisol System	-
Claus Plant	-
O_2 Plant W/Compression	-
Miscellaneous Offsites	
Total Brown-Root Plant Estimate	$35,000,000

NOTES: Turn-key price. Miscellaneous offsites: Flare, Cooling Tower and Fresh Water Treatment.

Brown & Root Estimates

BASE CASE ASSUMPTIONS
TEXACO COAL GASIFIER
Municipal Financing
Forest City Model

<u>Fixed Operating and Maintenance Costs ($1978)</u>

ITEM	AMOUNT	COST PER UNIT	ANNUAL COST
Operators (3 per shift)	26,280 Hr/Yr	12.50 $/Hr	$ 328,500
Supervisor (1 per shift)	8,760 Hr/Yr	15.55 $/Hr	136,218
Maintenance (6 Jobs)	12,480 Hr/Yr	12.50 $/Hr	156,000
Admin & Support (8 Jobs)	16,640 Hr/Yr	10.80 $/Hr	179,712
Total Fixed Operating & Maintenance Costs			$800,430

NOTES: 365 x 24 = 8,760 hours per year for operator and supervisory jobs. 52 x 40 = 2,080 hours per year for administrative, support and maintenance jobs.

Brown & Root Estimates

BASE CASE ASSUMPTIONS
TEXACO COAL GASIFIER
Municipal Financing
Forest City Model

Variable Operating and Maintenance Costs ($1978)

ITEM	AMOUNT	COST PER UNIT	ANNUAL COST
Power	16,498 MWH/Yr	25.00 $/MWH	$ 412,450
Water Make-Up	118,786 KGAL/Yr	.85 $/KGAL	100,968
Chemicals & Catalysts	330,000 $/Yr	1.00	330,000
Maintenance Supplies	234,000 $/Yr	1.00	234,000
Waste Water Treatment	30,000 KGAL/Yr	1.25 $/KGAL	37,500
Ash Disposal	16,214 Tn/Yr	4.00 $/Tn	64,856
Sulfur	5,279 Tn/Yr	(80.00) $/Tn	(422,320)
Total Variable Operating and Maintenance Costs			$757,454

Brown & Root Estimates

BASE CASE ASSUMPTIONS
TEXACO COAL GASIFIER
Municipal Financing
Forest City Model

Capital Requirement

ITEM	CAPITAL COST ($1978)
Total Plant Investment	$35,000,000
Pre-production Costs	870,369
Inventory Capital	239,921
Initial Catalyst & Chemicals	30,000
Allowance for Funds During Construction	2,450,000
Total Capital Requirement	$38,590,290

NOTES: Construction Period: Three Years

Plant Capacity: 4,900 MMBTU (HHV) H_2 per day

Capacity Factor: .904 = 330 days per year

Annual Production: 1,616,804 MMBTU per year

BASE CASE ASSUMPTIONS
TEXACO COAL GASIFIER
Municipal Financing
Forest City Model
Brown & Root Estimates

Financial Data

Debt Ratio: 100% (% of capital cost financed)

Debt Cost: 7% (% interest on borrowed capital)

Income Tax (Federal + State): Not applicable

Investment Tax Credit: Not applicable

Facility Life: 20 Years

Tax Life: 16 Years

Accounting Method: Straight Line

Tax Preference Allowance: Not applicable

Total Return (weighted cost of capital):	7.00%
Book Depreciation (Sinking Fund):	2.44%
Property Taxes + Insurance:	1.20%
Levelized Annual Fixed Charge Rate:	10.64%
Capital Recovery Factor:	9.44%

NOTE: Accelerated depreciation and investment tax credit decrease the fixed charge rate.

Brown & Root Estimates

BASE CASE ASSUMPTIONS
TEXACO COAL GASIFIER
Municipal Financing
Forest City Model

Fuel Cost Data ($1978)

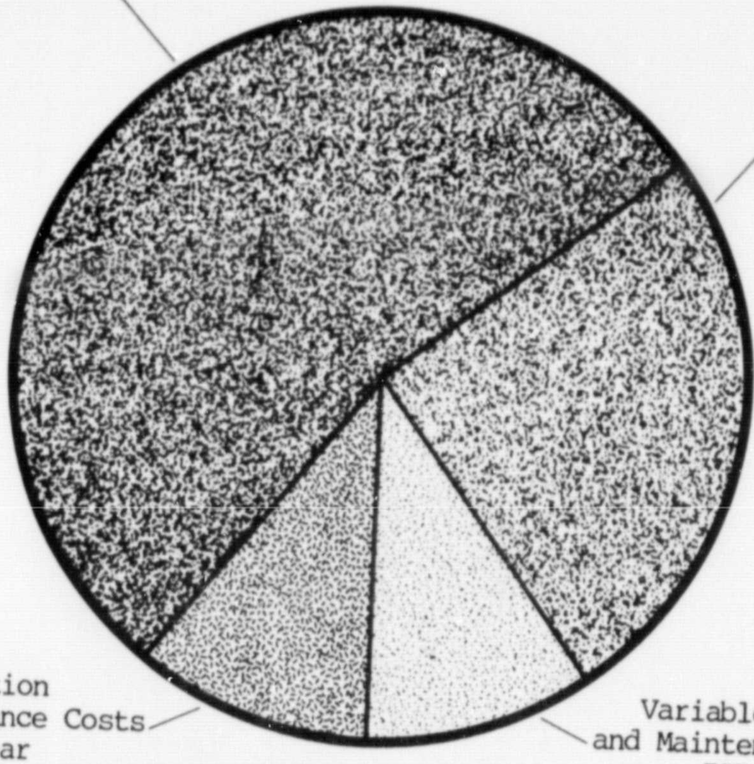
Coal Input	Cost Per Unit	Annual Cost
90,520 Tn/Yr	21.50 $/Tn	$1,946,180

First Year Cost of Hydrogen

	$1978/MMBTU H_2 (HHV)
Levelized Annual Capital Cost	$2.54
Levelized FOM & VOM Costs	.97
Levelized Annual Coal Cost	1.20
Total Cost of Hydrogen	$4.71

HYDROGEN COST FACTORS

Texaco (Brown-Root) Gasifier
Forest City Model
Cost of Hydrogen: $4.70*

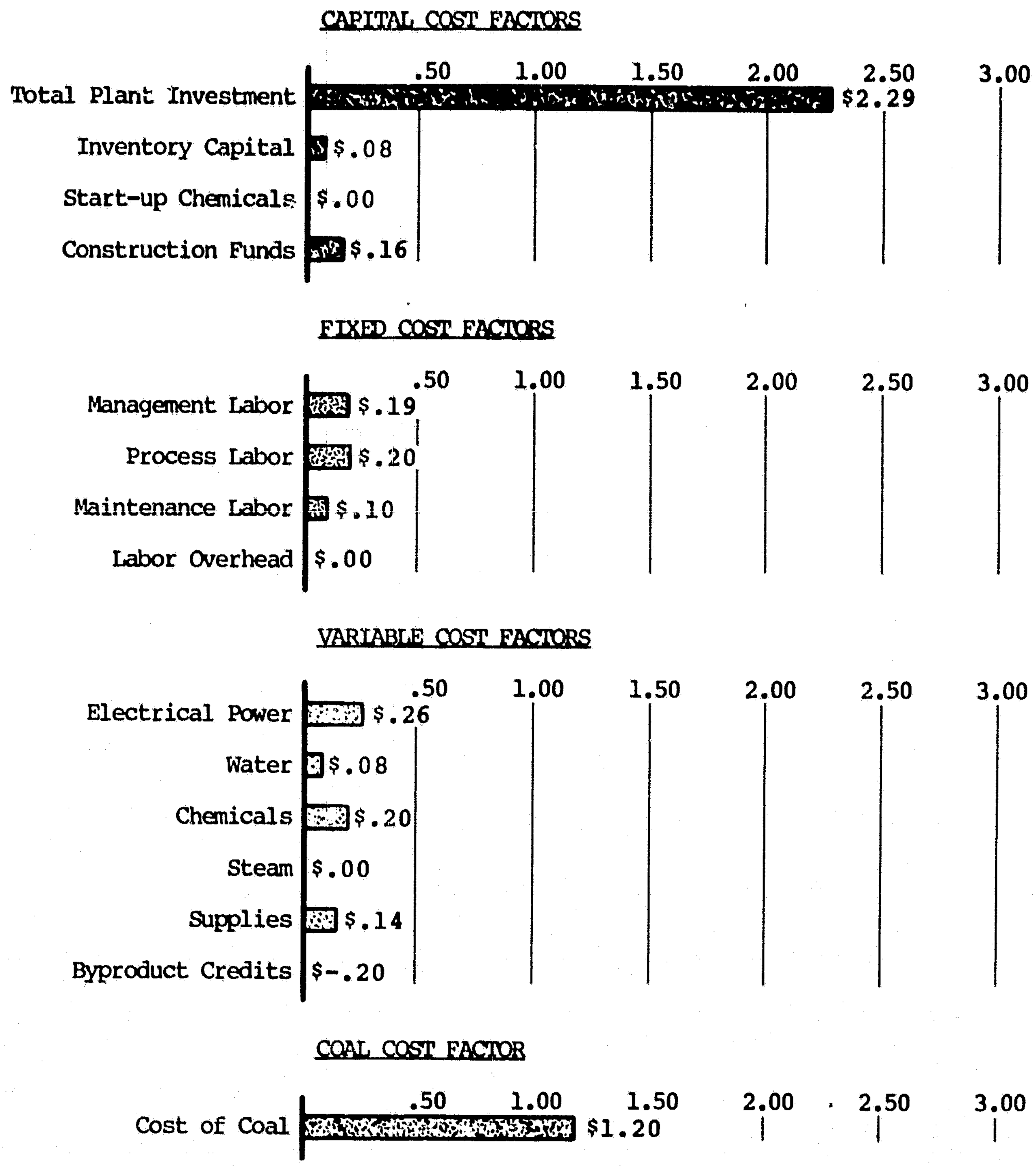


Base Case Summary Information - Municipal Finance

1. Total Plant Investment: $35,000,000 ($ 1978)
2. Plant Utilization Factor: .904 (330 Days/Year)
3. Plant Capacity: 4900 MMBTU H_2 (HHV/Day)
4. Debt Ratio (% of Capital Cost Financed): 100%
5. Debt Cost (Interest on Borrowed Capital): 7%
6. Accounting Method: Straight Line
7. Income Taxes (Fed. + State): Not Applicable
8. Property Taxes + Insurance: 1.20%
9. Investment Tax Credit: Not Applicable
10. Facility Life: 20 Years
11. Tax Life: 16 Years
12. Tax Preference Allowance: Not Applicable
13. Fuel (Coal) Input: 90,520 Tons/Year
14. Coal Unit Cost: $21.50/Ton ($ 1978)

*1978 dollars/million BTU's higher heating value.

Cost of Hydrogen - $ 1978/MMBTU



Brown & Root Estimates

BASE CASE ASSUMPTIONS
TEXACO COAL GASIFIER
Commercial Financing
Forest City Model

Total Plant Investment

ITEM	CAPITAL COST ($1978)
Coal Storage & Handling	-
Texaco Gasifier Unit	-
Waste Heat Recovery #1	-
Particulate Removal	-
Shift Conversion	-
Waste Heat Recovery #2	-
Rectisol System	-
Claus Plant	-
O_2 Plant W/Compression	-
Miscellaneous Offsites	
Total Plant Investment	$35,000,000

NOTES: Turn-key price. Miscellaneous offsites: Flare, Cooling Tower and Fresh Water Treatment.

Brown & Root Estimates

BASE CASE ASSUMPTIONS
TEXACO COAL GASIFIER
Commercial Financing
Forest City Model

Fixed Operating and Maintenance Costs ($1978)

ITEM	AMOUNT	COST PER UNIT	ANNUAL COST
Operators (3 per shift)	26,280 Hr/Yr	12.50 $/Hr	$ 328,500
Supervisor (1 per shift)	8,760 Hr/Yr	15.55 $/Hr	136,218
Maintenance (6 Jobs)	12,480 Hr/Yr	12.50 $/Hr	156,000
Admin & Support (8 Jobs)	16,640 Hr/Yr	10.80 $/Hr	179,712
Total Fixed Operating & Maintenance Costs			$800,430

NOTES: 365 x 24 = 8,760 hours per year for operator and supervisory jobs. 52 x 40 = 2,080 hours per year for administrative, support and maintenance jobs.

Brown & Root Estimates

BASE CASE ASSUMPTIONS
TEXACO COAL GASIFIER
Commercial Financing
Forest City Model

Variable Operating and Maintenance Costs ($1978)

ITEM	AMOUNT		COST PER HOUR		ANNUAL COST
Power	16,498	MWH/Yr	25.00	$/MWH	$ 412,450
Water Makeup	118,786	KGAL/Yr	.85	$/KGAL	100,968
Chemicals & Catalysts	330,000	$/Yr	1.00		330,000
Maintenance Supplies	234,000	$/Yr	1.00		234,000
Waste Water Treatment	30,000	KGAL/Yr	1.25	$/KGAL	37,500
Ash Disposal	16,214	Tn/Yr	4.00	$/Tn	64,856
Sulfur	5,279	Tn/Yr	(80.00)	$/Tn	(422,320)
Total Variable Operating and Maintenance Costs					$757,454

Brown & Root Estimates

BASE CASE ASSUMPTIONS
TEXACO COAL GASIFIER
Commercial Financing
Forest City Model

Capital Requirement

ITEM	CAPITAL COST ($1978)
Total Plant Investment	$35,000,000
Pre-production Costs	870,369
Inventory Capital	239,921
Initial Catalyst & Chemicals	30,000
Allowance for Funds During Construction	2,450,000
Total Capital Requirement	$38,590,290

NOTES: Construction Period: Three Years

Plant Capacity: 4,900 MMBTU (HHV) H_2 per day.

Capacity Factor: .904 = 330 days per year.

Annual Production: 1,616,804 MMBTU (HHV) H_2 per year.

BASE CASE ASSUMPTIONS
TEXACO COAL GASIFIER
Commercial Financing
Forest City Model
Brown & Root Estimates

Financial Data

Debt Ratio: 75% (% of capital cost financed)

Debt Cost: 10% (% interest on borrowed capital)

Preferred Stock Ratio: 8%

Preferred Stock Cost: 15%/Yr

Common Stock Ratio: 17%

Common Stock Cost: 15%/Yr

Income Tax (Federal + State): 50%

Investment Tax Credit: 10%

Facility Life: 20 Years

Tax Life: 16 Years

Accounting Method: Flow Through

Tax Preference Allowance: Accelerated Depreciation (Sum-of-the-years-digits)

Total Return (weighted cost of capital):	11.25%
Book Depreciation (Sinking Fund)	1.51%
Levelized Annual Income Tax	2.59%
Levelized Annual Accelerated Depreciation Allowance	(2.28%)
Levelized Annual Investment Tax Credit Allowance	(2.29%)
Property Taxes + Insurance	2.70%
Levelized Annual Fixed Charge Rate:	13.48%
Capital Recovery Factor:	12.76%

NOTE: Accelerated depreciation and investment tax credit decrease the fixed charge rate.

Brown & Root Estimates

BASE CASE ASSUMPTIONS
TEXACO COAL GASIFIER
Commercial Financing
Forest City Model

Fuel Cost Data ($1978)

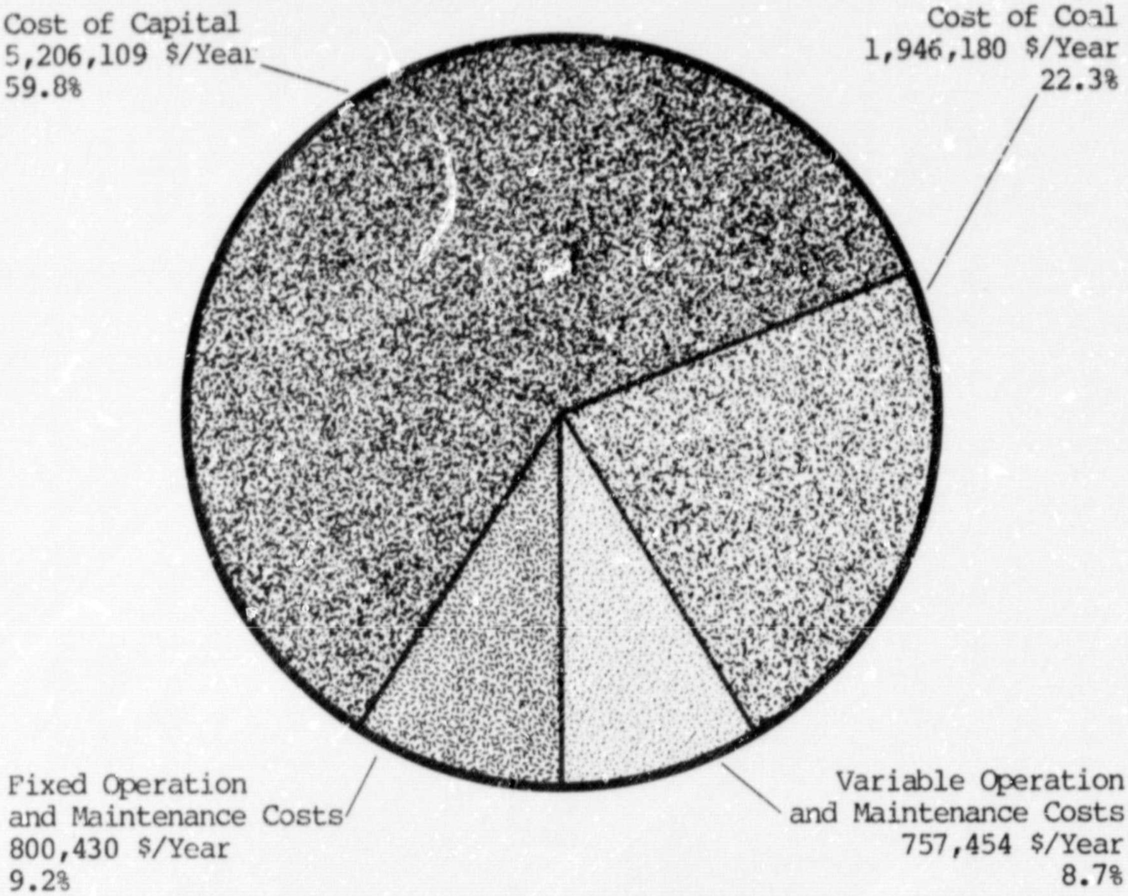
Coal Input	Cost Per Unit	Annual Cost
90,520 Tn/Yr	21.50 $/Tn	$1,946,180

First Year Cost of Hydrogen

	$1978/MMBTU H_2 (HHV)
Levelized Annual Capital Cost	$3.22
Levelized FOM & VOM Costs	.96
Levelized Annual Coal Cost	1.20
Total Cost of Hydrogen	$5.38

HYDROGEN COST FACTORS

Texaco (Brown-Root) Gasifier
Forest City Model
Cost of Hydrogen: $5.38*

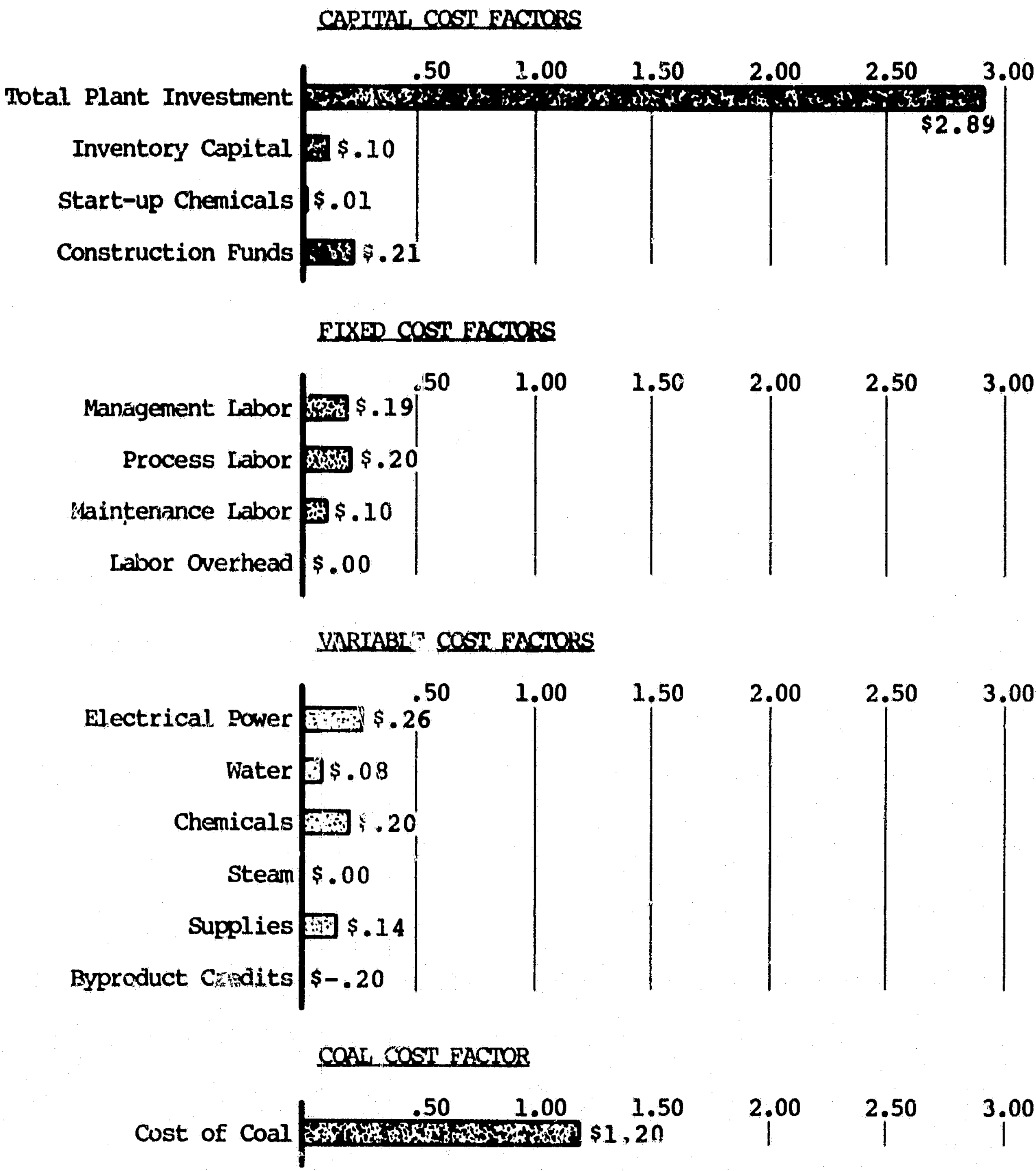


Base Case Summary Information - Commercial Finance

1. Total Plant Investment: $35,000,000 ($ 1978)
2. Plant Utilization Factor: .904 (330 Days/Year)
3. Plant Capacity: 4900 MMBTU H_2 (HHV/Day)
4. Debt Ratio (% of Capital Cost Financed): 75%
5. Debt Cost (Interest on Borrowed Capital): 10%
6. Accounting Method: Flow Through
7. Income Taxes (Fed. + State): 50%
8. Property Taxes + Insurance: 2.70%
9. Investment Tax Credit: 10%
10. Facility Life: 20 Years
11. Tax Life: 16 Years
12. Tax Preference Allowance: Accelerated Depreciation--Sum-of-the-Years-Digits
13. Fuel (Coal) Input: 90,520 Tons/Year
14. Coal Unit Cost: $21.50/Ton ($ 1978)

*1978 dollars/million BTU's higher heating value.

Cost of Hydrogen - $ 1978/MMBTU



2.3 Winkler Davy McKee Gasifier[9]

Forest City Model

A Winkler coal gasification plant was sized to process 370 tons/day of Iowa coal yielding 4.1 billion BTU/day of hydrogen fuel. In addition to the hydrogen product, 1.7 billion BTU/day of low BTU fuel gas is produced that can be used to generate steam for electric power generation (see simplified Block Flow Diagram).

Coal Unloading and Preparation

Run-of-mine Iowa coal will be delivered by rail in 100-ton cars to the Forest City Plant. Since the plant is located in a cold climate, thaw sheds will be provided for winter rail car unloading. A car shaker unloads the coal into an underground hopper. Vibrator feeders supply a conveyor which delivers coal from the hopper to a cage mill where coal is ground to 3/8". The coal is then conveyed to an 8-hour capacity surge hopper above the fluidized-bed "Winkler" gasifier.

Coal Gasification

Coal from the surge hopper passes through a rotary lock feeder and then through two lock hoppers in series which supply a feed screw carrying the coal into the bottom of the 7.5' I.D. "Winkler" fluidized-bed gasifier.

The gasifier operates at a pressure of 40 psig and temperature of approximately 1900^{o}F. Oxygen and steam are introduced into the bottom of the gasifier to provide bed fluidization and gasification of the coal. During gasification, the heavier and larger ash particles pass out the bottom of the gasifier, via a water-cooled ash screw, to lock hoppers. From the lock hoppers the ash is conveyed to an ash hopper for disposal.

The lighter and smaller ash particles produced during gasification are carried upward through the gasifier with the hot product fuel gas. Approximately 50-75% of the incoming ash is entrained with the gas. Because the gasification reactions take place at relatively high temperatures, no tars or oils are produced.

The product gas and entrained ash particles pass out the top of the gasifier and then downward through a waste heat, boiler feed water preheater where high pressure saturated steam is produced. Some ash particulates settle out in the boiler feed water preheater allowing removal via a rotary feeder which feeds a screw carrying the ash to lock hoppers for disposal.

The gas exits the boiler feed water preheater and enters a cyclone to remove more particulates. Product gas is then cleaned in a venturi scrubber and flows to a high temperature CO shift converter.

<u>Carbon Monoxide Shift Conversion</u>

The gas from the venturi scrubber feeds a gas saturator where moisture is added increasing the steam/carbon monoxide ratio for shift conversion. The gas passes from the saturator through a high temperature (H.T.), shift converter. Steam is also added here to the gas to provide the proper steam/CO ratio for CO shift conversion.

The gas exits the first stage H.T. shift converter and flows through a liquid/gas exchanger prior to entering the second stage H.T. shift converter. The gas from the second stage H.T. shift convertor is cooled and passes through knockout pots to removed entrained water prior to entering the hydrogen sulfide removal unit.

The condensate from the cooling of the gas is recycled to the gas saturator. Makeup water collected below the knockout pots is pumped to the coal gasification venturi scrubber system.

Hydrogen Sulfide Removal

The gas flows to a Stretford hydrogen sulfide removal absorber. Here the gas comes in contact with Stretford solution which is introduced into the top of an absorber and passes countercurrent to the upflowing gas. The absorber contains packing to provide contact surface. Over 99.9% of the H_2S is removed from the feed gas. The desulfurized gas exits the absorber and flows to the pressure swing adsorption unit.

The Stretford solution reactants are a mixture of sodium carbonate, sodium meta-vanadate, and reducible dye intermediates (sodium salts of anthra - quinone; 2, 6- and 2, 7- disulfonic acids). In the Stretford process, hydrogen sulfide is removed from the gas and converted to elemental sulfur by the following overall reaction:

$$H_2S + 1/2\ O_2 \dashrightarrow S + H_2O$$

However, this reaction takes place in two steps. In the absorber, the hydrogen sulfide is removed from the gas by the Stretford solution according to the following chemical reaction:

$$H_2S + Na_2CO_3 \dashrightarrow NaHS + NaHCO_3$$

The Stretford solution from the accumulator at the bottom of the absorber flows by gravity to a reaction tank where residence time is provided to allow the following reaction to go to completion:

$$NaHS + 2NaVO_3 + 1/2\ H_2 \dashrightarrow 1/2\ Na_2V_2O_9 + S + 2NaOH$$

Here the anthraquinone disulfonic acids (ADA) also provide for oxidation of the vanadate allowing the vanadate to be reused:

$$1/2\ Na_2V_4O_9 + NaOH + 1/2\ H_2O + ADA \dashrightarrow 2NaVO_3 + ADA\ (reduced)$$

The Stretford solution flows by gravity from the reaction tank through three oxidizer tanks in series. Here air is sparged through the solution to restore the ADA:

$$ADA\ (reduced) + 1/2\ O_2 \dashrightarrow ADA + H_2O$$

Besides oxidizing the ADA, the sparged air froths the sulfur in the solution causing it to float to top of the oxidizer tanks.

The last oxidizer tank acts as a sulfur solution separator. The sulfur froth overflows the oxidizer tank to gravity flow to a sulfur froth pit. The Stretford solution, relatively free of sulfur, flows up from the bottom of the tank behind an internal baffle and overflows to a balance pit.

Prior to the Stretford solution entering the balance pit, it is gravity fed through a cooling tower to remove heat and evaporate any water condensed from the gas in the Stretford absorber. The balance pit acts as a recirculating tank reservoir for the regenerated Stretford solution. The solution is pumped from the reservoir through a Stretford solution heater back to the absorber to remove more H_2S from the feed gas. Solution heating is required, especially during winter, to maintain an adequate temperature (95°F) so sulfates will not crystallize out of solution.

The sulfur froth entering the froth pit is deaerated by gentle agitation allowing the froth to change to a slurry. This slurry, containing approximately 10 wt. % sulfur, is pumped to a sulfur melter feed pump tank. The slurry is then pumped through a sulfur melter decanter where sulfur is melted and molten sulfur is gravity separated from the solution. The Stretford solution is level controlled from the top of the decanter and flows through a cooler back to the balance pit.

Molten sulfur level controlled in the bottom of the decanter passes through a cooler onto a belt. The molten sulfur is fed to the belt through a steam-heated wire feeder. Water sprays under this metal belt allowing the molten sulfur to cool and solidify on the belt as it advances. The solidified sulfur breaks into slates as it drops from the belt into a collecting hopper. The solid sulfur, relatively inert, is ready for disposal or sale.

In the Stretford operation, most of the hydrogen sulfide will be converted to elemental sulfur. However, trace amounts of other soluble compounds are also formed such as thiosulfate and sulfates. To prevent the solution from reaching a saturation point where salting out would occur, it is necessary to purge a portion of the solution from the system and add fresh reagents.

<u>Pressure Swing Adsorption</u>

Gas from the Stretford unit is compressed to 300 psig and enters a pressure swing adsorption unit. The adsorption units consist of four adsorber beds which operate with one bed in the adsorption position, while the other three are in various stages of depressurization, purging and repressurization. During the operation, the low molecular weight hydrogen is far less strongly adsorbed than the heavier components of the feed gas, CO_2, CO, CH_4, etc. At higher pressures, the hydrogen passes through the adsorber beds while the heavier gases remain. When the pressured onstream bed starts to become saturated with the heavier molecules, a regenerated bed is switched on-line and the existing bed is taken off-line, depressured, and purged to remove the heavier molecular weight impurities. The gas from depressurization will have a heating value of 115-120 BTU/scf and can be used as boiler fuel.

The product hydrogen will have a purity greater than 99.9 vol % with less than 10 ppm CO.

Waste Water Treatment and Off Gas Incineration

Waste water and off-gases produced from the coal gasification/gas purification units must necessarily be processed to satisfy state and/or federal environmental control standards.

Water blowdown from the coal gas quenching system and quench from the Stretford sulfur recovery units are the principal water effluents that must be treated prior to disposal.

Water blowdown from the gas quenching system is required to limit the dissolved solids in the quench water. This is necessary to prevent saturation levels from being reached with consequential precipitation of solids in equipment and piping. Besides dissolved solids, the blowdown will contain pollutants such as ammonia, cyanides, fluorides, chlorides, and reduced sulfur compounds in concentrations that are highly dependent upon the composition of the feed coal.

A purge from the Stretford sulfur recovery unit is required to prevent salt precipitation in the Stretford solution due to a buildup of sulfates and thiosulfates. The most significant pollutants in this purge stream are vanadium and its reduced compounds which exist in the form of thiocyanates and thiosulfates. Vanadium is somewhat toxic and could interfere with biological treatment, depending on solubility of the vanadium and acclimation factors. The reduced sulfur compounds would constitute a high oxygen demand on receiving water so oxidation treatment would be required. The Stretford purge is the major concern in waste water treatment, inasmuch as treatability of vanadium is somewhat uncertain and the oxygen demand for the reduced sulfur compounds is appreciable. Therefore, incineration of the Stretford purge is the preferred method of destroying this possible pollutant source.

Waste water from the coal gasification quenching system gravity flows to a waste water holding tank. The waste water is pumped with flow control via the stripper feed pump to the HCN stripper where acid gases are steam stripped from the waste water. The gases then flow to an incinerator. The waste water is pumped from the stripper via the HCN stripper bottom pump to the ammonia stripper. The pH of the feed to the ammonia stripper is raised to 10.5 by controlled addition of 50% NaOH, to free the fixed ammonia from the waste water. The ammonia is steam stripped; the stripper overhead joins the HCN stripper overhead and flows to an incinerator. The stripper bottom is pumped via the ammonia stripper bottom pump to the waste water storage tank. The storage tank is insulated and provides storage capacity to sustain the downstream biological activated sludge plant during periods of coal gasification/gas purification plant outage.

The waste water from the storage tank is fed to the activated sludge aeration tank through a heat exchanger whereby the water is cooled to 140^{o}F prior to entry into the aeration tank. Cooling would not be required in cold weather. The temperature of the aeration tank will range from 60^{o}F - 90^{o}F during winter to summer operation. The pH of the aeration tanks is maintained at about 8.9 by controlled feed of sulfuric acid. Nutrients, in the form of phosphoric acid, and other minerals, are fed to the aeration tank as required to maintain biological performance.

The treated waste water from the aeration tank flows to a clarifier where treated water is separated from the waste sludge. The waste sludge from the clarifier is then pumped to landfill.

Off Gas Incineration

Off gases from the HCN stripper and the NH_3 stripper are burned in an incinerator. The Stretford purge water is also fed to this incinerator and burned. Fuel oil or PSA waste gas is used to fire the incinerator. The off gases will be maintained at approximately 1300^{o}F with a flue gas at a temperature residence time of at least 0.3 seconds.

BASE CASE ASSUMPTIONS
WINKLER COAL GASIFIER
Municipal Financing
Forest City Model

Total Plant Investment

ITEM	CAPITAL COST ($1978)
Coal Handling and Preparation	$ 2,900,000
Coal Gasification	4,300,000
CO Shift	2,000,000
Acid Gas Removal & Sulfur Recovery	3,500,000
Gas Compression	1,600,000
Pressure Swing Adsorption	4,400,000
Waste Water Treatment	900,000
Oxygen Plant	3,600,000
Offsite and Miscellaneous	2,100,000
Total Plant Investment	$25,300,000

NOTES: Information from Davy Report, January 14, 1979.

BASE CASE ASSUMPTIONS
WINKLER COAL GASIFIER
Municipal Financing
Forest City Model

Fixed Operating and Maintenance Costs ($1978)

ITEM	AMOUNT	COST PER UNIT	ANNUAL COST
Operating Labor (16 Jobs)	46,592 Hr/Yr	12.50 $/Hr	$ 582,400
Technical Labor (5 Jobs)	14,560 Hr/Yr	15.55 $/Hr	226,408
Overhead	1.00	242,829 $/Yr	242,829
Total Fixed Operating & Maintenance Costs			$1,051,637

NOTES: Overhead is 30% of total labor costs. Labor rates are based on 365 days per year.

BASE CASE ASSUMPTIONS
WINKLER COAL GASIFIER
Municipal Financing
Forest City Model

Variable Operating and Maintenance Costs ($1978)

ITEM	AMOUNT	COST PER UNIT	ANNUAL COST
Water	22,225 KGAL/Yr	.85 $/KGAL	$ 18,891
Electricity	60,239 MWH/YR	25.00 $/MWH	1,505,975
Maintenance	506,000 $/Yr	1.00	506,000
Chemicals - Stretford	224 $/Day	330.00 Day/Yr	73,920
Sulfur	4,092 Tn/Yr	(80.00) $/Tn	(327,360)
Total Variable Operating and Maintenance Costs			$1,777,426

NOTES: Stretford Chemicals: Sodium Meta-Vanadate, Sodium Carbonate, and ADA.

BASE CASE ASSUMPTIONS
WINKLER COAL GASIFIER
Municipal Financing
Forest City Model

Capital Requirement

ITEM	CAPITAL COST ($1978)
Total Plant Investment	$25,300,000
Pre-production Costs	872,076
Inventory Capital	282,720
Initial Catalyst & Chemicals	13,440
Allowance for Funds During Construction	1,771,000
Total Capital Requirement	$28,239,236

NOTES: Construction Period: Three Years

Plant Capacity: 4,100 MMBTU (HHV) H_2 per day.

Capacity Factor: .904 = 330 days per year.

Annual Production: 1,352,836 MMBTU (HHV) H_2 per year.

BASE CASE ASSUMPTIONS
WINKLER COAL GASIFIER
Municipal Financing
Forest City Model

Financial Data

Debt Ratio: 100% (% of capital cost financed)

Debt Cost: 7% (% interest on borrowed capital)

Income Tax (Federal + State): Not applicable

Investment Tax Credit: Not applicable

Facility Life: 20 Years

Tax Life: 16 Years

Accounting Method: Straight Line

Tax Preference Allowance: Not applicable

Total Return (weighted cost of capital):	7.00%
Book Depreciation (Sinking Fund):	2.44%
Property Taxes + Insurance:	1.20%
Levelized Annual Fixed Charge Rate:	10.64%
Capital Recovery Factor:	9.44%

NOTE: Accelerated depreciation and investment tax credit decrease the fixed charge rate.

E-2

BASE CASE ASSUMPTIONS
WINKLER COAL GASIFIER
Municipal Financing
Forest City Model

Fuel Cost Data ($1978)

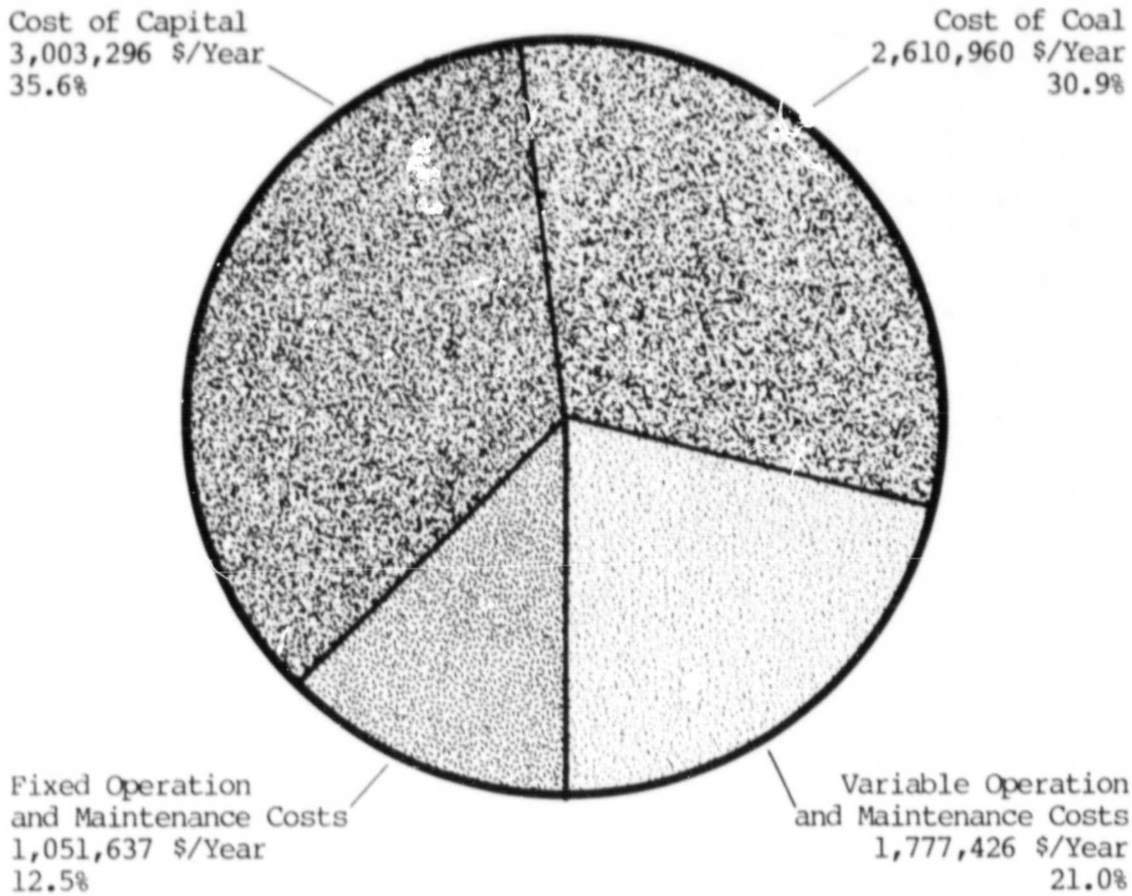
Coal Input	Cost Per Unit	Annual Cost
121,440 Tn/Yr	21.50 $/Tn	$2,610,960

First Year Cost of Hydrogen

	$1978/MMBTU H_2 (HHV)
Levelized Annual Capital Cost	$2.22
Levelized FOM & VOM Costs	2.09
Levelized Annual Fuel Cost	1.93
Total Cost of Hydrogen	$6.24

HYDROGEN COST FACTORS

Winkler Gasifier
Forest City Model
Cost of Hydrogen: \$6.24*

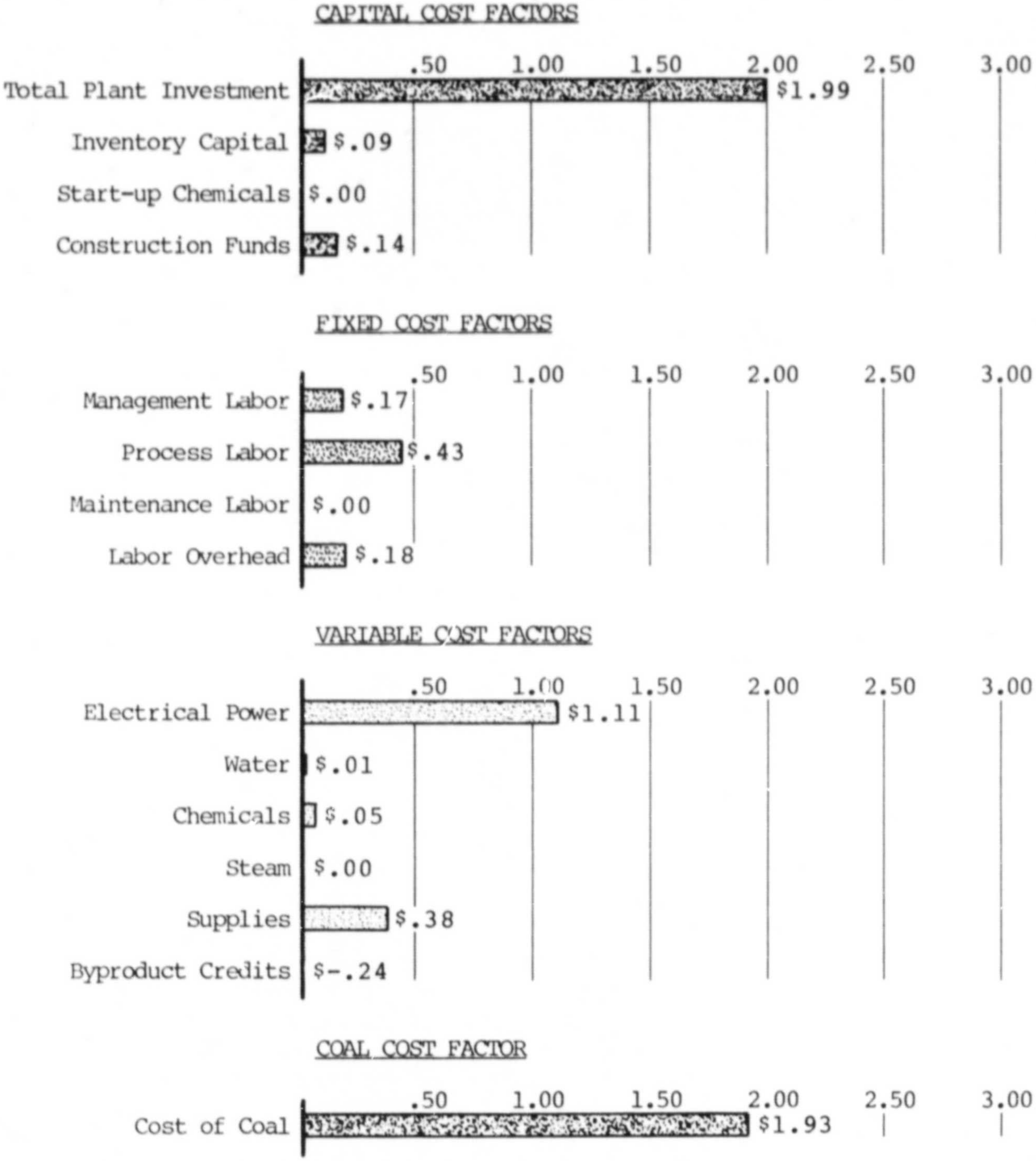


Base Case Summary Information - Municipal Finance

1. Total Plant Investment: \$25,300,000 (\$ 1978)
2. Plant Utilization Factor: .904 (330 Days/Year)
3. Plant Capacity: 4100 MMBTU H_2 (HHV/Day)
4. Debt Ratio (% of Capital Cost Financed): 100%
5. Debt Cost (Interest on Borrowed Capital): 7%
6. Accounting Method: Straight Line
7. Income Taxes (Fed. + State): Not Applicable
8. Property Taxes + Insurance: 1.20%
9. Investment Tax Credit: Not Applicable
10. Facility Life: 20 Years
11. Tax Life: 16 Years
12. Tax Preference Allowance: Not Applicable
13. Fuel (Coal) Input: 121,440 Tons/Year
14. Coal Unit Cost: \$21.50/Ton (\$ 1978)

*1978 dollars/million BTU's higher heating value.

Cost of Hydrogen - $ 1978/MMBTU



BASE CASE ASSUMPTIONS
WINKLER COAL GASIFIER
Commercial Financing
Forest City Model

Total Plant Investment

ITEM	CAPITAL COST ($1978)
Coal Handling and Preparation	$ 2,900,000
Coal Gasification	4,300,000
CO Shift	2,000,000
Acid Gas Removal & Sulfur Recovery	3,500,000
Gas Compression	1,600,000
Pressure Swing Adsorption	4,400,000
Waste Water Treatment	900,000
Oxygen Plant	3,600,000
Offsite and Miscellaneous	2,100,000
Total Plant Investment	$25,300,000

NOTES: Information from Davy Report, January 14, 1979.

BASE CASE ASSUMPTIONS
WINKLER COAL GASIFIER
Commercial Financing
Forest City Model

Fixed Operating and Maintenance Costs ($1978)

ITEM	AMOUNT	COST PER UNIT	ANNUAL COST
Operating Labor (16 Jobs)	46,592 Hr/Yr	12.50 $/Hr	$ 582,400
Technical Labor (5 Jobs)	14,560 Hr/Yr	15.55 $/Hr	226,408
Overhead	1.00	242,829 $/Yr	242,829
Total Fixed Operating & Maintenance Costs			$1,051,637

NOTES: Overhead is 30% of total labor costs. Labor rates are based on 365 days per year.

BASE CASE ASSUMPTIONS
WINKLER COAL GASIFIER
Commercial Financing
Forest City Model

Variable Operating and Maintenance Costs ($1978)

ITEM	AMOUNT		COST PER HOUR		ANNUAL COST
Water	22,225	KGAL/Yr	.85	$/KGAL	$ 18,891
Electricity	60,239	KGAL/Yr	25.00	$/MWH	1,505,975
Maintenance	506,000	$/Yr	1.00		506,000
Chemicals-Stretford	224	$/Day	330.00	Day/Yr	73,920
Sulfur	4,092	Ton/Yr	(80.00)	$/Tn	(327,360)
Total Variable Operating and Maintenance Costs					$1,777,426

NOTES: Stretford Chemicals: Sodium Meta-Vanadate, Sodium Carbonate, and ADA.

BASE CASE ASSUMPTIONS
WINKLER COAL GASIFIER
Commercial Financing
Forest City Model

Capital Requirement

ITEM	CAPITAL COST ($1978)
Total Plant Investment	$25,300,000
Pre-production Costs	872,076
Inventory Capital	282,720
Initial Catalyst & Chemicals	13,440
Allowance for Funds During Construction	1,771,000
Total Capital Requirement	$28,239,236

NOTES: Construction Period: Three Years

Plant Capacity: 4,100 MMBTU (HHV) H_2 per day.

Capacity Factor: .904 = 330 days per year.

Annual Production: 1,352,836 MMBTU (HHV) H_2 per year.

BASE CASE ASSUMPTIONS
WINKLER COAL GASIFIER
Commercial Financing
Forest City Model

Financial Data

Debt Ratio: 75% (% of capital cost financed)

Debt Cost: 10% (% interest on borrowed capital)

Preferred Stock Ratio: 8%

Preferred Stock Cost: 15%/Yr

Common Stock Ratio: 17%

Common Stock Cost: 15%/Yr

Income Tax (Federal + State): 50%

Investment Tax Credit: 10%

Facility Life: 20 Years

Tax Life: 16 Years

Accounting Method: Flow Through

Tax Preference Allowance: Accelerated Depreciation (Sum-of-the-years-digits)

Total Return (weighted cost of capital):	11.25%
Book Depreciation (Sinking Fund)	1.51%
Levelized Annual Income Tax	2.59%
Levelized Annual Accelerated Depreciation Allowance	(2.28%)
Levelized Annual Investment Tax Credit Allowance	(2.29%)
Property Taxes + Insurance	2.70%
Levelized Annual Fixed Charge Rate:	13.48%
Capital Recovery Factor:	12.76%

NOTE: Accelerated depreciation and investment tax credit decrease the fixed charge rate.

BASE CASE ASSUMPTIONS
WINKLER COAL GASIFIER
Commercial Financing
Forest City Model

Fuel Cost Data ($1978)

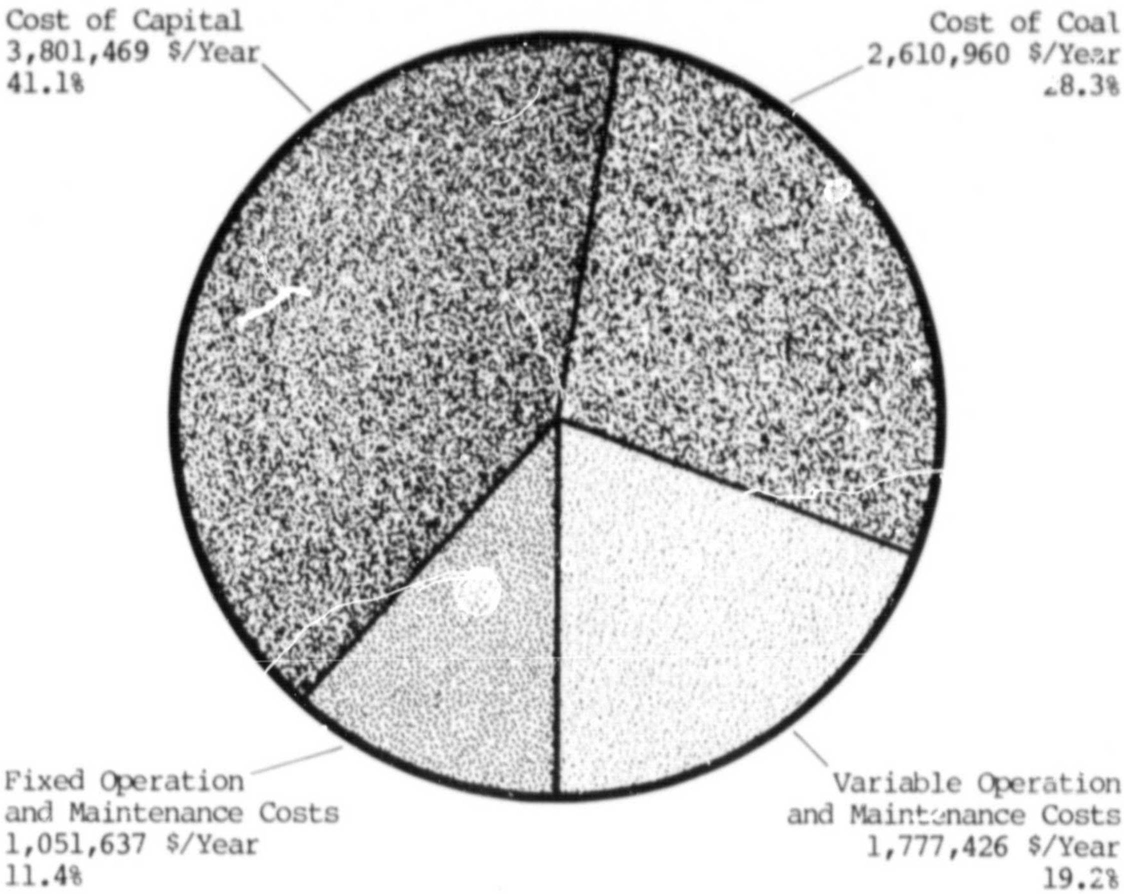
Coal Input	Cost Per Unit	Annual Cost
121,440 Tn/Yr	21.50 $/Tn	$2,610,960

First Year Cost of Hydrogen

	$1978/MMBTU H_2 (HHV)
Levelized Annual Capital Cost	$2.81
Levelized FOM & VOM Costs	2.09
Levelized Annual Fuel Cost	1.93
Total Cost of Hydrogen	$6.83

HYDROGEN COST FACTORS

Winkler Gasifier
Forest City Model
Cost of Hydrogen: $6.83*

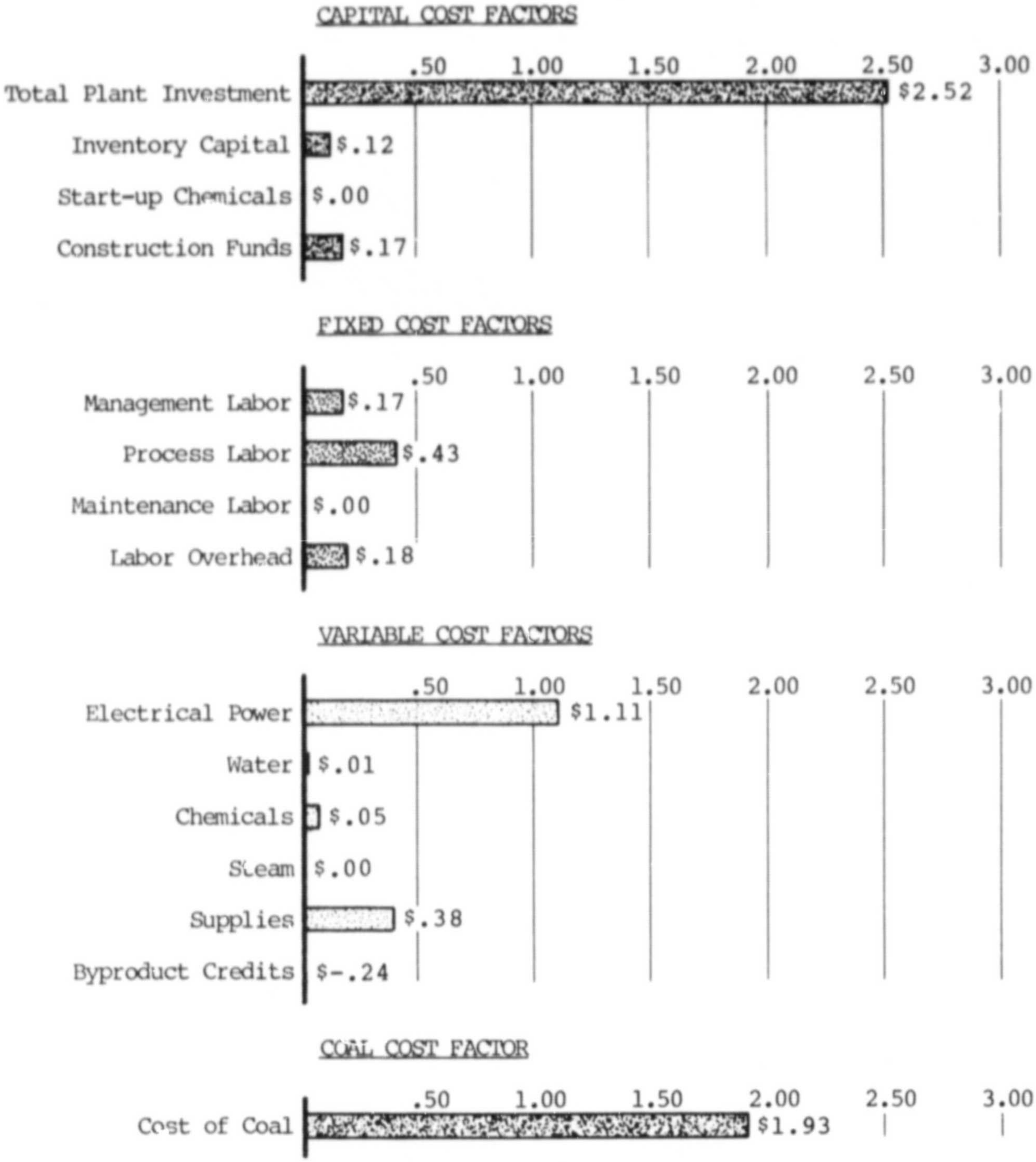


Base Case Summary Information - Commercial Finance

1. Total Plant Investment: $25,300,000 ($ 1978)
2. Plant Utilization Factor: .904 (330 Days/Year)
3. Plant Capacity: 4100 MMBTU H_2 (HHV/Day)
4. Debt Ratio (% of Capital Cost Financed): 75%
5. Debt Cost (Interest on Borrowed Capital): 10%
6. Accounting Method: Flow Through
7. Income Taxes (Fed. + State): 50%
8. Property Taxes + Insurance: 2.70%
9. Investment Tax Credit: 10%
10. Facility Life: 20 Years
11. Tax Life: 16 Years
12. Tax Preference Allowance: Accelerated Depreciation--Sum-of-the-Years-Digits
13. Fuel (Coal) Input: 121,440 Tons/Year
14. Coal Unit Cost: $21.50/Ton ($ 1978)

*1978 dollars/million BTU's higher heating value.

Cost of Hydrogen - $ 1978/MMBTU



CHAPTER II REFERENCES

1. Billings Energy Corporation, Hydrogen in Forest City, Final Report for Hydrogen Feasibility Study funded by Iowa Energy Policy Council and Forest City, Iowa, October, 1979

2. Ibid.

3. Ibid.

4. Black, Sivalls & Bryson, Inc., Houston, Texas

5. Texaco Development Corp., White Plains, New York

6. Ibid.

7. Davy McKee, Cleveland, Ohio

8. Brown & Root, Inc., Houston, Texas

9. Davy McKee, Cleveland, Ohio

CHAPTER III - COAL GASIFICATION KAIPAROWITS MODEL

CHAPTER III - COAL GASIFICATION - KAIPAROWITS MODEL

Introduction

A coal gasification facility having a production of 360 billion BTU's of hydrogen (HHV) per day was considered for construction on the Kaiparowits Plateau in Southern Utah. The facility, as considered, would supply hydrogen via underground pipeline to utility companies which have options on the Kaiparowits coal. Hydrogen produced here could foreseeably be utilized in distant population centers and converted via fuel cell or more conventional equipment to electricity. Also, hydrogen produced at Kaiparowits from nearby coal could, as conceived, become a source of fuel for vehicular applications.[1]

To consider the cost of producing this quantity of hydrogen at Kaiparowits, three separate coal gasification process schemes were analyzed and the costs of constructing and operating each were examined. The coal gasification technologies considered for the Kaiparowits model are the Koppers K-T, the Lurgi, and the Davy McKee Winkler.

3.1 K-T Gasifier[2]

KOPPERS ENGINEERING & CONSTRUCTION COMPANY

Kaiparowits Model

The Koppers plant facilities start with the delivery of 2" x 0" run of mine coal on a conveyor belt. Coal is delivered at a maximum rate of 52,000 NT per day, five days per week, with two shifts per day. Conveyors are provided allowing coal to be delivered to either of two travelling-type, bucket/wheeler, or stacker/reclaimers, each capable of stacking or reclaiming from two 55,000 NT storage piles. Thus, one unit is feeding coal to the plant on a 24 hour per day basis while the other is stocking coal.

The reclaimed coal is delivered to a crushing station where it is reduced to 3/4" x 0". The crushed coal is then split into two streams with approximately 10,400 NT per day being conveyed to four bins (one hour capacity, each) for the steam generating facilities and 26,000 NT per day being conveyed to four bins (one hour capacity, each) for the gasification plant facilities.

Coal from the gasification plant storage bins is delivered to a surge bin in the coal preparation building from which it is fed to four pulverizing, drying, and classifying systems. These systems reduce the coal size from 3/4" x 0" to 70% passing minus 200 mesh and the moisture content from 12.5% to 2%. The coal is discharged to four product bins after classification. Heat for coal drying is provided by hot flue gas from the steam generating facilities. Coal from the product bins is delivered via an N_2 fluidized distribution box to ten (9 operating, one spare), Fuller type coal pumps. Each pump delivers coal via an N_2 conveying system to service bins, two at each gasifier. Eight systems will each deliver coal to four gasifiers and one will deliver coal to three gasifiers. The plant is designed to have thirty-five gasifiers, thirty-three operating and two spares. Each service bin feeds two feed bins which in turn feed two screw conveyors. The eight screw feed conveyors feed four pairs of burners located 90^{o} apart and directed toward the center of each gasifier. Oxygen and steam carry the coal through the burner into the gasifier.

The oxygen, steam, and coal react to gasify the carbon and volatile matter of the coal and to convert the coal ash into molten slag. Part of the molten slag drops into quench tanks below the gasifiers. The gas exiting each gasifier is directly quenched with water to solidify entrained slag droplets, the heavier particles falling through a separate chute into the quench tank. Approximately 50% of the total ash is recovered in the quench tanks. Granular slag is conveyed from each quench tank to a collection conveyor system for delivery to storage area for truck disposal.

Low pressure saturated steam is produced in the jackets of the gasifiers from waste heat that passes through the refractories and through the ducts below the gasifiers and the waste heat boilers.

After quenching, the gas, entrained particles of ash, and unreacted carbon from each gasifier pass through a waste heat boiler in which 800 psig saturated steam is produced. The gas leaves each waste heat boiler at 350^{o}F and passes through a direct spray type washer/cooler in which the gas temperature is reduced to 100^{o}F and 90% of the particulates are removed. The gas then passes through two disintegrators connected in series, where more than 99% of the remaining particulates are removed and the gas is cooled to 98^{o}F. The gas passes through a moisture separator for the removal of entrained water droplets. The cooled and cleaned gas, containing about 0.002 grains of particulates per SCF (dry), enters a gas fan which boosts the gas pressure from about 12.5 psia to 12.6 psia. A quick seal valve is located immediately after each moisture separator which can direct gas produced in its respective gasification train to one or two flare stacks on start-up or in an emergency.

The thirty-five gasifiers are arranged in three rows of nine gasifiers each and one row of eight. The gas cleaning equipment, including the fans for each pair of these rows, connect to a common gas header that in turn connect to a large common header. A flare stack is located at each end of this header. Gas from this header is directed through eight electrostatic precipitators arranged in parallel to further reduce the particulate content to 0.0001 grains per SCF (dry) to permit subsequent compression and catalytic conversion. Gas from the precipitators again enters a common header for delivery to eight compressors arranged in parallel. Controls are provided to maintain a near constant suction pressure by controlling the compressor turbine drives. Emergency excess gas can be discharged to atmosphere via the flare system.

Gas from the compressors is routed through eighteen humidifiers followed by eighteen, three bed, CO shift reactors in parallel to produce hydrogen by catalytically reacting CO with steam. The CO shift systems utilize sulfided catalysts with condensate quenching between stages. Following the CO shift, three strings of Rectisol acid gas removal equipment remove essentially all of the CO_2 and H_2S from the gas. The acid gas rich effluent from the Rectisol system is sent to a Claus sulfur recovery system followed by a SCOT tail gas clean-up facility. The sulfur produced is sales grade quality.

The gas at this point still contains a small amount of CO (about 1.8%) and about 10 ppmv of CO_2. The CO is reduced to about 55 ppmv in six methanation reactors in parallel. Following methanation the gas contains about 1.8% water which is produced during methanation. Part of this water is condensed during gas cooling and the remainder of the water is removed and CO_2 further reduced by absorption on molecular sieves.

Design Data

Coal Required:

Coal Required for Gasification	N.T. Per Day
As received	25,927.3
As Fed to Gasifiers	23,136.2
Coal Required for Auxiliary Steam Production	10,400.0
Total Coal Required (As Received)	36,327.3

Coal Composition	% Wt. As Rec'd	% Wt. As Fed to Gasifiers
C	61.32	68.72
H	4.33	4.85
N	0.95	1.06
S	0.52	.58
O	11.06	12.40
Ash	9.25	10.37
H_2O	12.55	2.00
Cl	0.02	0.02
	100.00	100.00

Coal Ash Composition	Material received from Billings Energy	Used in Calculations
	Wt.%	Wt.%
SO_2	55.44	62.02
Al_2O_3	17.81	19.93
CaO	9.13	10.21
MgO	2.04	2.28
Fe_2O_3	4.97	5.56
Others	10.61	- -
	100.00	100.00

Coal Ash Fusion Temperatures		^{o}F
Reducing -	Initial Def.	2,235
	Soft (H = W)	2,300
	Soft (H = 1/2 W)	2,385
	Fluid	2,510
Oxidizing -	Initial Def.	2,285
	Soft (H = W)	2,360
	Soft (H = 1/2 W)	2,445
	Fluid	2,580
Grindability Index (Hargrove)		46.5
T $250^{o}F$		2,655
Heating Value, BTU/lb (as rec'd.)		10,800

Oxygen Required	N.T. Per Day
99.5% Purity	18,831

Composition	Vol.%
O_2	99.50
N_2	0.05
Ar	0.45
	100.00

Make-up Water

Water is to be pumped to the plant boundry. This water will be clarified and treated for use as process and cooling tower make-up water and part of it further filtered and demineralized to provide make-up boiler feedwater for the waste heat boilers.

Part of the filtered water will be chlorinated to provide potable water for use by plant personnel.

	Average GPM
Cooling Tower & Process Make-up Water	25,211
Make-up Boiler Feedwater	4,278
Potable	15
Miscellaneous	96
Total Lake Water Required	29,600

Steam Production	Pounds Per Hour
Average Power Required	465,375 KWH/Day

Labor Requirements	No. of Personnel
Administrative	25
Clerical	18
Technical	14
Operating	155
Maintenance	82
General Services	27
Spellmen	113
Total	435

*The above does not include sales personnel.

Supplies

Operating	0.1% per year of total plant investment.
Maintenance	0.75% per year of total plant investment.

Chemical & Catalysts

Methanol	9,170 gal. per day
Diisopropanol Amine	132 gal. per day
Alum	1,780 lbs. per day
Lime	4,347 lbs. per day
H_2SO_4	27.1 N.T. per day
Chlorine	1,159 lbs. per day
NaOH	22 N.T. per day
Hagatreet	900 lbs. per day
Biocide	200 lbs. per day
CO shift Catalyst	104,700 ft^3/3-5 years
Methanation Catalyst	10,340 ft^3/3-5 years
Claus Catalyst	123 N.T/3-5 years
Scot Catalyst	271 N.T. /3 years
Molecular Sieve Absorbant	257,640 lbs/2-4 years

Product Hydrogen

The amount and composition of hydrogen delivered to plant boundry at 1,200 psig and $100^{\circ}F$ is as follows:

Pounds/Hr	Mols/Hr.	BTU/Hr.
323,033	129,786	16,500,000,000

Composition	Vol. %
H_2	9[illegible].36
CH_4	1.96
N_2	0.51
Ar	0.17
CO	5 ppmv
CO_2	3 ppmv
H_2S	1 ppmv
H_2O	2 ppmv
	100.00

Sulfur By-product Production 90 L-Ton Per Day

Solid Effluents

	Pounds Per Hour	N.T. Per Day
Gasifier Slag	99,850	1,198.20
Sulfur in Slag	1,387	16.64
Water in Slag @ 15%	15,186	182.23
Total Wet Gasifier Slag	116,423	1,397.07

Gasifier Filter Cake

	Pounds Per Hour	N.T. Per Day
Ash in Filter Cake	100,005	1,200.06
Carbon in Filter Cake	105,982	1,271.78
Sulfur in Filter Cake	1,404	16.85
Water in Filter Cake @ 35%	111,672	1,340.06
Total Wet Gasifier Filter Cake	319,063	3,828.75
Total Wet Gasifier Solids	435,486	5,225.82
Total Water Lost with Gasifier Solids	*126,858	1,522.29
	*365,351 G.P.D.	
Steam Generation Slag	16,033	192.40
Sulfur in Slag	0	0.00
Water in Slag	2,829	33.95
Total Wet Steam Generator Slag	18,862	226.35
Steam Generator Fly Ash Collected	64,005	786.06
Sulfur in Fly Ash	0	0.00
Water in Fly Ash Collected	7,112	85.34
Total Wet Steam Generator Fly Ash	71,117	853.40
Total Wet Steam Generator Solids	89,979	1,079.75
Total Water Lost with Steam Generator Solids	*9,941	119.29
	*28,607 G.P.D.	

Gasifier Filter Cake (Cont'd)

Total Wet Solids Produced	925,465	6,305.57
Total Water Lost With Solids	*136,799	1,641.58
	*351,518 G.P.D.	

Particulate Emissions

All necessary equipment will be installed and the proper precautions taken to maintain particulate emissions within applicable environmental regulation standards. All coal transfer points in the coal handling, crushing, and storage system will be fitted with treated water dust suppression spray equipment; all conveyors will be covered to avoid wind blown particulates; all conveyor junctions will be enclosed in houses; and the crusher building and four each hour-storage bin houses and enclosures will have dust collection systems which will keep atmospheric particulate releases below 0.018 grains/SCF (dry basis).

The entire gasification coal preparation system will contain particulate release to the atmosphere with bag filters. The gasifier feed conveyor system from the product bins to the gasifiers will be nitrogen blanketed and, again, atmospheric releases will be contained via bag filters. All these filtering systems keep atmospheric particulate releases below 0.018 grains/SCF (dry basis).

Coal preparation and coal feed systems for the steam generating station will be handled in a manner similar to that described for coal gasification. Flue gas from this station will pass through electrostatic precipitators that will keep particulate emissions below required limits.

Particulate emissions in excess of regulations may occur at the coal storage piles. This problem can be minimized through the use of telescoping chutes, water spraying, wind breaks, such as trees or fences, and by training the operators to be as conscientious as possible in their stocking and reclaiming operations.

The remainder of plant presents no significant sources for undue particulate emissions.

SO_2 Emissions

The sources of SO_2 emissions are the steam generating station flue gas stacks, the coal drying facility in the gasification plant, and the Claus thermal oxidizer in the gasification plant.

SO_2 emissions from these sources are as follows:

Steam Generating Station	3.0 N.T./Hr
Coal Drying Facility	1.5 N.T./Hr
Claus Thermal Oxidizer	0.04 N.T./Hr
Total	4.54 N.T./Hr

This equates to an overall plant emission rate of 0.278 pounds of SO_2 per million BTU's of coal fired which is well within the existing Federal requirement of 1.2 pounds of SO_2 per million BTU of coal fired.

Liquid Effluents

Facilities are provided for collecting and treating liquid effluents to render them suitable for return to the lake supplying make-up water for the plant.

The liquid effluent sources and flow quantities are as follows:

	G.P.M.
Blowdown from Gas Cleaning Cooling Tower	637
Blowdown from Primary Gas Compressor Cooling Tower	2,240
Blowdown from Air Separation Plant Cooling Tower	2,220

	G.P.M.
Blowdown from Steam Production System	170
Effluent from Sanitary Waste Treatment System Storm Water	10
Oil Contaminated Wash-down Water	

The treatment system will include a compartmented collection sump, means for chlorination and dechlorination, equipment for adding acid and caustic, a biological unit, an API approved oil removal unit and a final retention tank. The aforementioned equipment will be complete with all instrumentation and controls necessary to assure that waters returned to the lake will meet all applicable codes.

Precautions will be taken to assure that storm water will not be contaminated.

Sumps will be provided to collect oil contaminated wash-down water for delivery to treatment system.

NO_x Emissions

The emission of NO_x compounds from the gasification plant will produce no adverse environmental effects. The two areas where the potential NO_x formation exist are the Steam Generating Facility and the Claus Thermal Oxidizers.

The major source of NO_x emissions will be the Steam Generating Facility and this facility will not exceed the Federal emissions standards. Substantiation for this statement is based on an EPA publication titled "NO_x Standards of Performance for New Lignite-Fired Steam Generators", written by John P. Christiano and Richard V. Crume. Actual test data contained within the report showed NO_x emission levels for various types of boilers. One of the boilers tested in this report is very similar to the boilers which will be installed in the gasification plant. Presently the proposed emission level for NO_x is 260 nanograms/joule (0.6 lbs/mm BTU). At no point during the testing sequence did NO_x emissions exceed 230 nanograms/joule. Using the reported figures as a base, a total NO_x emission of approximately 56 tons/day could be expected (0.50 lbs NO_x/mm BTU).

The only other potential source of NO_x is the Claus thermal oxidizer. Although the possibility of NO_x formation does exist, at this time reported, test results do not indicate its presence.

Thus an overall NO_x emission of approximately 56 tons/day would be a representative figure for the entire gasification plant.

OPERATING COST COMPONENTS

Plant Service Factor 330 Days On-Stream Per Year

Components		
Coal, as received	36,327.3 NT/day	By Purchaser
Make-up Water	29,600 GPM	By Purchaser
Electric Power	465,375 KWH/D	By Purchaser
Labor	435 People	By Purchaser
Chemicals & Catalysts		
Methanol	9,170 GPD	$0.50/gal.
Diisopropanol Amine	130 GPD	$4.50/gal.
Alum	1,780 lbs/D	$0.80/lb.
Lime	4,350 lbs/D	$25/NT
H_2SO_4	27.2 NT/D	$40/NT
Chlorine	1,160 lbs/D	$135/NT
NaOH	11 NT/D	$140/NT
Hagatreet	900 lbs/D	$0.88/lb.
Biocide	200 lbs/D	$1.37/lb.
CO Shift Catalyst	104,700 ft^3/4 yrs	$150/$ft^3$
Methanation Catalyst	10,340 ft^3/4 yrs	$121/$ft^3$
Claus Catalyst	123 NT/4 yrs	$500/NT
SCOT Catalyst	271 NT/3 yrs	$1,000/NT
Molecular Seive Absorb.	257,640 lbs/3 yrs	$1.50/lb.
Operating Supplies		0.1 per yr of total plant investment
Maintenance Supplies		0.75% per yr of total plant investment

BASE CASE ASSUMPTIONS
KOPPERS COAL GASIFIER
Municipal Financing
Kaiparowits Model

Total Plant Investment

ITEM	CAPITAL COST ($1978)
Coal Handling and Preparation	$ 74,100,000
Gasify, Cool and Clean	313,800,000
Raw Gas Compression	151,100,000
CO Shift	214,800,000
Acid Gas Removal	141,800,000
Sulfur Recovery	7,800,000
Final Gas Purification	34,800,000
Product Gas Compression	28,500,000
General Facilities	125,400,000
Non-Producing Building & Supplies	7,000,000
Steam Generation	100,800,000
Air Separation	150,100,000
Total Plant Investment	$1,350,000,000

BASE CASE ASSUMPTIONS
KOPPERS COAL GASIFIER
Municipal Financing
Kaiparowits Model

Fixed Operating and Maintenance Costs ($1978)

ITEM	AMOUNT	COST PER UNIT	ANNUAL COST
Operating Labor (155 Jobs)	322,400 Hr/Yr	14.00 $/Hr	$4,513,600
General Services (27 Jobs)	56,160 Hr/Yr	12.50 $/Hr	702,000
Spellmen Labor (113 Jobs)	235,040 Hr/Yr	12.50 $/Hr	2,938,000
Technical Labor (14 Jobs)	29,120 Hr/Yr	15.55 $/Hr	452,816
Clerical Labor (18 Jobs)	37,440 Hr/Yr	8.20 $/Hr	307,008
Administrative (26 Jobs)	54,080 Hr/Yr	16.80 $/Hr	908,543
Maintenance Labor (82 Jobs)	170,560 Hr/Yr	13.50 $/Hr	2,302,560
Total Fixed Operating & Maintenance Costs			$12,124,527

NOTES: Labor rates include 35% payroll burden and are based on 2,080 hours per year. (Sales personnel not included.)

BASE CASE ASSUMPTIONS
KOPPERS COAL GASIFIER
Municipal Financing
Kaiparowits Model

Variable Operating and Maintenance Costs ($1978)

ITEM	AMOUNT	COST PER UNIT	ANNUAL COST
Water	43,173 Ac-Ft/Yr	180 $/Ac-Ft	$7,771,140
Electric Power	153,574 MWH/Yr	40 $/MWH	6,142,960
Operating Supplies	12 Mo/Yr	112,500 $/Mo	1,350,000
Maintenance Supplies	12 Mo/Yr	843,750 $/Mo	10,125,000
Chemicals Consumed	12 Mo/Yr	293,675 $/Mo	3,524,100
Catalysts Consumed	12 Mo/Yr	372,797 $/Mo	4,473,564
Sulfur	33,264 Tn/Yr	(60) $/Tn	(1,995,840)
Total Variable Operating and Maintenance Costs			$31,390,924

BASE CASE ASSUMPTIONS
KOPPERS COAL GASIFIER
Municipal Financing
Kaiparowits Model

Capital Requirement

ITEM	CAPITAL COST ($1978)
Total Plant Investment	$1,350,000,000
Pre-production Costs	35,772,664
Inventory Capital	56,431,300
Initial Catalyst & Chemicals	17,969,000
Allowance for Funds During Construction	227,812,500
Total Capital Requirement	$1,689,485,464

NOTES: Construction Period: Three Years

Plant Capacity: 396,000 MMBTU (HHV) H_2 per day.

Capacity Factor: .904 = 330 days per year.

Annual Production: 130,664,160 MMBTU (HHV) H_2 per year.

BASE CASE ASSUMPTIONS
KOPPERS COAL GASIFIER
Municipal Financing
Kaiparowits Model

Financial Data

Debt Ratio: 100% (% of capital cost financed)

Debt Cost: 7% (% interest on borrowed capital)

Income Tax (Federal + State): Not applicable

Investment Tax Credit: Not applicable

Facility Life: 20 Years

Tax Life: 16 Years

Accounting Method: Straight Line

Tax Preference Allowance: Not applicable

Total Return (weighted cost of capital):	7.00%
Book Depreciation (Sinking Fund):	2.44%
Property Taxes + Insurance:	1.20%
Levelized Annual Fixed Charge Rate:	10.64%
Capital Recovery Factor:	9.44%

NOTE: Accelerated depreciation and investment tax credit decrease the fixed charge rate.

BASE CASE ASSUMPTIONS
KOPPERS COAL GASIFIER
Municipal Financing
Kaiparowits Model

Fuel Cost Data ($1978)

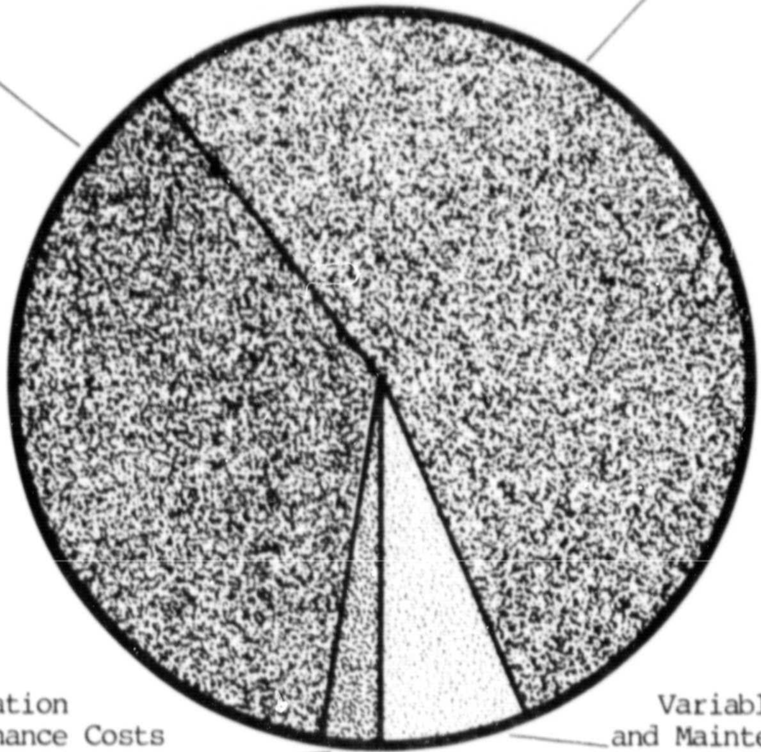
Coal Input	Cost Per Unit	Annual Cost
11,988,010 Tn/Yr	22.00 $/Tn	$263,736,220

First Year Cost of Hydrogen

	\$1978/MMBTU H_2 (HHV)
Levelized Annual Capital Cost	$1.38
Levelized Annual FOM & VOM Costs	.33
Levelized Annual Fuel Cost	2.02
Total Cost of Hydrogen	$3.73

HYDROGEN COST FACTORS

Koppers Gasifier
Kaiparowits Model
Cost of Hydrogen: \$3.73*

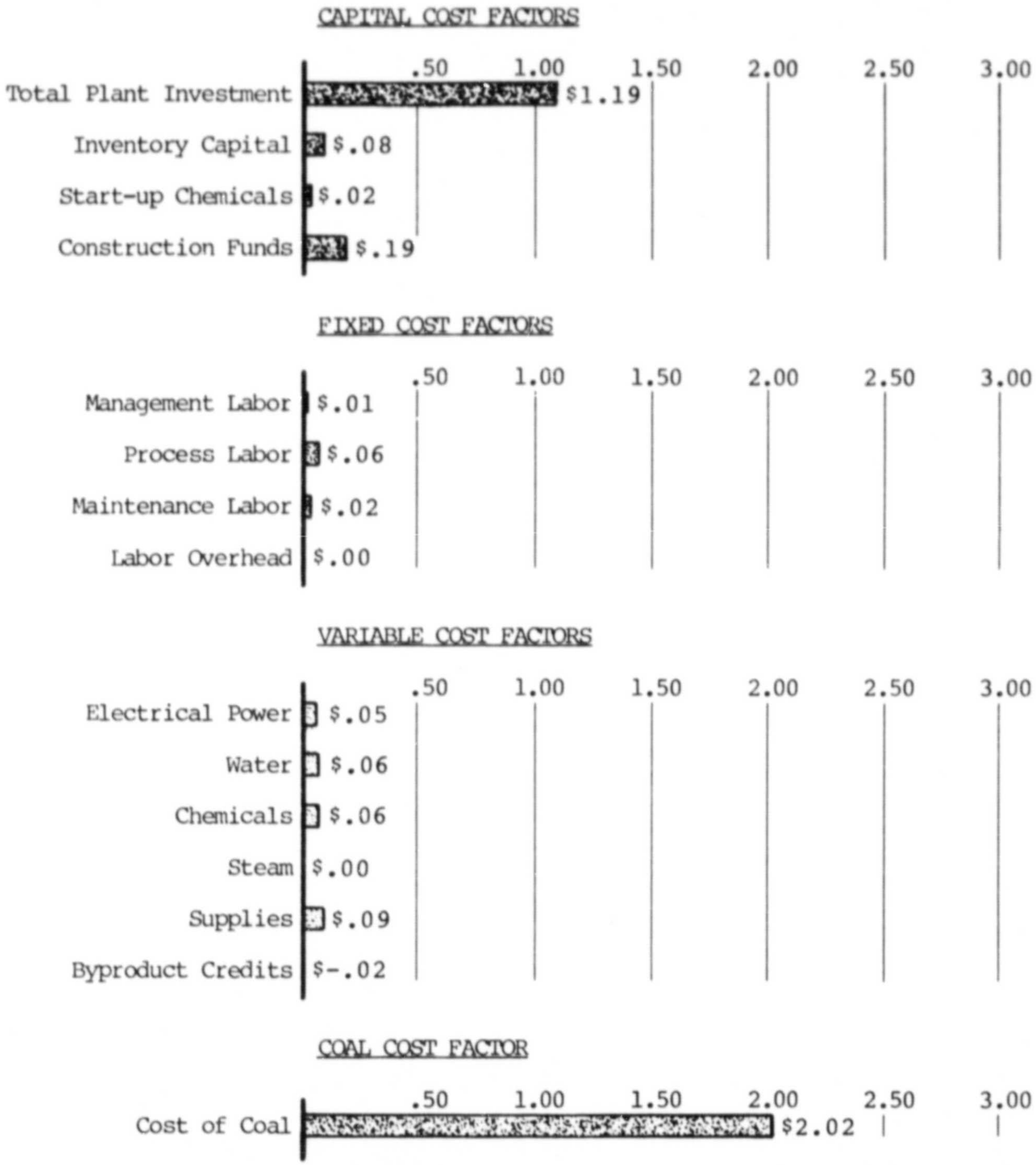


Base Case Summary Information - Municipal Finance

1. Total Plant Investment: \$1,350,000,000 (\$ 1978)
2. Plant Utilization Factor: .904 (330 Days/Year)
3. Plant Capacity: 396,000 MMBTU H_2 (HHV/Day)
4. Debt Ratio (% of Capital Cost Financed): 100%
5. Debt Cost (Interest on Borrowed Capital): 7%
6. Accounting Method: Straight Line
7. Income Taxes (Fed. + State): Not Applicable
8. Property Taxes + Insurance: 1.20%
9. Investment Tax Credit: Not Applicable
10. Facility Life: 20 Years
11. Tax Life: 16 Years
12. Tax Preference Allowance: Not Applicable
13. Fuel (Coal) Input: 11,988,010 Tons/Year
14. Coal Unit Cost: \$22.00/Ton (\$ 1978)

*1978 dollars/million BTU's higher heating value.

Cost of Hydrogen - $ 1978/MMBTU



BASE CASE ASSUMPTIONS
KOPPERS COAL GASIFIER
Commercial Financing
Kaiparowits Model

Total Plant Investment

ITEM	CAPITAL COST ($1978)
Coal Handling and Preparation	$ 74,100,000
Gasiffyy, Cool & Clean	313,800,000
Raw Gas Compression	151,100,000
CO Shift	214,800,000
Acid Gas Removal	141,800,000
Sulfur Recovery	7,800,000
Final Gas Purification	34,800,000
Product Gas Compression	28,500,000
General Facilities	125,400,000
Non-Proc Building Supplies	7,000,000
Steam Generation	100,800,000
Air Separation	150,100,000
Total Plant Investment	$1,350,000,000

BASE CASE ASSUMPTIONS
KOPPERS COAL GASIFIER
Commercial Financing
Kaiparowits Model

Fixed Operating and Maintenance Costs ($1978)

ITEM	AMOUNT	COST PER UNIT	ANNUAL COST
Operating Labor (155 Jobs)	322,400 Hr/Yr	14.00 $/Hr	$4,513,600
General Services (27 Jobs)	56,160 Hr/Yr	12.50 $/Hr	702,000
Spellmen Labor (113 Jobs)	235,040 Hr/Yr	12.50 $/Hr	2,938,000
Technical Labor (14 Jobs)	29,120 Hr/Yr	15.55 $/Hr	452,816
Clerical Labor (18 Jobs)	37,440 Hr/Yr	8.20 $/Hr	307,008
Administrative (26 Jobs)	54,080 Hr/Yr	16.80 $/Hr	908,543
Maintenance Labor (82 Jobs)	170,560 Hr/Yr	13.50 $/Hr	2,302,560
Total Fixed Operating & Maintenance Costs			$12,124,527

NOTES: Labor rates include 35% payroll burden and are based on 2,080 hours per year. (Sales personnel not included.)

BASE CASE ASSUMPTIONS
KOPPERS COAL GASIFIER
Commercial Financing
Kaiparowits Model

Variable Operating and Maintenance Costs ($1978)

ITEM	AMOUNT	COST PER HOUR	ANNUAL COST
Water	43,173 Ac-Ft/Yr	180 $/Ac-Ft	$7,771,140
Electric Power	153,574 MWH/Yr	40 $/MWH	6,142,960
Operating Supplies	12 Mo/Yr	112,500 $/Mo	1,350,000
Maintenance Supplies	12 Mo/Yr	843,750 $/Mo	10,125,000
Chemicals Consumed	12 Mo/Yr	293,675 $/Mo	3,524,100
Catalysts Consumed	12 Mo/Yr	372,797 $/Mo	4,473,564
Sulfur	33,264 Tn/Yr	(60) $/Tn	(1,995,840)
Total Variable Operating and Maintenance Costs			$31,390,924

BASE CASE ASSUMPTIONS
KOPPERS COAL GASIFIER
Commercial Financing
Kaiparowits Model

Capital Requirement

ITEM	CAPITAL COST ($1978)
Total Plant Investment	$1,350,000,000
Pre-production Costs	35,772,664
Inventory Capital	56,431,300
Initial Catalyst & Chemicals	17,969,000
Allowance for Funds During Construction	227,812,500
Land	1,500,000
Total Capital Requirement	1,689,485,464

NOTES: Construction Period: Three Years

Plant Capacity: 396,000 MMBTU (HHV) H_2 per day.

Capacity Factor: .904 = 330 days per year

Annual Production: 130,664,160 MMBTU (HHV) H_2 per year.

BASE CASE ASSUMPTIONS
KOPPERS COAL GASIFIER
Commercial Financing
Kaiparowits Model

Financial Data

Debt Ratio: 75% (% of capital cost financed)

Debt Cost: 10% (% interest on borrowed capital)

Preferred Stock Ratio: 8%

Preferred Stock Cost: 15%/Yr

Common Stock Ratio: 17%

Common Stock Cost: 15%/Yr

Income Tax (Federal + State): 50%

Investment Tax Credit: 10%

Facility Life: 20 Years

Tax Life: 16 Years

Accounting Method: Flow Through

Tax Preference Allowance: Accelerated Depreciation (Sum-of-the-years-digits)

Total Return (weighted cost of capital):	11.25%
Book Depreciation (Sinking Fund)	1.51%
Levelized Annual Income Tax	2.59%
Levelized Annual Accelerated Depreciation Allowance	(2.28%)
Levelized Annual Investment Tax Credit Allowance	(2.29%)
Property Taxes + Insurance	2.70%
Levelized Annual Fixed Charge Rate:	13.48%
Capital Recovery Factor:	12.76%

NOTE: Accelerated depreciation and investment tax credit decrease the fixed charge rate.

BASE CASE ASSUMPTIONS
KOPPERS COAL GASIFIER
Commercial Financing
Kaiparowits Model

Fuel Cost Data ($1978)

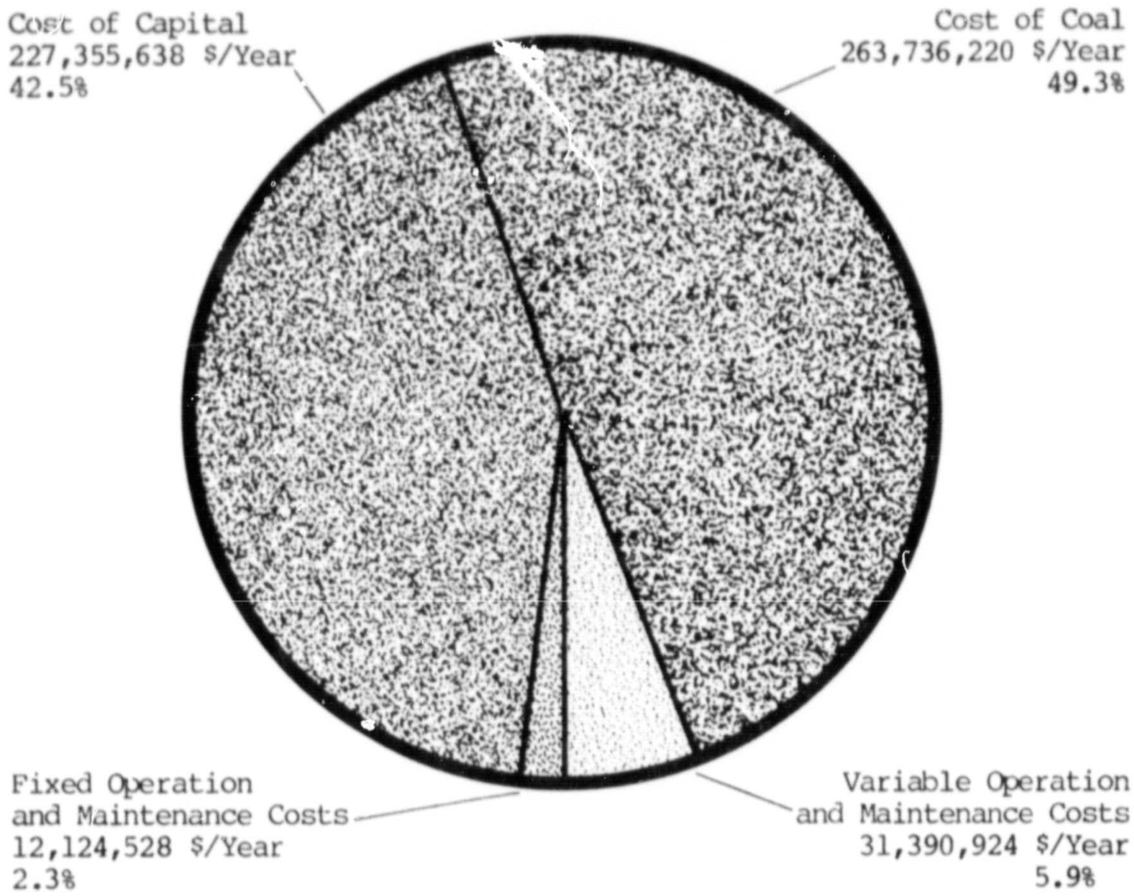
Coal Input	Cost Per Unit	Annual Cost
11,988,010	$22.00 $/Tn	$263,736,220

First Year Cost of Hydrogen

	$1978/MMBTU H_2 (HHV)
Levelized Annual Capital Cost	$1.74
Levelized FOM & VOM Costs	.33
Levelized Annual Fuel Cost	2.02
Total Cost of Hydrogen	$4.09

HYDROGEN COST FACTORS

Koppers Gasifier
Kaiparowits Model
Cost of Hydrogen: \$4.09*

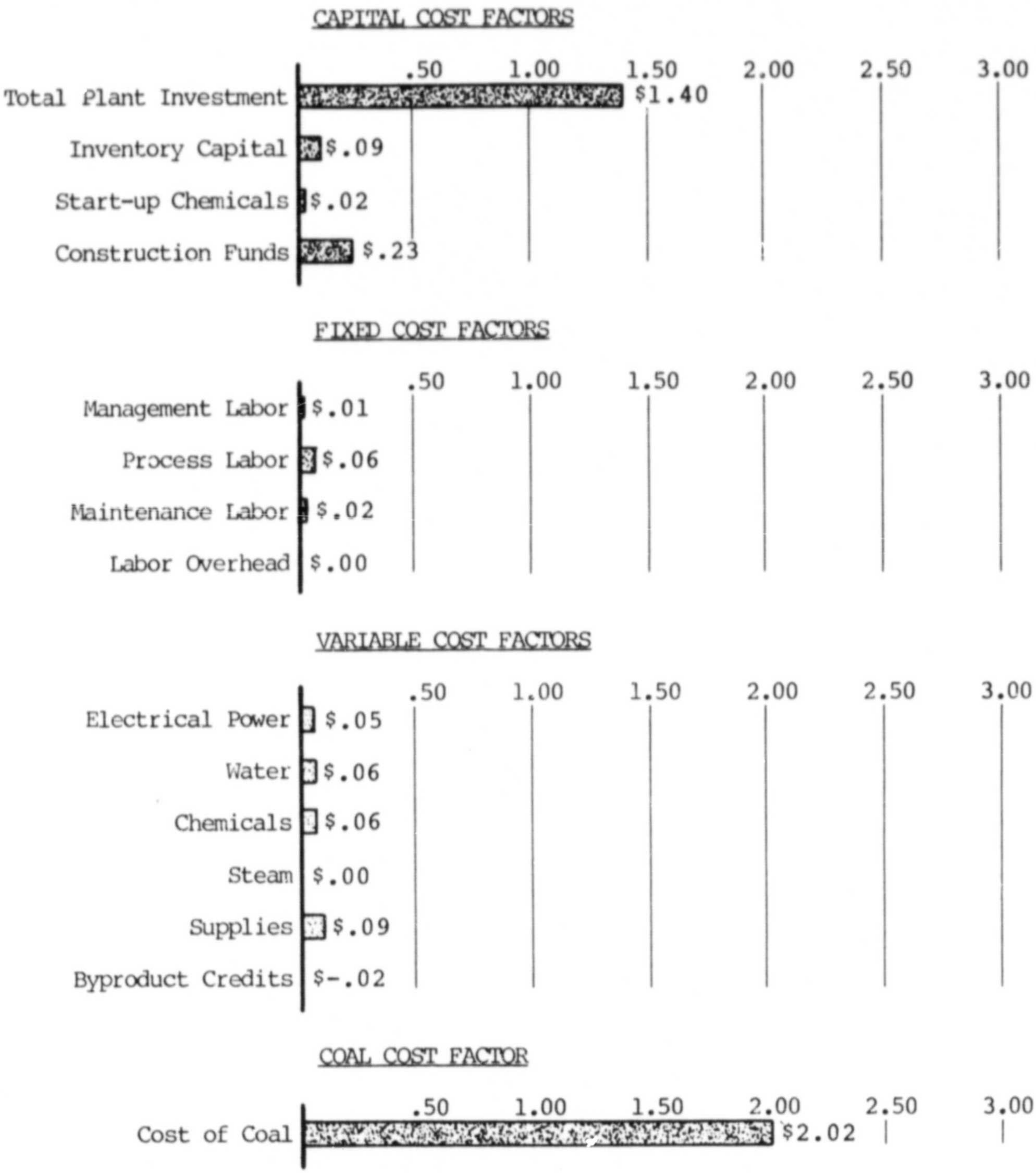


Base Case Summary Information - Commercial Finance

1. Total Plant Investment: \$1,350,000,000 (\$ 1978)
2. Plant Utilization Factor: .904 (330 Days/Year)
3. Plant Capacity: 396,000 MMBTU H_2 (HHV/Day)
4. Debt Ratio (% of Capital Cost Financed): 75%
5. Debt Cost (Interest on Borrowed Capital): 10%
6. Accounting Method: Flow Through
7. Income Taxes (Fed. + State): 50%
8. Property Taxes + Insurance: 2.70%
9. Investment Tax Credit: 10%
10. Facility Life: 20 Years
11. Tax Life: 16 Years
12. Tax Preference Allowance: Accelerated Depreciation--Sum-of-the-Years-Digits
13. Fuel (Coal) Input: 11,988,010 Tons/Year
14. Coal Unit Cost: \$22.00/Ton (\$ 1978)

*1978 dollars/million BTU's higher heating value.

Cost of Hydrogen - $ 1978/MMBTU



3.2 Lurgi Pressurized Gasifier (Oxygen Blown)[3, 4]

Kaiparowits Model

History

Since its development in Germany before World War II, the Lurgi process has been used in numerous commercial plants throughout the world. Although none of these plants are in the U.S., there has been much interest in the process for commercialization in this country. In the 1970's, several U.S. firms announced plans to study the Lurgi process for use in commercial coal gasification plants.[5]

Coal Preparation

Run-of-mine coal will be received at the plant from a belt conveyor. A splitter hopper will be utilized to divide the flow of coal between cage mills. The coal will be crushed to 1/4" x 1 3/4" and sent by conveyor to coal storage bunkers above the individual gasifiers. From these coal bunkers, the coal is fed into an automated lock chamber which controls the flow of coal into a distributor. The distributor introduces the coal evenly across the gasifier shaft area. To process caking coals, blades are mounted to the distributor which rotate within the fuel bed. The delivery and preparation of coal to the Lurgi gasifier for the proposed Kaiparowits plant is similiar in many aspects to the other gasification processes studied in this report.

Lurgi Gasifier

The Lurgi gasifier can best be described as a pressurized, counter-current flow, water jacketed, oxygen-blown reactor. The gasifier operates best at a controlled internal pressure of 20-30 atmospheres. The gas/coal counter-current mode of operation provides for optimum heat and mass transfer and consequently results in a comparatively high thermal efficiency. The reactor - not refractory lined - is surrounded instead by a water jacket. This avoids certain operational problems associated with refractories and also provides a safety feature in that oxygen is prevented from entering the reactor in case of an interruption of steam supply. This is accomplished through instrumented controls of the pressure and temperature of the steam generated in the water jacket. The pressure in the water jacket is the same as in the reactor. Thus the jacket is not exposed to pressure and the reactor's pressure bearing shell is not exposed to high temperatures. Finally, the steam produced in the water jacket is mixed into the gasification agent (described below), and is thus utilized in the process.

Coal gasification in the Lurgi Gasifier

The Lurgi gasifier process scheme shows two basic material inputs: coal and a "gasification agent." The coal, as mentioned before, is distributed into the top of the gasifier. The gasification agent, however, is injected into the bottom of the gasifier. It is comprised of an approximate 50%/50% by volume mixture of steam and oxygen. Gasifier operation is controlled just by controlling the flow of gasification agent, while the coal input adjusts itself to the consumption.

There are four identifiable operating areas or zones within the reactor during gasification. They are, from top to bottom: drying, carbonization, gasification, and combustion.

As the coal is fed down and enters the gasifier, it is dryed by the hot gases rising from below. Since the coal has not been previously dryed, this is a necessary step to rid the coal of "as received" 10-15% moisture. Also taking place in the drying zone is devolatilization of the lighter gases (such as methane) contained within the coal. Devolatilization commences at temperatures of 600°C (1110°F) to 750°C (1380°F).

Next the coal enters, for a relatively short time, a carbonization zone. In this zone the coal is prepared at 750°C (1380°F) to 850°C (1560°F) for the gasification step. This involves driving off more of the volatiles and small quantities of other compounds such as carbonyl sulfide (COS), ammonia (NH_3), and hydrogen sulfide (H_2S). Thus the material, containing a high percentage of carbon, now enters the gasification zone from the top and is in its best form for gasification.

In the gasification zone, steam from the gasification agent and the carbon from the coal react endothermically at approximately 1,200°C (2200°F) to produce hydrogen by the following reaction:

$$C + H_2O \dashrightarrow CO + H_2$$

Finally, heat for the above three steps is provided in the combustion zone of the gasifier. A certain amount of carbon, in the form of char, falls into the combustion zone and reacts exothermically with the oxygen in the gasification agent by the following reaction:

$$4C + 3O_2 \dashrightarrow 2CO_2 + 2CO$$

The heat necessary for the endothermic reaction in the gasification zone and the carbonization and drying zones is thus supplied by sensible heat of the gases rising from the combustion zone at a temperature of about 1200°C (2200°F).

The ash, left from the above processes, is now almost completely burned-out. It is removed from the bottom of the gasifier by a lock hopper system. The total residence time of coal in the gasifier is approximately one hour.

The above described scheme for gas production is a common starting point for a number of processes producing different kinds of useable gases. This base scheme generates a gas with the following approximate composition:

CO_2	10ppm to 10% plus
CO	3% to 30% plus
H_2	50% to 80%
CH_4	10% to 18%
N_2 + Ar	depends on oxygen purity

The remainder of this process will consider only the production of hydrogen as the desired product.

Gas Conditioning and Shift Conversion

The crude gas leaving the gasifier is intensively washed in a scrubber, and its sensible heat is recovered in a waste heat boiler. The wet scrubbing under pressure with a gas liquor containing hot tar eliminates all problems which otherwise particulates can create.

Then the gas passes to a crude gas shift conversion step which is also a Lurgi process. The conversion reaction, $CO + H_2O \rightarrow CO_2 + H_2$, utilizes steam contained in the crude gas, thus eliminating both the expensive cooler-saturator system (as often applied in conventional shift conversion processes) and the consumption of additional steam as well. The crude gas contains sulfur compounds and products originating from coal devolatilization, such as tar, naphtha, etc. The catalyst used is not affected by these impurities and moreover possesses hydrogenation properties which actually improve the quality of the by-products.

The gas can be passed through the shift conversion either totally or fractionally. It is thus possible to adjust the H_2/CO ratio of the gas to the required value. The lowest achievable CO content is about 3%.

By-product Recovery

By gas cooling, partly in waste heat boilers and partly in air or water coolers, steam and tarry products can be condensed. The resulting gas liquor is at first treated in a tar-gas liquor separation unit and then dephenolized in the Lurgi Phenosolvan Process by extraction with an organic solvent (butyl-acetate or isopropyl-ether). The by-products are tar, oil, gas naphtha, and phenols. The Phenosolvan process also provides for the removal of ammonia, which can, by the Chemie Linz-Lurgi Process (CLL-Process), be made available as anhydrous ammonia.

Gas Purification

Hydrogen gas produced by gasification of coal can contain a large amount of CO_2, H_2S, organic sulfur, and other impurities. The Rectisol Process utilizes the capability of cold methanol to absorb all impurities, thus achieving complete purification in a single process unit. Methanol temperatures below 0^oC are used since its absorption capacity increases with decreasing temperature.

A Rectisol unit for the purification of gas produced from coal consists of three process units. A prewash step removes gas naphtha, unsaturated hydrocarbons, and other impurities with higher boiling points. The following two steps remove H_2S, organic sulfur, and CO_2. The extent of CO_2 removal can be adjusted to meet any requirement. The extremely high purity of gas achieved during Rectisol purification makes it suitable for any type of synthesis, including those employing very sensitive catalysts.

Regeneration of the methanol is done by depressurization and distillation. The off-gases from the various stages of flashing and from the regeneration column have to be desulfurized before release to the atmosphere. Various processes are available for this purpose, e.g. the Claus process for off-gases rich in H_2S and the Stretford process for off-gases containing relatively small amounts of H_2S.

BASE CASE ASSUMPTIONS
LURGI COAL GASIFIER
Municipal Financing
Kaiparowits Model

Total Plant Investment

ITEM	CAPITAL COST ($1978)
Total Lurgi Plant Estimate	$1,800,000,000

NOTES: TPI includes all necessary offsites.

BASE CASE ASSUMPTIONS
LURGI COAL GASIFIER
Municipal Financing
Kaiparowits Model

Fixed Operating and Maintenance Costs ($1978)

ITEM	AMOUNT	COST PER UNIT	ANNUAL COST
Administrative (44 Jobs)	91,520 Hr/Yr	16.80 $/Hr	$1,537,535
Clerical (26 Jobs)	54,080 Hr/Yr	8.20 $/Hr	443,456
Technical (22 Jobs)	45,760 Hr/Yr	15.55 $/Hr	711,568
Operating (175 Jobs)	511,000 Hr/Yr	14.00 $/Hr	7,154,000
Maintenance (175 Jobs)	511,000 Hr/Yr	13.50 $/Hr	6,898,500
Service (61 Jobs)	178,120 Hr/Yr	12.50 $/Hr	2,226,500
Spellman (167 Jobs)	487,640 Hr/Yr	12.50 $/Hr	6,095,500
Total Fixed Operating & Maintenance Costs			$25,067,059

NOTES: Administrative, clerical and technical jobs all at 2,080 hours per year. Remainder of jobs at 365 x 8 = 2,920 hours per year.

BASE CASE ASSUMPTIONS
LURGI COAL GASIFIER
Municipal Financing
Kaiparowits Model

<u>Variable Operating and Maintenance Costs ($1978)</u>

ITEM	AMOUNT	COST PER UNIT	ANNUAL COST
Water	60,154 Ac-Ft/Yr	180.00 $/Ac-Ft	$10,827,720
Power	261,328 MWH/Yr	40.00 $/MWH	10,453,120
Maintenance Supplies	72,000,000 $/Yr	1.00	72,000,000
Catalysts/ Chemicals	6,534,000 $/Yr	1.00	6,534,000
Sulfur	36,624 Tn/Yr	(60.00) $/Tn	(2,197,440)
Total Variable Operating and Maintenance Costs			$97,617,400

BASE CASE ASSUMPTIONS
LURGI COAL GASIFIER
Municipal Financing
Kaiparowits Model

Capital Requirement

ITEM	CAPITAL COST ($1978)
Total Plant Investment	$1,800,000,000
Pre-production Costs	55,254,206
Inventory Capital	34,620,114
Initial Catalyst & Chemicals	1,204,500
Allowance for Funds During Construction	260,820,000
Land	1,500,000
Total Capital Requirement	$2,153,398,820

NOTES: Construction Period: Three Years

Plant Capacity: 396,000 MMBTU (HHV) H^2 per day.

Capacity Factor: .904 = 330 days per year.

Annual Production: 130,664,160 MMBTU (HHV) H_2 per year.

BASE CASE ASSUMPTIONS
LURGI COAL GASIFIER
Municipal Financing
Kaiparowits Model

Financial Data

Debt Ratio: 100% (% of capital cost financed)

Debt Cost: 7% (% interest on borrowed capital)

Income Tax (Federal + State): Not applicable

Investment Tax Credit: Not applicable

Facility Life: 20 Years

Tax Life: 16 Years

Accounting Method: Straight Line

Tax Preference Allowance: Not Applicable

Total Return (weighted cost of capital):	7.00%
Book Depreciation (Sinking Fund):	2.44%
Property Taxes + Insurance:	1.20%
Levelized Annual Fixed Charge Rate:	10.64%
Capital Recovery Factor:	9.44%

NOTE: Accelerated depreciation and investment tax credit decrease the fixed charge rate.

BASE CASE ASSUMPTIONS
LURGI COAL GASIFIER
Municipal Financing
Kaiparowits Model

Fuel Cost Data ($1978)

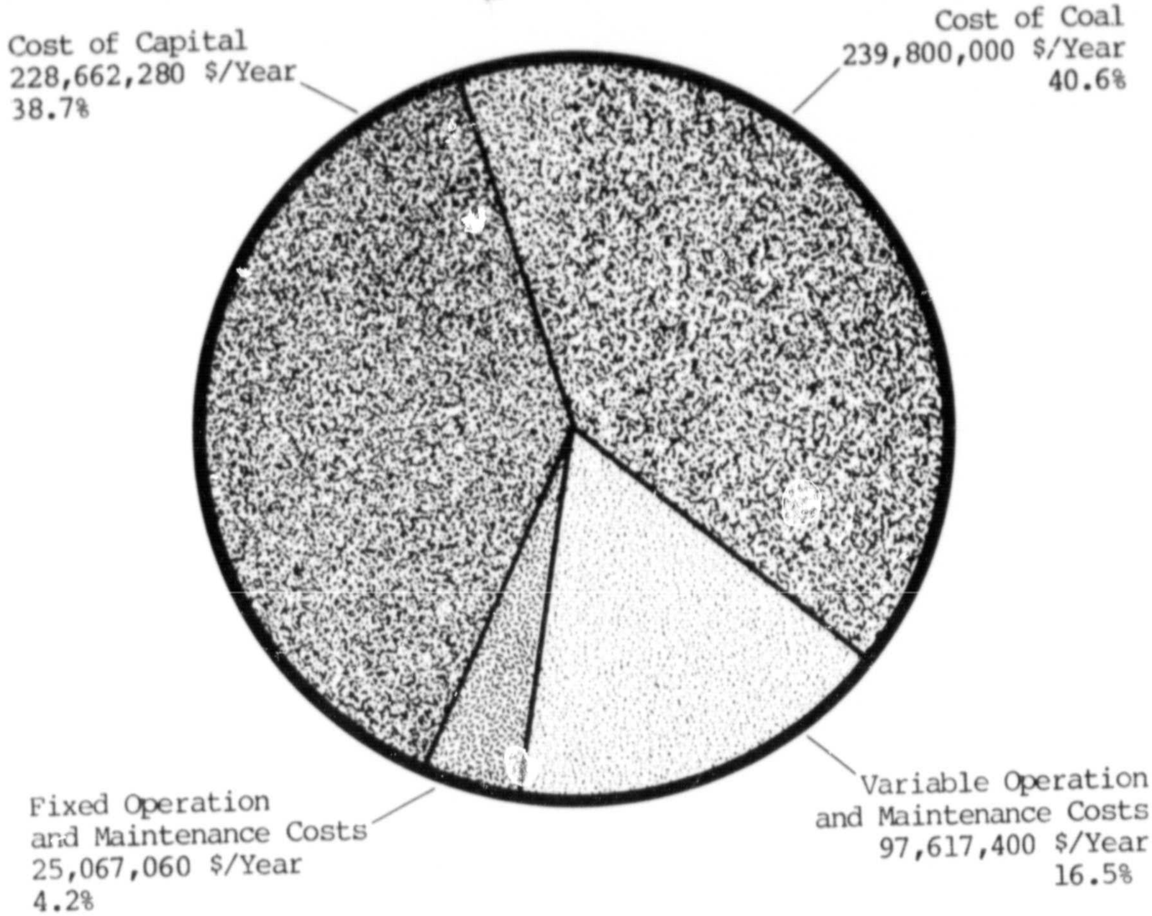
Coal Input	Cost Per Unit	Annual Cost
10,900,000 Tn/Yr	22.00 $/Tn	$239,800,000

First Year Cost of Hydrogen

	$1978/MMBTU H_2 (HHV)
Levelized Annual Capital Cost	$1.75
Levelized FOM & VOM Costs	.94
Levelized Annual Fuel Cost	1.84
Total Cost of Hydrogen	$4.53

HYDROGEN COST FACTORS

Lurgi Gasifier
Kaiparowits Model
Cost of Hydrogen: \$4.53*

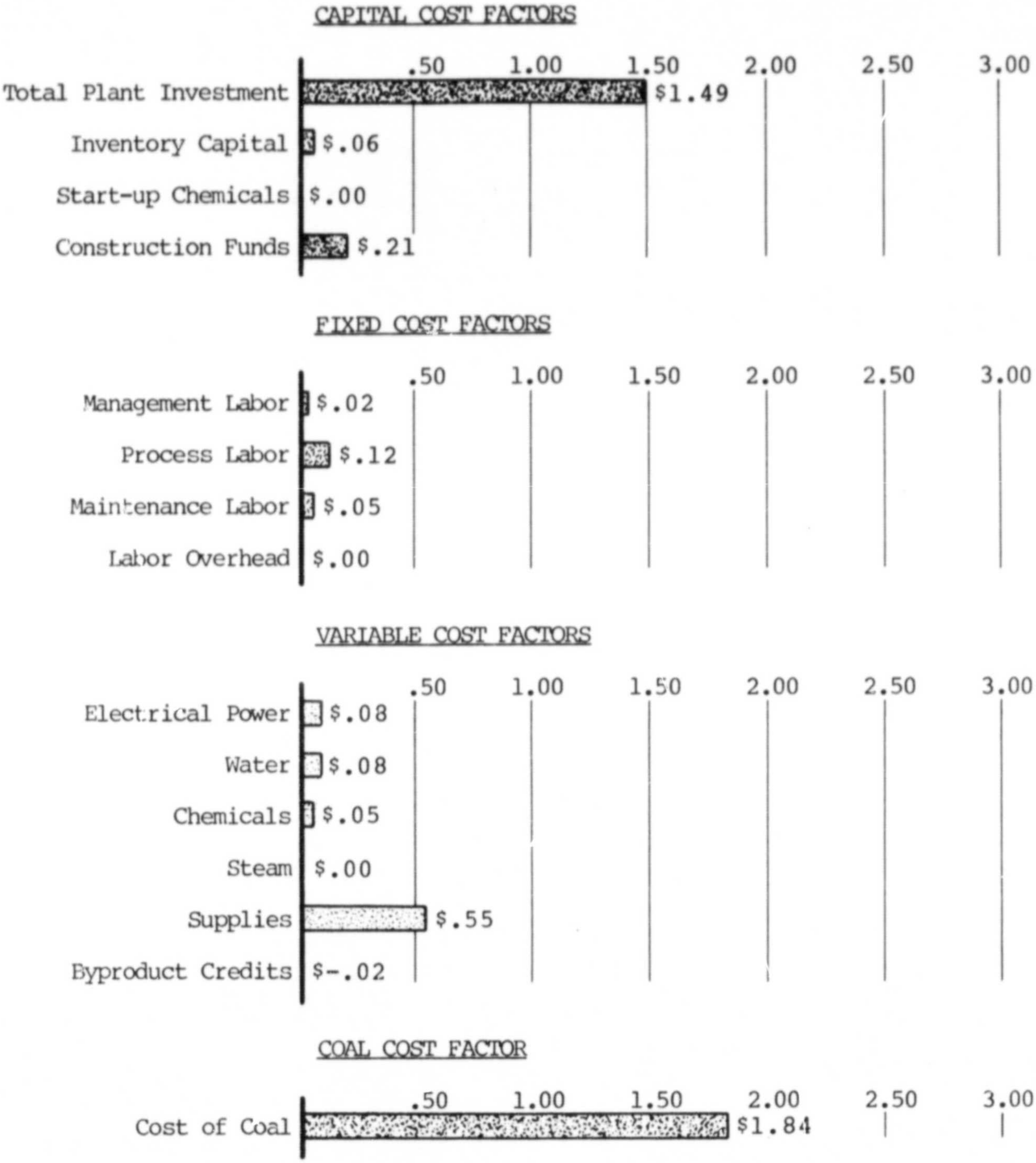


Base Case Summary Information - Municipal Finance

1. Total Plant Investment: \$1,800,000,000 (\$ 1978)
2. Plant Utilization Factor: .904 (330 Days/Year)
3. Plant Capacity: 396,000 MMBTU H_2 (HHV/Day)
4. Debt Ratio (% of Capital Cost Financed): 100%
5. Debt Cost (Interest on Borrowed Capital): 7%
6. Accounting Method: Straight Line
7. Income Taxes (Fed. + State): Not Applicable
8. Property Taxes + Insurance: 1.20%
9. Investment Tax Credit: Not Applicable
10. Facility Life: 20 Years
11. Tax Life: 16 Years
12. Tax Preference Allowance: Not applicable
13. Fuel (Coal) Input: 10,900,000 Tons/Year
14. Coal Unit Cost: \$22.00/Ton (\$ 1978)

*1978 dollars/million BTU's higher heating value.

Cost of Hydrogen - $ 1978/MMBTU



BASE CASE ASSUMPTIONS
LURGI COAL GASIFIER
Commercial Financing
Kaiparowits Model

Total Plant Investment

ITEM	CAPITAL COST ($1978)
Total Lurgi Plant Estimate	$1,800,000,000

NOTE: TPI includes all necessary offsites.

BASE CASE ASSUMPTIONS
LURGI COAL GASIFIER
Commercial Financing
Kaiparowits Model

Fixed Operating and Maintenance Costs ($1978)

ITEM	AMOUNT	COST PER UNIT	ANNUAL COST
Administrative (44 Jobs)	91,520 Hr/Yr	16.80 $/Hr	$1,537,535
Clerical (26 Jobs	54,080 Hr/Yr	8.20 $/Hr	443,456
Technical (22 Jobs)	45,760 Hr/Yr	15.55 $/Hr	711,568
Operating (175 Jobs)	511,000 Hr/Yr	14.00 $/Hr	7,154,000
Maintenance (175 Jobs)	511,000 Hr/Yr	13.50 $/Hr	6,898,500
Service (61 Jobs	178,120 Hr/Yr	12.50 $/Hr	2,226,500
Spellmen (167 Jobs)	487,640 Hr/Yr	12.50 $/Hr	6,095,500
Total Fixed Operating & Maintenance Costs			$25,067,059

NOTE: Administrative, clerical and technical jobs all at 2,080 hours per year. Remainder of jobs at 365 x 8 = 2,920 hours per year.

BASE CASE ASSUMPTIONS
LURGI COAL GASIFIER
Commercial Financing
Kaiparowits Model

Variable Operating and Maintenance Costs ($1978)

ITEM	AMOUNT		COST PER HOUR		ANNUAL COST
Water	60,154	Ac-Ft/Yr	180.00	$/Ac-Ft	$10,817,720
Power	261,328	MWH/Yr	40.00	$/MWH	10,453,120
Maintenance Supp	72,000,000	$/Yr	1.00		72,000,000
Catalysts Chem	6,534,000	$/Yr	1.00		6,534,000
Sulfur	36,624	Tn/Yr	(60.00)	$/Tn	(2,197,440)
Total Variable Operating and Maintenance Costs					$97,617,400

BASE CASE ASSUMPTIONS
LURGI COAL GASIFIER
Commercial Financing
Kaiparowits Model

Capital Requirement

ITEM	CAPITAL COST ($1978)
Total Plant Investment	$1,800,000,000
Pre-production Costs	55,254,206
Inventory Capital	34,610,114
Initial Catalyst & Chemicals	1,204,500
Allowance for Funds During Construction	260,820,000
Land	1,500,000
Total Capital Requirement	$2,152,298,820

NOTES: Construction Period: Three Years

Plant Capacity: 396,000 MMBTU (HHV) H_2 per day.

Capacity Factor: .904 = 330 days per year.

Annual Production: 130,664,160 MMBTU (HHV) H_2 per year.

BASE CASE ASSUMPTIONS
LURGI COAL GASIFIER
Commercial Financing
Kaiparowits Model

Financial Data

Debt Ratio: 75% (% of capital cost financed)

Debt Cost: 10% (% interest on borrowed capital)

Preferred Stock Ratio: 8%

Preferred Stock Cost: 15%/Yr

Common Stock Ratio: 17%

Common Stock Cost: 15%/Yr

Income Tax (Federal + State): 50%

Investment Tax Credit: 10%

Facility Life: 20 Years

Tax Life: 16 Years

Accounting Method: Flow Through

Tax Preference Allowance: Accelerated Depreciation (Sum-of-the-years-digits)

Total Return (weighted cost of capital):	11.26%
Book Depreciation (Sinking Fund)	1.51%
Levelized Annual Income Tax	2.59%
Levelized Annual Accelerated Depreciation Allowance	(2.28%)
Levelized Annual Investment Tax Credit Allowance	(2.29%)
Property Taxes + Insurance	2.70%
Levelized Annual Fixed Charge Rate:	13.48%
Capital Recovery Factor:	12.76%

NOTE: Accelerated depreciation and investment tax credit decrease the fixed charge rate.

BASE CASE ASSUMPTIONS
LURGI COAL GASIFIER
Commercial Financing
Kaiparowits Model

Fuel Cost Data ($1978)

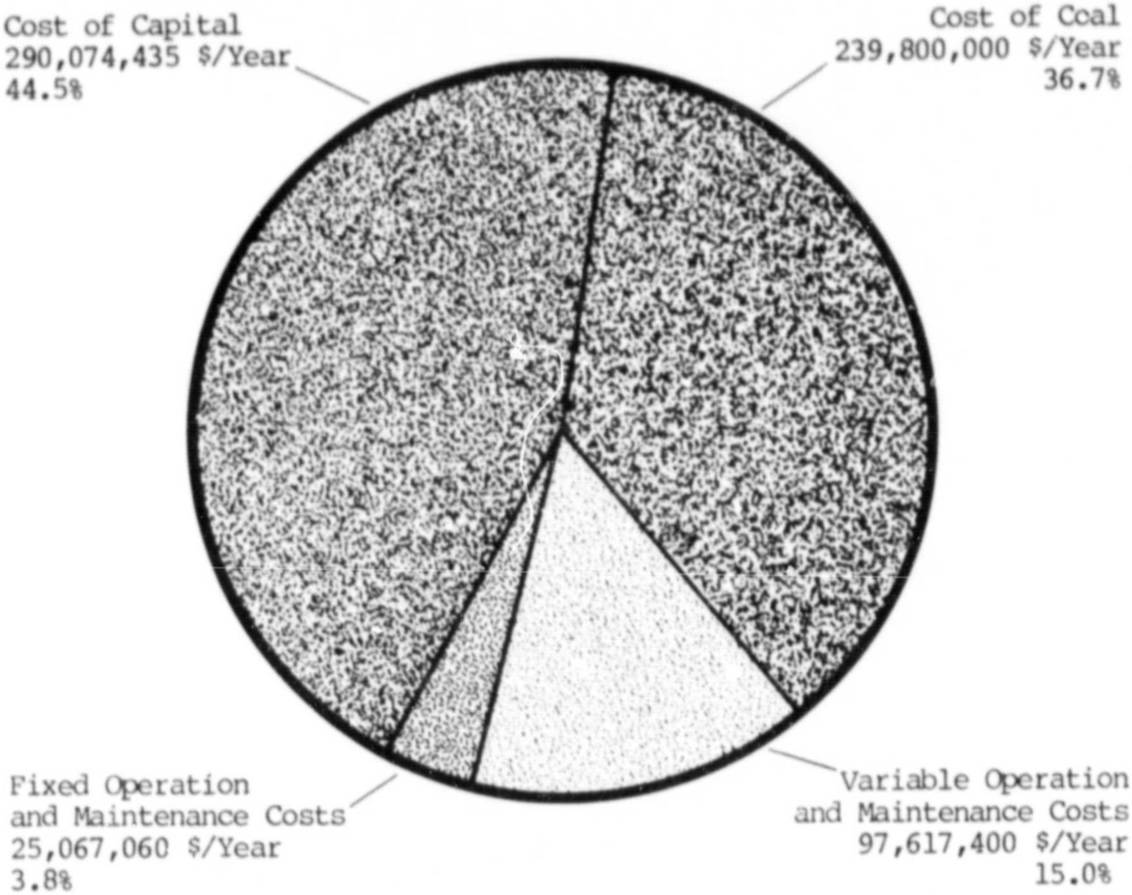
Coal Input	Cost Per Unit	Annual Cost
10,900,000 Tn/Yr	22.00 $/Tn	$239,800,000

First Year Cost of Hydrogen

	$1978/MMBTU H_2 (HHV)
Levelized Annual Capital Cost	$2.22
Levelized FOM & VOM Costs	.94
Levelized Annual Fuel Cost	1.84
Total Cost of Hydrogen	$5.00

HYDROGEN COST FACTORS

Lurgi Gasifier
Kaiparowits Model
Cost of Hydrogen: $5.00*

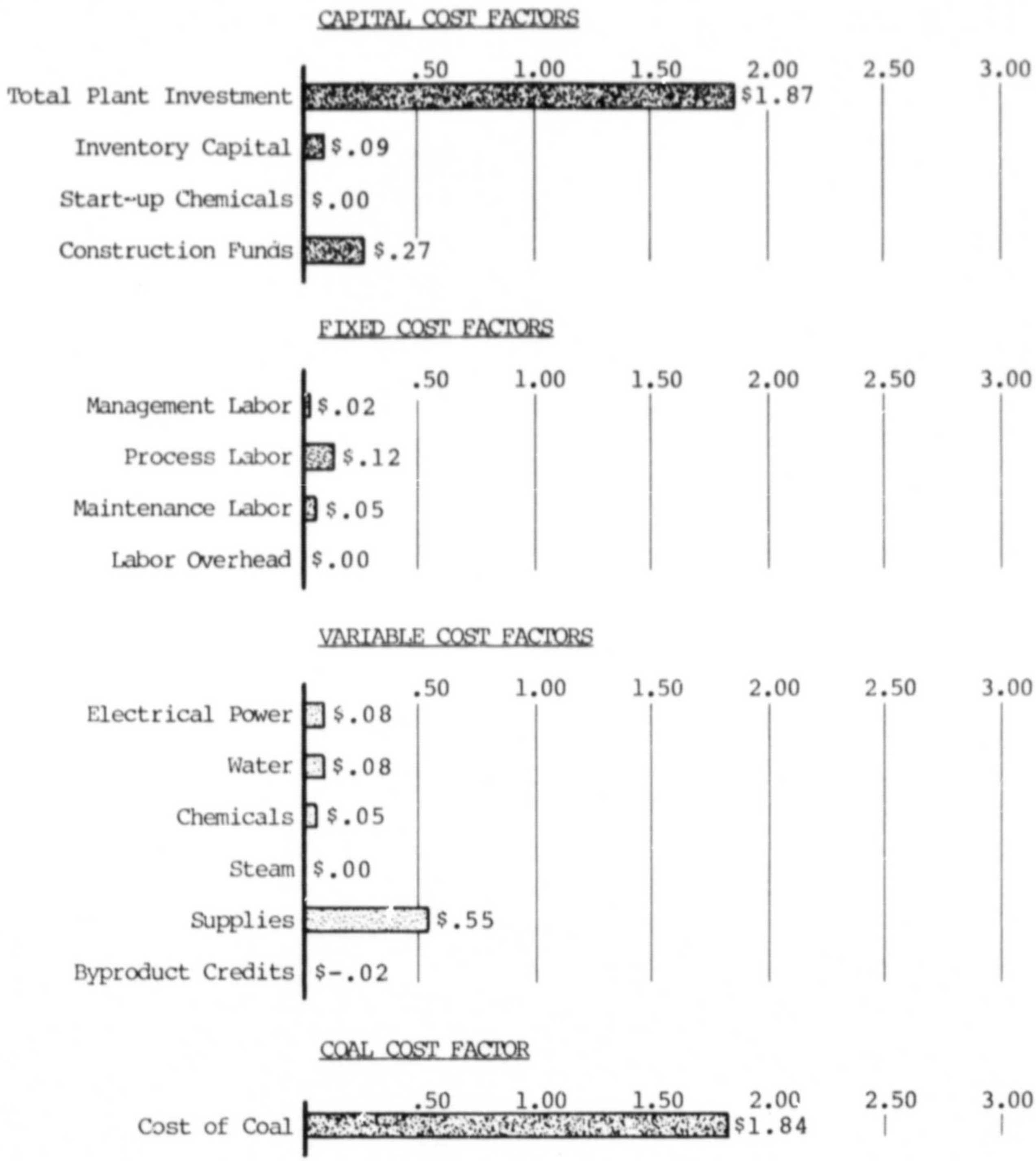


Base Case Summary Information - Commercial Finance

1. Total Plant Investment: $1,800,000,000 ($ 1978)
2. Plant Utilization Factor: .904 (330 Days/Year)
3. Plant Capacity: 396,000 MMBTU H_2 (HHV/Day)
4. Debt Ratio (% of Capital Cost Financed): 75%
5. Debt Cost (Interest on Borrowed Capital): 10%
6. Accounting Method: Flow Through
7. Income Taxes (Fed. + State): 50%
8. Property Taxes + Insurance: 2.70%
9. Investment Tax Credit: 10%
10. Facility Life: 20 Years
11. Tax Life: 16 Years
12. Tax Preference Allowance: Accelerated Depreciation--Sum-of-the-Years-Digits
13. Fuel (Coal) Input: 10,900,000 Tons/Year
14. Coal Unit Cost: 22.00 $/Ton ($ 1978)

*1978 dollars/million BTU's higner heating value.

Cost of Hydrogen - $ 1978/MMBTU



3.3 Winkler Davy McKee Gasifier[6]

Kaiparowits Model

The Winkler gasifiers have been in commercial operation since 1926. These units gasify coal for a variety of applications, including low and medium BTU fuel gas, ammonia, synthetic gas, and hydrogen. The process efficiency, ignoring the oxygen plant and power generation, is 63.1%.

The use of a pressurized gasifier is very attractive. A significant reduction in required compressor capacity reduces both capital and operating cost.

Sulfur control is acceptable in the Winkler, as it is in all gasification systems considered. Approximately 10,000 pounds per hour of sulfur is introduced into the gasifier. Of that amount, 9,950 pounds per hour is removed as sulfur in the sulfur filter cake, and the balance is vented as H_2S (.36 ppm) from the Holmes-Stretford unit. This represents nearly 99.9% sulfur recovery.

If the dry char is used for boiler fuel, more than 25 tons of carbon are available for steam generation. When burned with either sulfide free or product gas, this fuel should be ideal. There should be no SO_2 production at the auxiliary boiler.

The Winkler thermal balance indicates a process heat input of 10 MMBTU/day via a 400,000 lb/hr boiler having an input itself of about 13 MMBTU/day. The dry char output of 4.9×10^6 lb/day and a heating value of 3500 BTU/lb would furnish 132% of this heat requirement.

In addition to this boiler load the energy required for the plant compressor is estimated at 47 MMBTU/day. With a boiler efficiency of 85%, 55

MMBTU/day would be required. All the dry char and 51 MMBTU of product gas are required to operate the auxiliary boiler.

There is indication that the full net output could also be maintained by accepting a 3-5% lower carbon conversion efficiency. If this is true, the plant as described, could provide the 396 MMBTU net output at the stated capital investment.

The use of dry char mixed with product gas in the auxiliary boiler is both efficient and environmentally attractive, because it is commercial, its operating history is available, and because it uses a pressurized gasifier to reduce compression costs. Furthermore, the overall processing is designed to make good use of waste heat.

Design Basis

Plant Capacity - The plant described herein produces pipeline grade hydrogen gas 345 BTU/SCF containing less than 1 ppm (vol) sulfides. The total product gas generated is equivalent to 396 MMBTU/day. All gas flows refer to standard conditions of 14.7 psia and 60°F.

Product Specifications

Product Gas

Composition	Vol %
CO	0.42
CO_2	0.10
H_2	95.18
CH_4	3.63
N_2	0.67
Sulfides	less than 1 ppm
Total	100.00

H_2O, ppm (vol)	938
Pressure, psig	1000
Temperature, ^oF	100
HHV, BTU/SCF	345

<u>Char, Dry</u>

Carbon	25
Ash	<u>75</u>
Total	100
HHV, BTU/lb	3500

<u>Char, Wet</u>

Composition	Wt. %
Char	30
Water	<u>70</u>
Total	100
Temp., ^oF	100

<u>Sulfur Cake</u>

Sulfur	39
Water	<u>61</u>
Total	100

<u>H.P. Saturated Steam</u>

Delivered to the battery limits

Pressure, psig	675
Temp, ^oF	

<u>Process Condensate</u>

Delivered to the battery limits

Pressure, psig	100
Temp, ^oF	120

<u>H.P. Boiler Feed Water</u>

Delivered to the battery limits

Pressure, psig	740
Temp, ^oF	260

L.P. Boiler Feed Water

Delivered to the battery limits

Pressure, psig	90
Temp, °F	240

Turbine Steam Condensate

Delivered to the battery limits

Pressure, psig	40
Temp, °F	220

Reboiler Steam Condensate

Composition Wt. %

Delivered to the battery limits

Pressure, psig	40
Temp, °F	

Cooling Water

Delivered to the battery limits

Pressure, psig	40
Temp, °F	105

Blowdown Steams

The plant generates high and low pressure blowdowns, which are sent to the battery limit disposal.

High Pressure Blowdown

Pressure, psig	650
Temp, °F	500

Low Pressure Blowdown

Pressure, psig	50
Temp, °F	298

Plant Vent Gas Streams

The plant vents to the atmosphere are from the following units

Sulfur recovery unit

and

Acid gas removal unit II

Total sulfide emitted from these vents amount to less than 34 ppm (vol).

Raw Materials and Utility Specifications

This plant has been designed based on receiving the following raw materials and utilities at the battery limits at the specified conditions.

Coal

Composition	Wt. % (as required)
Moisture	12.55
Ash	9.27
C	61.32
H	4.33
N	0.95
S	0.52
O	11.06
Total	100.00

Particle Size	3" x 0
HHV, BTU/lb	10,800
Ash Deformation, Temp °F	2,285
Ash Fusion, Temp °F	2,360
Ash Fluid, Temp °F	2,580

Oxygen

Purity, Vol. %	99.5
Pressure, psig	275
Temp, °F	200

Nitrogen

Pressure, psig	275
Temp, °F	100

High Pressure Boiler Feed Water

Pressure, psig	750
Temp, °F	220

Low Pressure Boiler Feed Water

Pressure, psig	100
Temp, °F	220

Turbine Steam Condensate

Pressure, psig	50
Temp, °F	160

Low Pressure Steam

Composition	Wt. % (as received)
Pressure, psig	50
Temp, °F	298

High Pressure Steam

Pressure, psig	650
Temp, °F	750

Cooling Water

Pressure, psig	50
Temp, °F	85

Electrical Power

Standard voltage at 60 htz

Other Utilities

Potable water, service and fire water, sanitary and process sewers are to be available at the plant battery limits.

Process Description

The facilities described herein are capable of producing pipeline grade hydrogen from run-of-mine coal, using the Winkler coal gasification process. The product hydrogen will have a high heating value of approximately 345 BTU/SCF and total sulfides of less than 1 ppm level. The amount of product gas generated will be equivalent to 396 billion BTU per day.

The facilities have been based on using fourteen (14) parallel Winkler gasification trains, operating at 15 atmospheres. The raw product gas from the Winkler gasifiers will be shifted using high temperature CO shift catalyst, followed by removal of CO_2 and sulfur compounds by an acid gas treatment unit. The treated gas from this unit will be desulfurized in a zinc oxide reactor for further shift of CO in a low temperature shift converter. Following final removal of acid gas, the product hydrogen gas will be compressed to 1010 psig.

Coal Preparation

Run-of-mine coal will be received utilizing a belt conveyor. This conveyor will feed the cage mill directly through a splitter hopper which will divide the flow of material between the mills. The 3/8" x 0 size crushed material from the mills will be collected under the mills by a conveyor belt which will elevate the coal to the transfer conveyor. This conveyor will feed the bin conveyor which will provide material to the feed bins feeding the gasifiers. The coal will be discharged into the bins by means of movable trippers which will be positioned automatically over the openings. Each storage bin will have approximately 400 tons capacity, equivalent to five (5) hours of operation and will be provided with a vibrating bin discharger to insure continuous material flow. The bins will be equipped with a dust collector and fan system.

Gasification

Material from the storage bin will flow by gravity through a set of lock hoppers in series arrangement. The purpose of the lock hopper is to raise the pressure of the gas above the coal to the operating pressure of the gasifier. This is accomplished by filling the top hopper with coal, pressurizing the hopper up to the operating pressure with nitrogen, and then dropping the coal into the lower lock hopper which is maintained at the operating pressure.

The top hopper is then depressurized and refilled with coal to repeat the cycle. The pressurized coal is then fed into the gasifier by a variable speed screw conveyor.

Once inside the gasifier, the coal immediately comes in contact with a hot fluidized bed and gasifies, producing synthetic gas containing no measurable amounts of tars, oils, or high hydrocarbons. This fluidized bed gasification process is maintained by the injection of steam and oxygen into the gasifier to react with the coal feed. The gasification temperature is controlled by adjusting the ratio of oxygen and steam to coal. Oxygen is to be available at 275 psig at the battery limits.

As a result of the fluidization, the char particles, ash and contained carbon, are segregated according to size and specific gravity. The heavier particles fall back through the bed and pass into the char discharge unit at the bottom of the gasifier while the lighter particles are carried up and out of the gasifier in the product gas. Approximately fifty to seventy percent of the char leaves the gasifier in the product gas.

The hot gas leaving the gasifier passes through a waste heat boiler. This gas is cooled by generating 675 psig saturated steam from boiler feed water at 220°F. Steam in excess of that required for the process needs is generated and, therefore, is available for export to the battery limits.

Particulate Separation

Leaving the waste heat unit, the cooled gas enters the first stage of a two-stage particulate separation step. This first stage is a dry cyclone where the major portion of the dust is removed from the gas. The remaining dust is then removed from the gas in a wet venturi scrubber. This venturi system circulates a 5% solid slurry stream for particulate removal. A purge stream is extracted and passed through a thickener in order to remove the solids as a 30% solids sludge. The overflow effluent from the thickener is recycled to the venturi along with some make-up water to maintain the water balance.

The remaining char in the gasifier is withdrawn down through the bottom of the gasifier by a char cooling conveyor. The gasifier bed level is controlled by the rate of char withdrawal through this cooling conveyor. The cooled gasifier char is then combined with the char recovered from the dry cyclone. This total dry char is passed out of the system through a set of parallel lock hoppers. These lock hoppers operate alternately depressurizing the char.

High Temperature Carbon Monoxide Shift

The synthetic gas, leaving the venturi scrubber, enters a saturator/cooler tower. In the saturator section of the tower, the steam/dry gas ratio of the synthetic gas is raised by scrubbing the gas with hot circulating water from the cooler section of the saturator/cooler tower. The exit gas from the saturator, at 310°F, is heated to the CO shift reaction temperature (627°F) by heat interchange (with CO shift bed I, exit gas) and direct injection of 650 psig, 750°F steam. The H_2O/dry gas mole ratio is thus brought to 1:1 before entering CO shift reactors. The reaction which takes place is

$$CO + H_2O \text{ ----> } CO_2 + H_2$$

The reaction is exothermic and it is necessary to have two stages of high temperature conversion with interstage cooling in order to obtain the desired CO content in the outlet gas. The converted gas leaves the reactor with a 3.5% CO content.

The HT shift consists of two bed reactors. In the first bed, the CO content is reduced to 9.2% (dry basis). The hot gas leaving Bed I at 945°F is cooled to 626°F before entering the second bed by heat interchange with the shift feed gases.

The gas leaving the second bed, containing 3.5% (dry basis) is sent to the cooling section of the saturator/cooler tower where it is cooled to 292°F by heating the water return from the saturator and the make-up water. The hot water at 350°F leaving the cooling section is recirculated to the saturator.

The low level heat in the shifted gas at 292°F is utilized in the reboilers of the Acid Gas Removal Unit I. The gas exiting the reboiler is at 270°F. It's heat is further utilized in preheating high and low pressure boiler feed water. The hydrogen plant needs about 2.0 MM lb/hr of CO shift reaction steam, and 3.3 MM lb/hr of Boiler Feed Water (BFW) in the Winkler Waste Heat Boiler. We assume that the total required H.P. BFW for the integration plant would be about 9.3 MM lb/hr. This BFW from the battery limit offsite deaerator at 220°F can be preheated to 260°F by 270°F shifted gas.

The shifted gas from the H.P. BFW water heater is at 255°F and is further cooled to 250°F by preheating an estimated 3.0 MM lb/hr L.P. BFW, mainly for reboiler steam generation, to 240°F, from deaerated water at 220°F. The shifted gas is further cooled to 120°F, by means of air and trim coolers. The condensed water is separated and the gas is sent to the Acid Gas Removal Unit I.

Acid Gas Removal Unit I

This unit utilized the High Purity System, licensed by Benfield Corporation. This consists of hot carbonate scrubbing followed by a DEA Unit. The gases leaving the absorbers contain 500 ppm of CO_2 and the sulfide level is reduced to 2 ppm.

The acid gas laden solutions from hot carbonate and DEA absorbers are regenerated in their respective regenerators, utilizing the heat in the HTS gas and by 50 psig reboiler steam. The acid gases leaving the regenerators are cooled to 104°F and combined before being sent to the Sulfur Recovery Unit.

Sulfur Recovery Unit

The exit gas stream from the regenerators contain 99.4% CO_2 and 0.37% H_2S. This is sent to the Holmes-Stretford Unit where the sulfide is absorbed and regenerated in the Holmes-Stretford Chemical Plant. The sulfur is filtered out as a cake (39% by wt). Sulfur is about 99% processed. The gases leaving the Holmes-Stretford Unit contain 36 ppm H_2S.

Low Temperature CO Shift Conversion

In the Benfield High Purity System, the gas has been treated and the CO_2 content reduced to 500 ppm. While the sulfur content is not high for commercial use of the product, it is sufficient to reduce the activity of the lower temperature CO shift catalyst used to further reduce the CO content in the gas. To protect the catalyst, a zinc oxide bed system is used to remove sulfur compounds. Two zinc oxide beds operate on six-month life periods each. The feed gas is heated by means of heat interchangers to 400°F before entering the zinc oxide beds. The sulfur content is reduced to less than 1 ppm.

In the low temperature shift bed, CO content is reduced to 0.4% (dry). The required steam/dry gas ratio (0.5 vol/vol) is maintained by injecting 650 psig, 750°F steam into the shift feed gas. The hot shift exit gas at 480°F is cooled by producing 50 psig saturated steam for MEA Unit Reboiler II, and further cooled by utilizing its low level heat in the MEA Unit Reboiler I. Further heat utilization from the gas exiting Reboiler I is achieved by preheating an estimated 3 MM lb/hr of turbine steam condensate to 220°F. Final cooling to 120°F is done by using air and trim coolers.

<u>Acid Gas Removal Unit II, and Product Gas Preparation</u>

The cooled and converted gas enters the Acid Gas Removal Unit II. This is based on using 30% MEA solution for absorption of the CO_2 in the shifted gas. This unit is designed for scrubbing the gas so as to reduce the CO_2 level to 0.10% in the outlet gas. The regenerated gas from the MEA System is vented to the atmosphere.

From the second stage acid gas removal, the gas flows to a battery of reciprocating compressors to achieve 1,010 psig delivery pressure. The compression is done by two stage compressors, with interstage cooling by air coolers. The exit gas from the second stage at 338°F is cooled to 100°F by air and water trim coolers and the condensed water is separated. The water content of the compressed gas is about 938 ppm. The product gas has a heating value of 345 BTU/SCF with a hydrogen content of 95.2%.

Energy and Material Balance Summary

This plant has been designed based upon battery limit operation whereby the process requirements such as cooling water, boiler feed water, high pressure shift reaction steam, and low pressure steam are available.

Plant Waste Heat Recovery System

The sensible heats available in the shifted gas streams are utilized in the plant for preheating the boiler feed water and the turbine steam condensates. For a plant such as this, using 14,300 TPD of oxygen in the gasification section, the air separation units would normally use about 3 MM lb/hr of turbine steam for their drives. The turbine steam condensates are heated to 220^{o}F in the shifted gas waste heat recovery exchangers and are returned to the offsite boiler system. The heat available in the hot Winkler exit gas is utilized by generation 675 psig saturated steam from the preheated boiler feed water. Part of this steam is used in the gasification process and the rest is returned to the battery limit offsite boiler system. The overall plant waste heat recovery system thus utilized about 7.72% of the plant total input.

Plant Cooling System

Whenever possible in this plant the use of coolers is maximized accounting for 13% of the total input. The plant cooling water accounts for 7.1% of the plant heat input.

Plant Thermal Efficiency

The product gas thermal efficiency is about 63.1%. This is defined by the ratio of the HHV of the hydrogen product gas to the summation of the HHV of coal input, shift reaction steam enthalpy, and the acid gas reboiler heat consumed. The plant generated char (carbon content 25 wt%) which has a heating value of 3500 BTU/lb. This could be used in the plant offsite coal fired boilers. If char is considered for its heating value, then the gas thermal efficiency will be about 65.9%.

The plant overall thermal efficiency, defined by the ratio of the summation of higher heating values of the hydrogen product gas, dry char, enthalpies of the export high pressure steam, horsepower (hp) and L.P. boiler feed waters, turbine steam condensate, and reboiler steam condensates to the total plant heat input is about 77%.

The above thermal efficiency calculations do not account for the total hp input to the plant. The total power input is about 223,000 hp, of which 161,000 hp is required for final hydrogen product gas compression.

ENERGY SUMMARY
(Based on 60°F Liquid Water)

Heat In	MM BTU/hr	% Distribution
Coal, HHV	20,757.00	71.14
Oxygen, S.H. @ 200°F	37.04	0.1
Total boiler feed water @ 220°F	1,984.31	6.80
Shift reaction steam @ 650 psig 750°F	2,859.17	9.80
Reboiler steam @ 50 psig, 298°F	3,237.87	11.10
Turbine steam condensate @ 160°F	300.00	1.03
Total In	29,175.39	100.00

Heat Out

Product Gas		
HHV	16,500.00	56.55
S.H. @ 100°F	35.28	0.12
Sulfur HHV	33.71	0.12
Dry Char HHV	713.86	2.45
Wet Char HHV	119.95	0.41
L.P. BFW Return @ 240°F	538.33	1.85
H.P. BFW Return @ 260°F	1,172.51	4.02
Process condensate @ 120°F	109.64	0.38
Reboiler steam condensate @ 298°F	732.53	2.51
Turbine steam condensate return @ 220°F	480.00	1.64
Export steam @ 650 psig, 501°F	2,347.26	8.04
W.H.B. Blowdown @ 501°F	30.63	0.10
L.P. Blowdown @ 298°F	1.17	-
S.H. in Sulfur recovery unit vent gas @ 104°F	34.66	0.12
S.H. in Acid gas removel unit II Vent gas 130°F	4.69	0.02
Heat to cooling water @ = 20°F	2,068.36	7.09
Heat to Air Coolers	3,804.00	13.04
Unaccounted Losses	448.80	1.54
Total	29,175.39	100.00

MATERIAL BALANCE SUMMARY

In	LB/hr
Process Coal	1,921,944
Process Oxygen	1,197,250
LP BFW @ 220°F	3,232,720
HP BFW @ 220°F	9,153,740
Shift reaction steam @ 650 psig, 750°F	2,121,042
Reboiler steam @ 50 psig, 298°F	2,811,630
Total In	20,438,326

Out	LB/hr
Hydrogen Product Gas	361,185
Sulfur Cake (39% Sulfur by wt)	25,343
Dry Char	203,960
Wet Char	110,660
Export steam @ 675 psig, 501°F	1,999,030
LP BFW return @ 240°F	2,983,440
HP BFW return @ 260°F	5,839,200
Process condensate return @ 120°F	1,827,394
Reboiler steam condensate return	3,056,042
W.H.B. Blowdown	66,290
LP Boiler Blowdown	4,868
Vent gas from Sulfur Recovery Unit	3,651,916
Vent gas from Acid Gas Removal Unit II	308,998
Total Out	20,438,326

PROCESS MATERIAL AND UTILITIES DATA

A. Raw Materials and Utilities Imported

1. Coal

Rate, TPD	23,063
Moisture, %	23.5

2. Oxygen

Rate, TPD	14,367
Purity, %	99.5

3. Nitrogen

Rate, M SCFD	646

4. High Pressure Steam, 650 psig, 750°F

Rate, MM LB/day	50.905

5. Low Pressure Steam, 50 psig, 298°F

Rate, MM LB/day	67.479

6. High Pressure B.F.W.

Rate, MM LB/day	219,690

7. Low Pressure B.F.W.

Rate, MM LB/day	77,585

8. Turbine Steam Condensate

Rate, MM LB/day	72,000

9. Cooling Water

Rate, MM Gal/day	297.844

10. Electric Power

Rate, Connected hp.	223,000

11. HTS Catalyst

Bed I Charge, Cu. Ft.	12,180
Bed II Charge, Cu. Ft.	35,000

12. Hot Carbonate System

Chemicals Charge $/day	1,414

13. Holmes-Stretford Unit

Proprietary Chemicals, $/day	2,996
Soda ash make up, $/day	924

14. Zinc Oxide Bed

Total zinc oxide, cu. ft. (2 beds per train) (1/2 yr. life per bed).	12,600

PRODUCTS, BY-PRODUCTS AND UTILITIES EXPORTED

1. Hydrogen Product Gas

Rate, MM SCFD (day)	1148.227
Heat content, billion BTU/day	396

Composition	Vol. %
CO	0.42
CO_2	0.10
H_2	95.18
CH_4	3.63
N_2	0.67
Sulfides	Less than 1 ppm
Total	100.00
H_2O	938
Pressure, psig	1000
Temp, °F	100

2. Dry Char

Rate, MM lb/day 4.895

3. Wet Char

Rate, MM lb/day 2.656

4. High Pressure Steam 675 psig, 501°F

Rate, MM lb/day 47.977

5. High Pressure BFW

Rate, MM lb/day 140.141

6. Low Pressure BFW

Rate, MM lb/day 71.602

7. Turbine Steam Condensate

Rate, MM lb/day 72.000

8. Reboiler Steam Condensate

Rate, MM lb/day 73.345

9. Cooling Water

Rate, MM Gal/day 297,844

10. <u>Wet Sulfur Cake</u>

Rate, TPD (Sulfur 39%)	304.116

11. <u>Total Blowdowns</u>

Rate, MM lb/day	1.708

BASE CASE ASSUMPTIONS
DAVY-WINKLER COAL GASIFIER
Municipal Financing
Kaiparowits Model

Total Plant Investment

ITEM	CAPITAL COST ($1978)
Coal Handling and Preparation	$41,700,000
Gasifier, Cool and Clean	97,600,000
CO Shift, Raw Gas Compression, Acid Gas Removal, Sulfur Recovery	295,200,000
Product Gas Compression	91,600,000
General Facilities	125,400,000
Non-Producing Building Supplies	7,000,000
Total Plant Investment	$658,500,000

NOTES: Off-site steam and oxygen plants.

BASE CASE ASSUMPTIONS
DAVY-WINKLER COAL GASIFIER
Municipal Financing
Kaiparowits Model

Fixed Operating and Maintenance Costs ($1978)

ITEM	AMOUNT	COST PER UNIT	ANNUAL COST
Process Labor (280 Jobs)	582,400 Hr/Yr	13.30 $/Hr	$ 7,745,920
Technical Labor (12 Jobs)	24,960 Hr/Yr	15.55 $/Hr	388,128
Clerical Labor (18 Jobs)	37,440 Hr/Yr	8.20 $/Hr	307,008
Administrative (22 Jobs)	45,760 Hr/Yr	16.80 $/Hr	768,767
Maintenance (65 Jobs)	135,200 Hr/Yr	13.50 $/Hr	1,825,200
Total Fixed Operating and Maintenance Costs			$11,035,023

NOTES: Labor rates include 35% payroll burden and are based on 2,080 hours per year. (Sales personnel not included.)

BASE CASE ASSUMPTIONS
DAVY-WINKLER COAL GASIFIER
Municipal Financing
Kaiparowits Model

Variable Operating and Maintenance Costs ($1978)

ITEM	AMOUNT	COST PER UNIT	ANNUAL COST
Make-Up Water	10,044 Ac-Ft/Yr	180.00 $/Ac-Ft	$1,807,920
Oxygen	4,741,000 Tn/Yr	12.00 $/Tn	56,892,000
Electric Power	1,317,000 MWH/Yr	40.00 $/MWH	52,680,000
Operating Supplies	658,100 $/Yr	1.00	658,100
Maintenance Supp.	4,938,750 $/Yr	1.00	4,938,750
HP Steam @ 650 psig, 75°F	8,533,700 MMBTU(G)	3.23 $/MMBTU	27,563,852
LP Steam @ 50 psig, 298°F	6,446,600 MMBTU(G)	1.84 $/MMBTU	11,861,744
Boiler Feed-Water (In)	1,528,600 MMBTU(G)	.1000 $/MMBTU	152,860
Turbine Condensate	111,700 MMBTU(G)	.03	3,351
HTS Catalyst	23,590 Cu-Ft/Yr	63.00 $/Cu-Ft	1,486,170
Hot Carbonate System	98,288 $/Yr	1.00	98,288
Holmes-Stretford Chem.	988,680 $/Yr	1.00	988,680
Soda Ash Makeup	304,920 $/Yr	1.00	304,920

BASE CASE ASSUMPTIONS
DAVY-WINKLER COAL GASIFIER
Municipal Financing
Kaiparowits Model

Variable Operating and Maintenance Costs ($1978)
(Continued)

ITEM	AMOUNT	COST PER UNIT	ANNUAL COST
Zinc Oxide	25,000 Cu-Ft/Yr	80.00 $/Cu-Ft	$2,000,000
Dry Char (3500 BTU/LB)	807,675 Tn/Yr	(7.00) $/Tn	(5,653,725)
Wet Char (70% Water)	438,240 Tn/Yr	(2.10) $/Tn	(920,303)
Sulfur (Dry)	39,140 Tn/Yr	(60.00) $/Tn	(2,348,400)
HP Steam @ 675 psig, 502°F	6,717,700 MMBTU	(2.69) $/MMBTU	(18,070,614)
Boiler Feedwater (Out)	1,607,400 MMBTU	(.1200) $/MMBTU	(192,888)
Condensate (Out)	1,075,500 MMBTU	(.1600) $/MMBTU	(172,080)
Total Variable Operating and Maintenance Costs			$134,078,624

NOTES: Operating Supplies = .1% TPI; Maintenance Supplies = .75% TPI. Steam and hot water valves based on energy availability, G, @ 85°F.

BASE CASE ASSUMPTIONS
DAVY-WINKLER COAL GASIFIER
Municipal Financing
Kaiparowits Model

Capital Requirement

ITEM	CAPITAL COST ($1978)
Total Plant Investment	$658,500,000
Pre-production Costs	29,962,090
Inventory Capital	40,427,430
Initial Catalyst & Chemicals	4,000,000
Allowance for Funds During Construction	111,121,900
Land	1,500,000
Total Capital Requirement	$845,511,420

NOTES: Construction Period: Three Years

Plant Capacity: 396,000 MMBTU per day.

Capacity Factor: .904 = 330 days per year.

Annual Production: 130,664,160 MMBTU (HHV) H_2 per year

BASE CASE ASSUMPTIONS
DAVY-WINKLER COAL GASIFIER
Municipal Financing
Kaiparowits Model

Financial Data

Debt Ratio: 100% (% of capital cost financed)

Debt Cost: 7% (% interest on borrowed capital)

Income Tax (Federal + State): Not applicable

Investment Tax Credit: Not applicable

Facility Life: 20 Years

Tax Life: 16 Years

Accounting Method: Straight Line

Tax Preference Allowance: Not applicable

Total Return (weighted cost of capital):	7.00%
Book Depreciation (Sinking Fund):	2.44%
Property Taxes + Insurance:	1.20%
Levelized Annual Fixed Charge Rate:	10.64%
Capital Recovery Factor:	9.44%

NOTE: Accelerated depreciation and investment tax credit decrease the fixed charge rate.

BASE CASE ASSUMPTIONS
DAVY-WINKLER COAL GASIFIER
Municipal Financing
Kaiparowits Model

Fuel Cost Data ($1978)

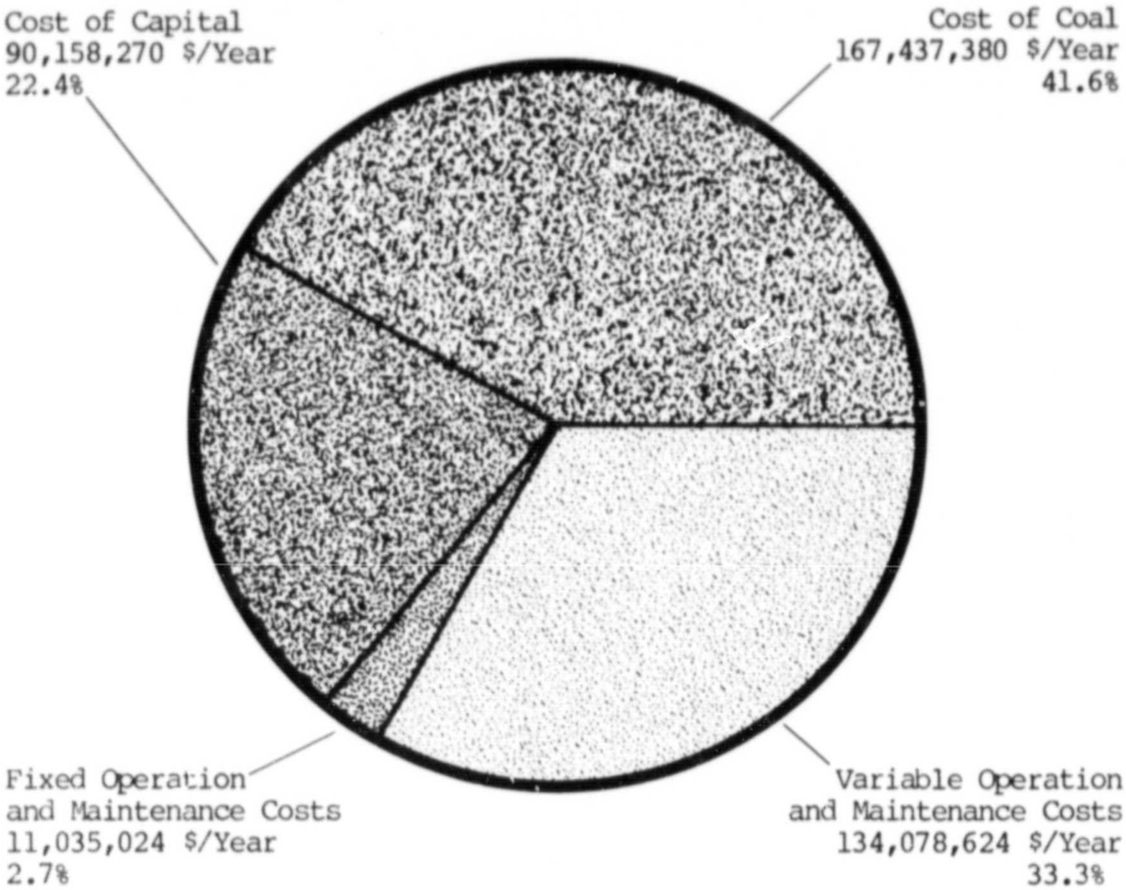
Coal Input	Cost Per Unit	Annual Cost
7,610,790 Tn/Yr	22.00 $/Tn	$167,437,380

First Year Cost of Hydrogen

	$1978/MMBTU H_2 (HHV)
Levelized Annual Capital Cost	$ .69
Levelized FOM & VOM Costs	1.11
Levelized Annual Fuel Cost	1.28
Total Cost of Hydrogen	$3.08

HYDROGEN COST FACTORS

Davy-Winkler Gasifier
Kaiparowits Model
Cost of Hydrogen: $3.08*

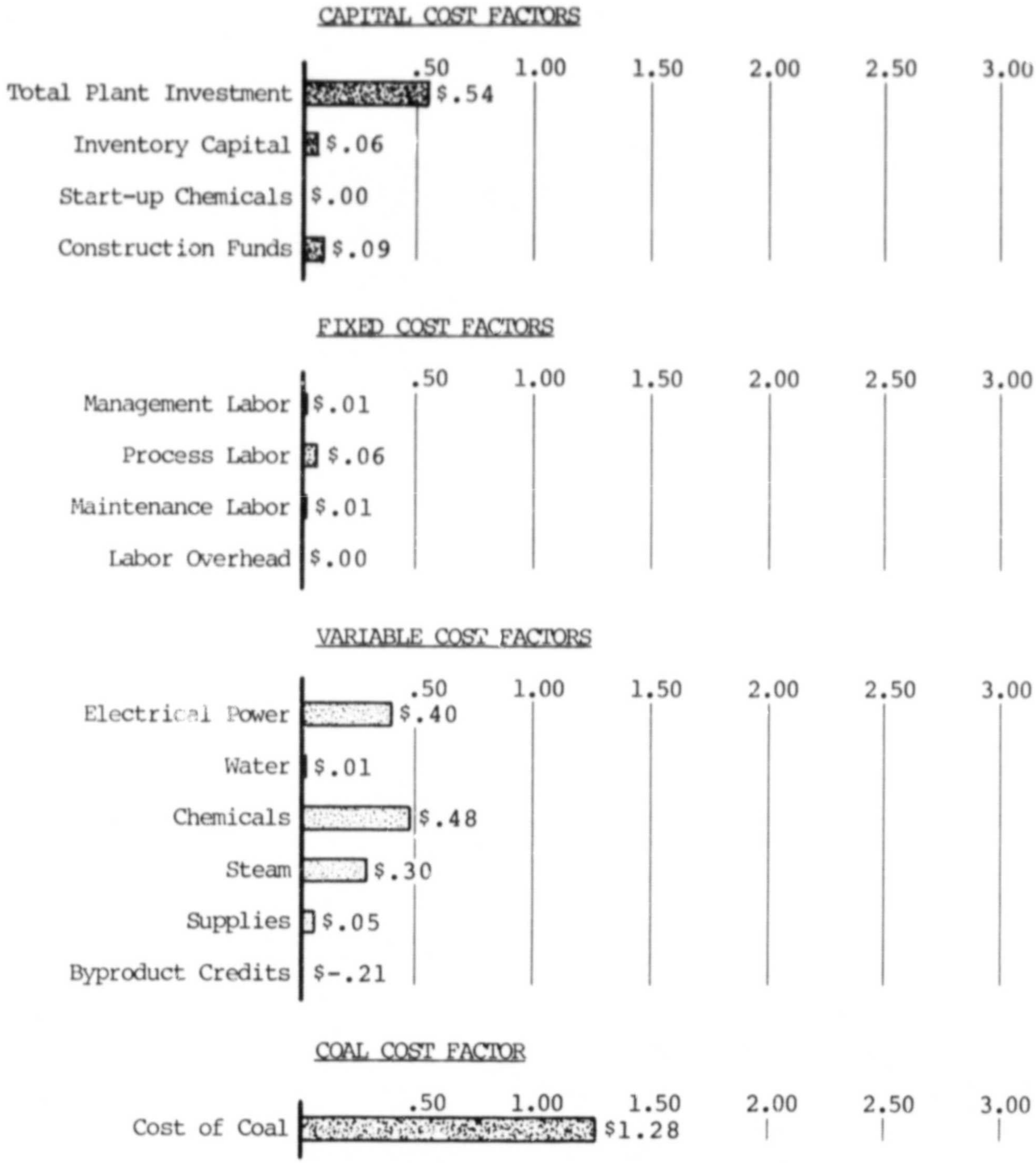


Base Case Summary Information - Municipal Finance

1. Total Plant Investment: $658,500,000 ($ 1978)
2. Plant Utilization Factor: .904 (330 Days/Year)
3. Plant Capacity: 396,000 MMBTU H_2 (HHV/Day)
4. Debt Ratio (% of Capital Cost Financed): 100%
5. Debt Cost (Interest on Borrowed Capital): 7%
6. Accounting Method: Straight Line
7. Income Taxes (Fed. + State): Not Applicable
8. Property Taxes + Insurance: 1.20%
9. Investment Tax Credit: Not Applicable
10. Facility Life: 20 Years
11. Tax Life: 16 Years
12. Tax Preference Allowance: Not Applicable
13. Fuel (Coal) Input: 7,610,790 Tons/Year
14. Coal Unit Cost: $22.00/Ton ($ 1978)

*1978 dollars/million BTU's higher heating value.

Cost of Hydrogen - $ 1978/MMBTU



BASE CASE ASSUMPTIONS
DAVY-WINKLER COAL GASIFIER
Commercial Financing
Kaiparowits Model

Total Plant Investment

ITEM	CAPITAL COST ($1978)
Coal Handling and Preparation	$41,700,000
Gasify, Cool and Clean	97,600,000
CO Shift, Raw Gas Compression, Acid Gas Removal, Sulfur Recovery	295,200,000
Product Gas Compression	91,600,000
General Facilities	125,400,000
Non-Proc Building Supplies	7,000,000
Total Plant Investment	$658,500,000

NOTES: Off-site steam and oxygen plants.

BASE CASE ASSUMPTIONS
DAVY-WINKLER COAL GASIFIER
Commercial Financing
Kaiparowits Model

Fixed Operating and Maintenance Costs ($1978)

ITEM	AMOUNT	COST PER UNIT	ANNUAL COST
Process Labor (280 Jobs)	582,400 Hr/Yr	13.30 $/Hr	$ 7,745,920
Technical Labor (12 Jobs)	24,960 Hr/Yr	15.55 $/Hr	388,128
Clerical Labor (18 Jobs)	37,440 Hr/Yr	8.20 $/Hr	307,008
Administrative (22 Jobs)	45,760 Hr/Yr	16.80 $/Hr	768,767
Maintenance (65 Jobs)	135,200 Hr/Yr	13.50 $/Hr	1,825,200
Total Fixed Operating & Maintenance Costs			$11,035,023

NOTES: Labor rates include 35% payroll burden and are based on 2,080 hours per year. (Sales personnel not included.)

BASE CASE ASSUMPTIONS
DAVY-WINKLER COAL GASIFIER
Commercial Financing
Kaiparowits Model

Variable Operating and Maintenance Costs ($1978)

ITEM	AMOUNT		COST PER HOUR		ANNUAL COST
Make-Up Water	10,044	Ac-Ft/Yr	180.00	$/Ac-Ft	$1,807,920
Oxygen	4,741,000	Tn/Yr	12.00	$/Tn	56,892,000
Electric Power	1,317,000	MWH/Yr	40.00	$/MWH	52,680,000
Operating Supp.	658,100	$/Yr	1.00		658,100
Maintenance Supp.	4,938,750	$/Yr	1.00		4,938,750
HP Steam @ 650 psig, 750°F	8,533,700	MMBTU(G)	3.23	$/MMBTU	27,563,852
LP Steam @ 50 psig, 298°F	6,446,600	MMBTU(G)	1.84	$/MMBTU	11,861,744
Boiler Feed-Water (In)	1,528,600	MMBTU(G)	.1000	$/MMBTU	152,860
Turbine Conden-sate	111,700	MMBTU(G)	.03	$/MMBTU	3,351
HTS Catalyst	23,590	Cu-Ft/Yr	63.00	$/Cu-Ft	1,486,170
Hot Carbonate System	98,288	$/Yr	1.00		98,288
Holmes-Stretford Chem.	988,680	$/Yr	1.00		988,680
Soda Ash Makeup	304,920	$/Yr	1.00		304,920

BASE CASE ASSUMPTIONS
DAVY-WINKLER COAL GASIFIER
Commercial Financing
Kaiparowits Model

Variable Operating and Maintenance Costs ($1978)
(Continued)

ITEM	AMOUNT	COST PER HOUR	ANNUAL COST
Zinc Oxide	25,000 Cu-Ft/Yr	80.00 $/Cu-Ft	$2,000,000
Dry Char (3500 BTU/LB)	807,675 Tn/Yr	(7.00) $/Tn	(5,653,725)
Wet Char (70% Water)	438,240 Tn/Yr	(2.10) $/Tn	(920,303)
Sulfur (Dry)	39,140 Tn/Yr	(60.00) $/Tn	(2,348,400)
HP Steam @ 675 psig, 501°F	6,717,700 MMBTU	(2.69) $/MMBTU	(18,070,614)
Boiler Feedwater (Out)	1,607,400 MMBTU	(.1200) $/MMBTU	(192,888)
Condensate (Out)	1,075,500 MMBTU	(.1600) $/MMBTU	(172,080)
Total Variable Operating and Maintenance Costs			$134,078,624

NOTES: Operating Supplies = .1% TPI: Maintenance Supplies = .75% TPI. Steam and hot water values based on energy availability, G, at 85°F.

BASE CASE ASSUMPTIONS
DAVY-WINKLER COAL GASIFIER
Commercial Financing
Kaiparowits Model

Capital Requirement

ITEM	CAPITAL COST ($1978)
Total Plant Investment	$658,500,000
Pre-production Costs	29,962,090
Inventory Capital	40,427,430
Initial Catalyst & Chemicals	4,000,000
Allowance for Funds During Construction	111,121,900
Land	1,500,000
Total Capital Requirement	$845,511,420

NOTES: Construction Period: Three Years

Plant Capacity: 396,000 MMBTU (HHV) H_2 per day.

Capacity Factor: .904 = 330 days per year.

Annual Production: 130,664,160 MMBTU (HHV) H_2 per year.

BASE CASE ASSUMPTIONS
DAVY-WINKLER COAL GASIFIER
Commercial Financing
Kaiparowits Model

Financial Data

Debt Ratio: 75% (% of capital cost financed)

Debt Cost: 10% (% interest on borrowed capital)

Preferred Stock Ratio: 8%

Preferred Stock Cost: 15%/Yr

Common Stock Ratio: 17%

Common Stock Cost: 15%/Yr

Income Tax (Federal + State): 50%

Investment Tax Credit: 10%

Facility Life: 20 Years

Tax Life: 16 Years

Accounting Method: Flow Through

Tax Preference Allowance: Accelerated Depreciation (Sum-of-the-years-digits)

Total Return (weighted cost of capital):	11.25%
Book Depreciation (Sinking Fund)	1.51%
Levelized Annual Income Tax	2.59%
Levelized Annual Accelerated Depreciation Allowance	(2.28%)
Levelized Annual Investment Tax Credit Allowance	(2.29%)
Property Taxes + Insurance	2.70%
Levelized Annual Fixed Charge Rate:	13.48%
Capital Recovery Factor:	12.76%

NOTE: Accelerated depreciation and investment tax credit decrease the fixed charge rate.

BASE CASE ASSUMPTIONS
DAVY-WINKLER COAL GASIFIER
Commercial Financing
Kaiparowits Model

Fuel Cost Data ($1978)

Coal Input	Cost Per Unit	Annual Cost
7,610,790 Tn/Yr	22.00 $/Tn	$167,437,380

First Year Cost of Hydrogen

	$1978/MMBTU H_2 (HHV)
Levelized Annual Capital cost	$ .87
Levelized FOM & VOM Costs	1.11
Levelized Annual Fuel Cost	1.28
Total Cost of Hydrogen	$3.26

BASE CASE ASSUMPTIONS
DAVY-WINKLER COAL GASIFIER
Commercial Financing
Kaiparowits Model

Fuel Cost Data ($1978)

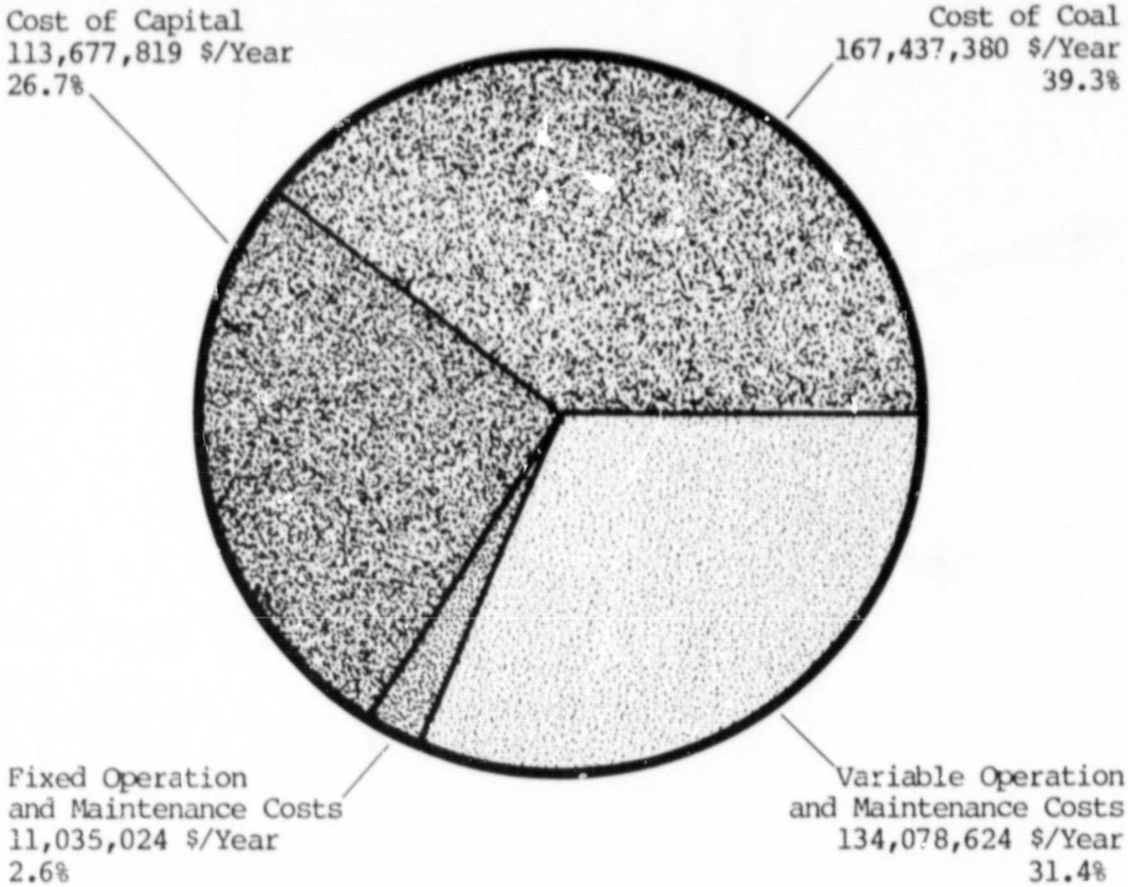
Coal Input	Cost Per Unit	Annual Cost
7,610,790 Tn/Yr	22.00 $/Tn	$167,437,380

First Year Cost of Hydrogen

	$1978/MMBTU H_2 (HHV)
Levelized Annual Capital cost	$ .87
Levelized FOM & VOM Costs	1.11
Levelized Annual Fuel Cost	1.28
Total Cost of Hydrogen	$3.26

HYDROGEN COST FACTORS

Davy-Winkler Gasifier
Kaiparowits Model
Cost of Hydrogen: $3.26*



Base Case Summary Information - Commercial Finance

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2. Plant Utilization Factor: .904 (330 Days/Year)
3. Plant Capacity: 396,000 MMBTU H_2 (HHV/Day)
4. Debt Ratio (% of Capital Cost Financed): 75%
5. Debt Cost (Interest on Borrowed Capital): 10%
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7. Income Taxes (Fed. + State): 50%
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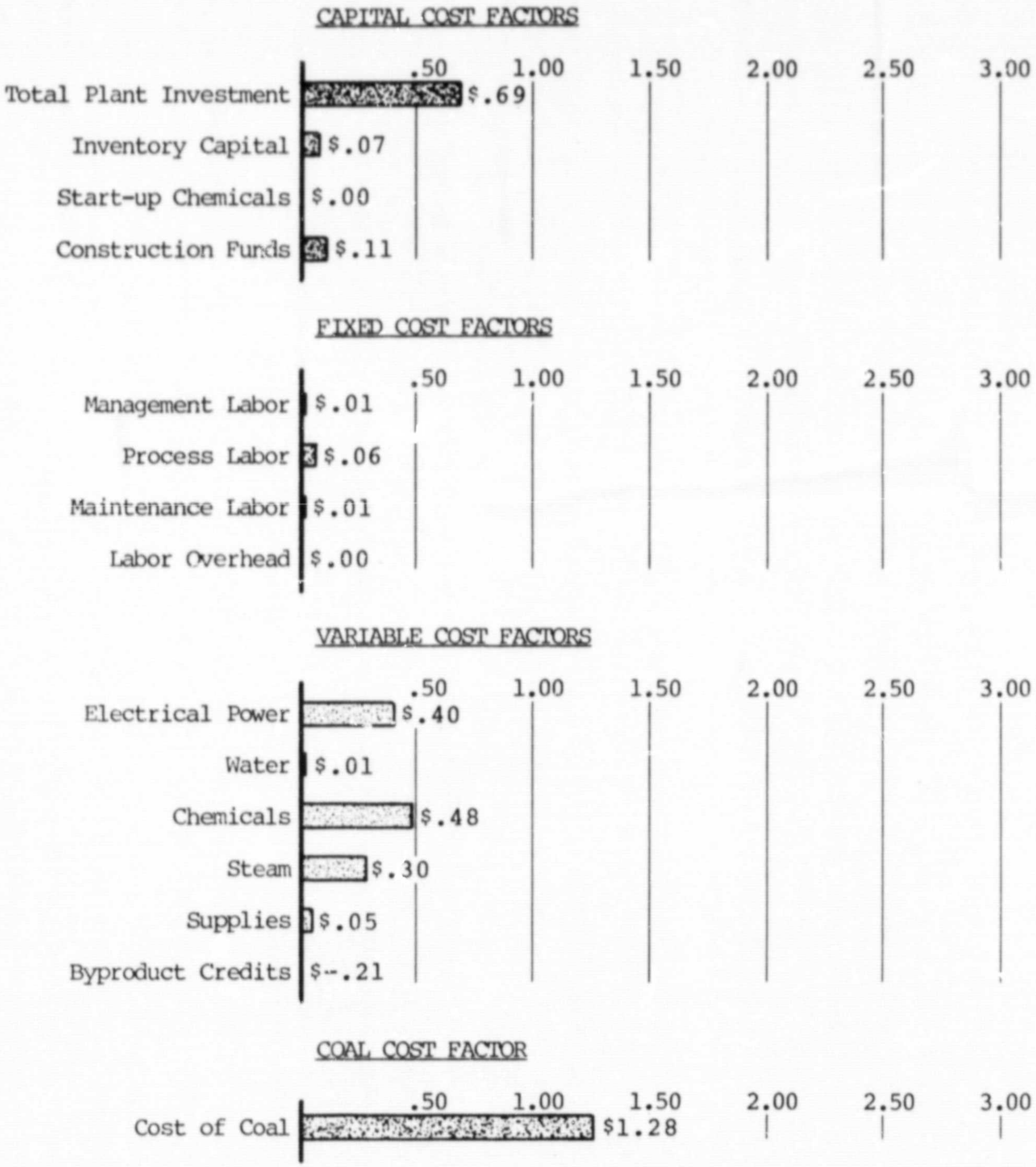
9. Investment Tax Credit: 10%
10. Facility Life: 20 Years
11. Tax Life: 16 Years
12. Tax Preference Allowance: Accelerated Depreciation--Sum-of-the-Years-Digits
13. Fuel (Coal) Input: 7,610,790 Tons/Year
14. Coal Unit Cost: $22.00/Ton ($ 1978)

*1978 dollars/million BTU's higher heating value.

Cost of Hydrogen - $ 1978/MMBTU



CHAPTER III REFERENCES

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2. Koppers Engineering and Construction Company, Pittsburg, Pennsylvania

3. Rudolph, Paul F. H. and Herbert, Peter K., "How to Apply Coal Gasification - Lurgi Express Information", Symposium on the Gasification and Liquification of Coal, Katowice, Poland (April, 1979).

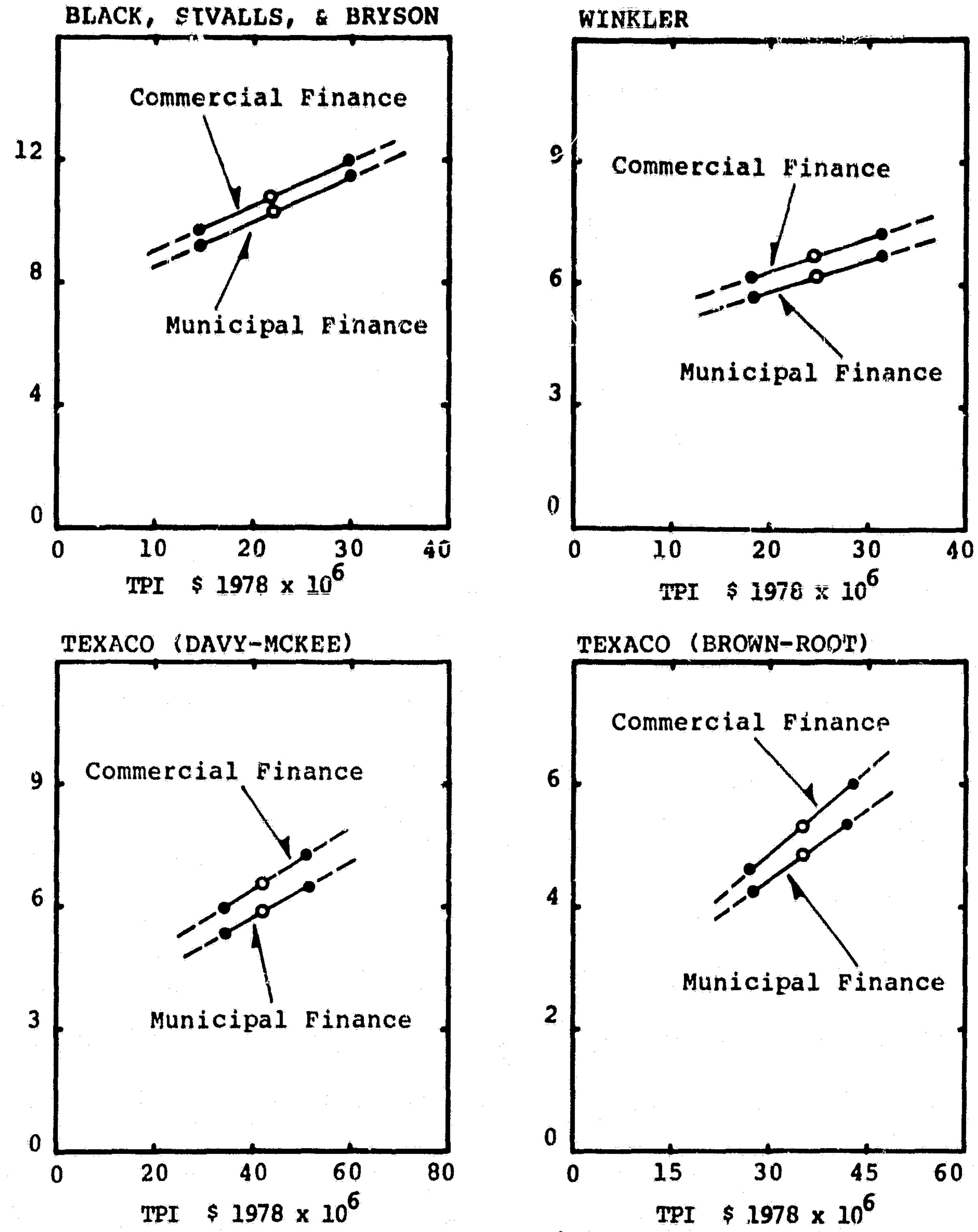
4. Rudolph, Paul F. H. and Herbert, Peter K., "Conversion of Coal to High Volume Products - Lurgi Express Information", Symposium on Coal Gasification, Liquification, and Utilization, University of Pittsburgh.

5. Boughman, Gary L., <u>Synthetic Fuels Data Handbook</u>, Cameron Engineers; Denver, Colorado; 1978, P. 219.

6. Davy McKee, Cleveland, Ohio

CHAPTER IV - SENSITIVITY ANALYSIS

SENSITIVITY ANALYSIS
FOREST CITY MODEL
Cost of Hydrogen - \$ 1978/MMBTU H_2, HHV



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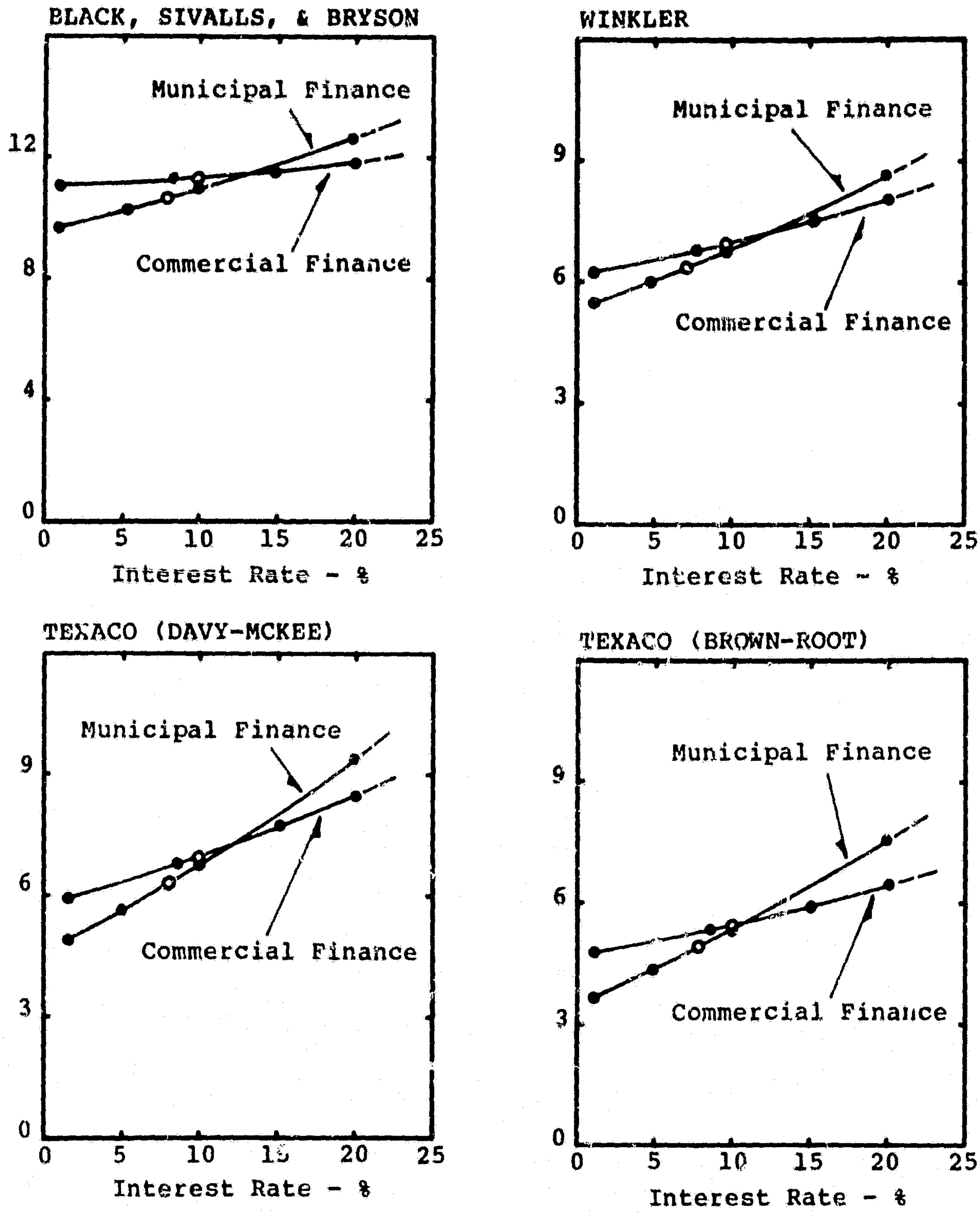
FOREST CITY MODEL

Cost of Hydrogen - \$ 1978/MMBTU H_2, HHV



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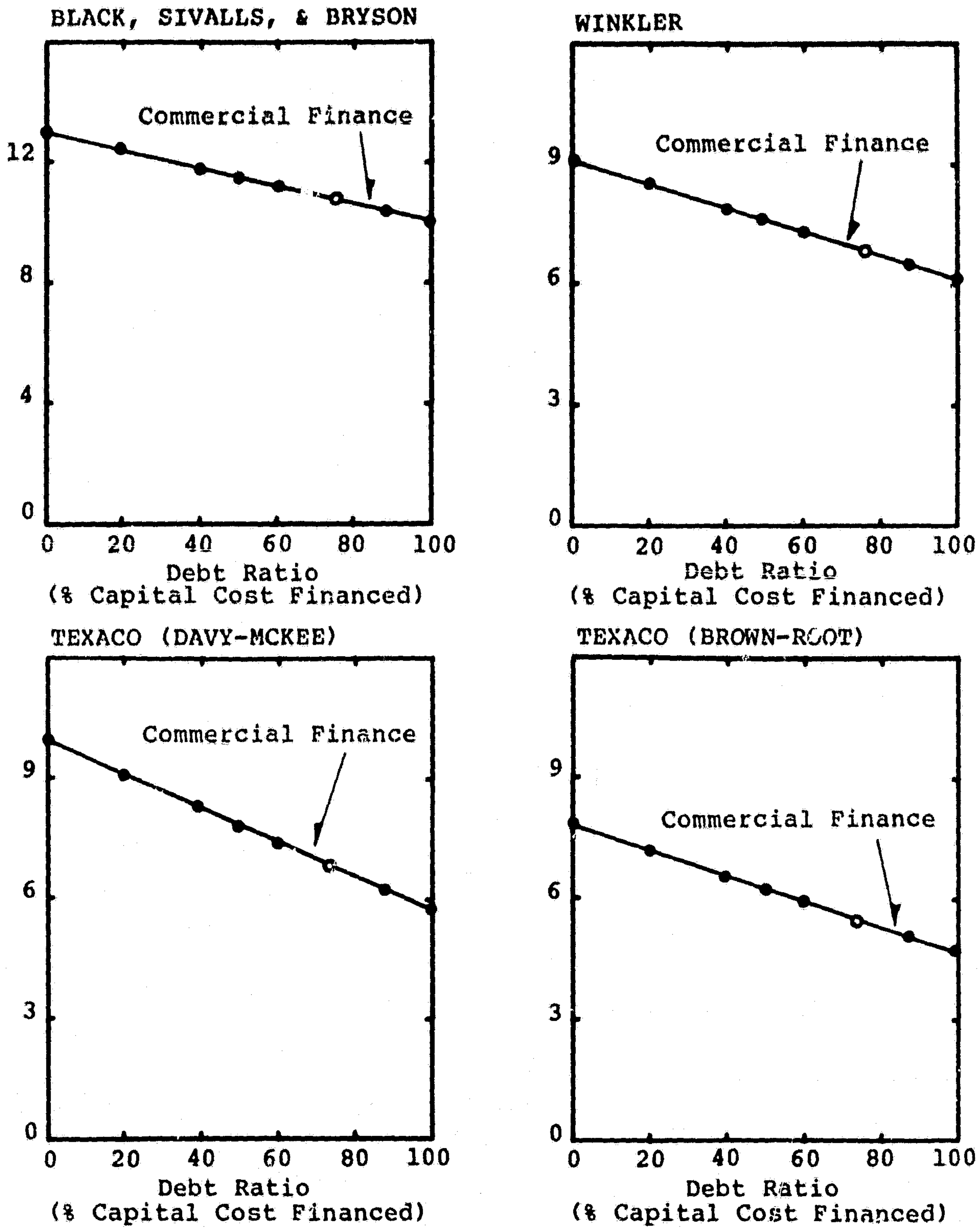

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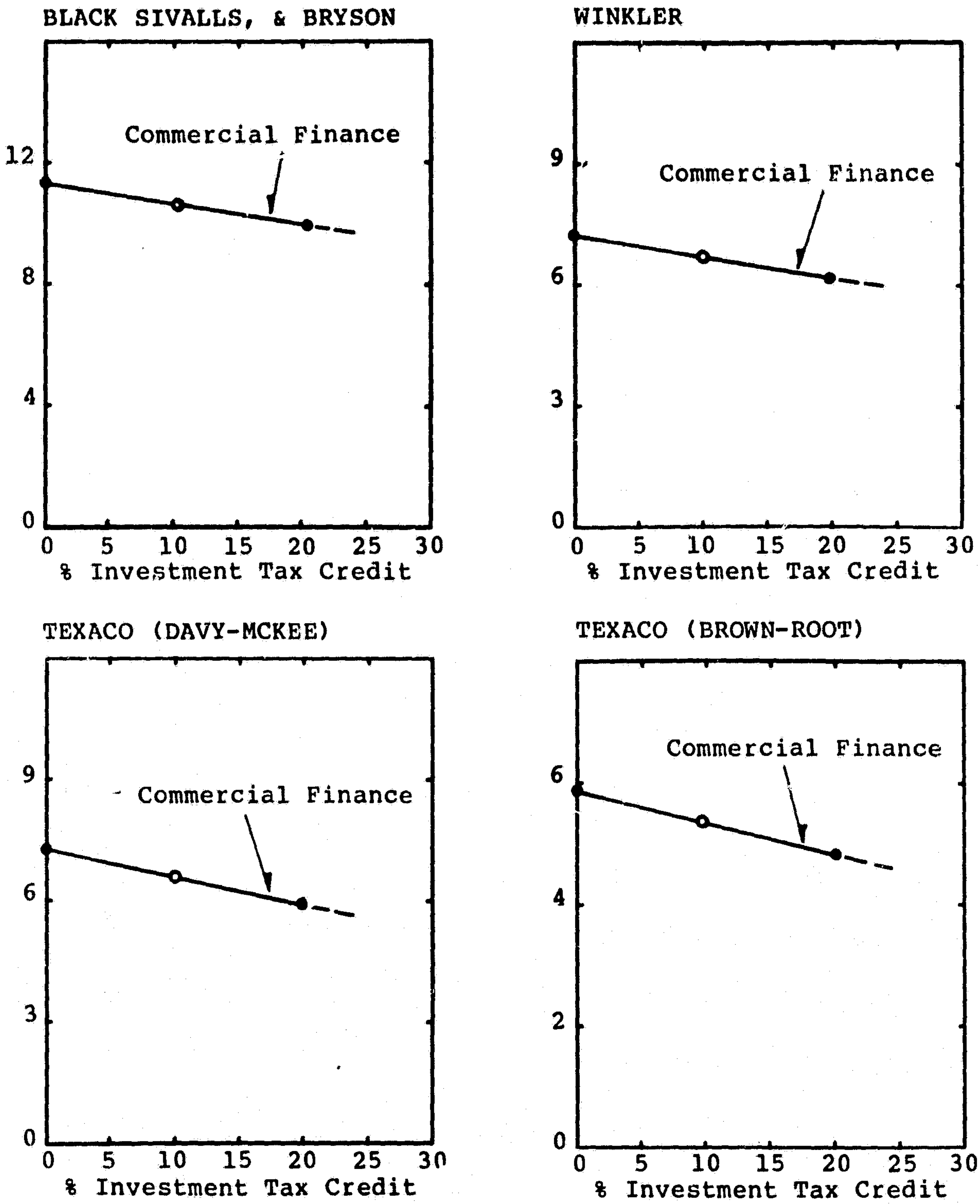

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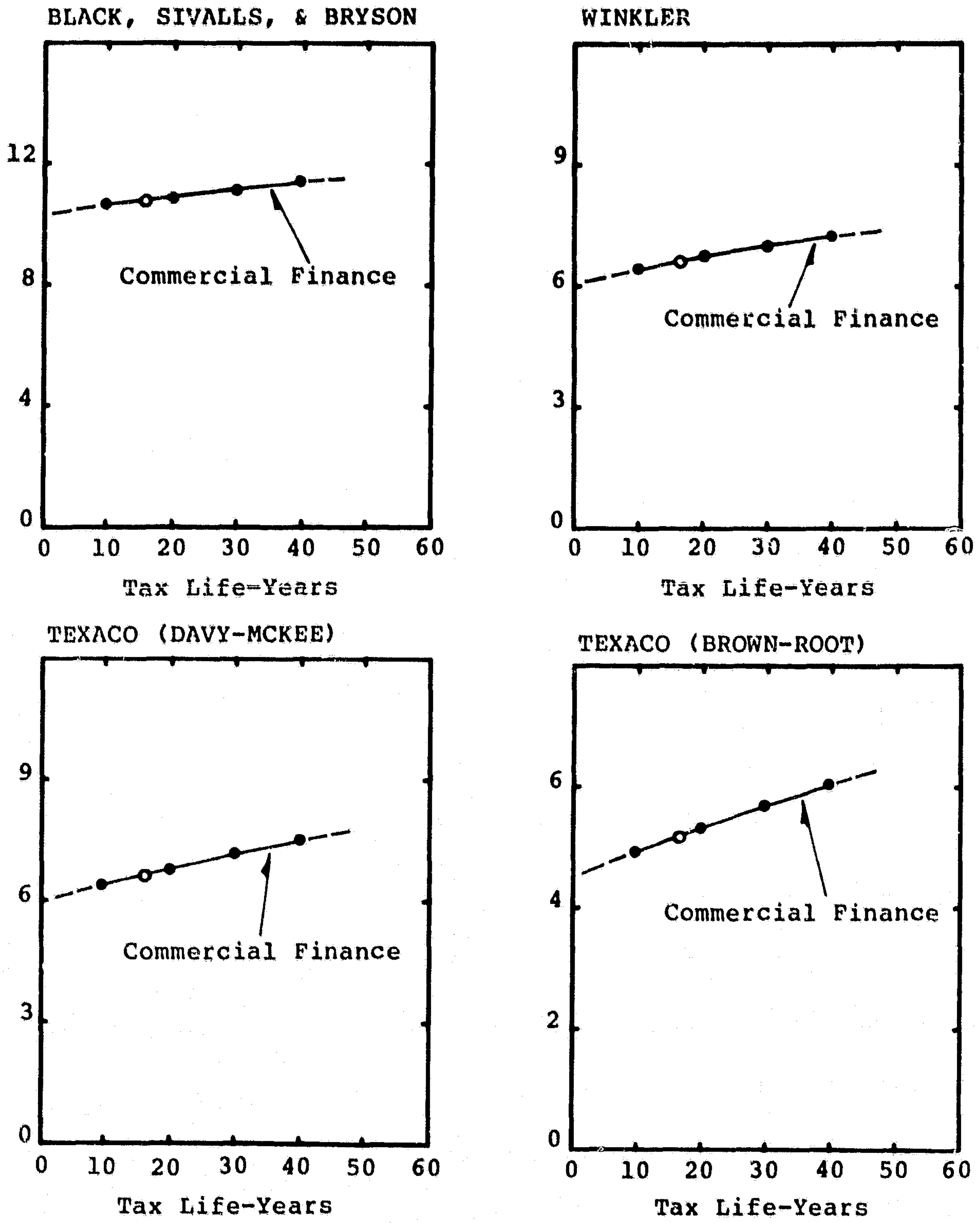

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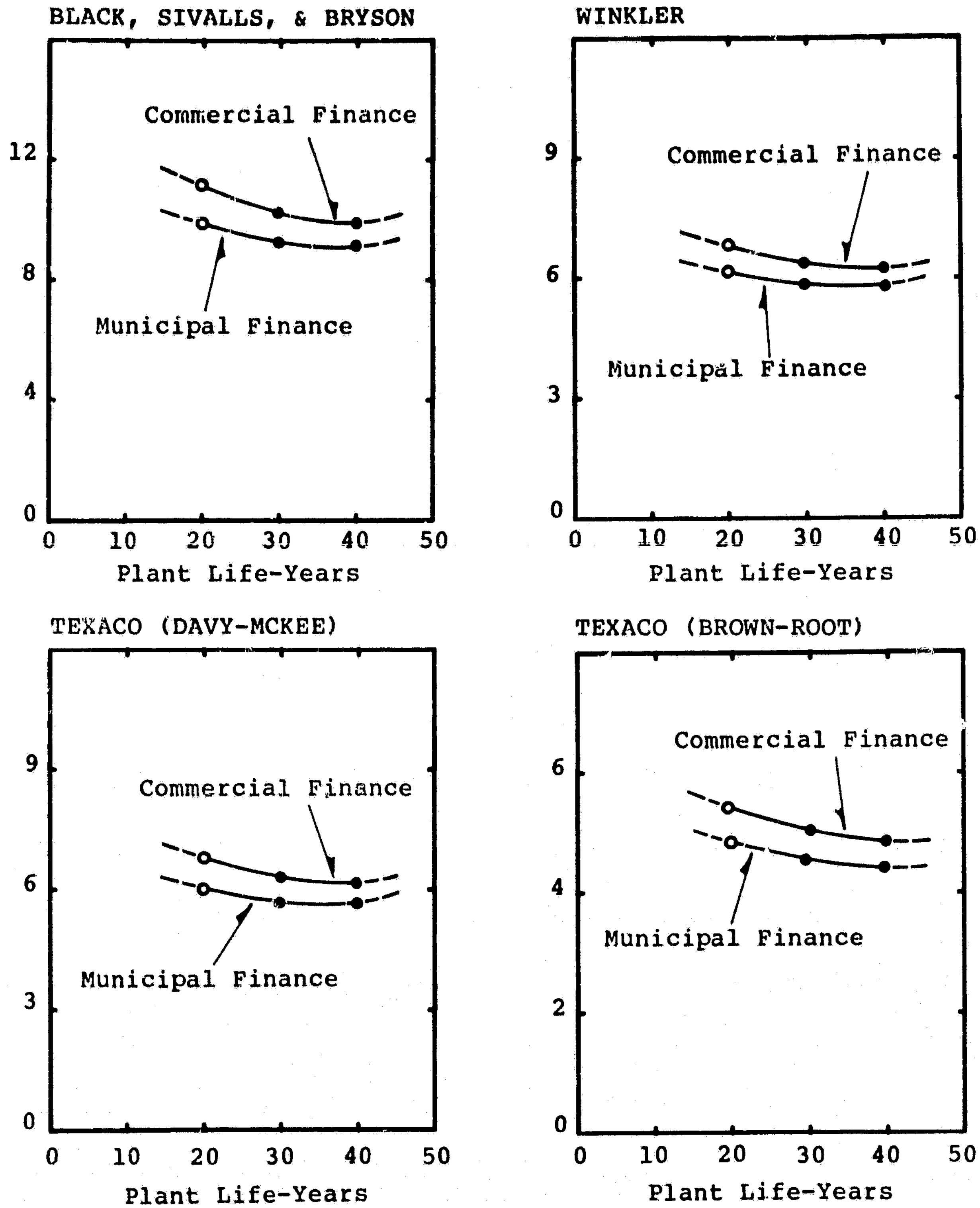

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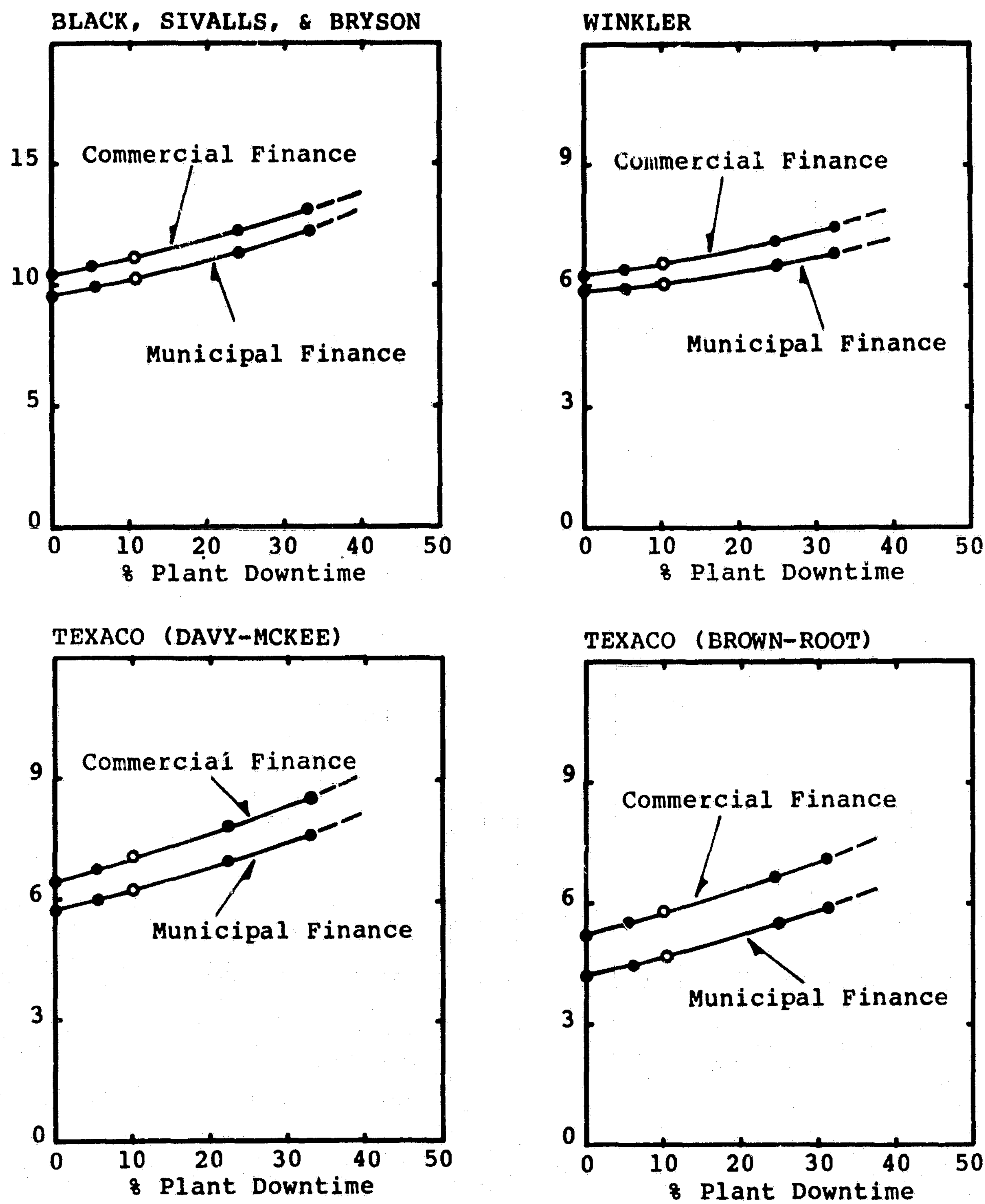
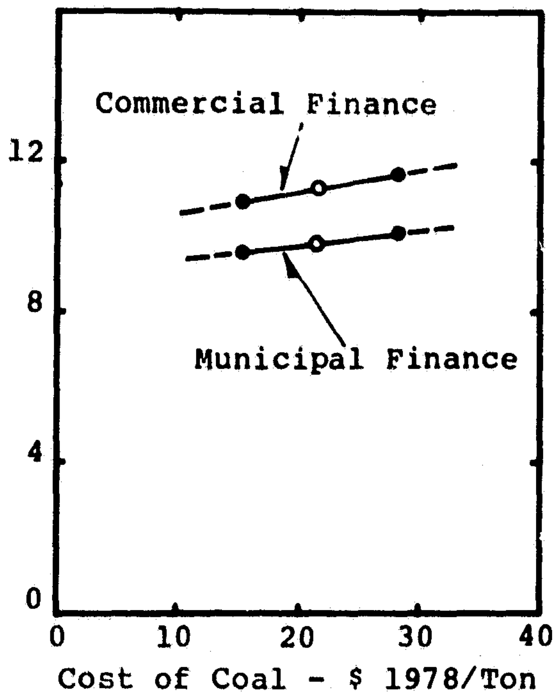


SENSITIVITY ANALYSIS

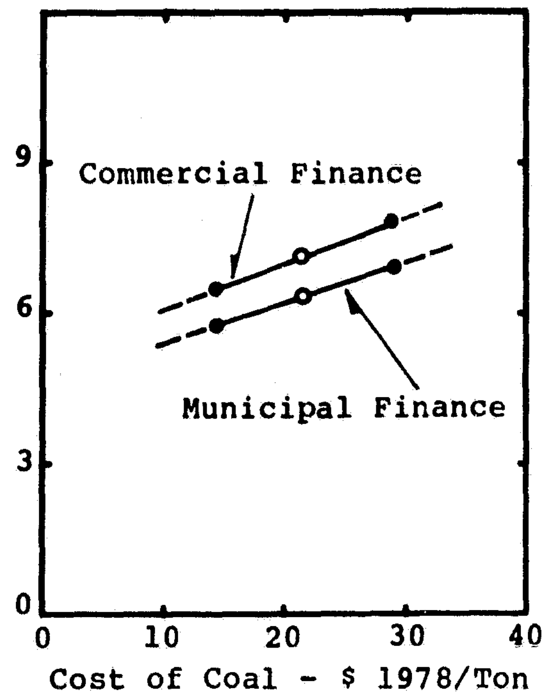
FOREST CITY MODEL

Cost of Hydrogen - \$ 1978/MMBTU H_2, HHV

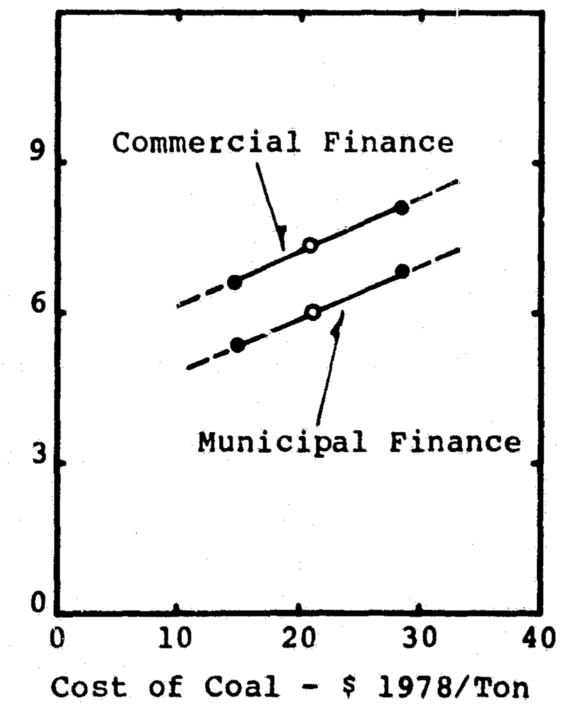
BLACK, SIVALLS, & BRYSON



WINKLER



TEXACO (DAVY-MCKEE)



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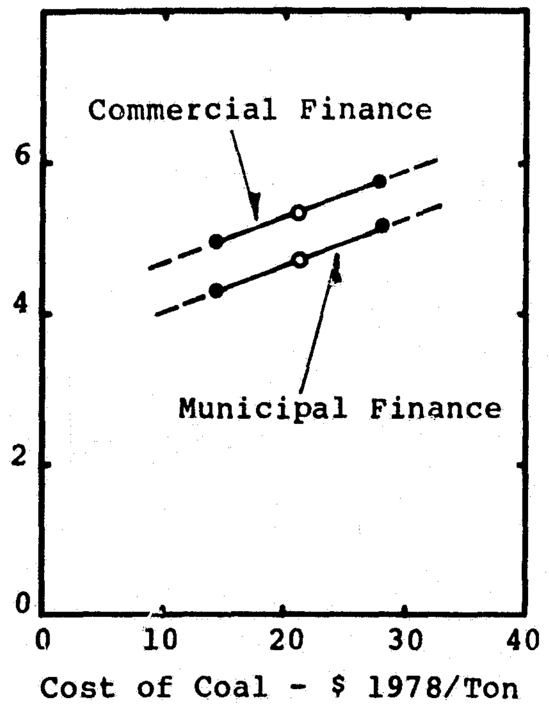

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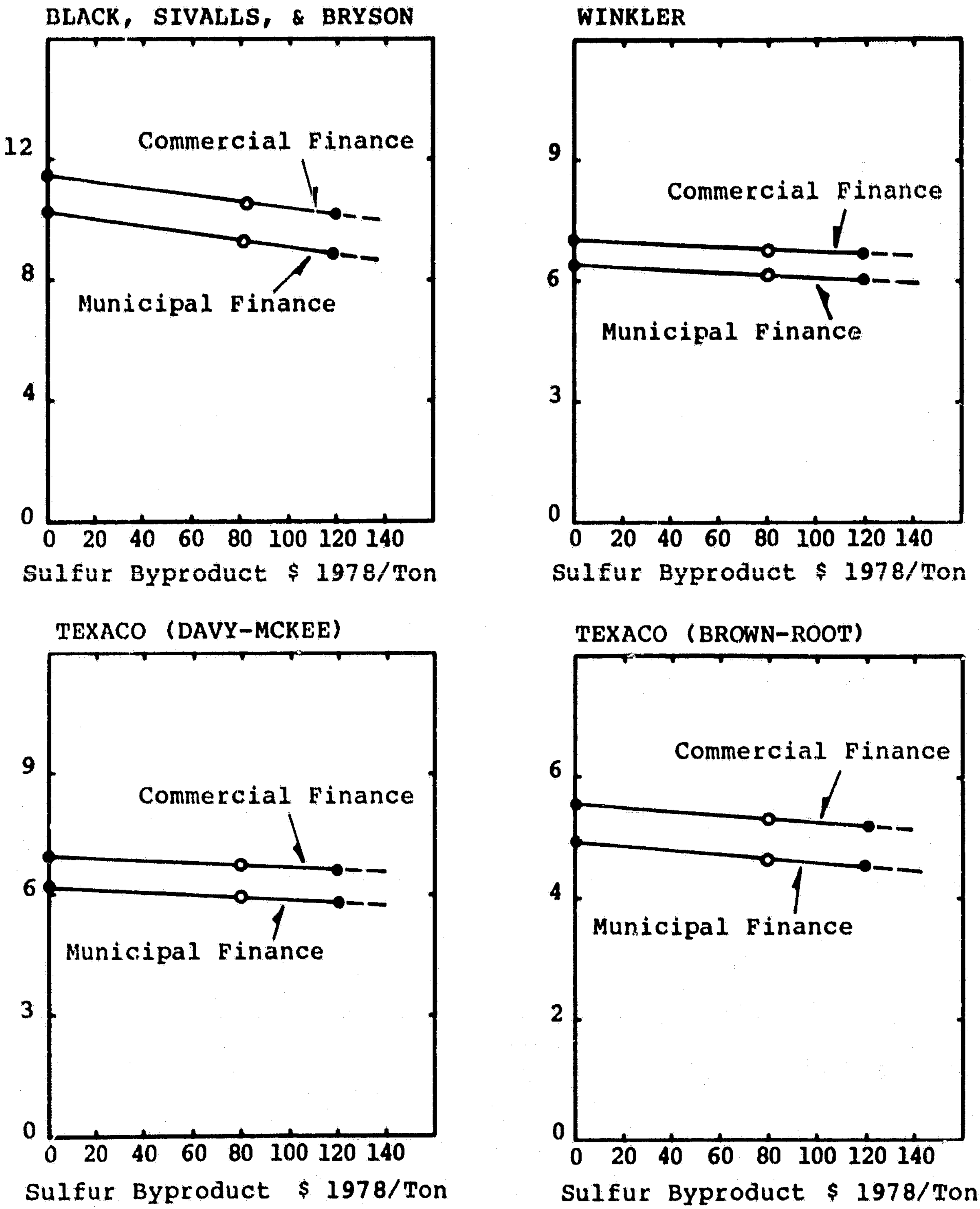
Cost of Hydrogen - \$ 1978/MMBTU H_2, HHV



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FOREST CITY MODEL

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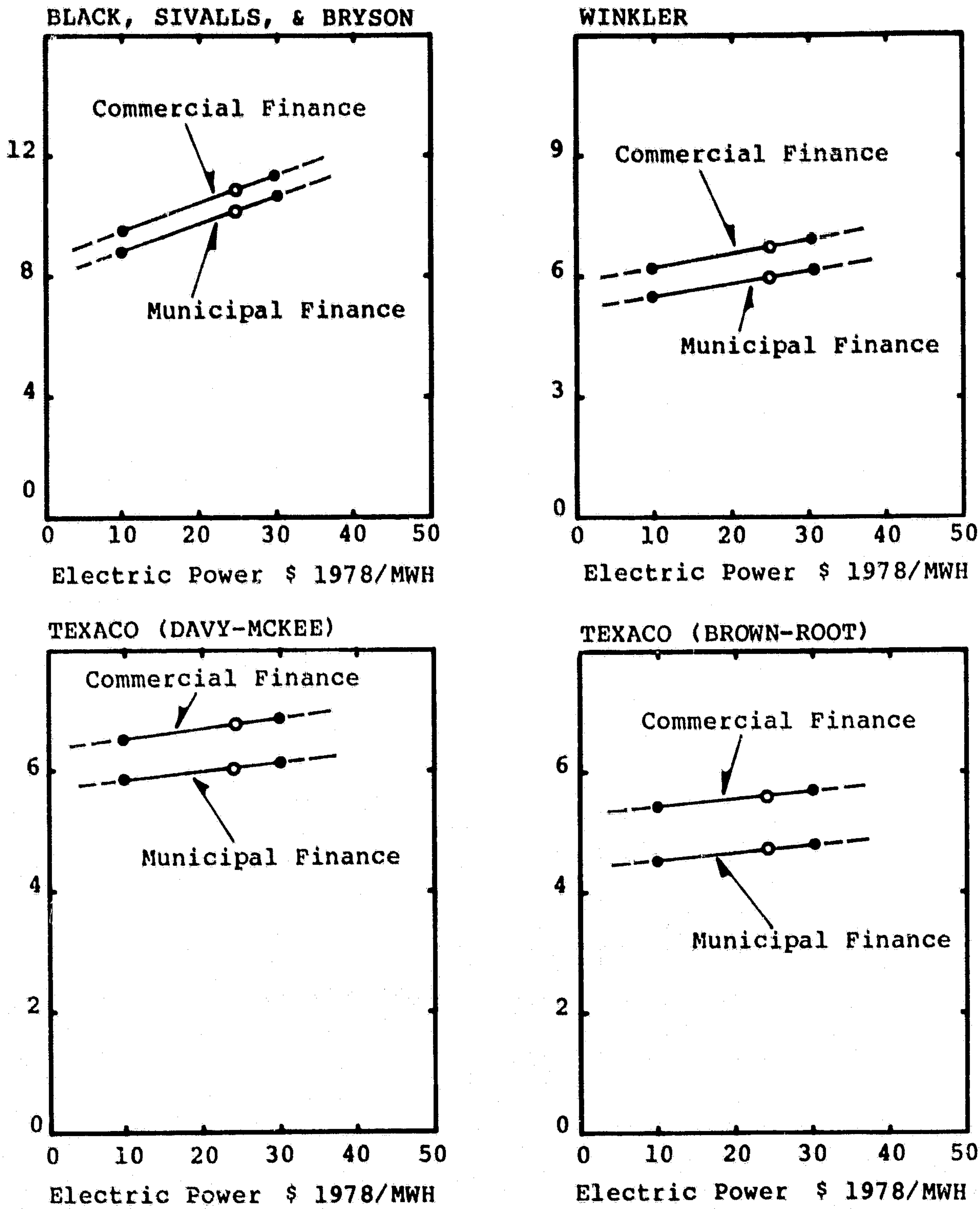

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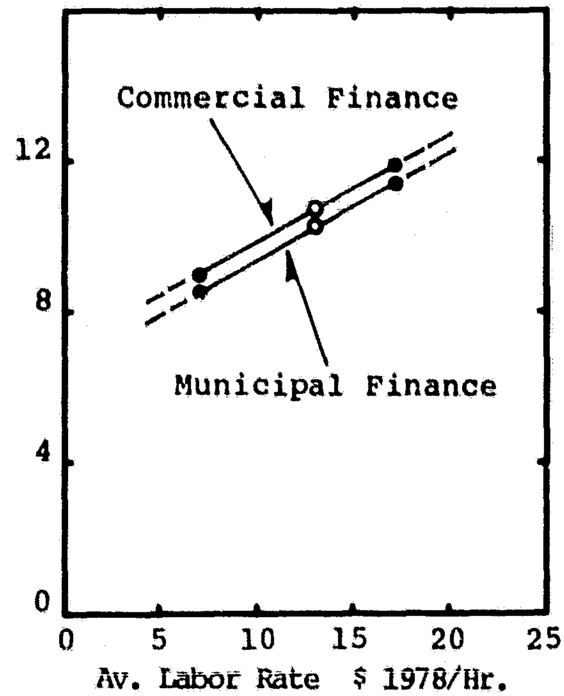
Cost of Hydrogen - \$ 1978/MMBTU H_2, HHV

BLACK, SIVALLS, & BRYSON



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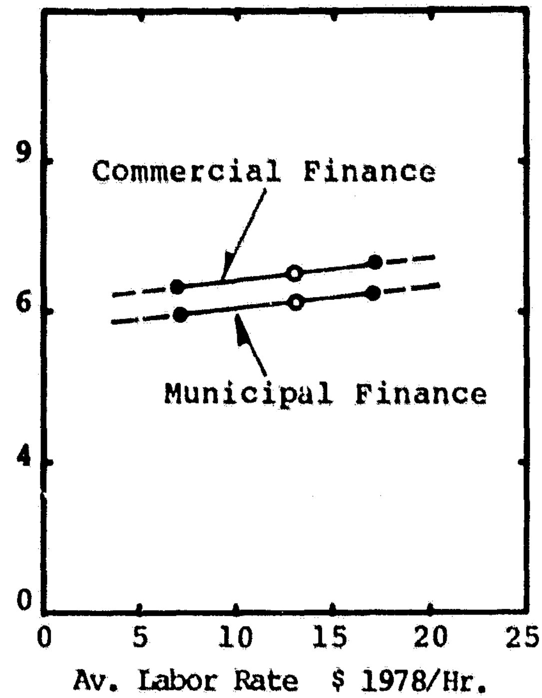

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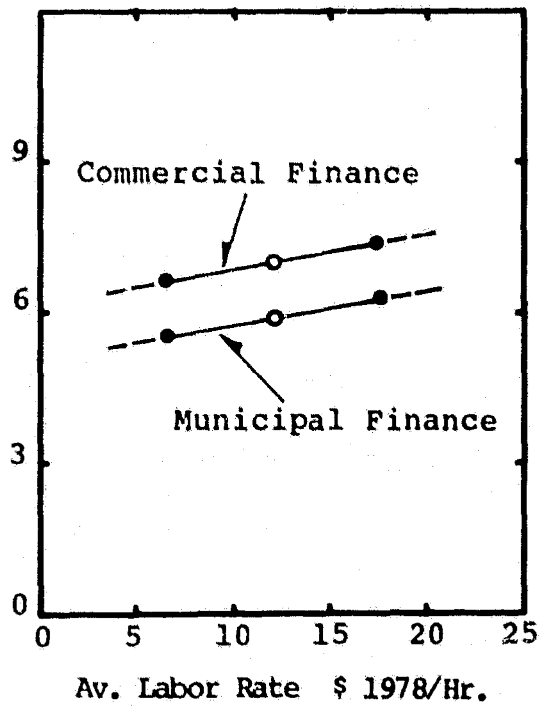

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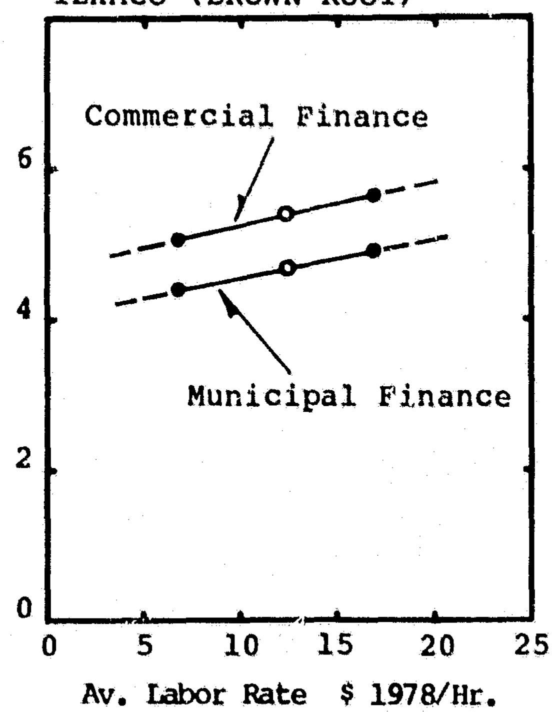
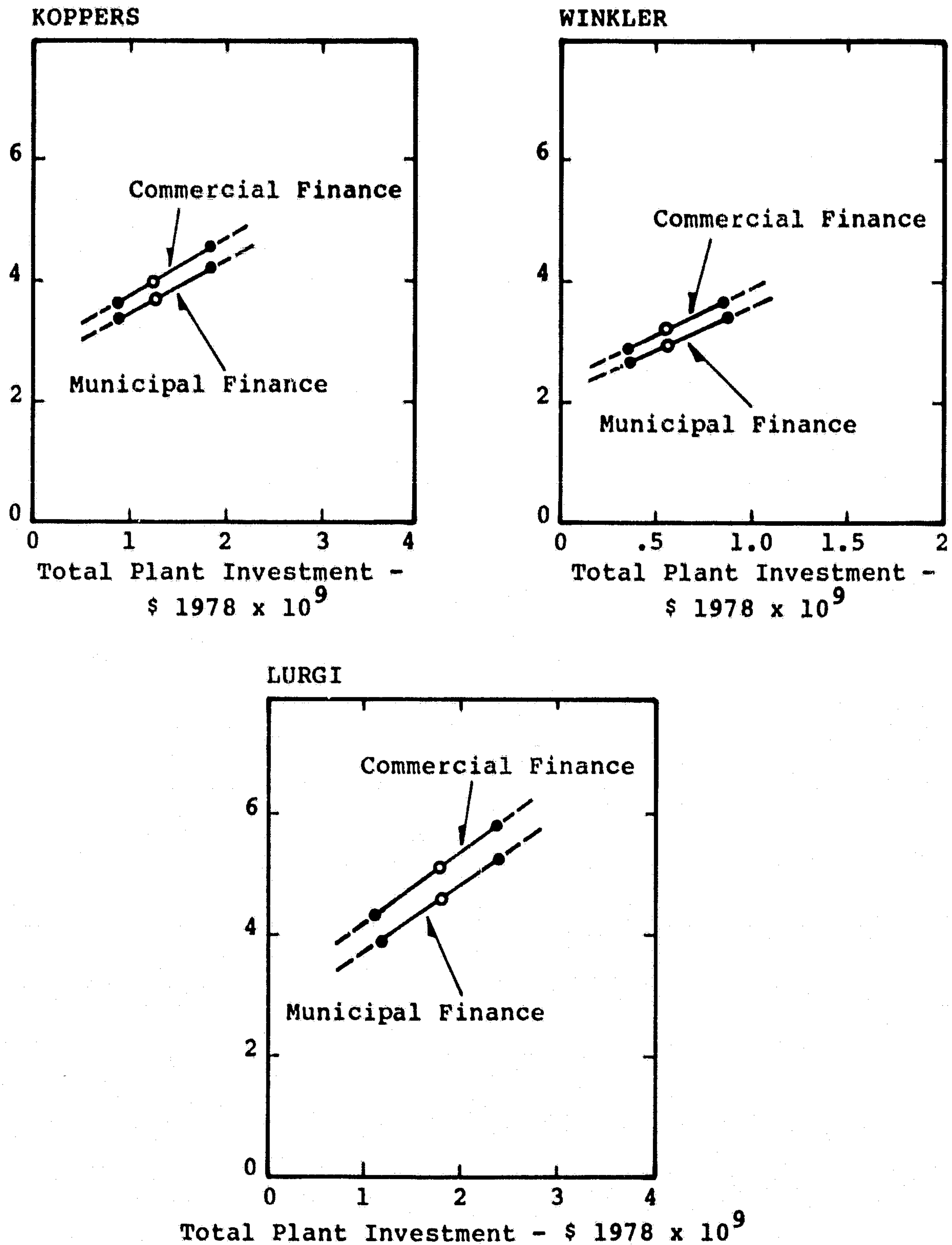


SENSITIVITY ANALYSIS
KAIPAROWITS MODEL
Cost of Hydrogen - $ 1978/MMBTU H_2, HHV



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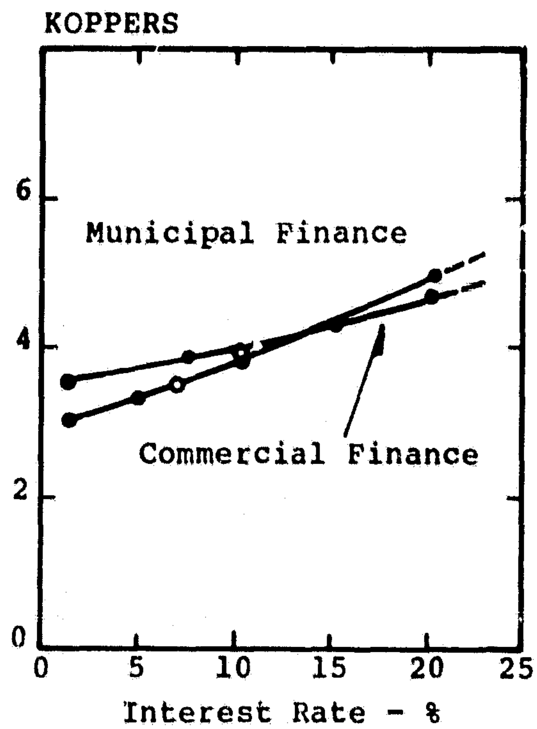

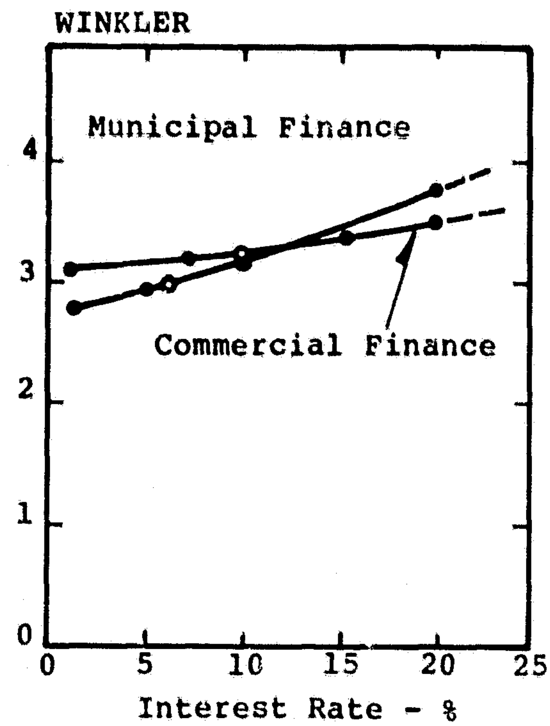

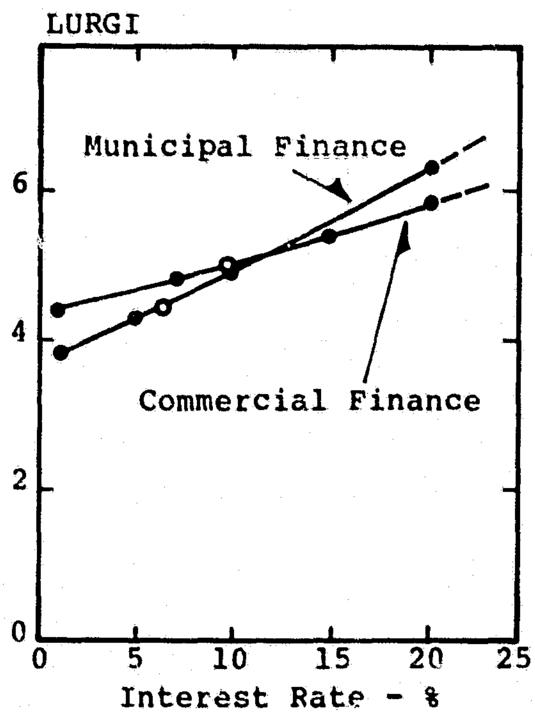

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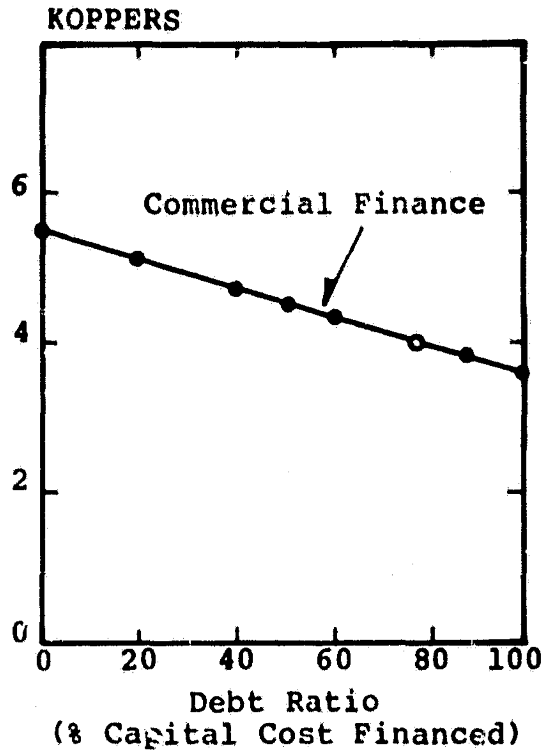
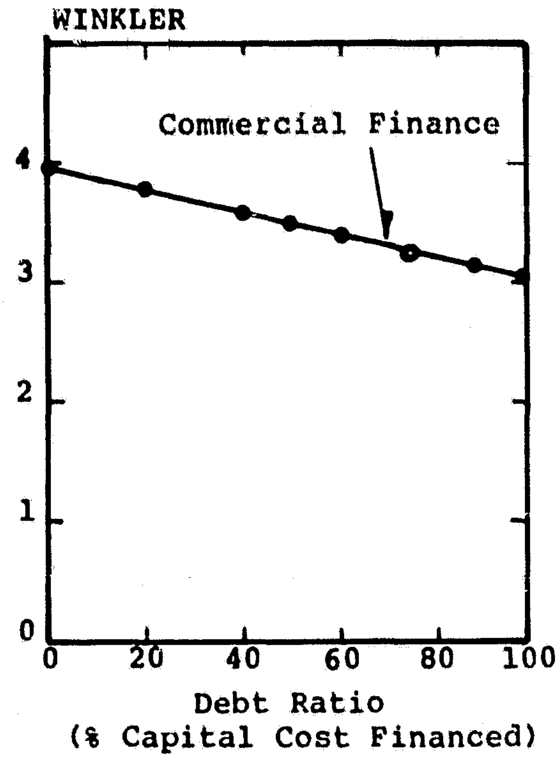
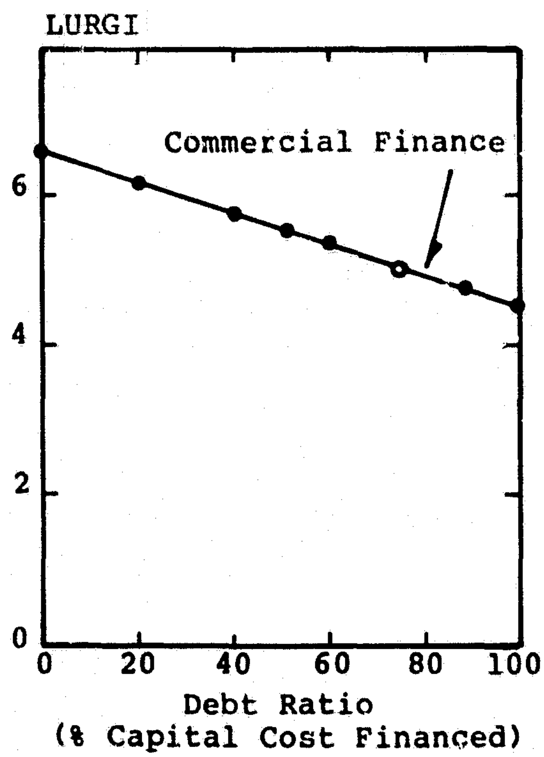
Cost of Hydrogen - \$ 1978/MMBTU H_2, HHV

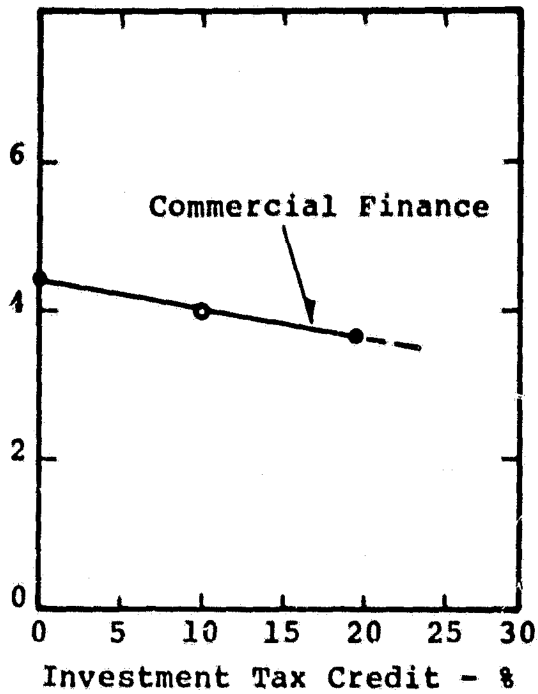




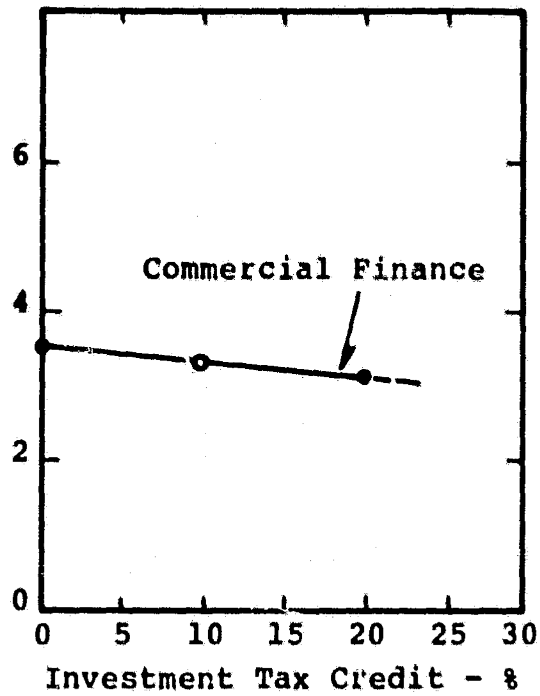


SENSITIVITY ANALYSIS
KAIPAROWITS MODEL
Cost of Hydrogen - $ 1978/MMBTU H_2, HHV

KOPPERS



WINKLER



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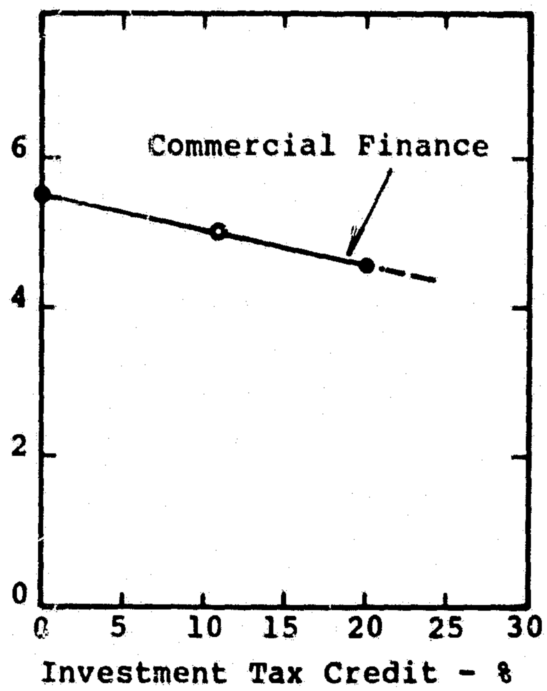
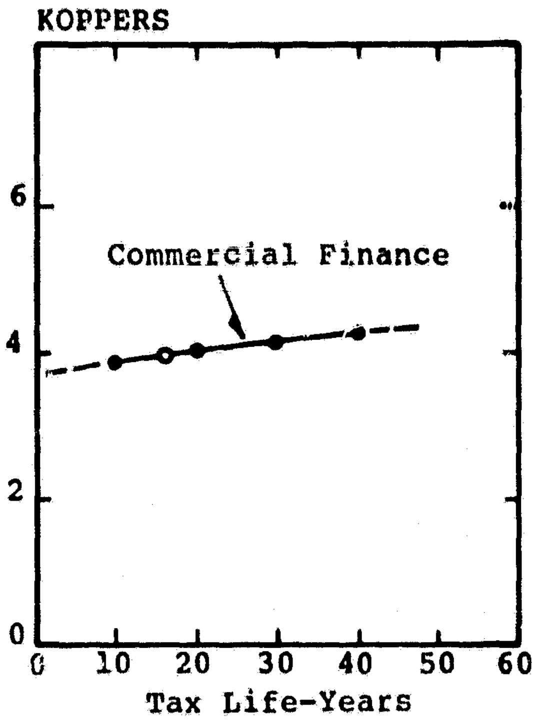
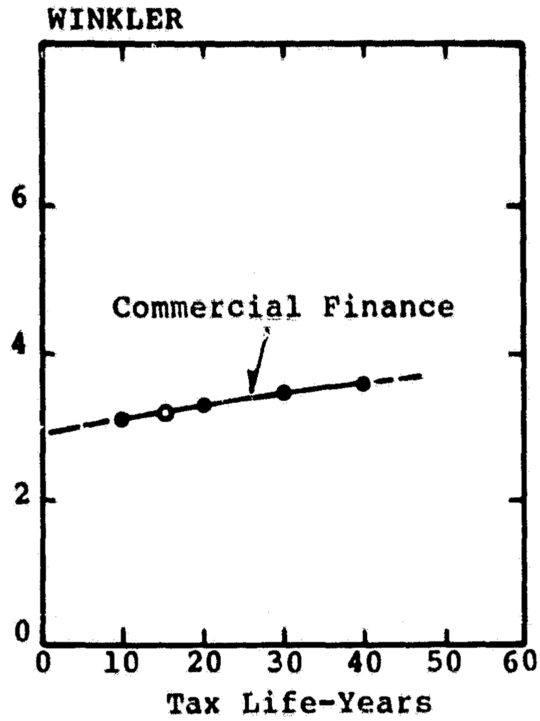


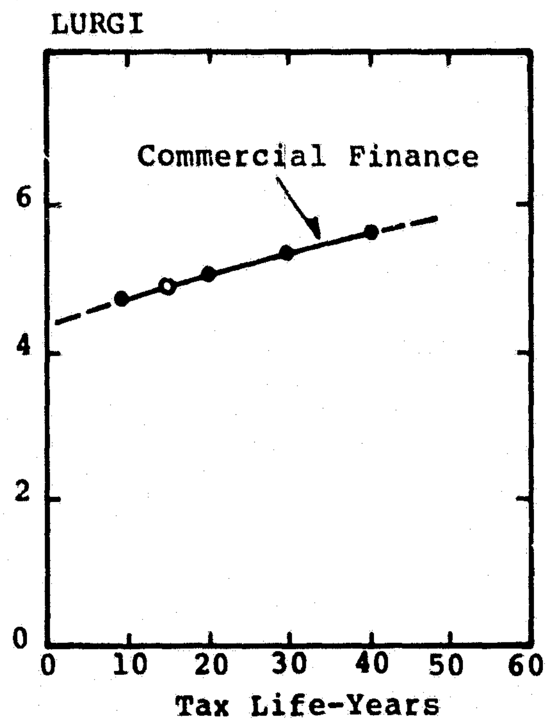
SENSITIVITY ANALYSIS

KAIPAROWITS MODEL

Cost of Hydrogen - \$ 1978/MMBTU H_2, HHV







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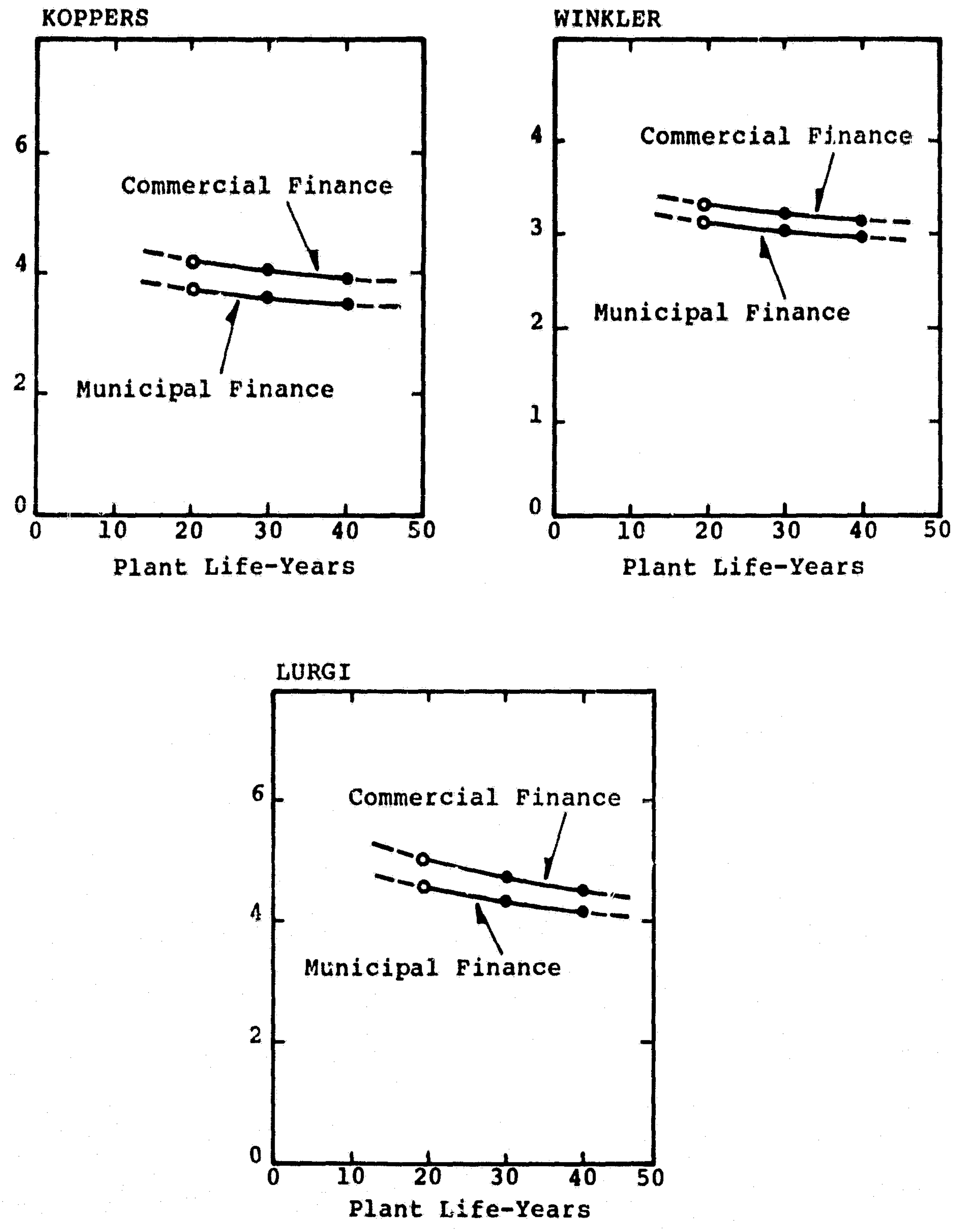
KAIPAROWITS MODEL
Cost of Hydrogen - $ 1978/MMBTU H_2, HHV



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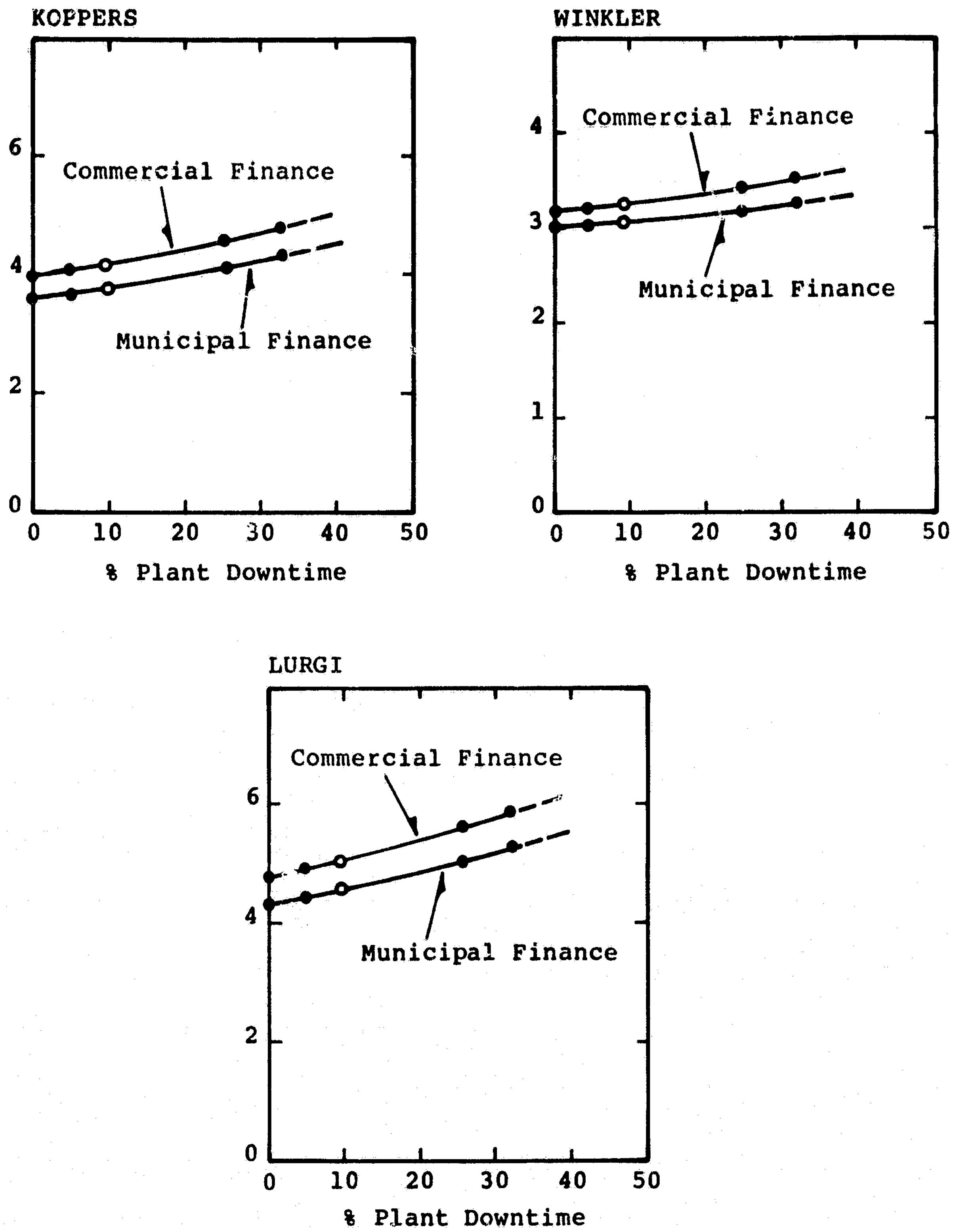
KAIPAROWITS MODEL
Cost of Hydrogen - $ 1978?MMBTU H_2, HHV



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KAIPAROWITS MODEL
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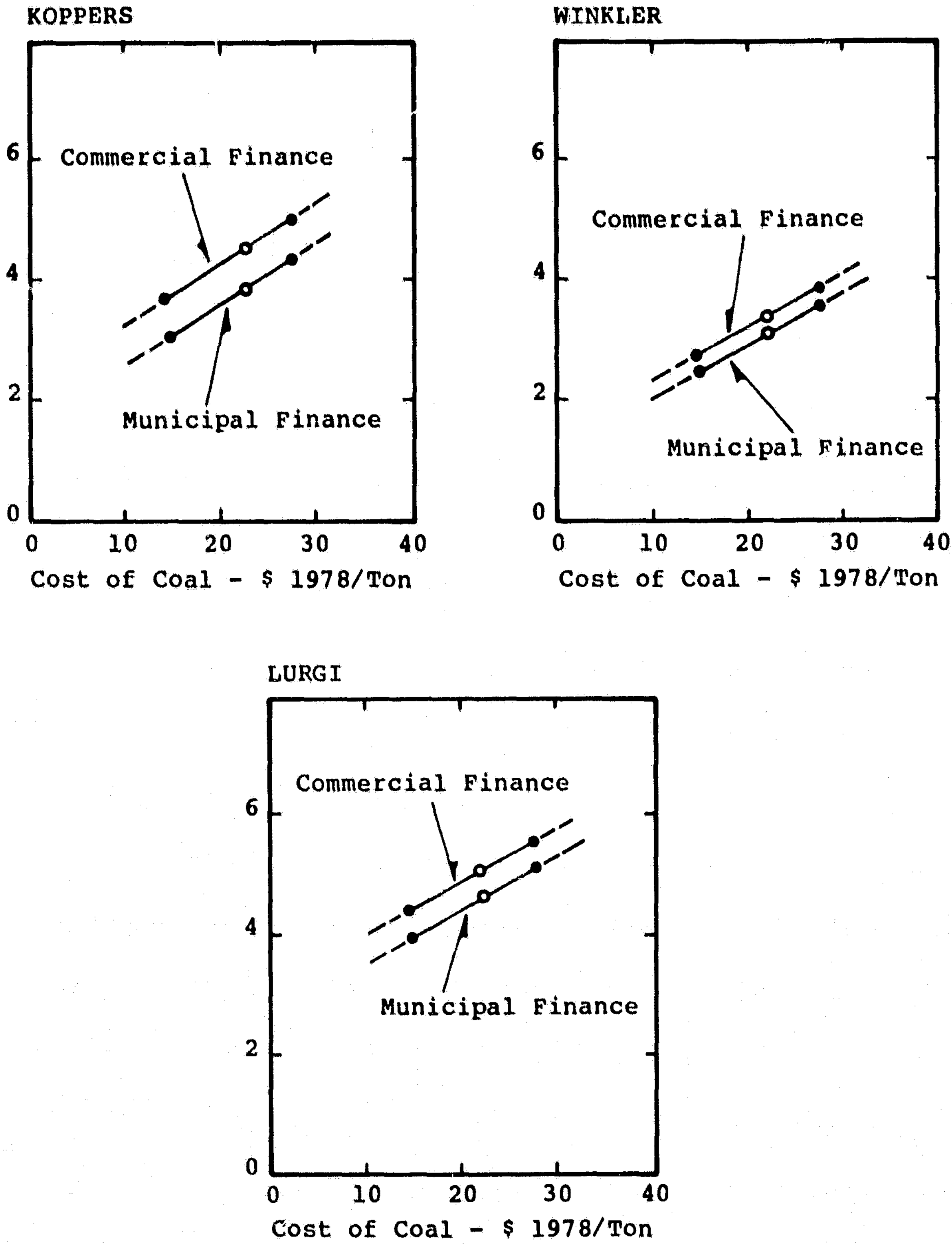

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KAIPAROWITS MODEL
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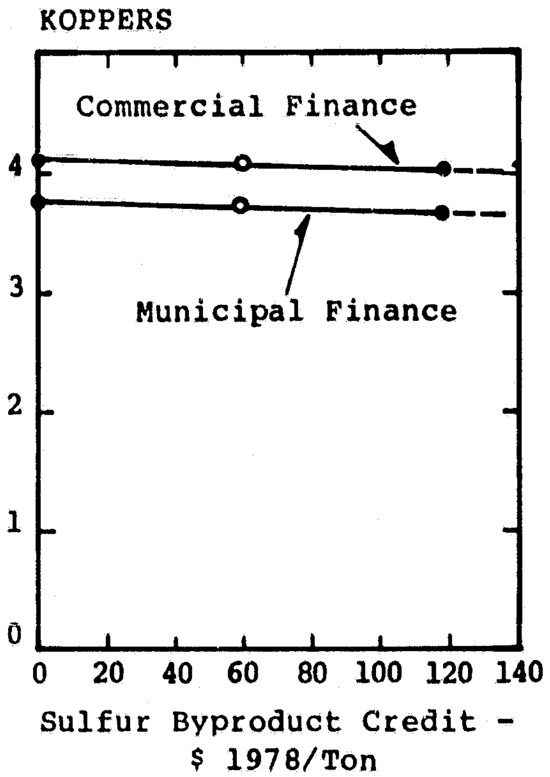

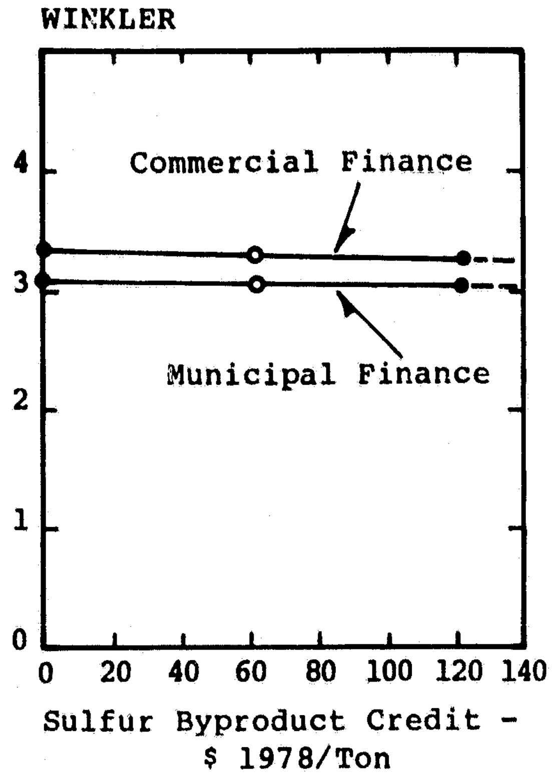

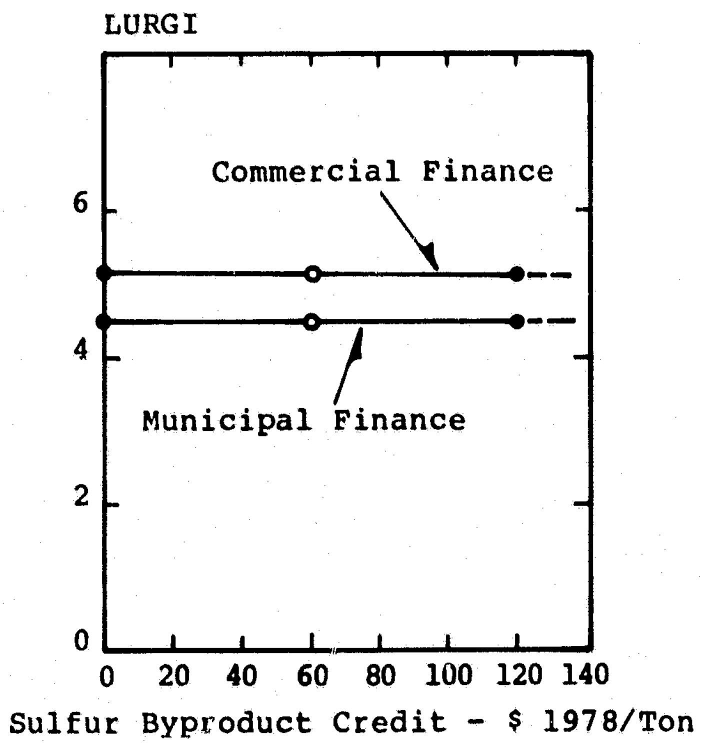

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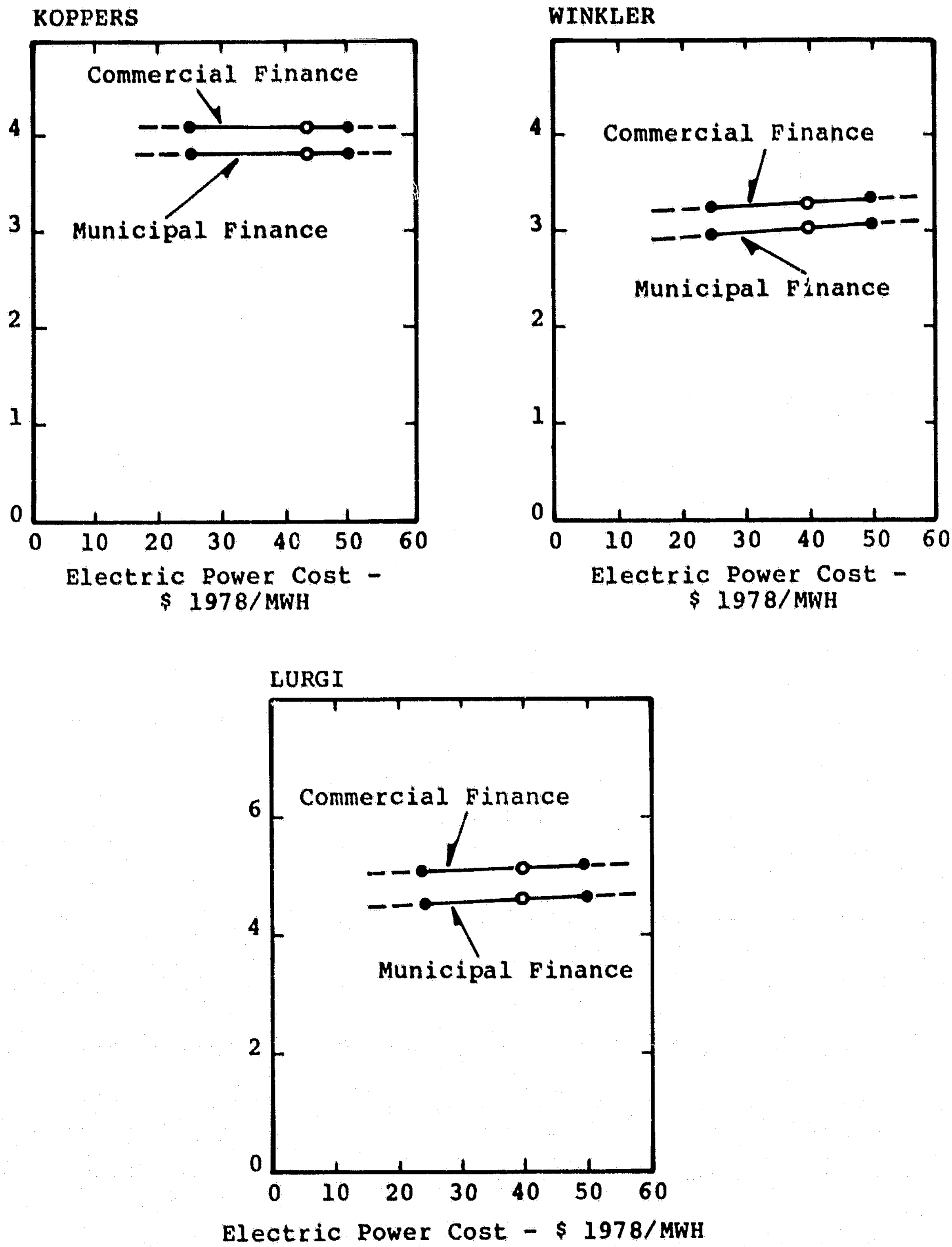

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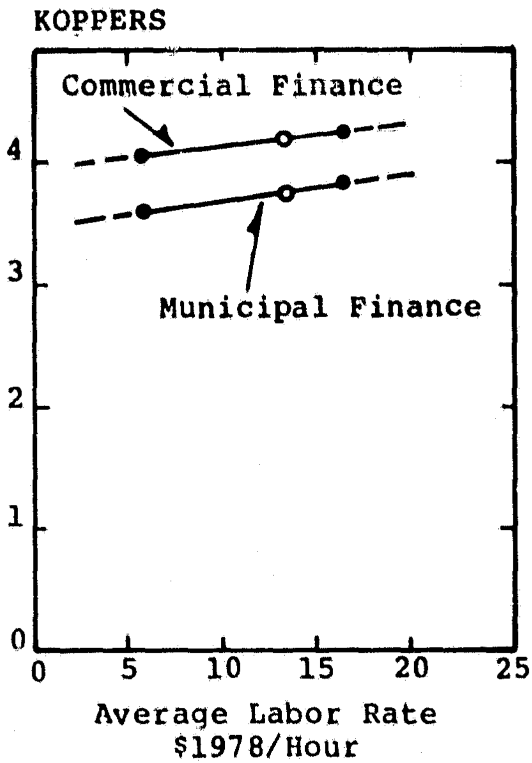
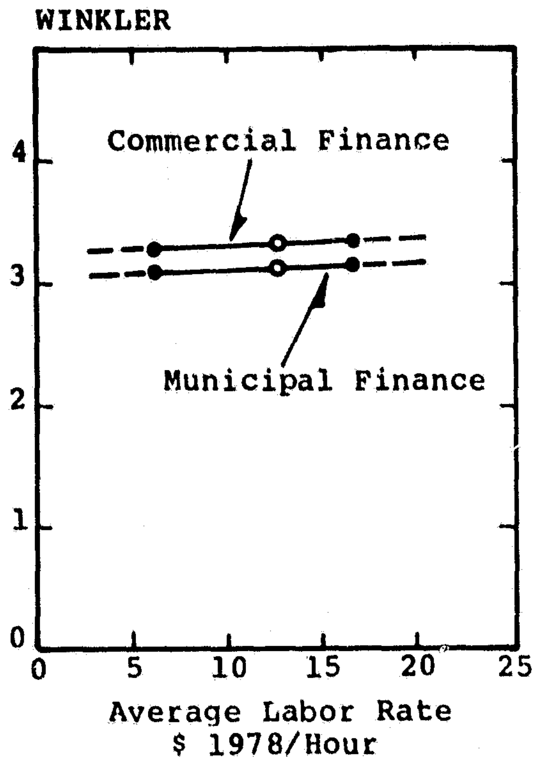
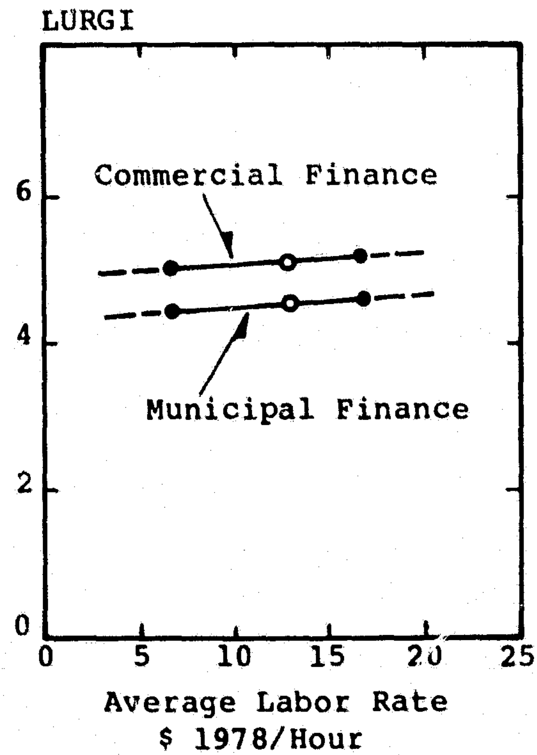
Cost of Hydrogen - \$ 1978/MMBTU H_2, HHV







APPENDIX A

ECONOMIC MODEL BASIS FOR CALCULATIONS

APPENDIX A: ECONOMIC MODEL BASIS FOR CALCULATIONS

Cost estimations for the coal gasification plants studied herein were evaluated with a computer model which provided for input of hardware and operating cost information as supplied by various manufacturers of the plants and input of financial assumptions as selected at the United States Department of Energy sponsored cost estimation seminar.

Cost calculations were performed as specified in Chapter V of the Technical Assessment Guide published by the Electric Power Research Institute ("Revenue Requirement Calculations for Economic Comparison of Alternating," EPRI PS-866-SR, Chapter V, June 1978).

The method followed is an extension of what is commonly referred to as the "Utility Financing Method", in that one of three accounting methods may be selected and tax incentive models for investment tax credit and accelerated depreciation are included.

This model thus has some of the features employed in "discounted cash flow" (DCF) methods, commonly used by corporations, but is strictly valid for a public utility that is constrained by regulation to use return on equity as the basis for profits rather than a profit on sales. Cost calculations using the utility finance method are characteristically lower than DCF methods for this reason. However, all calculations included herein were performed using the same model so that the comparisons between gasifiers of a given size are valid. Financial assumptions are the same within a size category. This is a different set of financial assumptions for the small size gasifier than for the large because of assumed difference in ownership.

Accounting methods that may be selected are:

1. Straight line (yields the highest revenue requirement).

2. Flow Through Accounting (yields the lowest revenue requirement).

3. Normalization Accounting - the method of accelerated depreciation provided in the model is "sum-of-the-years-digits".

Coal and operating costs must be combined with a portion of the capital and interest costs to find the proper price of the product. This is done by "levelizing" capital costs to a constant yearly payment that may be combined with annual costs.

The program provides for inflation escalation of the annual costs over the life of the plant through another levelizing factor for fuel and O&M costs. This method assumes that coal, operation, and maintenance costs increase while the price charged for the product hydrogen remains fixed over the life of the plant. In calculations performed at the seminar, it quickly became obvious that the selection of inflation rate over the plant life influenced the result much more than any other parameter. For example, a 6% rate of escalation increases the product cost by 34%, 10% escalation increases the required cost of hydrogen by 73%, and a 15% escalation rate increases the required cost of hydrogen by 155%. Clearly, in times of moderate to high inflation, a pricing structure must be constructed which allows product price to follow inflated costs. This may be accomplished in the model by performing the calculations on a "first year cost" basis.

First year cost is the simple summation of levelized capital costs with a representative years operation cost, maintenance cost, and fuel cost. Though referred to as first year costs, the calculation reflects an averaged annual cost rather than actual costs incurred in the fiscal year, which are frequently higher. Startup costs and extraordinary operation costs associated with equipment modification to bring the plant to full production are capitalized. To implement "first year cost" calculations it is necessary only to require zero escalation in coal and O&M costs. The result is valid at the particular point in time at which the capital costs are estimated and reflects the cost of the product in "constant dollars" relative to the economy. The seminar conferees agreed that removal of the inflation parameter from the calculation provided the most valid basis for comparison.

A description of the input parameters used in the program follows. This material is reprinted from the EPRI document "Economic Premises for Electric, Power Generating Plants, Complete Plant Utility Financing," July 26, 1978.

Total Plant Investment

The total plant investment is the sum of:

(a) Process (or Onsite) Capital

(b) General Facilities (or Offsite) Capital

(c) Engineering and Home Office Fees

(d) Project Contingency

(e) Process Contingency

Process Capital

Process capital is the total constructed cost of all onsite processing and generating units, including all direct and indirect construction costs. All sales taxes are included. When possible, the process capital costs have been broken down by major plant section (e.g., fuel storage, combustion system, emissions control systems, generators).

General Facilities or Offsite Capital

The capital cost of the offsite facilities is given explicitly in the report. The offsite facilities include roads, office buildings, shops, laboratories, etc., and generally are in the range of 5 to 20% of the onsite capital cost. Fuel, chemical, and by-product storage systems which are not part of the offsite facilities are included in the onsite capital cost.

Engineering and Home Office Overhead Indluding Fee

The contractor has included an estimate on the engineering and home office overhead and fee that are considered representative of this type of plant. These fees may be included in the process capital and general facility capital costs when the cost-estimating system incorporates estimates of these fees as a part of the equipment costs.

Project Contingency

A capital cost contingency factor has developed by the contractor for each major section of the plant. This is a project contingency factor that is intended to cover additional equipment or other costs that would result from a more detailed design of a definitive project at an actual site.

Process Contingency

This is a capital cost contingency applied to new technology in an effort to quantify the uncertainty in the design and cost of the commercial-scale equipment. The following guidelines were considered as an aid in assigning process contingency allowances to various sections of the plant.

State of Technology Development	% of Installed Section Cost
New concept with limited date	25% and up
Concept with bench-scale data available	15-25%
Small pilot plant data (e.g., 1 MW size) available	10-15%
A full-size module has been operated (e.g. 20-100 MW)	5-10%
The process is used commercially	0-5%

Total Capital Requirment

The total capital requirement includes all capital necessary to complete the entire project. These items include:

(a) Total Plant Investment
(b) Prepaid Royalties
(c) Preproduction (or startup) Costs
(d) Inventory Capital
(e) Initial Chemical and Catalyst Charge
(f) Allowance for Funds During Construction (AFDC)
(g) Land

These items are discussed below.

Preproduction Costs

The preproduction costs are intended to cover operator training, equipment checkout, major changes in plant equipment, extra maintenance, and inefficient use of fuel and other materials during plant startup. The preproduction costs are estimated as follows:

(a) One month fixed operating costs (Fixed operating costs are operating and maintenance labor, administrative and support labor, and maintenance materials).

(b) One month of variable operating costs at full capacity excluding fuel (These variable operating costs include chemicals, water, and other consumables and waste disposal charges).

(c) 25% of full capacity fuel cost for one month (This charge covers inefficient operation that occurs during the startup period).

(d) 2% of total plant investment (This charge covers expected changes and modifications to equipment that will be needed to bring the plant up to full capacity).

Inventory Capital

The value of inventories of fuel and other consumables is capitalized and included in the inventory capital account. The inventory capital is estimated as follows:

(a) One month supply of fuel based on full capacity operation.

(b) One month supply of other consumables (excluding water) based on full capacity operation.

Initial Catalyst and Chemicals Charge

The initial cost of any catalyst or chemicals that are contained in the process equipment (but not in storage, which is covered in inventory capital) is to be included.

Allowance for Funds During Construction (AFDC)

An AFDC charge is computed based on the time period from the center of gravity (cg) of expenditures until the plant is in commercial operation. The interest rate is 8%/yr. The AFDC is then calculated from the total plant inves[illegible] (TPI) as shown below.

$$AFDC = [(1.08)^{cg} - 1](TPI)$$

<u>Numerical Example</u>

TPI = \$100

cg = 2 years

$AFDC = [(1.08)^{2} - 1](100) = \$16.6$

The center of gravity time period (cg) is to be estimated - representative centers of gravities for several types of power plants are shown in the following table:

Type of Plant	Total Design-Construction Time	cg
Pulverized coal Fired (1000 MW)	5 years	2 years
Oil Fired Combined Cycle (500 MW)	3 years	1 year
Combustion Turbine Unit (75 MW)	2 years	0.5 year

Since the AFDC charge is to be expressed in the same year dollars as the total plant investment, cost escalation (inflation) is <u>not</u> included.

<u>Land</u>

Land costs are site-specific and variable. Specific land costs were determined for each of the scenarios considered.

<u>Capacity Factor</u>

For EPRI evaluation purposes, the following capacity factors (CF) are suggested as design values.

Type of Plant	Design Capacity Factor
Base	70%
Intermediate	30%
Peaking	10%

The design capacity factor for this study was selected by the contractor for each gasifier. The CF is assumed to be constant over the life of the plant (i.e., levelized).

Operating Cost Basis

The operating costs are to estimated on a first year basis. The operating costs are divided into fixed and variable costs. The fixed costs are essentially independent of capacity factor and are generally expressed in \$/KW-yr. The variable costs are directly proportional to the amount of power produced and are generally expressed in mils/KWH.

Fixed Operating Costs

Fixed operating costs include the following:

(a) Operating Labor

(b) Maintenance (may also have a variable component.

(c) Overhead Charges

These items are discussed below.

Operating Labor

The operating labor charges (OLC) are computed using the average labor rate (ALR) and operating jobs (OJ) as follows:

$$OLC = \frac{(OJ) \times (AKR) \times (8760 \text{ hr/yr})}{(\text{Full capacity of plant in KW})}$$

The average labor rate includes a payroll burden, as indicated.

Maintenance Costs

Annual maintenance costs for new technologies are often estimated as a percentage of the installed capital cost of the facilities. The percentage varies widely depending on the nature of the processing conditions and the type of design. Maintenance costs in the ranges shown below are representative.

Type of Processing Conditions	Maintenance % of Process (of Offsite) Capital Cost/Yr
Corrosive and abrasive slurries	6.0 - 10 (& higher)
Severe (solids, high pressure & temperature)	4.0 - 6 (& higher)
Clean (liquids and gases only)	2.0 - 4
Offsite facilities & steam/electrical systems	1.5

The maintenance costs have been developed by the contractor with concurrence of the EPRI project manager.

The maintenance costs are separately expressed as maintenance labor and maintenance materials when available. A maintenance labor/materials ratio of 40/60 was used for this breakdown when other information was not available.

Overhead Charges

The only overhead charge included in the power plant studies is a charge for administrative and support labor, which is taken as 30% of the operating and maintenance labor.

General and administrative expenses are not included.

<u>Variable Operating Costs - Consumables</u>

Variable operating costs includes fuel, water, chemicals, waste disposal, etc.

<u>Variable Maintenance Charges</u>

A variable component of the maintenance cost was included when there was a basis for estimating how maintenance costs vary with capacity factor.

<u>By-product Credits</u>

By-product credits (if any) are based on values given with each gasifier.

<u>Levelized Operating Costs</u>

Inflation will tend to increase the operating costs (in current dollars) over the life of the plant. In EPRI analyses, a long-term inflation rate of 6%/year is assumed in estimating the cost of capital (discussed in a following section) and in estimating the life cycle revenue requirements for other expenses. To represent these varying revenue requirements for fixed and variable costs (including fuel), a single "levelized" value is computed using the "present worth" concept of money. Based on the following assumptions,

Inflation rate = 6%/year
Discount rate = 10%/year

The 30-year levelization factor (LF) for operating and maintenance (O&M) costs (excluding fuel) is 1.886 (see Chapter V of the EPRI Technical Assessment Guide (TAG) for further detail).

30-year levelized O&M - 1.886 x (1st year O&M)

Cost of Capital

The cost of capital is based on assumptions for the following:

Finance Parameter	Sample Value
Debt/Equity Ratio	50%
Debt Cost	8%/yr
Preferred Stock Ratio	15%
Preferred Stock Cost	8.5%/yr
Common Stock Ratio	35%
Common Stock Cost	13.5%/yr
Weighted Cost of Capital	10%/yr
Federal + State Income Tax Rate	50%
Property Taxes and Insurance	2%/yr
Investment Tax Credit	0
Book Life	30 yr
Tax Life	20 yr

The 30-year levelized fixed charge rate (LFCR) calculated from the above assumptions is 18%/yr. For more information see Chapter V of the Technical Assessment Guide (TAG).

Levelized Fixed Charge (30 year plant)

The levelized fixed charges (LFC) are based on the total capital requirement (TCR) and are computed as follows:

$$LFC = \frac{(LFCR)\ (TCR)}{(\text{plant size in KW})} \quad - \ \$/\text{KW-yr}$$

Where LFCR = 0.18 for the sample finance data listed above.

Levelized Fixed Charges (Interim Replacements)

If major portions of the plant have a short life (5-10 years), and would have to be capitalized as interim replacements, a fixed charge rate consistent with the shorter life have been applied to these capital items.

<u>Formulas Used in EPRI "Utility Financing Method"</u>

Weighted Cost of Capital

= debt ratio x debt cost

+ preferred stock ration x preferred stock cost

+ common stock ratio x common stock cost

Levelized Annual Fixed Charge Rate

= return (weighted cost of capital)(*)

+ sinking fund depreciation(*)

+ levelized annual income tax - tax preference allowances

+ property taxes, insurance, etc.

Levelized Annual Income Tax

= Capital recovery factor + allowance retirement dispersion - straight line depreciation

x [1-(debt ratio x debt cost/weighted cost of capital)]

x [Tax rate/(1 - tax rate)]

(*)Capital recovery factor = return + sinking fund depreciation

$$= \frac{r\,(1+r)^N}{(1+r)^N - 1}$$

where r = discount rate

N = book life

Investment Tax Credit

a. Flow Through Accounting

Levelized annual investment tax credit allowance =

$$\frac{\text{CRF X Investment Tax credit rate}}{(1 + r)(1 - \text{tax rate})}$$

b. Normalization Accounting

Levelized annual investment tax credit allowance =

$$\frac{\text{Investment tax credit rate}}{1 - \text{tax rate}}$$

$$x\{\frac{CRF}{1+r}-[\frac{(\text{Tax rate})(\text{debt ratio})(\text{debt cost})}{r}x(\frac{CRF}{1+r}-\frac{1}{N})]\}$$

Where CRF = capital recovery factor based on book life

r = discount rate

N = book life

Levelizing Factor For Escalating Fuel and O&M Costs

If a cost escalates at a constant annual rate, a levelized cost can be calculated for the stream of escalating values by multiplying the cost in the initial year by the appropriate levelizing factor, L_f. The levelizing factor is calculated as follows:

$$L_f = [CRF\ (r,\ N)](k + K^2 + k^3 +...+ k^N)$$

$$= [CRF\ (r,\ N)][\frac{k(1-k^N)}{1-k}]$$

where CRF (r, N) is the capital recovery factor and

$$CRF\ (r,N) = \frac{r(1+r)^N}{(1+r)\ N-1}$$

r = the discount rate

N = the book life

$k = \frac{(1+e)}{(1+r)}$ and

e = the apparent escalation rate such that

$$1+e = (1 + \text{real escalation})(1 + \text{inflation rate})$$

APPENDIX B

SUMMARY OF GASIFIER TECHNOLOGIES

PROCESS NAME:	Agglomerating Burner
DEVELOPING COMPANY:	Union Carbide Corporation Battelle Memorial Instit.

Type:	Fluidized Bed
Plant Capacity: Tons Coal/Day	25 (pilot)
Extent of Application:	Pilot Plant Research & Analysis Air Blown Only
Operating Temperature: (^{o}F)	1800^{o}F
Pressure (psig)	100
Comments:	No gas composition data available

PROCESS NAME:	Carbon Dioxide Acceptor
DEVELOPING COMPANY:	Consolidation Coal Company

Type:	Fluidized Bed
Plant Capacity: Tons Coal/Day	40 (Pilot)
Extent of Application:	Several pilot plants built, tested & shut down.
Operating Temperature:	1550°F
Pressure (psig)	150
Feed:	Air
Percent Composition in Volume %:	
CO	25.5
CO_2	9.1
H_2	58.8
CH_4	13.7
N_2	2.9
H_2S	0.0
Comments:	Process gas composition in mole percent.

PROCESS NAME:	COED/COGAS
DEVELOPING COMPANY:	FMC Corporation

Type:	Fluidized Bed
Plant Capacity: Tons Coal/Day	36 (Pilot)
Extent of Application:	Pilot Plant Research
Operating Temperature:	600-1600°F (4 stages)
Pressure (psig):	22
Comments:	This process actually involves two separate steps. Char Oil Energy Development (COED) refers to a four stage pyrolysis process producing an oil, gas & char product. COGAS refers to the process applied to the gasification of the char.
Feed:	O_2
Comments:	No gas composition data available.

PROCESS NAME:	Hydrane
DEVELOPING COMPANY:	U. S. Bureau of Mines Pittsburgh Energy Research Center Bruceton, Pennsylvania

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Type:	Fluidized Bed
Plant Capacity: Tons Coal/Day	
Extent of Application:	Has only been pursued on a laboratory scale.
Operating Temperature:	
Pressure:	1000 (psig)
Comments:	Has been directed primarily toward methane production.
Feed:	O_2
Percent Composition In Volume %:	
CO	0.5 - 6.3
CO_2	0.4 - 5.9
H_2	18.1 - 27.9
CH_4	57.5 - 79.0
N_2	1.4 - 2.4
H_2S	0.1 - 0.4
Comments:	Very little data has been released.

PROCESS NAME:	**HYGAS**
DEVELOPING COMPANY:	**Instit. of Gas Technology Chicago, Illinois**

Type:	**Fluidized Bed**
Plant Capacity: Tons Coal/Day	**75 (Pilot)**
Extent of Application:	**Pilot Plant Research in 1975-76**
Operating Temperature:	2000^oF
Pressure:	1000 psig
Comments:	Has only been directed toward methane production.
Feed:	O_2
Comments:	No gas composition data available.

PROCESS NAME:	Synthane
DEVELOPING COMPANY	U. S. Bureau of Mines Pittsburgh Energy Research Center Bruceton, Pennsylvania

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Type:	Fluidized Bed
Plant Capacity: Tons Coal/Day	72 (Pilot)
Extent of Applications:	Pilot plant testing began in 1976.
Operating Temperature:	1800^{o}F
Pressure:	1000 psig
Feed:	O_2
Percent Composition in Volume %:	
CO	6.0
CO_2	51.5
H_2	31.0
CH_4	10.0
N_2	0.3
H_2S	0.3
Other	0.9 C_2H_6
Comments:	CO_2 includes 21,560 SCFH of transport, petrocarb, and purge CO_2. Data shows Run #1-T.

PROCESS NAME	TRI-GAS
DEVELOPING COMPANY:	Bituminous Coal Research Monroeville, Pennsylvania
Type:	Fluidized Bed
Plant Capacity: Tons Coal/Day	1.2 (Laboratory scale)
Extent of Application:	A process development unit located in Monroeville, Pennsylvania; conducting further studies.
Operating Temperature:	1000 ^{o}F
Pressure:	
Feed:	Air
Comments:	No gas composition data available.

PROCESS NAME:	U-GAS
DEVELOPING COMPANY:	Institute of Gas Technology

Type:	Fluidized Bed
Plant Capacity: Tons Coal/Day	18 (Pilot)
Extent of Application:	Larger plant now under consideration.
Operating Temperature:	1900°F
Pressure:	350 psig
Comments:	Recent contract awarded to design plant with capacity for 2,800 tons coal per day, producing 175 MMSCFD (Medium BTU Gas).
Feed:	Air
Comments:	No gas composition data available.

PROCESS:	Union Carbide Hydrocarbonation Process (COALCON)
DEVELOPING COMPANY:	COALCON Company, Inc.

Type:	Fluidized Bed
Plant Capacity:	2600 (intended, no pilot plant data available).
Extent of Application:	A large scale plant has been designed, but in 1977 COALCON was disbanded.
Operating Temperature:	1040°F
Pressure:	544 psig
Comments:	A large scale plant had been designed, but in 1977 COALCON was disbanded. No plant is scheduled.
Feed:	Not specified
Comments:	No gas composition data available.

PROCESS:	Westinghouse Pressurized Fluid-Bed
DEVELOPING COMPANY:	Westinghouse Electric Company

Type:	Fluidized Bed
Plant Capacity: Tons Coal/Day	15 (Pilot)
Extent of Application:	Scale-up from pilot plant is under study.
Operating Temperature:	$2000^{\circ}F$
Pressure:	176 psig
Feed:	Air
Comments:	No gas composition data available

PROCESS:	Winkler
DEVELOPING COMPANY:	Davy Powergas, Inc. Lakeland, Florida

Type:	Fluidized Bed
Plant Capacity:	Tons Coal/Day
Extent of Application:	16 plants built over the past 50 years - the largest with capacity 1.1 million cubic feet.
Operating Temperature:	$1800^{o}F$
Pressure:	44 psig
Comments:	Most of the plants produce low BTU gas.
Feed:	Air/O_2

Percent Composition in Volume %:

	Air	O_2
CO	22.01	34.70
CO_2	7.12	19.40
H_2	13.93	41.74
CH_4	0.82	3.09
N_2	0.11	0.12
Other	0.02 COS	0.02 COS

Comments: This data shows raw gas, mol. %.

PROCESS NAME:	BI-GAS
DEVELOPING COMPANY	Bituminous Coal Research, Inc.

Type:	Entrained Flow
Plant Capacity: Tons Coal/Day	120 (Pilot)
Extent of Application:	Pilot Plant Research underway
Operating Temperature:	3000°F
Pressure:	1470 psig
Comments:	Pilot plant produced 2 million SCF high BTU gas. Full scale evaluation scheduled for mid-1980's.

Percent Composition in Volume#:

	Gasifier Product	Acid Gas Removal Plant	Final Pipeline Gas
CO	29.3	19.3	0.5
CO_2	21.5	0.20	0.1
H_2	18.8	59.6	4.6
CH_4	15.6	20.0	92.7
N_2	0.7	0.9	2.1
H_2S	0.8	0	0

Feed: O_2

PROCESS NAME:	Combustion Engineering Entrained Bed
DEVELOPING COMPANY	Combustion Engineering, Inc.
Type:	Entrained Flow
Plant Capacity Coal Tons/Day	Pilot Plant Research underway
Operating Temperature:	1700°F
Pressure:	-
Comments:	This process produces low BTU gas
Percent Composition in Volume %:	No Composition gas data available
Feed:	Not available

PROCESS NAME:	Koppers-Totzek
DEVELOPING COMPANY:	Friedrich Totzek Essen, Germany Koppers Company, Inc. Pittsburgh, Pennsylvania

Type:	Entrained Flow
Plant Capacity Tons/Day	1210 (see comments)
Extent of Application:	20 plants are presently in operation throughout the world.
Operating Temperature:	3300-3500°F
Operating Pressure:	Slightly above atmospheric
Comments:	One plant presently under consideration has capacity for 1210 tons coal/day producing 29.5 million SCF/day hydrogen.

Percent Composition in Volume %:

	Eastern Coal	After Desulfurization	After CO Shift & Methanation
CO	55.07	55.90	0.03
CO_2	7.04	6.01	61.25
H_2	36.82	37.39	0.99
CH_4	-	-	36.62
N_2	0.69	0.70	1.11
H_2S	0.34	-	-
Others	0.04 COS		

Feed:	O_2

PROCESS NAME: Texaco

DEVELOPING COMPANY: Texaco Corporation

Type: Entrained flow

Plant Capacity: Tons/Day: 100 (Pilot)

Extent of Application: This process presently applies in the production of ammonia. One such plant to be completed in 1980.

Operating Temperature: -

Operating Pressure: 1200 psig

Percent Composition in Volume %:

	Western Coal Reduced Slurry Product Gas	Eastern Coal Water Slurry Product Gas	Western Coal Water Slurry Product Gas	California Vacuum Slurry Product Gas
Feed:	Air	O_2	O_2	O_2
CO	23.49	41.55	50.71	61.39
CO_2	3.11	20.64	13.14	6.96
H_2	12.95	36.15	35.79	31.05
CH_4	0.02	0.40	0.09	0.14
N_2	60.29	0.38	0.24	0.06
H_2S	0.13	0.80	0.02	0.39
Other	0.01 COS	0.05 COS	0.01 COS	0.01 COS

PROCESS NAME:	Foster-Wheeler/Stoic Process
DEVELOPING COMPANY:	Foster Wheeler Energy Corporation

Type:	Fixed Bed
Plant Capacity: Tons/Day	
Extent of Application:	30 installations worldwide
Operating Temperature:	1800°F
Operating Pressure:	
Comments:	When coal is heated to above 750°F the primary gases produced are ethane, methane, and propane. Above 900°F gases rich in hydrogen are produced.
Feed:	Air
Percent Composition in Volume %:	
CO	29.0 - 30.0
CO_2	3.0 - 4.0
H_2	14.0 - 16.0
CH_4	2.6 - 3.0
N_2	47.6 - 51.4
Comments:	Hot raw gas excluding light oil and tar oil.

PROCESS NAME: Lurgi

DEVELOPING COMPANY: American Lurgi Corporation
Hasbrouck Heights,
New Jersey

Type: Fixed Bed

Plant Capacity: Tons/Day 1050

Extent of Application: 19 commercial plants worldwide (none in USA).

Operating Temperature: 1140-1400^{o}F

Operating Pressure: 350-450 psig

Comments: This has been termed "the only process for which the technology has been sufficiently developed and demonstrated to be considered available for large scale production of SMG in the US.

Feed: Air

Percent Composition in Volume %:

	Rosebud Coal Flare Gas	Pittsburgh #8 Coal Flare Gas
CO	15.1	16.9
CO_2	30.4	31.5
H2	41.1	39.4
CH_4	11.2	9.0
H_2S	0.5	0.8

PROCESS NAME:	Slagging Fixed Bed
DEVELOPING COMPANY:	Grand Forks Energy Research Center

Type:	Fixed Bed
Plant Capacity: Tons/Day	24 (Pilot)
Extent of Application:	Pilot Plant Research by the U. S. Government
Operating Temperature:	2800^{o}F
Operating Pressure:	400 (psig)
Comments:	This is actually a modification upon the Lurgi Process. Lurgi has also developed a slagging gasifier.
Feed:	O_2
Percent Composition in Volume %:	
CO	57.5
CO_2	7.4
H_2	29.1
CH_4	4.9
N_2	-
Other	0.2 C_2H_6
Comments:	Data from Table 176 Synthetic Fuels Handbook, Page 226.

PROCESS NAME:	Wellman-Galusha
DEVELOPING COMPANY:	McDowell-Wellman Engineering Company Cleveland, Ohio

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Type:	Fixed Bed
Plant Capacity: Tons/Day	200
Extent of Application:	Over 150 gasifiers world-wide over the past 35 years. Currently six operating in the USA.
Operating Temperature:	2400^{o}F
Operating Pressure:	psig
Comments:	When air blown, low BTU gas produced; when oxygen blown, synthesis gas produced.
Feed:	Air/O_2

Percent Composition in Volume %:

	Air	O_2
CO	24.9	47.05
CO_2	6.2	13.90
H_2	18.7	36.25
CH_4	0.60	0.65
N_2	49.3	2.05
H_2S	0.3	0.10
Other	0.3	0.10

Comments: This data for single stage gasifier.

PROCESS NAME: Woodall-Duckham

DEVELOPING COMPANY: Gas Integrale
Milan, Italy

Type: Fixed Bed

Plant Capacity: Tons/Day 80-100

Extent of Application: Over 115 gasifiers operating worldwide over the past 30 years.

Operating Temperature: 2200°F

Operating Pressure psig

Percent Composition in Volume %:

	Air	O_2
CO	28.5	37.5
CO_2	8.0	18.0
H_2	52.2	38.4
CH_4	0.5	3.5
N_2	4.2	2.2
Other	0.6	0.4

Comments: Product gas composition

PROCESS NAME: Woodall-Duckham

DEVELOPING COMPANY: Gas Integrale
Milan, Italy

Type: Fixed Bed

Plant Capacity: Tons/Day 80-100

Extent of Application: Over 115 gasifiers operating worldwide over the past 30 years.

Operating Temperature: 2200°F

Operating Pressure psig

Percent Composition in Volume %:

	Air	O_2
CO	28.5	37.5
CO_2	8.0	18.0
H_2	52.2	38.4
CH_4	0.5	3.5
N_2	4.2	2.2
Other	0.6	0.4

Comments: Product gas composition

PROCESS NAME: ATGAS

DEVELOPING COMPANY: Applied Technology Corporation

Type: Molten Iron Bath

Plant Capacity:
Tons Coal/Day

Extent of Application: Atgas Research since 1967

Operating Temperature: 2600°F

Pressure:

Comments: Exiting gas is comprised of carbon monoxide, hydrogen and some methane.

Feed: O_2

Percent Composition in Volume %:

Gasifier Offgas		After Shift Conversion & Meth.		Synthetic Natural Gas	
CO	65	CO	25	CO	0.1
CO_2	-	CO_2	1.0	CO_2	-
H_2	35	H_2	74	H_2	4.0
CH_4	-	CH_4	-	CH_4	93
N_2	-	N_2	-	N_2	-
H_2S	-	H_2S	-	H_2S	-
Other	-	Other	-	Other	2.9 inerts

PROCESS NAME:	Atomics International Molten Salt
DEVELOPING COMPANY:	Atomics International

Type:	Molten Salt Bath
Plant Capacity: Tons Coal/Day	3.0
Extent of Application:	Research level development only.
Operating Temperature:	1800°F
Pressure:	294 psig
Feed:	Air
Percent Composition in Volume %:	
CO	29.7
CO_2	3.08
H_2	13.2
CH_4	1.50
N_2	48.0
H_2S	-
Other	1.4 O_2
Comments:	This data is based on cooled product gas.

APPENDIX C

GLOSSARY OF ABBREVIATIONS AND TERMS

APPENDIX C: Glossary of Abbreviations and Terms

Glossary of Abbreviations

ABBREVIATION	MEANING
AC-FT	Acre-Feet
BFW	Boiler Feed Water
CU-FT	Cubic Feet
FOM	Fixed Operating and Maintenance
GPD	Gallon Per Day
HHV	Higher Heating Value
H.P.	High Pressure
hp	Horsepower
H.T.	High Temperature
HTS	High Temperature Shift
Htz	Hertz
I.C.	Inside Diameter
K-GAL	Thousand (10^3) Gallon
K.O.	Knock-Out (As in knock-out pot)
KW	Kilowatt
KWH	Kilowatt-Hour
L-Ton	Long Ton = 2,240 Pounds
Lb	Pound
LHV	Lower Heating Value
L.P.	Low Pressure
L.T.	Low Temperature
LTS	Low Temperature Shift
MBTU	Thousand (10^3) British Thermal Units
Mil	.1 cent = $.001
MMBTU	Million (10^6) British Thermal Units
MMGAL	Million (10^6) Gallon
MSCF	Thousand (10^3) Standard Cubic Feet
MW	Megawatt = 10^6 Watt

MWH	Megawatt Hour = 10^6 Watt-Hours
NT	Net Tons
ppm	Parts Per Million
ppmv	Parts Per Million By Volume
psia	Pounds Per Square Inch Absolute
psig	Pounds Per Square Inch Guage
scf	Standard Cubic Feet
S.H.	Sensible Heat
Tn	Ton (2,000 Lbs.)
TPD	Ton Per Day
TPI	Total Plant Investment
VOM	Variable Operating & Maintenance
W.H.B.	Waste Heat Boiler
Yr	Year

Glossary of Terms

Absorption	The taking up of a matter in bulk by other matter, as in dissolving of a gas by a liquid.
Adiabatic	Referring to any change in which there is no gain or loss of heat.
Adsorption	The surface retention of solid, liquid, or gas molecules, atoms, or ions by solid or liquid.
Carbonaceous	Relating to or composed of carbon
Catalytic	The ratio of the space velocity of a catalyst being tested to the space velocity required for a standard catalyst to give the same conversion as the catalyst under test.
Compressor	A machine used for increasing the pressure of a gas or vapor.
Condensate	A liquid obtained by condensation of a gas.
Convection	Diffusion in which the fluid as a whole is moving in the direction of diffusion. Transmission of energy or mass by a medium involving movement of the medium itself.
Deaerator	A device in which oxygen and carbon dioxide are removed from boiler water.
Decantation	A method for mechanical dewatering of a wet solid by pouring off the liquid without disturbing underlying sediment or precipitate.
Disintegrator	An apparatus used for pulverizing or grinding substances. Usually consists of two steel cages which rotate in opposite directions. i.e. a cage mill.

Electrostatic Precipitator	A device which removes dust or other finely divided particles from a gas by charging the particle inductively with an electric field, then attracting them to a highly charged collector plate.
Endothermic	Indicating the intake of receiving of heat.
Entrain	To draw in and transport (as solid particles or gas) by the flow of a fluid.
Exothermic	Indicating liberation of heat.
Incandescent	Emitting of visible radiation by a hot body.
Liquid Effluent	The liquid waste of sewer and industrial processing.
Methanation	One of several chemical reactions or processes by which methane is produced; i.e.: $CO + 3H_2 \rightarrow CH_4 + H_2O$; $CO_2 + 4H_2 \rightarrow CH_4 + 2H_2O$
Pneumatic	Pertaining tc or operated by air or other gas.
Quench Tank	A liquid medium into which a material is plunged for heat-treatment purposes.
Reagent	A substance, chemical or solution, used in the laboratory to detect, measure, or otherwise examine other substances, chemicals or solutions.
Refractory	A material (usually brick-like in nature) of high melting point.
Slag	A nonmetallic product resulting from the interaction of flux and impurities in the smelting and refining of metals.

Standard Cubic Feet	Cubic feet per hour of gas flow at specified standard conditions of temperature and pressure ($60^{o}F$, 1 atmosphere).
Volatile	Easily vaporized.

APPENDIX D

ENERGY CONVERSION FACTORS

HYDROGEN CONVERSION FACTORS
(BASED ON LOWER HEATING VALUES)

Equals / One	Million BTU	Pounds of Hydrogen (LHV)	Thousand SCF of Hydrogen (LHV)	Thousand SCF of Hydrogen (LHV)
Million BTU	1	19.382	3.704	2.778
Pound of H_2 (LHV)	0.0516	1	0.1911	0.1433
Barrel of Crude Oil (LHV)	5.800	112.42	21.480	16.110
Gallon of Gasoline (LHV)	0.1100	2.132	0.4074	0.3055
Methanol (LHV)	0.0573	1.1106	0.2122	0.1592
Diesel Fuel Distillate (LHV)	0.1387	2.6883	0.5137	0.3853
Gallon of Jet Fuel (LHV)	0.1350	2.6166	0.5000	0.3750
Thousand SCF:				
Methane (LHV)	0.8960	17.366	3.3183	2.489
Propane (LHV)	2.2826	44.241	8.4536	6.3402
Butane (LHV)	2.969	57.545	10.996	8.2468
Low BTU Gas (130 BTU/SCF)	0.1300	2.5197	0.4815	0.3611
Med. BTU Gas (450 BTU/SCF)	0.4500	8.7219	1.6666	1.2499
High BTU Gas (950 BTU/SCF)	0.9500	18.413	3.5183	2.6388
Ton of Coal:				
Anthricite	25.760	499.28	95.403	71.552
Bituminous	26.100	505.87	96.662	72.496
Sub-Bituminous	19.210	372.33	71.145	53.358
Lignite	14.000	271.35	51.849	38.887
Electricity:				
Mega-Watt-Hr	3.412	66.131	12.636	9.4773
Giga Joules (10^9)	0.9478	18.370	3.5102	2.6326

HYDROGEN CONVERSION FACTORS
(BASED ON HIGHER HEATING VALUES)

Equals / One	Million BTU	Pounds of Hydrogen (HHV)	Thousand SCF of Hydrogen (HHV)	Thousand SCF of Hydrogen (HHV)
Million BTU	1	16.385	3.131	2.348
Pound of H_2 (HHV)	0.0610	1	0.1911	0.1432
Barrel of Crude Oil (HHV)	6.006	98.408	18.804	14.103
Gallon of Gasoline (HHV)	0.1187	1.9449	0.3716	0.2787
Methanol (HHV)	0.0652	1.068	0.2041	0.1531
Thousand SCF:				
Methane (HHV)	0.9947	16.298	3.1144	2.3358
Propane (HHV)	2.480	40.635	7.7649	5.8237
Butane (HHV)	3.216	52.694	10.069	7.5520
Low BTU Gas (130 BTU/SCF)	0.1300	2.1301	0.4070	0.3053
Med. BTU Gas (450 BTU/SCF)	0.4500	7.3733	1.4089	1.0567
High BTU Gas (950 BTU/SCF)	0.9500	15.566	2.9743	2.2307
Ton of Coal:				
Anthricite	25.760	422.08	80.655	60.491
Bituminous	26.100	427.65	81.719	61.289
Sub-Bituminous	19.210	314.76	60.144	45.108
Lignite	14.000	299.39	43.834	32.875
Electricity:				
Mega-Watt-Hr	3.412	55.906	10.683	8.0122
Giga Joules (10^9)	0.9478	15.530	2.9676	2.2257