REVIEW OF COAL GASIFICATION PROCESSES

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Bachelor of Science

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Varanasi, India

1971

Submitted to the Faculty of the Graduate College
of the Oklahoma State University
in partial fulfillment of the requirements
for the Degree of
Master of Science
July, 1972

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PREFACE

Projections of natural gas requirements for the next 25 years show that the present trends in gas supply industry probably won't be able to meet the growing gas demands. Many alternative measures are proposed to bridge the gap of supply and demand for gas. Considerable research has been done on one of the alternatives, coal gasification. This study presents some of the advanced coal gasification processes now under development along with the respective economics.

I am indebted to Dr. Billy Crynes for providing advice and guidance while serving as my adviser during this study. Appreciation is expressed to Dr. Robert N. Maddox for his valuable comments about this study. I wish to thank Mr. Ashok R. Sapre, graduate student in the School of Mechanical and Aerospace Engineering, for various informatory discussions on coal gasification.

The financial support from the School of Chemical Engineering of this Institution is gratefully acknowledged. I am grateful to Lynn Danvers for the proofreading and typing assistance.

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CHAPTER I

INTRODUCTION

Energy is undoubtedly the backbone of the industrial and, consequently, economic growth of any nation. The nineteenth century gave new dimensions to energy requirements by the industrial revolution. The twentieth century brought new technology of producing energy namely hydroelectric and nuclear power. And it can probably be said that the twenty-first century will always try to balance its energy requirements and production. There are enormous amounts of energy on earth in some form or another, but the fact of the matter is that it has to be recovered from its remote sources and converted into some convenient form before it can be used.

Any process, operation or life that one can think of requires energy for its own survival. The long life of earth has been a continuous operation of converting one form of fuel to another. The fossile fuels are available in the form of coal, oil and gas. Until recently these were the prime sources of energy in the U. S. and the entire world. Hydroelectric power has been on the scene for the last fifty years but could not capture a significant share of the energy supply. The other form of energy, nuclear, appears to have a bright future. Projections indicate that by the turn of the century, nuclear power will supply about one-fourth of the energy needs of the U. S. (1).

The United States is one of the most industrialized nations in the world. The industries are expanding every day. The standard of living has changed significantly in the last quarter century. Changing life style and speedy industrial growth have resulted in higher energy consumption and progressively increasing demands for the future.

The average annual growth in energy consumption was about six percent over the period 1936-1969 (2). If the energy consumption keeps on increasing at this enormous rate, then it might pose, apart from the supply problem, certain environmental probelms such as material and thermal pollution. Thus the time will come when total energy consumption must be controlled or possibly even reduced. Some project the date for control as early as 1985, whereas, others go far beyond 2000. Many sources have come up with several projections. These are summarized (2), pages 12-13, and the average annual growth rate is projected to be 3.2%.

The everyday use of energy in the U. S. has reached an all time high value of 68.8×10^{15} Btu in 1971 according to a recent release of the Department of Interior, Bureau of Mines (3). Fossil fuels provide the major portion of the energy needed. A large amount of energy is lost in converting the fossil fuels to what is more commonly used, electricity. Table I shows the distribution of the U. S. energy consumption in 1970 (2), page 9. The figures represent the percent of the certain type fuel consumed by corresponding category.

Recently, those interested in energy supply have begun to express their concern over the energy demand of the ever expanding U. S. economy. If the present trend in energy demand and production continues, soon serious cuts in supply may be necessary. In fact, the cuts have already started in some parts of the country.

TABLE I

DISTRIBUTION (% WISE) OF U. S. ENERGY CONSUMPTION, 1970

Category	Coal	Gas	Oil	Hydro electric	Nuclear	Total
Household & commercial	2.9	32.6	21.4	-	-	20.5
Industrial	40.3	46.6	17.1	-	-	30.7
Transportation	0.1	3.0	53.2	-	-	23.9
Electricity generation by utilities	56.7	17.8	7.7	100	100	24.7
	20.0	32.8	43.0	3.9	0.3	= 100.0

By over a factor of 100, the U. S.'s most abundant fossil fuel is coal, yet only 20.0% of the energy consumed was from this source. (Preliminary estimates by Dept. of the Interior)

All of the above can be summarized to say that under the present trend there will probably be an energy shortage in the foreseeable future. Something has to be done to avert it. The shortage will become more apparent and more severe with the passage of time. Out of all types of fuels, greater concern is put on natural gas.

Annual production of natural gas has increased more than fourfold in the last 25 years, from 4.9×10^{12} cu. ft. in 1946 to 22.0×10^{12} cu. ft. in 1970. Natural gas contributed more than 32% of the energy used in 1970. Most (about 80%) of it is used directly as a heating medium and the rest (about 20%) goes to produce electricity. The role of natural gas in the energy picture is very clearly defined by its contribution. A little less than one-third of the burden of the U. S. economy rests on gas and we just can't afford to neglect a source of convenient and clean fuel.

The shortage in gas has become apparent by a few recent news items. One of the largest gas supplying companies, Transcontinental Gas Pipeline Corporation, notified its customers of possible reductions of 12% in gas supply starting September 7, 1971. The cutback was to last about two months (4). Transco delivers gas from the Texas-Louisiana coast to the northeastern states of New York, New Jersey, and large cities such as Philadelphia. In the Great Lakes area, the gas suppliers asked their resale customers to curtail their interruptible (amount of gas that is required intermittently and not regularly) gas purchases voluntarily (5). In the Rocky Mountain area, gas sales to interruptible customers was to be curtailed more frequently. American Gas Association (A. G. A.) statistics show that cuts in gas supply in 1970 were about 2.9% (6). All these reductions were to allow for the build-up of a large amount of gas for use in the coming winter.

The present shortage of natural gas is a possible outcome of more than a decade long controversy between the Federal Power Commission (FPC) and principal gas producers over well-head gas price (price of gas at the site of the gas well). The FPC regulation in 1954 brought the field price of gas under direct control of the Government. Since then exploration activities, except for a couple of exceptions, have been reduced significantly. The reduction is best reflected by figures that show drilling efforts made during one full year. Drilling efforts were maximum in 1956 at 16,207 exploratory wells for oil and gas. Whereas, drilling efforts fell to a mere 6,617 wells in 1968 and 7,105 wells in 1965 (5). The report further indicates that if present trends in gas reserve additions and market requirements continue, the gas industry may fall to a ten percent deficiency in meeting gas needs as early as 1974.

There has been a significant increase in the cost of living. Construction costs and hourly earnings of petroleum workers have increased by more than 25% in the last ten years. Comparatively, however, there wasn't a noticeable increase in the gas price. The price of electricity is about six times that of gas for the same amount of energy (7). The low price of gas has attracted many customers and resulted in a sharp increase in gas demand and production.

Certain new market trends that consume natural gas as a source of energy are coming up. The rapid growth of central air-conditioning and onsite power generation from gas are the best examples. Air pollution legislation has forced many companies to switch to gas as a source of premium fuel. The Environmental Protection Agency (EPA) expects an increase of 15% in gas use in order to control oxides of sulfur emitted to the atmosphere.

Dr. Evans, director of the Potential Gas Agency at Colorado School of Mines (8), describes the gas shortage as "manmade," and Dr. Linden, Director of the Institute of Gas Technology (IGT), blames the shortage on an "artificial market" (9). In a recent presentation (10), Guy W. Nichols, President and Chief Executive of New England Electric System, rests the blame largely on federal pricing policies. He further added, "If prices are not sufficient to attract risk capital into new ventures, the capital goes elsewhere and we end up with a shortage." FPC control has made gas, comparatively, very cheap. This essentially has led to two things (i) a sharp increase in demand of gas and (ii) a general loss of incentive for exploration activities. Together these have resulted in the shortage of gas supply. The shortage does not necessarily mean that there is no gas. There is gas, but exploration is necessary to locate the remote sources and bring it to the market. Ever since natural gas captured the market from the low Btu gas (heating value less than 500 Btu/scf), the demand has steadily increased. Should the price of gas be more than what it is today, many consumers are likely to disappear, and at the same time, this would boost the much needed incentive for the exploration activities. In doing so, the natural gas may not enjoy its 32% of the total energy use, but it can definitely be in much better position as a constant source of premium fuel.

Table II (11) provides the facts and figures of the natural gas supply situation during the years after World War II. The ratio of proven reserves to yearly net production (R/P), shown in column 7, has steadily declined from a figure as high as 32.5 in 1946 to a mere 11.8 in 1970 with just two exceptions. Also the ratio of yearly findings to production (F/P), shown in column 6, has gone down from the high value of 3.6 in 1946 to an alarming value of 0.5 in 1970. There is a sudden drop in the F/P ratio in 1954, the year the FPC regulation came into effect. The maximum findings for any single year is less than 25 trillion cubic feet. The point that requires the focus of attention is that the rate of production of natural gas was more than its rate of findings during the last three years in a row. The F/P ratio improved slightly in 1970 but it still remained below a value of one.

The projections about the future U. S. needs of natural gas have been made by many authoritative sources. These projections are based on the assumption that enough gas will be available at present price

TABLE II

UNITED STATES NATURAL GAS SUPPLY,* ACTUAL 1946-70

Year	Annual net production[1]	Cumulative net production	Annual net reserve additions[a]	Year end proven reserves	F/P ratio (4)/(2)	R/P ratio (5)/(2)
(1)	(2)	(3)	(4)	(5)	(6)	(7)
1946	4.9	88.8	17.6	159.7	3.6	32.5
1947	5.6	94.4	10.9	165.0	2.0	29.5
1948	6.0	100.4	13.9	172.9	2.3	28.9
1949	6.2	106.6	12.7	179.4	2.0	28.9
1950	6.9	113.5	12.0	184.5	1.8	26.9
1951	7.9	121.4	16.1	192.8	2.0	24.3
1952	8.6	130.0	14.5	198.6	1.7	23.1
1953	9.2	139.2	20.9	210.3	2.3	22.9
1954	9.4	148.6	9.6	210.6	1.0	22.5
1955	10.1	158.7	22.0	222.5	2.2	22.1
1956	10.9	169.6	24.8	236.5	2.3	21.8
1957	11.4	181.5	20.2	245.2	1.8	21.4
1958	11.4	192.4	19.0	252.8	1.7	22.1
1959	12.4	204.8	20.8	261.2	1.7	21.1
1960	13.0	217.8	14.1	262.3	1.1	20.1
1961	13.4	231.2	16.5	265.4	1.2	19.8
1962	13.6	244.8	18.9	270.6	1.4	19.9
1963	14.5	259.3	18.4	274.5	1.3	18.9
1964	15.3	274.6	20.3	279.4	1.3	18.2
1965	16.3	290.8	21.3	284.5	1.3	17.5
1966	17.5	308.3	19.4	286.4	1.1	16.4

TABLE II (Continued)

Year	Annual net production[1]	Cumulative net production	Annual net reserve additions[2]	Year end proven reserves	F/P ratio (4)/(2)	R/P ratio (5)/(2)
(1)	(2)	(3)	(4)	(5)	(6)	(7)
1967	18.4	326.7	21.3	289.3	1.2	15.7
1968	19.3	346.0	12.1	282.1	0.6	14.6
1969**	20.5	366.5	8.3	269.9	0.4	13.2
1970**	22.0	388.5	11.1	259.0	0.5	11.8

*Excluding Alaska. (All volumes in trillion cubic feet at 14.73 psia and 60° F)

Source: Based on AGA data.

[1] Net production is defined as the total volume of natural gas withdrawn from producing reservoirs in recycling, repressuring of oil reservoirs and conservation operation.

[2] Annual net reserve additions include all new gas reserves resulting from new field and new reservoir discoveries plus new reserves resulting from extensions and upward and downward revisions of reserves previously discovered.

**From "Studies of Coal Gasification" by Frank C. Schora, Jr., presented at The Synthetic Fuels from Coal Conference at Oklahoma State University, Stillwater, Oklahoma on May 3, 1971.

levels. The projected values of annual growth rate in demand of natural gas vary from 2.5% to somewhat less than five percent. At this point recall that the annual growth rate has in fact remained steady at about six percent during the years after World War II. The future annual growth rate will strongly depend upon the price of gas, which cannot likely stay at its present low levels.

The future requirements committee of the Department of the Interior in its fourth nationwide survey of the U. S. gas requirement reports consumers of gas in the U. S. will require 54.9 trillion cubic feet of gas in 1995, and an additional 3.2 trillion cubic feet will be required for field use (12). This means the usage in 1995 will be about 2.5 times the gas usage in 1970, equivalent to an annual average growth rate of 3.8% (19-year doubling). This corresponds to an annual average production of 36.5 trillion cubic feet or a total requirement of 910 trillion cubic feet during the entire 25-year period. Also a minimum of ten years reserve to production ratio is required at the end of 1995 for a smooth supply of gas for the years after that. This increases the total gas requirements from 910 trillion cubic feet to 1459 trillion cubic feet for the 25-year period.

The 1970 year-end proven reserves were 259 trillion cubic feet (excluding Alaska). This is deducted from the value of 1459 trillion cubic feet and we are left with the balance of requirements at 1200 trillion cubic feet. This much natural gas must be obtained somehow during the span of 25 years in order to meet the U. S. needs. The various alternatives open to us are discussed in the next chapter. No matter which alternative or combination of alternatives are chosen, we have to bring about 48 trillion cubic feet of gas to our markets annually. This is about 94% more than the maximum amount of gas that has been added to our reserves in any single year. It is implicit that a lot has to be done before this goal is reached.

CHAPTER II

WHY COAL GASIFICATION?

Much has been written and discussed about a possible shortage in gas supply in the near future; much more is yet to come. Everybody wants to avert the projected crisis. Many have come forward with alternate measures - some known, some unknown. Work has already been started for practically all the alternatives. This chapter reviews possibly all the alternatives with regard to their supply situation, economics, industrial and political restrictions, if any.

As mentioned in the preceeding chapter, we need to bring about 48 trillion cubic feet of gas per year to our markets. It should be recalled that only 11.1 trillion cubic feet of gas was brought to our markets in 1970. The requirements are more than four times the net additions. This means that the regulatory authorities must give a realistic approach to the field price of gas which will then provide the much needed incentive to accelerate the exploration activities in the U. S. The crisis can be averted with the combined efforts of regulatory authorities and the gas producers.

We have six alternatives at hand:

(i) To explore for more gas in the U. S.
(ii) Import gas from Canada
(iii) Import gas as liquefied natural gas (LNG)
(iv) Coal gasification

(v) Deep drilling

(vi) To get more energy out of our gas

(i) The first of the alternatives is to explore for more gas in the U. S. The proven reserves (including Alaska) were at 290 trillion cubic feet at the end of 1970. The latest report of Potential Gas Committee at Colorado School of Mines reveals that there is 1,178 trillion cubic feet of gas yet to be discovered in the U. S., one-third of which is in Alaska (13). The report also indicated that most of the gas is deeper than 15,000 feet on shore and off shore bordering the U. S. and Alaska, compared to the average well depth of about 5,000 feet today. Exploratory efforts must be made to bring this gas to the markets. At the present rate of growth in demand, this much gas could meet the U. S. requirements for about another 40 years. Due to the depth of the gas, the exploration has become more expensive and at the same time requires more efforts than in the past. These high expenses and efforts cannot stand within the present controlled gas price but can certainly stand in competition with other sources of energy and other alternative measures. There have been some delays in selling new leases by the federal government. This and other problems have hampered the offshore drilling substantially. Past Interior Secretary, Walter J. Hickel, once noted that less than two percent of the U. S. 800 square miles of continental shelf has been adequately tested and only 43 trillion cubic feet of gas has been added to the reserves over the past 20 years (14). We need to overcome these obstacles to achieve our goal of getting the convenient and clean quality fuel for the years to come.

(ii) While every effort is and will be made to explore the domestic gas reserves, gas also needs to be imported to supplement the demand. Until recently gas imports from Canada were about 1.8 billion cubic feet per day (Bcfd). Applications for additional import quota were made by many companies but were disapproved by the Canadian authorities. Thus the total imports of gas from Canada remain at 1.8 Bcfd or slightly less than two-third Tncf per year. The price of this gas is about 32-40 cents/Mcf (15,16), relative to the well-head price of 18-26 cents/Mcf. There are plans to lay pipeline to bring this huge quantity of gas to the U. S. The pipeline cost may go up to one billion dollars. The pipeline can smooth the supply of gas and is cheaper on a long-term basis. Gas from Alaska can also be brought to the lower 48 states by pipeline through Canada. It is cheaper to transport gas to the interior of the U. S. by pipeline than as LNG.

(iii) One of the alternatives open to us is to import gas in the form of liquid, generally referred to as LNG. LNG occupies only 1/600th the volume of natural gas. And this has led LNG to become an international commodity. It can be transported across the oceans in large cryogenic tankers and can be stored for peak shaving period (the period of the year when the gas demand increases sharply). Contracts have already been signed to import LNG from Algeria and Venezuela, and plans are underway to bring it from other parts of the world. The delivered cost of LNG depends largely upon the mode of transportation and the distance of travel within the U. S. This is best reflected in the following two tables (17).

TABLE III

ESTIMATED DELIVERED COST OF LNG BY TRUCK

One way distance in miles	LNG c.i.f.* at p.o.d.**	Receiving facilities	Transportation	Total cost
	(Cost in cents per thousand cubic feet)			
100	60	5	15	80
200	60	5	30	95
300	60	5	45	110
400	60	5	60	125

*Cost including freight

**Port of delivery

TABLE IV

ESTIMATED DELIVERED COST OF LNG BY RAIL

One way distance in miles	LNG c.i.f.* at p.o.d.**	Receiving facilities	Transportation	Total cost
	(Cost in cents per thousand cubic feet)			
400	60	5	12-8	83-77
900	60	5	15-9	80-74
2500	60	5	25-11	90-76

*Cost including freight

**Port of delivery

It can be seen that gas prices via LNG are very high compared to current gas prices even if it is transported by rail.

One of the chief factors associated with LNG imports is that it enters the U. S. through the ports and much of the industry in the U. S. is located near the coastal areas. This makes these sections dependent for their energy requirements on the countries that are politically unstable. The plants for liquefaction require huge investments in those countries as well as for tankers. The advantage of LNG is that it does not significantly pollute the environment or atmosphere of the U. S. The air pollution control regulations are likely to become more and more stringent and, unlike some other alternatives, those regulations would not affect the price of gas from LNG. Secondly, such imports keep the U. S. reserves, which would otherwise have been used, intact, thus saving the gas for future years.

(iv) Another alternative is to produce gas from coal and/or oil. Coal gasification is one of the oldest industries, and the gases which have been produced include water gas, producer gas, carburetted blue gas, town gas, and oil gas. The heat content of these gases is low and varies from 70 Btu/scf to 420 Btu/scf. These gases have become obsolete after the introduction of natural gas which has a heat content of more than 1000 Btu/scf. The present drive for coal gasification requires the manufacture of gas with heat content close to that of natural gas. The technology for producing 1000 Btu/scf gas is relatively new and under developmental stages. The U. S. has vast coal reserves, about 3.21 trillion tons, scattered throughout the country (18). At 50% recovery and 65% thermal efficiency in conversion to gas, that would amount to 23,000 trillion cubic feet of gas. Recall that metallurgical and power generation industries are the primary consumers of coal and about ten percent of the coal may be available for the gasification process.

That comes to about 2300 trillion cubic feet (Tncf) of gas. Also the U. S. has oil shale equivalent to four trillion barrels of oil. If gasified, this will contribute about 20,000 Tncf of gas. If only ten percent of it is recoverable then the amount of gas at our disposal is 2000 Tncf. Total the two - coal and oil shale can thus yield over 4300 Tncf of gas which at the present growth rate is sufficient for no less than 80 years. This and other indigenous methods could keep the U. S. self-sufficient for its gas needs. The research and development for coal gasification have been underway for more than a decade, and hopefully, the first commercial plant will go on stream by 1980.

The price of gas by coal gasification has been reported by most of the researchers and varies from about 43 cents per thousand cubic feet (Mcf) to about 90 cents/Mcf. In some cases the prices of gas reported earlier are escalated due to many reasons. This means that the price of gas by coal gasification may increase significantly by 1980. Meeting the emission standards is also a very serious consideration. With the air pollution control regulations becoming more and more stringent, the price of gas from this alternative may keep on increasing.

(v) New and advanced technology is required to find more gas by deep drilling. Some of the regions of the U. S. are not yet tested. For example, in West Virginia only 15% of its approximately 100,000 cubic miles of sediments have been tested. The atomic energy commission and the gas industry together are working on a nuclear detonation technique for finding new reserves of gas.

Advances are being made in offshore drilling also. In the past, it was not possible to drill at a depth of over 300 feet of water; whereas, now it is feasible to drill even beyond 1500 feet.

(vi) The last, but not the least, alternative is to get more energy out of gas. The days of wasteful use of natural gas are gone. Every effort must be made to get the most energy from gas. Heat recovery from the exhaust gases, lower heat losses and preheating are some of the methods to conserve gas. Today the trend is for clean energy fuel which means a demand for natural gas. Yet, about 35% of the energy is lost in using gas to generate electricity.

Now consider the economics and restrictions of some of the alternatives. Certainly gas from Canada is cheaper than LNG or that from coal gasification or Arctic gas. Its cost varies from 32 to 40 cents per Mcf. This is more than the present selling price of gas, which varies from 18 to 26 cents/Mcf. Secondly, the quantity of import depends upon the National Energy Board of Canada. Recently it has denied approval for the additional exports of one Bcfd of gas. This means that the U. S. will get only 1.8 Bcfd of gas or 657 Bcf per year from Canada under the present policy. This amount is inadequate for supplementing our growing demands. We must consider some other alternatives.

One-third of the 1,178 Tncf of the U. S. potential gas reserve is in Alaska. There are two ways to bring the Alaskan and Arctic gas to the lower 48 states. One is to bring it in the form of LNG. This requires huge investments in Alaska for liquefaction plants and also for the supertankers for transportation. Liquefaction, transportation, and regasification charges should be taken into account before any commodity charges are considered. Again the transportation charges increase as the market gets farther from the port of delivery. Another choice is to bring gas through 3000 to 3500 miles of pipeline across Canada. At the rate of 1.7 cents/Mcf per 100 miles, the operational cost of transporting gas would be about 50 cents/Mcf (19). The transportation cost will be less for the northern states compared to the southern states. The investment for laying pipeline will be enormous. The final decision on either of the choices is subject to the approval of the Canadian Goverment to lay the pipeline. Another cost estimation in detail with individual costs is shown in Table V (20). The best part of this alternative is that the gas is indigenous, and, of course, clean.

TABLE V

COST ESTIMATION OF GAS DELIVERED TO U. S. FROM ALASKA AND CANADA

	West Coast			Midwest	
Various costs	GAS PHASE pipeline	LNG pipeline	LNG tanker	GAS PHASE pipeline	LNG pipeline
			$/Mcf		
Transmission cost	.54	.33	.24	.44	.27
Liquefaction cost	--	.20	.28	--	.20
Gas cost	.15	.15	.15	.15	.15
Total cost	.69	.68	.67	.59	.62

One of the other alternatives is LNG. Some contracts are already signed and many are underway pending approval from the FPC. The contracts signed by some of the companies brought LNG at very high cost in the winter of 1971. But the new and long term contracts are likely to bring gas at about 60 cents/Mcf at the port of entry. Other cost factors are given in Tables III and IV. The lowest price of all is 73 cents/Mcf which is subject to ratification depending upon the U. S. market situation and further negotiations.

As mentioned earlier, the most industrialized sections of the U. S. will then have to depend upon politically unstable countries. Hence, political trouble elsewhere can create a power crisis and subsequently lead to economic and social problems in the U. S. According to Barry Hunsaker, total investments to bring one Bcfd of gas will be about $1.469 billion out of which $628 million will be in Algeria (21). The price of gas as LNG is about three times the present gas price. Import means loss of trade as well as employment. The same investment in the U. S. could boost the exploratory efforts and could make the U. S. more self-reliant for its gas requirements. This was also reflected in his address to the annual meeting of the American Petroleum Institute (API) by Interior Secretary Rogers C. B. Morton when he emphasized the role of "domestic reliability" of energy supplies (8).

One of the main alternatives open to us that can bring domestic reliability is to produce gas from coal. The U. S. has enough coal reserves which, upon gasification, could provide gas for many years to come. Much research has been done for coal gasification. Many companies and institutes, under the sponsorship of the Interior's Office of Coal Research and/or American Gas Association and the Bureau of Mines, have come forward with different processes to produce gas from coal that can substitute for natural gas. The 20-year average gas price as claimed varies from 44.0 cents/MMBtu to as high as 90 cents/MMBtu depending upon the type of coal used and also on the process employed. The gas price claimed is certainly much higher than the present selling price of gas but can very well stand in competition with LNG. The coal reserves are widely scattered in the country and hence, coal gasification can supplement the gas supply practically in every region of the country. G. J. Tankersley, AGA President stated, "An engineering study has pinpointed over 150 domestic locations where coal, water, and labor resources would support commercial coal gasification projects." (22). Some believe that the number is well over 150 sites. This means that even though the coal gasification plants will be located near the coal mines, the gas will not have to be transported very far to reach the market. This reduces the ultimate gas price to the consumer. As the Institute of Gas Technology (IGT) people claim, "The success of the Hygas process will bring other important benefits to the nation - clean air, new jobs, and a contribution to our economy and security." It goes without saying that these claims are true not only for the Hygas process but for the coal gasification program as a whole and every effort and money put in this program will yield multiple benefits, direct and indirect, to the nation.

In the following chapter, detailed discussion is given to coal gasification techniques now under development in the United States.

CHAPTER III

COAL GASIFICATION PROCESSES

A few private companies, institutions, and the American Gas Association (AGA) started feasibility studies of manufacturing high Btu gas from coal as early as the 1950's. The federal government came on the scene in the early 1960's and has supported the research efforts, in part or in full, and set forth certain guidelines to ensure common goals for all the research programs.

The specifications of the quality of pipeline gas set forth by the Interior's Office of Coal Research (OCR) on June 4, 1965 are shown in Table VI (23).

TABLE VI

SPECIFICATIONS OF THE QUALITY OF PIPELINE GAS

Delivery pressure	1000 psig
Heating value	≥ 900 Btu/scf
CO content	≤ 0.1%
Sulfur content	≤ 10 gr./100 scf
CO_2 content	≤ 3.0%
Total inerts	≤ 5.0%
Water content	≤ 7 lb/MMscf

Also on June 4, 1965, OCR adopted the AGA accounting procedure to ensure common ground for estimating the price of gas produced by various processes (23).

TABLE VII

AGA ACCOUNTING PROCEDURE

(i)	20-year plant life
(ii)	Straight line depreciation
(iii)	7% gross return on rate base
(iv)	Financing - 65% debt, 35% equity
(v)	Interest rate 5%
(vi)	Federal income tax at 48%

Many prefer to deviate a bit from the accounting procedure shown in Table VII advocating many reasons. Since 1965 the interest rate has risen significantly. Many are not satisfied with the 7% gross return on rate. Compared to other industries the 7% rate of return is very low and they are afraid big establishments may not be attracted to venture in the coal gasification field.

The U. S. Government is definitely attracted to the idea of coal gasification and has given a boost to the research programs from time to time in the way of funds and other help. Coal gasification was enlisted as high priority by President Nixon in his budget message to the Congress in 1971 (24). Appropriations of $21 million were asked for the OCR in fiscal year 1972. Out of these $9,720,000 are for coal gasification research programs, FMC Corporation's COED process obtained $3,035,000. Others in the list are Consolidation Coal Company's pilot plant at Rapid City, S. D., with $3,420,000 and IGT's pilot plant at Chicago with $3.5 million. Hollis Dole, Assistant Secretary of the Interior, has assured government help pending Congressional approval (8). Recently, in November, 1971, Bituminous Coal Research, Incorporated was awarded $24,830,000 contract for construction and operation of a pilot plant converting coal into synthetic natural gas (25). The award signifies the government's effort to avert gas shortages and its confidence in coal gasification programs.

The basic idea in coal gasification is to manufacture high Btu gas from coal which can be substituted for the natural gas. The natural gas as received from the wells has a heating value of about 1100 Btu/scf. By gasifying coal, if we can produce gas which has heating value somewhere close to 1100 Btu/scf, our purpose is served. The chief constituent of natural gas is methane (CH_4, above 90%) and hence, to produce gas having more than 90% methane has become the guideline for practically all the research efforts.

Some implicit restrictions come in the picture from the clean air act. Control in emissions of oxides of sulfur, oxides of nitrogen, carbon monoxide, hydrocarbons, and particulates play a significant role in the design and plant outlay. In general the process elements for a typical gasification as presently concerned are listed in Table VIII.

The line-up of these elements does not change in practically all the processes known to date. Some of these may disappear and/or some additional may be introduced depending upon the method of gasification and the quality of coal treated.

TABLE VIII

TYPICAL GASIFICATION PROCESS ELEMENTS

(i)	Pretreatment of coal (for sizing, drying, etc.)
(ii)	Gasification
(iii)	Char removal
(iv)	Char treatment
(v)	Shift conversion (to balance CO-H_2 ratio for further reactions)
(vi)	Acid removal and sulfur recovery
(vii)	Methanation (convert CO and H_2 to CH_4)
(viii)	Drying ---- high Btu pipeline gas

The principal reactions of coal gasification can be summarized as follows:

Coal + Water → Methane + Carbon dioxide

This can not be achieved in one step and many side and intermediate reactions take place before the ultimate goal is reached. The more common intermediate reactions can be listed as follows:

Gasification:

		Reaction
Coal + $H_2 \rightarrow CH_4$ + C (Char)	exo.	(A)
C (Char) + $2H_2 \rightarrow CH_4$	exo.	(B)
C (Char) + $H_2O \rightarrow CO + H_2$	endo.	(C)
$CO + H_2O \rightarrow CO_2 + H_2$	exo.	(D)
Methanation:		
$CO + 3H_2 \rightarrow CH_4 + H_2O$	exo.	(E)
$CO_2 + 4H_2 \rightarrow CH_4 + 2H_2O$	exo.	(F)
$CO + H_2O \rightarrow CO_2 + H_2$	exo.	(G)

The letters at the right will henceforth be used to designate the corresponding reaction. The first four of these reactions take place primarily in the gasification and the last three take place on the surface of a catalyst during methanation. There are two possible approaches to gasification. Either to produce CO and H_2 according to reaction (C) and later react them to produce methane, reaction (E), in a methanator or to produce methane directly in the gasifier, reaction (A). The procedures employed in present research programs are a compromise of the two, and thus, the gas from the gasifier contains a large quantity of methane. The extent of production of methane in the gasifier depends largely upon gasifier conditions and mode of gasification. Reaction (B) is favored by high pressure but even then the conversion rate is low. Reaction (C) is favored by high temperature. The heat generated by reaction (B) is used to accelerate reaction (C). But the total heat generated by the reactions (A), (B), and (D) is far less than what is required for reaction (C). There are many ways by which heat can be supplied to the gasifier and that is where the basic difference lies between various processes. The amount of methane formation depends largely upon the efficiency of the heating system. More often, heat is supplied by combustion of coal to produce carbon dioxide. It can be accomplished by one of the ways shown below:

$C + O_2 \rightarrow CO_2$ exo. (requires O_2 plant)
$C + 2H_2O \rightarrow CO_2 + 2H_2$ exo. (steam reformer)
$C + O_2(\text{air}) \rightarrow CO_2$ exo. (N_2 introduced into system)

Production of CO_2 is undesirable and thus in the presence of more carbon it reacts to give CO.

$CO_2 + C \rightarrow 2CO$ endo.

Other methods of heat supply are nuclear, electrical, and any other chemical reactions generating heat without the production of undesirable products.

Char carried away by the synthesis gas from the gasifier is removed in subsequent steps and either recycled to the gasifier or used for other purposes. These will be discussed with the presentation of individual processes. The gas, now containing CH_4, H_2 and CO, is then treated with steam over a catalyst to shift the H_2-to-CO ratio to 3.0, the desirable ratio for methanation. The undesirable components of the gas, CO_2 and H_2S, are removed by solvent extraction. The resultant extract solution is sent for sulfur recovery and the gas is then sent to the methanator.

Next, CO and H_2 react over a catalyst bed to give methane and steam in the methanator. Reactions (E), (F), and (G) are favored by high pressures and low temperatures. These reactions are highly exothermic, and hence, one of the greatest problems faced in the methanator is the removal of this heat. There are only a few catalysts that can be employed to accelerate the conversion rate. Special techniques are required to manufacture these catalysts.

The gas from the methanator, containing more than 90% methane, passes through a drier to remove moisture which comes from the steam or from various intermediate reactions. The heat content of the product gas must be more than 900 Btu/scf. That complies with the OCR specifications and is adequate for pipeline gas.

At present there are many institutes and companies in the field of coal gasification. The history of different research programs ranges from just a beginning to about two decades. Some of the research programs are sponsored by OCR and/or the American Gas Association. The processes that have been under development for some time are listed along with the name of their developers:

(i) CO_2 Acceptor - Consolidation Coal Company
(ii) Bigas - Bituminous Coal Research, Inc.
(iii) Hygas-Electrothermal - Institute of Gas Technology
(iv) Hygas-Oxygen - Institute of Gas Technology
(v) Hygas-Steam-Iron - Institute of Gas Technology
(vi) Synthane - Bureau of Mines
(vii) Molten Salt - M. W. Kellogg Company
(viii) Lurgi - Lurgi Mineraloltechnik GmbH
(ix) COED - FMC Corporation, synthetic natural gas is a byproduct.

The companies that came on the scene at the later stage are:

(i) Stone and Webster Engineering Corporation
(ii) Columbia Coal Gasification Company
(iii) Panhandle Eastern Pipeline Company and Peabody Coal Company

(iv) Pacific Lighting Service Company, Utah International, Incorporated, and Texas Eastern Transmission Company.

These companies have either a process under consideration or have initiated detailed programs to assess the status of coal gasification. This second list is, by no means, complete.

Research on these first eight processes is extensively underway and all but COED will be discussed at length. A brief outline of others will follow.

CHAPTER IV

PROCESS DETAILS

The general outline of a typical coal gasification process has been given in the previous chapter. In this chapter, an attempt is made to go into the details of each process and discuss certain unique features of many of the processes now under development.

CO_2 Acceptor Process (23, 2, 26)

The name of the process has been derived from the mode of heat supply for the gasifier. The process now under development by Consolidation Coal Company (Consol) produces pipeline gas from lignite. A simplified flow diagram of the process is shown in Figure 1. The research program at present is at a pilot plant stage, and is under construction at Rapid City, S. D. It is not known if the gas clean-up and methanation steps will be included in the pilot plant. Partial operational tests have begun on certain units.

The experiments carried out thus far employed North Dakota lignite. Coal as received from the mines requires pretreatment. It is crushed to less than ¼" by gas impact mills. The moisture content of the coal, as received, is usually about 34% by weight and hence, the crushed coal is dried in two stages to almost zero percent water. The dry lignite is then preheated to 572° F, in a fluidized preheater, for the removal of some volatile matter and to reduce certain properties that tend to

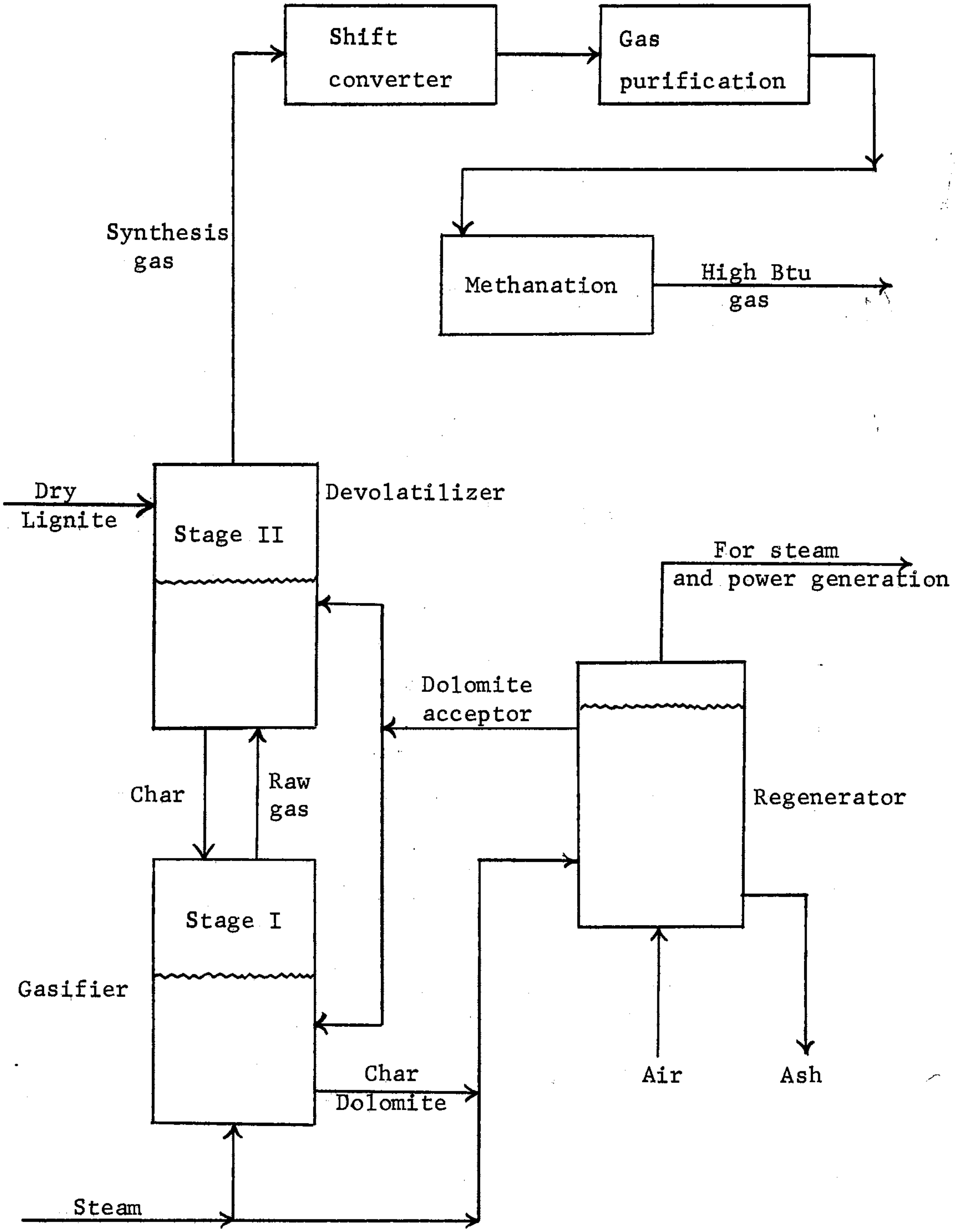

Figure 1. CO_2 Acceptor Process

induce agglomeration. Next the coal is ready for gasification. Any inert gas or the product gas can be used for the pneumatic transportation of the coal to the top of the gasifier.

Lock hopper system is employed to feed the coal into the gasifier. Gasification is carried out in two stages. Preheated lignite enters the Stage II, called devolatilizer. It operates at 1500° F and 290 psia pressure. Regenerated dolomite, MgO.CaO, and gas from Stage I also enter the devolatilizer. Dolomite serves two purposes simultaneously. It acts as a heat carrier, and secondly, it reacts with CO_2 produced and thus eliminates one of the undesirable products according to the following reaction.

$$MgO.CaO + CO_2 \rightarrow MgO.CaCO_3 \qquad \text{exo.} \quad (H)$$

The removal of CO_2 favors methanation because the heat generated is used for the endothermic reaction (C), shown here:

$$C(Char) + H_2O \rightarrow CO + H_2$$

This CO and H_2 are both reactants for the methanation reaction. The char produced and $MgO.CaCO_3$ and part of the regenerated dolomite are then transferred to the Stage I, which is the gasifier. Steam enters the gasifier from the bottom section. The steam reacts with char to give CO, CO_2, H_2, and CH_4. Part of the CO_2 reacts with regenerated dolomite according to reaction (H). The gas mixture consisting of CO, H_2, CH_4, and a small amount of unreacted CO_2 is sent to the devolatilizer and the unreacted char and dolomite are transferred to a regenerator. Heat is required to regenerate the reacted or spent dolomite. This heat is supplied by the exothermic reaction between char and oxygen from the air. The amount of heat required to regenerate the dolomite determines the quantity of char to be reacted in the regenerator and this, in turn, fixes the amount of char that should be left unreacted in the gasifier. Usually about 15% of the char entering the gasifier is left unreacted. Air is supplied to the regenerator from the bottom. It reacts with char at 1940° F producing CO_2 and evolving enormous quantities of heat. This heat is employed to calcine the dolomite. The combustion of char and calcination of dolomite take place simultaneously. The residual char and effluents are then sent for energy recovery as either steam or electricity. The regenerated dolomite along with some makeup dolomite are sent to the devolatilizer.

About 46% of the methane in the final product gas is produced in the gasification step. The gas from the devolatilizer, mainly containing CO, H_2, CH_4, and CO_2 and H_2S as impurities, passes through a cyclone separator to remove any entrained char particles. The recovered char is recycled to the gasifier. The hot gas mixture at about 1100° F and 270 psia is expanded in turbines to 459° F and 15.5 psia to generate power for in-plant use. The H_2-to-CO ratio may not be at the desired value of 3.0, as required for best results in the methanator, and hence, it must be shifted. Steam is introduced at this stage and passed over an iron oxide catalyst. The ratio of H_2-to-CO is shifted to 3.0 by the exothermic reaction (D) shown below:

$$CO + H_2O \rightarrow CO_2 + H_2 \qquad \text{exo.} \quad \text{(D)}$$

The gas now requires purification before it is processed any further. The gas is scrubbed by solvents which absorb practically all of the CO_2 and H_2S. Any traces of sulfur act as a poison for the methanation catalyst and hence, must be eliminated completely. This is done in the second stage scrubber. H_2S is then sent for sulfur recovery which is then, hopefully, sold as a byproduct.

The purified gas is now ready for methanation. This is carried out with the help of a fixed-bed of pelletized nickel catalyst. The reactions (E), (F), and (G) taking place in the methanator are highly exothermic and a considerable amount of heat must be removed to achieve higher conversions. The gas from the methanator passes through a drier to remove any moisture in excess of the OCR specifications. The final product gas has a heating value of about 953 Btu/scf.

Significant improvements and changes in this overall process may develop after the pilot plant goes on stream and its findings are available for analysis. Consol has an alternate process that operates at a gasification pressure of 150 psia. The pilot plant at Rapid City is designed on the basis of 290 psia pressure, thus it can be safely used to test the advantages and disadvantages of the process using low pressures for gasification.

Bigas Process (2, 26, 27)

This concept, also termed as a two-stage, super-pressure gasification process, is under development at Bituminous Coal Research, Inc. (BCR). Recently BCR was awarded a $24,830,000 contract for the construction and operation of a pilot plant (26). A simplified flow diagram of the process under development is shown in Figure 2.

Most of the experiments thus far were carried out on west Kentucky number 11 seam coal. The thermal efficiency (the ratio of total Btu's ouput to input) achieved in those experiments was 65.8%. The oxygen can be termed as the heat supplier in this process. The oxygen reacts with coal or char to produce CO_2 with the generation of large amounts of

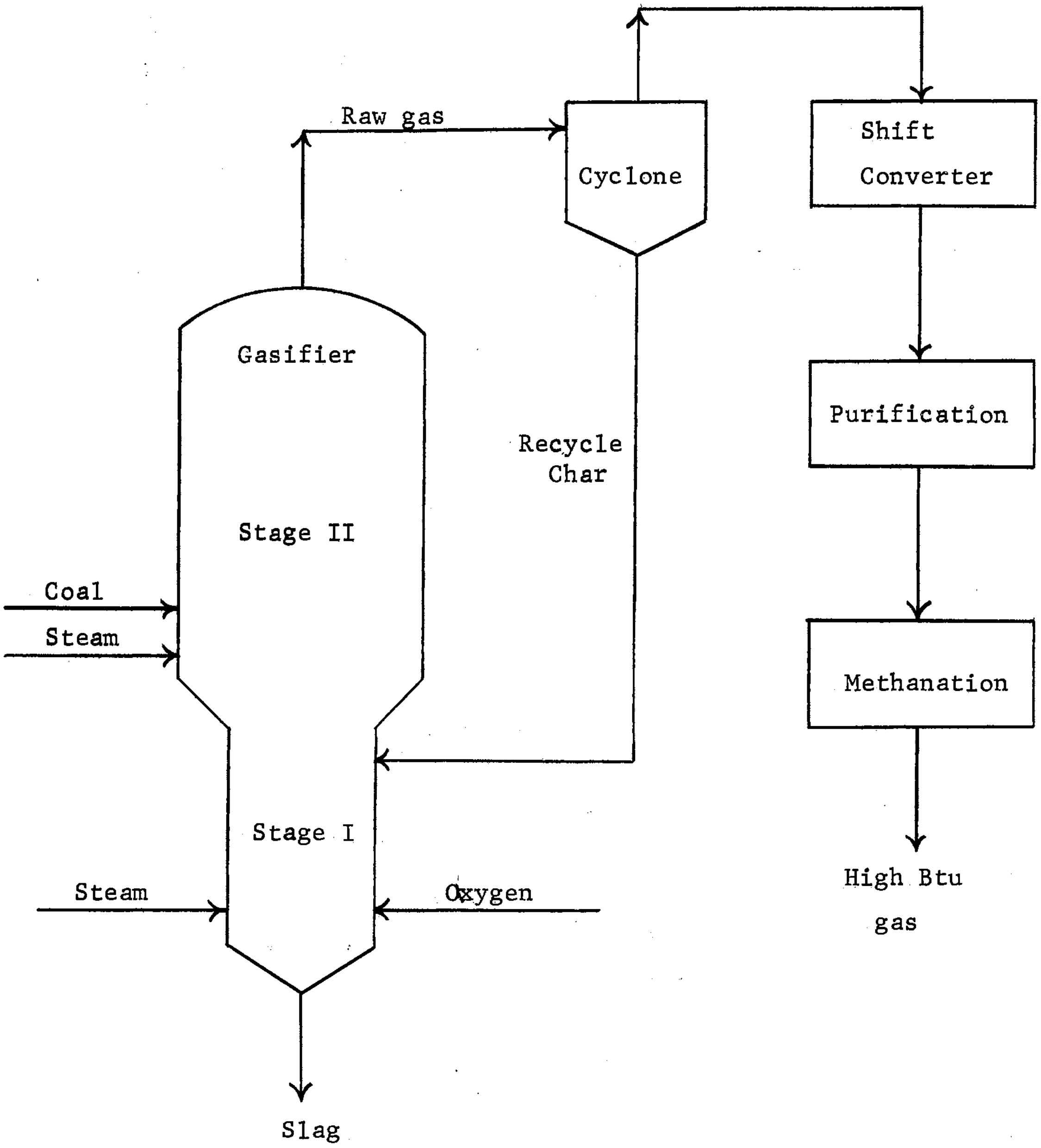

Figure 2. Bigas Process

heat which are sufficient enough to promote the water-gas shift reaction, reaction (C).

The coal as received from mines requires preparation, a series of three operations. The 10" size coal is passed through a breaker which reduces the size to 1½" and at the same time removes about 20% refuse. The coal is then washed using a heavy media washer removing another 20% refuse. The coal is dried and sent to the pulverizer that reduces 70% of the coal to the -200 mesh size. The coal is now ready for gasification.

The gasification section of the process consists of coal feeder, two-stage gasifier, char recovery cyclone, and steam and oxygen supply lines. The gasifier is operated at about 1200 psig. There is a substantial temperature gradient from the bottom of Stage I to the top of Stage II. The gasifier operates on an entrained system. Coal and steam are forced into Stage II by four concentric injection nozzles. Also hot synthesis gas comes from Stage I below. Reactions start instantaneously and produce methane and highly reactive char, reaction (A). The char reacts with hydrogen to produce additional methane according to reaction (B). Char also reacts with steam to produce CO and H_2, reaction (C). The residence time of gases in the Stage II is about six seconds, and the temperature is about 1700° F. About 52% of the total methane in the final product is produced in the gasifier. The gas leaves the gasifier at 1700° F carrying along small quantities of char. This char is separated in a cyclone separator and sent to Stage I of the gasifier via char hopper. The synthesis gas, coming out from Stage II of the gasifier, is cooled by way of quenching which serves a dual purpose of generating steam for process use and to minimize any unwanted side reactions. The cooled gas is then sent to the shift conversion section.

Stage II of the gasifier is the one into which the coal feed enters and from which the product gas leaves. But part of the reactions are carried out in the Stage I of the gasifier, too. The char, unreacted from Stage II and recycled from the cyclone separator, enters Stage I of the gasifier. Other streams entering Stage I are steam and oxygen. Char and steam enter via concentric nozzles and react with oxygen at about 2700° F to produce synthesis gas and ash residue. The melting point of ash residue is about 2000° F and hence, it forms a molten slag and can be drained out from time to time. The residence time of gases in Stage I is two seconds. The hot gas then enters Stage II of the gasifier.

The rate of oxygen is controlled to maintain Stage II temperature at 1700° F. Any excess oxygen for Stage I automatically goes to Stage II where it reacts with either coal or char exothermically to raise the temperature to a level of 1700° F. The rate of steam is controlled to maintain Stage I temperature at 2700° F. The steam reacts endothermically with char to produce CO and H_2 and reduces Stage I temperature to the level of 2700° F.

The shift conversion section is comprised of sand filters, recycle compressor, shift convertor, and heat recovery system. Sand filters are used to trap any char which was not removed in the cyclone separator. Char is recovered by backflow of gas and returned to char hopper. The gas coming from the filter has an H_2-to-CO ratio of 0.56:1.0; whereas, for methanation it should be of the order of 3:1, reaction (E). Hence, steam is introduced at this stage such that the steam to dry gas ratio is 1:1. The mixture is then passed through an adiabatic shift convertor which shifts the H_2-to-CO ratio to 3:1. The shift is basically due to reaction (D) which tends to reduce CO and increase H_2. Since the ratio 3:1 is the most desired one, the extent of shift must be well controlled. The more commonly employed catalyst for this purpose is iron oxide in the form of a spongy bed, a very porous bed. The gas from the convertor is at about 950° F and hence, the high heat content of the gas is recovered to generate steam and power.

The gas is then sent to the acid-gas removal and sulfur recovery system. Here H_2S and CO_2 are absorbed by scrubbing with certain solvents. The absorbed H_2S is recovered and oxidized to give elemental sulfur. The purified gas is now ready for methanation. The methanator is a fixed-bed catalytic convertor, and uses an aluminum supported nickel catalyst. Reaction (E) should be carried out at a thermodynamically optimum temperature of 850° F. The reactions taking place in the methanator are very exothermic in nature and hence, require a large quantity of recycled product gas to control the temperature in the methanator. Sulfur poisons the methanation catalyst, and thus, the gas entering the methanator must be practically free of sulfur. The product gas from the methanator is then passed through triethylene glycol drier to attain the allowable moisture levels in the final product gas. Gross heating value of this product gas is about 943 Btu/scf.

Oxygen is required for the process and for that air is purified, liquefied, and subsequently O_2 and N_2 are separated by distillation.

The research at BCR was done over a period of six years. Most of the research efforts were concentrated on coal beneficiation, coal feeding, and direct methanation of coal in the gasifier. In coal beneficiation the idea is to split the coal into three fractions - superior fraction for the production of methane, the average fraction for producing synthesis gas and the third fraction for steam generation. Mechanical methods are employed for the separation of coal into different fractions depending upon the nature of coal treated. All this coal beneficiation is necessary where one can use the synthesis gas and the steam at the plant itself. This will not be the case for the coal gasification plants. Lock hopper type of coal feeding system has been developed. Direct methanation has been tried at many different conditions and their final results were given in the process description.

BCR also tried to evaluate the effects of reduced oxygen consumption, higher operating pressure, and use of rectisol acid-gas removal process on thermal efficiency, capital cost, and gas price. The results are shown in Table IX.

TABLE IX

OPERATING PARAMETERS OF GAS COST FOR 250 MMscfd GAS PLANT

	Improvement in thermal efficiency, %	Decrease in capital cost ($M)	Reduction in gas price (cents/MMBtu)
Decreased O_2 consumption	3	14,000	5.0
Higher operating pressure (80-100 atm)	4	1,700	1.6
Rectisol acid gas removal system	3	10,000	2.9

If all these can be utilized simultaneously, great savings and advantages can be anticipated. The results from laboratory scale experiments will now have to be confirmed by the experiments of the pilot plant which is now under construction at Homer City, Pennsylvania.

Hygas Process (2, 7, 26, 28, 29, 30)

The Institute of Gas Technology (IGT) under the sponsorship of Interior's Office of Coal Research and American Gas Association has developed the Hygas process. The history of research at IGT goes back to the early 1950's. IGT has developed this high pressure and high temperature process to convert coal and hydrogen into methane. The process is termed hydrogasification from which comes the name Hygas. IGT has developed three alternate ways of supplying heat to the process:

(i) Electrothermal, Figure 3
(ii) Oxygen, Figure 4
(iii) Steam-iron, Figure 5

Apart from the heat supply technique, the rest of the process is essentially the same. Coal pretreatment is the first place to begin. IGT has carried out experiments employing wide varieties of coal ranging from lignite to subbituminous to bituminous. The raw coal is crushed to a size less than 1/8" and dried. To get away from the tendency of some coals to agglomerate during actual processing, air at 800° F is blown through the coal particles. During this operation low Btu synthesis gas is produced which can be used as boiler fuel. A few types of coal such as western subbituminous and lignite do not require pretreatment. The coal particles are then mixed with light oil to prepare a mud-like slurry which makes it easier to transport coal by high pressure pumps.

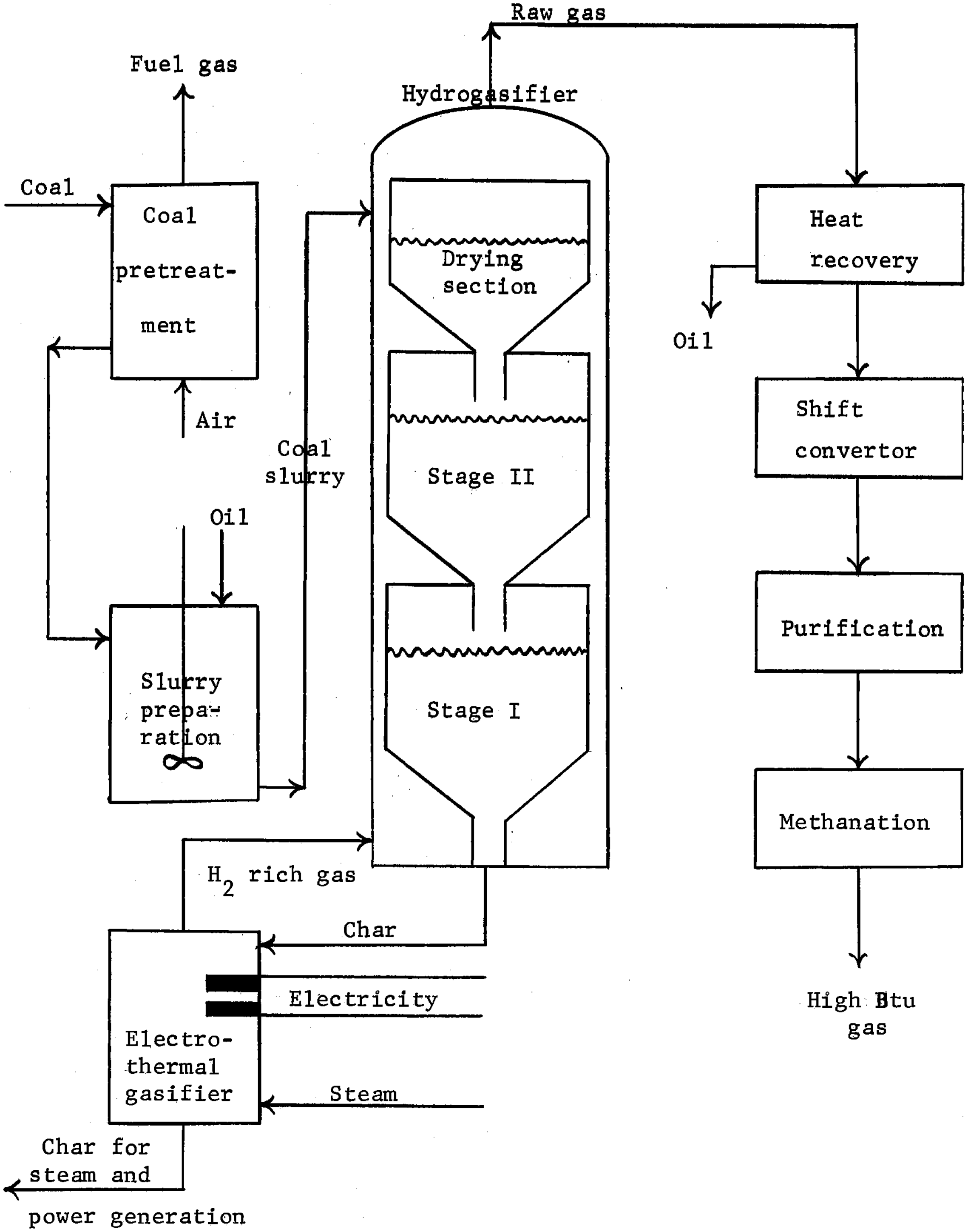

Figure 3. Hygas-Electrothermal Process

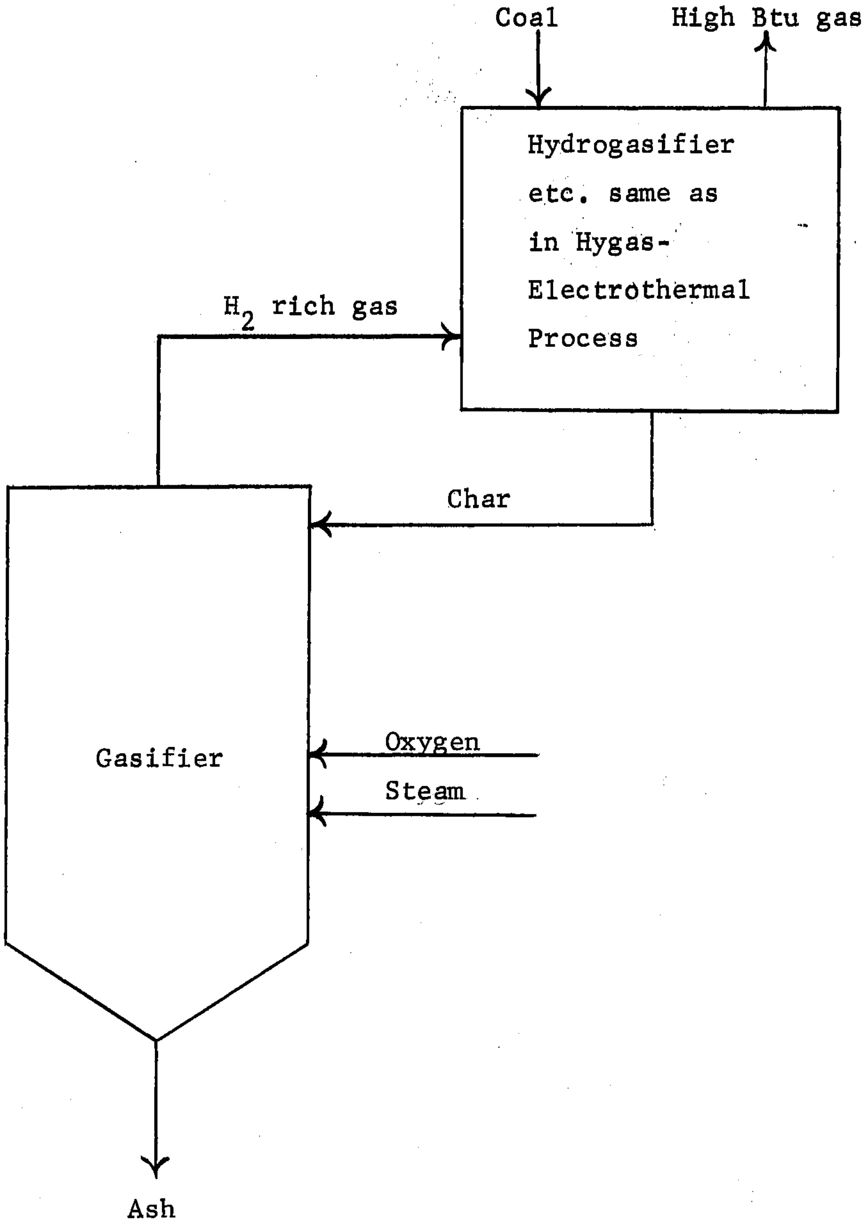

Figure 4. Hygas-Oxygen Process

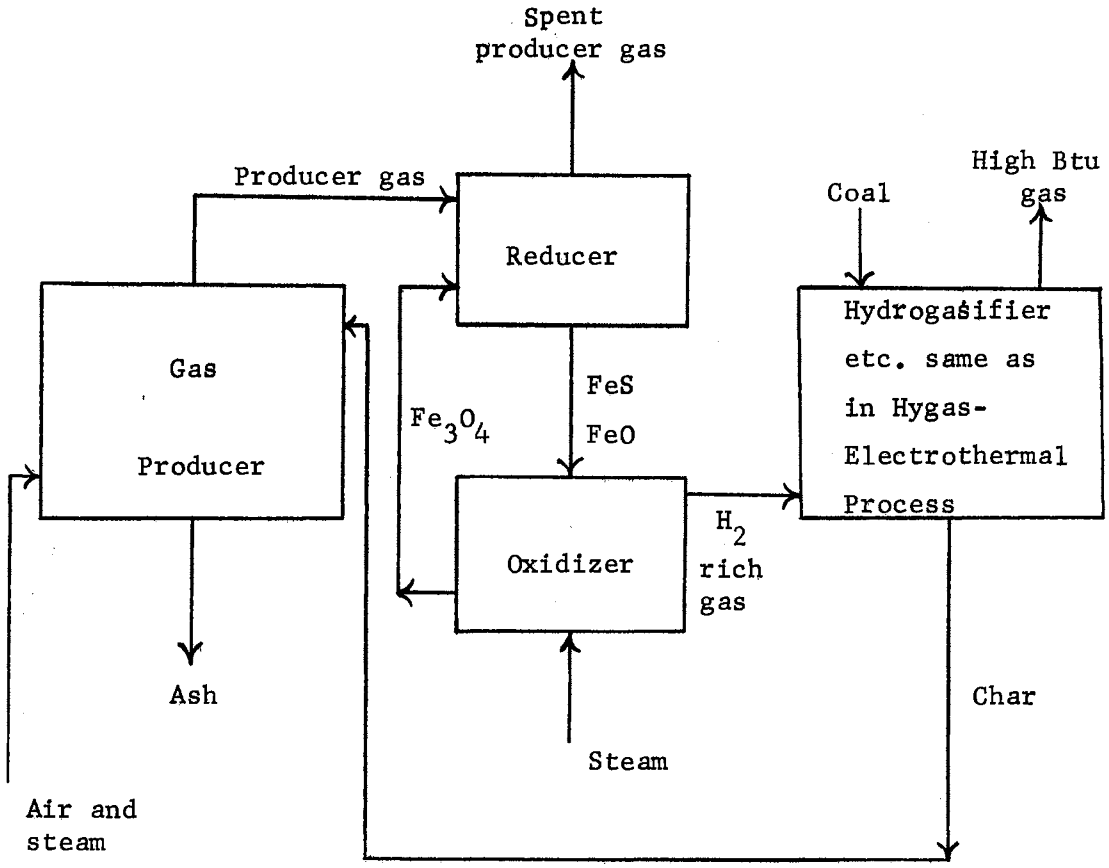

Figure 5. Hygas-Steam-Iron Process

The slurry is pumped to the top of the hydrogasifier. The hydrogasifier is subdivided into three sections. The top section is coal feeding and drying and Stages I and II follow. The hydrogasifier operates at 1000 to 1500 psia pressure. Coal, in the form of slurry, enters from the side of the top section and gas from Stage I, rich in methane, enters from below to create a fluidizing effect. Considerable energy in the gas is transferred to the coal, and at the same time, the oil in the slurry is vaporized. The oil vapors are carried away by the product gas. The percent of the methane produced in the gasifier to the amount of methane in the final product gas depends upon the mode of heat supply. For Hygas-Electrothermal process, the ratio is highest at 83%. For Steam-Iron process, the ratio is 64%. The data on Hygas-Oxygen are not available.

The gas moves up and out of the drying section, whereas, the heated coal moves downward to the next section of the hydrogasifier, i.e. Stage II. There the coal meets the hot gas coming from the stage below, creating a fluidizing effect. Fluidization allows thorough mixing of solids and gas and aids in higher heat exchange and reactivity. The gas coming from Stage I contains methane, carbon oxides, hydrogen and steam. All of the reactions (A) through (D) take place and the temperature rises to 1300 to 1500° F. About 1/3 of the methane in the final product gas is produced in this stage. The highly reactive char, a product of those four reactions, moves doward to Stage I and encounters the hydrogen rich gas and steam coming from the hydrogen generator. Here again, the reactions (A) through (D) take place producing methane and oxides of carbon. The temperature attained in this stage is about 1700° F to 1800° F. Any unreacted char is transferred to the hydrogen generator.

At this stage the three alternatives come into picture. Char and steam are fed into the hydrogen generator. Char and steam react, according to reaction (C), to give carbon monoxide and hydrogen. This is an endothermic reaction. In the Hygas-Electrothermal process, heat is supplied by direct current electric power in a special electrofluidic process. In the Hygas-Oxygen process, oxygen is also introduced into this stage. Char reacts with oxygen to give carbon dioxide with the generation of large amounts of heat for reaction (C), Figure 4. In the Hygas-Steam-Iron process, three more chambers are required to accomplish the conversion, Figure 5. Iron and ferrous oxide reduce steam and become oxidized to give hydrogen and ferric oxide according to the following reactions:

$$2Fe + 3H_2O \rightarrow Fe_2O_3 + 3H_2$$

$$2FeO + H_2O \rightarrow Fe_2O_3 + H_2$$

These reactions are carried out in the oxidizer. The hydrogen and unreacted steam are sent to Stage I of the hydrogasifier, whereas, ferric oxide is sent to the reducer to be prepared for reuse. In the reducer, the ferric oxide is reduced to iron or ferrous oxide by the producer gas. There is a substantial amount of heat carried away by the spent producer gas and should be recovered for economic reasons. The producer gas is generated by partial oxidation of residual char from the hydrogasifier by air and steam in the producer. Any residual char from the hydrogen generation system is used for power and steam generation.

In a recently patented Steam-Iron process (31) assigned to Consolidation Coal Company, only two chambers are employed for hydrogasification instead of four. Unlike the previous one, the reactions carried out in the reducer and producer are carried out in one chamber called the iron reducer vessel, and, similarly oxidizer and hydrogasifier are combined together into a single chamber called the iron oxidizer vessel. The rest of the operations and reactions taking place are essentially the same.

The hot gas, at 600° F, coming out from the top of the hydrogasifier is cooled in subsequent steps which simultaneously liquefies part of the oil. It is then subjected to a water quench which removes light oil, steam, and entrained coal particles. The light oil is separated and reused for slurry preparation. The coal particles are returned to Stage I of the gasifier. The gas is then treated with steam in a CO-shift convertor to shift H_2-to-CO ratio to 3:1. The gas is then scrubbed by a special solution which absorbs any H_2S, SO_2, and CO_2. Sulfur is recovered in its elemental form and, hopefully, sold as a byproduct. The gas has yet to undergo two purifying steps. The first step is scrubbing by caustic soda that removes any traces of sulfur, and the second step is scrubbing by water to remove any traces of solvents and caustic soda. The purified gas consisting largely of methane and small quantities of hydrogen and carbon monoxide is ready for methanation.

Methanation is carried out in a fixed-bed catalytic convertor. The gas passes over an aluminum-based nickel catalyst. The reactions (E) through (G) take place simultaneously and convert practically all the CO and H_2 to additional methane and steam. After methanation the gas is cooled, condensing part of the steam, and ultimately removing it in the drier. The product gas is then compressed and delivered to the pipeline. This product gas has the heating value of about 954 Btu/scf.

IGT has constructed a pilot plant based on the above discussed process in Chicago. The pilot plant construction was completed in the Fall of 1970 and partial operational tests have begun on certain units. The methanation step has been included in the pilot plant. The pilot plant has the capacity of processing 75 tons of coal per day producing 1.5 million scfd of clean and high Btu gas. The results of the pilot plant study will probably be available soon.

Synthane Process (2, 26, 32)

The Interior's Bureau of Mines has developed this process to manufacture high Btu gas from coal. A simplified diagram of the process under development is shown in Figure 6. Pittsburgh seam coal, Illinois number 6, Montana subbituminous coal, and North Dakota lignite were employed for experiments. Oxygen is the heat supplier in the process.

The process does not require coal to be pretreated. Caking coal can also be used. Actually the process has a built-in pretreatment stage in the hydrogasifier itself. The raw coal is crushed to sizes such that more than 70% of it can pass through 200 mesh screen. Prior to crushing to such a small size, the coal is washed with water and then dried. The coal is now ready for gasification. The coal is transferred to the top of the hydrogasifier.

The fluid-bed hydrogasifier operates at 600 to 1000 psia pressure. The temperature varies significantly from top to bottom. At the comparatively narrow pretreatment stage the temperature is 750° F and it increases steadily to about 1700° to 1800° F at the bottom. Coal enters

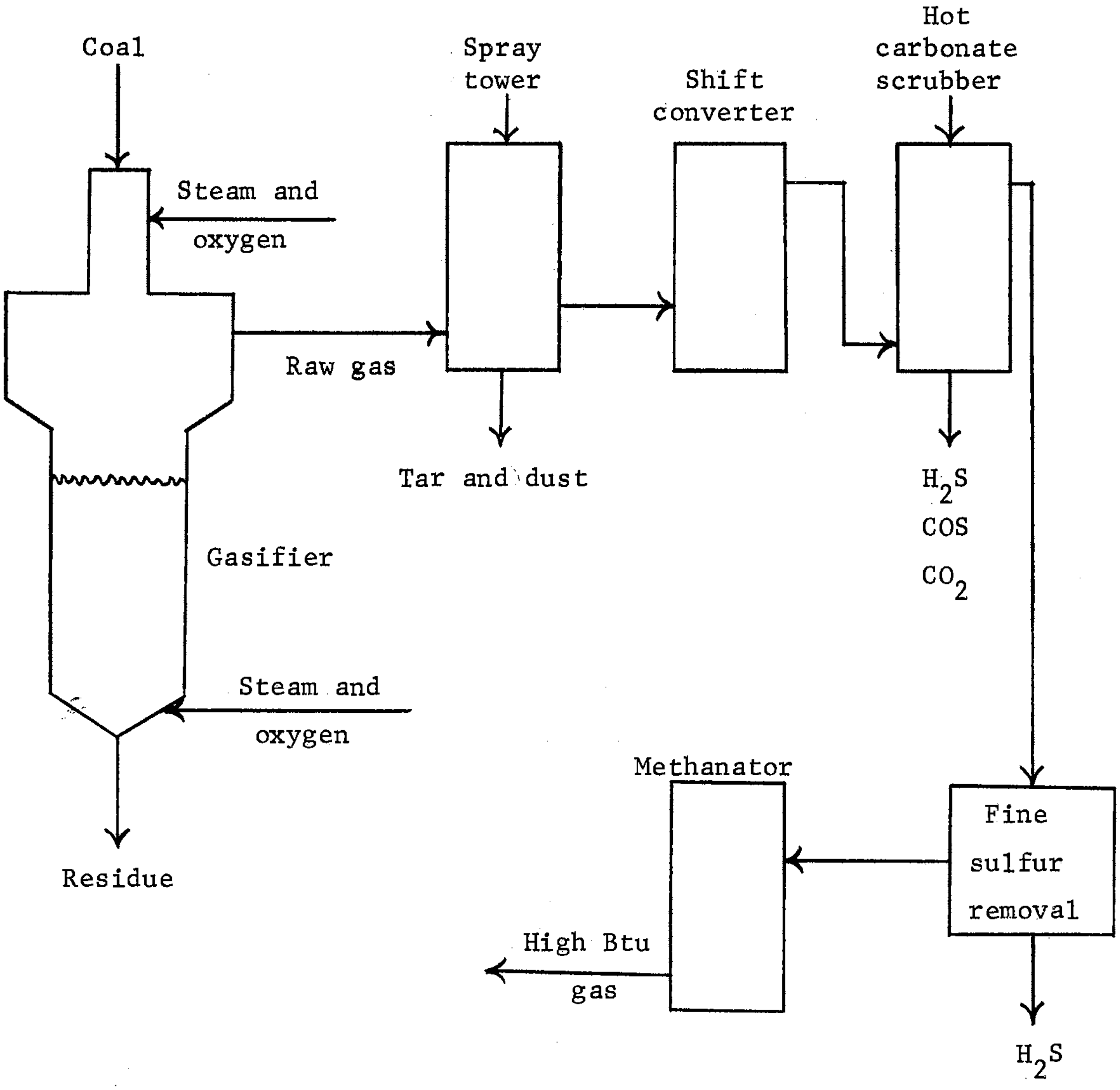

Figure 6. Synthane Process

from the top of the hydrogasifier and is pretreated during its free fall by reacting with small quantities of steam and oxygen, which are fed to this stage. The steam and oxygen required in the hydrogasification stage are fed from the lower part of the gasifier. Coal moves downward and steam and oxygen move upward, and reactions (A) through (D) take place to produce raw gas which has a heating value of about 500 Btu/scf. About 55% of the methane in the product gas is produced in the hydrogasifier. Residual char from the gasifier is used for power and steam generation.

The raw gas from the gasifier is treated with water in a spray tower to remove any entrained tar and coal dust and simultaneously cool the gas significantly. The gas is then sent to a shift convertor where the H_2-to-CO ratio is adjusted to 3:1 by reacting the gas with steam in the presence of a catalyst. Spongy, very porous, iron oxide is the most commonly employed catalyst. The gas now requires purification by scrubbing with potassium carbonate which removes most of the CO_2 and sulfur compounds present. The last traces of sulfur are removed in the second stage purification.

A tube-wall (catalyst flame sprayed on the wall of the tubes) reactor is employed for methanation. The process uses a flame sprayed Raney nickel catalyst. The temperature in the methanation step is maintained at 750^{o} F to 800^{o} F. The reactions taking place, reactions (E) through (G), are very exothermic and a large amount of heat must be removed in the methanator. Dowtherm is used to accomplish the cooling. The gas coming from the methanator has a heat content of more than 900 Btu/scf, and hence, meets the OCR specifications.

The Lummus Company has designed a plant based on Synthane process. The award of the contract from the OCR is expected by December, 1972. The construction of the pilot plant will take another eighteen months.

Molten Salt Process (2, 26, 33)

This process is developed by M. W. Kellogg Company. A simplified flow diagram of the process under development is shown in Figure 7. Many types of coal were tested in the bench scale experiments and it appears that pretreatment is not required for the coal to be used for gasification. Oxygen from air is the heat supplier and the molten salt, sodium bicarbonate, is the heat carrier.

The raw coal is crushed to a size of -12 mesh. It is then washed and dried and is ready for gasification. The gasifier operates at 430 psia. It is divided into two parts by a vertical partition which is perforated at places below the liquid level. Coal and steam are introduced into the left compartment and preheated, compressed air is introduced into the right compartment from the bottom of the gasifier. Molten salt is introduced at a level slightly above the bottom into the right compartment. A difference in aeration or circulation of the salt in the two compartments can be induced by proper adjustment of gas velocity and the vessel configuration. Coal reacts with oxygen from the air to give carbon dioxide with the generation of large amounts of heat in the right compartment. The reactions (A) through (D) take place producing synthesis gas in the left compartment. The necessary heat is taken from the molten salt. The flue gas from the right compartment leaves the gasifier at about 2200° F and 405 psia. This heat is used to preheat the incoming air and also to generate steam and to run a turbine.

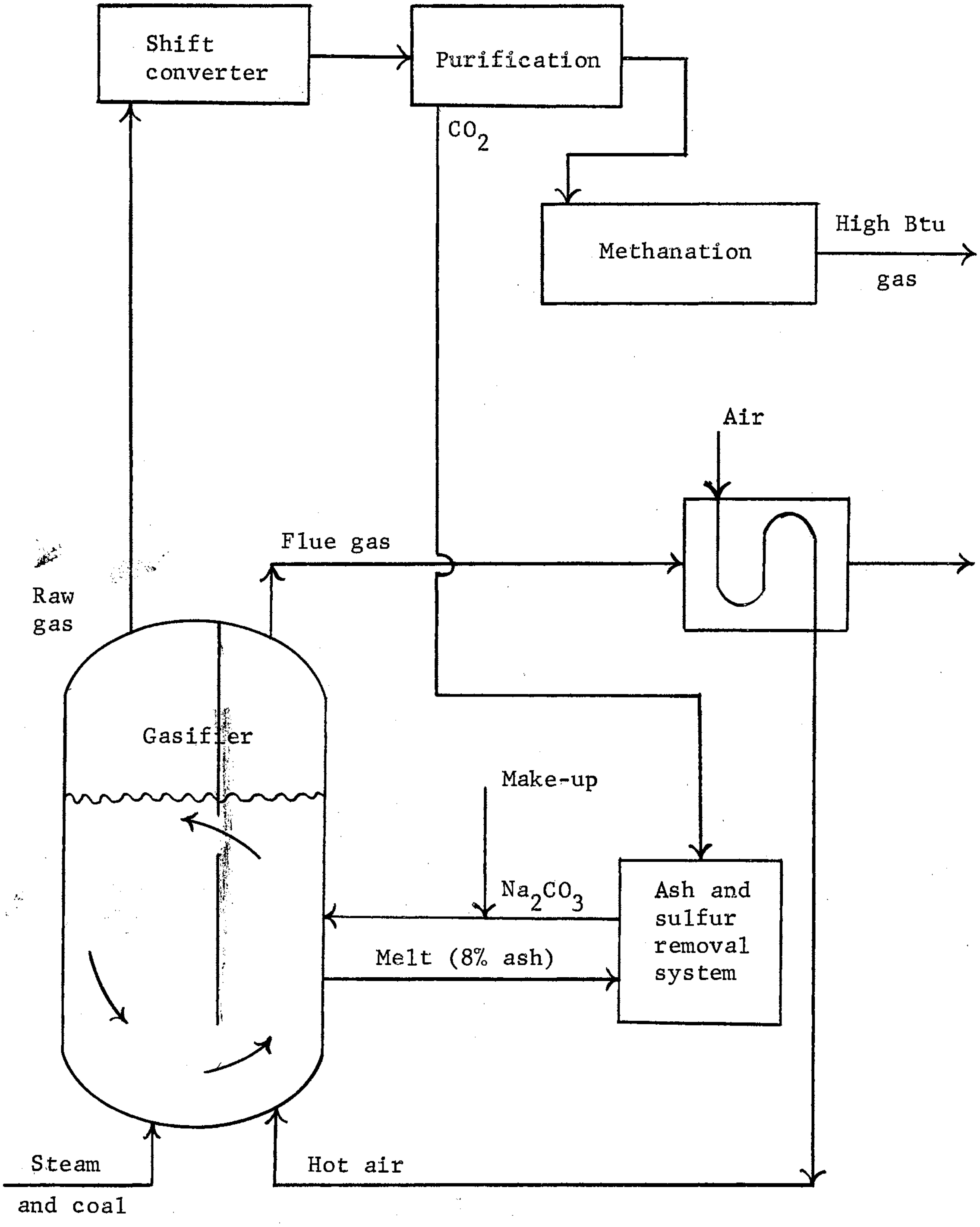

Figure 7. Molten Salt Process

Part of the molten salt is removed from the vessel when the ash content of the melt reaches 8%. The ash is removed and the salt is returned to the vessel for reuse. Only about 29% of the methane in the final product is produced in the gasifier. The synthesis gas leaves the vessel at about 1800° F and is cooled in the subsequent steps to generate steam.

One of the chief drawbacks of this process is that the molten salt is very corrosive, and thus far no satisfactory material of construction has been found. The rest of the process steps are similar to those discussed in the earlier processes. Those steps include cyclone separation, CO shift conversion, purification, methanation, and drying. Some of the solvents preferred for purification are propylene carbonate, hot potassium carbonate, monoethanolamine, acetone, and sulfinol.

It can be seen that combustion and gasification steps take place in just one chamber. Further study has indicated that carrying out these steps in separate chambers would not affect the economics of the process significantly. Rather it reduces any possibility of mixing of flue gas and synthesis gas. The construction of separate chambers is favored for the pilot plant.

Until recently the research program was sponsored by OCR. The earlier contract has expired and has not yet been renewed.

Lurgi Process (34,35)

This process is under development at Lurgi Mineraloltechnik GmbH, Frankfort, West Germany, and El Paso Natural gas Corporation has announced plans to employ this process in their SNG plant. A simplified flow diagram of the process under development is shown in Figure 8.

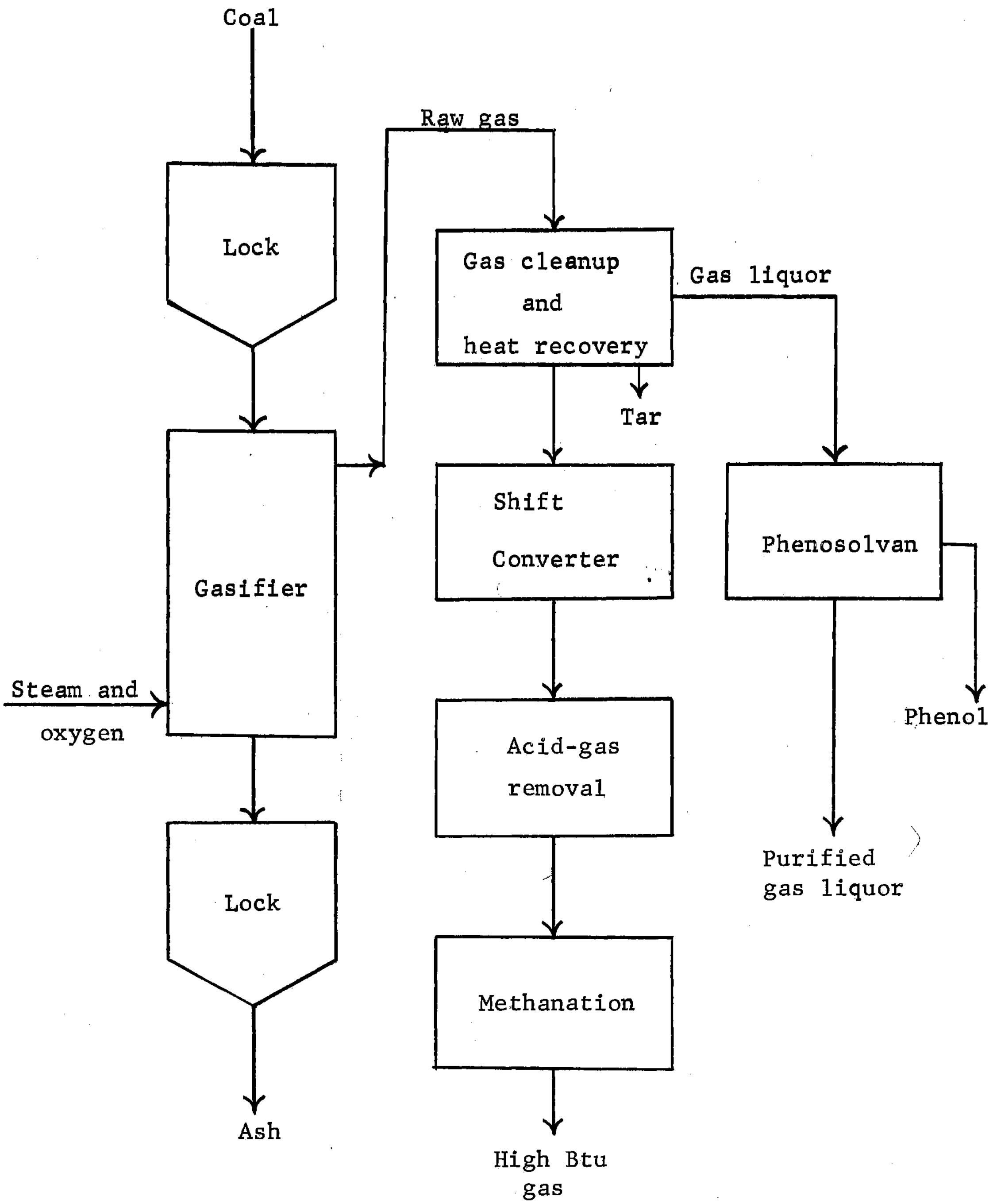

Figure 8. Lurgi Process

There are many plants using this process (minus methanation) to produce synthesis gas of heating value about 400-450 Btu/scf. The gasifier, primary unit of the process, has been in operation for more than two decades. The gasifier has been tested with several types of feedstock from all over the world. These tests show that the ideal temperature for some of the major classes of coal are approximately: Lignite, 1200° F: Sub-bituminous 1350° F; Semi-anthracite, 1450° F; and Coke 1550° F. Those tests also show that the gasifier pressure beyond 400 psig has insignificant effect on amount of methane generation in the gasifier. Instead, the process employing higher pressure in the gasifier has more construction cost.

The thermal efficiency of the process is claimed to be 68% to 70%. The mode of heat supply to the gasifier is by partial combustion of char with oxygen. About 86% of the coal fed to the gasifier is gasified to produce synthesis gas and the balance of 14% is burnt with oxygen to provide the necessary heat.

This process consists of these major units: Pressure gasification; Crude gas shift conversion; Rectisol gas purification; Methane synthesis; and Phenosolvan plant for the treatment of gas liquor. After preparation, coal is fed into the fixed-bed gasifier by a lock hopper system. Each gasifier has a capacity of processing slightly less than 500 tons per day of coal. Since the gasifiers employed in the SNG plant will be of same size, the plant will require about 30 identical gasifiers to produce 250 MMscfd high Btu gas. Some of the unique features of the gasifier include a coal distributor to ensure uniform distribution of coal across the gasifier, revolving grate at lower section of the gasifier for uniform distribution of steam and oxygen and for collection of ash.

Coal is preheated and dried in the uppermost section of the gasifier. After drying, the coal enters the devolatilization section. Reactions (A) through (D) start taking place at 1200° F to 1400° F temperature producing synthesis gas and char. Gasification of char also starts simultaneously. Finally in the combustion zone, the balance of char and oxygen react to supply heat to the gasifier.

The gas leaving the gasifier consists of CO, CO_2, H_2, CH_4, coal and ash particles, carbonization products, and H_2S. The gas, which is at about 700° F to 1100° F, is cooled to 300° F to 400° F in waste heat boilers. The cooling condenses some hydrocarbons and removes tar and dust. The hydrocarbon liquor is separated and sent to gas liquor treatment. Tar and dust are returned to the gasifier.

The gas leaving the waste-heat boiler may not have the H_2-to-CO ratio at the desired value of 3.0. The gas has impurities of sulfur compounds and carbonization products. These impurities are removed by passing the gas over Comox catalyst. Now the gas is ready for shift conversion. The gas is then passed over iron oxide catalyst to accomplish shift conversion. Steam required for the conversion is supplied to the convertor from the gas mixture and/or additional supply.

From the shift convertor, the gas is sent to rectisol purification unit. The purification is basically gas absorption process using methanol at temperatures between +30° F to -80° F. The unit consists of three sections. In the first section, gas naphtha, unsaturated hydrocarbons, and other boiling impurities are removed by a prewash with water. In the second section, CO_2, H_2S, and COS are removed by dissolving them in the solvent. In the third section, any traces of CO_2 are removed and the gas is dehydrated.

The purified gas is now ready for methanation. A commercial demonstration of the methanation unit has not yet been done. But the bench scale studies have shown that the final product SNG will have heating value of about 970 Btu/scf.

The phenosolvan process treats the liquor condensed out from the gas leaving the gasifier. Phenol and ammonia are removed and sold as byproducts.

Summary

These more advanced processes which have been discussed here are summarized in Table X for ease of comparison.

Other Processes

There are a few other processes in the development stage at present. One that has reached pilot plant stage is FMC's COED process. This process produces oil from coal and gas is really only a byproduct.

Another process that has extensive theoretical and research background to support its claim is Stone and Webster/ Gulf Coal Solution-Gasification process (36, 37). This process has been developed by Stone and Webster Engineering Corporation of Boston. The plant, still on paper, is designed to produce about 300 million scfd gas of heating value more than 900 Btu/scf. The process is claimed to have a thermal efficiency of about 70%. A simplified flow diagram of the process under development is shown in Figure 9.

TABLE X

PROCESSES UNDER DEVELOPMENT

Process			Hygas					
	CO_2 acceptor	Bigas	Electrothermal	Oxygen	Steam-Iron	Synthane	Molten salt	Lurgi
Developer	Consolidation Coal Company	Bituminous Research, Inc.	Institute of Gas Technology			Bureau of Mines	M. W. Kellogg Co.	Lurgi Mineralol-technik GmbH
Operating pressure	150-300 psia	1200 psig	1000-1500 psia			600-1000 psia	430 psia	350-450 psig
Pretreater	yes, fluidized	none	none (lignite), yes (bituminous) fluidized			none	none	none
Gasifier	two stage fluidized bed	two stage entrained flow	two fluid bed plus electro-thermal	two fluid bed plus oxygen	two fluid bed	two stage fluid bed	single stage molten salt	30 single stage fixed bed
Energy source	Char-air combustion; dolomite-CO_2 reaction	Char-oxygen combustion	Electrical energy, heat of Char-H_2 reaction	Char-oxygen combustion, heat of Char-H_2 reaction	Char-air reaction, heat of Char-H_2 reaction	Char-oxygen combustion	Coal-air combustion	Char-oxygen combustion
% methane produced in gasifier	46%	52%	83%	-	64%	55%	29%	-
Methanation	fixed-bed pelletized nickel catalyst	fixed-bed nickel catalyst	fixed-bed nickel catalyst			tube-wall fixed-bed, flame-sprayed Raney-nickel catalyst	open	open
Present status	pilot plant construction	pilot plant construction	pilot plant operation			pilot plant construction	laboratory stage	process minus methane synthesis in operation

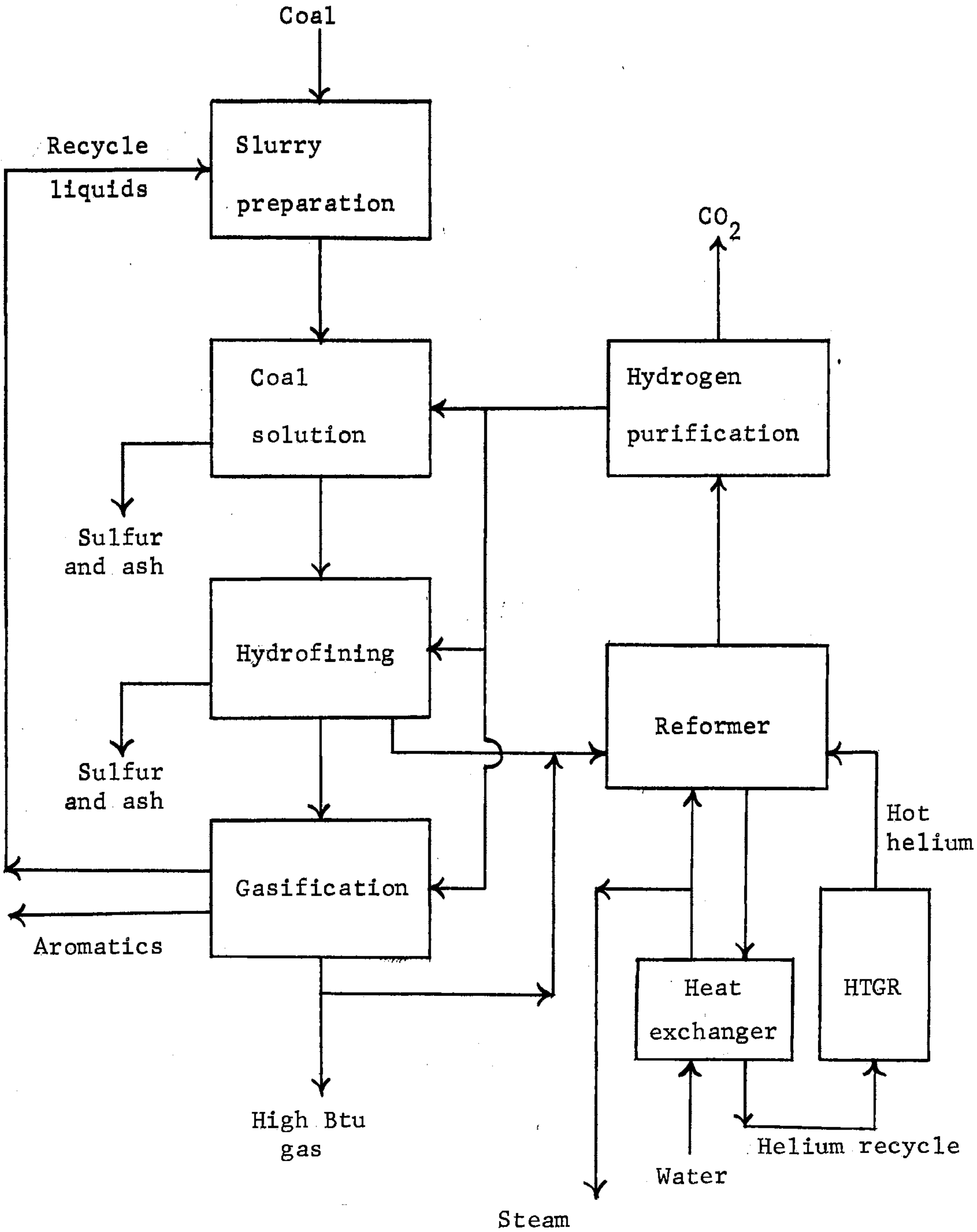

Figure 9. Stone and Webster/Gulf Coal Solution - Gasification Process

This process consists of four basic steps: Coal solution; Hydrofining; Hydrogasification; and Hydrogen manufacture. Pretreatment of coal is not required and hence, volatile matter is retained in the coal resulting in the reduction of hydrogen requirement by 30 to 40 percent. The heat required for the process is supplied by a nuclear reactor, called high temperature gas reactor (HTGR), developed by Gulf Oil Corporation.

The coal as received from the mines requires preparation. It is crushed to small sizes and washed with water to remove refuse. The coal is then dried and fed to the coal solution unit. A fraction of the coal fed to the plant is solubilized in a self-derived solvent in the presence of hydrogen gas and recycle liquids from the Hydrogasification step. This coal solution step removes most of the ash and considerable amount of sulfur in the coal fed.

The coal solution is then transferred to the catalytic hydrofining unit. Hydrogen is supplied to this unit. Sulfur and other heteroatoms are hydrogenated and removed. The coal solution from this step, essentially of low-sulfur and low-ash content, is transferred to the hydrogasification step.

The coal solution comes in contact with hydrogen in this step and produces high Btu gas which is claimed to meet OCR specifications.

Hydrogen required for the process is produced by a typical reforming process. A fraction of the final product gas and also gas from hydrofining step are fed into a reformer. A large quantity of treated and conditioned water is also supplied to the reformer. Hydrogen produced in this step is purified before using in other units of the process.

The mode of heat supply is unique by itself. A nuclear reactor, HTGR, generates heat which is transferred to the process by helium as a heat carrier gas (38).

The estimated capital investment for a plant with a capacity of producing 630 million scfd pipeline gas is about $500 million. Considering the byproduct credit for light petroleum liquids or fuel gas, the twenty-year average selling price of gas is estimated to be about 60 cents/MMBtu.

CHAPTER V

ECONOMICS AND CONCLUSION

A significant amount of paper and laboratory work have been done on the subject of coal gasification. The numerous processes under development were discussed in the preceding chapter. Their operational feasibility will have to be confirmed by the results of the pilot plants. There are many problems that are unsolved and many new may arise in the pilot plant study. All these problems need to be solved and present programs are directed to achieve this.

The various processes have different advantages and disadvantages. In some, air is used instead of oxygen, thus reducing capital and operational cost of oxygen plant, but then require nitrogen barrier (the mechanism to keep the nitrogen from getting into the product gas). Some have problems due to corrosive nature of the heat carrier. These problems and others can be settled only after pilot plant study.

The process developers have also come up with tentative economics and the expected gas selling prices. OCR has adopted the AGA accounting procedure as shown in Table VII. Rate of return of 7% is low compared to other industries. Interest rates have gone up since 1965. Some believe that the low rate of return may distract many investors. Thus some process developers have diverted to a certain extent from the AGA accounting procedure. As will be seen in the later discussion, the cost of coal is the most important factor in determining the price of product gas.

CO_2 Acceptor Process (23)

AGA accounting procedure is adopted for calculating gas price. The study has been made at two different pressures, 300 and 150 psia, and based on that, two sets of results are reported. The thermal efficiency in 150 psi pressure process is higher than that for 300 psi pressure and consequently, the gas price is less in the former process. The lignite is considered to be 10.74 cents/MMBtu, $2.75/ton, for a plant capactiy of 250 MMscfd of product gas.

TABLE XI

ECONOMICS OF CO_2 ACCEPTOR PROCESS

	Operating Pressure	
	300 psi	150 psi
Total fixed investment	$90.60 MM	$88.40 MM
Working capital	$ 4.98 MM	$4.957 MM
Operating expenses per year	$31.37 MM	$30.63 MM
Twenty-year total average revenue required per year	$36.25 MM	$35.38 MM
Twenty-year average gas price	44.2 ¢/MMBtu	43.1 ¢/MMBtu

The cost of the acceptor, in this case dolomite, does not affect the gas price appreciably. But the coal price does. With the lignite cost changing from 8, 9.5 and 11 cents/MMBtu ($2.00, $2.40, and $2.80 per ton, respectively) the gas price changes from 39.4, 42.0, and 44.6 cents/MMBtu, respectively.

Liquid fuels and aromatic concentrates cost 70 cents to 114 cents/MMBtu. This leads to an idea of selling part of the products in the form of liquid hydrocarbons. If only 5% of the product is sold "as liquid," that would reduce the gas price by 2 to 2½ cents/MMBtu. But then the investment is likely to go higher.

Bigas Process (27)

Plant capacity is for 250 MMscfd of pipeline gas from coal. The cost estimation and design for BCR has been done by Air Products and Chemicals, Inc. The rate of return on average equity is maintained at 9.4%. The interest rate counted is 9% instead of 5% specified by AGA accounting procedure. The contractors fee has gone as high as 11%. All these lead to an increase in the total fixed investment and the gas price. Based on the above, the ~~total~~ fixed investment is at $168,970,000. Total operating expense is $39,512,000. Coal price varies from $2.0, $2.5, and $3.0 per ton and depending upon that, the twenty-year average gas price varies from 58.7, 64.0, to 69.3 cents/MMBtu, respectively. The gas price includes the sulfur credit at the rate of $20 per long ton. There has been an attempt to increase the thermal efficiency, reduce capital and gas selling price by changing certain parameters such as oxygen consumption, operating pressure, and choice of acid-gas removal process. The results of these are shown in

Table VIII. These optimization efforts will have to be confirmed by the pilot plant operation.

Hygas Process (39)

This process has three different ways of supplying heat, namely electrothermal, oxygen, and iron oxide but the economics are available for electrothermal Hygas process only. The second most important factor in determining gas price is the cost of electricity. The latest published economics divert from the AGA accounting procedure. The return on rate base is raised from 7% to 9.4% and the interest rate on the debt raised from 5% to 7.5%. The operating labor cost considered is $4.25 per hour. The power cost, if purchased, is considered at 4 mills/kWhr. Calculations are made for coal-based design with plant capacity of producing 258 BBtu/day (270 MMscfd) pipeline gas and another lignite-based with plant capacity of 500 BBtu/day (524 MMscfd) pipeline gas.

TABLE XII

ECONOMICS OF HYGAS PROCESS - COAL-BASED DESIGN - 258 BBtu/DAY

Power source	Onsite conventional	Purchased
Investment, $MM	169.6	108.3
Total operating expenses, $MM	46.4	54.4
Annual revenue required, $MM	54.3	50.3
20-year average gas price, cents/MMBtu (16 cents/MMBtu coal)	64.1	59.4

TABLE XIII

ECONOMICS OF HYGAS PROCESS - LIGNITE-BASED DESIGN - 500 BBtu/DAY

Power source	Onsite conventional	Purchased
Investment, $MM	304.8	186.5
Total operating expenses, $MM	76.3	82.1
Annual revenue required, $MM	85.3	80.1
20-year average gas price, cents/MMBtu (12 cents/MMBtu lignite)	52.0	48.8

Cost of coal affects the gas price significantly and as it varies from 8 cents to 24 cents per MMBtu, the gas price varies from 42 cents to 78 cents per MMBtu. Annual revenue requirement is less than operating expenses in purchased power source because of thebbyproduct credit.

Synthane Process (33)

The AGA accounting procedure is employed in determinining gas price. This plant has a capacity of producing 250 MMscfd gas of heating value of 930 Btu/scf. The total capital investment has been estimated at $165 million. The annual operating expenses are estimated at $39.6 million. And the 20-year average gas price would be 54 cents per thousand cubic feet.

Molten Salt Process (34)

The AGA accounting procedure is employed in determinig the gas price. This plant has a capacity of producing 250 MMscfd pipeline gas.

The study has been done for five different types of coal. Stream efficiency considered is about 90 percent.

TABLE XIV

ECONOMICS OF MOLTEN SALT PROCESS

Feedstock	Sub-bituminous ($2/ton)	Bituminous ($4/ton)	Lignite ($1.5/T)	Char (10¢/MMBtu)	Anthracite ($8/T)
Total capital investment, $MM	146.7	140.3	161.9	191.7	169.4
Total operating expenses, $MM/yr	29.7	34.7	40.0	49.9	65.0
Gas selling price, ¢/Mscf	43.5	50.3	58.3	72.1	89.9

Sub-bituminous and bituminous type feedstock give a reasonably priced gas and it is believed that with further optimization the cost of gas from lignite can also be reduced to the range of 50¢/Mscf. Char contains high percent of ash (17.4% assumed) and its removal contributes a large share of the ultimate gas price. Anthracite is costly by itself and that gives costly gas, but if a large quantity of feedstock of anthracite at lower price can be found, anthracite, too, would yield reasonably priced gas.

Lurgi Process (34, 35)

Plant has capacity of producing 250 MMscfd gas of heating value of 970 Btu/scf. The total capital investment for this plant is estimated at about $250 million. Out of this only 15% of the capital goes for the primary units, gasifiers. The annual operating expense is estimated at about $57 million. Based on these, the twenty-year average gas selling price would be about 65.7 cents/Mscf.

Economics of Various Processes on Common Basis

An attempt is made here to summarize, on a common basis, the economics of the various processes discussed earlier. The numbers and values presented in the preceeding paragraphs were taken from available references, and therefore, they represent a wide spectrum of accounting procedures. As they stand, a direct comparison of gas selling price is not easily made. The basis chosen for the purpose is shown in Table XV.

TABLE XV

COMMON BASIS EMPLOYED FOR ECONOMIC EVALUATION
OF VARIOUS PROCESSES

(i) 250 million scfd gas plant capacity

(ii) twenty-year plant life

(iii) Straight line depreciation

(iv) 12% gross return on rate base

(v) Financing - 65% debt, 35% equity

(vi) Interest rate - 7.5%

TABLE XV (Continued)

(vii) Federal income tax at 48%

(viii) Coal price at 35 cents/MMBtu

(ix) Onsite power [illegible]

(x) Load factor 95%, i.e. 347 days operation per year at full capacity

(xi) Contractor's overhead and profit 7.5%

(xii) Byproduct credit:

Char	$4/27 MMBtu
Ammonia	$20/ton
Sulfur	$5/ton
Phenols	$80/ton

(xiii) Labor charges at $4.25/hour

(xiv) Maintenance at 3% of bare plant cost

(xv) Supplies at 15% of maintenance

(xvi) Supervision at 10% of direct labor charges

(xvii) Payroll overhead at 10% of direct labor and supervision charges

(xviii) General overhead at 50% of direct labor, maintenance, supplies, and supervision

(xix) Local taxes and insurance at 3% of total fixed investment.

The detailed economics of all but the Synthane Process are shown in Appendix A (Tables XVII through XXI) along with a brief discussion of some of the base factors shown in Table XV. The results of those calculations are summarized in Table XVI for ease of comparison.

TABLE XVI

ECONOMICS OF PROCESSES UNDER DEVELOPMENT

Process	CO_2 acceptor	Bigas	Hygas	Synthane	Molten Salt	Lurgi
Total fixed investment, $MM	103.31	170.00	156.12	165.00	159.60	286.00
Total working capital, $MM	11.68	11.28	12.47	-	11.19	13.07
Total capital investment, $MM	114.99	181.28	168.59	-	170.79	299.07
Net operating expenses per year, $MM	64.021	68.812	74.304	69.375	65.541	81.109
Annual average revenue requirement, $MM	75.342	85.707	90.439	-	81.529	108.430
20-year average gas selling price, ¢/MMBtu	91.2	104.9	109.0	100.00	103.1	134.8

Conclusion

The price of gas from coal is certainly higher than the present gas price but can stand very much in competition with imported LNG. The well-head gas prices are likely to increase. President Nixon's Council of Economic Advisers (40), in its recent Congressional report, expressed the view that it would be less expensive to try to find domestic natural gas rather than going for LNG or SNG from oil. The report also places the fault for present gas shortage on the too low well-head prices. G. P. Mitchell, president of the Texas Independent Producers and Royalty Owners, recently predicted an increase in gas prices to 50 or even 70 cents per Mcf in some regions (41). Certain State Department documents currently circulating are highly critical of the nation's dependence on imported gas and oil (42). The high dependency can create many political problems and constraints. Thus it appears that gas from coal is in the making.

The numbers from Table XVI reveal that gas manufactured by CO_2 acceptor process is the cheapest of all those shown. Also the total fixed investment is least in CO_2 acceptor process. But the present status of the process is comparatively behind the Lurgi and Hygas processes. With regard to cost and investment, Molten Salt process also appears attractive but is still only at the laboratory stage. Many problems inherent in this process are not resolved and the operational feasibility is yet to be established. Hygas process is well ahead of others in its present status, excluding Lurgi. Whereas, plants employing Lurgi process are in use except for the methanation unit. Thus it is hard to predict at this stage which of the processes can produce gas by optimum of investment and gas price giving a minimum of technical problems. This can be done after the pilot plant studies. The U.S. has many varieties of coal scattered throughout the nation. Those various processes employ only a few varieties of coal in experiments and thus any single process may have operational feasibility with only those varieties of coal that are employed for experiments.

George Fumich, Jr. (5), director of OCR, once informed the Congress that about 180 coal gasification plants will be needed by 1985 to meet the growing gas demand. He also mentioned that a synthetic natural gas plant would have to produce at least 250 MMscfd to be economically feasible. An engineering study by AGA reveals over 150 domestic locations where coal, water, and labor sources would attract commercial coal gasification plants. Thus the nation appears to have many of the things that can help it become self-sufficient for its gas needs.

The following specific conclusions are made:

1. Coal gasification will likely be commercialized, possibly by 1980.
2. An increase in gas prices will probably be allowed by the FPC. This could make the price of SNG from coal more competitive with natural sources, but also it could stimulate increased exploration.
3. The order of technological advancements in coal gasification processes is Lurgi, Hygas and CO_2 acceptor, followed by the others.
4. All gasification processes will probably yield a gas selling price at about 100 cents per Mcf or higher.
5. For the common basis shown in Table XV, Lurgi requires the greatest investment and gas selling price. The CO_2 acceptor process if the lowest in both cases.

6. The methanation step is still a questionable part of all processes. This must be given large scale testing on coal derived gases. Such testing will probably be underway in the next few months by at least one company.

7. Possibly more than one of the coal gasification processes will reach commercialization. This will be dictated by regional coal characteristics, economics, and, of course, timing.

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APPENDIX A

ECONOMIC CALCULATIONAL DETAILS

Calculations for the numbers shown in Table XVI are given below. In Table XV, the 12% gross return on rate base was chosen as more representative of that needed for industry-government interests. The range reported varies from 7 to 15%. The financing of 65% debt to 35% equity was taken directly from AGA recommendation. The 7.5% interest rate was taken as being representative of the range reported (5 to 9%). To put all the operations on a common coal base, a coal price of 35 cents/MMBtu was chosen from a presentation by Neal P. Cochran of the OCR (43). This is probably somewhat higher than that used in most economic estimations to date. The price, of course, will vary between lignite and bituminous. There would be a wide price range in a per ton basis. Note that some processes are better suited to using lower grade liquid coal and others must use bituminous.

The byproduct prices are probably the most debatable and questionable aspects. Char is taken at a low value similar to that given in a previous report (35). Sulfur is given only a $5/ton value even though some reports take as much as $20/ton credit. The sulfur market will likely be oversupplied, especially as air pollution controls become operable.

In the following tables, the plants are based on 250 MMscfd. The bare plant costs were obtained from the reports referenced and adjusted to a common date basis, 1971. The accounting procedure is similar to that of AGA. Byproduct credit is the summation of the estimated value of all byproducts from a process. A simple gross rate of return is used in the calculations for ease of estimation. Any one of several return rates could be used.

TABLE XVII

REVISED ECONOMICS OF CO_2 ACCEPTOR PROCESS

Investment (in $MM)		
	Bare plant cost (24)	89.40
	Contractor's fee at 7.5%	6.70
	Sub-total installed plant cost	96.10
	Interest during construction at 7.5%	7.21
	Total fixed investment (TFI)	103.31
Working capital (in $MM)		
	Coal, 30 days at 35¢/MMBtu	4.49
	Chemicals and catalysts, 30 days	0.243
	Accounts receivable, 30 days at 91.2¢/MMBtu	6.947
	Total working capital	11.680
Total capital investment (in $MM)		114.990
Operating expenses (in $MM/year)		
1)	Coal	48.400
2)	Other direct materials	2.625
3)	Direct operating labor	1.050
4)	Maintenance[1]	2.404
5)	Supplies[2]	0.361
6)	Supervision[3]	0.105
7)	Payroll overhead[4]	0.116
8)	General overhead[5]	1.960
9)	Depreciation (5% of TFI)	5.170
10)	Local taxes and insurance (3% of TFI)	3.101
	Sub-total	65.282
11)	Contingency at 2%	1.306
	Total operating expenses	66.588
12)	Byproduct credit	2.567
	Net operating expenses	64.021

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[1] 3% of bare plant cost.

[2] 15% of maintenance.

[3] 10% of direct operating labor.

[4] 10% of direct operating labor and supervision.

[5] 50% of direct operating labor, maintenance, supplies, and supervision.

TABLE XVII (Continued)

Gross return (12%), 20-year average	7.296
Federal income tax, 20-year average	4.025
Total revenue requirement	75.342
20-year gas selling price (in ¢/MMBtu)	91.2

TABLE XVIII

REVISED ECONOMICS OF BIGAS PROCESS

Investment (in $MM)	
Bare plant cost (29)	147.10
Contractor's fee at 7.5%	11.02
Sub-total installed cost	158.12
Interest during construction at 7.5%	11.88
Total fixed investment (TFI)	170.00
Working capital (in $MM)	
Coal, 30 days at 35¢/MMBtu	3.76
Chemicals and catalyst, 30 days	0.08
Accounts receivable, 30 days at 104.9¢/MMBtu	7.44
Total working capital	11.28
Total capital investment (in $MM)	181.28
Operating expenses (in $MM/year)	
1) Coal	43.500
2) Other direct materials	0.963
3) Direct operating labor	1.485
4) Maintenance[1]	4.193
5) Supplies[2]	0.629
6) Supervision[3]	0.148
7) Payroll overhead[4]	0.163
8) General overhead[5]	3.228
9) Depreciation (5% of TFI)	8.500
10) Local taxes and insurance (3% of TFI)	5.100
Sub-total	67.909
11) Contingency at 2%	1.358
Total operating expenses	69.267
12) Byproduct credit	0.455
Net operating expenses	68.812

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[1] 3% of bare plant cost.

[2] 15% of maintenance.

[3] 10% of direct operating labor.

[4] 10% of direct operating labor and supervision.

[5] 50% of direct operating labor, maintenance, supplies, and supervision.

TABLE XVIII (Continued)

Gross return (12%), 20-year average	11.010
Federal income tax, 20-year average	5.885
Total revenue requirement	85.707
20-year average gas selling price (in ¢/MMBtu)	104.9

TABLE XIX

REVISED ECONOMICS OF HYGAS-ELECTROTHERMAL PROCESS

Investment (in $MM)	
Bare plant cost (41)	135.10
Contractor's fee at 7.5%	10.12
Sub-total installed cost	145.22
Interest during construction	10.90
Total fixed investment (TFI)	156.12
Working capital (in $MM)	
Coal, 30 days at 35¢/MMBtu	4.65
Chemicals and catalyst, 30 days	0.03
Accounts receivable, 30 days at 109.0¢/MMBtu	7.79
Total working capital	12.47
Total capital investment (in $MM)	168.59
Operating expenses (in $MM/year)	
1) Coal	53.700
2) Other direct materials	0.256
3) Direct operating labor	1.154
4) Maintenance[1]	4.050
5) Supplies[2]	0.608
6) Supervision[3]	0.115
7) Payroll overhead[4]	0.127
8) General overhead[5]	2.964
9) Depreciation (5% of TFI)	7.806
10) Local taxes and insurance (3% of TFI)	4.685
Sub-total	75.465
11) Contingency at 2%	1.509
Total operating expenses	76.974
12) Byproduct credit	2.670
Net operating expenses	74.304

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[1] 3% of bare plant cost.

[2] 15% of maintenance.

[3] 10% of direct operating labor.

[4] 10% of direct operating labor and supervision.

[5] 50% of direct operating labor, maintenance, supplies, and supervision.

TABLE XIX (Continued)

Gross return (12%), 20-year average	10.475
Federal income tax, 20-year average	5.660
Total revenue requirement	90.439
20-year average gas selling price (in ¢/MMBtu)	109.0

TABLE XX

REVISED ECONOMICS OF MOLTEN SALT PROCESS

Investment (in $MM)	
Bare plant cost (35)	138.10
Contractor's fee at 7.5%	10.37
Sub-total installed cost	148.47
Interest during construction at 7.5%	11.13
Total fixed investment (TFI)	159.60
Working capital (in $MM)	
Coal, 30 days at 35¢/MMBtu	3.54
Chemicals and catalyst, 30 days	0.58
Accounts receivable, 30 days at 103.1¢/MMBtu	7.07
Total working capital	11.19
Total capital investment (in $MM)	170.79
Operating expenses (in $MM/year)	
1) Coal	41.150
2) Other direct materials	3.441
3) Direct operating labor	1.476
4) Maintenance[1]	3.427
5) Supplies[2]	0.515
6) Supervision[3]	0.148
7) Payroll overhead[4]	0.163
8) General overhead[5]	2.783
9) Depreciation (5% of TFI)	7.980
10) Local taxes and insurance (3% of TFI)	4.790
Sub-total	65.873
11) Contingency at 2%	1.318
Total operating expenses	67.191
12) Byproduct credit	1.650
Net operating expenses	65.541

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[1] 3% of bare plant cost.

[2] 15% of maintenance.

[3] 10% of direct operating labor.

[4] 10% of direct operating labor and supervision.

[5] 50% of direct operating labor, maintenance, supplies, and supervision.

TABLE XX (Continued)

Gross return (12%), 20-year average	10.410
Federal income tax, 20-year average	5.578
Total revenue requirement	81.529
20-year average gas selling price (in ¢/MMBtu)	103.1

TABLE XXI

REVISED ECONOMICS OF LURGI PROCESS

Investment (in $MM)	
Bare plant cost (37)	247.50
Contractor's fee at 7.5%	18.54
Sub-total installed cost	266.04
Interest during construction at 7.5%	19.96
Total fixed investment (TFI)	286.00
Working capital (in $MM)	
Coal, 30 days at 35¢/MMBtu	3.47
Chemical and catalyst, 30 days	0.24
Accounts receivable, 30 days at 134.8¢/MMBtu	9.36
Total working capital	13.07
Total capital investment (in $MM)	299.07
Operating expenses (in $MM/year)	
1) Coal	40.150
2) Other direct materials	2.810
3) Direct operating labor	3.710
4) Maintenance[1]	5.850
5) Supplies[2]	0.877
6) Supervision[3]	0.371
7) Payroll overhead[4]	0.408
8) General overhead[5]	5.404
9) Depreciation (5% of TFI)	14.300
10) Local taxes and insurance (3% of TFI)	8.590
Sub-total	82.470
11) Contingency at 2%	1.649
Total operating expenses	84.119
12) Byproduct credit	3.010
Net operating expenses	81.109

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[1] 3% of bare plant cost.

[2] 15% of maintenance.

[3] 10% of direct operating labor.

[4] 10% of direct operating labor and supervision.

[5] 50% of direct operating labor, maintenance, supplies, and supervision.

TABLE XXI (Continued)

Gross return (12%), 20-year average	17.880
Federal income tax, 20-year average	9.441
Total revenue requirement	108.430
20-year average gas selling price (in ¢/MMBtu)	134.8

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VITA

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