COAL SEAMS

UNCONVENTIONAL GAS SOURCES

NATIONAL PETROLEUM COUNCIL • JUNE 1980

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John F Bookout, Chairman—Committee on Unconventional Gas Sources

NATIONAL PETROLEUM COUNCIL

U.S. DEPARTMENT OF ENERGY

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The sole purpose of the National Petroleum Council is to advise, inform, and make recommendations to the Secretary of Energy on any matter requested by the Secretary relating to petroleum or the petroleum industry.

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PREFACE

By letter dated June 20, 1978, the National Petroleum Council, an industry advisory committee to the Secretary of Energy, was requested to prepare an analysis of potential natural gas recovery from coal seams, Devonian Shale, geopressured brines, and tight gas reservoirs. In requesting the study, the Secretary stated that:

> ...Your analysis should assess the resource base and the state-of-the-art of recovery technology. Additionally, your appraisal should include the outlook for cost and recovery of unconventional gas and should consider how government policy can improve the outlook. (See Appendix A for complete text of the Secretary's letter and a further description of the National Petroleum Council.)

To aid it in responding to this request, the National Petroleum Council established a Committee on Unconventional Gas Sources under the chairmanship of John F. Bookout, President and Chief Executive Officer, Shell Oil Company. R. Dobie Langenkamp, Deputy Assistant Secretary for Resource Development & Operations, Resource Applications, U.S. Department of Energy, served as Government Cochairman of the Committee. A Coordinating Subcommittee and four task groups, by source, were formed to assist the Committee. The Coal Seams Task Group was chaired by William N. Poundstone, Consolidation Coal Company, and cochaired by Troyt York of the Department of Energy. (Rosters of the study groups responsible for this volume are included in Appendix B.)

The National Petroleum Council's report on <u>Unconventional Gas Sources</u> is being issued in five volumes:

- Volume I - Executive Summary
- Volume II - Coal Seams
- Volume III - Devonian Shale
- Volume IV - Geopressured Brines
- Volume V - Tight Gas Reservoirs.

The Coal Seams, Devonian Shale, and Geopressured Brines volumes are being issued in June 1980 with the Executive Summary and Tight Gas Reservoirs volumes being issued in late 1980.

For each source, reserve additions and producing rates are calculated at five gas prices, three rates of return, and at least two levels of technology. Constant January 1, 1979, dollars were used in all analyses. <u>The report presents estimates of what could happen under certain technical and economic circumstances and is not intended to represent a forecast of what will occur.</u>

SUMMARY

The main objective of this report is to go beyond the projection of in-place coal-bed gas resources in the United States and attempt to estimate what fraction of this resource is economically recoverable. Projections are based on the economic analysis of state-of-the-art technology and extrapolation of gas recovery rates from historical data. Since the total quantity of in-place gas is quite substantial, and since most studies done in the past have addressed only this total resource base, an impression has been created that the size of the economically recoverable reserves is also very large. This report attempts to provide a qualified and educated guess as to the quantities of coal-bed gas that could be recovered under various price scenarios.

Data on the gas content of coals in place are very sparse, being limited to about 50 coal seams out of the many hundreds that are known to exist. Besides, the bulk of data available pertain to mineable bituminous coal seams, where concern for mine safety provided the primary impetus for collection of gas-related information. Over the past few years some data have been obtained specifically for proposed gas recovery projects, but the total amount of information is still quite inadequate for proper analysis.

Theoretical models to project the flow of gas through porous media, such as coal, are in use. However, the physical prospectuses of coal that are relevant in such analyses are not available for a vast majority of coal seams in the country. Actual experience with gas recovery projects is also quite limited, and the results to date have shown substantial variability. In view of this paucity of information, as well as experience, the study participants could do no better than to extrapolate from the little that is known by making certain gross assumptions on costs and production. The results should, therefore, be viewed as nothing more than an order-of-magnitude projection based on current information. A concerted effort will have to be made to collect much more information and to acquire much more experience before reliable estimates could properly be projected.

Pre-drainage of significant amounts of coal-bed gas is likely to have a positive effect on the safety of eventual mining operations. However, there is risk involved in recovering gas from coal beds by hydraulic fracturing of coal seams through vertical wells. Serious concern was expressed that the fracturing technique had the potential of rendering some coal seams unmineable or, at the very least, increasing the likelihood of roof damage in mines and thereby jeopardizing the safety of mine workers and affecting the cost of mining. Since the energy content of the gas amounts to only 1 to 2 percent of the energy content of coal, some study participants felt that even a little risk in this regard was unwarranted. If the alternative approaches to gas recovery through horizontal or slant holes manifest comparable levels of gas recovery economics,

the question of hydraulic fracturing may become moot. In the meantime, the risk of damage to coal seams being mined or likely to be mined needs to be assessed carefully for each situation.

There are other constraints that will need to be addressed and which are elaborated on later in this report. The greatest constraints are the issue of legal ownership of gas and the problem of the treatment and disposal of water in accordance with applicable environmental requirements.

Keeping the above qualifications in mind, the study has projected quantities of economic reserves of coal-bed gas for the case where the raw gas, as produced, could be used on site at relatively low pressures. These projections are shown in Table 8. Also included are projections of the likely annual rates of production of this gas, under two different scenarios, up to the year 2000. In one scenario, gas is recovered by vertical wells and hydraulic stimulation, and in the other, this is done using shafts and horizontal drilling.

A separate set of economics is presented for the case where the recovered gas will need scrubbing for removal of carbon dioxide and other contaminants, high-pressure compression, and delivery to an offsite utility pipeline.

CHAPTER ONE

INTRODUCTION

REPORT OBJECTIVES

The objectives of this analysis of coal-bed gas are to:

- Identify and evaluate the resource base of the coal-bed gas
- Assess the state-of-the-art of coal gas recovery technology with projections for the future
- Project the economics of gas recovery projects and quantify the amounts of recoverable gas at various support levels
- Project rates of recovery of this reserve to the year 2000
- Analyze the constraints which may preclude recovery levels from being achieved.

ORIGIN OF COAL-BED GAS

Coal-bed gas is formed during the natural processes that lead to the formation of coal. Although much of the gas formed during the initial coalification process is lost to the atmosphere, a significant portion is retained in one of three ways:

- As free gas contained in the cracks and fractures of the coal bed
- As adsorbed gas on the internal surfaces of micropores within the structure of the coal itself
- As desorbed gas in adjacent strata which may serve as supplementary reservoirs for such gas.

CHEMICAL COMPOSITION OF COAL-BED GAS

Methane (CH_4) is the primary component of coal-bed gas, generally comprising 85 to 99 percent by volume. Other hydrocarbons account for minor quantities, not exceeding 2 percent, while contaminants such as carbon dioxide (CO_2) and nitrogen (N_2) make up the rest. Table 1 (see Appendix I, Ref. 1) shows the analysis of gas from some selected coal beds, and also the average composition of natural gas.

The presence of carbon dioxide, as evidenced by most of the gas recovered from the Pittsburgh seam, poses a potential problem because of its corrosive action in association with water and the impact that it can have on delivery lines, compressors, etc. All

TABLE 1

Composition Of Coal-Bed Gas* Compared With Natural Gas†
(Shown In Percent)

	Pocahontas #3	Pittsburgh	Kittanning	Lower Hartshorne	Mary Lee	Natural Gas
CH_4	96.37	90.75	97.32	99.22	96.05	94.40
C_2H_6	1.39	0.29	0.01	0.01	0.01	3.80
C_3H_8	0.0147	--	--	--	--	0.6
C_4H_{10}	0.0008	--	--	--	--	0.3
C_5H_{12}	--	--	--	--	--	0.2
O_2	0.17	0.20	0.24	0.10	0.15	--
N_2	1.7	0.59	2.3	0.6	3.5	0.4
CO_2	0.36	8.25	0.14	0.06	0.10	--
H_2	0.01	--	--	--	--	--
He	0.03	--	--	--	0.27	--
Btu/SCF§	1,059	973	1,039	1,058	1,024	1,068

*Deul, M., and Kim, A. G., "Methane in Coal: From Liability to Asset," Mining Congress Journal.

†Moore, B. J., et al., "Analyses of Natural Gas of the United States," USBM IC 8302, 1966.

§British thermal unit per standard cubic foot at atmospheric pressure. Note: 252 kilogram calories per Btu and 0.0283 cubic meters per cubic foot.

utilities specify a maximum limit for carbon dioxide, and where coal-bed gas exceeds this limit, it will need to be "scrubbed" or cleaned before it can be delivered into such a utility pipeline.

The heat content of most coal-bed gas varies from about 850 Btu to about 1,050 Btu per cubic foot. For purposes of this study, an average value of 1,000 Btu per cubic foot is assumed.

LIBERATION OF COAL-BED GAS

Some of the gas thus entrapped in and around coal seams can be liberated either by the act of mining itself or by techniques of pre-mining degasification. The liberation of large amounts of gas in the mining of some of the more gassy coal seams, and the risk of ignition and explosion related thereto, has established a need for investigating the occurrence of coal-bed gas for many years. Thus, while the impetus for degasification has primarily come from considerations of safe mineability, it has been recognized for some years now that this gas could have value as a supplemental energy source if it could be commercially recovered and used.

Generally, three modes of gas liberation are recognized:

- Gas liberated at the mine face where coal is cut and loaded or from the ribs and pillars of coal left in place. This gas is carried away in the mine ventilation air current in an extremely diluted form, and is probably not amenable to any economic recovery, even at higher prices. Research effort is and has been, therefore, better directed at recovering as much gas as possible prior to the mining of coal.

- Gas liberated in bleeders and gob degas holes. This is the gas which gradually bleeds either from coal or other gas reservoir areas near the mine workings after the coal has been fully extracted, thus breaking the immediate roof and other superposed strata. This gas may have been contained in other porous media in proximity to the coal seam or it may be coal-bed gas that originated in the coal seam and then migrated into the porous media.

  This gas is usually in a more concentrated form, but from time to time will contain large percentage amounts of air and other contaminants. While more effective pre-mining gas drainage will reduce the amount of such gas, there may be situations where it could be used locally as an energy source.

  The total amount of gas available for recovery is limited by the amount of underground mining with full extraction. Since the potential for such gas is insignificant in relationship to the projected resource base, it is not considered in detail in this report.

- Gas obtained by pre-mining drainage of coal seams. This gas is drained by drilling vertical or horizontal holes, and by other such techniques which are described later in this report.

ANALYSIS OVERVIEW

Since the coal gas resource is intimately connected with the resource base of the coal itself, the first step in the analysis was an evaluation of the coal resources of the country (Coal Resource section of Chapter Two). The average in-place gas content of bituminous coals was estimated for this report, based on the limited available information. Since hardly any data are available for subbituminous coals and lignites, their gas contents were extrapolated using an empirical relationship that relates gas content to the moisture content of bituminous coals (Gas Resource section of Chapter Two).

In order to relate gas production to a generalized set of project economics, it was decided to estimate an average initial gas recovery rate per well, per foot of coal seam thickness (Production Per Foot of Seam Thickness section in Chapter Four). A gas production decline of 10 percent per year was assumed, and a producing life of 12 years was used for each well. Economics were developed for a typical project, assuming a total project life of 20 years.

An analysis of the coal reserves was done to identify the total in-place coal resource for various cumulative thicknesses of reported coal seams (Computation of Coal Seam Thickness section of Chapter Four). Relating the total seam thickness to the flow of gas per well, and hence to the economics of gas recovery, it was possible to project economically recoverable gas reserves at various price levels.

Investment and operating costs were developed by the individual study participants for the types of projects they are now utilizing or would utilize (Estimation of Costs section of Chapter Five). From these, it was possible to extract average per-foot costs for vertical well projects for a base case where the recovered gas is assumed to be utilized at the project site itself without high-pressure compression, cleanup, or delivery costs. The costs for the latter items were estimated separately as add-on amounts.

The project economics were evaluated using a discounted cash flow (DCF) method of analysis (DCF Analysis section of Chapter Five). Gas prices were projected at 10, 15, and 20 percent internal rates of return (ROR's) for the two cases; i.e., (1) the base case, which assumes that the gas can be used on site without additional high-pressure compression, scrubbing, and delivery through a trunk pipeline, and (2) the case where costs for these add-on items were included. Economical gas reserves at various price levels were projected separately for the two cases mentioned above (Projection of Economic Reserves section of Chapter Six). Projected annual rates of gas production to the year 2000 are presented in the Projection of Rate of Development by Vertical Wells section of Chapter Six for the vertical wells case, and in the Projection of Rate of Development by Shafts and Horizontal Drilling section of Chapter Six for the case where the technique of horizontal drilling from shaft bottoms is utilized for gas recovery.

UNCERTAINTIES

- The U.S. Geological Survey coal resource data utilized for this study are less than precise. However, uncertainties about the coal resource are dwarfed by the much greater uncertainties that exist when extrapolating from the coal in place to the quantities of recoverable gas.

- Very little is known about the gas content of the vast majority of coals in the country. Out of the hundreds of coal seams that are known to exist, gas content information is available on about 50, limited primarily to mineable bituminous coal seams.

- The uncertainty regarding in-place gas content is compounded vastly by the fact that the values of physical parameters that control the flow of gas through coal beds are not available for the vast majority of coal seams in the country.

  The few actual gas recovery projects have shown variable and sometimes erratic results. Hardly any consistent data on gas flow rates over an appreciable length of time are available for analysis.

- Major uncertainties also exist over the possible risks associated with hydraulic fracturing, a technique that has been used to enhance the flow of gas through coal seams, and without which many vertical well projects do not produce significant amounts of gas. There is concern that in the process of fracturing the coal seam, the roof strata may be fractured so as to render some seams more hazardous and more expensive to mine, and possibly even render some seams unmineable.

  Since the energy content of the gas in a coal seam is only equivalent to 1 to 2 percent of the energy content of the coal itself, the concerns associated with hydraulic fracturing of vertical wells should be fully addressed before large-scale use of this technique is carried out in coal seams that are being mined now or are likely to be mined in the future.

- Other constraints and problems also exist, and are presented briefly in Chapter Seven. These include the issues of gas ownership, water disposal, etc.

CHAPTER TWO

RESOURCES

COAL RESOURCE

The U.S. Geological Survey reports on "mineable" coal resources in the country, based on its own definition related to the minimum seam thicknesses of various ranks and types of coal. As of 1974, it reported about 1.73 trillion tons of identified and 1.85 trillion tons of hypothetical coal resources. Another 0.39 trillion tons were reported as hypothetical resources in deeper structural basins (3,000 to 6,000 ft). A summary presentation is shown in Table 2, and a breakdown of these resources by state is presented in Table 3 (see Appendix I, Ref. 2).

A more recent computerized data base of mineable coal is also available from the U.S. Geological Survey. This data base covers only the identified reserves and shows a county-by-county listing of known coal seams by rank and by depth. This information was used in arriving at commercially recoverable gas reserves as described later in this report.

TABLE 2

Estimated Remaining Coal Resources in the United States
(January 1, 1974)

Category	Billions (10^9) of Short Tons
1. Identified (measured, indicated and inferred) resources:	
A. Reserve base	434
B. Additional identified	1,297
Total Identified	1,731
2. Hypothetical:	
A. 0-3,000 ft overburden	1,849
B. 3,000-6,000 ft overburden	388
Total Hypothetical	2,237
Grand Total -- Identified and Hypothetical	3,968

TABLE 3

Total estimated remaining coal resources of the United States, January 1, 1974

[In millions (10^6) of short tons. Estimates include beds of bituminous coal and anthracite generally 14 in. or more thick, and beds of subbituminous coal and lignite generally 2½ ft or more thick, to overburden depths of 3,000 and 6,000 ft. Figures are for resources in the ground]

State	Overburden 0–3,000 feet: Remaining identified resources, Jan. 1, 1974 (from table 2): Bituminous coal	Subbituminous coal	Lignite	Anthracite and semianthracite	Total	Estimated hypothetical resources in unmapped and unexplored areas[1]	Estimated total identified and hypothetical resources remaining in the ground	Overburden 3,000–6,000 feet: Estimated additional hypothetical resources in deeper structural basins[1]	Overburden 0–6,000 feet: Estimated total identified and hypothetical resources remaining in the ground
Alabama	13,262	0	2,000	0	15,262	20,000	35,262	6,000	41,262
Alaska	19,413	110,666	([2])	([3])	130,079	130,000	260,079	5,000	265,079
Arizona	[4]21,234	([4])	0	0	21,234	0	21,234	0	21,234
Arkansas	1,638	0	350	428	2,416	[5]4,000	6,416	0	6,416
Colorado	109,117	19,733	20	78	128,948	161,272	290,220	143,991	434,211
Georgia	24	0	0	0	24	60	84	0	84
Illinois	146,001	0	0	0	146,001	100,000	246,001	0	246,001
Indiana	32,868	0	0	0	32,868	22,000	54,868	0	54,868
Iowa	6,505	0	0	0	6,505	14,000	20,505	0	20,505
Kansas	18,668	0	([6])	0	18,668	4,000	22,668	0	22,668
Kentucky:									
Eastern	28,226	0	0	0	28,226	24,000	52,226	0	52,226
Western	36,120	0	0	0	36,120	28,000	64,120	0	64,120
Maryland	1,152	0	0	0	1,152	400	1,552	0	1,552
Michigan	205	0	0	0	205	500	705	0	705
Missouri	31,184	0	0	0	31,184	17,489	48,673	0	48,673
Montana	2,299	176,819	112,521	0	291,639	180,000	471,639	0	471,639
New Mexico	10,748	50,639	0	4	61,391	[7]65,556	126,947	74,000	200,947
North Carolina	110	0	0	0	110	20	130	5	135
North Dakota	0	0	350,602	0	350,602	180,000	530,602	0	530,602
Ohio	41,166	0	0	0	41,166	6,152	47,318	0	47,318
Oklahoma	7,117	0	([6])	0	7,117	15,000	22,117	[8]5,000	27,117
Oregon	50	284	0	0	334	100	434	0	434
Pennsylvania	63,940	0	0	18,812	82,752	[9]4,000	86,752	[10]3,600	90,352
South Dakota	0	0	2,185	0	2,185	1,000	3,185	0	3,185
Tennessee	2,530	0	0	0	2,530	2,000	4,530	0	4,530
Texas	6,048	0	10,293	0	16,341	[11]112,100	128,441	([11])	128,441
Utah	[12]23,186	173	0	0	23,359	[13]22,000	45,359	35,000	80,359
Virginia	9,216	0	0	335	9,551	5,000	14,551	100	14,651
Washington	1,867	4,180	117	5	6,169	30,000	36,169	15,000	51,169
West Virginia	100,150	0	0	0	100,150	0	100,150	0	100,150
Wyoming	12,703	123,240	([2])	0	135,913	700,000	835,913	100,000	935,913
Other States[14]	610	[15]32	[16]46	0	688	1,000	1,688	0	1,688
Total	747,357	485,766	478,134	19,662	1,730,919	1,849,649	3,580,568	387,696	3,968,264

[1]Source of estimates: Alabama, W. C. Culbertson; Arkansas, B. R. Haley; Colorado, Holt (1975); Illinois, M. E. Hopkins and J. A. Simon; Indiana, C. E. Wier; Iowa, E. R. Landis; Kentucky, K. J. Englund; Missouri, Robertson (1971, 1973); Montana, R. E. Matson; New Mexico, Fassett and Hinds (1971); North Dakota, R. A. Brant; Ohio, H. R. Collins and D. O. Johnson from data in Struble and others (1971); Oklahoma, S. A. Friedman; Oregon, R. S. Mason; Pennsylvania anthracite, Arndt and others (1968); Pennsylvania bituminous coal, W. E. Edmunds; Tennessee, E. T. Luther; Texas lignite, Kaiser (1974); Virginia, K. J. Englund; Utah, H. H. Doelling; Washington, H. M. Beikman; Wyoming, N. M. Denson, G. B. Glass, W. R. Keefer, and E. M. Schell; remaining States, by the author.

[2]Small resources of lignite included under subbituminous coal.

[3]Small resources of anthracite in the Bering River field believed to be too badly crushed and faulted to be economically recoverable (Barnes, 1951).

[4]All tonnage is in the Black Mesa field. Some coal in the Dakota Formation is near the rank boundary between bituminous and subbituminous coal. Does not include small resources of thin and impure coal in the Deer Creek and Pinedale fields.

[5]Lignite.

[6]Small resources of lignite in western Kansas and western Oklahoma in beds generally less than 30 in. thick.

[7]After Fassett and Hinds (1971), who reported 85,222 million tons "inferred by zone" to an overburden depth of 3,000 ft in the Fruitland Formation of the San Juan basin. Their figure has been reduced by 19,666 million tons as reported by Read and others (1950) for coal in all categories also to an overburden depth of 3,000 ft in the Fruitland Formation of the San Juan basin. The figure of Read and others was based on measured surface sections and is included in the identified tonnage recorded in table 2.

[8]Includes 100 million tons inferred below 3,000 ft.

[9]Bituminous coal.

[10]Anthracite.

[11]Lignite, overburden 200–5,000 ft; identified and hypothetical resources undifferentiated. All beds assumed to be 2 ft thick, although many are thicker.

[12]Excludes coal in beds less than 4 ft thick.

[13]Includes coal in beds 14 in. or more thick, of which 15,000 million tons is in beds 4 ft or more thick.

[14]California, Idaho, Nebraska, and Nevada.

[15]California and Idaho.

[16]California, Idaho, Louisiana, and Mississippi.

GAS RESOURCE

The gas content of the above coal resources cannot be estimated with any degree of confidence, since the tests to determine the in-place gas content have not been conducted on the vast majority of coal seams in the country. The limited data available, mostly from mineable bituminous coals, show considerable variability and little, if any, data are available for subbituminous coal and lignite. It is generally agreed, however, that the gas content of these lower rank coals is likely to be considerably less than that of bituminous coal on a per-ton basis.

The study participants considered published information on the gas content of coals (see Appendix I, Refs. 3, 4, 5) as well as some data produced by a few of the study participants from their ongoing programs. A listing of all such data is given in Appendix C. In making a judgment as to the average gas content of all bituminous coals, the study participants weighed two opposing considerations. First, based on mining experience, it was obvious that the majority of seams on which gas content data had been collected were the more "gassy" seams. In fact, it was concern for mine safety in gassy coal seams that had led to the collection of some of this data. The second consideration was that there was at least some indication that the gas content of coal, in general, increased with the depth of coal seams. It could, therefore, be said that deeper coal seams, especially in the western United States, may have high gas content. Weighing the two factors, the study participants decided to use a value of 200 cubic feet of gas per ton of coal for bituminous coal seams.

Later, a more comprehensive listing of gas content data was obtained from the U.S. Bureau of Mines, as presented in Appendix D. These data average about 175 cubic feet of gas per ton of coal and are generally in line with the data considered by the study participants in their deliberations.

In extrapolating the above value of 200 cubic feet per ton to subbituminous coals and lignites, it was decided to use an empirical relationship (see Appendix I, Refs. 6, 7) that relates gas content to the moisture content of coal, using a moisture content of 16 percent for subbituminous coals, and 38 percent for lignites. It was recognized that the relationship applied to bituminous coals only, but in the absence of any other information it was decided to extrapolate the equation to lower rank coals. As shown in Appendix E, such an extrapolation resulted in a value of 80 cubic feet per ton for subbituminous coals and 40 cubic feet per ton for lignites. It was also agreed that seams less than 300 feet deep probably contained no economically recoverable gas.

The above values can be used to project the gas resource base in conjunction with the coal resource data mentioned before. Since the hypothetical coal resources are not classified into different ranks, an approximate classification was used, based on the ratios between different coals in the identified category. Table 4 shows the coal-bed gas resource base that can thus be projected.

TABLE 4

Estimated In-Place Resource of Coal-Bed Gas

Coal Category	Estimated Coal Resource (Billions of Short Tons)	Estimated Gas Content (Ft^3/Ton)	Projected Gas Resource (TCF)
1. 300-3,000 feet deep (identified and hypothetical)			
A. Anthracite	46	200	9
B. Bituminous	1,001	200	200
C. Subbituminous	1,137	80	91
D. Lignite	504	40	20
2. 3,000-6,000 feet deep (hypothetical)	388	200	78
Total			398

CHAPTER THREE

TECHNOLOGY

The major techniques for recovering coal-bed gas are:

- Vertical wells
- Horizontal holes from mine access
- Horizontal holes from shaft bottoms
- Slant holes.

VERTICAL WELLS

This technique of recovering coal-bed gas consists of drilling vertical holes from the surface to the coal seam. The holes are generally 9 inches (0.23 meters) in diameter or less. Experience has shown that the amount of gas that will flow to such vertical holes through the natural cleat system or from the microporous structure of the coal seam is generally quite limited unless the area is naturally highly fractured. In order to increase the gas drainage area, a technique known as hydraulic fracturing has been used.

Hydraulic fracturing is the application of a fluid pressure to a desired section of formation (in this case the coal seam) until parting or formation "breakdown" occurs. This parting or crevice is extended with further pumping under pressure, establishing a new, larger flow channel to the well bore. Higher effective average permeability is created, resulting in increased gas flow to the well bore.

The most commonly used hydraulic fracturing fluids are gelled-water and nitrogen-water foam. Propping agents such as carefully sized sand grains are carried by the fluid into the crevice, preventing it from closing or healing when the hydraulic pressure is reduced.

The extension of hydraulically created fractures into strata overlying coal seams can constitute a deterrent to the safe and efficient mining of coal. This can be especially problematic when the strata immediately above the coal are comprised of thin layers of coal and weak shale. A number of experienced coal mine operators have expressed concern over the possibility that hydraulically created fractures extending into strata overlying mineable coal seams can create additional risks to safe and efficient mining.

There have been reports of at least 10 hydraulically induced fractures that were later mined through. A synopsis of the observations made in these various reports is given below:

- The Bureau of Mines reported on two such observations, one in the Pittsburgh seam and the other in the Illinois No. 6 seam (see Appendix I, Ref. 8). While the conclusion of the report was that "no adverse effect or extension of the induced fractures into the roof or floor rock of the mine was evident," it was mentioned in the body of the report that in the Illinois No. 6 seam a "hairline crack in the roof was exposed when the continuous miner removed a small area of hard coal," and "the crack extended a few inches into the roof rock."

- The Bureau of Mines also reported two other mine-through observations in Alabama's Mary Lee seam (see Appendix I, Ref. 9). This report contained the comment "no cement was found in the southern half of the well bore; instead, prop sand and/or gel filled this annular space at both the floor and the roof." This indicates that zonal isolation of roof and floor strata from the hydraulic pressure did not exist. Other relevant comments were "cement bond to casing were generally poor," and "the lack of cement within approximately one-half of the well bore annulus in the roof also indicates poor cementing." It was further mentioned in respect to one of these mine-throughs that "although sand-filled channels were not observed at TW-1, there is sufficient evidence to indicate that partings in the coal and roof rock had been opened during drilling, cementing, and early stages of stimulation," and "the gel in the roof contained no sand and therefore must have been included in the initial fluid pad before the proppant was added."

- In a paper about another hydraulic fracture, which was later mined in the Pittsburgh seam, "fracture penetration of three strata overlying the seam" was reported (see Appendix I, Ref. 10).

- In a court testimony (Mary Cunningham vs. U.S. Steel) relating to four mine-throughs in the Mary Lee seam and three in the Pittsburgh seam, it was mentioned that two of the former and one of the latter showed penetration of the roof.

Reports of these observations clearly demonstrate that cementing and hydraulic fracturing are unpredictable at best, and that the likely impact on the safe and economic mineability of coal seams needs to be assessed carefully for each situation.

As presented in more detail later, there are situations where the technique of drilling horizontal wells from shaft bottoms is comparable in economics to the vertical well technique, and could therefore be a practical alternative to degasification by hydrofracturing through vertical wells.

HORIZONTAL HOLES FROM MINE WORKINGS

This process consists of drilling horizontal holes into virgin coal from active working sections of an underground mine. The coal-bed gas that is thus liberated is conveyed through a piping system to the surface collecting site.

It is generally agreed that this method of recovering coal-bed gas is likely to be the most economical of all alternatives. The total potential for gas recovery from this technique, however, is limited by the number of underground mines that are under development at a given point in time. Consequently, this method is not expected to yield significant production in the foreseeable future.

HORIZONTAL HOLES FROM SHAFT BOTTOMS

In this technique, vertical shafts, ranging from 8 to 20 feet in diameter, are sunk to the bottom of the coal seam. Working within the confines of the shaft, small-diameter (approximately 4 inches) horizontal holes are drilled radially into virgin coal. The holes intersect the numerous repetitive fissures (cleats) characteristic of most coal formations and provide highly conductive vents through which the trapped gas can flow. The wellheads of the various horizontal holes are located around the perimeter of the shaft bottom and are connected through a common manifold which directs the gas to a vertical transport pipe. Once at the surface, the gas can be treated in a manner similar to that of coal-bed gas derived from vertical bore holes.

It has been reported that the rate of gas flow from horizontal holes drilled in permeable coal beds has reached up to 30 thousand cubic feet per day (MCF/D) (850 cubic meters) per 100 feet. Also, lengths of horizontal holes greater than 1,000 feet (304.8 meters) have been successfully demonstrated. This makes the concept potentially viable, even though there is a large front-end investment for shaft sinking. As pointed out earlier, in certain situations this method of gas recovery is economically comparable to a vertical well project. It could therefore be preferred, since it should have no adverse impact on the safe mineability of the coal seam.

SLANT HOLES

In this method, a small-diameter vertical hole is drilled from the surface and then intentionally and progressively deflected to penetrate the coal bed parallel to its bedding plane. The hole then continues into the coal seam as a horizontal hole.

Attempts to date to accomplish this method appear to be more costly than other techniques. In addition, it is technically difficult, and the risk involved in getting the hole properly deflected to penetrate the seam and then stay within it for long distances is quite high. Dewatering of such slant holes also poses a problem which has not been fully resolved. Improvements in the drilling and dewatering techniques are necessary before this method can be considered a proven technology. Nonetheless, the approach clearly offers an area of potential research activity, as in the case of two reported U.S. Bureau of Mines tests, which were considered sufficiently successful to warrant further testing (see Appendix I, Ref. 11).

CHAPTER FOUR

PRODUCTION HISTORY AND PROJECTIONS

BACKGROUND

Though the in-place gas content of coal is important, it is not directly related to the gas producing ability of a coal seam. There is general agreement, however, that some of the important factors that control rates of gas recovery are:

- In situ gas content of coal
- Diffusivity coefficient of coals
- Extent and permeability of the natural fracture system
- Efficiency of stimulation techniques
- Efficiency of water removal and disposal methods
- Reservoir pressure (depth of coal seam).

Quite a few efforts have been made to date to recover gas from coal beds. Although some of these have been successful, no single project has established a long-term economic viability as purely a gas recovery project, and results have been spotty and somewhat unpredictable.

PRODUCTION DATA FROM VERTICAL WELLS

A number of vertical wells, with and without hydraulic stimulation, have been drilled into coal measures, and the results from 39 such wells reported by the U.S. Bureau of Mines are presented in Table 5 (see Appendix I, Ref. 12). Of these, 23 stimulated wells averaged less than 24 MCF/D per well of gas recovery. Of the latter 23 wells, 14 were producing gas from the Pittsburgh seam, and their average production was about 30 MCF/D per well.

The U.S. Steel Corporation presented results of their gas recovery project in the Blue Creek coal seam in Jefferson County, Alabama, during the study deliberations. A rectangular pattern of vertical wells was drilled on a 21-acre spacing and hydraulically fractured. The average field production of 15 wells over the preceding four months was reported to be 65 to 70 MCF/D per well. Five of these wells had been producing for approximately one year.

Another project that has recently started producing coal-bed gas is the Waltz Mill project in Pennsylvania (see Appendix I, Ref. 5). A cumulative coal seam thickness of 27 feet, covering 12 different seams, has been tapped by a vertical well. Three of the zones containing a total of eight seams have been hydraulically

TABLE 5

Gas Production from Vertical Bore Holes

Coal Bed and Location	Bore Hole Number	Pre-Stimulation			Post-Stimulation		
		Average Production Rate (Ft^3/D)	Cumulative Production (MM Ft^3)	Water Production (B/D)	Average Production Rate (Ft^3/D)	Cumulative Production (MM Ft^3)	Water Production (B/D)
Pocahontas #3, Wyoming, WV	PK-1	5,300	2.3	6	--	--	--
	PK-2	830	0.5	3	5,390	2.3	9
	PK-3	970	0.9	5	--	--	--
	PK-4	4,680	2.6	23	--	--	--
	PK-5	3,100	1.3	8	--	--	--
Pittsburgh, Washington, PA	PV-1	6,800	2.3	3	21,125	11.4	14
	PV-2	955	0.2	1	15,725	5.2	19
	PV-3	5,450	2.5	8	15,875	15.5	25
	PV-5	333	0.1	1	15,440	6.5	25
Pittsburgh, Marion, WV	PL-1	3,650	2.5	1	--	--	--
	PL-2	820	0.6	0	--	--	--
	PL-3	350	0.1	1	16,700	10.5	3
	PL-4	7,300	3.5	1	20,350	16	20
	PL-5	1,420	0.5	1	--	--	--
Pittsburgh, Monongalia, WV	PF-1	540	0.2	7	--	--	--
	PF-2	630	0.4	20	--	--	--
	PF-3	1,730	1.3	8	--	--	--
	PF-5	4,060	1.8	13	--	--	--

TABLE 5 (continued)

Coal Bed and Location	Bore Hole Number	Pre-Stimulation: Average Production Rate (Ft^3/D)	Pre-Stimulation: Cumulative Production (MM Ft^3)	Pre-Stimulation: Water Production (B/D)	Post-Stimulation: Average Production Rate (Ft^3/D)	Post-Stimulation: Cumulative Production (MM ft^3)	Post-Stimulation: Water Production (B/D)
Pittsburgh, Greene, PA	PE-1	--	--	--	7,500	3.0	NA
	PE-3	--	--	--	26,800	5.6	NA
	PE-4	--	--	--	12,300	3.1	NA
	PE-5	--	--	--	61,100	23.8	NA
	PE-6	--	--	--	46,700	7.0	NA
	PE-7	--	--	--	70,000	10.5	NA
	PE-8	--	--	--	8,360	3.3	NA
	PE-11	--	--	--	62,200	3.7	NA
Castlegate Subseam #3, Carbon, UT	CC-1	36	0.02	1	--	--	--
	CC-3	15	0.01	1	851	.2	1
	CC-4	68	0.04	1	--	--	--
	CC-5	26	0.02	1	--	--	--
Hartshorne, LeFlore, OK	HL-1	6,000	3.8	2	--	--	--
	HL-4	820	0.7	1	--	--	--
	HL-5	1,100	0.2	1	2,200	5.5	2
Mary Lee, Jefferson, AL	ML-1	--	--	--	4,800	0.07	NA
	ML-2	--	--	--	12,000	0.9	NA
	ML-3	--	--	--	7,500	18.0	13
	ML-4	--	--	--	80,000	4.8	2
	ML-9	--	--	--	9,000	1.4	25
	ML-22	--	--	--	20,000	3.0	82

fractured. A production rate of about 40 MCF/D has been reported (see Appendix I, Ref. 20).

PRODUCTION DATA FROM LONG HORIZONTAL HOLES

Long horizontal holes can be drilled in virgin coal either from a location in an active underground mine or from the bottom of a shaft. After such holes have been sufficiently dewatered, gas flows through them. This gas can be captured in a pipeline and taken to the surface of the mine, either for onsite use or for delivery to a gathering pipeline.

Table 6 presents available results from horizontal hole projects. It may be seen from this table that while some initial horizontal holes did not produce any gas, subsequent efforts have yielded an average of about 15 MCF/D of gas per 100-foot length of the hole.

PRODUCTION PER FOOT OF SEAM THICKNESS

In order to relate gas production on a uniformly applicable basis, it was decided to project likely gas production per foot of coal seam thickness. This would lend itself to an economic analysis based on the total thickness of coal-bearing strata at any particular location.

All available data on gas recovery rates reduced to a gas flow per foot of seam thickness, as compiled in Table 7, were considered by the study participants. The coal and gas company representatives who have been associated with many of the projects listed therein believe that their efforts to date have been conducted in seams that they consider to have the best potential for gas recovery. For projecting gas recovery rates to all other seams in the country, with the limited information available, they felt that an average of 3 MCF/D per well per foot of bituminous coal seam thickness was a value that could perhaps be attained.

Representatives of an engineering consulting company, on the other hand, felt that much of the effort to date has been limited to drilling either one well or a few wells within a project area. They believe that this approach did not enable efficient removal of water from the seams, and had an adverse effect on gas flow rates. On the basis of theoretical computer models, which, they claim, have been authenticated with performance data, they were much more optimistic about the gas recovery possible from all seams in the country. The study participants failed to reach a consensus on this issue. A majority, however, felt that projections should be based on an average of 3 MCF/D per foot, but that the final results qualified appropriately to indicate that available information was very sparse and that most of the data were related to Appalachian experience.

TABLE 6

Horizontal Hole Gas Production
(Compiled 2/79)

Seam	Location	Total Length of Holes	MCF/D 100 Ft	Age	Depth
Pocahontas #3	VA	503	16.6	2 days	1,450
Pocahontas #3	VA	300	11.5	5 days	1,450
Pocahontas #3	VA	108	nil	5 days	1,450
Pocahontas #3	VA	255	nil	5 days	1,450
Pocahontas #3	VA	259	nil	5 days	1,450
Pocahontas #3	VA	95	nil	5 days	1,450
Pocahontas #3	VA	140	nil	5 days	1,450
Pocahontas #3	VA	90	nil	5 days	1,450
Lwr. Sunnyside	UT	430	37.0	2 mos.*	1,100-1,200
Lwr. Sunnyside	UT	450	28.0	2 mos.*	1,100-1,200
Pittsburgh	WV/PA	--	25	5 days	500-900
Pocahontas #3	VA	--	34	5 days	1,500-1,600
Blue Creek	AL	--	6	4 mos.	1,100
Mary Lee	AL	--	20	5 days	2,100
Pittsburgh	WV	4,290	3.7	2 yrs.	800
Pittsburgh	WV	5,000	0.2	2 yrs.	600
Pittsburgh	PA	3,000	10.4	6 mos.	700
Pittsburgh	WV	4,325	13.5	2 yrs	600
Pittsburgh	WV	4,325	13.1	4 yrs.	600
Pittsburgh	WV	4,524	18.9	2 yrs.	600
Pittsburgh	WV	4,524	14.8	4 yrs.	600

*Declined substantially in later months.

TABLE 7

Coal-Bed Gas Production From Vertical Wells

Coal-Bed & Location Particulars	Well I.D.	Estimated Seam Thickness (Ft)	Gas Production		Production Per Foot of Seam Thickness (MCF/D Ft)	Referring Number In Appendix I
			Pre-Stimulation (MCF/D)	Post-Stimulation (MCF/D)		
Pittsburgh, Washington, PA	PV-1	6.0	6.8	21.1	3.5	12
	PV-2	6.0	1.0	15.7	2.6	12
	PV-3	6.0	5.5	15.9	2.7	12
	PV-5	6.0	0.3	15.4	2.6	12
Pittsburgh, Greene, PA	PE-1	7.0	--	7.5	1.1	12
	PE-3	7.0	--	26.8	3.8	12
	PE-4	7.0	--	12.3	1.8	12
	PE-5	7.0	--	61.1	8.7	12
	PE-6	7.0	--	46.7	6.7	12
	PE-7	7.0	--	70.0	10.0	12
	PE-8	7.0	--	8.4	1.2	12
	PE-11	7.0	--	62.2	8.9	12
	1034	8.0	--	10.0	1.3	17
	1035	8.0	0.0	45.0	5.6	18
Pittsburgh, Monongalia, WV	PF-1	7.0	0.5	--	0.1	12
	PF-2	7.0	0.6	--	0.1	12
	PF-3	7.0	1.7	--	0.2	12
	PF-5	7.0	4.1	--	0.6	12

TABLE 7 (continued)

Coal-Bed & Location Particulars	Well I.D.	Estimated Seam Thickness (Ft)	Gas Production: Pre-Stimulation (MCF/D)	Gas Production: Post-Stimulation (MCF/D)	Production Per Foot of Seam Thickness (MCF/D Ft)	Referring Number In Appendix I
Pittsburgh, Marion, WV	PL-1	7.0	3.7	--	0.5	12
	PL-2	7.0	0.8	--	0.1	12
	PL-3	7.0	0.4	16.7	2.4	12
	PL-4	7.0	7.3	20.3	2.9	12
	PL-5	7.0	1.4	--	0.2	12
	L-5	8.5	0.0	8.6	1.0	10
	L-6	8.5	0.0	50.4	5.9	10
	L-7	8.5	0.2	15.0	1.8	22
Pocahontas #3, Wyoming, WV	PK-1	6.0	5.3	--	0.9	12
	PK-2	6.0	0.8	5.4	0.9	12
	PK-3	6.0	1.0	--	0.2	12
	PK-4	6.0	4.7	--	0.8	12
	PK-5	6.0	3.1	--	0.5	12
Pocahontas #3, Buchanan, VA	1	6.0	0.6	12.0	2.0	8
Castlegate #3, Carson, UT	CC-1	6.0	0.0	--	0.0	12
	CC-3	6.0	0.0	0.9	0.2	12
	CC-4	6.0	0.0	--	0.0	12
	CC-5	6.0	0.0	--	0.0	12
Hartshorne, LeFlore, OK	HL-1	5.0	6.0	--	1.2	12
	HL-4	5.0	0.8	--	0.2	12
	HL-5	5.0	1.1	2.2	0.4	12

TABLE 7 (continued)

Coal-Bed & Location Particulars	Well I.D.	Estimated Seam Thickness (Ft)	Gas Production Pre-Stimulation (MCF/D)	Gas Production Post-Stimulation (MCF/D)	Production Per Foot of Seam Thickness (MCF/D Ft)	Referring Number In Appendix I
5 seams in same well, Clay, IL	NK*	8.0	10.0	--	1.3	4
Illinois #6, Jefferson, IL	1	9.0	0.0	4.3	0.5	19
5 seams in same well, Rio Blanco, CO	TA-1	7.9	0.0	--	0.0	4
12 seams in same well, Westmoreland, PA	1	23.5	--	40.0	1.7	20
6 seams in same well, Cambria, PA	32-13	23.5	--	40.0	1.7	20
Blue Creek (15 wells), Jefferson, AL	NK*	5.5	--	67.5	12.3	21
9 seams in same well, Noble, OH	GT-1	11.0	0.1	1.6	0.1	22

*Not known.

COMPUTATION OF COAL SEAM THICKNESS

The U.S. Geological Survey's (USGS) computerized data base contained a county-by-county listing of coal resource information by rank, depth, and thickness. For each coal-bearing county, the average coal thickness was calculated by dividing the total in-place coal reserves by the area of the county, and using the density of coal assumed in the USGS data base. Thirty percent of the reserves within each county in the depth range of 0 to 1,000 feet was assumed to lie less than 300 feet from the surface, and was subtracted first with the assumption that this coal would contain no economically recoverable gas. In certain states, the USGS report indicated additional reserves in the unassigned and unclassified category. These were allocated on a pro-rata basis to the individual coal-bearing counties in the particular state. Also included on a pro-rata basis were the additional hypothetical coal resources by state, listed in Table 3. Graphs were plotted to indicate total resource for each rank of coal against total coal thickness as depicted in Figures 1, 2, and 3.

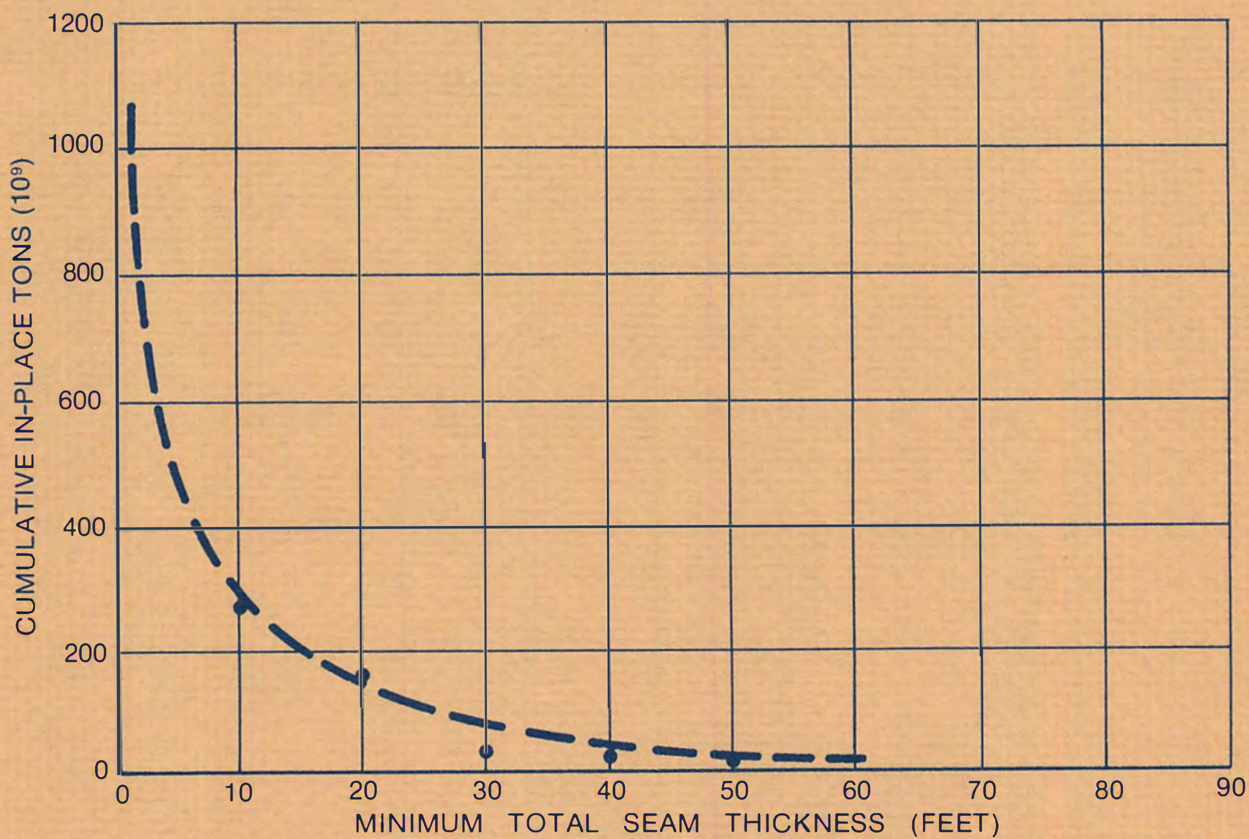


Figure 1. Estimated Distribution of Bituminous Coal.

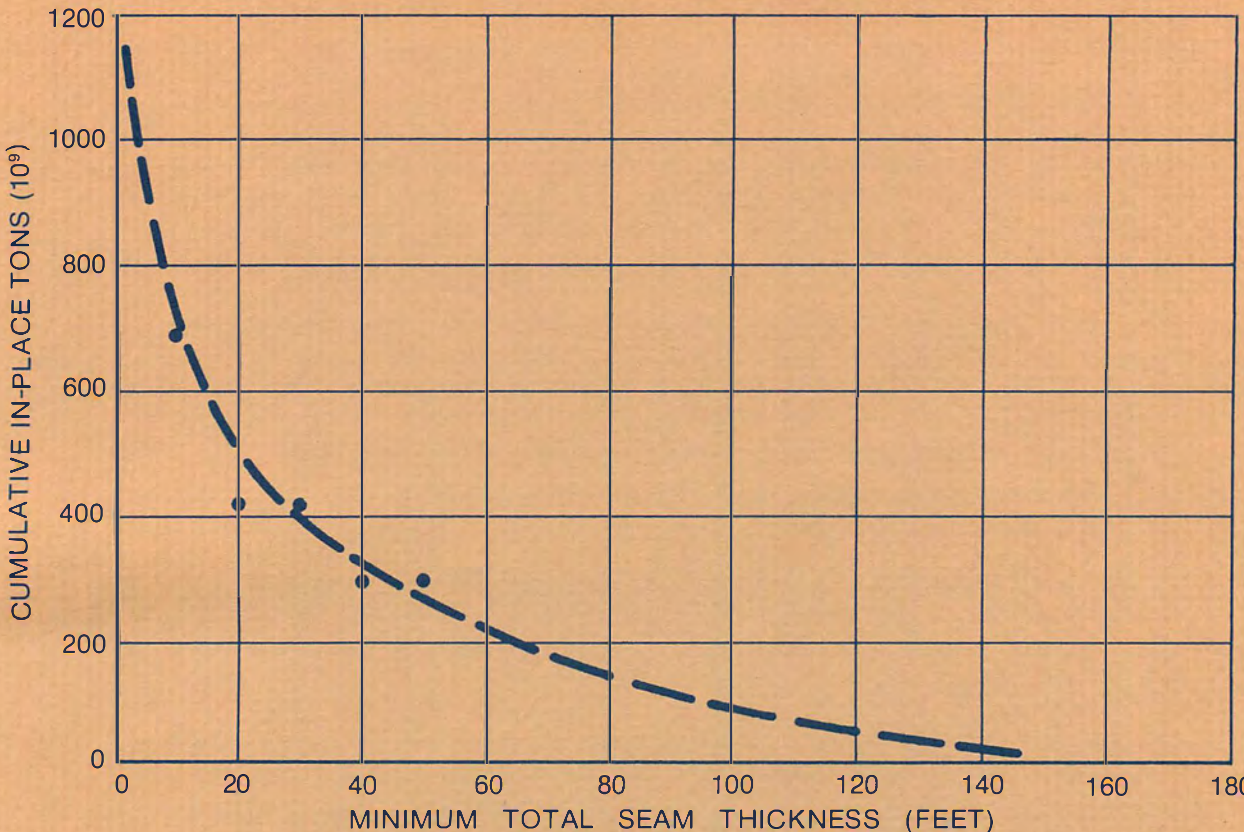


Figure 2. Estimated Distribution of Subbituminous Coal.

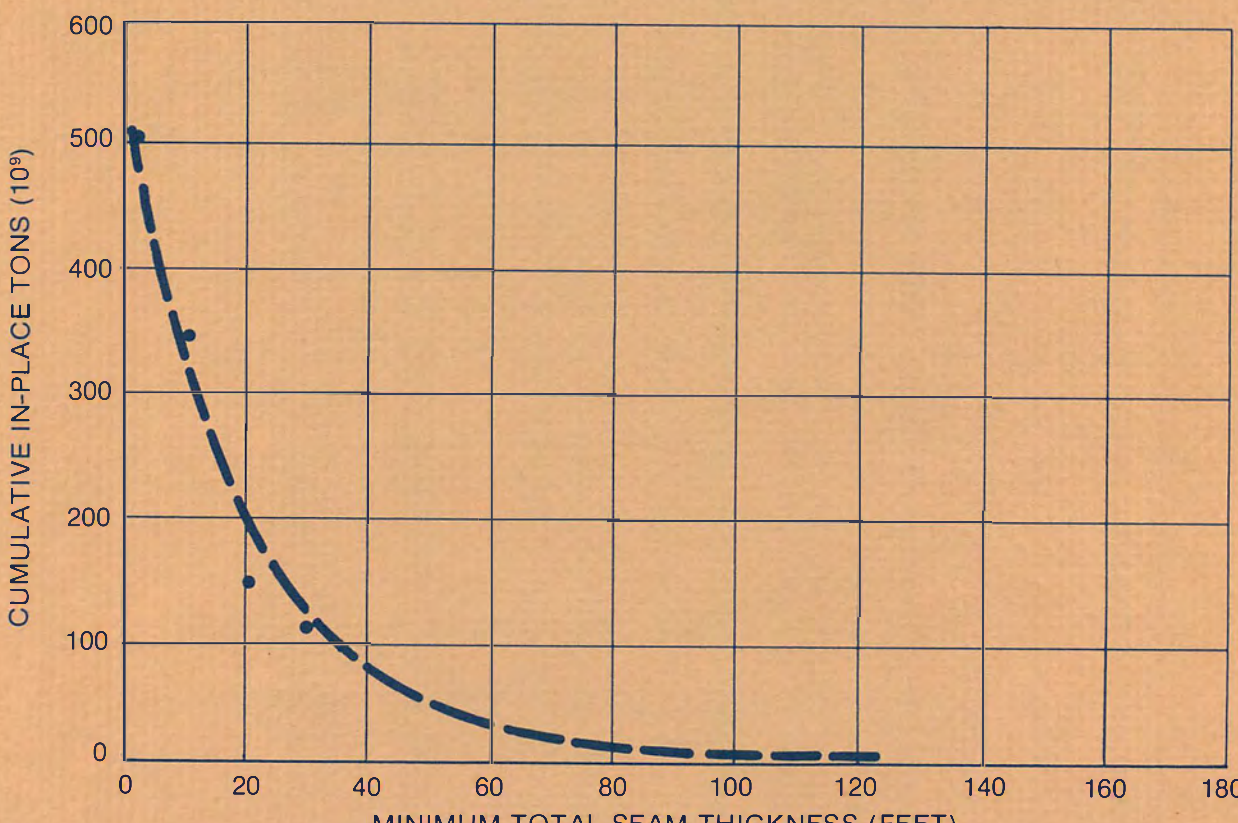


Figure 3. Estimated Distribution of Lignites.

CHAPTER FIVE

ECONOMIC ANALYSIS

BACKGROUND

It must be noted at the outset that no published data are available on the economics of coal-bed gas recovery projects. Of the few gas recovery projects that have been in operation, or are now in operation, most are primarily research oriented, with the active cooperation and assistance of the U.S. Bureau of Mines and the Department of Energy. Cost information has either not been fully developed or is not released for proprietary reasons. Economic projections cannot, therefore, be based on historical information.

Problems associated with the general lack of cost information are immeasurably compounded by the fact that gas recovery rates and volumes cannot be projected with any degree of confidence, as discussed earlier.

ESTIMATION OF COSTS

Individual study participants estimated investment costs for the type of vertical wells project they are utilizing or would utilize. The individual analyses were then compared with the objective of reconciling disparities for reasons of differing assumptions and assessments. Many of the costs are site specific in nature and these showed wide variability. Setting these items of cost aside, it was possible to synthesize average costs per foot length of a well for 3,000-foot wells, with a spacing of 3,000 feet between wells. The site-specific costs were averaged to provide a typical-case scenario.

Items of cost included water handling, wellhead compressors, all piping, etc., within the project area. High-pressure compression was not included in the base case since it was felt that in some situations the gas could be delivered directly to a low-pressure pipeline. Some of the gas is expected to need scrubbing to remove contaminants like carbon dioxide, water, etc., that may be present. These costs were estimated separately so that they could be added to the base case economics along with the cost of extending an estimated 5-mile average length of a gathering or trunk pipeline, and an estimated 10,000 feet of power transmission line, to the project site.

A "typical" hypothetical project scenario was used, comprising 20 initial wells drilled on a 5 x 4 grid to a 3,000-foot depth and a 3,000-foot spacing. It was recognized that in actual practice the spacing would be quite variable for each situation. However, the costs related to spacing between wells are a small proportion of total cost and, therefore, within the accuracy of this analysis, the per-well costs were considered to be applicable for a wide range of well spacings.

Using a 10 percent decline rate, it was necessary to bring additional wells on line every year so as to stay with a constant yearly production. A 90 percent success ratio was assumed; i.e., of all the wells that will be drilled in a project, 10 percent will have mechanical or other drilling problems which will require that the hole be plugged, and will therefore produce no gas. A 12-year producing life was used for an individual well, and a 20-year life of the project was used for economic analysis.

It is felt that with such a hypothetical project the total field size must be consistent with that of a large commercial venture in order to properly absorb the cost of high capital investments for compression, scrubbing, trunklines, etc.

The capital costs connected with such a hypothetical project are given in Appendix F, and the operating costs are shown in Appendix G for six different levels of gas production, at 10, 25, 50, 75, 100, and 150 MCF/D per well. Costs for add-on items like scrubbing, high-pressure compression, etc., are shown separately for each case.

It may once again be emphasized that the per-well costs shown in Appendix F include not only the direct drilling and hydraulic fracturing costs, but also an apportionment of costs on items like water handling, connecting pipelines, and power transmission, as well as costs on acquiring right-of-ways, access roads, etc.

DISCOUNTED CASH FLOW (DCF) ANALYSIS

A DCF analysis was done to project gas prices under different scenarios of gas production per well, using financial guidelines established for this study. An economic case at a 10 percent ROR, using uninflated 1979 costs, was thus completed along with two other cases at 15 and 20 percent ROR's. Mid-year discount factors were used throughout.

The tangible equipment costs were depreciated by a combination of double declining balance and the sum-of-digits method of depreciation, so as to gain the fastest depreciation of assets possible. A 10 percent investment tax credit was used. All intangible costs were expensed.

A federal income tax rate of 46 percent and an average state income tax of 2 percent were used, as per the guidelines. No depletion credit was taken, and a royalty rate of one-eighth was utilized.

Gas prices were thus calculated first for the case where the produced gas will be delivered on site in a low-pressure pipeline.

The price impact of the other add-on items, like high-pressure compression, scrubbing costs, trunk gas line costs, etc., was separately assessed.

GAS PRICE PROJECTIONS

Figure 4 depicts the relationship (for the base case) between gas production per day per vertical well and the selling price of gas at 10, 15, and 20 percent ROR's. Figure 5 depicts the same relationship when costs for add-on items like high-pressure compression, scrubbing, trunk delivery line, and power transmission lines are included.

Also analyzed were economics for a project where 2,000-foot horizontal holes are drilled from the bottom of a shaft. Gas flow rate assumed in this situation was 15 MCF/D per 100-foot hole length, based on experience in the Pittsburgh seam. Assuming that the entire shaft cost was written off within the project life of 12 years, the economics were comparable to a vertical wells project where the production per well was in the 20-30 MCF/D range, which is about what the average production has been from the Pittsburgh seam.

It can, therefore, be said that in situations where production ratios between vertical and horizontal holes are comparable to what has been observed in the Pittsburgh seam, the shaft approach may provide a viable alternative to stimulated vertical wells. This approach is preferable in coal seams that may be mineable now or in the future.

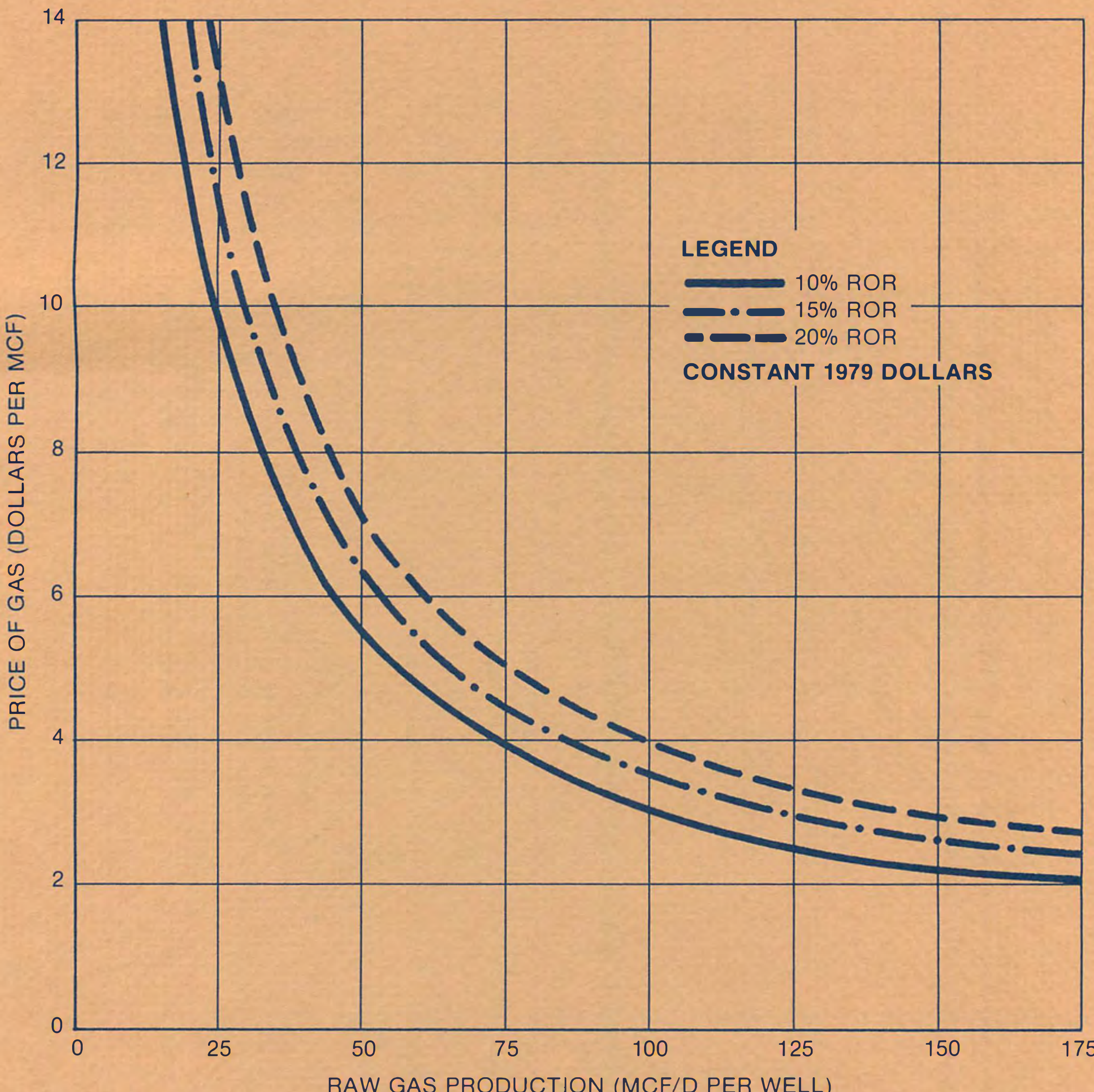


Figure 4. Estimated Gas Price at Various Production Levels—Vertical Wells Project (3,000-ft Depth)—Raw Gas On Site.

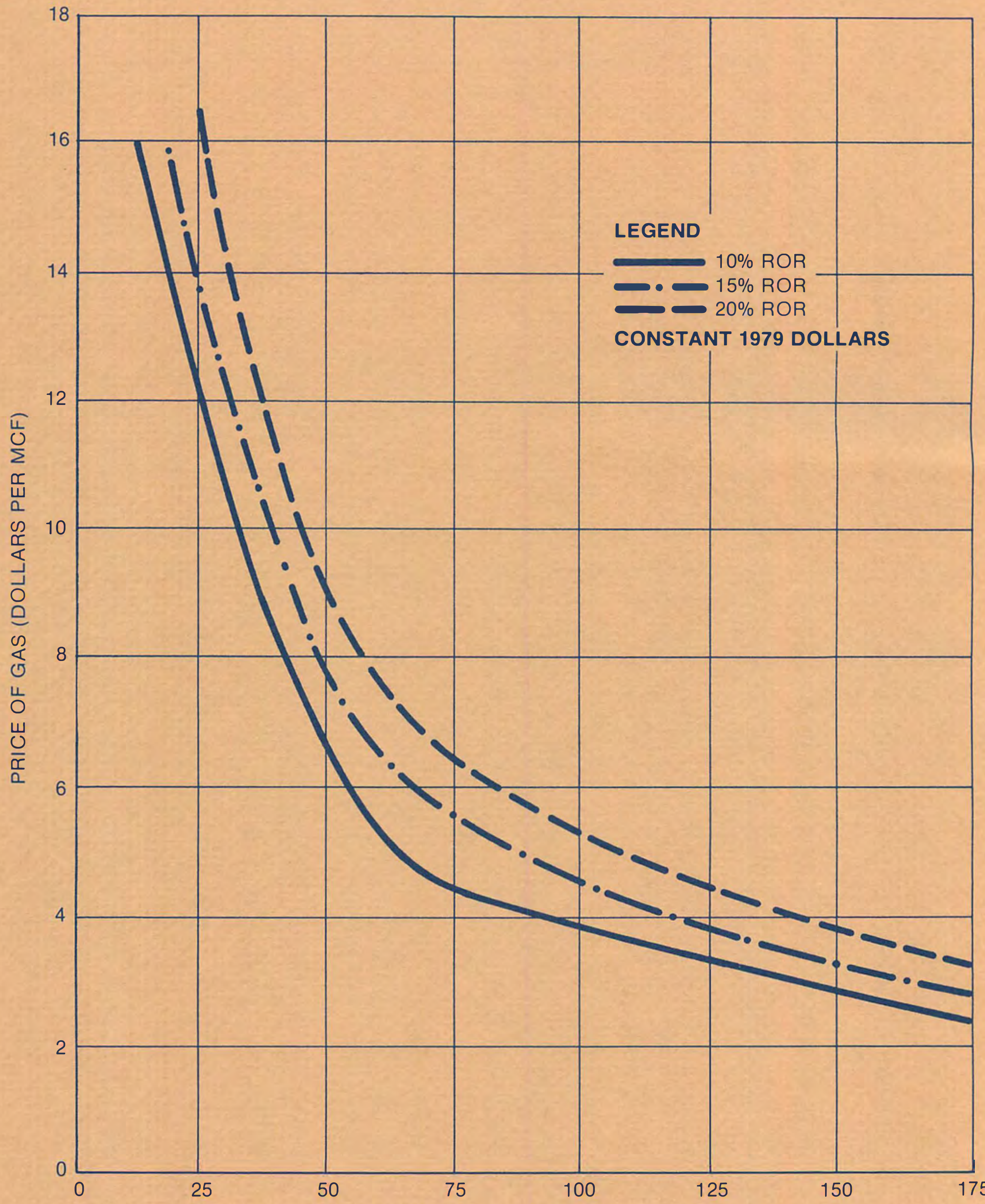


Figure 5. Estimated Gas Price at Various Production Levels—Vertical Wells Project (3,000-ft Depth)—Gas Cleaned and Delivered.

CHAPTER SIX

PROJECTION OF RESERVES AND PRODUCTION

PROJECTION OF ECONOMIC RESERVES

For each gas price level, the minimum initial gas flow required per well can be determined from either Figure 4 or Figure 5, depending upon whether or not the add-on items like high-pressure compression, etc., are to be included. Using the average gas flow of 3 MCF/D per foot of bituminous coal seam thickness per well, the above minimum gas flow per well can be converted into an equivalent thickness of bituminous coal. Figure 1 can then be used to read the total bituminous coal resource in place for that particular coal thickness. A similar set of calculations can be made for subbituminous coals and lignites, with the further assumption that the gas flow per foot of seam thickness for these lower rank coals will be 40 percent and 20 percent, respectively, of that of bituminous coals, in accordance with their similarly lower estimated gas contents in place.

In extrapolating from the coal resource to the economic gas resource in place, the estimated average gas content of the different ranks of coal (200 cubic feet per ton for bituminous coals, 80 cubic feet per ton for subbituminous coals, and 40 cubic feet per ton for lignites) can be used. Recoverable gas reserves were obtained using an estimated 50 percent recovery, and further assuming that 10 percent of the recoverable gas will be inaccessible because of its location below riverbeds, recreational and wildlife areas, etc.

Table 8 shows the estimated amounts of economically recoverable reserves for the base case at different ROR's. Figure 6 shows a smoothed graph showing the same projections.

BACKGROUND FOR ANALYSIS OF POTENTIAL PRODUCTION

The rate of development of gas reserves projected above will depend on the realities of the marketplace, the federal and state regulatory climate, availability of capital, and the ability of the industry to develop the resource. A delaying factor is likely to be the issue of coal-bed gas ownership, which will have to resolve itself through the courts before a full-fledged countrywide program for coal-bed gas recovery will be established.

For purposes of this analysis it is assumed that a market will exist for coal-bed gas produced at a price based on a 10 percent ROR, and that sufficient capital will be available and can be attracted at such an ROR. It is also assumed that a favorable regulatory climate will exist for production and marketing of this gas. As far as the ownership issue is concerned, it is assumed here that it will sort itself out by the end of the year 1984. The interim period will provide sufficient time to collect additional data on

TABLE 8

Projected Economic Reserves of Coal-Bed Gas
(Raw Gas On Site With No Compression)
(Constant 1979 Dollars)

Price Level	ROR	Recoverable Reserves (TCF)
$2.50/MCF	10%	5.0
	15%	2.5
	20%	2.0
$3.50/MCF	10%	13.1
	15%	9.9
	20%	7.1
$5.00/MCF	10%	25.4
	15%	19.9
	20%	16.7
$7.00/MCF	10%	33.9
	15%	30.7
	20%	24.3
$9.00/MCF	10%	44.7
	15%	38.4
	20%	33.2

the gas content of coals and on the physical and chemical characteristics of gas flow through coal seams, which should reduce the uncertainties that now exist.

Once the assumptions outlined above have been made, the controlling factor would be the ability of the industry to develop this resource. This will depend primarily on the availability of equipment and trained crews needed for gas recovery projects.

PROJECTION OF RATE OF DEVELOPMENT BY VERTICAL WELLS

For development of the potential gas resource by vertical well projects, the prime requirement will be the availability of sufficient drill rigs and related equipment, along with trained personnel to man the projects. It is the view of the NPC that the manufacturing industry will be able to keep pace with the production of the modest amounts of additional rigs required for this purpose, and that additional trained personnel can be put in place. With this assumption, a scenario has been developed for the drilling of the required vertical wells over a period of about 18 years, and the recovery of the resource for a total of 28 years. Such a rate of development will require the deployment of an additional 80 rigs per year for a period of eight years, assuming that each rig will be able to drill an average of 45 producing wells per year. A spare capacity already exists for the manufacturing of these additional rigs, and should therefore cause no constraint on gas production.

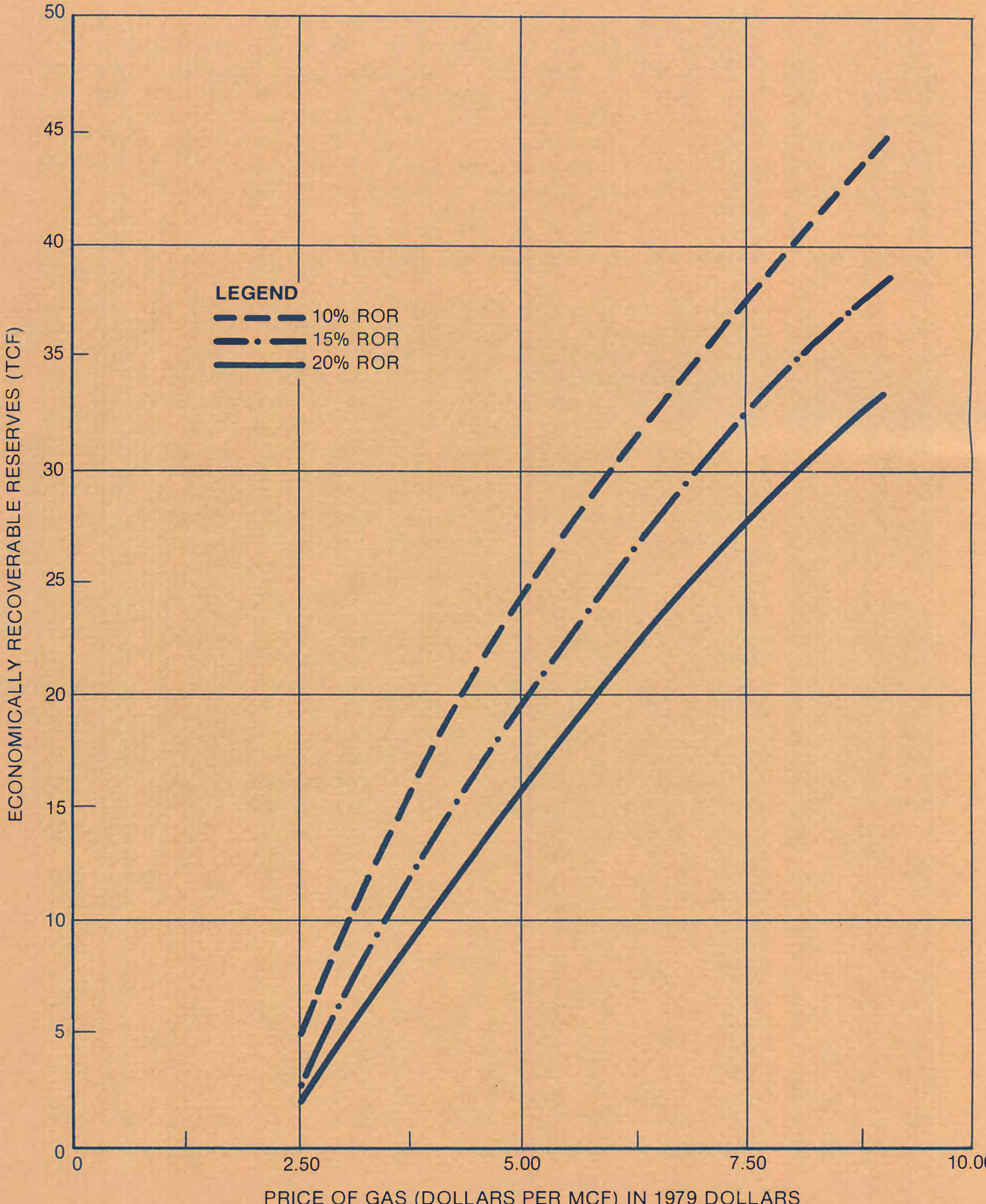


Figure 6. Projected Economic Reserves of Coal-Bed Gas (Raw Gas On Site Without Compression).

The projected rate at which the gas can be produced until the end of this century is shown in Figure 7. Also shown are the additional wells that will need to be drilled each year and the coal-bed gas reserves added as a consequence of such drilling. Figure 8 shows the cumulative number of wells in place, the cumulative annual production, and the remaining reserves of recoverable gas at the end of each year. It is emphasized that the graphs relate to the base case where recovered gas can be used as produced.

PROJECTION OF RATE OF DEVELOPMENT BY SHAFTS AND HORIZONTAL DRILLING

It may be deemed necessary to recover the coal-bed gas resource using alternate techniques of drilling horizontal holes from shafts if the concerns regarding hydraulic stimulation cannot be eliminated. In that case there could be a constraint, not so much in the manufacture of additional shaft-sinking equipment, but in the training of crews in this specialized field. Inquiries to this effect revealed a present capacity for sinking about 50 shafts a year, and an estimate of 20 percent additional capacity every year, if sufficient demand was at hand. Using such a timetable for the sinking of additional shafts, a 22-year shaft-sinking program will be required to recover the total projected gas resource in a period of about 35 years.

The rate at which the gas can be produced until the end of the century, using the shaft approach, is shown in Figure 9. Also shown are additional shafts per year and the additions to committed reserves. Figure 10 shows cumulative production, the cumulative number of shafts, and the resources of gas remaining every year. Once again, it is emphasized that the quantities shown relate to the base case, and that the cumulative amounts recovered will be less because of scrubbing, high-pressure compression, and delivery into a pipeline that may be required in some areas.

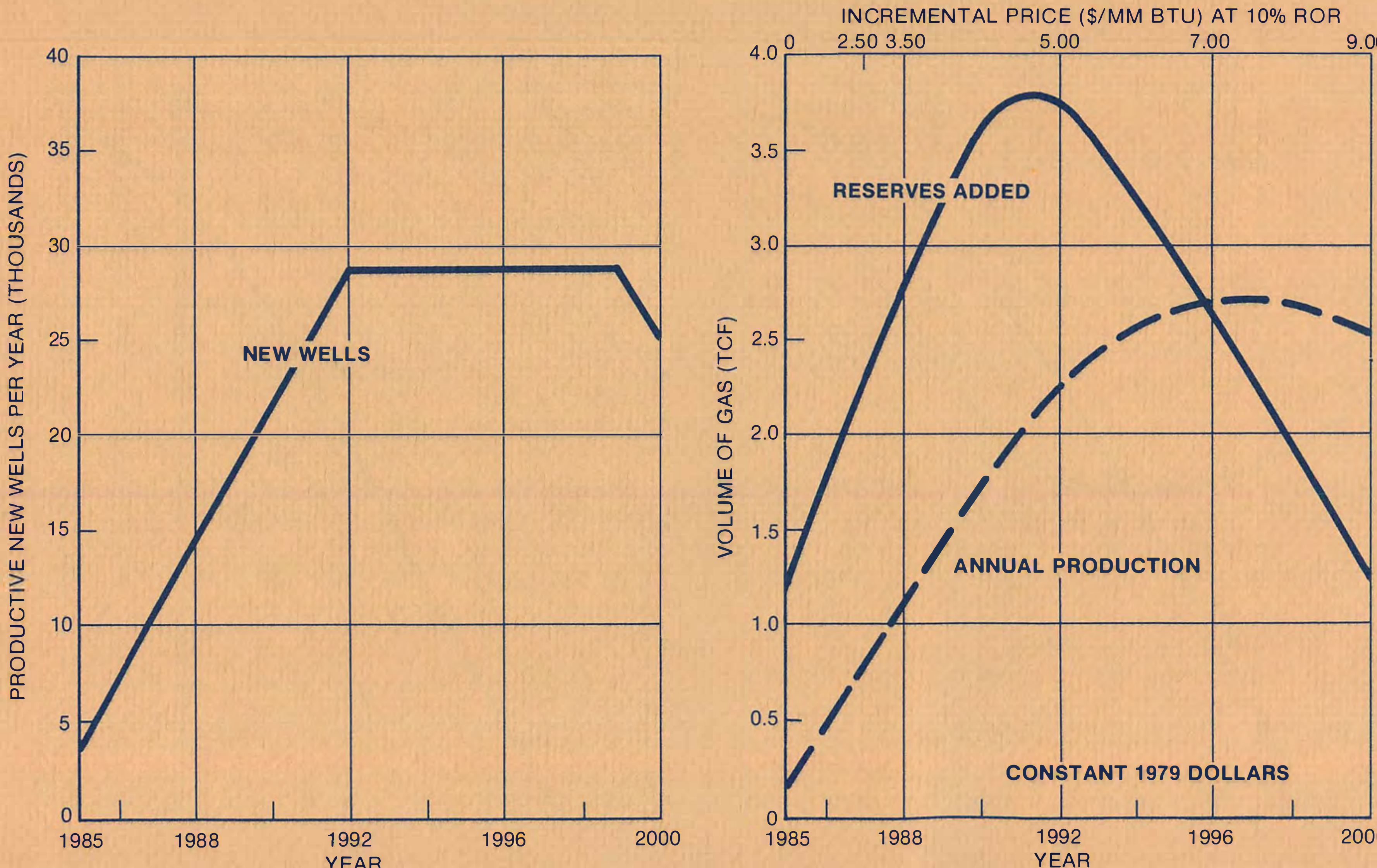


Figure 7. Annual Rates as a Function of Time—Vertical Wells Projects (Raw Gas on Site).

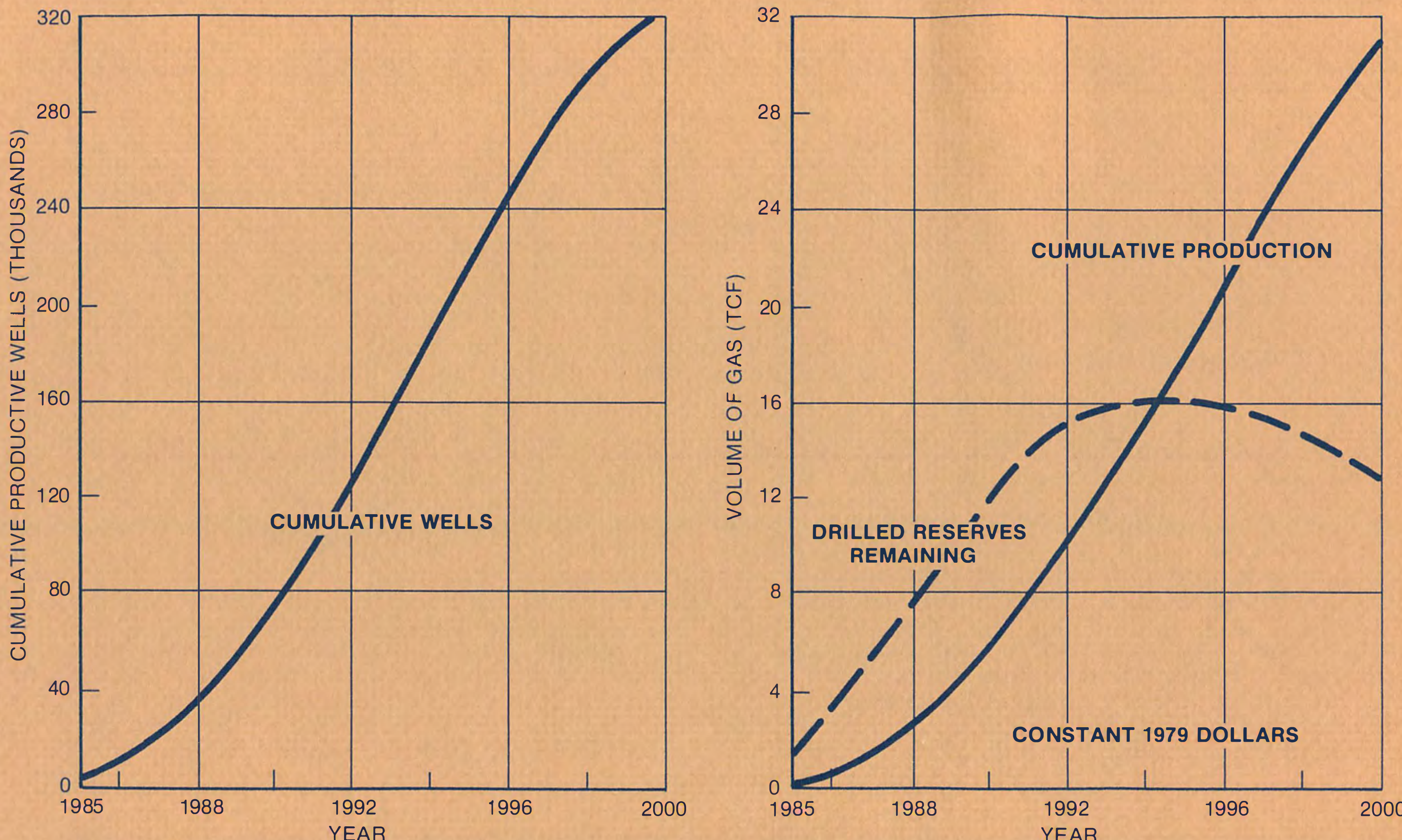
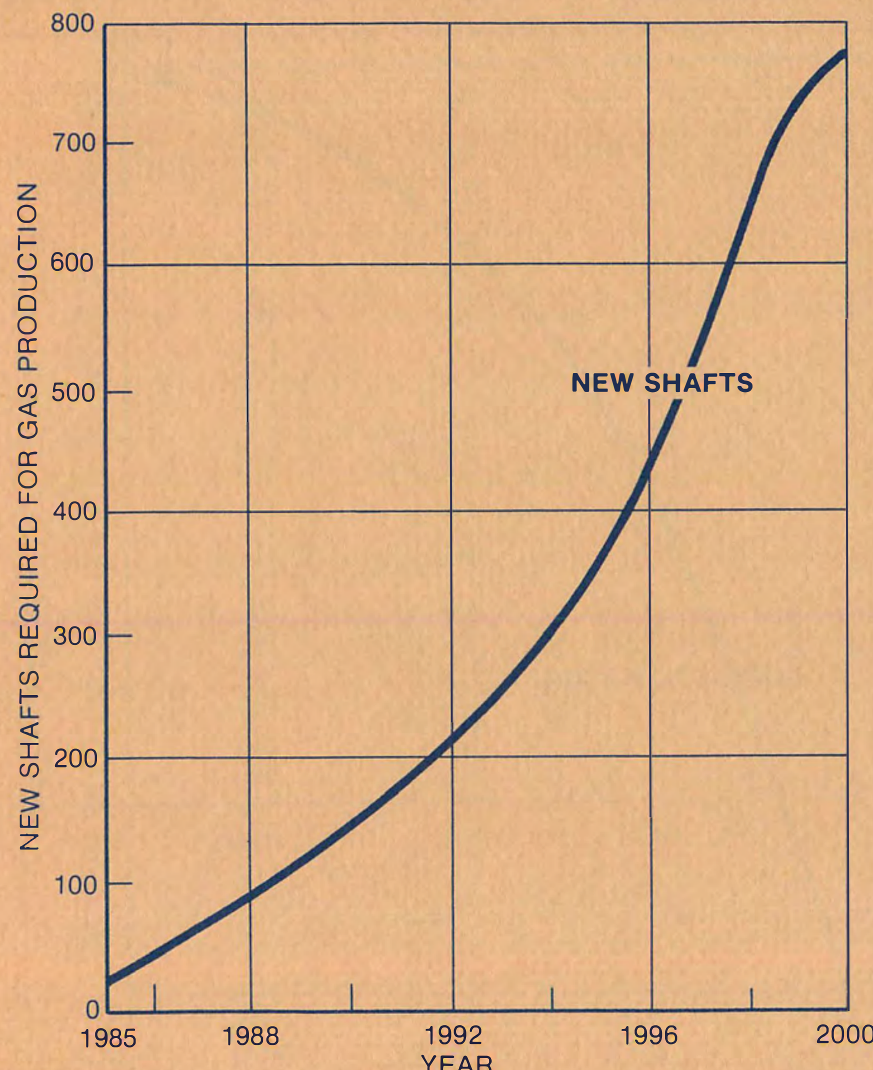


Figure 8. Cumulative Wells, Production, and Reserves as a Function of Time
Vertical Well Projects (Raw Gas on Site).



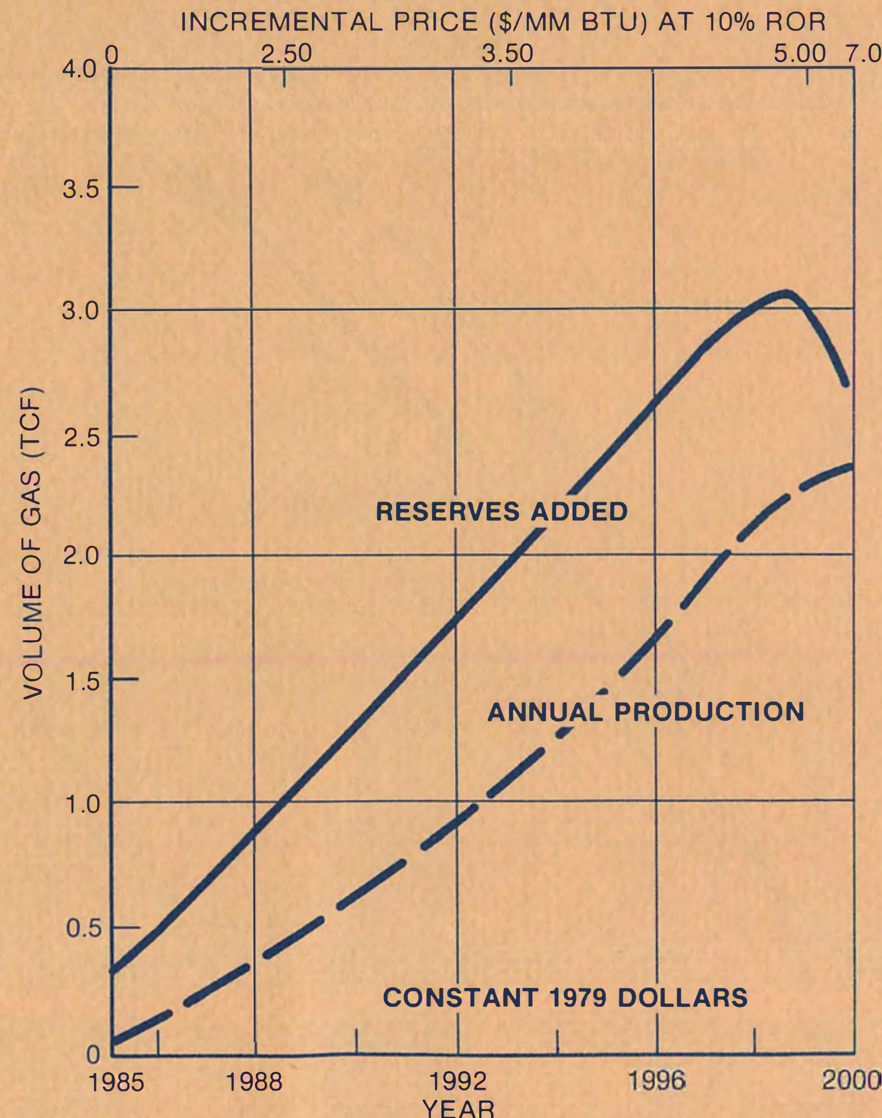


Figure 9. Annual Rates as a Function of Time
Shafts with Horizontal Holes (Raw Gas on Site).

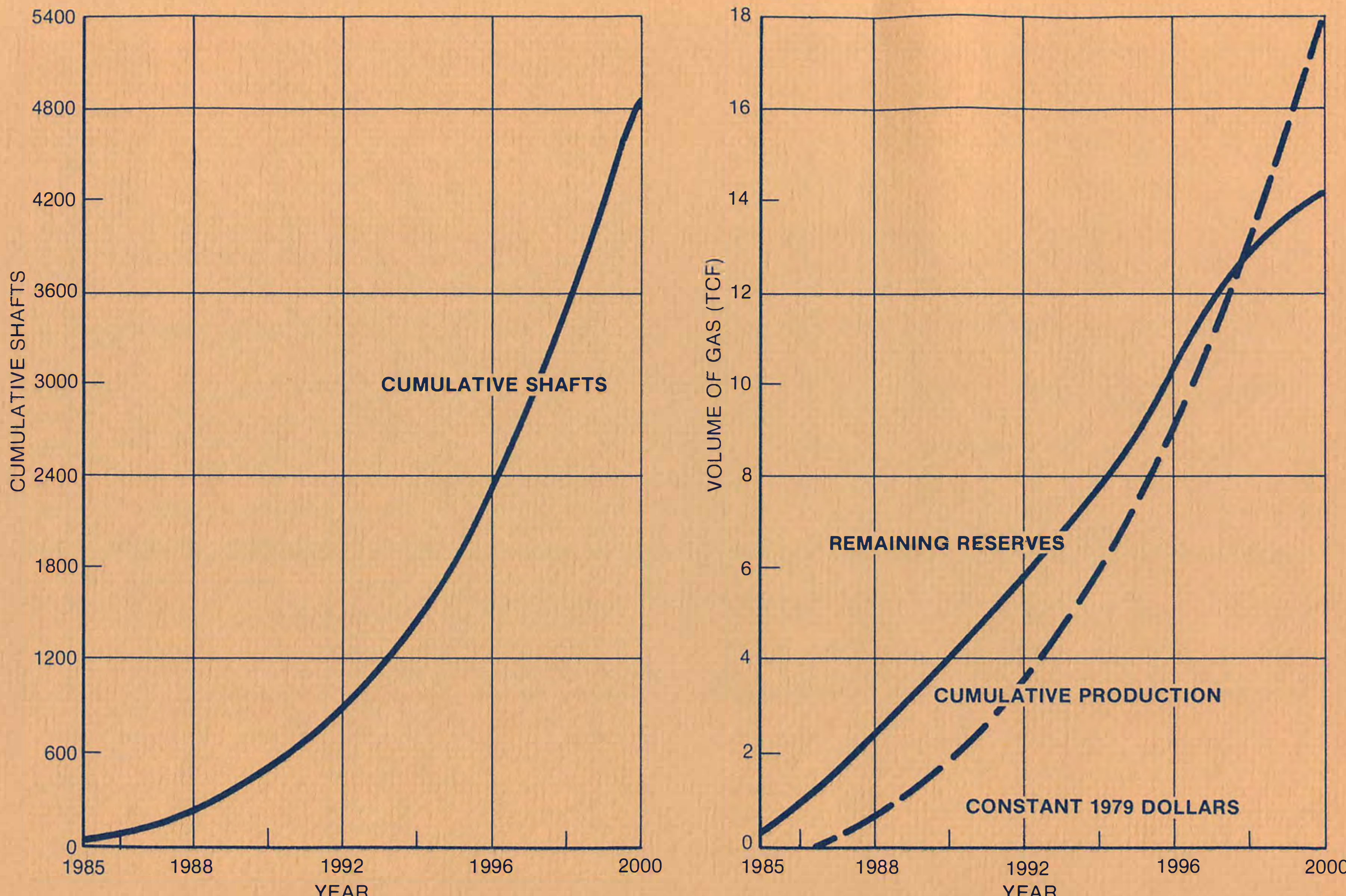


Figure 10. Cumulative Shafts, Production, and Reserves as a Function of Time
Shafts with Horizontal Holes (Raw Gas on Site).

CHAPTER SEVEN

CONSTRAINTS

BACKGROUND

The coal-bed gas resource is of a fairly impressive size and there are situations where it could be commercially exploited to reduce this country's dependence on foreign energy sources. There are, however, constraints that will have to be addressed in order to encourage the flow of sizeable capital requirements in these ventures. Some of these constraints are institutional, others are regulatory, while still others emanate from technical uncertainties due to limited availability of data.

LEGAL CONSTRAINTS

The issue of gas ownership is unresolved and will have to await a final decision from the courts of this country. Until then, to legally recover and market gas, the company must have coal as well as oil and gas rights in an area; or where two or more parties are involved in the ownership of either the coal or the oil and gas, they may join in a compromise to produce the gas. In cases where gas recovery is sought from long horizontal holes, and land ownership over the project area is divided into many small parcels, the gas ownership issue is of added significance. There is also the need to scrutinize state and other local regulations that might preclude or discourage the recovery and marketing of coal-bed gas.

ENVIRONMENTAL CONSTRAINTS

The most important environmental constraint is the disposal of coal-bed water. The composition of coal-bed water varies widely, from slightly acidic to slightly alkaline, and is often saline. Environmental requirements vary from state to state, but where large quantities of water need to be removed and treated before disposal, the costs could be substantial. Also, where availability of water is an issue, as in some western states, the drawdown of the water table due to gas recovery projects could become a significant issue.

COMMERCIAL CONSTRAINTS

Coal companies and public utilities both have limited experience in the recovery and marketing of coal-bed gas. Uncertainties involved in the rate and duration of delivery and the composition and heating value of the delivered gas is likely to complicate signing of gas purchase agreements generally sought by utility companies. Impurities in coal-bed gas, like water and carbon dioxide, are also of concern because of their corrosive action on pipelines and other equipment. These impurities will have to be removed, if necessary at added cost. If the gas recovery project is connected to active coal mining operations, the utility will have to accept deliveries of all gas that is produced, as the concern for safety will probably leave no choice but to vent the additional gas if it is not saleable.

TECHNOLOGICAL CONSTRAINTS

Much of the technology for gas recovery is proven. The risk lies not in the equipment itself, but in the fact that gas flow rates cannot now be projected with any amount of certainty. There is a basic lack of information and a vital need, therefore, to collect baseline data on the gas content of different types of coal and on the parameters that control the flow of gas in coal beds, as well as to do research on the reservoir characteristics and gas producing ability of coal beds.

Drilling technology, especially for horizontal and slant holes, needs improvement in the drill guidance system and in continuous in-hole surveying instrumentation.

CHAPTER EIGHT

COMPARISON WITH OTHER STUDIES

COAL-BED GAS RESOURCE IN PLACE

Based on the estimates of coal resources and gas content used in this analysis, an in-place gas resource base of 398 TCF has been projected (Table 4). A comparison with other studies conducted in the past is shown in Table 9.

As can be seen from Table 9, the NPC's projection of the potential gas resource base is consistent with other recent estimates. Further, high accuracy in the resource base is not of great importance at this time, due to the myriad of other uncertainties.

TABLE 9

Comparison of Projections on In-Place Gas Resource

Study	Estimate (TCF)
NPC, 1979 (This Study)	398
FERC, 1979*	850
TRW, 1978†	72-860
Wise, 1978§	300-800
Deul, 1978¶	258-629
Natl. Acad. Sci., 1976**	300

*Appendix I, Ref. 1.
†Appendix I, Ref. 13.
§Appendix I, Ref. 14.
¶Appendix I, Ref. 12.
**Appendix I, Ref. 15.

ECONOMICALLY RECOVERABLE GAS RESERVES

Unfortunately, most studies do not go beyond projections of the coal-bed gas resource base and attempt to estimate the quantities of economically recoverable gas reserves. Since the magnitude of the resource base is large, an unfounded and unintentional impression tends to be created that the level of economically recoverable gas reserves is equally large.

This study has attempted (1) to estimate costs of recovering the resource base and (2) to develop projections of economically recoverable quantities of gas, which are a much more relevant input for policy making. Summaries of projected economic reserves of coal-bed gas are presented in Table 8 for various price and ROR scenarios. The only other recent study which attempted to examine potential quantities of economically recoverable coal-bed gas reserves is the report by Lewin and Associates, Inc. (see Appendix I, Ref. 16).

The Lewin study was done in 1977 and is based on a 10-year payout period, while this NPC study assumes 1979 costs and is based on various internal DCF ROR's. Table 10 compares the results of the Lewin study with the projections of this study, at a 10 percent ROR.

TABLE 10

Comparison of Projected Recoverable Reserves

	Projected Reserves (TCF)	
Gas Price ($/MCF)	NPC	Lewin
2.50	5.0	2-11
3.50	13.1	2-11
5.00	25.4	2-27

Note: NPC study assumes constant 1979 dollars.

The range specified in the Lewin study is a reflection of the uncertainties involved in such projections. The results of the two studies are, however, quite consistent and reinforce the conclusion that economic reserves of coal-bed gas are only a fraction of the total projected in-place resource. It is critically important that policy makers distinguish between the resource base and economic reserves.

APPENDICES

APPENDIX A

Request Letter
and
Description of the
National Petroleum Council

Department of Energy
Washington, D.C. 20585

June 20, 1978

Dear Mr. Chandler:

An objective of the energy supply initiatives of the President's energy policy is to promote domestic energy production from unconventional sources as well as from conventional sources. One of the areas to be encouraged is the recovery of natural gas from unconventional sources.

In the past, the National Petroleum Council has provided the Department of the Interior with appraisals on the extent and recovery of the Nation's oil and gas resources through such studies as Future Petroleum Provinces, U. S. Energy Outlook, Ocean Petroleum Resources, and Enhanced Oil Recovery.

Therefore, the National Petroleum Council is requested to prepare, as an early and important part of its new relationship with the Department of Energy, a study on unconventional sources of natural gas to include deep geopressured zones, Devonian shale, tight gas sands, and coal seams. Your analysis should assess the resource base and the state-of-the-art of recovery technology. Additionally, your appraisal should include the outlook for costs and recovery of unconventional gas and should consider how Government policy can improve the outlook.

For the purpose of this study, I will designate the Deputy Assistant Secretary for Policy and Evaluation to represent me and to provide the necessary coordination between the Department of Energy and the National Petroleum Council.

Sincerely,

James R. Schlesinger

James R. Schlesinger
Secretary

Mr. Collis P. Chandler, Jr.
Chairman, National Petroleum
Council
1625 K Street, N. W.
Washington, D.C. 20006

DESCRIPTION OF THE NATIONAL PETROLEUM COUNCIL

In May 1946, the President stated in a letter to the Secretary of the Interior that he had been impressed by the contribution made through government/industry cooperation to the success of the World War II petroleum program. He felt that it would be beneficial if this close relationship were to be continued and suggested that the Secretary of the Interior establish an industry organization to advise the Secretary on oil and natural gas matters.

Pursuant to this request, Interior Secretary J. A. Krug established the National Petroleum Council (NPC) on June 18, 1946. In October 1977, the Department of Energy was established and the Council's functions were transferred to the new department.

The purpose of the NPC is solely to advise, inform, and make recommendations to the Secretary of Energy on any matter, requested by him, relating to petroleum or the petroleum industry. The Council is subject to the provisions of the Federal Advisory Committee Act of 1972.

Matters which the Secretary of Energy would like to have considered by the Council are submitted as a request in the form of a letter outlining the nature and scope of the study. The request is then referred to the NPC Agenda Committee, which makes a recommendation to the Council. The Council reserves the right to decide whether or not it will consider any matter referred to it.

Examples of recent major studies undertaken by the NPC at the request of the Department of the Interior and the Department of Energy include:

- Petroleum Resources Under the Ocean Floor (1969, 1971)
  Law of the Sea (1973)
  Ocean Petroleum Resources (1974, 1975)
- Environmental Conservation -- The Oil and Gas Industries (1971, 1972)
- U.S. Energy Outlook (1971, 1972)
- Emergency Preparedness for Interruption of Petroleum Imports into the United States (1973, 1974)
- Petroleum Storage for National Security (1975)
- Potential for Energy Conservation in the United States: 1974-1978 (1974)
  Potential for Energy Conservation in the United States: 1979-1985 (1975)
- Enhanced Oil Recovery (1976)

- Materials and Manpower Requirements (1979)

- Petroleum Storage & Transportation Capacities (1979).

The NPC does not concern itself with trade practices, nor does it engage in any of the usual trade association activities.

Members of the National Petroleum Council are appointed by the Secretary of Energy and represent all segments of petroleum interests. The NPC is headed by a Chairman and a Vice Chairman who are elected by the Council. The Council is supported entirely by voluntary contributions from its members.

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APPENDIX B
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APPENDIX C

Gas Content Data on Bituminous Coals (Considered in this Report)

TABLE C-1

In-Place Gas Content of Coal

Coal Bed/ Location	Depth (ft)	Gas Content cm^3/g	Gas Content ft^3/ton	Reference in Appendix I
Beckley	991	13.0	416	3
	876	14.0	448	3
	830	15.0	480	3
	742	14.0	448	3
Hartshorne	1,480	16.0	512	3
	1,295	18.0	576	3
	571	12.0	384	3
	553	13.0	416	3
	488	11.0	352	3
	252	5.0	160	3
New Castle	2,137	17.0	544	3
Pocahontas No. 3	2,110	14.0	448	3
	2,038	17.0	544	3
	1,736	11.0	352	3
	1,621	12.0	384	3
	1,588	16.0	512	3
	1,529	15.0	480	3
	761	9.0	288	3
Pratt	1,365	15.0	480	3
Mary Lee	2,185	16.0	512	3
	1,706	12.0	384	3
	1,703	14.0	448	3
	1,700	13.0	416	3
	1,099	14.0	448	3
Pittsburgh	850	7.0	224	3
	771	6.0	192	3
	676	5.0	160	3
	427	3.0	96	3
	312	2.0	64	3
Redstone	747	4.0	128	3
Sewell	679	9.0	288	3
Sewickley	675	5.0	160	3
Waynesburg	402	3.0	96	3
Sublette Cty., WY	3,480	10.5	336	4
	3,500	13.0	416	4
	3,512	11.9	381	4
Mesa Verde Cty., CO	3,930	1.6	51	4
	4,660	7.2	230	4
	4,720	8.7	278	4
Pittsburgh Cty., OK	1,903	4.1	130	4
	2,129	6.6	211	4
	2,725	2.3	73	4
Rio Blanco Cty., CO	685	1.0	31	4
	698	.6	20	4
	759	.8	25	4
	791	.4	14	4
	774	.8	25	4
	802	.7	23	4

TABLE C-1 (Continued)

Coal Bed/ Location	Depth (ft)	Gas Content cm^3/g	Gas Content ft^3/ton	Reference in Appendix I
Rio Blanco Cty., CO	805	.6	20	4
	827	.9	28	4
	1,585	.6	18	4
	1,603	.5	16	4
Clay Cty., IL	993	.9	28	4
	994	.9	28	4
	994	.5	16	4
	1,034	.6	18	4
	1,035	.2	8	4
	1,075	.4	14	4
	1,090	.8	26	4
	1,352	1.2	40	4
Westmoreland Cty., PA	188	.4	12	5
	240	.7	21	5
	325	.8	26	5
	385	1.7	53	5
	435	.7	23	5
	460	.9	28	5
	480	2.0	63	5
	520	1.0	31	5
	550	1.5	47	5
	590	1.4	46	5
	620	1.8	59	5
	630	3.2	104	5

APPENDIX D

Gas Content Data on Bituminous Coals (Additional Data Obtained from the U.S. Bureau of Mines)

TABLE D-1

Gas Content Data Obtained from the U.S. Bureau of Mines

Coal Bed	County and State	Sample Depth (ft)	Total Gas Content (cm^3/g)
Alma	Mingo, West Virginia	753	.3
"	"	819	1.5
"	"	855	1.2
"	"	869	.4
"	"	934	1.3
"	"	963	.3
"	"	996	.8
"	"	1,029	1.1
"	"	1,059	3.4
A Seam	Emery, Utah	388	.1
Bald Knoll	Garfield, Utah	273	.4
Bear Canyon	Emery, Utah	979	.1
Beckley	Raleigh, West Virginia	558	.3
"	"	588	4.8
"	"	653	5.6
"	"	655	11.5
"	"	740	13.7
"	"	830	15.4
"	"	850	9.6
"	"	852	12.4
"	"	875	14.1
"	"	990	12.6
"	"	1,198	10.5
"	"	1,200	11.6
Brookville	Allegheny, Pennsylvania	1,013	2.2
"	"	1,020	2.5
Castlegate	Emery, Utah	129	1.2
"	"	160	1.1
"	"	170	1.3
"	"	300	2.1
"	Carbon, Utah	1,016	4.7
"	Emery, Utah	1,248	.7
"	Carbon, Utah	1,430	1.6
"	"	1,645	.2
"	"	1,952	.5
"	"	2,170	7.8
"	"	2,186	2.5
"	"	2,221	.4
Cedar Grove (Lower)	Mingo, West Virginia	682	.2
"	"	704	2.0
"	"	819	.6
"	"	833	1.0
"	"	842	1.3
"	"	851	.2
"	"	878	1.3
"	"	936	.2
"	"	943	.3
"	"	993	1.0
"	"	1,037	3.5

Coal Bed	County and State	Sample Depth (ft)	Total Gas Content (cm^3/g)
Clarion	Barbour, West Virginia	818	5.2
"	"	821	3.5
"	Allegheny, Pennsylvania	966	2.5
Coalburg	Mingo, West Virginia	506	.1
Emery	Garfield, Utah	273	.4
Elkorn	Pike, Kentucky	400	2.0
Flat Canyon	Emery, Utah	1,367	.3
Freeport (Upper)	Westmoreland, Pennsylvania	598	3.4
"	Allegheny, Pennsylvania	603	1.9
"	Greene, Pennsylvania	704	.3
"	"	706	1.6
"	"	892	3.9
"	"	936	4.8
"	"	1,058	7.6
"	"	1,071	3.4
Fruitland	San Juan, New Mexico	1,475	4.2
"	"	1,485	3.9
Gibson	Emery, Utah	2,339	1.3
Hartshorne(Lower)	LeFlore, Oklahoma	175	2.6
"	"	252	5.7
"	"	313	9.4
"	"	356	10.4
"	"	488	10.8
"	"	489	10.6
"	"	516	11.5
"	"	553	13.3
"	"	556	10.7
"	"	561	11.1
"	"	571	11.6
"	"	892	16.2
"	Haskell, Oklahoma	1,295	17.5
"	"	1,439	16.7
"	"	1,440	15.4
Hartshorne(Upper)	"	822	15.1
Hiawatha	Emery, Utah	356	.1
"	"	448	1.1
"	"	616	1.5
"	"	872	.1
Illinois No. 5	Jefferson, Illinois	793	1.0
"	Wayne, Illinois	1,010	3.7
"	"	1,066	2.7
Illinois No. 6	Jefferson, Illinois	733	1.9
"	Wayne, Illinois	900	1.9
"	"	969	3.4
Indiana No. 3	"	1,287	2.0
"	"	1,290	3.1
Indiana No. 6	Knox, Indiana	340	2.8
Indiana No. 7	"	360	1.7

TABLE D-1 (Continued)

Coal Bed	County and State	Sample Depth (ft)	Total Gas Content (cm^3/g)
Ivie (Upper)	Emery, Utah	81	.1
"	"	275	.1
Kenilworth	"	245	1.3
"	"	2,448	11.1
Kittanning (Upper)	Barbour, West Virginia	706	2.7
"	Allegheny, Pennsylvania	834	2.4
"	Buckhannon, West Virginia	838	1.3
" (Middle)	Upshur, West Virginia	908	2.4
"	"	909	2.4
"	"	911	2.3
Kittanning (Lower)	Armstrong, Pennsylvania	323	.4
"	"	324	.4
"	"	325	.7
"	"	326	.6
"	Indiana, Pennsylvania	621	.8
"	Barbour, West Virginia	801	1.4
"	Westmoreland, Pennsylvania	1,057	11.2
Mary Lee (UB)	Walker, Alabama	639	2.8
"	"	721	1.0
"	Jefferson, Alabama	1,084	6.8
"	Tuscaloosa, Alabama	1,700	12.2
Mary Lee (LB)	Jefferson, Alabama	1,086	23.1
"	"	1,099	13.3
"	Tuscaloosa, Alabama	1,704	14.6
"	"	1,705	11.0
"	"	1,706	11.6
"	"	1,910	9.2
"	"	1,929	15.7
"	"	2,185	17.4
Menefee	LaPlata, Colorado	295	.2
"	"	310	.3
Mercer	Allegheny, Pennsylvania	1,103	1.1
New Castle	Tuscaloosa, Alabama	2,137	17.5
Peach Mountain	Schuylkill, Pennsylvania	684	8.4
"	"	686	7.4
Pittsburgh	Greene, Pennsylvania	313	1.6
"	Washington, Pennsylvania	427	3.7
"	Greene, Pennsylvania	675	4.0
"	"	680	6.5
"	"	770	5.9
Pittsburgh	"	779	5.6
"	Marion, West Virginia	848	4.7
"	"	850	6.5
"	"	850	7.0
"	Wetzel, West Virginia	1,147	3.2
"	"	1,260	3.4
"	"	1,267	-

TABLE D-1 (Continued)

Coal Bed	County and State	Sample Depth (ft)	Total Gas Content (cm^3/g)
Pittsburgh	Greene, Pennsylvania	1,273	6.0
"	"	1,276	6.9
Pittsburgh (Rider)	Marion, West Virginia	839	1.3
"	Wetzel, West Virginia	1,131	1.0
"	Greene, Pennsylvania	1,272	6.8
Pocahontas No. 3	Wyoming, West Virginia	778	8.9
"	"	930	10.0
"	Buchanan, Virginia	1,316	12.1
"	"	1,430	13.6
"	"	1,518	14.5
"	"	1,528	14.9
"	"	1,551	17.3
"	"	1,554	16.6
"	"	1,589	16.3
"	"	1,621	11.5
"	"	1,621	12.2
"	"	1,737	11.1
"	"	1,764	17.8
"	"	1,845	10.9
"	"	1,999	15.8
"	"	2,022	16.4
"	"	2,036	17.5
"	"	2,108	13.8
"	"	2,143	10.4
Pond Creek	Pike, Kentucky	125	2.0
"	Martin, Kentucky	400	2.2
"	Pike, Kentucky	500	1.2
Pratt	Tuscaloosa, Alabama	1,365	15.1
Redstone	Monongalia, West Virginia	736	3.9
"	"	744	4.1
"	Marion, West Virginia	836	2.4
"	Wetzel, West Virginia	1,099	.8
Rock Canyon (Upper)	Emery, Utah	2,339	2.7
Rock Canyon (Lower)	"	2,352	5.4
Sewell	Raleigh, West Virginia	680	9.3
"	"	700	4.1
"	Braxton, West Virginia	981	2.7
Sewickley	Monongalia, West Virginia	60	.7
"	Washington, Pennsylvania	449	1.2
"	Greene, Pennsylvania	669	2.5
"	Monongalia, West Virginia	670	4.6
"	"	675	4.7
"	Marion, West Virginia	740	1.6
"	"	740	2.1
"	Monongalia, West Virginia	823	1.5
"	Wetzel, West Virginia	1,039	1.1
"	Monongalia, West Virginia	1,145	1.2
"	Greene, Pennsylvania	1,176	4.2
"	"	1,182	2.4

TABLE D-1 (Continued)

Coal Bed	County and State	Sample Depth (ft)	Total Gas Content (cm^3/g)
Sewickley	Greene, Pennsylvania	1,591	4.2
Smirl	Garfield, Utah	442	.1
"	Kane, Utah	752	.1
Sunnyside (Lower)	Emery, Utah	1,798	4.6
Tunnel	Schuylkill, Pennsylvania	602	14.1
"	"	604	12.6
"	"	606	18.5
Vermejo	Huerfano, Colorado	111	.1
"	"	155	.2
Wadge	Routt, Colorado	335	.3
"	"	1,284	0
"	"	1,393	.1
Waynesburg	Monongalia, West Virginia	400	2.8
"	"	402	2.7
"	Greene, Pennsylvania	458	3.8
"	"	971	3.1
"	"	973	4.5
"	"	1,231	3.5
"	"	1,553	4.1
"	"	1,667	2.7
Wolf Creek	Routt, Colorado	488	0
"	"	1,123	.2

APPENDIX E

Gas Content of Non-Bituminous Coals

GAS CONTENT OF NON-BITUMINOUS COALS

It has been shown that the methane content of bituminous coals is a function of moisture content.[1]

$$Vd/Vw = C_o m + 1$$

where Vd & Vw are the volumes (cm^3 (STP)/gm) of methane adsorbed in dry and moist coal, respectively; C_o = empirically determined constant = 0.31 for bituminous coals; and m = moisture content of the coal in wt %. Thus, for bituminous coals, the equation becomes

$$\frac{Vw}{Vd} = \frac{1}{1 + 0.31m}$$

A recent (June 1979) scan of existing USGS data[2] indicated the following mean moisture contents for various ranks of coals:

Rank	Mean Moisture Content (wt %)
Bituminous	4.53
Subbituminous	16.01
Lignite	37.64

The gas content of dry bituminous coal would then become 2.4 times the quantity contained at a moisture content of 4.53 percent. It is recognized that although this empirical relationship is for bituminous coals, the extension of its application to non-bituminous coals probably represents the most logical approach to determining their gas content. The resulting gas content of subbituminous coal and lignite then becomes 16.8 and 7.9 percent, respectively, of that for dry bituminous coals.

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[1]Ettinger, I. L.; Lidin, G. D.; Dmitriev, A. M.; and Zhupakhina, E. A., "Systematic Handbook for the Determination of the Methane Content of Coal Seams from the Seam Pressure of the Gas and the Methane Capacity of the Coal," Moscow, 1958; National Coal Board Translation No. 1606/SEH.

[2]Personal communication from Toni Medlin, U.S. Dept. of Int., June 28, 1979.

In summary, if the gas content of wet bituminous coals is 200 ft^3/ton (6.25 cm^3/gm), as agreed upon by the study participants, the subbituminous coal and lignite would contain 80 and 38 cubic feet per ton, respectively.

Discussion of these volumes, along with the general agreement with a single value for lesser rank coals supplied by an independent consulting firm, resulted in agreement on the gas content of coal for the purpose of this study as follows:

Rank	ft^3/ton	(cm^3/gm)
Bituminous	200	6.25
Subbituminous	80	2.50
Lignite	40	1.25

APPENDIX F
Capital Costs

TABLE F-1

Vertical Wells Project -- Estimated Capital Investment for a 3,000-Foot, 10 MCF/D Well
(Base Case)
(Constant 1979 Dollars)

	Cost Categories	Per-Well Costs (Thousands of Dollars) Tangible	Intangible
1	Lease, R.O.W. Location		13.8
2	Drill, Case, Cement	13.7	54.6
3	Frac (1500 BBL)	-	27.8
4	Well Head Compr.	7.9	4.5
5	Water Disposal	4.0	16.4
6	Water Lines, Pumps	21.6	2.2
7	Gas Lines (Internal)	7.5	17.5
8	Power Lines (Internal)	4.3	2.5
	Subtotal	59.0	139.3
	Contingency (10%)	5.9	13.9
	Overhead (10%)*		21.8
	Total (Base Case)	64.9	175.0

*Overhead calculated as 10% of the summation of tangible costs, intangible costs, and their respective contingency costs.

TABLE F-2

Vertical Wells Project -- Estimated Capital Investment for a 3,000-Foot, 25 MCF/D Well
(Base Case)
(Constant 1979 Dollars)

	Cost Categories	Per-Well Costs (Thousands of Dollars) Tangible	Intangible
1	Lease, R.O.W. Location		13.8
2	Drill, Case, Cement	13.7	54.6
3	Frac (1500 BBL)	-	27.8
4	Well Head Compr.	12.4	4.5
5	Water Disposal	4.0	16.4
6	Water Lines, Pumps	21.6	2.2
7	Gas Lines (Internal)	8.8	20.6
8	Power Lines (Internal)	8.2	3.0
	Subtotal	68.7	142.9
	Contingency (10%)	6.9	14.3
	Overhead (10%)*		23.3
	Total (Base Case)	75.6	180.5

*Overhead calculated as 10% of the summation of tangible costs, intangible costs, and their respective contingency costs.

TABLE F-3

Vertical Wells Project -- Estimated Capital Investment for a 3,000-Foot, 50 MCF/D Well
(Base Case)
(Constant 1979 Dollars)

	Cost Categories	Per-Well Costs (Thousands of Dollars) Tangible	Intangible
1	Lease, R.O.W. Location		13.8
2	Drill, Case, Cement	13.7	54.6
3	Frac (1500 BBL)	-	27.8
4	Well Head Compr.	17.6	4.5
5	Water Disposal	4.0	16.4
6	Water Lines, Pumps	21.6	2.2
7	Gas Lines (Internal)	10.0	23.4
8	Power Lines (Internal)	13.9	3.5
	Subtotal	80.8	146.2
	Contingency (10%)	8.1	14.6
	Overhead (10%)*		25.0
	Total (Base Case)	88.9	185.8

*Overhead calculated as 10% of the summation of tangible costs, intangible costs, and their respective contingency costs.

TABLE F-4

Vertical Wells Project -- Estimated Capital Investment for a 3,000-Foot, 75 MCF/D Well
(Base Case)
(Constant 1979 Dollars)

	Cost Categories	Per-Well Costs (Thousands of Dollars) Tangible	Intangible
1	Lease, R.O.W. Location		13.8
2	Drill, Case, Cement	13.7	54.6
3	Frac (1500 BBL)	-	27.8
4	Well Head Compr.	21.5	4.5
5	Water Disposal	4.0	16.4
6	Water Lines, Pumps	21.6	2.2
7	Gas Lines (Internal)	10.8	25.1
8	Power Lines (Internal)	19.1	3.9
	Subtotal	90.7	148.3
	Contingency (10%)	9.1	14.8
	Overhead (10%)*		26.3
	Total (Base Case)	99.8	189.4

*Overhead calculated as 10% of the summation of tangible costs, intangible costs, and their respective contingency costs.

TABLE F-5

Vertical Wells Project -- Estimated Capital Investment for a 3,000-Foot, 100 MCF/D Well
(Base Case)
(Constant 1979 Dollars)

	Cost Categories	Per-Well Costs (Thousands of Dollars) Tangible	Intangible
1	Lease, R.O.W. Location	-	13.8
2	Drill, Case, Cement	13.7	54.6
3	Frac (1500 BBL)	-	27.8
4	Well Head Compr.	24.9	4.5
5	Water Disposal	4.0	16.4
6	Water Lines, Pumps	21.6	2.2
7	Gas Lines (Internal)	11.4	26.5
8	Power Lines (Internal)	24.1	4.3
	Subtotal	99.7	150.1
	Contingency (10%)	10.0	15.0
	Overhead (10%)*	-	27.5
	Total (Base Case)	109.7	192.6

*Overhead calculated as 10% of the summation of tangible costs, intangible costs, and their respective contingency costs.

TABLE F-6

Vertical Wells Project -- Estimated Capital Investment for a 3,000-Foot, 150 MCF/D Well
(Base Case)
(Constant 1979 Dollars)

	Cost Categories	Per-Well Costs (Thousands of Dollars) Tangible	Intangible
1	Lease, R.O.W. Location	-	13.8
2	Drill, Case, Cement	13.7	54.6
3	Frac (1500 BBL)	-	27.8
4	Well Head Compr.	30.5	4.5
5	Water Disposal	4.0	16.4
6	Water Lines, Pumps	21.6	2.2
7	Gas Lines (Internal)	12.2	28.5
8	Power Lines (Internal)	33.7	5.0
	Subtotal	115.7	152.8
	Contingency (10%)	11.6	15.3
	Overhead (10%)*	-	29.5
	Total (Base Case)	127.3	197.6

*Overhead calculated as 10% of the summation of tangible costs, intangible costs, and their respective contingency costs.

TABLE F-7

Vertical Wells Project -- Estimated Capital Investment for a 10 MCF/D Well Project
(Add-on Items)
(Constant 1979 Dollars)

	Cost Categories	Per-Project Costs (Thousands of Dollars) Tangible	Intangible
1	Compressor (Central)	87.7	5.0
2	Scrubber	130.0	125.0
3	Trunk Line (5 Miles)	66.0	150.2
4	Primary Power (10,000 ft.)	60.0	20.0
	Subtotal	343.7	300.2
	Contingency (10%)	34.4	30.0
	Overhead (10%)*		70.8
	Total	378.1	401.0

*Overhead calculated as 10% of the summation of tangible costs, intangible costs, and their respective contingency costs.

TABLE F-8

Vertical Wells Project -- Estimated Capital
Investment for a 25 MCF/D Well Project
(Add-on Items)
(Constant 1979 Dollars)

	Cost Categories	Per-Project Costs (Thousands of Dollars) Tangible	Intangible
1	Compressor (Central)	115.0	5.0
2	Scrubber	219.5	142.0
3	Trunk Line (5 Miles)	85.8	152.6
4	Primary Power (10,000 ft.)	60.0	20.0
	Subtotal	480.3	319.6
	Contingency (10%)	48.0	32.0
	Overhead (10%)*		88.0
	Total	528.3	439.6

*Overhead calculated as 10% of the summation of tangible costs, intangible costs, and their respective contingency costs.

TABLE F-9

Vertical Wells Project -- Estimated Capital Investment for a 50 MCF/D Well Project
(Add-on Items)
(Constant 1979 Dollars)

	Cost Cagegories	Per-Project Costs (Thousands of Dollars) Tangible	Intangible
1	Compressor (Central)	154.0	5.0
2	Scrubber	340.0	160.0
3	Trunk Line (5 Miles)	85.8	152.6
4	Primary Power (10,000 ft.)	60.0	20.0
	Subtotal	639.8	337.6
	Contingency (10%)	64.0	33.8
	Overhead (10%)*		107.5
	Total	703.8	478.9

*Overhead calculated as 10% of the summation of tangible costs, intangible costs, and their respective contingency costs.

TABLE F-10

Vertical Wells Project -- Estimated Capital Investment for a 75 MCF/D Well Project
(Add-on Items)
(Constant 1979 Dollars)

	Cost Categories	Per-Project Costs (Thousands of Dollars) Tangible	Intangible
1	Compressor (Central)	177.2	5.0
2	Scrubber	400.0	190.0
3	Trunk Line (5 Miles)	85.8	152.6
4	Primary Power (10,000 ft.)	60.0	20.0
	Subtotal	723.0	367.6
	Contingency (10%)	72.3	36.8
	Overhead (10%)*		120.0
	Total	795.3	524.4

*Overhead calculated as 10% of the summation of tangible costs, intangible costs, and their respective contingency costs.

Table F-11

Vertical Wells Project -- Estimated Capital Investment for a 100 MCF/D Well Project (Add-on Items) (Constant 1979 Dollars)

	Cost Categories	Per-Project Costs (Thousands of Dollars) Tangible	Intangible
1	Compressor (Central)	196.3	5.0
2	Scrubber	527.9	180.3
3	Trunk Line (5 Miles)	105.6	184.8
4	Primary Power (10,000 ft.)	60.0	20.0
	Subtotal	889.8	390.1
	Contingency (10%)	89.0	39.0
	Overhead (10%)*		140.8
	Total	978.8	569.9

*Overhead calculated as 10% of the summation of tangible costs, intangible costs, and their respective contingency costs.

TABLE F-12

Vertical Wells Project -- Estimated Capital Investment for a 150 MCF/D Well Project
(Add-on Items)
(Constant 1979 Dollars)

	Cost Categories	Per-Project Costs (Thousands of Dollars) Tangible	Intangible
1	Compressor (Central)	227.0	5.0
2	Scrubber	620.0	214.1
3	Trunk Line (5 Miles)	105.6	184.8
4	Primary Power (10,000 ft.)	60.0	20.0
	Subtotal	1012.6	423.9
	Contingency (10%)	101.3	42.4
	Overhead (10%)*		158.0
	Total	1113.9	624.3

*Overhead calculated as 10% of the summation of tangible costs, intangible costs, and their respective contingency costs.

APPENDIX G

Operating Costs

TABLE G-1

Vertical Wells Project -- Estimated
Operating Costs for a 3,000-Foot, 10 MCF/D Well
(Constant 1979 Dollars)

Operating Costs		Dollars Per Year
A BASE CASE:		
1. Per Well Costs:		
(i) Power		1043.0
(ii) Maintenance		1400.0
Overhead (20%)		488.6
Total		2931.6
2. Per Project Costs:*		
(i) Labor -		
240 days @ $80/day		
50 days @ $120/day		
36 days @ $160/day		31000.0
(ii) Other Costs -		
2 Trucks - 50 miles/day; 30¢/mile; 350 days/year	= $10,500	
Leasing costs - 2 Trucks	= 4,000	
Miscellaneous Tools	= 750	
Road Maintenance	= 3,000	18250.0
Overhead (20%)		9850.0
Total		59100.0
B ADD-ONS:		
1. Central Compressor Maintenance		9650.0
2. Scrubber - Maintenance		14300.0
3. Scrubber - Glycol		1168.0
Overhead (20%)		5023.6
Total		30141.6

*See Estimation of Costs and DCF Analysis sections of Chapter Five.

TABLE G-2

Vertical Wells Project -- Estimated
Operating Costs for a 3,000-Foot, 25 MCF/D Well
(Constant 1979 Dollars)

Operating Costs		Dollars Per Year
A BASE CASE:		
1. Per Well Costs:		
(i) Power		1391.0
(ii) Maintenance		1900.0
Overhead (20%)		658.2
Total		3949.2
2. Per Project Costs:*		
(i) Labor -		
240 days @ $80/day		
50 days @ $120/day		
36 days @ $160/day		31000.0
(ii) Other Costs -		
2 Trucks - 50 miles/day; 30¢/mile; 350 days/year	= $10,500	
Leasing costs - 2 Trucks	= 4,000	
Miscellaneous Tools	= 750	
Road Maintenance	= 3,000	18250.0
Overhead (20%)		9850.0
Total		59100.0
B ADD-ONS:		
1. Central Compressor Maintenance		12650.0
2. Scrubber - Maintenance		24145.0
3. Scrubber - Glycol		2920.0
Overhead (20%)		7943.0
Total		47658.0

*See Estimation of Costs and DCF Analysis sections of Chapter Five.

TABLE G-3

Vertical Wells Project -- Estimated
Operating Costs for a 3,000-Foot, 50 MCF/D Well
(Constant 1979 Dollars)

Operating Costs		Dollars Per Year
A BASE CASE:		
1. Per Well Costs:		
(i) Power		1739.0
(ii) Maintenance		2500.0
Overhead (20%)		847.8
Total		5086.8
2. Per Project Costs:*		
(i) Labor -		
240 days @ $80/day		
50 days @ $120/day		
36 days @ $160/day		31000.0
(ii) Other Costs -		
2 Trucks - 50 miles/day; 30¢/mile; 350 days/year	= $10,500	
Leasing costs - 2 Trucks	= 4,000	
Miscellaneous Tools	= 750	
Road Maintenance	= 3,000	18250.0
Overhead (20%)		9850.0
Total		59100.0
B ADD-ONS:		
1. Central Compressor Maintenance		16940.0
2. Scrubber - Maintenance		37400.0
3. Scrubber - Glycol		5840.0
Overhead (20%)		12036.0
Total		72216.0

*See Estimation of Costs and DCF Analysis sections of Chapter Five.

TABLE G-4

Vertical Wells Project -- Estimated
Operating Costs for a 3,000-Foot, 75 MCF/D Well
(Constant 1979 Dollars)

Operating Costs		Dollars Per Year
A BASE CASE:		
1. Per Well Costs:		
(i) Power		2087.0
(ii) Maintenance		2900.0
Overhead (20%)		997.4
Total		5984.4
2. Per Project Costs:*		
(i) Labor -		
240 days @ $80/day		
50 days @ $120/day		
36 days @ $160/day		31000.0
(ii) Other Costs -		
2 Trucks - 50 miles/day; 30¢/mile; 350 days/year	= $10,500	
Leasing costs - 2 Trucks	= 4,000	
Miscellaneous Tools	= 750	
Road Maintenance	= 3,000	18250.0
Overhead (20%)		9850.0
Total		59100.0
B ADD-ONS:		
1. Central Compressor Maintenance		19492.0
2. Scrubber - Maintenance		44000.0
3. Scrubber - Glycol		8760.0
Overhead (20%)		14450.4
Total		86702.4

*See Estimation of Costs and DCF Analysis sections of Chapter Five.

TABLE G-5

Vertical Wells Project -- Estimated
Operating Costs for a 3,000-Foot, 100 MCF/D Well
(Constant 1979 Dollars)

Operating Costs		Dollars Per Year
A BASE CASE:		
1. Per Well Costs:		
(i) Power		2609.0
(ii) Maintenance		3300.0
Overhead (20%)		1181.8
Total		7090.8
2. Per Project Costs:*		
(i) Labor -		
240 days @ $80/day		
50 days @ $120/day		
36 days @ $160/day		31000.0
(ii) Other Costs -		
2 Trucks - 50 miles/day; 30¢/mile; 350 days/year =	$10,500	
Leasing costs - 2 Trucks =	4,000	
Miscellaneous Tools =	750	
Road Maintenance =	3,000	18250.0
Overhead (20%)		9850.0
Total		59100.0
B ADD-ONS:		
1. Central Compressor Maintenance		21593.0
2. Scrubber - Maintenance		58069.0
3. Scrubber - Glycol		11680.0
Overhead (20%)		18268.4
Total		109610.4

*See Estimation of Costs and DCF Analysis sections of Chapter Five.

TABLE G-6

Vertical Wells Project -- Estimated
Operating Costs for a 3,000-Foot, 150 MCF/D Well
(Constant 1979 Dollars)

Operating Costs			Dollars Per Year
A BASE CASE:			
1. Per Well Costs:			
(i) Power			3479.0
(ii) Maintenance			3900.0
Overhead (20%)			1475.8
Total			8854.8
2. Per Project Costs:*			
(i) Labor -			
240 days @ $80/day			
50 days @ $120/day			
36 days @ $160/day			31000.0
(ii) Other Costs -			
2 Trucks - 50 miles/day; 30¢/mile; 350 days/year	=	$10,500	
Leasing costs - 2 Trucks	=	4,000	
Miscellaneous Tools	=	750	
Road Maintenance	=	3,000	18250.0
Overhead (20%)			9850.0
Total			59100.0
B ADD-ONS:			
1. Central Compressor Maintenance			24970.0
2. Scrubber - Maintenance			68200.0
3. Scrubber - Glycol			17520.0
Overhead (20%)			22138.0
Total			132828.0

*See Estimation of Costs and DCF Analysis sections of Chapter Five.

APPENDIX H

Yearly Capital and Operating Costs

TABLE H-1

Vertical Wells Project*
3,000-Foot, 10 MCF/D Well
(Raw Gas On Site)
(Constant 1979 Dollars)

Year	No. Wells Drilled	No. Wells Plugged	Total Active Wells	Tangible Investment (Thousands of Dollars)	Intangible Investment (Thousands of Dollars	Operating Costs ($/MCF)
0	12	0		778.8	2100.0	
1	10	0	20	649.0	1750.0	1.70
2	2	0	22	129.8	350.0	1.78
3	2	0	24	129.8	350.0	1.87
4	2	0	26	129.8	350.0	1.95
5	2	0	28	129.8	350.0	2.04
6	2	0	30	129.8	350.0	2.12
7	2	0	32	129.8	350.0	2.21
8	2	0	34	129.8	350.0	2.29
9	2	0	36	129.8	350.0	2.38
10	2	0	38	129.8	350.0	2.46
11	2	0	40	129.8	350.0	2.55
12	2	0	42	129.8	350.0	2.63
13	8	20	30	519.2	1640.0	2.12
14	2	2	30	129.8	374.0	2.12
15	3	2	31	194.7	549.0	2.17
16	2	2	31	129.8	374.0	2.17
17	3	2	32	194.7	549.0	2.21
18	2	2	32	129.8	374.0	2.21
19	3	2	33	194.7	549.0	2.25
20	2	2	33	129.8	374.0	2.25
21	0	33	0	-	396.0	

*See Estimation of Costs and DCF Analysis sections of Chapter Five.

TABLE H-2

Vertical Wells Project*
3,000-Foot, 25 MCF/D Well
(Raw Gas On Site)
(Constant 1979 Dollars)

Year	No. Wells Drilled	No. Wells Plugged	Total Active Wells	Tangible Investment (Thousands of Dollars)	Intangible Investment (Thousands of Dollars	Operating Costs ($/MCF)
0	12	0		907.2	2166.0	
1	10	0	20	756.0	1805.0	0.80
2	2	0	22	151.2	361.0	0.84
3	2	0	24	151.2	361.0	0.89
4	2	0	26	151.2	361.0	0.93
5	2	0	28	151.2	361.0	0.98
6	2	0	30	151.2	361.0	1.02
7	2	0	32	151.2	361.0	1.07
8	2	0	34	151.2	361.0	1.11
9	2	0	36	151.2	361.0	1.16
10	2	0	38	151.2	361.0	1.20
11	2	0	40	151.2	361.0	1.25
12	2	0	42	151.2	361.0	1.29
13	8	20	30	604.8	1684.0	1.02
14	2	2	30	151.2	385.0	1.02
15	3	2	31	226.8	565.5	1.05
16	2	2	31	151.2	385.0	1.05
17	3	2	32	226.8	565.5	1.07
18	2	2	32	151.2	385.0	1.07
19	3	2	33	226.8	565.5	1.09
20	2	2	33	151.2	385.0	1.09
21	0	33	0	-	396.0	

*See Estimation of Costs and DCF Analysis sections of Chapter Five.

TABLE H-3

Vertical Wells Project*
3,000-Foot, 50 MCF/D Well
(Raw Gas On Site)
(Constant 1979 Dollars)

Year	No. Wells Drilled	No. Wells Plugged	Total Active Wells	Tangible Investment (Thousands of Dollars)	Intangible Investment (Thousands of Dollars	Operating Costs ($/MCF)
0	12	0		1066.8	2229.6	
1	10	0	20	889.9	1858.0	0.46
2	2	0	22	177.8	371.6	0.49
3	2	0	24	177.8	371.6	0.52
4	2	0	26	177.8	371.6	0.55
5	2	0	28	177.8	371.6	0.58
6	2	0	30	177.8	371.6	0.61
7	2	0	32	177.8	371.6	0.64
8	2	0	34	177.8	371.6	0.67
9	2	0	36	177.8	371.6	0.79
10	2	0	38	177.8	371.6	0.73
11	2	0	40	177.8	371.6	0.76
12	2	0	42	177.8	371.6	0.79
13	8	20	30	711.2	1726.4	0.61
14	2	2	30	177.8	395.6	0.61
15	3	2	31	266.7	581.4	0.63
16	2	2	31	177.8	395.6	0.63
17	3	2	32	266.7	581.4	0.64
18	2	2	32	177.8	395.6	0.64
19	3	2	33	266.7	581.4	0.65
20	2	2	33	177.8	395.6	0.65
21	0	33	0	-	396.0	

*See Estimation of Costs and DCF Analysis sections of Chapter Five.

TABLE H-4

Vertical Wells Project*
3,000-Foot, 75 MCF/D Well
(Raw Gas On Site)
(Constant 1979 Dollars)

Year	No. Wells Drilled	No. Wells Plugged	Total Active Wells	Tangible Investment (Thousands of Dollars)	Intangible Investment (Thousands of Dollars	Operating Costs ($/MCF)
0	12	0		1197.6	2272.8	
1	10	0	20	998.0	1894.0	0.34
2	2	0	22	199.6	378.8	0.37
3	2	0	24	199.6	378.8	0.39
4	2	0	26	199.6	378.8	0.42
5	2	0	28	199.6	378.8	0.44
6	2	0	30	199.6	378.8	0.47
7	2	0	32	199.6	378.8	0.49
8	2	0	34	199.6	378.8	0.52
9	2	0	36	199.6	378.8	0.54
10	2	0	38	199.6	378.8	0.57
11	2	0	40	199.6	378.8	0.59
12	2	0	42	199.6	378.8	0.62
13	8	20	30	798.4	1755.2	0.47
14	2	2	30	199.6	402.8	0.47
15	3	2	31	299.4	592.2	0.48
16	2	2	31	199.6	402.8	0.48
17	3	2	32	299.4	592.2	.49
18	2	2	32	199.6	402.8	0.49
19	3	2	33	299.4	592.2	0.51
20	2	2	33	199.6	402.8	0.51
21	0	33	0	-	396.0	

*See Estimation of Costs and DCF Analysis sections of Chapter Five.

TABLE H-5

Vertical Wells Project*
3,000-Foot, 100 MCF/D Well
(Raw Gas On Site)
(Constant 1979 Dollars)

Year	No. Wells Drilled	No. Wells Plugged	Total Active Wells	Tangible Investment (Thousands of Dollars)	Intangible Investment (Thousands of Dollars)	Operating Costs ($/MCF)
0	12	0		316.4	2311.2	
1	10	0	20	1097.0	1926.0	0.29
2	2	0	22	219.4	385.2	0.31
3	2	0	24	219.4	385.2	0.33
4	2	0	26	219.4	385.2	0.35
5	2	0	28	219.4	385.2	0.37
6	2	0	30	219.4	385.2	0.39
7	2	0	32	219.4	385.2	0.41
8	2	0	34	219.4	385.2	0.43
9	2	0	36	219.4	385.2	0.45
10	2	0	38	219.4	385.2	0.47
11	2	0	40	219.4	385.2	0.49
12	2	0	42	219.4	385.2	0.51
13	8	20	30	877.6	1780.8	0.39
14	2	2	30	219.4	409.2	0.39
15	3	2	31	329.1	601.8	0.40
16	2	2	31	219.4	409.2	0.40
17	3	2	32	329.1	601.8	0.41
18	2	2	32	219.4	409.2	0.41
19	3	2	33	329.1	601.8	0.42
20	2	2	33	219.4	409.2	0.42
21	0	33	0	-	396.0	

*See Estimation of Costs and DCF Analysis sections of Chapter Five.

TABLE H-6

Vertical Wells Project*
3,000-Foot, 150 MCF/D Well
(Raw Gas On Site)
(Constant 1979 Dollars)

Year	No. Wells Drilled	No. Wells Plugged	Total Active Wells	Tangible Investment (Thousands of Dollars)	Intangible Investment (Thousands of Dollars)	Operating Costs ($/MCF)
0	12	0		1527.6	2371.2	
1	10	0	20	1273.0	1976.0	0.23
2	2	0	22	254.6	395.2	0.24
3	2	0	24	254.6	395.2	0.26
4	2	0	26	254.6	395.2	0.27
5	2	0	28	254.6	395.2	0.29
6	2	0	30	254.6	395.2	0.30
7	2	0	32	254.6	395.2	0.32
8	2	0	34	254.6	395.2	0.33
9	2	0	36	254.6	395.2	0.35
10	2	0	38	254.6	395.2	0.36
11	2	0	40	254.6	395.2	0.38
12	2	0	42	254.6	395.2	0.39
13	8	20	30	1018.4	1820.8	0.30
14	2	2	30	254.6	419.2	0.30
15	3	2	31	381.9	616.8	0.31
16	2	2	31	254.6	419.2	0.31
17	3	2	32	381.9	616.8	0.32
18	2	2	32	254.6	419.2	0.32
19	3	2	33	381.9	616.8	0.33
20	2	2	33	254.6	419.2	0.33
21	0	33	0	-	396.0	

*See Estimation of Costs and DCF Analysis sections of Chapter Five.

TABLE H-7

Vertical Wells Project*
3,000-Foot, 10 MCF/D Well
(Gas Cleaned and Delivered)
(Constant 1979 Dollars)

Year	No. Wells Drilled	No. Wells Plugged	Total Active Wells	Tangible Investment (Thousands of Dollars)	Intangible Investment (Thousands of Dollars)	Operating Costs ($/MCF)
0	12	0		967.8	2300.5	
1	10	0	20	868.0	1950.5	2.32
2	2	0	22	129.8	350.0	2.41
3	2	0	24	129.8	350.0	2.50
4	2	0	26	129.8	350.0	2.58
5	2	0	28	129.8	350.0	2.67
6	2	0	30	129.8	350.0	2.75
7	2	0	32	129.8	350.0	2.84
8	2	0	34	129.8	350.0	2.92
9	2	0	36	129.8	350.0	3.01
10	2	0	38	129.8	350.0	3.09
11	2	0	40	129.8	350.0	3.18
12	2	0	42	129.8	350.0	3.26
13	8	20	30	519.2	1640.0	2.75
14	2	2	30	129.8	374.0	2.75
15	3	2	31	194.7	549.0	2.80
16	2	2	31	129.8	374.0	2.80
17	3	2	32	194.7	549.0	2.84
18	2	2	32	129.8	374.0	2.84
19	3	2	33	194.7	549.0	2.88
20	2	2	33	129.8	374.0	2.88
21	0	33	0	-	396.0	

*See Estimation of Costs and DCF Analysis sections of Chapter Five.

TABLE H-8

Vertical Wells Project*
3,000-Foot, 25 MCF/D Well
(Gas Cleaned and Delivered)
(Constant 1979 Dollars)

Year	No. Wells Drilled	No. Wells Plugged	Total Active Wells	Tangible Investment (Thousands of Dollars)	Intangible Investment (Thousands of Dollars)	Operating Costs ($/MCF)
0	12	0		1171.3	2385.8	
1	10	0	20	1020.2	2024.8	1.16
2	2	0	22	151.2	361.0	1.21
3	2	0	24	151.2	361.0	1.26
4	2	0	26	151.2	361.0	1.31
5	2	0	28	151.2	361.0	1.36
6	2	0	30	151.2	361.0	1.41
7	2	0	32	151.2	361.0	1.46
8	2	0	34	151.2	361.0	1.51
9	2	0	36	151.2	361.0	1.56
10	2	0	38	151.2	361.0	1.61
11	2	0	40	151.2	361.0	1.66
12	2	0	42	151.2	361.0	1.71
13	8	20	30	604.8	1684.0	1.41
14	2	2	30	151.2	385.0	1.41
15	3	2	31	226.8	565.5	1.44
16	2	2	31	151.2	385.0	1.44
17	3	2	32	226.8	565.5	1.46
18	2	2	32	151.2	385.7	1.46
19	3	2	33	226.8	565.5	1.48
20	2	2	33	151.2	385.0	1.48
21	0	33	0	-	396.0	

*See Estimation of Costs and DCF Analysis sections of Chapter Five.

TABLE H-9

Vertical Wells Project*
3,000-Foot, 50 MCF/D Well
(Gas Cleaned and Delivered)
(Constant 1979 Dollars)

Year	No. Wells Drilled	No. Wells Plugged	Total Active Wells	Tangible Investment (Thousands of Dollars)	Intangible Investment (Thousands of Dollars)	Operating Costs ($/MCF)
0	12	0		1418.7	2469.0	
1	10	0	20	1240.9	2097.5	0.67
2	2	0	22	177.8	371.6	0.70
3	2	0	24	177.8	371.6	0.73
4	2	0	26	177.8	371.6	0.76
5	2	0	28	177.8	371.6	0.79
6	2	0	30	177.8	371.6	0.82
7	2	0	32	177.8	371.6	0.85
8	2	0	34	177.8	371.6	0.88
9	2	0	36	177.8	371.6	0.91
10	2	0	38	177.8	371.6	0.94
11	2	0	40	177.8	371.6	0.97
12	2	0	42	177.8	371.6	1.00
13	8	20	30	711.2	1726.4	0.82
14	2	2	30	177.8	395.6	0.82
15	3	2	31	266.7	581.4	0.83
16	2	2	31	177.8	395.6	0.83
17	3	2	32	266.7	581.4	0.85
18	2	2	32	177.8	395.6	0.85
19	3	2	33	266.7	581.4	0.86
20	2	2	33	177.8	395.6	0.86
21	0	33	0	-	396.0	

*See Estimation of Costs and DCF Analysis sections of Chapter Five.

TABLE H-10

Vertical Wells Project*
3,000-Foot, 75 MCF/D Well
(Gas Cleaned and Delivered)
(Constant 1979 Dollars)

Year	No. Wells Drilled	No. Wells Plugged	Total Active Wells	Tangible Investment (Thousands of Dollars)	Intangible Investment (Thousands of Dollars)	Operating Costs ($/MCF)
0	12	0		1596.2	2535.0	
1	10	0	20	1395.7	2152.2	0.55
2	2	0	22	199.6	378.8	0.58
3	2	0	24	199.6	378.8	0.60
4	2	0	26	199.6	378.8	0.63
5	2	0	28	199.6	378.8	0.65
6	2	0	30	199.6	378.8	0.68
7	2	0	32	199.6	378.8	0.70
8	2	0	34	199.6	378.8	0.73
9	2	0	36	199.6	378.8	0.75
10	2	0	38	199.6	378.8	0.78
11	2	0	40	199.6	378.8	0.80
12	2	0	42	199.6	378.8	0.83
13	8	20	30	798.4	1755.2	0.68
14	2	2	30	199.6	402.8	0.68
15	3	2	31	299.4	592.2	0.69
16	2	2	31	199.6	402.8	0.69
17	3	2	32	299.4	592.2	0.70
18	2	2	32	199.6	402.8	0.70
19	3	2	33	299.4	592.2	0.72
20	2	2	33	199.6	402.8	0.72
21	0	33	0	-	396.0	

*See Estimation of Costs and DCF Analysis sections of Chapter Five.

TABLE H-11

Vertical Wells Project*
3,000-Foot, 100 MCF/D Well
(Gas Cleaned and Delivered)
(Constant 1979 Dollars)

Year	No. Wells Drilled	No. Wells Plugged	Total Active Wells	Tangible Investment (Thousands of Dollars)	Intangible Investment (Thousands of Dollars)	Operating Costs ($/MCF)
0	12	0		1805.8	2596.2	
1	10	0	20	1586.4	2210.9	0.49
2	2	0	22	219.4	385.2	0.51
3	2	0	24	219.4	385.2	0.53
4	2	0	26	219.4	385.2	0.55
5	2	0	28	219.4	385.2	0.57
6	2	0	30	219.4	385.2	0.59
7	2	0	32	219.4	385.2	0.61
8	2	0	34	219.4	385.2	0.63
9	2	0	36	219.4	385.2	0.65
10	2	0	38	219.4	385.2	0.67
11	2	0	40	219.4	385.2	0.69
12	2	0	42	219.4	385.2	0.71
13	8	20	30	877.6	1780.8	0.59
14	2	2	30	219.4	409.2	0.59
15	3	2	31	329.1	601.8	0.60
16	2	2	31	219.4	409.2	0.60
17	3	2	32	329.1	601.8	0.61
18	2	2	32	219.4	409.2	0.61
19	3	2	33	329.1	601.8	0.62
20	2	2	33	219.4	409.2	0.62
21	0	33	0	-	396.0	

*See Estimation of Costs and DCF Analysis sections of Chapter Five.

TABLE H-12

Vertical Wells Project*
3,000-Foot, 150 MCF/D Well
(Gas Cleaned and Delivered)
(Constant 1979 Dollars)

Year	No. Wells Drilled	No. Wells Plugged	Total Active Wells	Tangible Investment (Thousands of Dollars)	Intangible Investment (Thousands of Dollars)	Operating Costs ($/MCF)
0	12	0		2084.6	2683.3	
1	10	0	20	1829.9	2288.2	0.39
2	2	0	22	254.6	395.2	0.40
3	2	0	24	254.6	395.2	0.42
4	2	0	26	254.6	395.2	0.43
5	2	0	28	254.6	395.2	0.45
6	2	0	30	254.6	395.2	0.46
7	2	0	32	254.6	395.2	0.48
8	2	0	34	254.6	395.2	0.49
9	2	0	36	254.6	395.2	0.51
10	2	0	38	254.6	395.2	0.52
11	2	0	40	254.6	395.2	0.54
12	2	0	42	1018.4	1820.8	0.46
13	8	20	30	254.6	419.2	0.46
14	2	2	30	381.9	616.8	0.47
15	3	2	31	254.6	419.2	0.47
16	2	2	31	381.9	616.8	0.48
17	3	2	32	254.6	419.2	0.48
18	2	2	32	381.9	616.8	0.49
19	3	2	33	254.6	419.2	0.49
20	2	2	33	-	396.0	
21	0	33	0			

*See Estimation of Costs and DCF Analysis sections of Chapter Five.

APPENDIX I
References

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