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NATIONAL GAS SURVEY

REPORT TO THE FEDERAL ENERGY REGULATORY COMMISSION
BY THE SUPPLY-TECHNICAL ADVISORY TASK FORCE ON

NONCONVENTIONAL NATURAL GAS RESOURCES

U.S. DEPARTMENT OF ENERGY

Federal Energy Regulatory Commission

June 1978

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U.S. DEPARTMENT OF ENERGY
Federal Energy Regulatory Commission
Washington, D.C. 20426

June 1978

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FOREWORD

The National Gas Survey Advisory Committee was created under the authority of the Federal Advisory Committee Act, Public Law 92-463 which authorizes Federal agencies to create and administer committees composed of experts, representing various interests, to provide advice to the agency. One of the provisions of the Act is to "...assure that the advice and recommendations of the advisory committee will not be inappropriately influenced by the appointing authority or by any special interest, but will instead be the result of the advisory committee's independent judgment...." (Sec. 5(b)(3)).

On February 28, 1975 the Federal Power Commission issued a notice of proposed rulemaking requesting comments on the establishment of a number of new committees and task forces to carry out new and continuing programs of the National Gas Survey.

By Order issued September 15, 1975, after adopting many of the comments received, the Commission established the Supply-Technical Advisory Task Force-Nonconventional Natural Gas Resources among several other committees and task forces. The first meeting of the task force was held in Washington, D.C. on January 13, 1976. The final task force meeting was held March 15, 1977.

In describing the National Gas Survey, the Federal Power Commission stated that the Survey - "is designed to provide a balanced approach to the industry, its problems and its outlook, representing all points of view relevant to the areas of study. It is designed to include a cross-section of consumer, environmental and industrial interests and to receive input from academicians and representatives from Federal, State and local government organizations."

The goal of the Survey was considered by the Federal Power Commission to be "a periodically updated comprehensive analysis of our future energy situation with emphasis on the natural gas industry, its probable future course, and its impact on consumers and on the economy."

This report, therefore, represents the National Gas Survey Advisory Committee's independent judgment concerning the advice it feels appropriate to transmit to the Federal Power Commission for its consideration. All of its meetings were open to the public and publicly announced at least two weeks preceeding each meeting. Any member of the public had the opportunity to participate in the meetings and/or submit any information he or she wished to.

In accordance with Federal Power Commission "Order Establishing National Gas Survey Advisory Committee", issued November 11, 1976, each member of the Executive Advisory was provided a copy of the final draft and "asked to review and comment" on the draft report before it was published. Every comment received from the Executive Advisory Committee is included as an appendix to this report.

This report, therefore, represents only the views of the members of the Advisory Committee which have not in any way been influenced by the Federal Power Commission. As such, it reflects the views of the Committee and not the Federal Energy Regulatory Commission, nor is the Federal Energy Regulatory Commission obligated to adopt any of the views or recommendations contained in the report. The report combines the data and information submitted to the Survey by members of the task force and is reproduced here exactly as it was received.

The Commission and its staff appreciate the time, effort and expertise contributed by the Advisory Committee. We would like also to acknowledge the typing and other support work graciously contributed by the committee members.

STANFORD UNIVERSITY
STANFORD, CALIFORNIA 94305

DEPARTMENT OF APPLIED EARTH SCIENCES
School of Earth Sciences

JUN 1 8 1977
R...
GAS POLICY ADVISORY COUNCIL

June 6, 1977

Chairman
Federal Power Commission
825 North Capitol Street, NE
Washington, D.C. 20426

Dear Mr. Chairman:

As Chairman of the Supply Technical Advisory Task - Nonconventional Natural Gas Resources I am pleased to submit for your approval the attached reports. These three reports pertain to work of three of the four sub-task forces established as part of the overall Nonconventional Natural Gas Resources Task Force, as follows:

Sub-Task Force II	Methane in Coal
Sub-Task Force III	Gas Generated under Natural Conditions in Recent Organic Material
Sub-Task Force IV	Gas in Tight Formations

The report of the remaining sub-task force (Sub-Task Force I - Gas Dissolved in Water) will be submitted as soon as it is completed, which is anticipated later in 1977.

Sincerely,

John W. Harbaugh

John W. Harbaugh
Chairman
Supply Technical Advisory Task Force
Nonconventional Natural Gas Resources

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SUPPLY-TECHNICAL ADVISORY TASK FORCE
NONCONVENTIONAL NATURAL GAS RESOURCES

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REPORT TO SUPPLY-TECHNICAL ADVISORY TASK FORCE--
NONCONVENTIONAL NATURAL GAS RESOURCES
BY SUB-TASK FORCE II: METHANE IN COAL

WASHINGTON, D. C.

Supply-Technical Advisory Task Force-Nonconventional
Natural Gas Resources-Sub-Task Force II
Methane in Coal

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FPC Coordinating Representative & Secretary	Thomas Jennings

Members

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CHAPTER I

HISTORICAL RESEARCH EFFORTS

Coal Mine Safety

The occurrence of methane in coal was the subject of investigations by R. T. Chamberlin (1) and N. H. Darton (2) conducted for the U. S. Department of the Interior from 1907 to 1915. The frequency and severity of coal mine disasters caused by the accumulation, ignition, and explosion of indigenous methane gas established the need to investigate the occurrence and disposal of methane in coal mines. For many years, improving ventilation or reducing the rate of coal extraction were the only methods employed for preventing dangerous concentrations of methane in underground mines. Later the European practice of piping methane-rich air mixtures from mine workings to the surface atmosphere was developed where longwall mining methods are employed for extracting coal (3).

In 1964, a comprehensive applied research program was initiated by the U. S. Bureau of Mines (4) to better understand and control methane emission in coal mines. The methane drainage research program is described in Appendix A.

Initially, the Bureau of Mines research effort was concerned mainly with identifying fundamental principles regarding methane associated with coal. The basic questions were:

- Why are some coalbeds "more gassy" than others?
- What are the physical factors that control the migration and retention of methane in coalbeds?
- To what extent does the geology of the coalbed influence these factors?

The research projects included laboratory studies of sorption and diffusion properties of coal samples from various coalbeds (5 through 10). Such projects helped to explain the methane emissions observed in deep mines (11 through 17). The first comprehensive survey of the amount of gas emitted from United States coal mines was completed in 1972 (18). An updated report followed in 1974 (19).

Measuring Methane Content of Coalbeds

The study of such physical properties of coal as porosity, permeability, diffusion constants relative to methane and water, fine structure, and composition of sorbed gases (20,21) made it possible to determine directly the gas content of a coalbed (22). Additional refinements have made it possible to quantify the in-place gas content of coalbeds. (23,24). The direct determination technique consists of putting a cored coal sample in a sealed canister, and periodically removing the desorbed gas and measuring the quantity by water displacement; the process is continued until the rate of methane desorption declines to 0.5 cubic centimeters of gas per gram (0.87 cubic inches per ounce) of coal in 24 hours. The gas remaining in the coal is estimated either by using an empirical curve for blocky or friable coals or by measuring directly the gas desorbed from the finely pulverized coal core.

Based on considerable data using the direct determination technique, it was concluded that coalbeds may constitute an important potential methane resource (25), and further development of this resource has been urged (26 through 29). It is estimated that the cumulative total of coalbed gas vented from deep coal mines ranges from 200 to 250 million cubic feet (MMcf) per day [5.7 to 7.1 million cubic meters (MM cu m) per day] or between 73 to 91 billion cubic feet (Bcf) per year (19) [2.1 to 2.6 billion cubic meters (B cu m) per year]. This is equivalent, in calorific value, 1/ to more than 3 million tons (2.7 million metric tons) of coal, or about 1 percent of the annual production from U. S. underground coal mines. The methane normally is diluted by air as it is vented from coalbeds; 200 parts of air per 1 part methane. The total quantity of gas vented to the atmosphere will increase as deeper coalbeds are developed (30), unless measures are taken to capture the coalbed methane.

Chemical Composition

The chemical composition of the gas drained directly from coalbeds is primarily methane (CH_4). The quantity of other hydrocarbons found in coal tested to date does not exceed two percent by volume. The few impurities, found in significant quantities, consist of carbon dioxide (CO_2) and nitrogen (N_2) (15,20,21). No hydrogen sulfide (H_2S) or sulfur dioxide (SO_2) has been detected in coalbed gas. Thus, the composition of most coalbed gas is somewhat similar to and compatible with natural gas. Table 1 shows the analysis of gas from several selected coalbeds.

In addition, the thermal quality of methane associated with coal is practically identical to a high methane-content natural gas. Pure methane has a heat content of 1,012 Btu per cubic foot at 60° Fahrenheit (7.1 Kgcal per cu m at 15.55° Celsius) and atmospheric pressure. Pipeline grade natural gas normally ranges from 950 to 1,035 Btu per cf (6.8 to 7.4 Kgcal per cu m).

1/ Based on the calorific value of methane and coal of 1,000 British Thermal Units (Btu) per cubic foot [7.13 Kilogram calories per cubic meter (Kgcal per cu m)] and 25 million Btu per ton (5.7 million Kgal per metric ton) of coal, respectively.

TABLE 1

COMPOSITION OF COALBED GAS[2/] COMPARED WITH NATURAL GAS[3/]

	Coalbed (Shown in Percent)					
	Pocahontas No. 3	Pittsburgh	Kittanning	Lower Hartshorne	Mary Lee	NATURAL GAS
CH_4	96.87	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[4/]	1059	973	1039	1058	1024	1068

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

3/ Moore, B.J., etal., "Analyses of Natural Gas of the United States," USBM IC 8302, 1966.

4/ British Thermal Unit per Standard Cubic foot at atmospheric pressure. Note: 252 Kilogram calories per Btu and scf 0.0283 cubic meters.

Quantifying Methane in Coalbeds

The quantity of methane in a specific coalbed, estimated in the laboratory by the direct determination method, indicates that the methane content of bituminous coalbeds range from nearly zero to 600 cf per ton (15.4 cu cm/gram) (23,29). However, data for all type of coals are limited. Most of the data that is available have been derived only from bituminous coalbeds; very few data are available for anthracite and sub-bituminous coals.

The total volume of methane in a coalbed may be determined by multiplying the estimated quantity of coal in-place by the gas-content measured in a core of the specific coal. If a core is not available or cannot be obtained from a coalbed to make a laboratory analysis, the gas content may be estimated by using the relationship established by Kim (31). That relationship, illustrated by Figure 1, "Estimated Methane Content with Depth and Rank," is based on the fixed carbon and volatile matter content of coal, the depth of the coal, and constants determined experimentally. Specifically, the chart shows the relationship between the depths of coal, the rank of coal, and the methane content for depths to 2,300 feet (700 m).

Table 2 provides the conversion factors for calculating the volume of gas contained in coalbeds of different thicknesses and gas content. By using Kim's chart and Figure 1 with Table 2, it is possible to estimate the amount of methane in a coalbed of known rank, thickness, areal extent, and depth.

The total estimated remaining U.S. coal resources as of January 1, 1974, are shown in Table 3 (32). The areal distribution of U.S. coals are shown in Figures 2 and 3. Based on Averitt's coal resource estimates and the calculated or postulated gas content of coal per ton, it is estimated that there are 300 trillion cubic feet (Tcf) (7.4 T cu m) of methane gas associated with coals classified as "remaining identified sources;" a total of 1.5 trillion tons (1.4 T metric tons) of minable coal with less than 3,000 feet (approximately 1,000m) of overburden, excluding strippable coalbeds, and with an average gas content of 200 cf per ton (5.1 cu m per metric ton). In addition, it is estimated that the gas content of coal classified as "estimated hypothetical resources" in unmapped and unexplored areas, amounting to 1.8 trillion tons (1.6 T metric ton), and 0.4 trillion tons (0.36 T metric ton) of coal classified as "estimated additional hypothetical resources in deeper structural basins," situated between 3,000 to 6,000 feet (approximately 1,000 to 2,000 m) below the surface, may be as great as 550 Tcf (15.6 T cu m). 5/ In total, therefore, it is estimated that 850 Tcf (22.9 T cu m) of methane may be present in the shallow and deep coalbeds of the United States.

5/ This volume is derived by assuming 200 cf of gas per ton of coal for the 1.8 trillion tons and 480 cf per ton (12.3 cu m per metric ton) for the 0.4 trillion tons of coal.

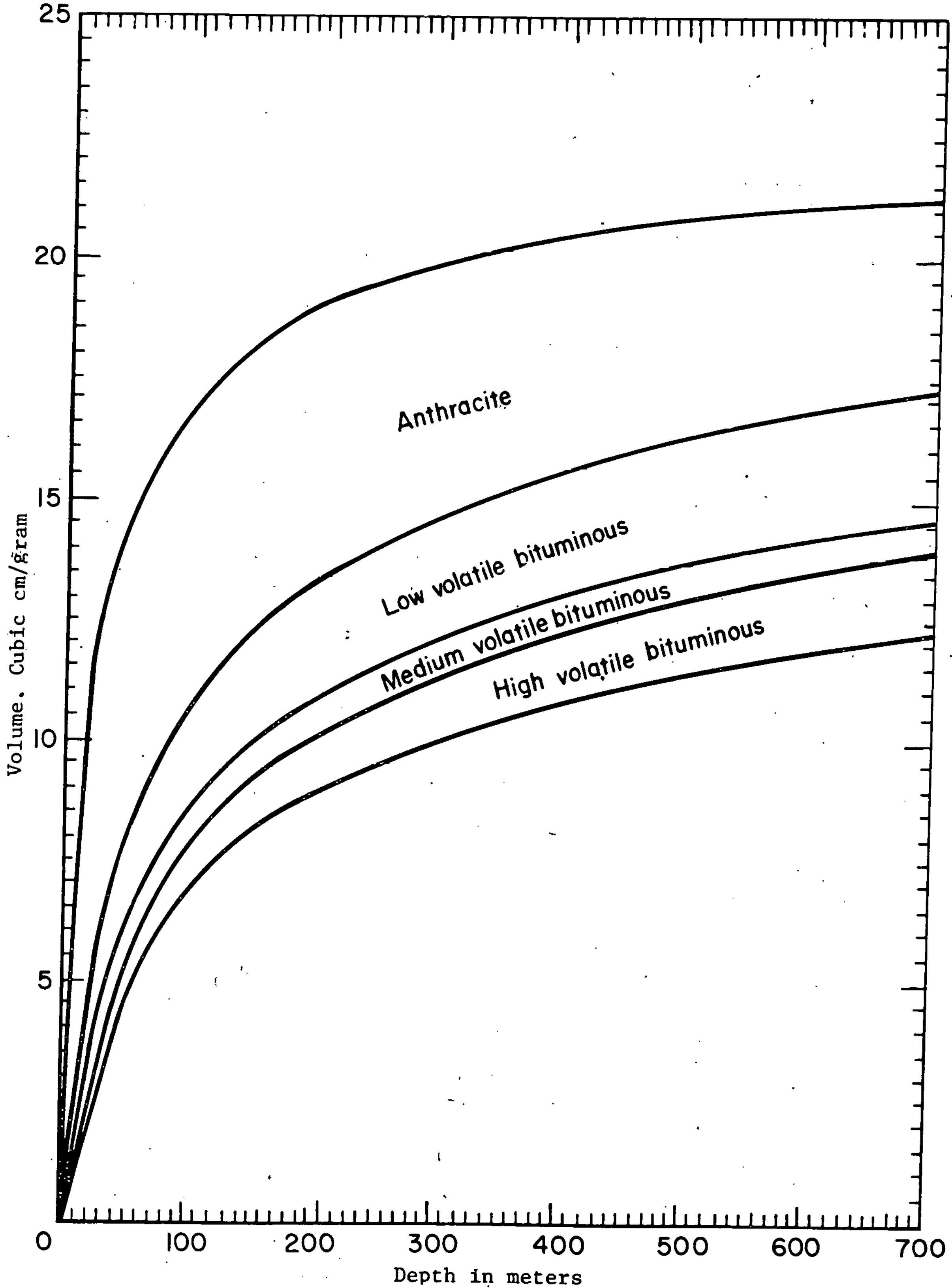

Figure 1. Estimated methane content with depth and rank.

TABLE 2

VOLUME OF GAS IN COAL BEDS[1/]

Coal Volume		Acre-foot	1 ft/sq mi	3 ft/sq mi	6 ft/sq mi	50 ft/sq mi
Coal-tons	One ton	1,800	1.15×10^6	3.45×10^6	6.9×10^6	57.5×10^6
Gas Content in Cubic Feet	50	90×10^3	58×10^6	173×10^6	345×10^6	2.9×10^9
	75	135×10^3	87×10^6	255×10^6	515×10^6	4.3×10^9
	100	180×10^3	115×10^6	345×10^6	690×10^6	5.8×10^9
	200	360×10^3	230×10^6	690×10^6	1.4×10^9	11.6×10^9
	300	540×10^3	345×10^6	1×10^9	2×10^9	-
	400	720×10^3	460×10^6	1.4×10^9	2.7×10^9	-
	500	900×10^3	575×10^6	1.7×10^9	3.4×10^9	-
	600	1.1×10^6	690×10^6	2×10^9	4.1×10^9	-
	650	1.2×10^6	748×10^6	2.2×10^9	4.5×10^9	-

1/ Assuming Various Gas Contents (in Cubic Feet Per Ton) and Thicknesses of Coal (in Feet per Acre and Feet per Square Mile)

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	135,943	700,000	835,943	100,000	935,943
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. England; 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. England; 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]I [illegible]

[6]S [illegible] ources of lignite in western Kansas and western Oklahoma in beds generally less than 30 i [illegible]

[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.

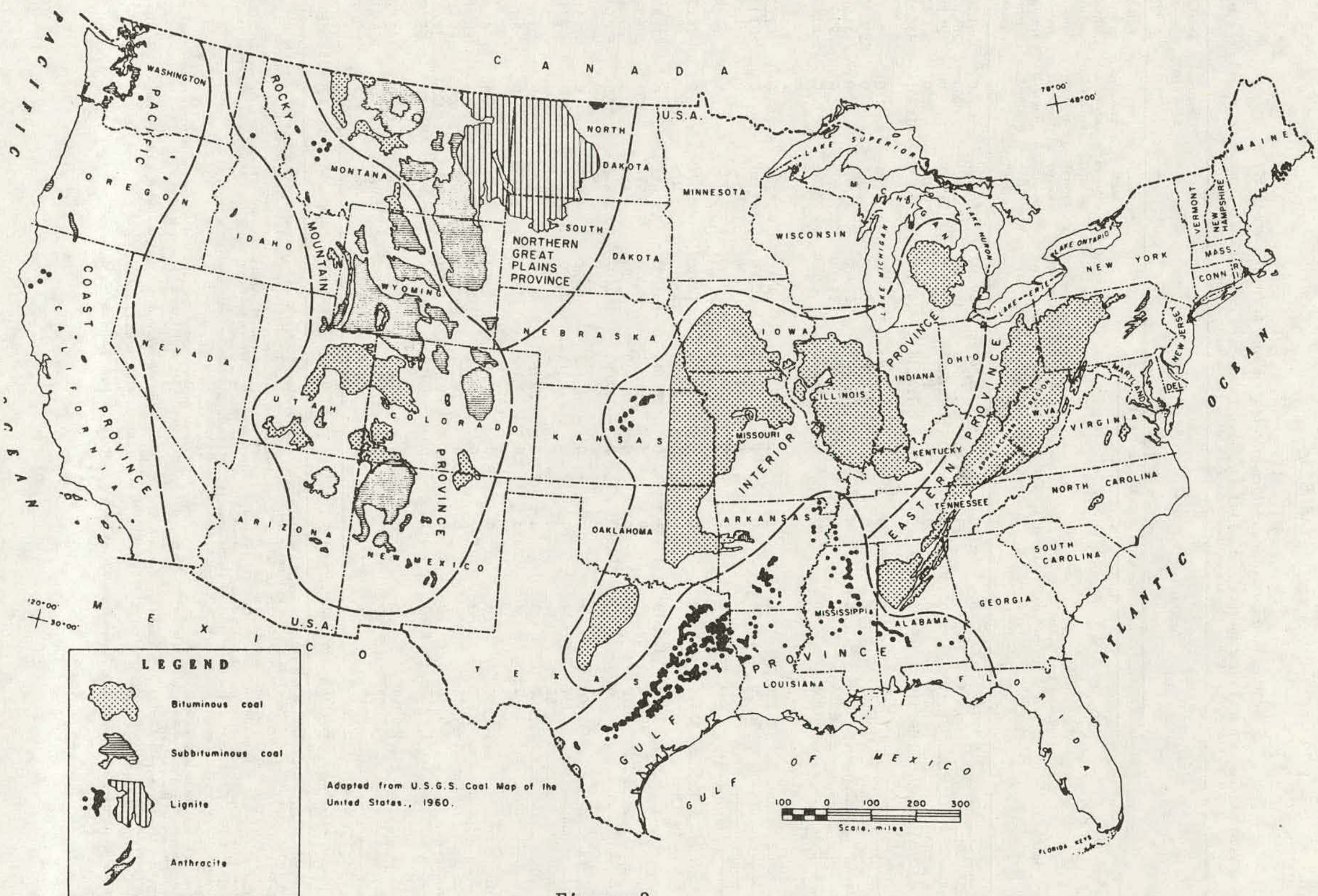

Figure 2.
Areal Distribution of Coals in the Contiguous U.S.

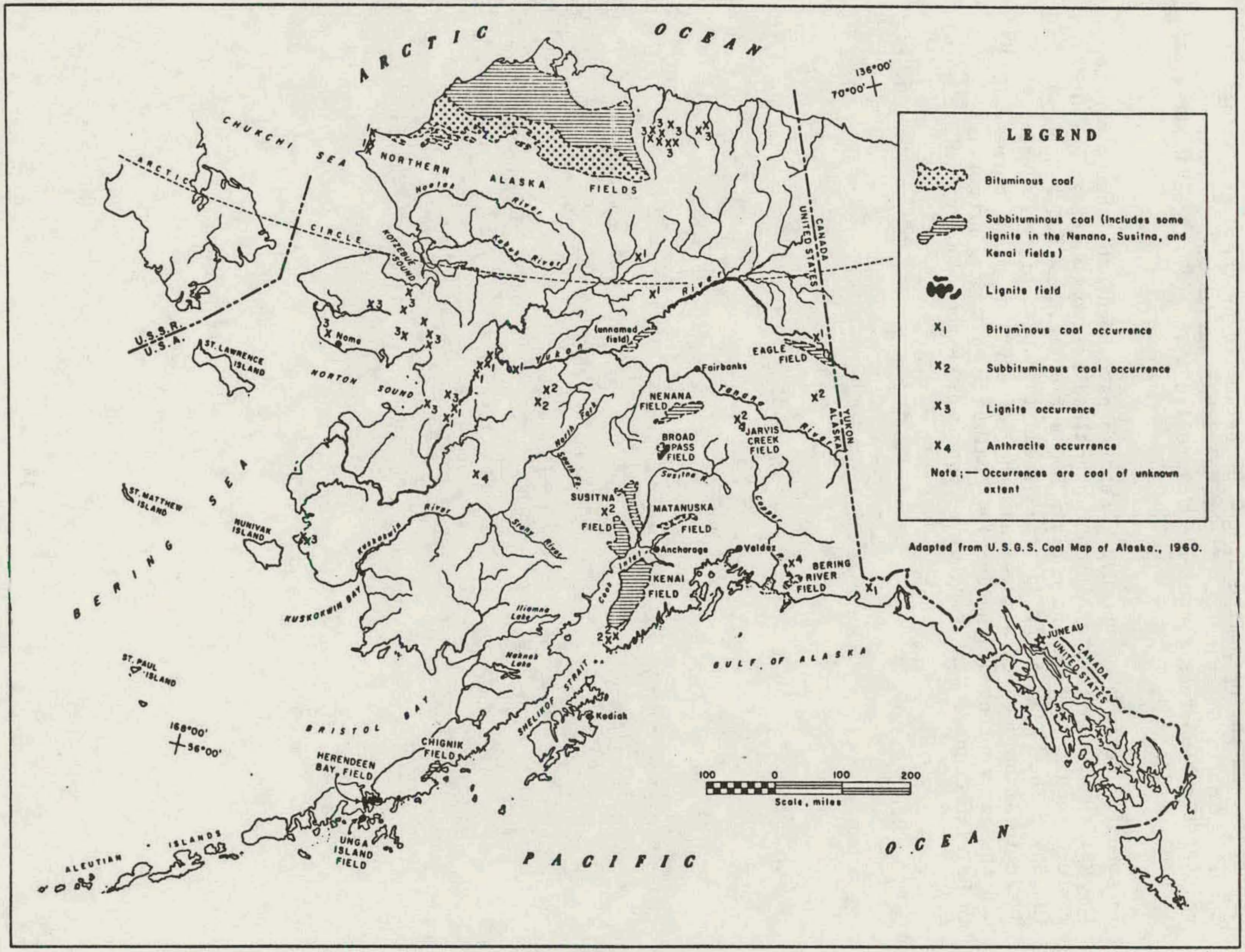

Figure 3.
Areal Distribution of Coals in Alaska

The estimated quantity of methane associated with coal is roughly equivalent to the total reserves and undiscovered recoverable natural gas resources in the United States as estimated by the U.S. Geological Survey. The USGS estimates of natural gas reserves and undiscovered recoverable resources range from 761 to 1,094 Tcf (21.55 to 30.98 T cu m). (33)

In specific regions of the U.S., reports have been published that show the gas resources in the Pittsburgh coalbed in two counties in southwestern Pennsylvania alone contain 500 Bcf of methane (14.2 B cu m) (34,35). The Mary Lee group of coalbeds in a part of the Warrior Basin in Alabama contain more than one Tcf (28 B cu m) of methane (36), and the gas content of the Beckley coalbed in six mine properties in Raleigh County, West Virginia, contain more than 100 Bcf (2.8 B cu m) (37).

CHAPTER II

INDUSTRY CRITERIA FOR COMMERCIALIZATION OF COALBED GAS

Utilization by Coal Mining Companies

None of the methane being vented from mines, to date, is utilized by coal mining companies for their own use 6/ and only one mining company, in cooperation with a Bureau of Mines' mine health and safety demonstration program, is producing and selling commercial quantities of methane (16,30). This project is discussed later.

Commercial Criteria

Coal companies and public utilities both have limited experience in the commercialization and the economic evaluation of coalbed gas. Also the criteria for such important considerations as the deliverability rates, the quality of the supply, and the terms of purchase (sale) of such gas have not been established. Any utility decision relative to the commercialization of coalbed gas at this time is dependent upon fragmentary data developed primarily for mine health and safety purposes. The data are not sufficiently detailed or precise to be useful.

It is the view of the utility industry that the limited statistical base, with regard to such data as the composition and heating value of coalbed gas for example, preclude planning commercial development. In preparing a gas purchase agreement, a utility must consider gas quality in terms of market acceptability, compatibility with conventional supplies, and Federal and State specifications.

Appendix B is an example of a typical gas utility standard agreement to purchase coalbed gas. Tables 1 and 4 further illustrate the kind of information essential when preparing purchase contracts. The above data also show that coalbeds locally may contain a large percentage of carbon dioxide, which reduces the Btu value of the gas, as indicated. If a substantial volume of a gas with such impurities is commingled with conventional natural gas of a higher Btu content, the heating value of the resultant product would be reduced and thus would adversely affect customer utilization. A high content of impurities in coalbed gas especially carbon dioxide, also increases the probability of corrosion to gathering and transmission lines, and to distribution equipment. A utility will incur additional costs to remove such impurities.

6/ For example, the mines owned by Island Creek Coal Company in Buchanan County, Virginia, and Bethlehem Mines Corporation in Cambria County, Pennsylvania, vent in excess of 10 MMcf (283 M cu m) per day.

TABLE 4

COMPOSITION OF PITTSBURGH COAL BED GAS, 7/

	Methane	Ethane	Oxygen	Nitrogen	Carbon Dioxide	BTU/scf (Dry Basis)
	87.01	0.14	0.01	0.29	12.55	885
	88.49	0.07	0.02	0.37	11.04	899
	88.36	0.07	0.02	0.37	11.17	897
	86.88	0.08	0.34	1.35	11.35	882
	87.78	0.05	0.02	0.21	11.94	891
AVERAGE	87.70	0.08	0.08	0.51	11.61	891

7/ Letter, Consolidated Gas Supply Corporation to FPC Supply Technical Advisory Task Force, January 12, 1976.

The moisture content of coalbed gas also is of concern to utilities. Appendix B shows that the moisture content must not exceed 7 pounds of water per 1 MMcf of gas (89.7 g per 1 MM cu m). Coalbed gas analyses indicate that as much as 400 pounds of water per 1 MMcf (5.1 Kg per one cu m) may be typical. The moisture content, therefore, must be reduced, thus further adding to the cost of producing methane from coal.

Deliverability

The deliverability criteria for coalbed gas are important, not only to the utility and to the ultimate purchaser, but to the coal company as well. A coal company's principal interest is to vent the methane as quickly as possible to maintain mine safety. Consequently, a coal company cannot be restricted by the deliverability criteria of the utility company. A coal company operating in a gassy mine therefore will be compelled to reserve the right to vent coalbed gas to the atmosphere, at a rate it deems essential regardless of the utility company's ability to accept such rates into its pipeline system. Utilities on the other hand also must consider the long term availability of such supplies.

Agreements between coal operators and gas purchasers will have to be specifically written to take into account unusual environmental conditions, unusual operating situations, and unknowns relative to extraction technology.

Research efforts are being made by various Federal and State agencies to utilize coalbed gas for power generation purposes, as an internal source of electrical power for a mine complex. With proper design of gas-burning equipment, coalbed gas could be used for these purposes.

Utilization Experience

Natural gas companies operating in the Appalachian area have long noted the presence of gas in coal-bearing rock formations. A case in point is the Big Run gas field, an anticlinal structure, located in Wetzel County, West Virginia. The discovery well of the Big Run field was drilled in 1905. In 1931, an application was made to the West Virginia Department of Mines to abandon the well. When the casing was cut at the depths of 1,078 to 1,080 feet (approximately 339 m) and the well was plugged back to a depth of 1,118 feet (340 m), methane began issuing from the Pittsburgh coalbed. The well was tested and found to have an open flow of 28 Mcf (792 cu m) per day with a bottom hole pressure of 92 pounds per square inch (6.47 Kg per cm^2) in 16 hours. Consequently, the well was reinstated as a gas well in January 1932, and remained productive until 1968. During this period the well produced in excess of 212 MMcf (6 MM cu m) of coalbed gas. Prior to the abandonment of the well, a total of 23 wells were drilled and completed as gas producing wells from the Pittsburgh coalbed. The cumulative production through 1974 was 1.7 Bcf (48 MM cu m). The wells are productive because of the natural permeability caused by the tension cracks on the crest and lee flank of the anticline. At least 783 wells have been drilled through the Pittsburgh coalbed. Drilling densities into other coalbeds have been greater, but fewer productive wells have been completed in the other coalbeds. This may be due to the lack of permeability in such coalbeds.

The first major effort to produce methane from coalbeds as part of a degasification program was at the Federal No. 2 Mine in Monongalia County, West Virginia, where a 839-foot-deep (256 m) shaft was enlarged to permit seven holes to be drilled horizontally into the coalbed. Since September 1972 after 1,438 days of operation, 834 MMcf of gas has been produced, (24 MM cu m) of which 427 MMcf (12 MM cu m) has been commingled in a natural gas distribution pipeline and marketed. Another shaft, at the same mine, was made available for additional experimental drilling tests. Five holes were drilled and after 1,073 days, some 784 MMcf (22 MM cu m) of methane was produced of which 121 MMcf (3.5 MM cu m) was delivered to a distribution pipeline.

In less than 4 years, more than 1.6 Bcf (45 MM cu m) of gas was produced from the West Virginia mine with no appreciable decline in the flow rate.

CHAPTER III

TECHNOLOGY FOR RECOVERING METHANE FROM COALBEDS

Methane can be recovered from coalbeds by draining either in advance of mining or during mining. Methods for removing the methane ahead of mining employ vertical boreholes drilled from the surface, horizontal boreholes drilled from shaft bottoms, and directional slant holes drilled from the surface. In active mines methane can be removed from the coalbed through horizontal holes drilled in appropriate areas of the mine.

Transportation of methane produced from coalbeds to United States markets should be a minimal concern. Most major coal basins are either near major population centers or are presently crossed by or near existing natural gas pipelines. The existing gas transportation systems for the most part could be utilized for marketing methane from coal.

Vertical Surface Boreholes

One technique of recovering methane from coal several years ahead of mining actively consists of drilling small diameter (less than 9-inch or 0.23 m) vertical boreholes from the surface to the coalbed. The hole is cased and cemented, and existing fractures in the coal are widened and extended by the application of hydraulic pressure and controlled injection of gelled water. Sand grains in the treatment fluid serve as a propping agent to keep the fractures open when pressure applied from the surface is released. The hydraulic stimulation increases the permeability of the coal, and enlarges the gas drainage area. 8/ When stimulation is applied to minable coalbeds, the effect of this treatment on the future minability of the coal must be considered.

The production rate from the vertical holes depends on the effectiveness of the stimulation treatment. A production rate of 50 M to 100 Mcf (1.4 to 2.8 M cu m) per day per well appears feasible.

Horizontal Boreholes from Shaft Bottoms

Another method of producing gas from coalbeds is by drilling horizontal holes from the bottom of shafts sunk to the coalbeds. The rate of gas flow per linear foot of 3-inch (7.7 cm) diameter horizontal hole drilled in permeable coalbeds ranges from 100 to 450 cf

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8/ Bureau of Mines News Release dated November 10, 1976, reports a contractual agreement to test this technique in a mine in Greene County, Pennsylvania, which has not commenced coal production.

(2.8 to 12.7 cu m) per day. In one demonstration seven horizontal holes were drilled from the bottom of a small-diameter shaft. The aggregated length of the horizontal holes was 4,325 feet (1,318 m). After the coalbed was sufficiently dewatered, gas flowed from the horizontal holes at an initially high rate and continued with only a modest decline over a period of almost four years. In another demonstration of this technique, five horizontal holes, with an aggregate length of 5,830 feet (1,777 cu m), were drilled from the bottom of an 18-foot (5.5 m) ventilation shaft. The initially high average gas flow declined only slightly over a three year period. The production history of these two field demonstrations in Monongalia, West Virginia, was discussed under Utilization Experience in Chapter II.

The gas produced in this way is manifolded to a pipe that carries it to the surface. The possible rate of production from each such shaft is estimated conservatively at 1 MMcf of gas per day.

Directional Slant Holes from the Surface

The directional drilling technique for removing methane from coal combines features of horizontal and vertical degasification boreholes. A small diameter borehole is drilled from the surface and intentionally deflected to penetrate the coalbed and continue into the coal parallel to the bedding plane, thereby maximixing the penetration of horizontal fractures. The Bureau of Mines has conducted two preliminary tests with sufficient success to warrant further testing of this method of recovering methane from coal. More data and information regarding slant-hole drilling will be available in the near future.

Horizontal Boreholes in Active Mines

Methane can be produced from the active working sections of a developing mine that has not been advanced to the property limits. The process consists of drilling small diameter horizontal boreholes into the virgin coal as the working face is advanced. Coalbed gas flowing from these holes can be conducted to the surface through a suitable piping system in the mine.

CHAPTER IV

IDENTIFICATION OF PROBLEMS

Methane Capture

A major problem in commercializing methane produced from active mines is transporting the gas through pipes in underground coal mines. A recent study (38) contracted by the Bureau of Mines proposed a design for a safe piping system for transporting drained gas through a mine.

Methane produced through wells completed in coalbeds may be handled conventionally. However, the two phase flow of methane and the water, associated with the coal, (39) must be considered in production planning.

Depending on the ultimate market supplied, the compression of methane for transmission may be essential. The gas pressures in coalbeds seldom exceed hydrostatic pressures. Pressures in relatively shallow beds where there is some producing experience have never exceeded 670 psig (47.1 Kg cm^2) at atmospheric pressure. Such pressures, however, drop rapidly as production begins; the gas is held by sorption rather than by compression (16).

Sampling of Coalbeds

Historically, the importance of coal as a fuel resource necessitated detailed quantification and delineation of its geographic location and depth. Little interest existed for quantifying the amount of methane associated with such coal resources. Subsequent efforts to quantify the amount of methane in coal have been related to coal mine health, safety, and productivity concerns. However, with the declining availability and the increasing cost of domestic conventional natural gas, the identification and quantification of methane in coal may take on added importance.

Methods for measuring methane associated with relatively shallow coalbeds and the technology for extracting such gas for commercial use generally are understood, but little is known of the methane in the thick coalbeds at the depths of more than 3,000 feet. Specifically, there is no experience, and there are no active programs directed towards developing technology for methane production from deep coalbeds.

Before it is possible to assess reasonably the resource potential of methane in deep coals, core samples must be obtained and the areal limits must be determined. The most likely source for recovering such cores is from wells drilled for oil and natural gas. However, the coring of coal sections, particularly deep coal, is not the common practice when drilling for oil and gas.

For the most part, oil and gas drilling programs have not provided detailed data regarding the deep coalbeds that may have been penetrated, although coalbeds are used as "marker-beds". It is likely that the depths and thicknesses of important deposits are identified on the mechanical and electric logs maintained by petroleum companies. It is possible that, as the value of methane from coal increases, future drilling programs by the petroleum industry will consider the coring and testing of coalbeds an essential part of their exploration program.

Required Technology Improvements

Commercial production of methane from coal has not been realized in part, because the techniques and the technology demonstrated in research efforts have not been applied on a commercial scale.

Continuous In-Hole Surveying:

No satisfactory method for continuous surveying of non-vertical boreholes during drilling has been developed. There is a need for a system that would provide near continuous drill orientation while drilling is in progress. This would eliminate the need to interrupt drilling to make measurements for determining borehole azimuth and inclination.

Drill Guidance:

A companion technology to the continuous surveying system would be an improved drill bit guidance system to operate effectively in the hard sediments associated with coal. To date the special tools developed for offshore directional drilling have not been totally compatible with the objectives of coalbed gas production.

Increasing Coalbed Permeability:

The low permeability of coalbeds is the main impediment to producing methane at commercial rates-of-flow. Coalbeds are anisotropic, that is they have directional permeability. Coalbeds can be drained most efficiently if horizontal boreholes intersect the face cleats perpendicularly. 9/ Blocky coals, generally found at depths of 800 feet (244 m) to 1,200 feet (366 m), have prominent cleats. The friable, medium- to low-volatile bituminous coals generally have complex cleat systems, thus directional permeability is difficult to measure, and these coalbeds require unique stimulation methods to increase their permeability.

9/ Cleat--The natural occurring vertical fracture in coal. The face cleat cuts across bedding surfaces and extends for many feet. The butt cleat is a short poorly developed fracture commonly truncated by the face cleat.

Economic Uncertainty

There is no "typical situation" upon which to base the economics of methane production from coalbeds. It is apparent, however, that certain unique factors can contribute to making the utilization of methane from coal feasible, such as proximity to existing pipelines, shallow depth, effective coalbed permeability, favorable geologic structural conditions which minimize water production and disposal, and a mutual commercial interest between the producers of coal and methane.

Another consideration which bears indirectly on the economics of methane extraction from coalbeds is the benefit derived by reducing coal mine hazards caused by methane-air mixtures.

In view of the limited experience in utilizing methane and the experimental nature of methane production, the cost of developing such supplies and the ultimate cost to the consumer cannot be established with certainty at this time. Although the benefits of evacuating methane from minable coal deposits is apparent.

Institutional Constraints

The institutional constraints to developing coalbed methane may be identified as legal and proprietary. The legal considerations are discussed later. The proprietary issue, as used herein, refers to the conflict that may arise between the objectives of a coal operator to mine coal and retain as confidential, information concerning his operation and coal ownership, with the objectives of a gas developer. The gas developer's interests very likely depend on information concerning coal reserves, as this permits quantification of methane resources. In addition, both the coal operator and the gas developer have an interest in the application of technology to extract methane; the technology must be effective, but not diminish or impede the opportunity to mine coal.

CHAPTER V

LEGAL CONCERNS

Status of Developer

If coalbed gas utilization is both technically feasible and desirable from an energy conservation and the all important mine safety point-of-view, both the State and Federal Governments must become active in quantifying and defining the potentially large methane resource. Cooperation will be required between State and Federal agencies in order to recommend appropriate new legislation which prescribes the rights of all interests.

Eventually the legal question as to methane ownership must be resolved by State courts. Until then methane utilization probably will be practical only in instances where one company owns both the coal and the mineral rights or where a coal company and a gas company can cooperate in a methane production program.

At such time as it becomes economic to produce methane from active mines, such Federal agencies as MESA (mining Enforcement and Safety Administration of the U.S. Department of the Interior), and the Department of Transportation, and State agencies governing mine safety and pipeline construction may require developers to apply for permits and meet construction standards.

In the event methane is produced through vertical boreholes drilled several years in advance of mining, the operating company may be classified and subject to a separate set of regulations applicable to gas producers. For example, the State of West Virginia does not require permits for air shafts and gob ventilation holes 10/. However, permits are required for any shaft or hole dug or drilled to produce gas. Thus, a coal company wishing to degasify its mine and sell the methane would be required to meet all of the obligations currently imposed on gas producers concerning drilling, completing, producing, and plugging of wells, obtaining permits for other operations, and posting performance bonds. A developer also will be affected by State and Federal laws which require a support pillar to be left around a well that penetrates a minable coalbed. In Pennsylvania the pillar requirement is 200 feet (approximately 60 m) in diameter. In West Virginia permission must be obtained before mining closer than 200 feet. Thus, clarification and/or modification of existing laws governing natural gas drilling and production may be necessary to accommodate methane extraction and not unduly limit the extraction of coals.

10/Vertical holes drilled from the surface into caved and abandoned mined areas.

In essence, total cooperation is essential between natural gas and coal companies involved in this common interest. They, with State and Federal regulatory agencies, must provide appropriate rules and regulations that will enhance methane utilization while preserving mine safety and coal productivity.

It may be necessary for the Federal Power Commission, insofar as its jurisdiction is concerned, to regulate coalbed gas production operations, particularly in granting pipeline permits, determining cost of service, and the abandonment requirements for pipelines and wells. A determination must be made whether separate rules other than those currently in effect for conventional natural gas are appropriate.

Status of Resource

The legal issue of ownership of methane in coalbeds could develop into a major impediment to its commercial development. Generally, mineral rights, including the right to explore for, develop and produce natural gas, may be contracted for separately from surface rights. A land owner may by deed or lease transfer acreage, and the intent of the parties governs what is conveyed. Thus, each deed and lease having a bearing on the right to the minerals must be examined separately before answering the question: Who has the right to the methane underlying a given acreage? Usually, coal leases are held separate from oil and natural gas leases, when the land is owned in fee simple, or when the land is owned outright by a governmental body. Over the years, the courts have been called upon to construe deeds and leases relating to minerals. In some places it will be found that certain general principles of interpretation have evolved. Under Pennsylvania law, according to the "Dunham" rule, a deed conveying all coal and other minerals of every kind and character under a described tract of land grant does not include natural gas subsequently discovered on the land. New York State Natural Gas Corp. v Swan-Finch Gas Development Corp., 278 F.2d 577 (3d Cir. 1960). But whether the same courts would treat methane associated with coalbeds in the same way is open to speculation. In short, one cannot expect that every court in each State where coal deposits are to be found would resolve in the same way a dispute as to whether a particular deed or lease conveyed the right to develop and produce methane.

There are other considerations which have contributed to the present lack of clarity regarding rights to methane. The presence of methane in coalbeds creates a hazard for coal mining. Methane is something to be evacuated from the mine to avoid explosions, damages, injuries, and/or death. Methane is hardly considered an asset in these circumstances. Given the fact that coal has been mined in the United

States for over one hundred and fifty years, one can expect to find many deeds and leases which refer to rights to coal without making any particular reference to methane found in conjunction with it. This ambiguity about rights to methane was raised before the legislature of West Virginia in a recent session, but was not resolved. In Pennsylvania a bill was proposed to have gas in coalbeds not specifically covered by existing natural gas leases revert to the Commonwealth. This proposal has not yet been introduced to the legislature. The general consensus is that only after the methane in coal becomes more valuable can any reasonable settlement on the issue be expected.

Some coal companies claim ownership of coalbed gas if they own the coal. The opinion is at odds with the petroleum industry's position and several legal opinions which state that the coalbed gas belongs to the holder of the natural gas rights. An oil and natural gas lease gives one the right to drill and produce oil and natural gas from any formation, while the ownership of the reservoir remains with the owner of the land surface. Ownership of the natural gas is not perfected until the gas is under control, i.e., in the casing at the wellhead.

Mine operators must remove the methane from the mine in order to meet stringent safety laws, and consistent with that purpose, must therefore control the coalbed gas to that extent. It has been ruled by the Pennsylvania Supreme Court in Chartiers Block Coal Company Vs. Mellon, 152 Pa. 286, 296 (1893) that this control does not give title to the coal grantee. The court stated that the

> '...grantee of coal owns the coal but nothing else, save the right of access to it and the right to take it away.' This is not to say, however, that the coal mine operator may not expel methane gas into the atmosphere. To deprive him of this right would, in effect, be depriving him of his access to the coal, since coal cannot be mined without expelling the methane from the mine shaft. Thus, the right to mine for coal necessarily includes the right to perform those actions necessary to insure the safety of such mining. Since the coal owner or grantee only retains the right to extract coal, however, the right to access to, and economic control of, the methane gas belongs to the owner or grantee of the gas rights.

The above was quoted from Official Opinion No. 53 of the Office of the Attorney General, Commonwealth of Pennsylvania, October 31, 1974, by Israel Packel, Attorney General, and Theodore A. Adler, Deputy Attorney General, who concluded that "only those persons who own or have obtained the right to extract gas have the right to assert title thereto."

Beyond the question of ownership, another legal question involves the jurisdictional responsibility, of the Federal Power Commission. Conventional wisdom would suggest that the FPC has jurisdiction over methane when it is transported and sold for resale in interstate commerce because it is likely to be considered a natural gas within the meaning of the Natural Gas Act. See Deep South Oil Co. Of Texas v FPC, 247 F.2d 882, 888 (5th. Cir. 1957).

CHAPTER VI

ENVIRONMENTAL CONSIDERATIONS

There is little recorded experience with commercial gas production from coalbeds, except that discussed by Tilton (40), to provide a meaningful understanding of the environmental aspect of such production. Some of the problems encountered in drilling to coalbeds from the surface to produce gas are common to all drilling operations.

Water in Coalbeds

The composition of coalbed waters varies widely, from slightly acid to slightly alkaline, and from potable to saline. The composition of water from three separate coalbeds is shown in Table 5. The planning of pollution control and water disposal systems must be determined on the basis of the water at each site. Water from some coalbeds, especially in the Western part of the United States, may be of a higher quality than the alkaline surface waters.

Drilling Effects on Surface

The environmental impact of drilling to recover gas from coalbeds should be minimal. The sludge and mud pits are usually small in size (about 25 cubic yards or 19 cu m), and the quantity of drillpipe casing and tubing is relatively minor; thus problems, not already resolved by the petroleum industry are not expected.

Except for the laying of gathering lines and site preparation, surface damage should be minimal. Abandonment can be accomplished by plugging the holes according to State or Federal regulations. In some instances, boreholes drilled from the surface may be used by the coal mining companies as vent holes, for powerline entry, or rock dust supply holes, etc.

Favorable Impact on Mining

Improved mine safety and increased productivity make drainage of gas from coalbeds worthwhile and essential. One of the long range benefits of methane drainage is that deep coalbeds, below 3,000 feet, which might otherwise not be mined for many years, may well prove economic for mining if the hazards of excessive methane emissions are eliminated.

TABLE 5

COMPOSITION OF WATER FROM THREE COALBEDS

Coalbed Identification	Pittsburgh				Mary Lee	Pocahontas No. 3
pH	7.45	7.65	8.15	8.05	8.35	6.75
Acidity	0	0	0	0	0	110
Alkalinity . . . . ppm	1,825	790	2,043	876	355	0
Dissolved solids . . . ppm	4,478	9,774	17,246	3,108	1,428	156,440
SO_4 . . . . ppm	63	133	ND	ND	ND	2
Ca . . . . ppm	159	477	127	162	12.5	*2.95%
Mg . . . . ppm	132	193	482	29	8	*0.67%
Fe . . . . ppm	0.5	ND	ND	0.13	ND	1
Chlorides . . . . ppm	2,356	7,700	13,600	2,200	700	*13.97%

ND Not detected.
* Reported as percent.

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APPENDIX A

METHANE PROGRAM OF THE BUREAU OF MINES

The Bureau of Mines methane program currently includes two separate but related objectives. The original and continuing objective is to develop the technology necessary for safe and economic mining of methane-laden coalbeds so as to prevent the mine disasters caused by accidental ignition of methane-air mixtures. Recently the objective of demonstrating the feasibility of recovering commercial quantities of methane from virgin coalbeds and from underground gob areas to increase the production potential and productivity from United States coal deposits has been added.

The present methane control program was started in 1964. Appropriation of funds in Fiscal Year (FY) 1965 for the purpose was triggered by the Robena mine disaster. From 1965 through 1968 the research was funded at an annual level of $250,000 to $300,000 and was concerned mainly with establishing principles that are dominant in controlling the occurrence and movement of methane in coalbeds.

As a result of the No. 9 mine disaster at Farmington, West Virginia, in 1968 an accelerated program was instituted. With annual funding of $1.7 million in FY 69 and FY 70, in-mine work was expanded to establish relationships of coalbed properties to methane emission and to develop control techniques.

In FY 71 the program was again expanded as it became part of the research under the Coal Mine Health and Safety Act. A funding level of $5 million was maintained through FY 72. The increased expenditures were for development and acquisition of necessary tools and instruments, expansion of in-mine testing, and experimental vertical degasification borehole patterns in eight different coalbeds. In FY 73 and FY 74 annual funding averaged about $2 million. In FY 75 and FY 76 the funding increased to about $3 million when research to improve coal productivity was included.

Selected major accomplishments are as follows:

Developed technology for drilling long horizontal holes (more than 1000 feet) into a coalbed for degasification.

Demonstrated degasification of Pittsburgh coal through horizontal holes into the coalbed from the bottom of a shaft.

Demonstrated degasification of permeable coalbeds through vertical boreholes with hydraulic stimulation in advance of mining.

Developed simple, inexpensive direct method for estimating the methane content of a coalbed from a core sample.

Demonstrated control of methane at the face with water infusion.

Fstablished the dependency of methane emission rate during mining on numerous factors including nature of coalbed and surrounding strata, depth, fracture permeability, reservoir pressure, and coal production rate.

Demonstrated control of methane in gob areas by vertical holes from the surface ahead of pillaring and longwall operations.

APPENDIX B

EXAMPLE OF COALBED GAS QUALITY SPECIFICATION FOR GAS PURCHASE AND SALES AGREEMENT

STANDARD

Quality of purchased gas.

REFERENCE(s)

"XYZ" Gas Company's gas utility standard 90.0.

GENERAL

The intent of this standard is to specify the quality of gas purchased by the "XYZ" Gas Company. Deviations from this standard will be specifically noted in the Purchase Agreement. "XYZ" Gas Company's standard base measurement is as specified in the Purchase Agreement. The barometric pressure for pressure calculation is 14.4 psia.

GAS QUALITY SHALL:

a) Be in its natural state as produced.

b) Be commercially free from dusts, gums, gum forming constituents, or other liquid or solid matter which might become separated from the gas in the course of transportation through pipelines.

c) Not contain more than three-tenths (0.3) of a grain of hydrogen sulfide (H_2S) per one hundred (100) cubic feet.

d) Not contain more than thirty (30) grains of total sulfur per one hundred (100) cubic feet.

e) Not contain more than four (4%) percent by volume of a combined total of inerts such as carbon dioxide, nitrogen, argon and helium; provided, however, that the total carbon dioxide content shall not exceed three (3%) percent by volume.

f) Not contain more than one (1%) percent of oxygen by volume.

g) Have at least nine hundred and fifty (950) British Thermal Units per cubic foot calculated as the gross saturated value at 14.73 psia and 60°F as setforth in "XYZ" Gas Company's Standard 90.0.

APPENDIX B (Continued)

EXAMPLE OF COALBED GAS QUALITY SPECIFICATION FOR GAS PURCHASE AND SALES AGREEMENT

h) Be dehydrated by seller, if necessary, and shall in no event have a water content in excess of seven (7) pounds of water per million cubic feet of gas measured at our purchase base (14.73 psia at 60°F).

i) Be in conformance with any existing regulatory standards.

REPORT TO SUPPLY-TECHNICAL ADVISORY TASK FORCE-
NONCONVENTIONAL NATURAL GAS RESOURCES
BY SUB-TASK FORCE III: GAS GENERATED
UNDER NATURAL CONDITIONS IN
RECENT ORGANIC MATERIAL

TO THE

FEDERAL POWER COMMISSION

Supply-Technical Advisory Task Force-Nonconventional
Natural Gas Resources-Sub-Task Force III
Gas Generated Under Natural Conditions in Recent Organic Material

Membership

Chairman	L.E. Elkins
FPC Coordinating Representative & Secretary	Thomas Jennings

Members

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John L. McCormick
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Former Member

Howard Walton

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APPRAISAL OF MARSH GAS AS A POTENTIAL DOMESTIC NATURAL GAS RESOURCE IN THE UNITED STATES

INTRODUCTION

Methane-rich gas is being generated and steadily released into the atmosphere from marshes in tropical and semitropical climates. The feasibility and cost of collecting and concentrating this gas for market consumption has been addressed and results are reported herein.

CONCLUSIONS

1. Methane-rich gas production rates with ideal soil and temperature conditions can range from around 75 to 100 SCF/day/acre.

2. Methane content typically may vary from about 50% to perhaps 80% with nitrogen as the principal contaminant.

3. To provide air-free collection a "tent-like" apparatus hovering over the marsh areas with water seals at its edges would be one key step in the collection process.

4. The gas collected could best be used as boiler fuel because of its varying methane content. Otherwise, costly separation processes would have to be provided.

5. On a commercial scale, the cost of collecting impure methane gas (at about 75% purity) would be about $130/MCF methane. This is approximately 30- to 50-fold higher than price ranges indicated respectively for synthesis gas from coal or recent upper range contract prices in intrastate markets.

6. Although immense volumes of this type of gas escape to the atmosphere in some semitropical marshlands in the United States, its collection is too difficult and costly for it to contribute significantly to the future energy supplies in this country.

MECHANISM OF GAS GENERATION

When organic matter in an aqueous environment is decomposed by bacterial action, the high energy reactions with dissolved oxygen first occur, yielding CO_2, H_2O and nitrates. When all the oxygen is consumed, the anaerobic reactions proceed. Favored in the anaerobic energy yield sequence are oxidation reactions by the nitrate ion to yield N_2, CO_2 and H_2O and by sulfate ion, to yield sulfur, H_2S, CO_2 and H_2O. When sulfate and nitrate ions are depleted, methane production by anaerobic digestion proceeds. This usually is considered as a two-stage process, in the first stage of which the larger organic molecules are broken down into alcohols, fatty acids, CO_2 and H_2. In the second stage, these compounds are reduced by bacterial action to methane by such reactions as:

$$CH_3\ COOH \longrightarrow CH_4 + CO_2$$

$$CO_2 + 4H_2 \longrightarrow CH_4 + 2H_2O$$

It is apparent that the rate and composition of gas generated by bacterial action in sediments can vary widely depending on the specific conditions existent. 11/

GAS PRODUCTION RATE DATA

Koyama has collected samples of paddy soils in Japan and measured the rate of methane production in laboratory incubation apparatus. 12/ Figure 4 presents his data on the rate of methane production from several soils as a function of incubation temperature. These data illustrate the high sensitivity of the methane rate to temperature and type of soil. A wide variation in gas composition was observed with methane content ranging from 54% to 82%, the major contaminants being CO_2, N_2 and H_2. Koyama estimated an average methane production rate for paddy soils in Japan equivalent to 44 SCFD per acre. Measurements made on Japanese upland and forest soils indicated much lower gas rates, less than 1/200 and 1/1000, respectively, of the paddy soil rates.

Conger reported rates of gas evolution from a stagnant eutrophic lake at Drum Point, Maryland. 13/ Sediments from a three-square-mile drainage area have almost filled the lake, which has a water depth of about six feet. During August 1942, with water temperature of about 27°C, the average measured gas rate was 90 SCFD per acre. The methane content varied from 58% to 82%, the major contaminant being nitrogen. Assuming an average methane content of 70%, the summer methane rate was about 63 SCFD per acre.

Unpublished data have been secured on gas evolution at room temperature (20°C) in a laboratory aquarium containing a four-inch layer of mud from

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11/ Whelan, Thomas III, "Methane and Carbon Dioxide in Marsh Sediments," LSU, Natural Gases in Marine Sediments, edited by I. R. Kaplan, Plenum Press, 1974, pp. 27-46.

12/ Koyama, Tadashiro, "Gaseous Metabolism in Lake Sediments and Paddy Soils," Adv. in Org. Chem., McMillan, 1964, pp. 363-375.

13/ Conger, Paul S., "Ebullition of Gases from Marsh and Lake Waters," Chesapeake Biological Laboratory, Publication No. 59, Nov. 1973.

the White Rock Lake in Dallas, Texas. During initial weeks of the experiment, the methane rate was 75 SCFD per acre. During a 16-month test period, the rate gradually declined to less than 4 SCFD per acre, presumably due to depletion of the bacterial nutrients.

Based on these limited data from a preliminary review of the literature, it is presumed for purposes of expediting this evaluation that a favorable marshy site can be located wherein an average methane production rate of 75 SCFD per acre can be sustained.

As a matter of interest, substantially higher methane production rates can be attained in digesters operating at higher temperature and with carefully controlled feeds and selected bacterial strains. For example, Pfeffer of University of Illinois demonstrated rates up to 1.0 SCFD of methane (55% purity) per cubic foot of digester volume from a 20 wt % garbage slurry at 60°C.[14/] For a one-foot-thick layer of slurry, this corresponds to a rate of 43,560 SCFD per acre.

Gas Collection System

To collect the gas, it is proposed that one acre of marshy area be covered with a reinforced plastic sheet. To prevent displacement by wind or wave action, the sheet will be held in place by steel stakes tied to grommets at intervals sufficient to hold the edges of the sheet below the water level. For gas removal, a small diameter plastic line is attached to a fitting at the center of the sheet, which is supported at this point to prevent blocking of the drawoff opening. It is apparent that the area selected must be free from brush and debris to prevent film puncture. The weight of the sheet is about 62 lbs per 1000 sq ft, which can be supported by a gas pressure of 0.012 inches of water.

The gas from each isolated sheet is collected by a header system feeding a blower which delivers the gas to a boiler or gas turbine installation for power generation. The low quality of the gas renders it unacceptable without further processing for distribution and sale as natural gas.

Economics

Based on a quote from the Griffolyn Company, the cost of a 210-ft by 210-ft sheet (one acre) of 4-ply nylon thread reinforced polyethylene with a 9-year outdoor exposure life is $0.20 per sq ft, f.o.b. Houston. To allow for transportation and installation of sheet and lines, an additional cost of $0.05 per sq ft is (optimistically) assumed. Operating costs assume only sheet maintenance at 3% per year on the invest-

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14/Pfeffer, John T., "Reclamation of Energy from Organic Refuse," Report for EPA under Grant No. EPA-R-800776, April 1973.

ment with overhead and miscellaneous costs at 2% per year. A utility level rate of return is assumed amounting to 12% per year on the average investment (100% equity) with a 10-year project life. The following costs apply on a one-acre basis:

Investment	
Plastic Sheet @ $0.20 per sq ft	$ 8,700
Piping & Installation @ $0.05 per sq ft	2,200
Total	$10,900
Operating Cost per Annum	
Maintenance @ 3% per year	$ 330
Overhead & Misc. @ 2% per year	220
Total	$ 550
Capital Costs per Annum	
Depreciation @ 10% per year	$ 1,090
Federal Tax @ 48% of gross profit	600
Net Return @ 12% per year on avg. invest.	650
Total	$ 2,340
Net Annual Revenue Required for Gas Sale	$ 2,890
Royalty @ 12.5% of Gross Revenue	450
Severance Tax @ 7.0% of Gross Revenue	250
Gross Revenue from Gas Sale	$ 3,590
Annual Gas Sales - MSCF @ 75 SCF/day	27.5
Gas Sales Price - $/MSCF	$ 130

Discussion of Results

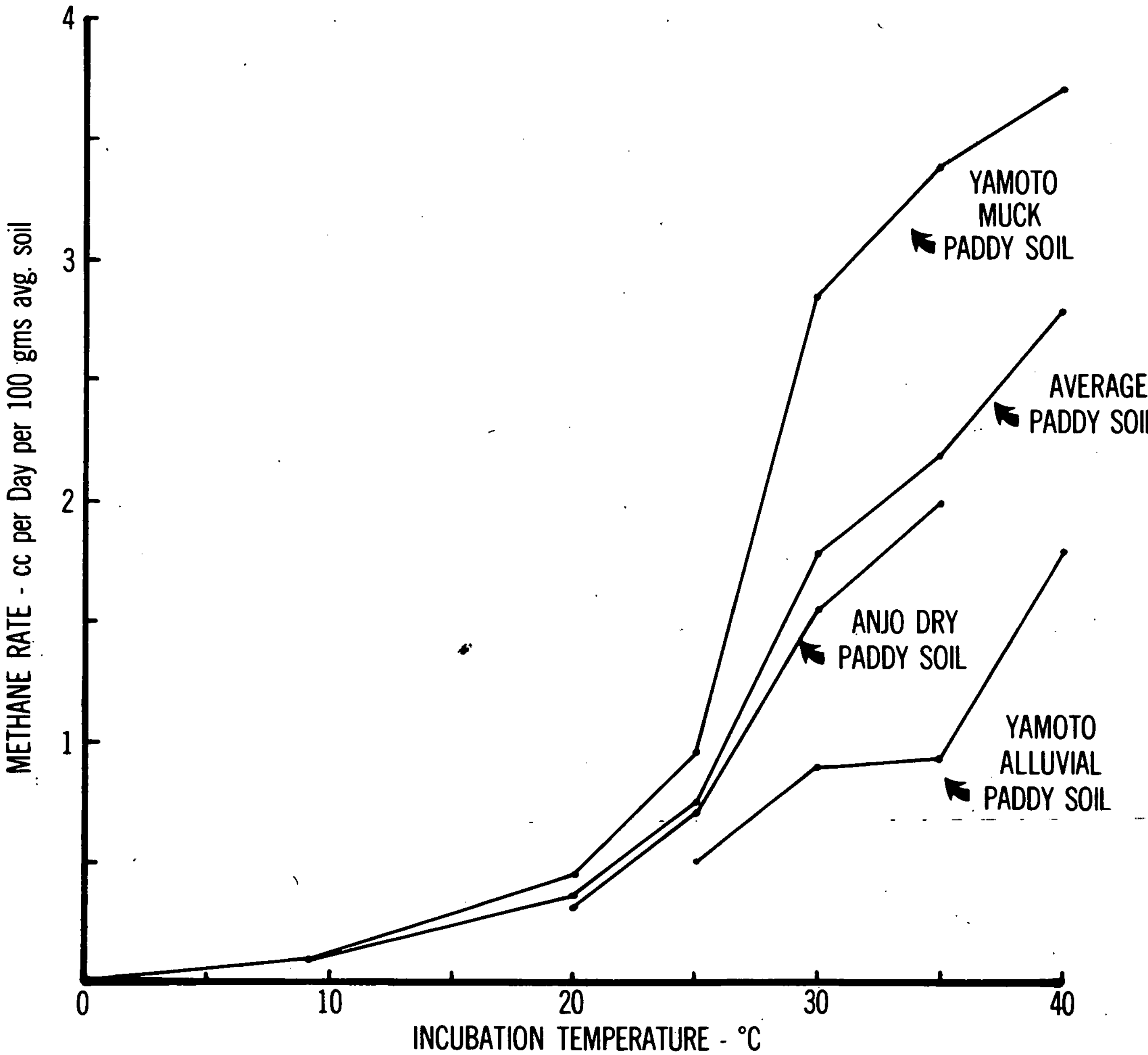
The preceding calculations indicate a gas sales price of $130 per MSCF of methane content would be required to obtain a 12% return on invested capital. To reduce the price to a high range of some intrastate contract prices ($2.50 to $3.00 per MCF) or to some estimated gas prices needed for coal gasification ($4 plus per MCF) appears out of reach. Yield already optimistically high in this calculation would have to be increased at least by a factor of 30, and perhaps 50.

In addition to the unfavorable economics, there might be environmental objections to destruction of marine life due to exclusion of air from the covered surface. The gas production rate decline curve also is uncertain. If maintenance of the gas rate is dependent on a continuing supply of fresh sediments, covering of large areas might interfere with the depositional process with resulting rapid decline in the gas production rate.

A more attractive approach to production of methane by microbial reaction appears to be via plant digesters processing garbage, sewage or waste effluents under closely controlled temperature, organic content and bacterial species.

FIGURE 4

PRODUCTION RATE OF METHANE FROM JAPANESE PADDY SOILS



DATA OF KOYAMA
"Adv. in Org. Chem," McMillan, 1964 p. 371

REPORT TO SUPPLY-TECHNICAL ADVISORY TASK FORCE--
NONCONVENTIONAL NATURAL GAS RESOURCES
BY SUB-TASK FORCE IV: GAS IN TIGHT FORMATIONS
TO THE
FEDERAL POWER COMMISSION

Supply-Technical Advisory Task Force-Nonconventional
Natural Gas Resources-Sub-Task Force IV
Gas in Tight Formations

Membership

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FPC Coordinating Representative & Secretary	Thomas Jennings

<u>Members</u>

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William K. Overbey, Jr.
A. B. Waters

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GAS IN TIGHT FORMATIONS

INTRODUCTION

Significantly large nonconventional resources of natural gas are either known or inferred to occur in many regions of the United States; these resources are characterized by very low permeability to gas flow so that present production techniques are inadequate to develop such resources as economically recoverable reserves. In general, the low flow rate for gas leads directly to high wellhead costs, at least several fold greater than current wellhead prices for conventionally produced natural gas. Thus, these resources, whether identified or undiscovered, fall in the category of subeconomic or noncommercial.

Nonconventional resources are usually described as occurring in tight formations, also loosely and somewhat synonomously termed tight rocks, tight sands, dirty sands, "tight gas" deposits, tight (gas) reservoirs, low permeability reservoirs, shale-gas reservoirs, and tight pay zones. This variety of terminology, in itself, clearly indicates the difficulty of precisely defining nonconventional resources by specific reservoir characteristics, by a single physical property, or by a minimum volume of contained gas.

Discussion of gas resources in tight formations will be restricted primarily to the resource aspects, i.e., the types and properties of gas-bearing rocks, the locations of such rocks, and possible volumes of gas in such rocks. The National Gas Survey by the Federal Power Commission--in particular, Volume II: Task Force Report of the Supply-Technical Advisory Task Force--Natural Gas Technology, 1973--dealt comprehensively with various emerging technologies which might be further developed to recover natural gas from tight formations; techniques included nuclear explosive fracturing, massive hydraulic fracturing (hereafter termed MHF), and chemical explosives fracturing, together with extensive estimates of production costs and volumes for selected tight formations in the Rocky Mountain area. It is not necessary to reevaluate the work of the Natural Gas Technology Task Force, but only as a secondary objective to describe any significant progress in the foregoing techniques, and to provide supplemental data which might suggest minor modifications to the Task Force report.

TYPES AND PROPERTIES OF TIGHT FORMATIONS

The so-called tight formations occur at one extreme as single, relatively thin (10-100 ft) gas-bearing zones of generally uniform thickness over a large area. At the other extreme would be relatively thick (possibly 1,000 or more ft) sections, either somewhat uniformly gas bearing as in organic-rich marine shales, or containing multiple, lenticular gas-sand zones scattered throughout the section as in nonmarine formations of the Rocky Mountain basins (41).

Arbitrarily, tight formations are herein defined by an in situ gas permeability of less than 50 μd (microdarcy). Where the in situ gas permeability is greater than 50 μd, the formations--or better stated, the gas-bearing zones--can probably be exploited economically by relatively conventional production techniques, and would not require advanced and presently developing production stimulation techniques such as massive fracturing by large-scale hydraulic injection, chemical explosives, or nuclear explosives.

For simplicity, because of rather sharply contrasting physical properties, the mostly nonmarine tight sandstone formations in the western United States can be considered separately from the thick marine shales of Devonian age in the eastern United States; available data show:

Characteristics of tight formations

	Western sandstones	Eastern shales
Depth (ft)	Moderate to deep 4,000-20,000	Shallow to moderate 2,000-6,000
Permeability (μd)	Low 0.5-50	Very low 0.001-1.0
Porosity (%)	Low 8-12	Very low 0.5-5.0
Water saturation (%)	Moderate to high 30-70	Low 1-10
Gas-filled porosity (%)	Medium to low 3-6	Low 1-3
Pressure	Normal to high	Low to normal

Because the eastern shales occur on the average at shallower depths than the tight sandstone formations, the lower gas pressures lead to lesser gas in place; additionally, the shales have much lower porosity than the sandstones, by about a factor of five, which leads to lesser gas in place. In general, the shales contain one to two orders of magnitude less gas in place per unit volume of rock than the sandstones.

Permeability

Other factors being constant, an increase in confining pressure leads to a marked decrease in gas permeability, particularly for those rock types where the initial unconfined permeability is relatively low--at about 1 md (millidarcy) or less. This reduction is at least an order of magnitude greater than would be predicted from the reduction in pore volume due to rock compressibility (42). The strong influence of confining pressure on permeability suggests that, under compression, the interconnecting pathways, microfractures or pore throats, between pores are contracted to isolate pore space which would otherwise sustain gas flow, and that the reduction in pore volume is not a controlling factor.

Summarized in figure 5 are data for permeability versus net confining pressure for sandstone core samples (43, 44) from: (1) Project Gasbuggy; in the San Juan Basin, New Mexico; samples from the Picture Cliffs sandstone at a depth of 4,000 feet; (2) Project Rio Blanco; in the Piceance Basin, Colorado; samples from the Fort Union sandstones, at a depth of 6,000 feet; and (3) Project Wagon Wheel; Green River Basin, Wyoming; samples from the Fort Union sandstones (8,000 ft) and the Mesaverde sandstones (10,000 ft). The reduction from unconfined or initial permeability, to the permeability at net confining pressure, equivalent to the overburden pressure less the internal pore pressure, is: (1) factor of three for Gasbuggy samples at 2,700 lb/in^2 confining pressure; (2) factor of 10 for Rio Blanco samples at 3,200 lb/in^2 confining pressure; and (3) factor of five for Wagon Wheel samples at 5,000 lb/in^2 confining pressure. It is obvious that, given essentially the same porosities and water saturations: (1) the reduction in permeability is not a simple linear function of present overburden pressure or net confining pressure; i.e., the samples from the Piceance Basin at intermediate depth of 6,000 feet, between 4,000 feet for the San Juan Basin and 8,000-10,000 feet for the Green River Basin, show a much larger reduction in permeability; and (2) the reduction in permeability reflects the pressure loading-unloading history of the rock, including herein the variability introduced by tectonic stresses--folding, faulting, and thrusting--as opposed to simple gravitational loading in relatively undeformed basins.

Illustrated in figures 6, 7, 8, and 9, and table 6, for sandstone core samples from the Fort Union Formation in the Piceance Basin--the Rio Blanco site--are measured values of gas (nitrogen) permeability at initial unconfined conditions and also at various net confining pressures (43). For the samples studied, absolute permeability is greatly reduced

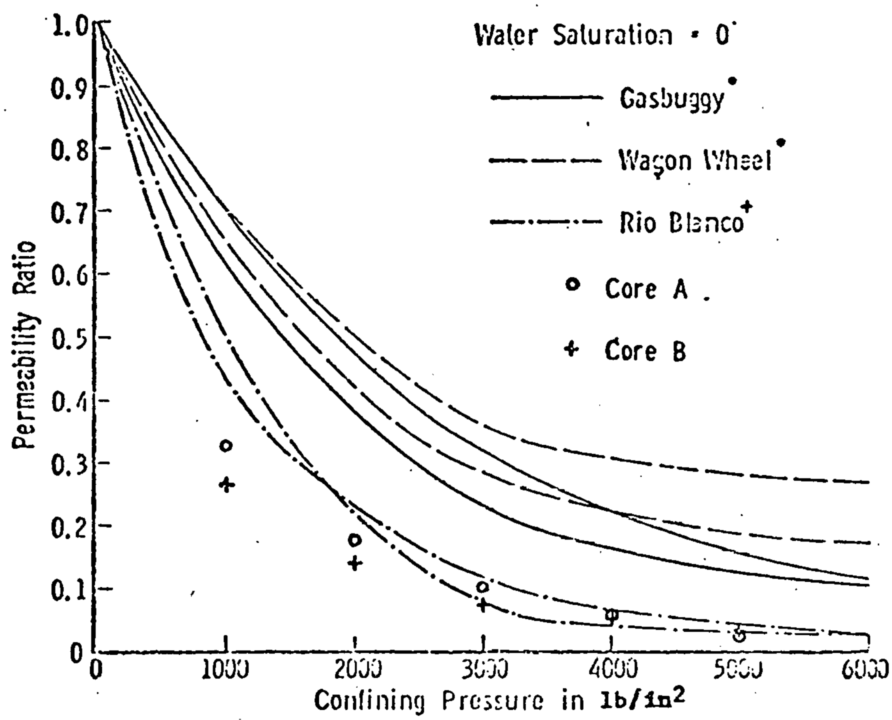

Figure 5 Permeability as a function of confining pressure.

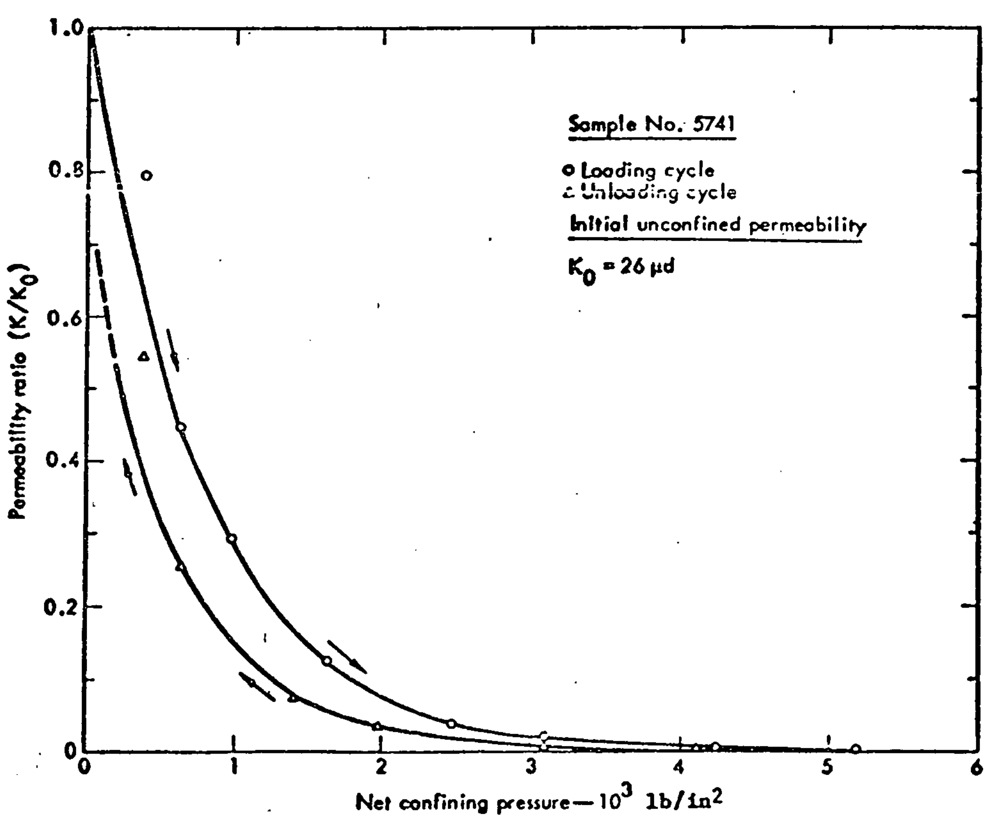

Fig. 6 Effect of confining pressure on the permeability of Fort Union formation sandstone sample at 45% water saturation.

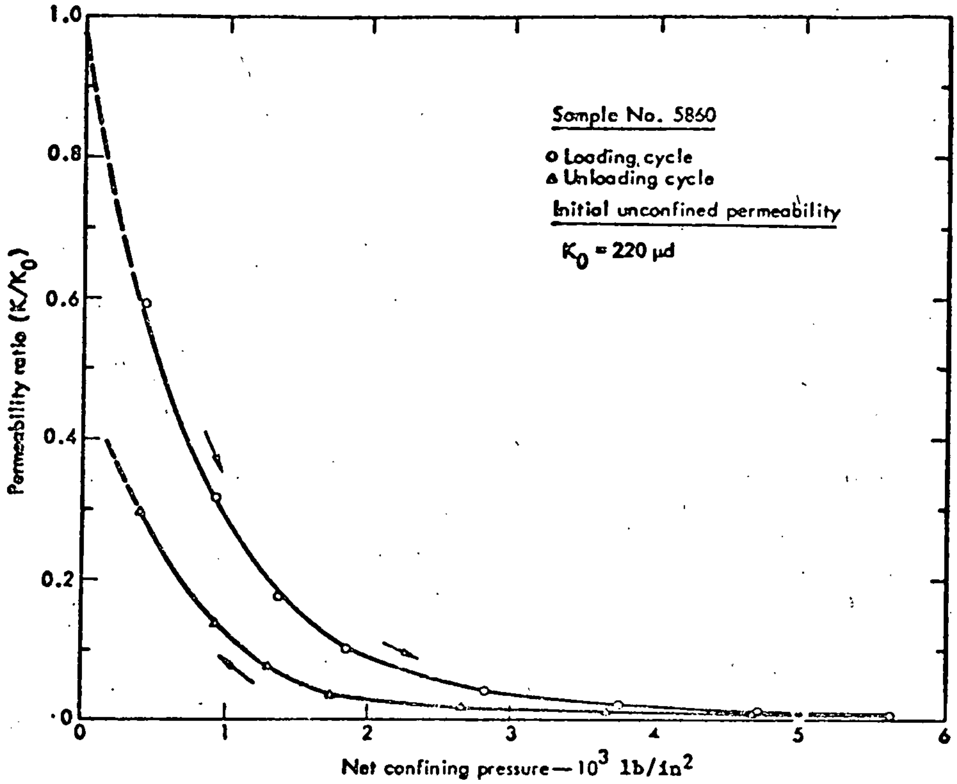

Fig. 7 Effect of confining pressure on the permeability of Fort Union formation sandstone sample at 46.4% water saturation.

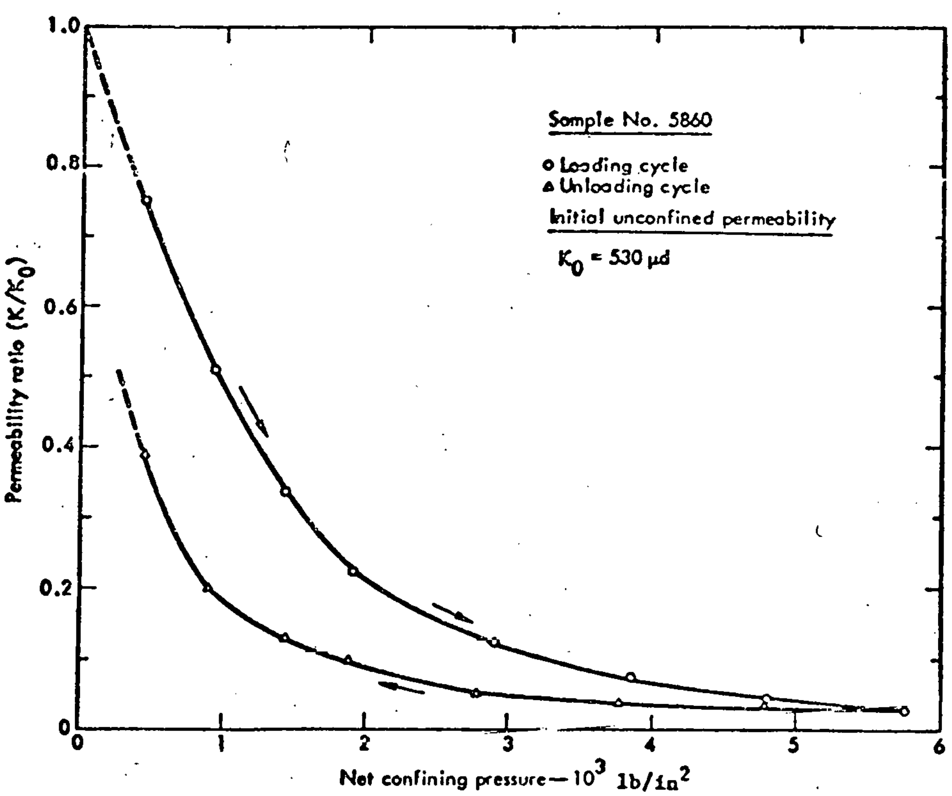

Fig. 8 Effect of confining pressure on the permeability of Fort Union formation sandstone sample at 4.1% water saturation.

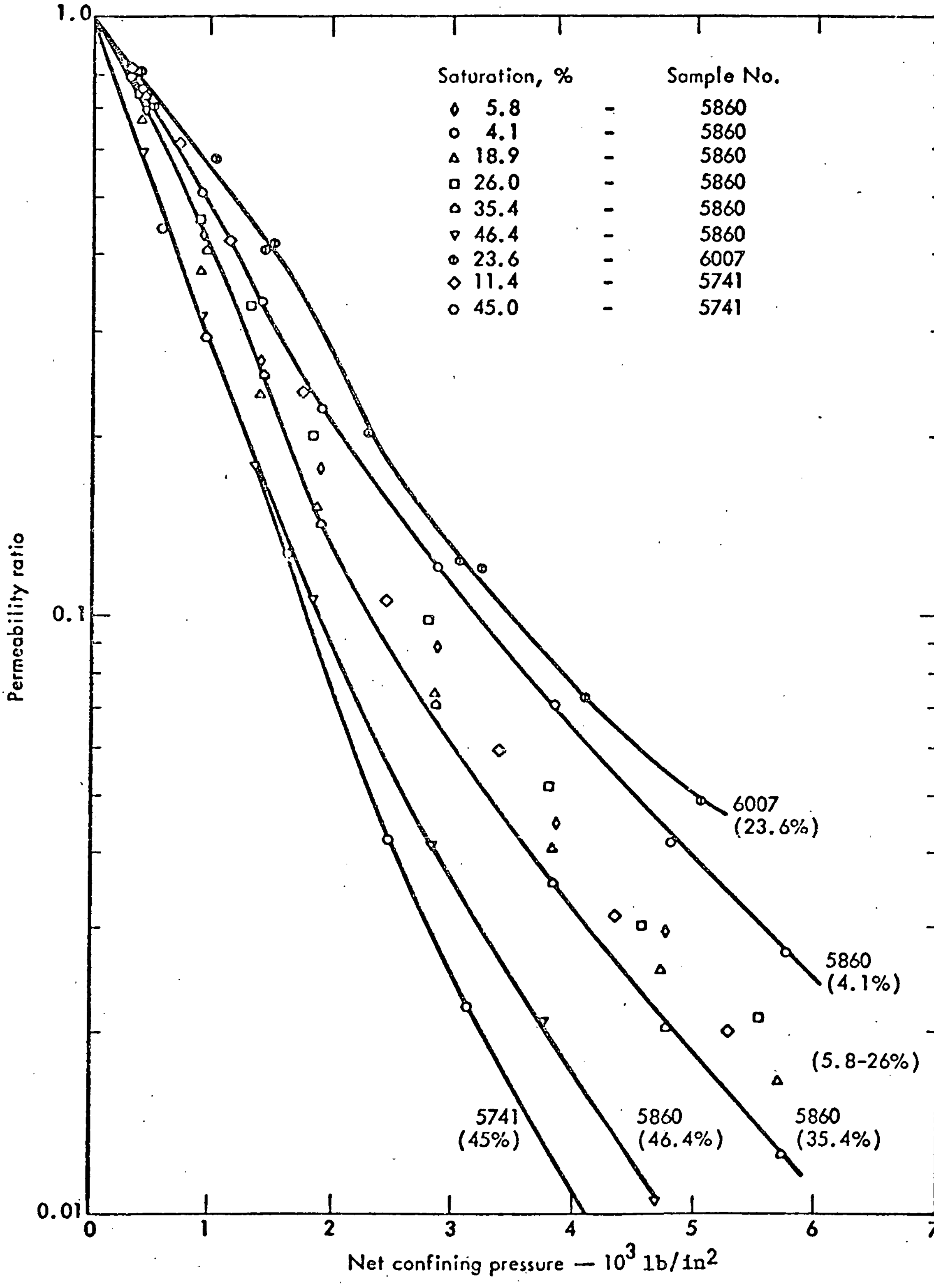

Fig. 9. Effect of confining pressure on the permeability of Fort Union formation sandstone samples at various levels of water saturation.

Table 6. Permeability, porosity, and percentage water saturation of Fort Union formation sandstone samples.

Sample depth below surface, ft	Unconfined permeability, μd	Permeability at simulated in situ confining pressure, μd	Interconnected porosity, %	Water saturation, %
5741	31	2.2	8.76	11.4
5741	26	0.6	8.76	45.0
5860 (air cored)	580	44	8.70	5.8
5860	530	58	8.68	4.1
5860	330	21	8.70	18.9
5860	250	20	8.74	26.0
5860	370	23	8.63	35.4
5860	220	7.5	8.86	46.4
6007	3.8	0.46	4.0	23.6

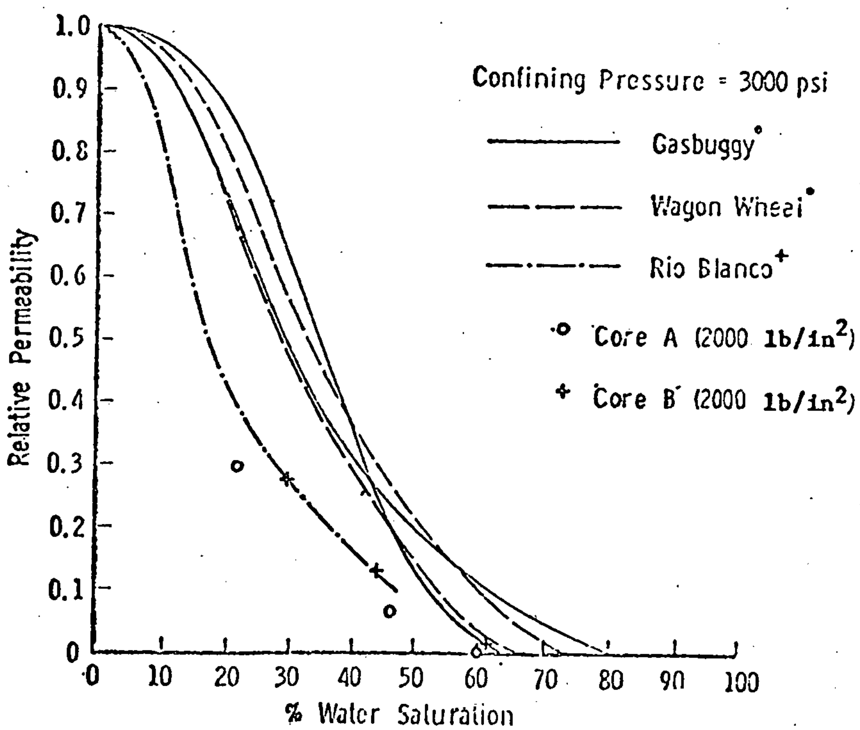

Figure 10. Permeability as a function of water saturation.

by increased confining pressure, with the reduction at least an order of magnitude greater than would be predicted from reduction of pore volume due to rock compressibility.

Data on the permeability of shales and closely related rocks such as silty shale, and shaly siltstone, are sparse, and are usually based on measurements made with water as the working fluid rather than air or other gases (45, 46). Such permeability measurements, although not precisely applicable to gas-bearing shaly rocks, do indicate the range in in situ permeability to be expected--from 1.0 to 10^{-4} μd or possibly less, with a few reservoir pressure drawdown and buildup measurements suggesting as high as 0.7 μd for a silty shale. Arbitrarily, in later calculations of flow capacity of shales, a lower limit of 0.1 μd (0.0001 md) for in situ matrix permeability has been used, even though it is obvious that most truc shaly rocks would be below this limit.

Water saturation

As shown in figures 9 and 10, and in table 6, the in situ permeability for the flowing gas phase decreases rather sharply with increasing water saturation, with permeability decreasing to essentially zero at 60 to 80 percent water saturation. Again, these data are for sandstone core samples from the three major industry-government, gas-stimulation projects: (1) Rio Blanco site, Piceance Basin, in figure 9 and table 6; (2) Gasbuggy site, San Juan Basin, in figure 10, and (3) Wagon Wheel site, Green River Basin, in figure 10. Similar data are lacking for the Uinta Basin.

In table 6, for the Rio Blanco site data for sample 5860 (number is sample depth in ft) show a reduction in gas permeability: (1) at 35.4 percent water saturation, from 370 μd at unconfined pressure to 23 μd at simulated reservoir confining pressure; and (2) at 46.4 percent water saturation, from 220 μd to 7.5 μd. Other data for this sample interval at 5,680 feet show: (1) by conventional core analyses--910 μd at dry and unconfined conditions, 9.8 percent porosity, and 36 percent water saturation; and (2) by log evaluation--10.5 percent porosity, and from 33 to 50 percent water saturation. Although the foregoing data derived by three dissimilar methods of evaluation are reasonably compatible, it should be noted that misjudgment of in situ water saturation could lead to much larger misjudgment of in situ permeability--i.e., at 35.4 percent water saturation the permeability is 23 μd, and at 50 percent water saturation the permeability is about 5 μd, or an increase in water saturation from 35.4 to 50 percent, a ratio of 1:1.4 leads to a decrease in permeability from 23 μd to 5 μd, a ratio of 4.6:1.

The combined effect of increasing net confining pressure and increasing water saturation sharply decreases the initial dry permeability. For example, the Wagon Wheel cores show an average initial permeability of 68 μd when dried and unconfined; they show an average water saturation of 50 percent. From figure 6, at a net confining pressure of 3,000 lb/in^2, the reduction from initial permeability is a factor of 0.28; and from figure 10, the reduction at 50 percent water saturation is a factor of 0.18 (45). The combined effect, or total reduction in permeability, is then a factor of 0.05, or an in situ value of 3.4 μd. This value of 3.4 μd has been used to predict gas well production rates in the Green River Basin using nuclear stimulation and massive hydraulic fracturing (47, App. E).

The combined effect of net confining pressure and water saturation for core samples from the Rio Blanco site, as shown in figures 5, 9, and 10, is larger than the effect on cores from Gasbuggy and Wagon Wheel, although Rio Blanco is intermediate in depth at 6,000 feet, compared to Gasbuggy at 4,000 feet and to Wagon Wheel at 8,000-10,000 feet. The Rio Blanco cores show an initial unconfined permeability of 530 μd at 4.1 percent water saturation (table 6). At 55 percent water saturation, the reduction from the initial permeability is a factor of 0.05; and at 3,600 lb/in^2 confining pressure the reduction is a factor of 0.08; or a combined reduction by a factor of 0.004, leading to an in situ permeability of 2.1 μd. This compares with: (1) 14 μd based on logging data for the interval adjusted by pressure-buildup measurements in an adjacent well, Fawn Creek No. 1; (2) 7 and 15 μd used to predict gas well production in the Piceance Basin (47, App. E); and (3) about 2 μd derived from production tests both in the original well RE-E-01 from which the core samples were obtained, and in an adjacent formation evaluation well RB-U-4, 600 feet to the northwest (48). It should be noted that, if the 930 μd permeability (air) measured on dried core at atmospheric pressure by conventional core analysis methods is accepted, then the reduction from initial to in situ permeability at simulated reservoir pressure is 931 μd to 2 μd, a reduction factor of 0.0021, or reciprocally 465:1.

For the organic-rich shales in the eastern United States, data on water saturation are extremely sparse. In general, based on well production histories, water saturation is low, somewhere about 10 percent, with porosity also relatively low, in the range of a few percent.

Size distribution of sands

The gas-bearing sandstone zones in the Cretaceous and Tertiary nonmarine tight formations in the Rocky Mountains are predominantly fluvial channel-fill deposits with some point-bar sandstones. Well logs and core samples from the Mesaverde and the Fort Union Formations obtained in the Piceance, Uinta, and Green River Basins show sand lenses varying from less than a foot up to 50 feet thick, interbedded with shales, siltstones, and sandstones having no effective gas permeability. The percentage of gas-bearing sand lenses (with less than 65-70 percent water saturation) varies from about 15 percent to about 30 percent of the gross section thickness. For example, in the massive hydraulic fracture experimental well RB-MHF-3, using limits of 65 percent or less water saturation and of 5 percent or more porosity, 45 sand lenses averaging 13 feet thickness, or 589 feet total sand, were selected in a gross section interval of 2,200 feet; lenticular sands are 26 percent of the gross section interval (50).

The expected sizes of channel-fill sandstone in the northern Piceance Basin would be: thicknesses from 20 to 30 feet; widths from 280 to 420 feet; and lengths from 2,800 to more than 4,200 feet. Point-bar sandstones, occurring mostly in the Tertiary Fort Union Formation and its equivalents in other basins, tend to be somewhat larger than channel-fill sandstones. Recent data (51) show average length-L/width-W/thickness-H ratios as follows:

Formation	Sandstone type	L/W/H
Fort Union (Typical case)	Point-bar	190/ 90/ 1 (7,600/3,600/40 ft)
Mesaverde (Typical case)	Channel-fill	140/ 14/ 1 (3,500/350/25 ft)

Rather obviously, any reservoir evaluation, using a homogeneous flow model with constant gas-bearing sand thickness, would overestimate the resources, production rates, and ultimate recovery.

Based on recent studies (51), in a sequence of channel-fill sandstones in the Piceance Creek Basin, an average conventional well will be connected to about 18 percent of the in-place reservoir volume in a 320-acre area, including herein allowance for erosional contact or interflow connection between sand lenses. For a well treated by massive hydraulic fracturing, with fracture wing dimensions of 2,000 feet, the well will be connected with 70 percent of the reservoir volume in a 320-acre area, assuming the fracture remains within the designed limits.

In 1973, as part of the National Gas Survey, the National Gas Technology Task Force carefully evaluated the effect of sand lensing on estimated productivity of stimulated wells; this evaluation is still valid and is a valuable reference. However, it should be noted that this evaluation was completed during the early developmental stage of massive hydraulic fracturing and used a 500-foot fracture-wing length for flow calculations, whereas today a fracture-wing length of 2,000 feet or more is used both experimentally and in application.

Spatial variation of physical properties

To illustrate the spatial variations of physical properties within tight formations, data are taken from two major projects in the Piceance Basin, Colorado, and one in the Green River Basin, Wyoming.

Piceance Basin

The two projects in the Piceance Basin are: first, Project Rio Blanco, a joint Government-industry experiment in stimulating flow of tightly held gas from deep formations (circa 6,000 ft) using nuclear-explosive fracturing; and second, the Rio Blanco Massive Hydraulic Fracturing (MHF) Experiment, a joint Government-industry experiment in stimulating gas flow from the same formations using hydraulic fracturing (48, 49). These two projects are spaced less than 1 mile apart, are not yet completed, and may provide an index to the relative efficiency of nuclear-explosive and massive-hydraulic fracturing. Independent analyses of the reservoir properties in the Project Rio Blanco emplacement well, in terms of net pay (sand) thickness and of permeability--thickness, based on core sample measurements and geophysical log interpretation, were made by VP (H. K. Van Poolen and Associates), CER (CER-Geonuclear and CONOCO), and LLL (Lawrence Livermore Laboratory); these analyses are shown in figure 11, together with the reservoir intervals expected to be in communication with each of the three nuclear explosive cavity/chimney regions (49). Although pressure drawdown/buildup tests were not run in the emplacement well prior to the major fracture stimulation, a nearby well at about 1,300 feet to the south had been flow tested over a limited interval; these data were extrapolated to the nuclear-emplacement well.

As shown in figure 11, 421 feet of net-pay sand, with individual sands ranging from 6 to 110 feet, in a total interval of 1,350 feet, were estimated using a cutoff of 30 percent for gas saturation and 5 percent for porosity.15/ For the reservoir interval stimulated by the upper explosion cavity, the reservoir capacity or permeability-height, $k_g h$, ranged from the low VP estimate of 4.13 md-ft in four separate sands to the high CER estimate of 7.62 md-ft in three separate sands. These values should be compared to 0.45 md-ft, derived from postdetonation drawdown and buildup tests of the top explosion cavity/chimney region, and to 0.73 md-ft from a best-fit chimney/reservoir simulation model.16/ As the quantity of gas which might be produced by the top chimney/reservoir interval is directly proportional to $k_g h$, the observed gas production from the top chimney in the Fort Union gas sands is a factor of about 10 less than preducted from estimated reservoir properties. This lack of fit between prediction and actual drawdown/buildup tests indicates

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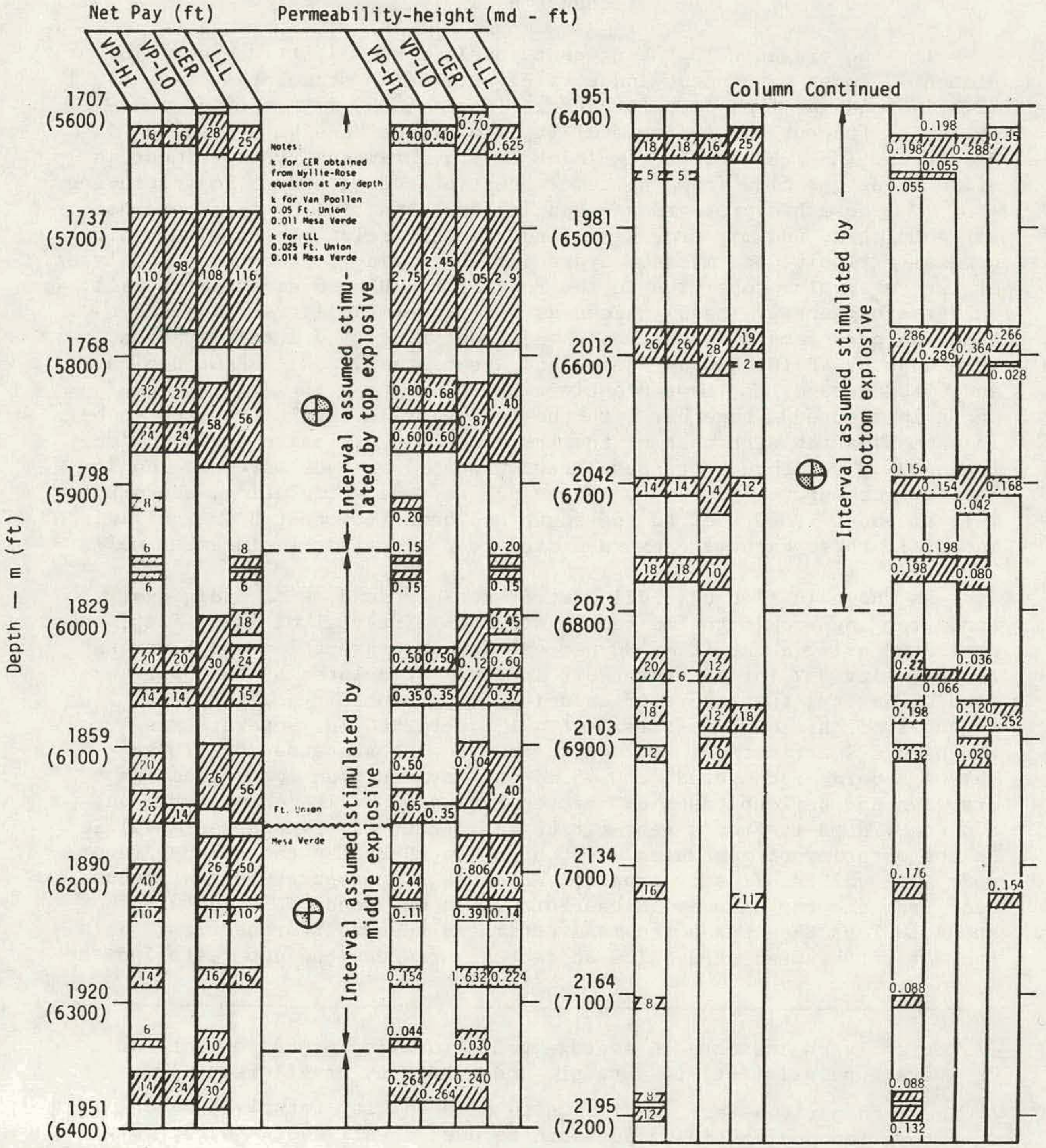
15/ Log analyses indicate an average gas saturation of 57 percent, an average porosity of 9.4 percent, and a net pay of 421 feet (10).

16/ Where comparisons are made, in situ permeability for given water saturation and confining pressure is used in all cases (8, 9, 10).

Figure 11

Spatial Variation of Net Pay and Permeability Height

(In m with ft in parenthesis)



the substantial uncertainty regarding the actual physical properties of the reservoir, and the difficulty of determining physical properties such as water saturation, permeability, and individual sand thickness from exploratory well core and logging data.

Primarily to permit additional evaluation of the predetonation or undisturbed reservoir properties, a formation evaluation well was drilled 624 feet from the Project Rio Blanco emplacement well (49). After well completion, the casing was perforated from 5,836 to 5,892 feet, a 56-foot sand zone in the Fort Union; this sand zone is the equivalent of a 51- to 58-foot sand in the emplacement well (fig. 11). Gas production could not be obtained, and a limited hydraulic fracture treatment (approximately 16,000 gal, and 4,250 lb of sand) was performed. After the well returned approximately all of the injected fracture fluid, natural flow ceased and a pumping unit was installed.

An initial gas production rate of 53 MSCF per day was then obtained, but this decreased to 7 MSCF per day in about 3 weeks. The calculated gas permeability for the 56-foot interval was 0.0005 md; this value should be compared to: (1) the value estimated for the equivalent sand zone in the emplacement well, from a high estimate of 0.025 md for 57 feet, to a low estimate of 0.015 md for 58 feet (fig. 11); and (2) the value for the upper chimney/reservoir zone measured by drawdown/buildup production tests, at about 0.002 md for the "56-foot" sand. Of course, these values are not directly comparable, as the first value is based on drawdown/buildup measurements following a limited fracture treatment in the formation evaluation well, the second value is calculated from core and log data for the emplacement well, and the third value is based on drawdown/buildup measurements following a massive fracture treatment (the upper nuclear explosion) in the emplacement well. Nevertheless, the marked discrepancy among these values--an order of magnitude or more--indicates the difficulty of obtaining adequate data on reservoir properties.

Bearing on the lateral extent of lenticular sands, in the Project Rio Blanco bottom explosion region in well RB-E-01 (fig. 11) and as measured in the reentry well RB-AR-2, the pressure history suggests a reservoir of limited extent; i.e., the effective mean radius of drainage must be reduced to about 400 feet in order to model the observed pressure history (48). Based on geophysical log interpretation, at least three sands at 12, 19, and 25 feet thick (fig. 11, LLL) are interconnected to the bottom explosion region; these sands do not correlate simply with sands at an equivalent depth in the adjacent formation evaluation well RB-U-4 at a distance of 600 feet, thus confirming the probability that the effective drainage radius is less than 600 feet. It should be noted that the estimated average channel-fill sandstone in the Piceance Basin has dimensions of 3,500 feet length, 350 feet width, and 25 feet thick, and that with adjustments for interconnection between sand lenses should have an effective drainage radius of about 900 feet (51).

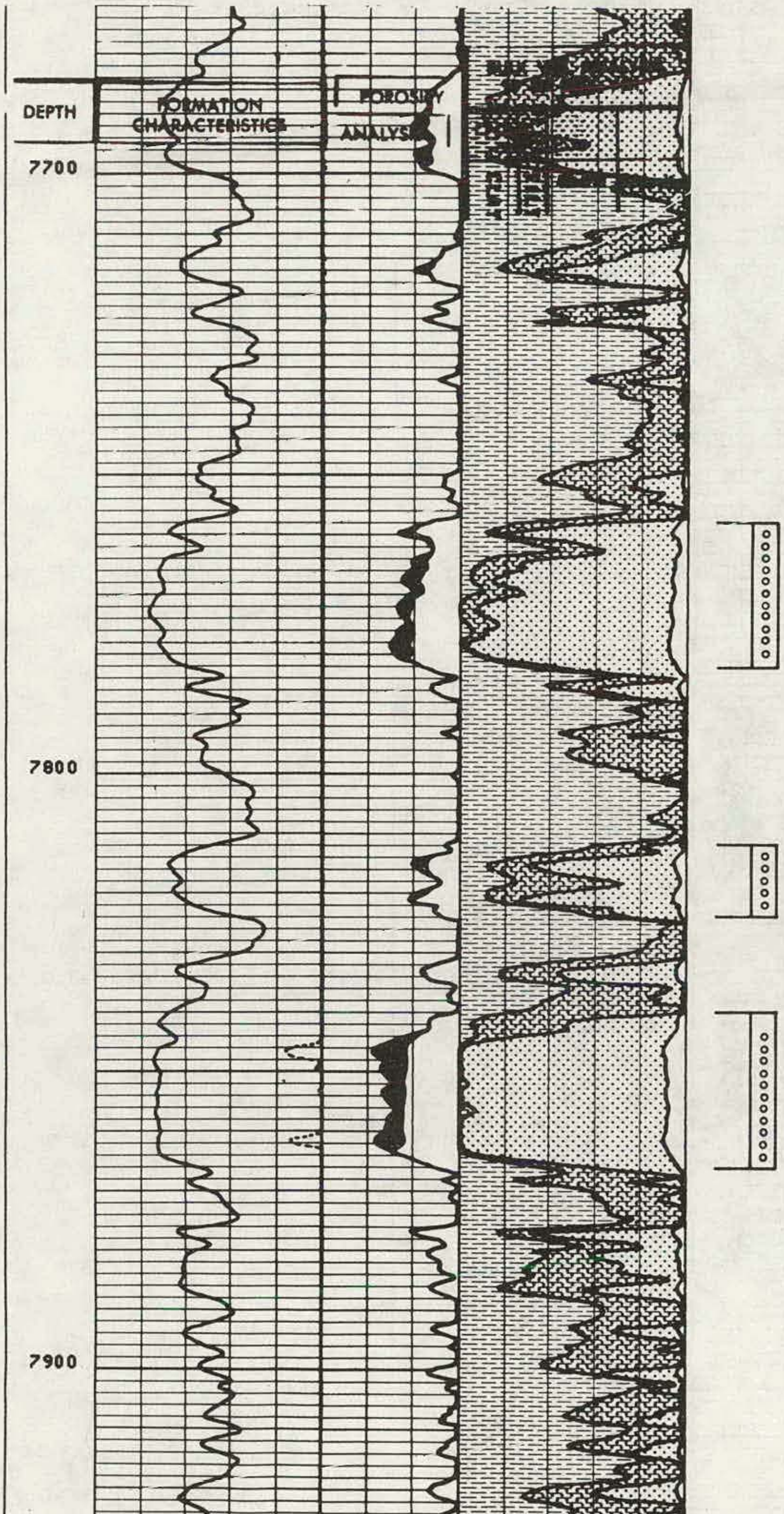
The Rio Blanco Massive Hydraulic Fracturing (MHF) Experiment, a joint Government-industry undertaking started in 1974, is planned to test the relative effectiveness of MHF and nuclear explosion fracturing in the same gas-producing formations; this is in accordance with the identification by the Natural Gas Technology Task Force of two emerging technologies, nuclear stimulation and massive hydraulic fracturing, that should be explored to determine their potential for developing gas resources in tight formations. The experimental well, RB-MHF-3, is located about 5,000 feet northeast of the nuclear stimulated well RB-E-01; the formation evaluation well RB-U-4 is located between these two wells, at a distance of 600 feet from well RB-E-01. Four separate fracture treatments have been executed in well RB-MHF-3, the last of which occurred in November 1976 and has yet to be evaluated (64).

Fracturing treatment No. 1.--Took place in October 23, 1974, in a single Mesaverde sand at a depth of 8,048-8,073 feet (25 ft thick); static bottom-hole pressure at 3,450 lb/in^2; bottom-hole temperature at 242° F; gas-filled porosity at about 4 percent; gas flow after breakdown at 60 MCF/D.

Fracture treatment was 117,500 gal of polyemulsion fluid (2/3 naptha-diesel oil mixture and 1/3 a 2 percent KCl brine), with 400,000 lb of sand. Postfracture data show: flow rate at about 60 MCF/D, with the fracture treatment not increasing the productive capacity; very poor lateral propagation of the fracture compared to design length of 2,500 feet; productive capacity at about 0.15 md-ft, with an in situ permeability of 6 µd; postfracture flow rates were below predicted values by a factor of 5 to 8. Additional downhole surveys suggest that the fracture probably propagated upward to 8,000 feet and downward below the sand zone, rather than outward from the wellbore.

Fracturing treatment No. 2.--Conducted on May 2, 1975, in three separate Mesaverde sands over the depth interval of 7,760-7,864 feet (fig. 12); fracture treatment was 285,000 gal of polyemulsion fluid (single-phase refined naptha and a KCl brine); postfracture gas flow averaged 137 MCF/D, a 2.5 fold increase over the pretreatment rate of 57 MCF/D, but declined steadily without reaching a stabilized flow during a 30-day test; again, the postfracture flow was well below predicted flow of 500-1,000 MCF/D for a fracture of 500-2,500 feet in length.

Fracturing treatment No. 3.--Conducted on May 4, 1976, in three separate sands in the middle Fort Union Formation (fig. 13), corresponding



FRAC 2: 7760' - 7864'
MESA VERDE
5-2-75

FIGURE 12
MESA VERDE FORMATION

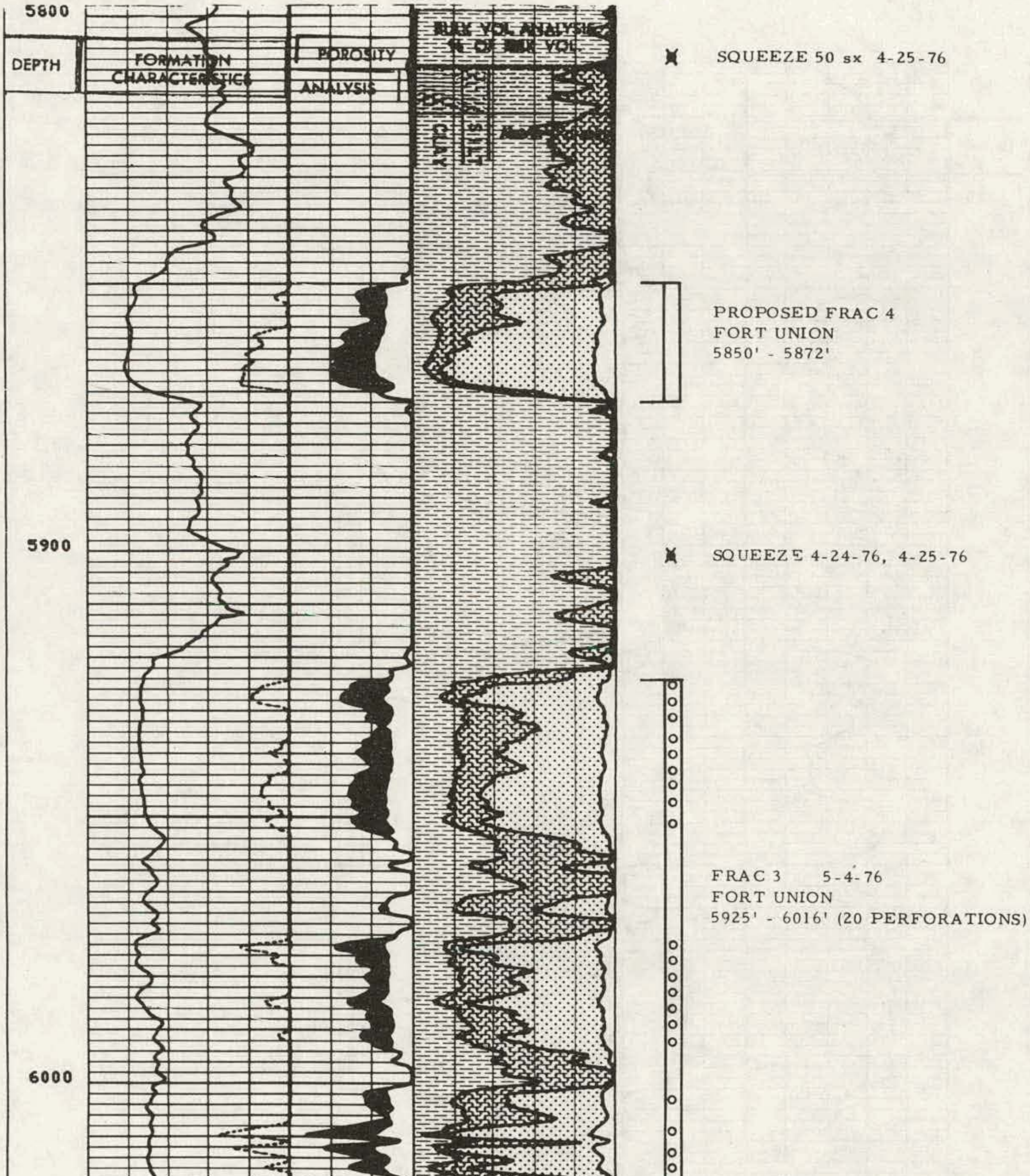


FIGURE 13

FORT UNION FORMATION

FRACS 3 and 4

to the Fort Union II sand in the nuclear stimulation well RB-E-01 and in the formation evaluation well RB-U-4, although these sands are not known to be the same in a depositional sense. Fracture treatment was 344,000 gal of gelled water-base fluid with 809,000 lb of sand; post-fracture flow stabilized at 160 MCF/D or an indicated factor of four over the pretreatment rate.

Green River Basin

Data for the Green River Basin are drawn from Project Wagon Wheel, a proposed nuclear-explosion gas-stimulation experiment (52), and from three massive hydraulic fracturing experiments recently conducted by El Paso Natural Gas Company with partial support by the Energy Research and Development Administration (53).

The sand lenses in the Fort Union and Mesaverde Formations seem to be somewhat smaller and fewer than in the Piceance Basin; i.e., 4,000 feet gross section containing more than 100 potentially productive sands with an average thickness of 7 feet, or 17.5 percent sands in the total section, for the Green River Basin; compared to 2,200 feet gross section containing 45 sands averaging 13 feet thick, or 26 percent sand in the total section, for the Piceance Basin. Although the sand lenses in the Green River Basin exhibit the same range in porosity, water saturation, and permeability as do sands in the Piceance and Uinta Basins, the Green River sands are geopressured; i.e., gas pressure varies from 3,900 lb/in^2 (1.13 times hydrostatic pressure) at 8,000 feet, to about 8,100 lb/in^2 (1.56 times hydrostatic pressure) at a depth of 12,000 feet.

The three MHF experiments, in the El Paso Natural Gas Pinedale Unit near Pinedale, Wyo., are summarized below, with the number and depth of lenticular sands shown in table 7.

Pinedale Unit No. 7 Well.--Took place on September 12, 1974, in three sands at 12, 19, and 20 feet thick at a depth of 8,990-9,190 feet containing an estimated 19.7 X 10^9 SCF/MI^2; fracture treatment was 257,000 gal of polyemulsion fluid with 775,000 lb of sand; no prefracture flow measurements were made; postfracture flow decreased to 100,000 MSCFD in 1 year without reaching stabilized flow; modeling suggests an effective in situ permeability of less than 1.0 μd, and a flow capacity--permeability times thickness--of roughly 0.5 md-ft.

Pinedale Unit No. 5, First Stage.--Took place on July 2, 1975, in two sands at 51 and 70 feet thick at a depth of 10,950-11,180 feet containing an estimated 40.5 X 10^9 SCF/MI^2; prefracture with 46,000 gal permitted gas production in the range of 100 to 200 MSCFD at a pressure insufficient to lift liquid to maintain a bottom-hole pressure below

TABLE 7

Number of Sandstone Strata Included in Pinedale Experiments

MHF Fracture Date	Well	Depth Interval (feet)	Number of Sandstone Strata	Estimate of Gas-in-Place (Bcf per square Mile)
September 11, 1974	Pinedale Unit No. 7	8,990 - 9,190	3	19.7
July 2, 1975	Pinedale Unit No. 5	10,950 - 11,180	2	40.5
October 20, 1975	Pinedale Unit No. 5	10,120 - 10,790	6	54.3

2,500 lb/in^2 or to obtain sufficient stability for accurate measurements; fracture treatment was 191,000 gal of polyemulsion fluid with 518,000 lb of sand; from 485 MSCFD on the 15th day to 340 MSCFD on the 37th day, presumably without reaching stabilized flow; modeling suggests an effective in situ permeability of less than 1.0 μd and a flow capacity of roughly 0.1 md-ft.

Pinedale Unit No. 5 Well, Second Stage.--Took place on October 20, 1975, in six sands at 235 feet thick in a total interval of 670 feet, at a depth of 10,120 to 10,790 feet, estimated to contain 54.3×10^9 SCF/MI^2; prefracture breakdown flow was time limited and showed 1,100 MSCF of gas produced in a 21-hour period as wellhead pressure decreased from 2,200 lb/in^2 to 500 lb/in^2; fracture treatment was 458,000 gal of gelled water with 1,422,000 lb of sand; postfracture flow showed a peak on the 6th day at 850 MSCFD, decreasing on the 15th day to 250 MSCFD, and on the 43rd day to 150 MSCFD; calculations suggest an effective in situ permeability of about 0.2 μd, with a flow capacity of 0.04 md-ft.

Denver Basin

The Wattenberg gas field of about 980 $miles^2$ is located in the western portion of the Denver Basin, and typifies a tight gas reservoir considered noncommercial prior to stimulation by massive hydraulic fracturing. The major gas-producing zone in this field is the Muddy J sandstone of Cretaceous age, which is marine, blanket-type sand with relatively uniform thickness over a wide area (54). The Muddy J sandstone is found at a depth of 7,600-8,400 feet; gross sand thickness is 50-100 feet; net-pay sand thickness is 10-50 feet; porosity is 8-12 percent; in situ permeability is 5-50 md; bottom-hole temperature is 260° F; bottom-hole pressure is 2,900 lb/in^2; water saturation at 30-50 percent.

Flow rates, from conventional wells, stimulated by hydraulic fracturing treatment of limited size (30,000-50,000 gal), were in the range of 30 to 50 MSCFD. Following massive hydraulic treatments in the range of 133,000 to 180,000 gal of polyemulsion fracturing fluid, flow rates increased three to fourfold as compared to conventional wells (55).

This field can now be considered commercial, and serves as an example of a tight formation (i.e., less than 50 μd in situ permeability) which could be stimulated successfully. The recoverable reserves are estimated at 1.3 trillion ft^3.

In general, gas-bearing blanket-type sands, even when characterized by very low in situ permeability, can probably be exploited by MHF as currently developed; gas in such sands would then be an undiscovered recoverable reserve, rather than a nonconventional resource.

STIMULATION TECHNOLOGIES

One of the objectives of the Natural Gas Technology Task Force in 1973 (47) was: " . . . to assess the current status and future potential of new or advancing technologies which might be used to produce economically a marketable natural gas from gas deposits which are considered noncommercial and which are not presently (1972) in the nation's potential gas resources." Two different approaches were considered potentially capable of creating the extensive and large-scale fracture systems needed to produce gas from very thick (2,000-4,000 ft) and very low permeability gas-bearing sections; these are:

1. Nuclear explosion fracturing.

2. Massive hydraulic fracturing.

Nuclear-explosion fracturing

To date, three nuclear-stimulation experiments have been performed and evaluated. An explosive-development program has produced a system, less than 8 inches in diameter, which can be detonated in the multiple simultaneous mode with yields in the range of 20-100 KT (kilotons of conventional explosive equivalent). With respect to stimulation effects, the lateral permeability enhancement from explosion fracturing appears to fall within the range of prediction. Although this is a very difficult parameter to measure directly, simulation-inferred values appear to be reasonably consistent.

The economic viability of explosion fracturing has been studied parametrically, appears to be within the range of projected costs for supplemental gas supplies, and does not stand out as markedly more or less expensive than alternate techniques such as MHF (48).

There are no active plans for additional research and development experiments on nuclear-explosion stimulation application in the United States; this application must remain in the category of apparent technical feasibility, with additional development required for reduction to economic commercial practice.

Massive hydraulic fracturing

Massive hydraulic fracturing, in contrast to the long-established hydraulic fracturing, is designed to create a vertical fracture extending at least 500 feet away from the wellbore in two directions (a total length of 1,000 ft or more); i.e., MHF is a newly developing, large-scale application of fracturing techniques, where the length of a fracture (one wing) may be in thousands of feet and the height of the fracture may be in hundreds of feet. The 1973 Natural Gas Technology Task Force report has summarized adequately: (1) the development and status of hydraulic fracturing; (2) the fracture geometry created by hydraulic fracturing under specified conditions appropriate for tight formations; and (3) predictions of flow rates for selected MHF treatments (47, App. C, D). More recent advances in the MHF technology have been described in various meetings (56, 57).

Shown in figure 14 is a plan view of a MHF treatment with a fracture length (one wing) of 2,000 feet, or a total length of 4,000 feet; arbitrarily, the drainage area is a 160-acre unit, 1,320 by 5,280 feet, which is the basic reservoir unit for later calculations. 17/ It should be noted that early gas flow into a fractured well, as indicated by arrows in figure 14, may be largely linear, and gradually changes from linear-elliptical to a rather radial flow configuration, a complex flow system difficult to calculate and to model. To obtain an approximation of flow to be anticipated from a MHF treatment, an effective well radius--about one-half of the designed fracture length--may be substituted in radial flow equations (58). It follows that a well stimulated by a MHF treatment designed to produce a 2,000-foot fracture length should show about a 20-fold increase in flow rate compared to the unstimulated well.

A variety of cases have been studied to determine the reservoir parameters that would permit application of MHF in stimulating gas production from tight formations (1). These studies, backed by a moderate number of case histories, suggest that, if MHF is to be economically viable, certain minimal physical properties in a pay zone are needed as shown in table 8. Additionally, a major requirement for evaluating tight formations, particularly individual pay zones, is a reliable determination of the in situ permeability (k_g) and the thickness (h), which provides the "permeability-times-thickness factor, the k_gh, usually expressed as permeability-height, permeability-feet, or reservoir capacity. Unfortunately, given the present state of the art, neither the in situ permeability nor the effective thickness of a pay zone is easy to obtain by geophysical log evaluation or by core analysis; in fact, as described above for carefully controlled stimulation experiments in the Piceance and Green River Basins, the flow capacity, k_gh, tends to be overestimated by a factor of 10 or thereabouts.

17/Data on production rates and relative costs for various combinations of fracture length, depth to pay zones, thickness of pay zones, porosity, permeability, and pressure provided by L. E. Elkins and C. R. Fast, Amoco Production Company.

Table 8.--Minimal physical properties in pay zones

Thickness (h)	400 ft or greater	$k_g h$=0.04+md-ft
Gas permeability (k_g)	0.0001 md or greater	
Gas-filled porosity	1.0 percent or greater	
Thickness (h)	50 ft or greater	$k_g h$=0.15+md-ft
Gas permeability (k_g)	0.003 md or greater	
Gas-filled porosity	3.0 percent or greater	
Thickness (h)	25 ft	$k_g h$=0.25+md-ft
Gas permeability (k_g)	0.010 md or greater	
Gas-filled porosity	4.0 percent or greater	
Thickness (h)	20 ft	$k_g h$=0.50+md-ft
Gas permeability (k_g)	0.025 md	
Gas-filled porosity	5.0 percent or greater	

One possible option for obtaining adequate flow-capacity data is to conduct an actual production rate test for isolated pay zones, hopefully without the necessity of running full strings of casing in the exploratory well.

MHF gas-well simulator

The MHF gas-well simulator is a computer program which simulates the Darcy flow performance of a well completed in a low-permeability reservoir and stimulated with a massive hydraulic fracture treatment. Specifically, two-dimensional unsteady-state flow of gas in the horizontal plane is computed for the system consisting of a rectangular region bounded by no-flow boundaries, having a fracture and well located symmetrically within the flow region and parallel to one of the sides (fig. 15). The fracture is portrayed simply as a very narrow strip of the reservoir having an extremely high permeability. In addition, the following effects can be accounted for: (1) turbulent flow in the fracture, (2) variation of reservoir permeability as a function of confining pressure, (3) variation of fracture permeability as a function of confining pressure, and (4) specification of as many as three permeability zones within the fracture. A standard finite-difference solution technique is employed.18/

In the following figures bearing on flow performance, the terminology is:

1. Normal (N) pressure is a hydraulic-pressure gradient of 0.5 $lb/in^2/ft$; 1.25 N is then 0.625 $lb/in^2/ft$, and 0.75 N is 0.375 $lb/in^2/ft$.

2. Reservoir drainage area is 160 acres (fig. 14), with uniform properties.

3. Porosity in all cases means gas-filled porosity.

4. Pay zones are centered at the stated reservoir depth; i.e., a 2,000-foot pay zone (eastern shales) at a depth of 5,000 feet extends 1,000 feet above and below the 5,000-foot reservoir depth.

18/ Provided by Amoco Production Company.

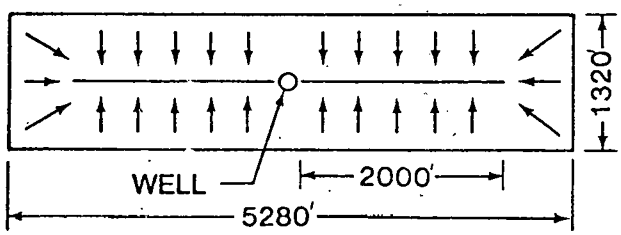


FIGURE 14-Plan view of 160-acre-unit drainage area showing flow paths (arrows) into a symmetrical, double-winged fracture. Fracture length by definition is measured from the well outward along one wing; as shown, fracture length is 2000 feet (one wing); the total fracture length (two wings) for gas flow calculations would be 4000 feet.

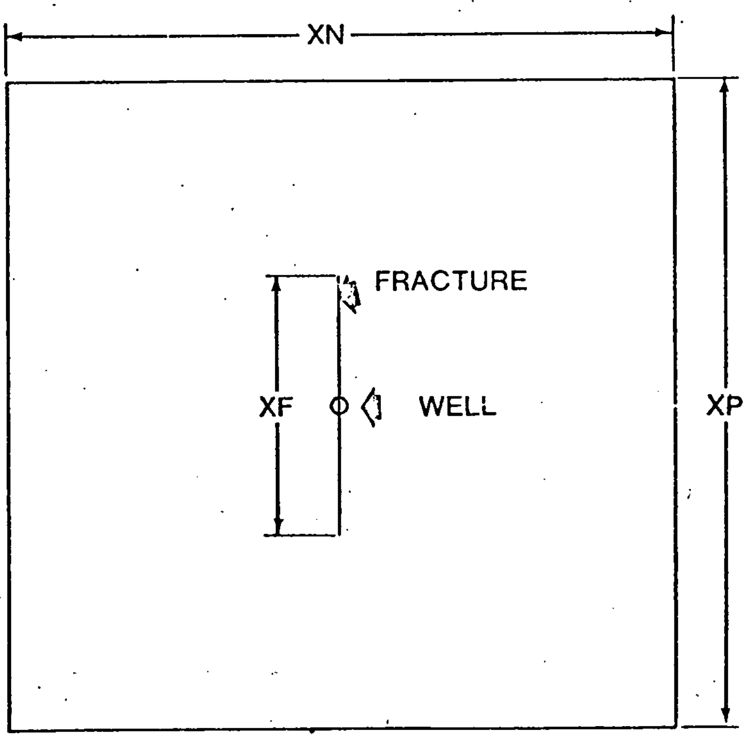


FIGURE 15--DIAGRAM ILLUSTRATING DEFINITION OF WELL DRAINAGE AREA AND FRACTURE DIMENSIONS EMPLOYED AS INPUT DATA.

The effect of fracture length on production, for a pay zone 100 feet thick at a depth of 12,000 feet, with 5 percent gas-filled porosity and at 1.0 N pressure, is shown for two in situ permeabilities: (1) 0.001 md in figure 16 --daily production, and in figure 17—cumulative production; and (2) 0.05 md in figure 18 --daily production, and in figure 19--cumulative production. These data show that in situ gas permeability controls the shape of the production curve, and that doubling the fracture length almost doubles the production rate. In general, these data pertain to the tight sandstone formations, and should permit appraisal of potential production wherever the physical properties of pay zone are adequately known.

The effects of varying pressure, permeability, porosity, pay zone thickness, and pay zone depth on cumulative production, for a constant fracture length of 2,000 feet, are shown in figures 20, 21, 22, and 23. In figure 20, the production varies almost linearly with gas-filled porosity, but nonlinearly with permeability. In figure 21, production varies almost linearly with pay zone thickness. In figure 22, the production varies exponentially with depth, roughly by the square-root function. In figure 23, production varies exponentially with pressure.

The effect of fracture length of 1,000 and 2,000 feet, for pay zones of 1,000 and 2,000 feet thick at a depth of 5,000 feet, for reservoir conditions at 3 percent gas-filled porosity, 0.75 N pressure, and 0.0002 md in situ permeability, is shown in figures 24 and 25. The physical properties were selected to model a hypothetical pay in the eastern black shales, probably near the upper limits of the reservoir parameters as presently known; also, the calculations assume a uniform pay zone without any natural fractures which might increase or otherwise modify gas production rates. The production rates (figs. 24, 25) are, at 10 years, about 100 MSCFD for a 1,000-foot fracture length, and about 200 MSCFD for a 2,000-foot fracture. Production rates, after the initial sharp decline in the first few years, decline rather slowly, as would be anticipated for such a very low permeability reservoir with less than normal pressure.

Effect of reservoir parameters on economics

The economic evaluations were made through a computer system named PLANS, which includes a standard discounted cash flow analysis with the additional capabilities to save selected operational data such as gas production, well drilling, fracturing, and workover activity by years. The system is modified to incorporate economic criteria and to offer ease of data input and analysis.

The basic unit of economic evaluation is the individual reservoir and includes consideration of projected production, operating expenses,

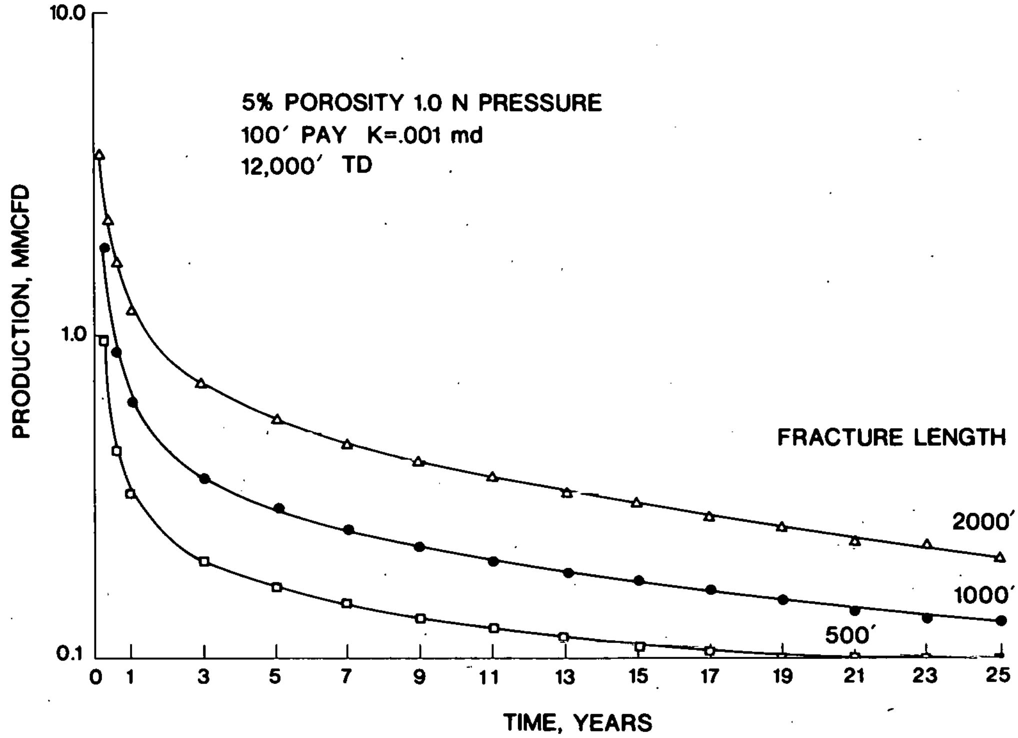


FIGURE 16 EFFECT OF FRACTURE LENGTH ON DAILY PRODUCTION

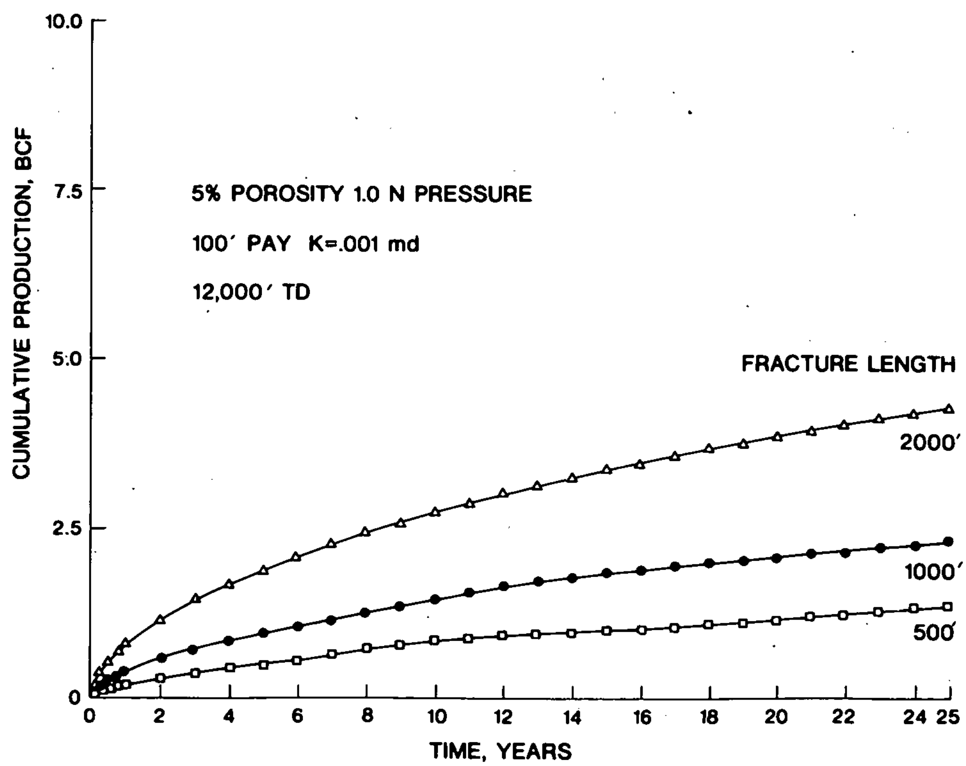


FIGURE 17 -EFFECT OF FRACTURE LENGTH ON CUMULATIVE PRODUCTION

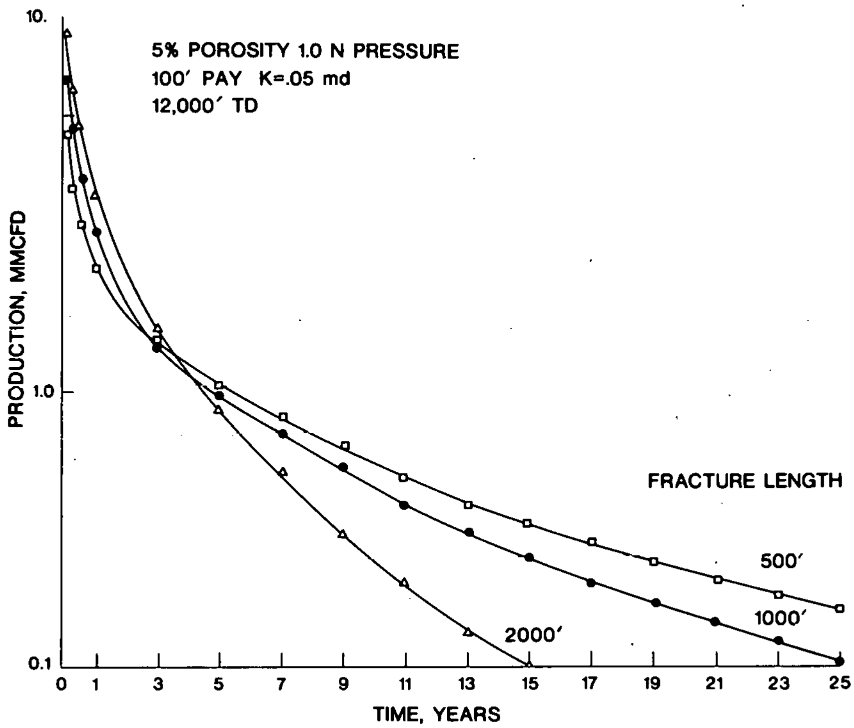


FIGURE 18 EFFECT OF FRACTURE LENGTH ON DAILY PRODUCTION

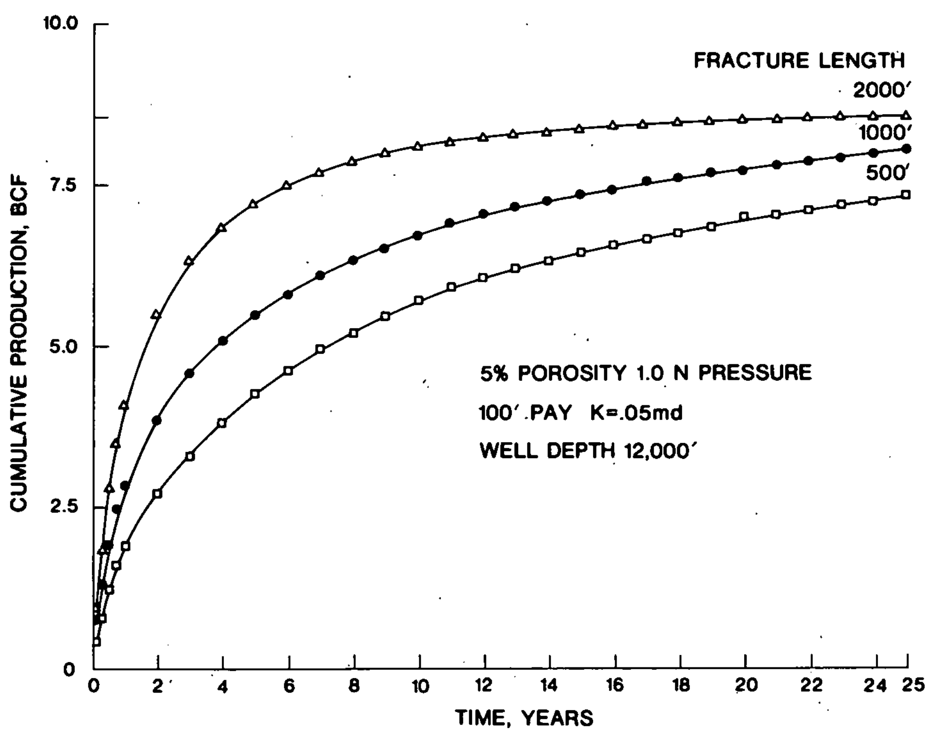


FIGURE 19 -EFFECT OF FRACTURE LENGTH ON CUMULATIVE PRODUCTION

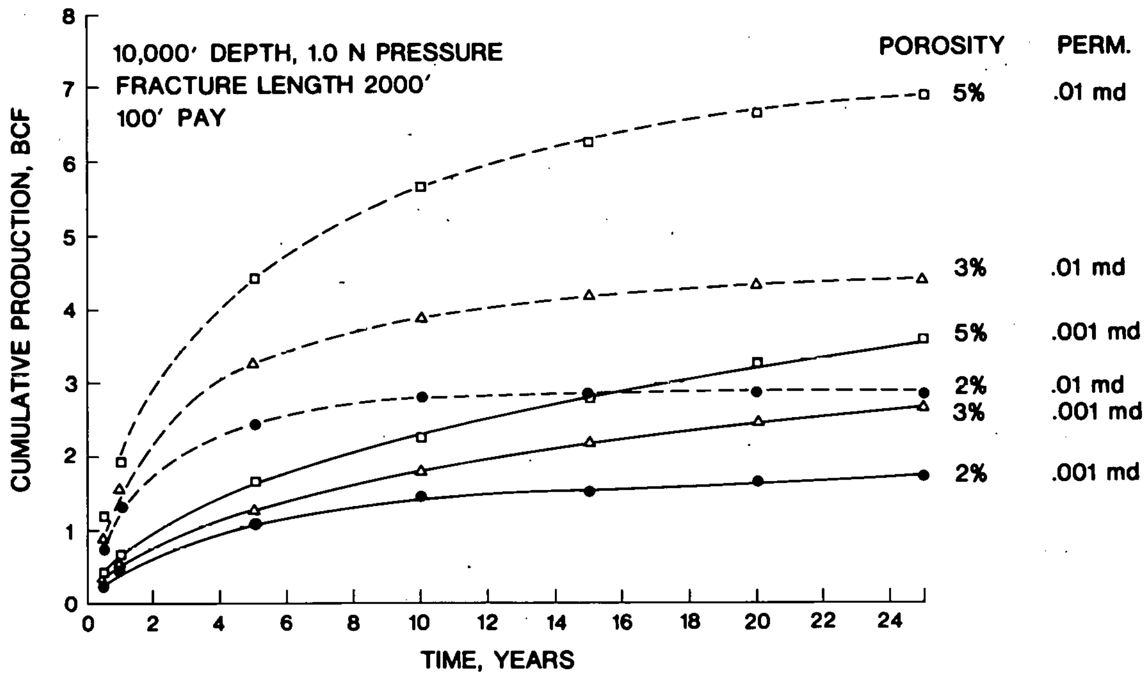


FIGURE 20.-EFFECT OF POROSITY AND PERMEABILITY ON CUMULATIVE PRODUCTION

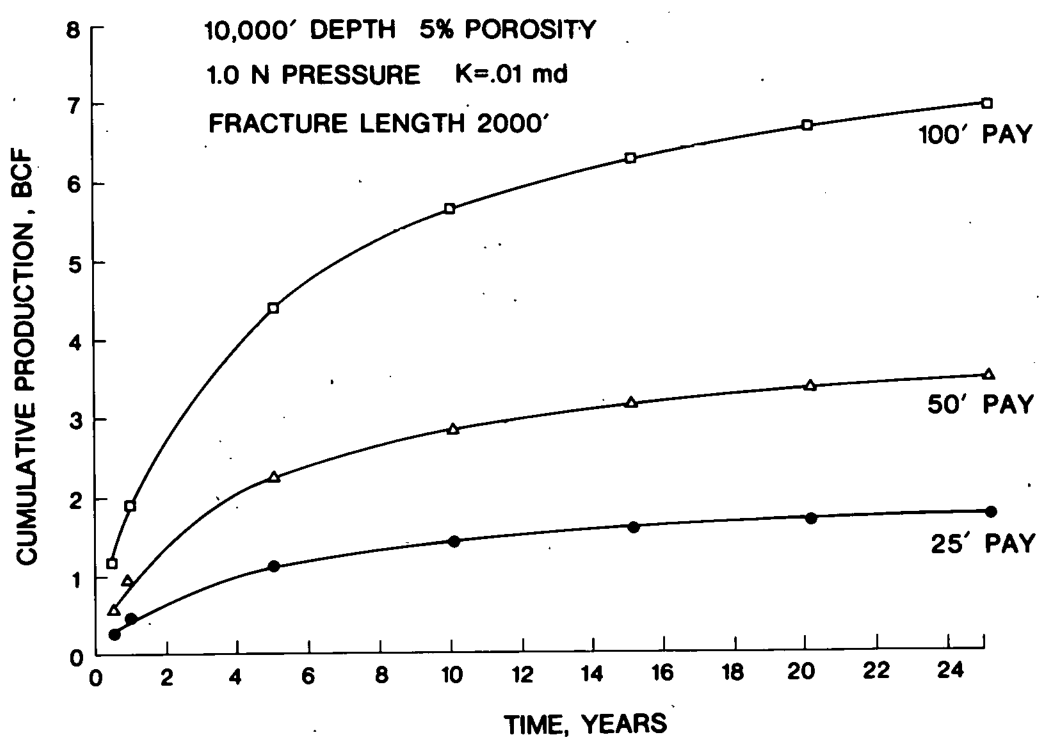


FIGURE 21 -EFFECT OF PAY THICKNESS ON CUMULATIVE PRODUCTION

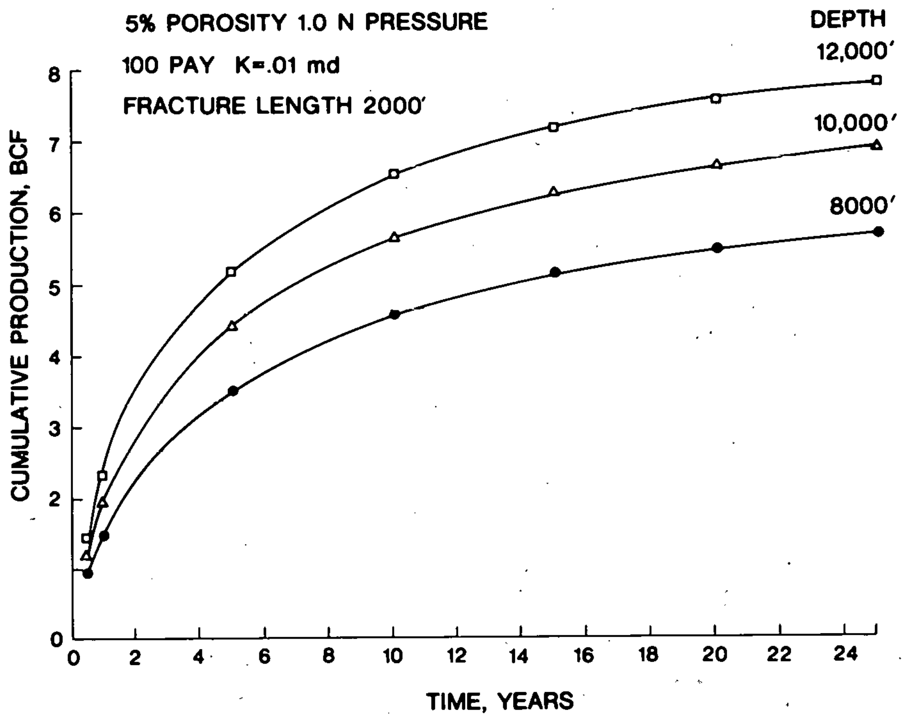


FIGURE 22EFFECT OF DEPTH OF PAY ZONE ON CUMULATIVE PRODUCTION

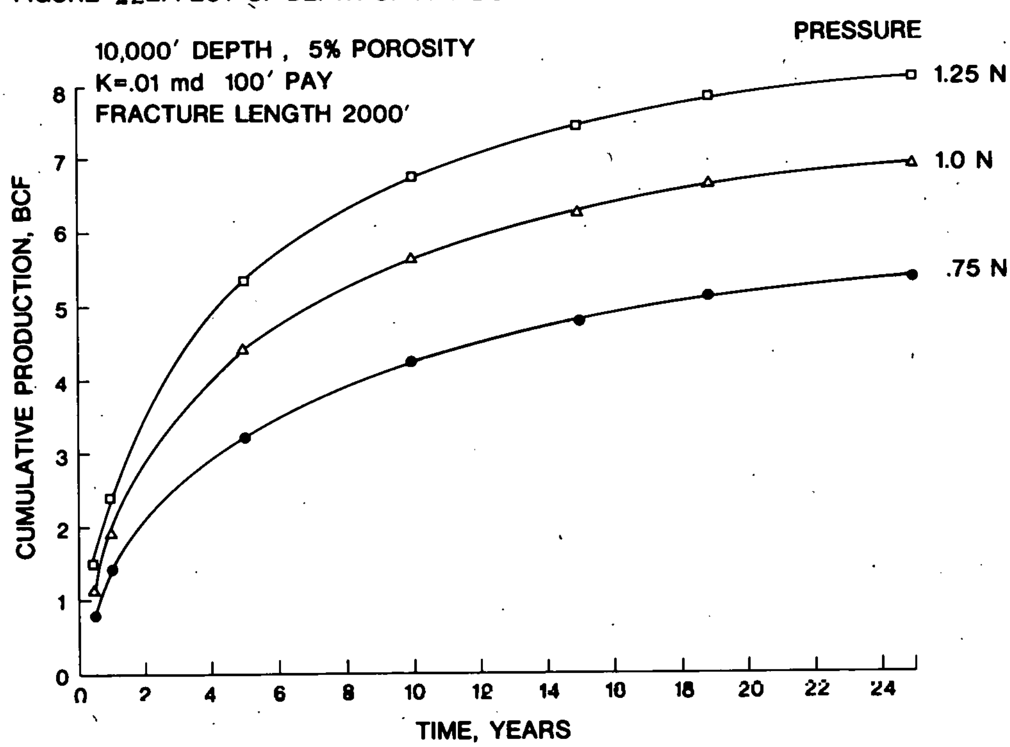


FIGURE23-EFFECT OF PRESSURE ON CUMULATIVE PRODUCTION

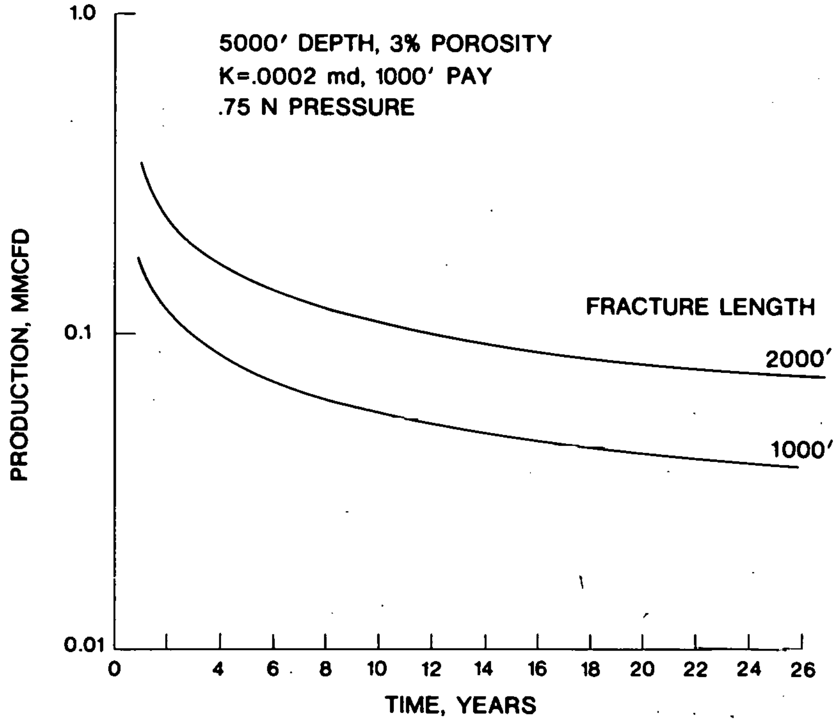


FIGURE 24 EFFECT OF FRACTURE LENGTH ON DAILY PRODUCTION

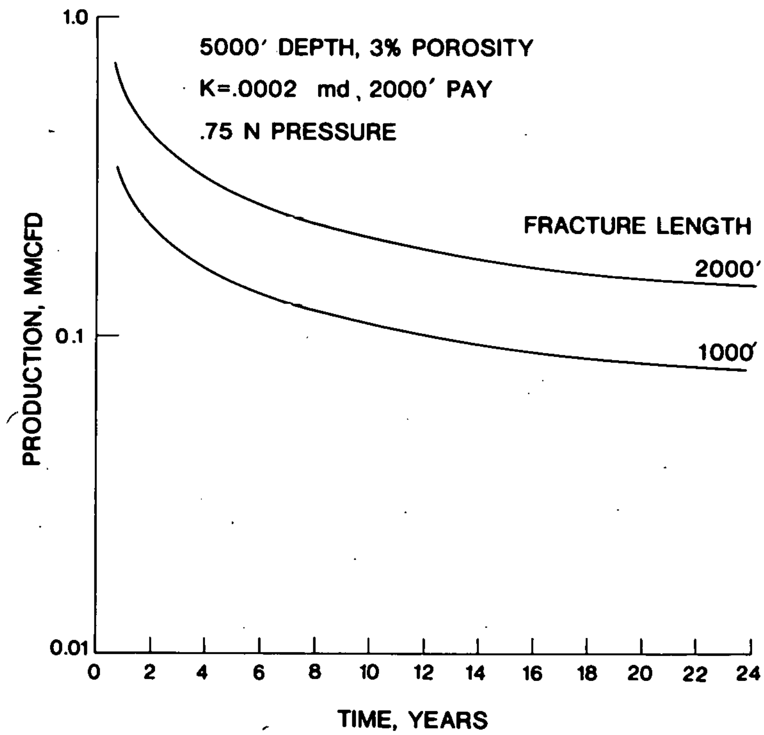


FIGURE 25 EFFECT OF FRACTURE LENGTH ON DAILY PRODUCTION

and investment. Each reservoir is evaluated by computing the present worth of the net cash produced at stipulated gas prices of $0.83, $1.66, $2.50, $3.33, and $4.15 per MCF; these prices are equivalent on a BTU energy basis to oil at $5.00, $10.00, $15.00, $20.00 and $25.00 per barrel.

In the following figures, the economic evaluations are expressed in terms of the profitability index, P.I., where profitability index, or present worth rate of return, is that interest rate which will equate the present worth of cash income to the present worth of cash outflow; alternatively, it is that interest rate which will discount the net cash-flow series to a present worth of zero.

The effect on economics, for a constant fracture length of 2,000 feet, is shown in figure 26 for various in situ permeability and pay thickness, in figure 27 for various pressure and pay thickness, in figure 28 for various gas-filled porosity and pay thickness, and in figure 29 for various pay depth and pay thickness. It is difficult to summarize in simple terms the complex information here presented; it is best used by interpolation based on specific reservoir conditions as are either known or reasonably indicated at any given time. Rather arbitrarily in the following discussion, a P.I. of 20 (20 percent) is used as a cutoff limit, below which an attempt to produce gas would be uneconomical; obviously, other cutoff limits, either higher or lower, could be used dependent on specific conditions such as the total amount of gas in place within a given area, the proximity of a major market, and the availability of gas pipelines.

In figure 26 by inspection and using a P.I. cutoff of 20, pay zones in the range of a few microdarcy in situ permeability could not be stimulated by MHF treatments, unless the value of gas was in excess of $0.83/MCF. A rather crude generalization, in terms of reservoir properties rather than economics, is that the flow capacity, $k_g h$ (md-ft), must be above 0.1 to 0.2 md-ft to warrant consideration for MHF treatment.

In figure 27 assuming a low permeability of 0.001 md, it is obvious that low reservoir pressures, which tend to occur in the eastern black shales, lead to higher wellhead costs.

In figure 28 again based on a low permeability of 0.001 md, as the gas-filled porosity decrease (or conversely as the water saturation increases), the value or cost of gas production would increase to about $2.50/MCF.

In figure 29 again for a low permeability of 0.001 md, shown is the effect of reservoir or pay depth on economics, suggesting that wellhead prices in excess of $0.83/MCF would be needed to warrant MHF stimulation of gas production.

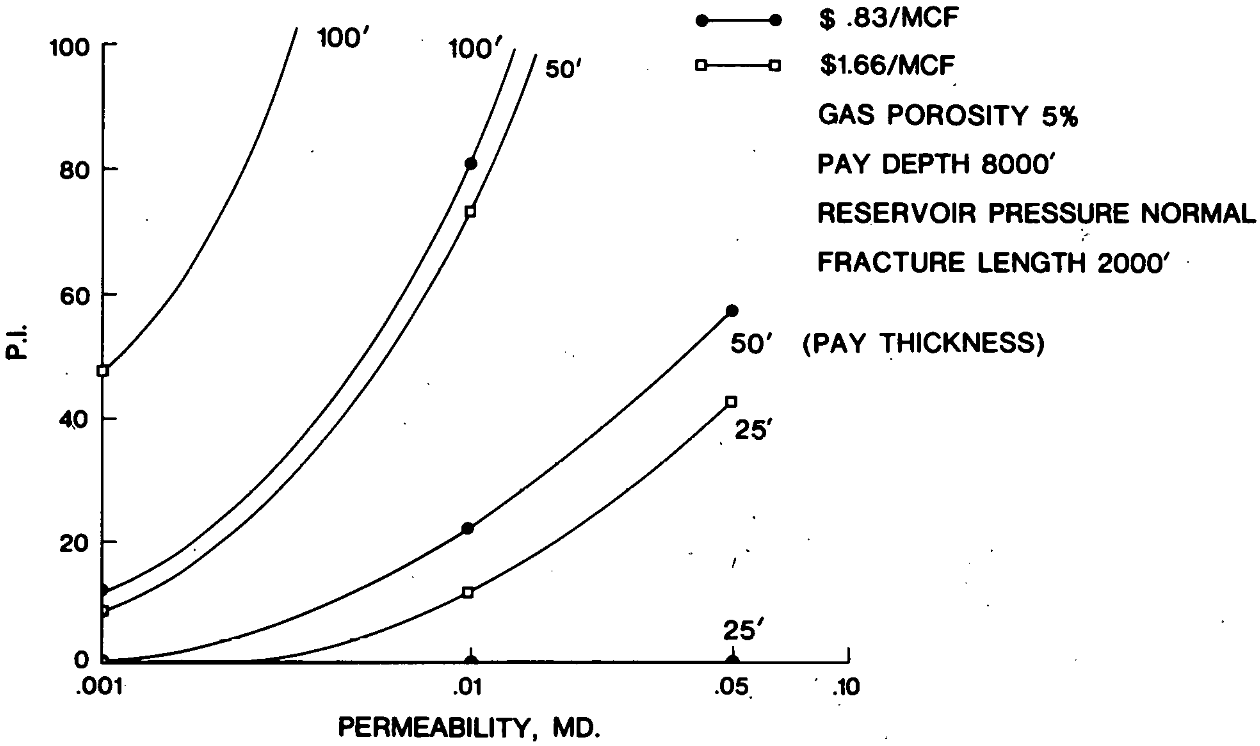


FIGURE 26.-EFFECT OF RESERVOIR PARAMETERS ON ECONOMICS

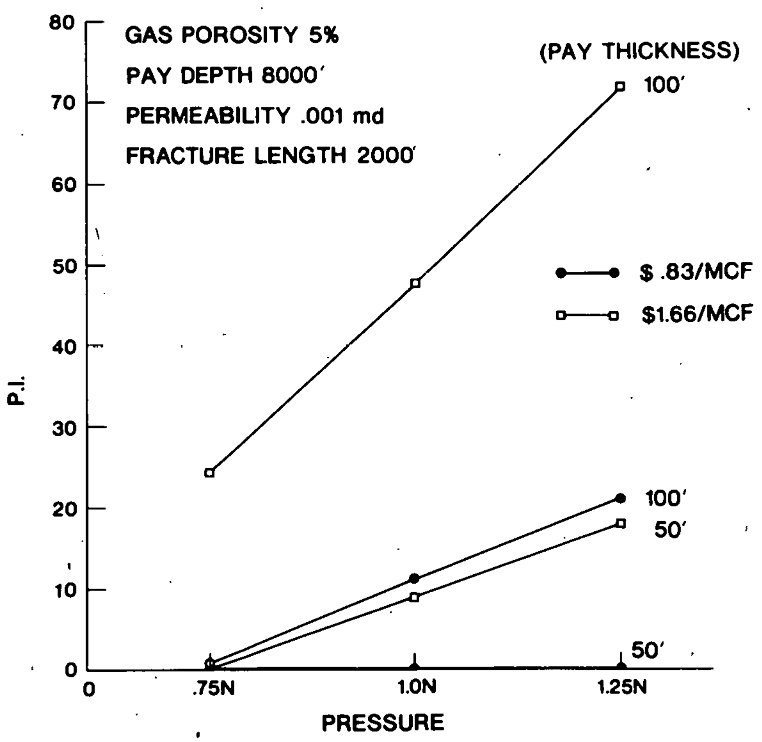


FIGURE 27-EFFECT OF RESERVOIR PARAMETERS ON ECONOMICS

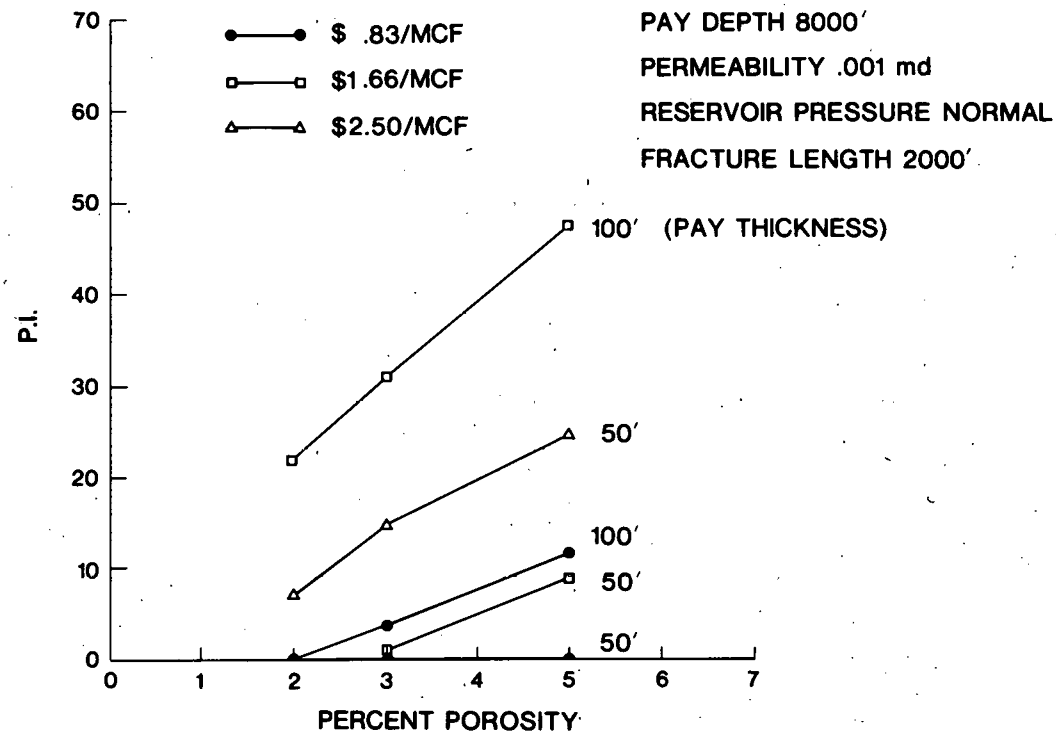


FIGURE 28. -EFFECT OF RESERVOIR PARAMETERS ON ECONOMICS

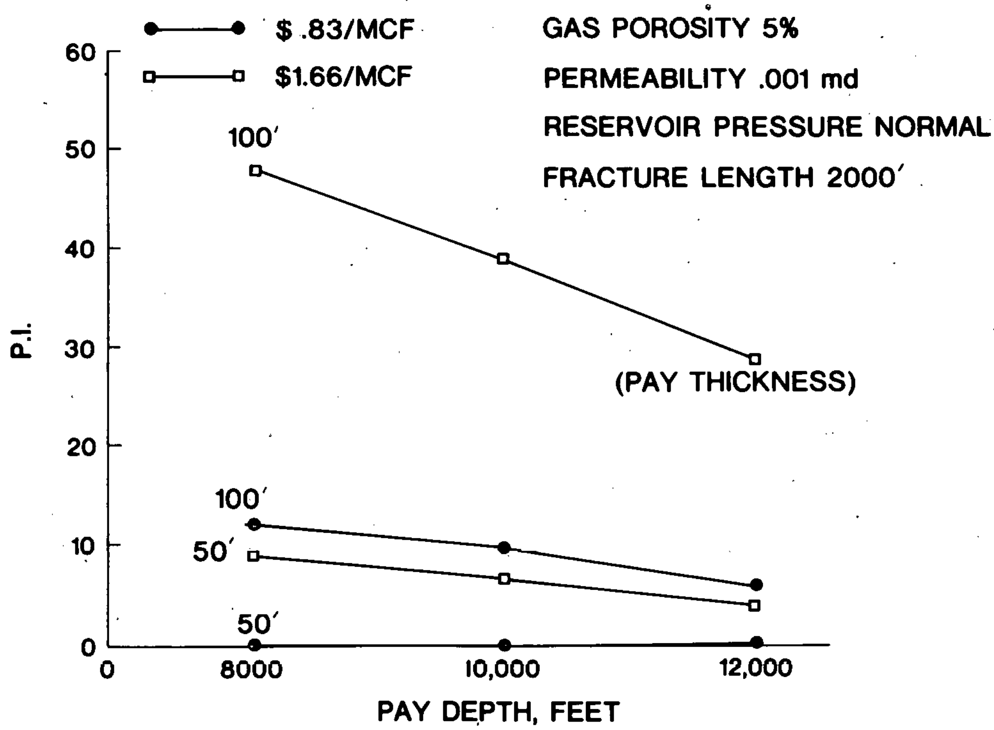


FIGURE 29-EFFECT OF RESERVOIR PARAMETERS ON ECONOMICS

The foregoing data on the anticipated effects of MHF treatments, although somewhat circumscribed by boundary conditions such as the 160-acre uniform reservoir drainage area and by assumptions on the lateral and vertical reach of a fracture, do provide limits within which tight formations or gas-bearing zones should fall to warrant consideration as potential resources.

The data provided in figures 30 and 31 are applicable to the eastern black shales, with reservoir parameters hopefully representative of a significant portion of the shale, namely in situ permeability at 0.0001 md (0.1 microdarcy); pay zone thickness at 400 and 1,000 feet; pay zone depth at 2,000 and 4,000 feet; gas-filled porosity at 1.5-5 percent; and 0.75 N pressure. The following limitations should be noted: (1) uniform drainage area of 160 acres with no natural fracturing; (2) gas production from the gas-filled porosity with no contribution from occluded gas which might be slowly released under absolute open-flow conditions; and (3) gas-filled porosity at 3-5 percent in figure 31 is probably in the uppermost range of shale porosity; the more probable range of porosity seems to be 1-2 percent. By inspection, it is obvious that a 400-foot uniform pay zone with a 2,000-foot MHF treatment will produce gas at a slow rate (fig. 24) and at a high cost.

As shown in table 9, a number of demonstration projects, supported by ERDA (Energy Research and Development Administration) in cooperation with industry, are in progress and should provide significant data on experimental MHF treatments in a variety of reservoir settings. The El Paso Natural Gas and the CER Geonuclear MHF experiments were described above.

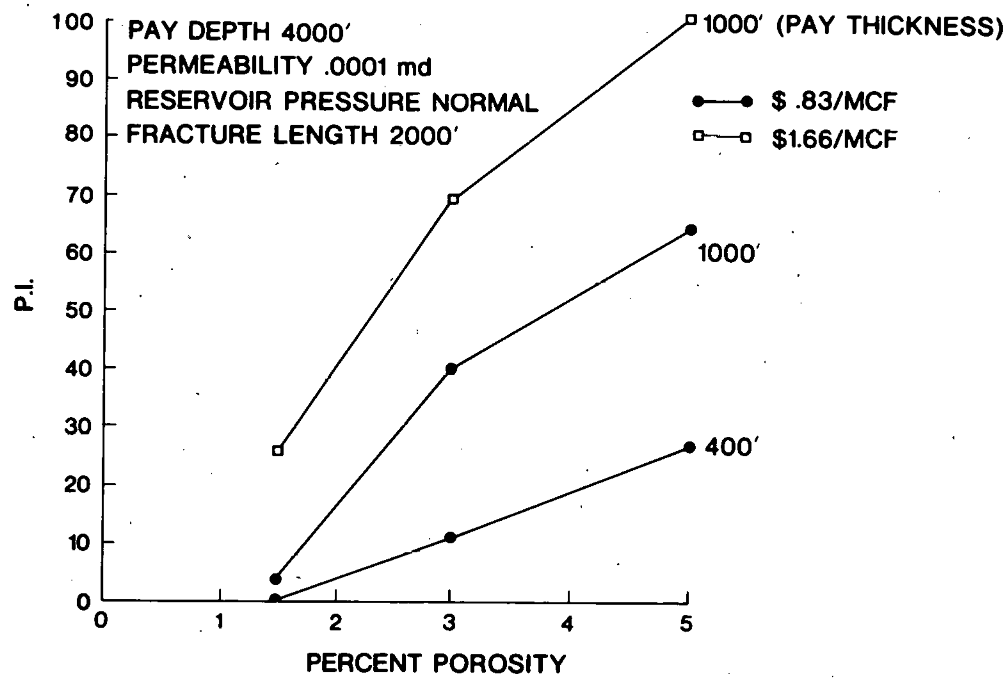


FIGURE 30 -EFFECT OF RESERVOIR PARAMETERS ON ECONOMICS

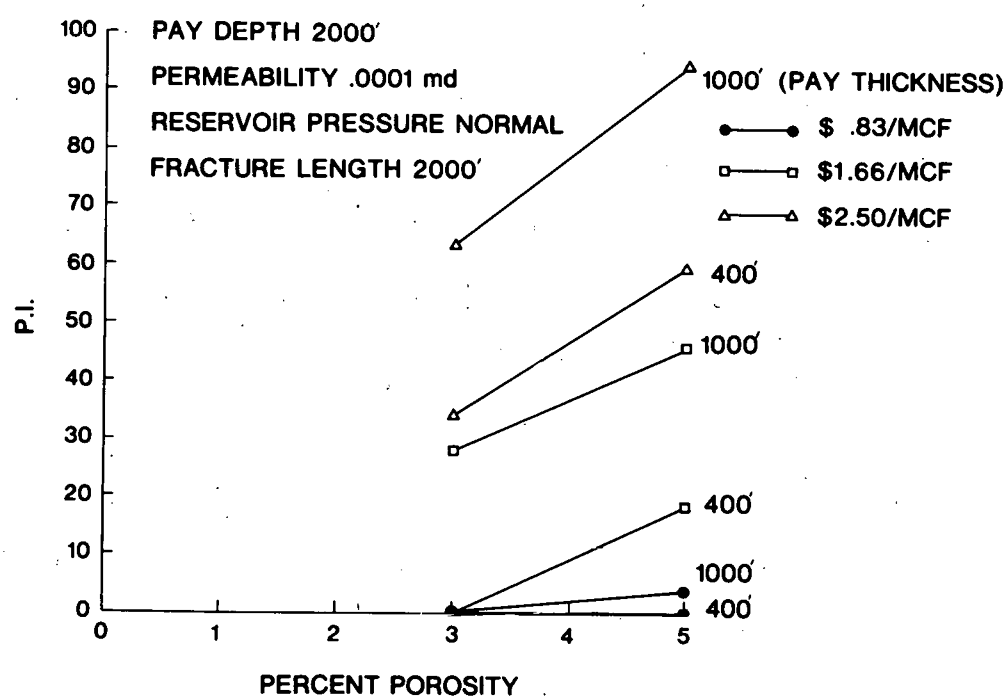


FIGURE 31 -EFFECT OF RESERVOIR PARAMETERS ON ECONOMICS

TABLE 9.--Contractor, Scope of Work, and Target of Demonstration Projects

CONTRACTOR	SCOPE OF WORK	TARGET OF DEMONSTRATION PROJECTS
El Paso Natural Gas	Massive Hydraulic Fracturing	Green River Basin
CER Geonuclear	Massive Hydraulic Fracturing	Piceance Basin
Austral Oil	Massive Hydraulic Fracturing	Piceance Basin
Mobil Oil	Massive Hydraulic Fracturing	Piceance Basin
Rio Blanco	Massive Hydraulic Fracturing	Piceance Basin
Coastal States	Massive Hydraulic Fracturing	Uinta Basin
Pacific Transmission Supply	Massive Hydraulic Fracturing	Uinta Basin
TAO-Westco	Massive Hydraulic Fracturing	Uinta Basin
Columbia Gas	Massive Hydraulic Fracturing	Appalachian Basin (Shale)
Petroleum Technology Corp.(42)	Explosive Fracturing	Appalachian Basin (Shale)
Proposed Project	Massive Hydraulic Fracturing	Appalachian Basin (Shale)
Proposed Project	Deviated Wells	Appalachian Basin (Shale)
Proposed Project	Deviated Wells	Appalachian Basin (Shale)
Columbia Gas	Massive Hydraulic Fracturing	Appalachian Basin (Sand)
Proposed Project	Recompletion	Appalachian Basin (Sand)
Physics International	Explosive Fracturing	Appalachian Basin (Sand)
Petroleum Technology	Explosive Fracturing	Canyon Sand
Dallas Production	Massive Hydraulic Fracturing	Bend Conglomerate

RESOURCES

In the 1973 Natural Gas Technology Task Force report (47), potential gas resources were established only for the thick sequences of Upper Cretaceous and Lower Tertiary fluvial sandstones in the Piceance Basin of northwestern Colorado, in the Green River Basin in southwestern Wyoming, and in the Uinta Basin in eastern Utah. The criteria used to establish reservoirs acceptable in the resource base were:

1. Low permeability reservoir rock containing gas, not commercially recoverable with existing technology.

2. At least 100 feet of net pay, which is defined as sand having 65 percent or less water saturation and porosity from 5 to 15 percent.

3. At least 15 percent of the gross productive interval is pay sand.

4. The objective interval is between about 5,000 and 15,000 feet below the surface.

5. The prospective reservoir underlies at least 12 miles^2.

6. The reservoirs are in remote areas.

7. Pay sands are not interbedded with high-permeability aquifers.

Some of the foregoing criteria, in particular 6 and 7, were included because of the possible use of nuclear-explosive fracturing; thus, other areas known to contain nonconventional gas resources, but not sufficiently remote from population centers for large explosion stimulation experiments, were briefly reviewed and then excluded such as: Atoka-Morrow (Pennsylvanian) sands of the Arkoma Basin, Oklahoma, and the nearby Stanley-Jack Fork (Mississippian) sands of the Ouachita Mountain province; downdip Wilcox (Eocene) and Houston (Cretaceous) sands of the Western Gulf Basin, Texas; and the Oriskany (Devonian) sands of the Appalachian province. These other areas were not then considered to contain significant large resources in comparison to the three major basins; because of lack of pertinent reservoir data, these areas cannot be evaluated at this time for inclusion in the resource base.

The foregoing criteria have been modified slightly, as indicated on table 3, to include pay zones where: (1) thickness is as little as 20 feet; (2) gas-filled porosity is as low as 1 percent; (3) depth of pay zone is as shallow as 1,500 feet; and (4) remoteness from population centers and proximity to aquifers are not limiting factors. With these modifications, resources such as in the eastern Devonian black shales, in the Upper Cretaceous siltstones and sandstones in the Northern Great Plains provinces, and in the San Juan Basin, can be included.

It should be clearly noted that the criteria used herein for estimating nonconventional gas resources are based fundamentally on two reservoir parameters, the gas-filled porosity and the reservoir pore pressure, which define the amount of gas contained within a given reservoir volume. Thus, these estimated resources do not imply in any way whatsoever a recoverability at a small or large fraction of the total; they state the amounts of gas in place under the stipulated reservoir conditions. To avoid ambiguity in resource terms, using definitions established by the Department of Interior and the U.S. Geological Survey (59), the following terms may be applied to the nonconventional gas resources: (1) subeconomic--identified and undiscovered resources not presently recoverable because of technological and economic factors, but which may be recoverable in the future; (2) identified--specific accumulations whose location, quality, and quantity are estimated from geologic evidence supported by engineering measurements; (3) undiscovered--unspecified accumulations surmised to exist on the basis of broad geologic knowledge and theory. The term, reserves, is defined as that portion of the identified resource which is economically recoverable at the time of determination (using existing technology); reserves cannot be applied literally to any part of the gas resources in tight formations, which are subeconomic.

In a somewhat negative sense. as shown on table 8, the flow capacity, $k_g h$, which is the cross product of the in situ permeability times the thickness of the interval at that permeability, has been used to set a minimal or lower limit below which gas in place would not be included in a resource estimate. Although this, in part, violates the concept of a resource as an accumulation of a commodity in such form that economic extraction is currently or potentially feasible, this lower boundary, together with the upper limit of 50 μd in situ permeability, was used to bracket the subeconomic resources in tight formations. This bracketed range was selected to fit the assumed limitations of present and currently developing technologies such as massive hydraulic fracturing, chemical explosive fracturing, and deviated wellbores; presumably, if these technologies advance as rapidly as hoped, some presently unknown portion of the subeconomic resources would be developed and converted to economic reserves.

It is generally agreed that the occasional and naturally high rate of gas production from the tight formations reflects an unusual reservoir condition, where a joint-fracture system, intensively developed within a limited area and with high flow capacity for gas, has been intercepted by wellbores. Because such areas of fracturing are relatively small compared to the thousands of square miles underlain by tight formations, and because adequate data are lacking to define such fracturing at reservoir depth, no attmept has been made to adjust the following resource estimates for such an effect.

Tight sandstone formations

The gas-in-place resources for the tight sandstone formations in the three major basins were estimated by the 1973 Task Force (47), and are shown in detail in table 10 and summarized as follows:

	Trillion $feet^3$	Billion $feet^3/miles^2$
Green River Basin, Wyoming	240	120-145
Piceance Basin, Colorado	210	145-240
Uinta Basin, Utah	150	240-340
	600	

There are no compelling reasons, based on additional but still scanty data from controlled experiments over the last few years--the three nuclear and the numerous MHF experiments, to change these estimates by any significant amount. The volume of gas in place is determined by the gas-filled porosity and the reservoir gas pressure, and basic reservoir properties have not been changed except in minor degree by recent data.

Changes of some importance have occurred in the earlier "Predicted Gas Well Production Rates for the Rocky Mountain Basin" (47, App. E), because the reservoir flow capacity, k_gh, has been demonstrated to be significantly less than originally estimated by a factor of 5 to 10, as discussed above for experiments in the Piceance and Green River Basins. These changes in flow capacity lead to a decrease in gas production, both daily and cumulative, and to an increase in costs (47, section VIII, Gas Production Economics). Thus, although the resources of gas in place have not changed significantly, the resources are much less attractive as targets for currently developing techniques of gas production stimulation.

Two additional areas containing tight sandstone formations have been added to the resource base: (1) the San Juan Basin, northern New Mexico, containing an estimated gas-in-place of 63 trillion $feet^3$; and (2) the Northern Great Plains province, Montana and North Dakota, containing an estimated 130 trillion $feet^3$.

Table 10 - Reservoir Characteristics and Productive Areas

Reservoir and location		Productive area, square miles	Depth below surface, feet	Gross interval, feet	Net pay, feet	Porosity	Water saturation	Effective permeability, md 20/	Initial average BHP, psia	Average BHT, °F	Well Design case	Area, sq. mi.	Gas-in-place Per sq. mi. Billion cf	Gas-in-place Total Trillion cf
PICEANCE BASIN, COLORADO 19/														
CATEGORY 1 (Essentially proved: Based on data from nearby wells)														
Fort Union	North	200	5,600 - 6,200	600	200	0.100	0.50	0.025	2,360	170				
Mesaverde I	half	300	6,200 - 7,400	1,200	300	0.095	0.50	0.007-0.015	2,720	187	IA	200	239.6	47.9
Mesaverde II	of	300	7,400 - 8,500	1,100	165	0.095	0.50		3,180	206	IB	100	192.3	19.2
Mesaverde III	basin	300	8,500 - 9,700	1,200	300	0.095	0.50		3,640	230				
Mesaverde (south half)		250	6,250 - 8,750	2,500	625	0.090	0.45	0.020	2,750	204	IC	250	144.4	36.1
CATEGORY 2 (Gas in place inferred from geological interpretation)											IVC +			
Fort Union	North	50	same								IVD	100	148.8	14.9
Mesaverde I	half	250	characteristics								IA	50	239.6	12.0
Mesaverde II	of	150	as								IB	100	192.3	19.2
Mesaverde III	basin	250	category 1											
Mesaverde (south half)		400									IC	400	144.4	57.8
													Basin total	207.1
GREEN RIVER BASIN, WYOMING														
CATEGORY 1														
Fort Union		140	8,000 - 12,000	4,000	700	0.092	0.54	0.0034	6,820	203	IV	140	264.7	37.1
CATEGORY 2														
Fort Union & Mesaverde		300	11,500 - 13,000	1,500	320	0.090	0.55	0.0034	8,000	225	IXA	300	121.5	36.4
			13,000 - 14,300		0									
			14,300 - 15,800	1,500	340	0.090	0.55	0.0034	9,800	260	IXB		135.8	40.7
Mesaverde		200	9,500 - 12,000	2,500	600	0.080	0.55	0.015	4,700	200	X	200	156.4	31.3
CATEGORY 3 (Speculative)														
Fort Union & Mesaverde		500	9,000 - 12,000	3,000	500	0.092	0.54	0.0034	6,820	203	XII	500	189.1	94.5
													Basin total	240.0
UINTA BASIN, UTAH														
CATEGORY 1														
Mesaverde		300	8,000 - 11,000	3,000	1,000	0.10	0.50	0.007-0.015	4,300	200	V	300	338.8	101.6
CATEGORY 2														
Mesaverde		200	8,000 - 11,000	3,000	700	0.10	0.50	0.007-0.015	4,300	200	XI	200	237.2	47.5
													Basin total	149.1
													Total	596.2

19/ Mesoverde 1, 11, and 111 have identical areal configurations in category 1 and line up vertically so that any well will penetrate all three sands. The Fort Union lies above the Mesoverde sands and any well in it can penetrate the three Mesoverde sands. The same situation exists for category 2 with the exception that Mesoverde 11 have reduced areal extent, but still is within the boundary of 1 and 111. All productive areas in the Green River and Uinta basins are geographically separated.

20/ As stated in text, the effective or in situ permeability derived from recent drawdown and buildup tests is less than here shown. For the Piceance Basin, the permeability is about 2 md, and for the Green River Basin about 1 md. New data are lacking for the Uinta Basin.

The Northern Great Plains was not previously included in natural gas resource estimates because of inadequate data, but it is now known that the area contains significantly large resources entrapped at shallow depths (less than 4,000 feet) in thin, discontinuous, low permeability Upper Cretaceous offshore siltstones and sandstones. These fine-grained clastics, enclosed in a thick sequence of marine shale, were deposited on the western side of a north-south trending Interior Cretaceous seaway. Current investigations by D.D.Rice of the U. S. Geological Survey using carbon isotope ratios indicate that the contained gas was generated by anaerobic bacteria at shallow depths in the accumulating sediments. These shallow accumulations have generally been overlooked in the past; however, recent exploration and evaluation in western Canada along the trend of accumulations extended from eastern Montana indicate that major resources are present in this type of accumulation. The Suffield Evaluation Committee in 1974(65) assigned an in-place gas reserve of 3.7 trillion cubic feet to an area of 1,000 square miles in southeastern Alberta (Canada) where the area was evaluated by a 77 well program, of which 76 wells were completed as economically producible wells. This gas-bearing facies extends into Montana and is present over approximately 35,000 square miles in the United States portion of the northern Great Plains. Using the Suffield Block reserve data, the United States portion of this province should contain 130 trillion cubic feet of gas in place and a potentially recoverable gas resource of approximately 95 trillion cubic feet. General characteristics of the area are: (1) depth of gas-bearing zones, 1,200 to 4,000 feet; (2) multiple pay zones from 20 to 100 feet individual thickness; (3) porosity from 8 to 15 percent: (4) water saturation at 50 to 60 percent; and (5) gas in place at 3 to 4 billion feet^3 per mile^2.

Data for the San Juan Basin, for which the type locality was the Project Gasbuggy site, has been previously described: in general, the characteristics are very similar to the Piceance, Green River, and Uinta Basins, with experimental data again suggesting a flow capacity less than originally estimated.

Tight shale formations

The very extensive and thick shale formations of Devonian age, in the eastern United States, contain a large resource of gas in place (57). In contrast to the tight sandstone formations, the shales in general are characterized by: (1) a lower gas-filled porosity, ranging from less than 1 percent to possibly 5 percent; (2) a lower reservoir pressure, both because of a shallower depth of burial of the gas-bearing zones, and because of a less-than-normal hydraulic pressure gradient; and (3) very low in situ gas permeability, probably in the range of 4×10^{-4} μd to about 1 μd.

The shale formations have then much less gas in place per unit volume or individual reservoir volume than do the tight sandstone formations: from less than one to possibly four SCF of gas per $feet^3$ of shale, compared to 9 to 14 SCF/ft^3 for sandstone. On the other hand, the shales have an extremely large areal extent--roughly 150,000 $miles^2$--and, more importantly, have a low water saturation, possibly about 10 percent. Such low saturation is favorable in that, although the in situ permeability for gas is very low, it should be reasonably uniform and not subject to large changes with minor variation in water saturation.

The available resource estimates for the Devonian black shales vary over an implausibly large range, from as high as 460,000 trillion $feet^3$ in the Appalachian Basin alone, to as low as 60 trillion $feet^3$ in the same general area; this wide range in estimates--roughly four orders of magnitude--indicates a critical lack of information on the general stratigraphic and structural setting and for reservoir properties. It is not difficult to determine how some of those estimates were made; for example, from information provided by Battelle Columbus Labs (fig. 32) based on 20 samples, the calculated maximum gas-in-place per unit volume of 1,000 feet thick by 1 $mile^2$ is 2,900 billion $feet^3$ for Washington County, Ohio, which when multiplied by 160,000 $miles^2$ underlain by shale leads to 464,000 trillion $feet^3$ of gas; or for the low estimate, by a major company, the Big Sandy gas field in eastern Kentucky has reserves (past production plus remaining reserves) of about 4 trillion $feet^3$ in an area of 2,000 $miles^2$; the probability of similar gas fields occurring is one in each 10,000 $miles^2$, where the total area is 150,000 $miles^2$, leading to potentially recoverable resources of 60 trillion $feet^3$ of which 4 trillion $feet^3$ have been discovered and developed as reserves.

Both the foregoing examples are based on what is essentially point source information extrapolated to a very large area--or volume--of shale; this approach neither requires nor provides: (1) structural and stratigraphic information, particularly stratigraphic information on facies distribution which might control the amount of gas in place and other parameters; and (2) reservoir parameters such as flow capacity, gas-filled porosity, in situ permeability, and reservoir pore pressure, which would permit calculation not only of gas in place but also of production rates, percentage recovery of the resources, and production costs.

CALCULATED GAS IN PLACE - (BCF PER UNIT VOLUME OF 1000 FT X 1 MI^2)

(BATTELLE COLUMBUS LABS)

METHOD OF DETERMINATION	CORE SITES			
	LINCOLN COUNTY WEST VIRGINIA	WASHINGTON CO. OHIO	SULLIVAN COUNTY INDIANA	CHRISTIAN COUNTY KENTUCKY
WEIGHT LOSS (100-125°C)	500-1400	500-2900	—	800
FREE GAS DETERMINATION	40-80	40-110	40-140	110

FIGURE 32

Also indicated by the data in figure 32 is a behavior of gas in the organic-rich shales, previously noted and difficult to evaluate; namely, the gas evolved at essentially standard conditions of temperature and pressure -- "free gas" -- is much less than the gas evolved at 100 - 125°C and at low (near vacuum) pressure, by a factor of 1:7 to 1:18. How much of this bound or adsorbed gas might be released by a pore pressure reduction during production from a given reservoir volume is not known; neither is it clearly known how such gas is related to particular shale facies, such as those containing a high organic fraction. Because well production methods do not raise temperature during flow--in fact, the rock temperature would decrease, and because the back pressure in the production well is normally considerably higher than atmospheric pressure, it is difficult to evaluate what fraction of such gas might be released and then to add such gas to resource estimates. Obviously, some resource estimates of gas in place include all such gas, which is not incorrect in the broad sense of a resource, but which is here considered unrealistic.

A recent MHF experiment by Columbia Gas in conjunction with ERDA (63) was conducted in western Lincoln County, West Virginia, well No. 20403, as follows: Took place on June 21, 1976, in two shale zones from 3,858 to 3,918 feet and from 3,971 to 4,031 feet with 24 perforations; bottom-hole pressure about 0.5 N; prefracture breakdown with 1,500 gal gave no measurable gas flow; fracture design was for 200-foot fracture height; fracture treatment at 220,000 gal of 80 quality foam in two stages, with 282,000 lb of sand; zone fractured had gas-filled porosity at about 1 percent, or 0.6 SCF/ft^3 (63, fig. 8); postfracture flow after initial flush production (mostly return flow of injected nitrogen gas) was about 80 MCFD. Based on the foregoing data, the gas in place would be 3.36 billion feet^3 per mile^2, or 840 million feet^3 for a 160-acre drainage area. Assuming a stabilized production rate of 30 MCFD for 25 years, or 275 million feet^3, the percentage recovery would be 32 percent of the gas in place per 160-acre drainage area appropriate for MHF treatments of this size. It should be noted that, if the 3.36 billion feet^3/mile^2 is accepted--and it is based on somewhat adequate reservoir properties, then for the 150,000 miles^2 of shale the total resource in place would be 500 trillion feet^3. Of more interest is the flow capacity, $k_g h$, at 0.6 md-ft after the MHF; making approximate correction based on linear-elliptical flow equations appropriate for MHF (58), the pre-MHF in situ permeability would be 0.2 μd, within the range of physical properties shown in table 8.

This particular MHF experiment is of importance for several reasons: (1) the in situ permeability calculated from the observed flow rate (80 MCFD open flow) is about 0.2 μd, reasonable for a shale; (2) assuming the MHF treatment created fracture (one wing) at 200 feet high and 2,000 feet long, the observed flow rate can be supported by a $k_g h$ of 0.6 md-ft (0.2 μd times 200 ft times 16 for fracture linear flow correction); (3) it is not necessary to appeal to unknown natural fractures being intercepted by the MHF and thereby contributing an unknown portion of the flow; and (4) it is not necessary to include a contribution from release of bound gas; the "free gas" in the porosity is adequate to support the observed flow rate. Alternatively, if the effective fracture dimensions of the MHF treatment are 200 feet height and 1,000 feet length, the in situ $k_g h$ would be 0.1 md-ft, the in situ permeability would be 0.5 μd, and following the MHF the $k_g h$ would be 1.6 md-ft with an effective 8.2 μd permeability. The flow from the well prior to MHF stimulation should have been less than 5,000 cubic feet per day, a rather small flow to measure.

On the basis of accordance with the rather sparse geologic and physical property data, including that from various gas stimulation experiments in the last few years, the resources estimated by ERDA (57, 60, 61, 62) at 285 trillion cubic feet for the Appalachian Basin (table 10) are accepted as the best fit with our present knowledge. Shown in table 10 is a summary of reservoir characteristics and resources clearly indicating the rather fragmentary nature of the available data. Of interest, the data derived from the MHF stimulation experiment in Well 20403 are in good agreement with ERDA resource estimate, and provide support for that estimate.

Table 10--Reservoir characteristics and resources-Devonian Shales

	Appalachian Basin 20/	Well 20403 W. Va. 21/	Ohio, W. Va., Ky., and Ind. 22/	Appalachian Basin 23/
Area (mi^2)	55,000-110,000	1	1	160,000
Volume (mi^3)		---	---	12,600
Depth below surface (ft)	3,000-6,000	3,945	---	---
Gross interval (ft)	600-3,000		---	25-1,500
Net pay-h (ft)	200-400	200	1,000	24/ 491
Porosity (%)	2	---	---	---
Gas-filled porosity (%)	1.8	1.1	1-4	24/ 1.3
Water saturation (%)	10	---	---	---
BHP (lb/in^2a)	400	800	---	---
BHT (°F)	---	112	---	---
Permeability, gas-k_g (μd)	---	25/ 0.2-0.5	---	---
Flow capacity-k_gh (md-ft)	---	25/ 0.4-1.0	---	---
Gas in place, SCF/ft^3	0.47	0.6	1.4-5.0	24/ 0.35
Gas in place, $SCF \times 10^9/mi^2$	2.6-5.2	3.38	40-140	0.9
Gas in place, trillion ft^3	285	---	---	149

20/ Estimates by ERDA (Reference: 57, 60, 61, 62).

21/ Data from MHF treatment, Well 20403, Lincoln Co., W. Va. (63).

22/ Data from figure 32.

23/ Data from Department of Interior News Release, Geological Survey, March 31, 1976.

24/ Based on gas production and other data from Big Sandy gas field, Kentucky.

25/ Values post-MHF are: for 1,000-ft fracture--k_gh at 1.64 md-ft, k_g at 8.2 μd; for 2,000-ft fracture--k_gh at 0.6 md-ft, k_g at 3.0 μd.

Estimates of nonconventional gas resources

Estimates of nonconventional gas resources, for these areas considered to contain the predominance of such resources, are summarized as follows:

	Trillion cubic feet	Billion cubic feet per square mile
Green River Basin	240	120-145
Piceance Basin, Colorado	210	145-240
Uinta Basin, Utah	150	240-340
San Juan Basin, New Mexico	63	30-40
Northern Great Plains, Montana	130	3-5
Appalachian Basin	285	3-5
	1,078	

By inspection, the energy density of the foregoing resources, expressed here as the amount of gas in place per square mile, is significantly higher by one or two orders of magnitude for resources in tight sandstones of the four major basins in the western United States, in contrast to the energy density in the siltstone/sandstone of the Northern Great Plains and in the shales of the Appalachian Basin. It follows that the development of reserves within the resource base, and the future gas production from such resources, will reflect in major part the initial energy distribution; i.e., for a given production level, the high energy density resources in sandstones will require proportionately fewer developmental wells, interconnecting pipelines, and access roads in a small land area, than would the low energy density resources in the Northern Great Plains and the Appalachian Basin.

It should be clearly noted and emphasized that these resources cannot be directly compared to present-day conventional reserves of natural gas, where the production rate per well is relatively high and where the percentage recovery of gas in place, frequently quoted and demonstrated by production records, is about 80 percent of the gas in place. These nonconventional resources, characterized by a low in situ gas permeability and a related low flow capacity, will provide a relatively low production rate, over a longer production interval, with a much lower percentage recovery of the gas in place.

It is not the purpose of this report to evaluate wellhead production costs of gas from tight formations; such cost estimates were made in the 1973 Task Force Report (47) and can be modified to fit the changing reservoir conditions. Some data have been provided on the effect of reservoir parameters on economics (figures 26 through 31), which should permit an approximation of wellhead costs given the necessary reservoir properties. It should be noted that the Pinedale Unit MHF Experiments (52, 53) provide data which show that the production capacity in the type locality used to characterize the Green River Basin is about one-fifth of that projected by the 1973 Task Force Report (47), and that combination of larger fracture treatments and higher than estimated inflation leads to twice the cost in 1972 dollars used in the 1973 report; combining the lower production with higher costs leads to a wellhead development cost of about ten times the 47 cents per MCF reflected in the 1973 Task Force Report. Data from the Rio Blanco site in the Piceance Basin, again the type locality used to characterize the basin, suggest an even higher increase in projected wellhead costs, because the flow capacity is about a factor of 10 lower than forecast.

Clearly, the major problems in estimating resources in tight formations are: (1) in situ permeability, (2) the thickness of pay zones, and (3) water saturation. Establishing reserves of gas within the large resource base, producible under various stimulation technologies and under various wellhead prices, will require similar data on particular reservoir volumes; such data can become available only through extensive developmental effort. Current research, both by industry and as sponsored by government, may provide answers to these problems.

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Comments from the Executive Advisory Committee

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June 20, 1977

Mr. Thomas Jennings
Gas Policy Advisory Council
Federal Power Commission, Room 7306
825 N. Capitol Street, N. E.
Washington, D. C. 20426

Dear Tom:

The final report of the Supply-Technical Advisory Task Force-Nonconventional Natural Gas Resources contains important information on the extent of these substantial energy resources and some of the technical, legal and other barriers which must be overcome to develop them. I believe the report is worthwhile and should be published.

If it can be arranged, it would be helpful to point out in an introductory summary for the report (or in the Commission's letter of transmittal with the report) that because of unfavorable economics and technical problems the U. S. should not expect significant, early natural gas production from these resources. While a person knowledgeable in U. S. energy production will recognize the extent of delay, which the barriers noted in the report can cause, this critical matter may not be so obvious to lay readers.

I look forward to reviewing the remaining section of the report on Gas Dissolved In Water.

Thank you for the opportunity of presenting these comments.

Sincerely,

J.

JRR:aa

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May 31, 1977

Mr. Thomas Jennings
Gas Policy Advisory Council
Federal Power Commission, Room 7306
825 N. Capitol Street, N.E.
Washington, D.C. 20426

Dear Tom,

Thank you for the copy of the final report of the Supply Technical Advisory Task Force-Nonconventional Natural Gas Resources. I believe the Task Force did an excellent job of preparing the report. It is detailed enough to give the reader sufficient information on which to reach conclusions. I believe it will be a very useful addition to the total report.

Sincerely,

Jerry

Gerard C. Gambs

GCG:iw

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