DM 406

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

ILLUSTRATIONS

Figures

CONTENTS

Tables

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 (1).

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 (ud)	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 (2). 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 1 are data for permeability versus net confining pressure for sandstone core samples (3, 4) 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 2, 3, 4, and 5, and table 1, 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 (3). For the samples studied, absolute permeability is greatly reduced

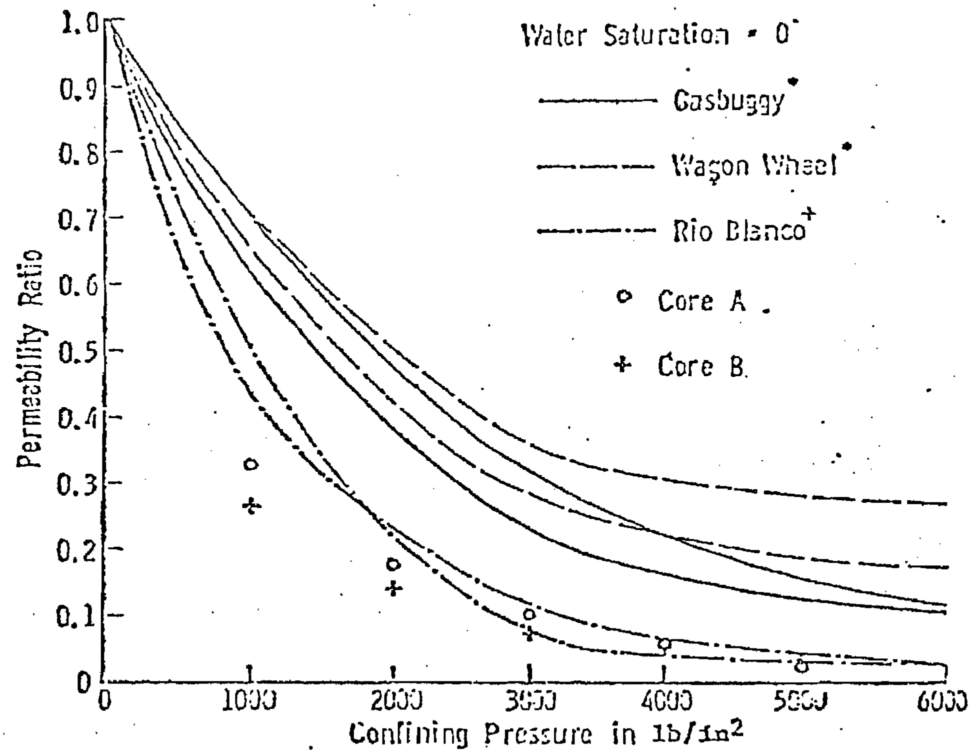


Figure 1. Permeability as a function of confining pressure.

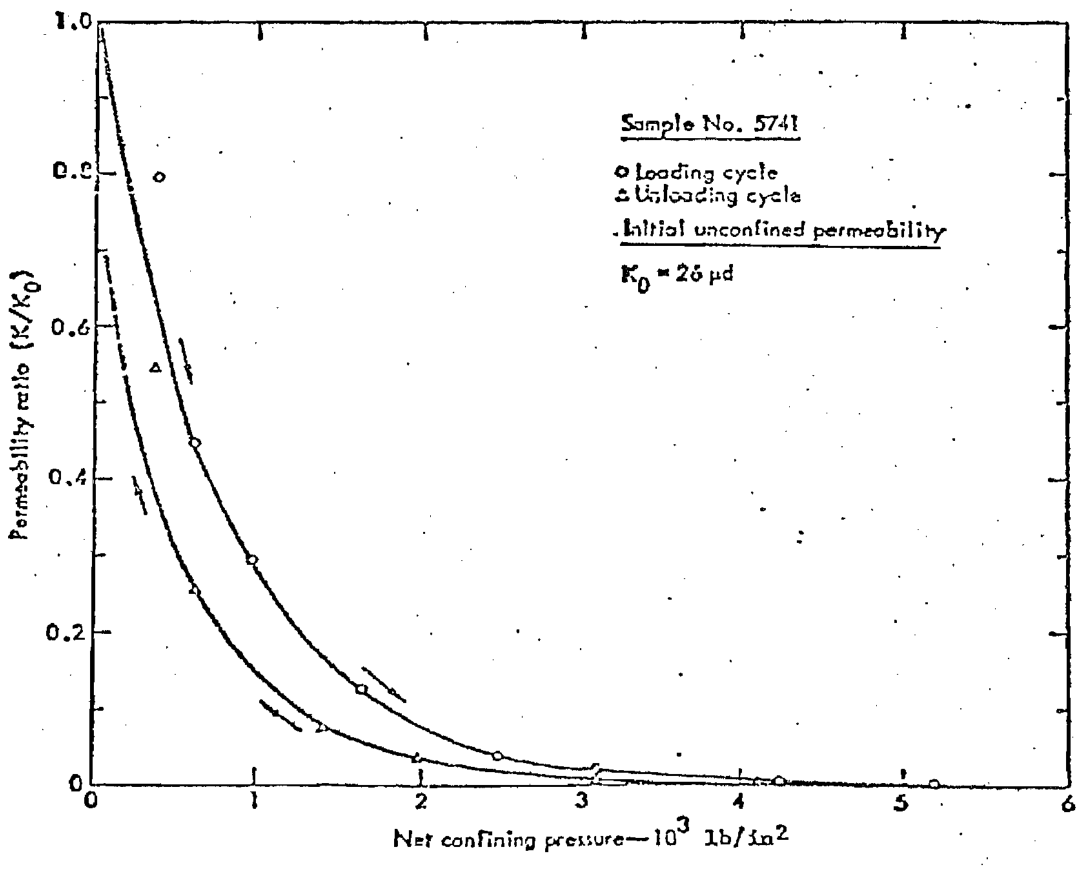


Fig. 2. Effect of confining pressure on the permeability of Fort Union formation sandstone sample at 45% water saturation.

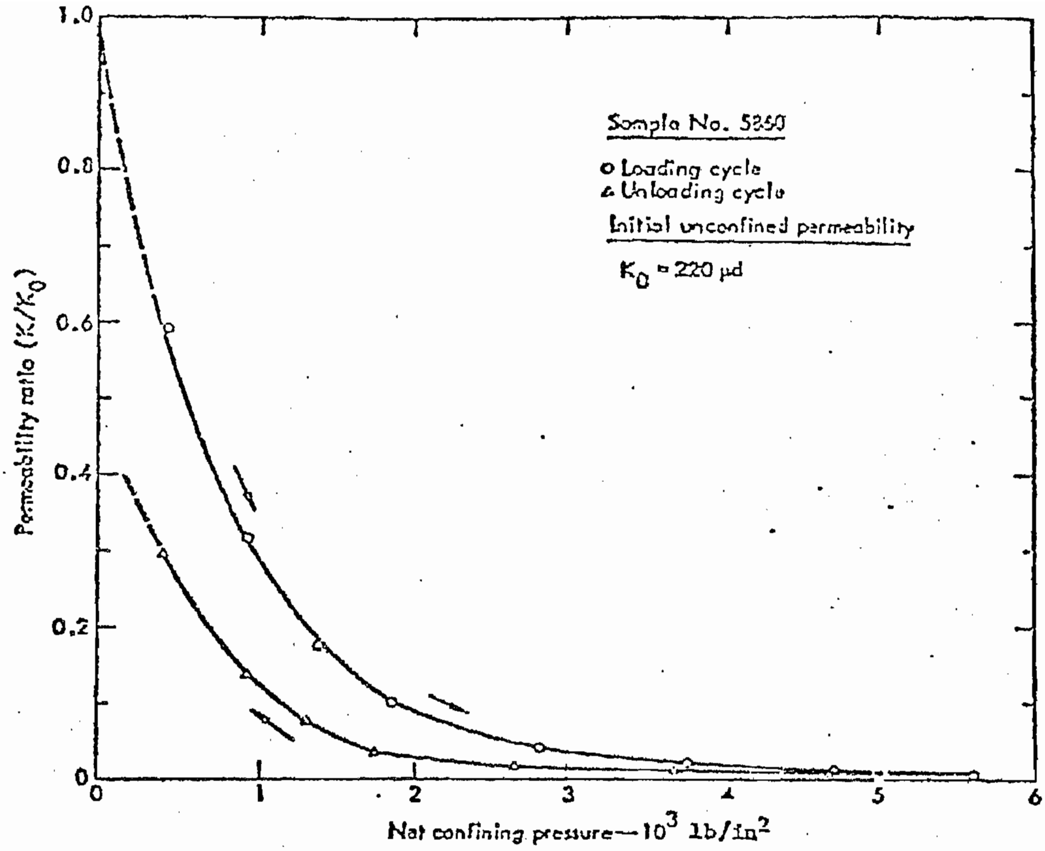


Fig. 3. Effect of confining pressure on the permeability of Fort Union formation sandstone sample at 46.4% water saturation.

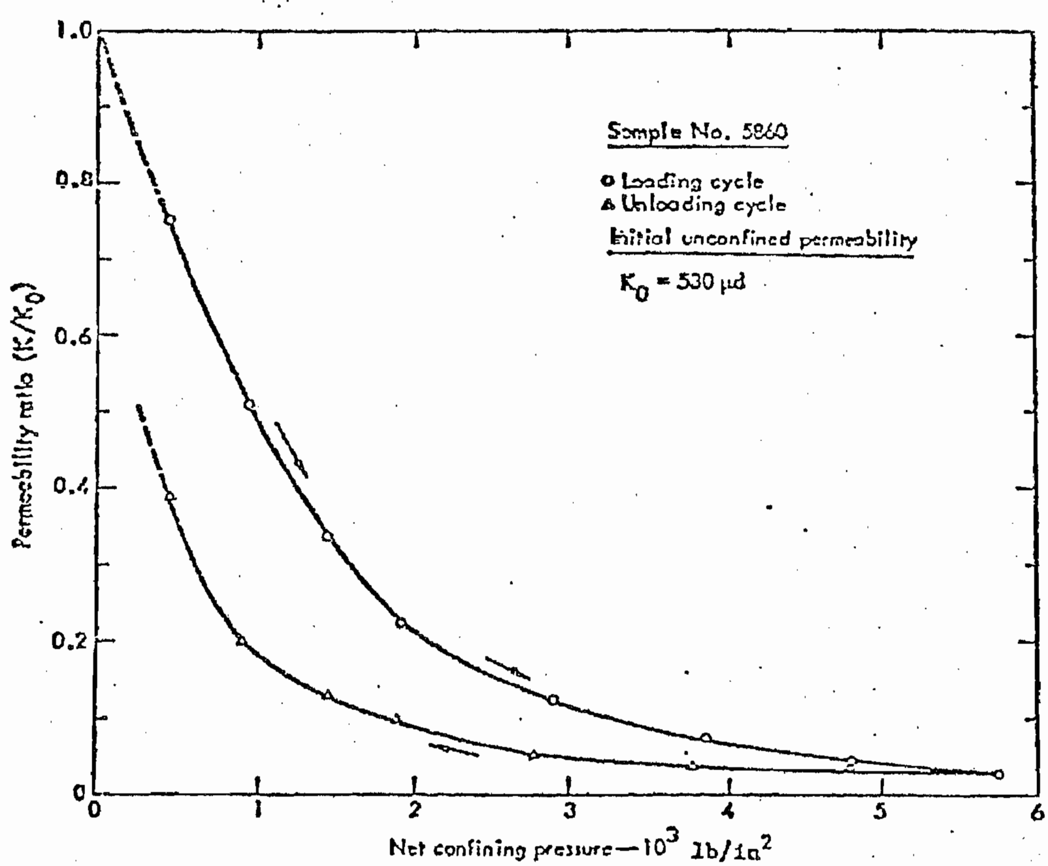


Fig. 4. Effect of confining pressure on the permeability of Fort Union formation sandstone sample at 4.1% water saturation.

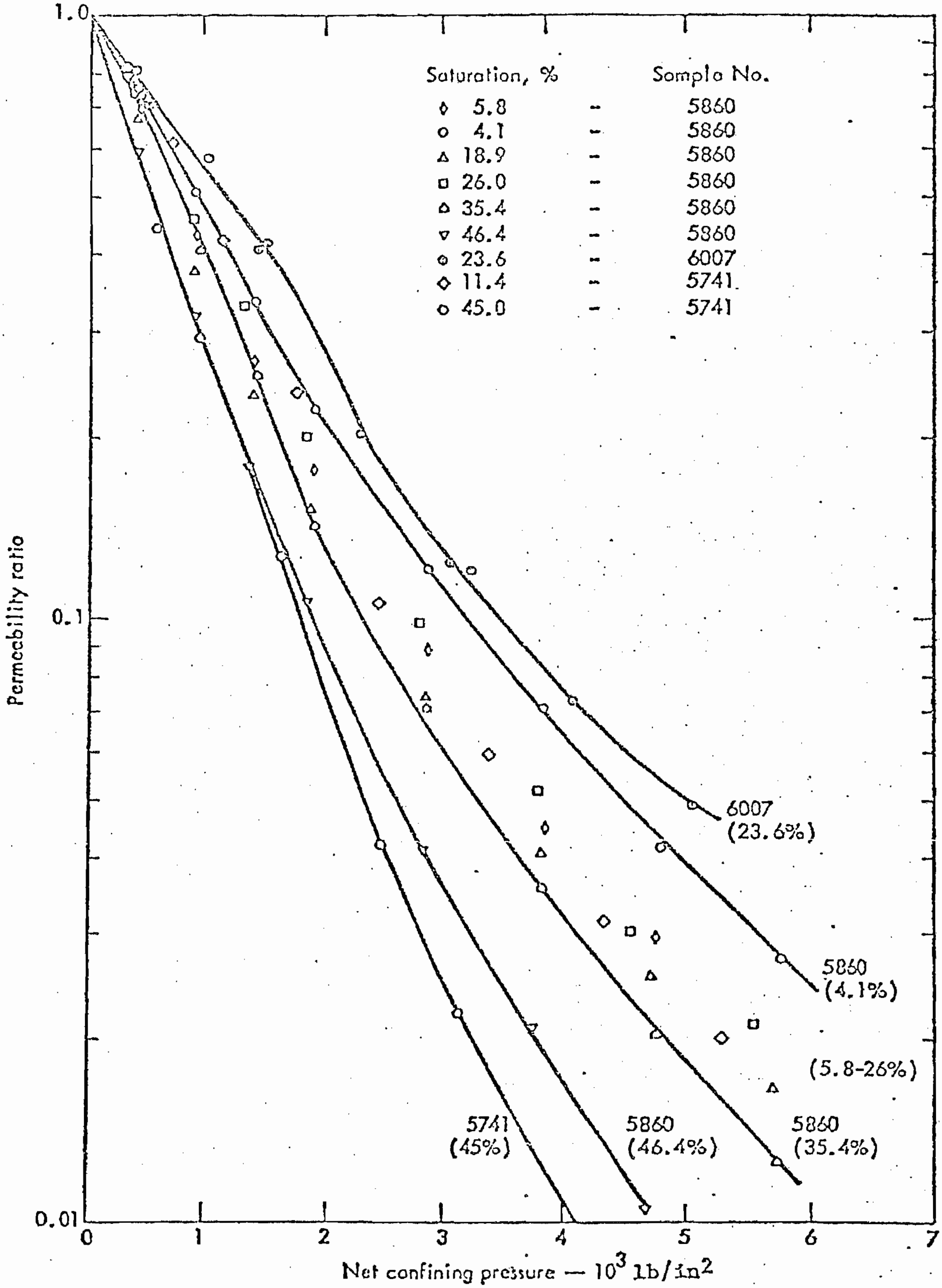


Fig. 5. Effect of confining pressure on the permeability of Fort Union formation sandstone samples at various levels of water saturation.

Table 1. 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	81	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

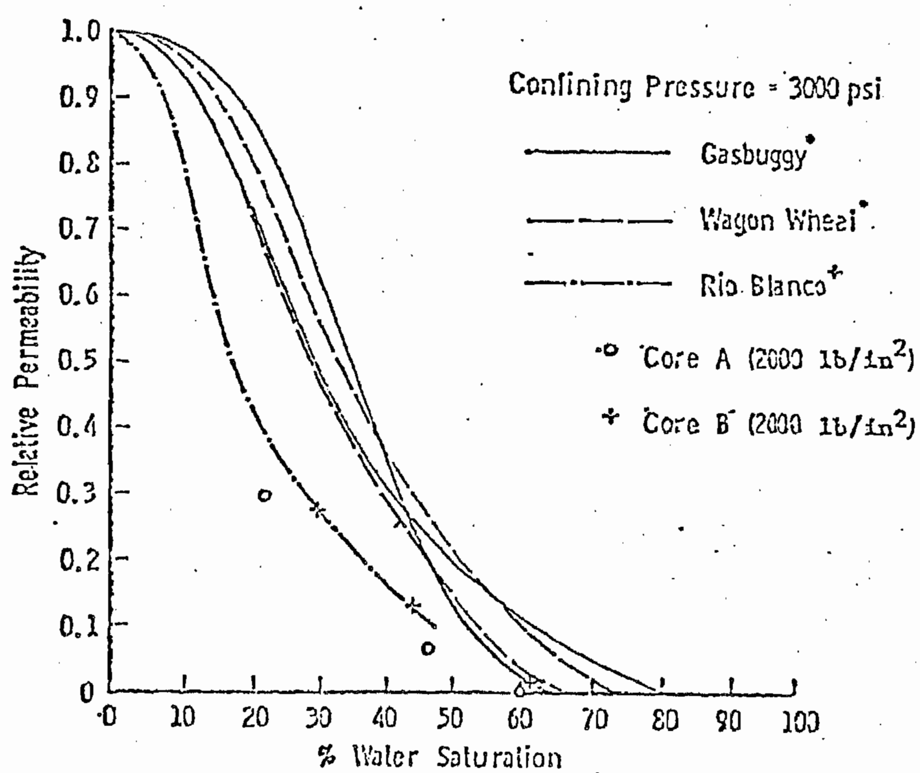


Figure 6. Permeability as a function of water saturation.

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 (5, 6). 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 true shaly rocks would be below this limit.

Water saturation

As shown in figures 5 and 6, and in table 1, 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 5 and table 1; (2) Gasbuggy site, San Juan Basin, in figure 6; and (3) Wagon Wheel site, Green River Basin, in figure 6. Similar data are lacking for the Uinta Basin.

In table 1, 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 1, 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 6, the reduction at 50 percent water saturation is a factor of 0.18 (5). 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 (7, App. E).

The combined effect of net confining pressure and water saturation for core samples from the Rio Blanco site, as shown in figures 1, 5, and 6, 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 1). 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 (7, 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 (8). 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 sand are 26 percent of the gross section interval (10).

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 (11) 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 (7,600/3,200/40 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.

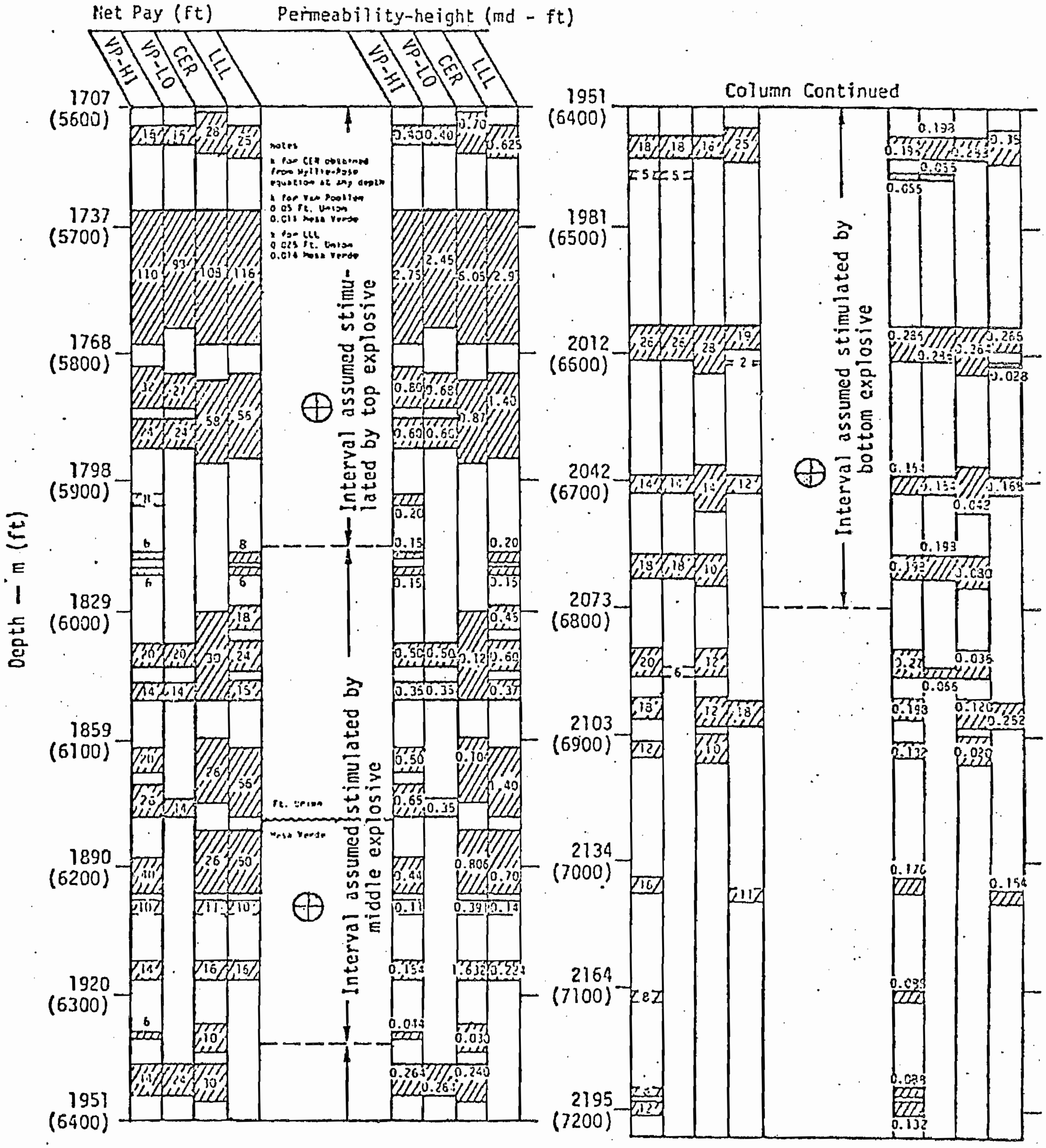
Based on recent studies (11), in a sequence of channel-fill sandstones in the Piceance Creek Basin, an average conventional well will be connected to about 18 percent of the in-place reservoir volume in a 320-acre area, including herein allowance for erosional contact or interflow connection between 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.

Figure 7

Spatial Variation of Net Pay and Permeability Height

(In m with ft in parenthesis)



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 (8, 9). 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 7, together with the reservoir intervals expected to be in communication with each of the three nuclear explosive cavity/chimney regions (9). 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 7, 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.1/ 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.2/ 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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1/ 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).

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

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 (9). 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. 7). 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. 7); 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. 7) 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 (8). Based on geophysical log interpretation, at least three sands at 12, 19, and 25 feet thick (fig. 7, 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 (11).

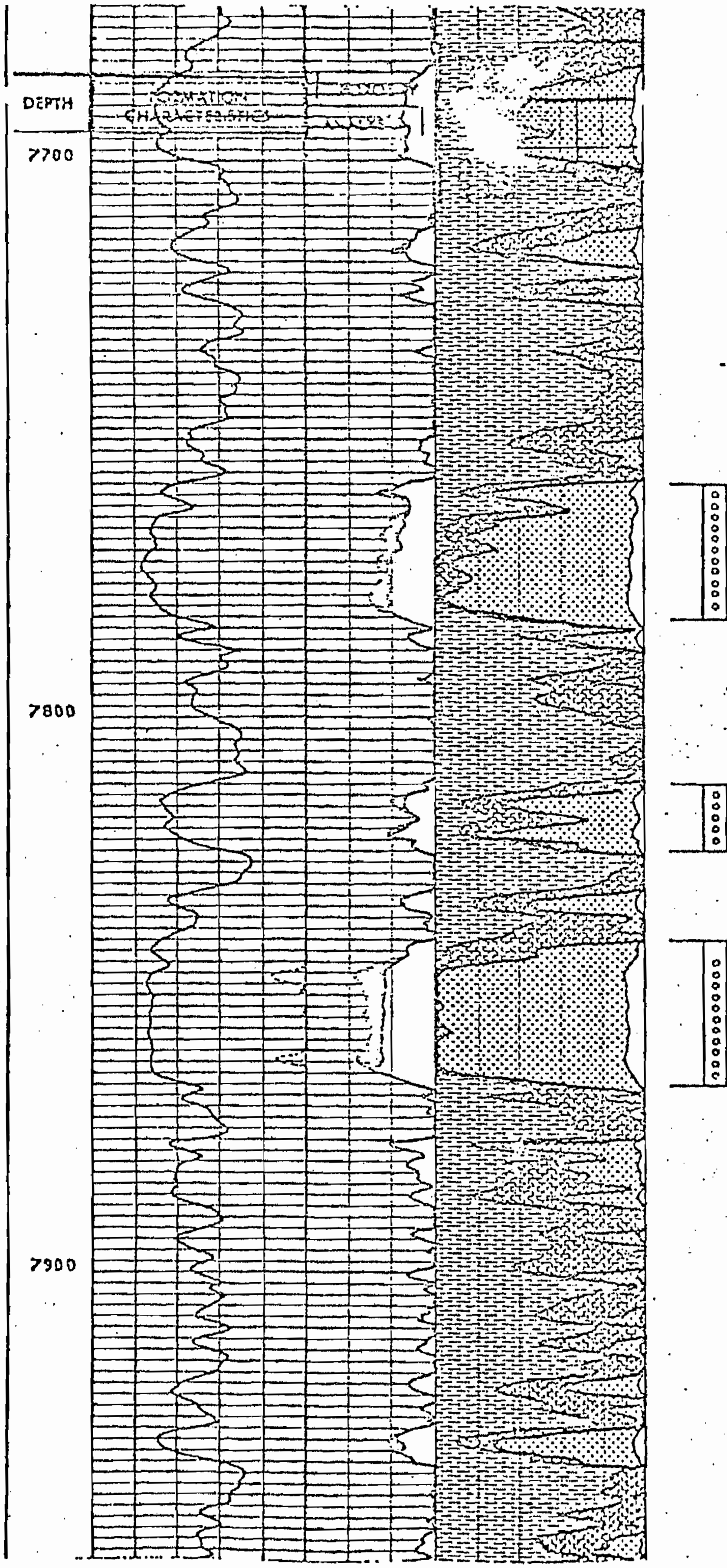
The Rio Blanco Massive Hydraulic Fracturing (MHF) Experiment, a joint Government-industry undertaking started in 1974, is planned to test the relative effectiveness of MHF and nuclear explosion fracturing in the same gas-producing formations; this is in accordance with the identification by the Natural 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 (24).

<u>Fracturing treatment No. 1.</u>--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.

<u>Fracturing treatment No. 2.</u>--Conducted on May 2, 1975, in three separate Mesaverde sands over the depth interval of 7,760-7,864 feet (fig. 7A); 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.

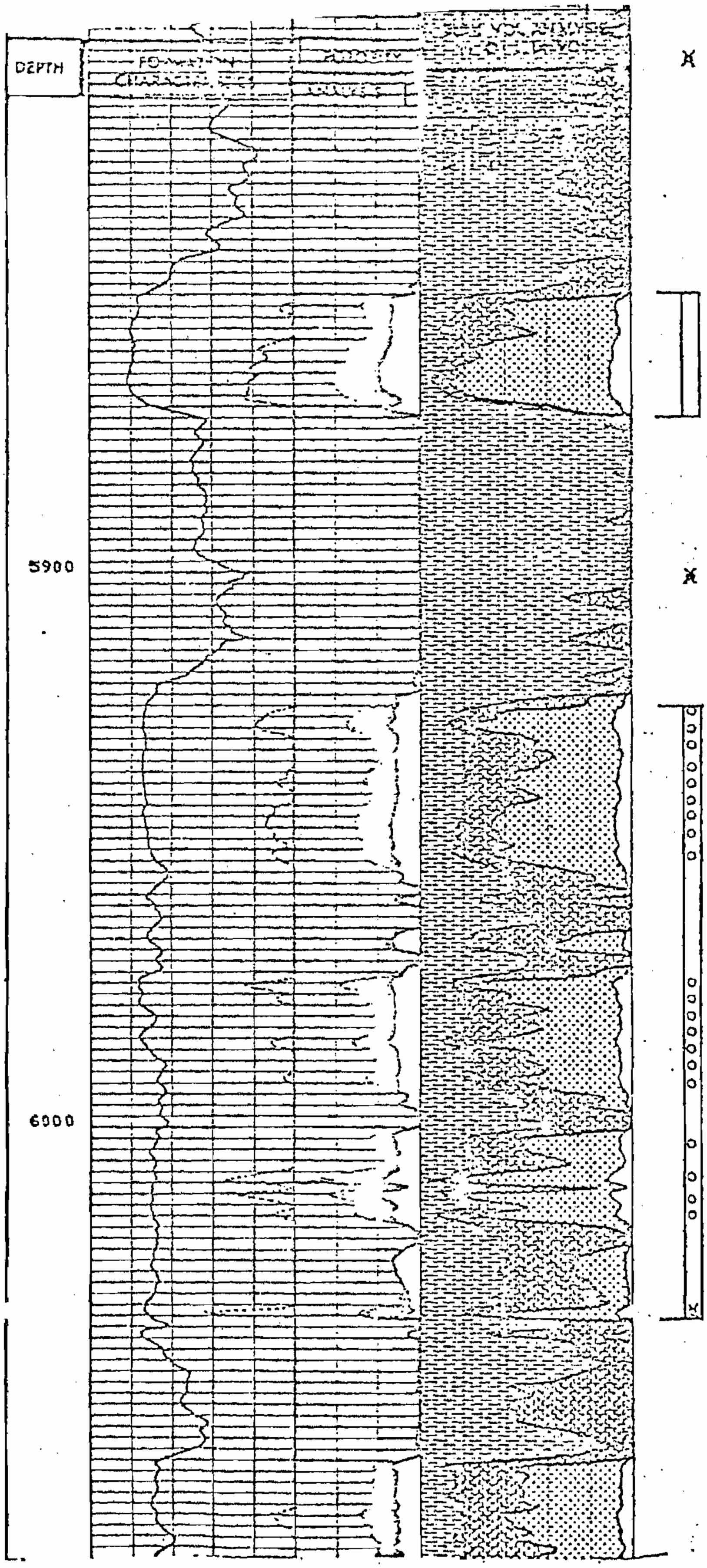
<u>Fracturing treatment No. 3.</u>--Conducted on May 4, 1976, in three separate sands in the middle Fort Union Formation (fig. 7B), corresponding



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

FIGURE 7A

MESA VERDE FORMATION



SQUEEZE 50 sx 4-25-76

PROPOSED FRAC 4
FORT UNION
5850' - 5872'

SQUEEZE 4-24-76, 4-25-76

FRAC 3 5-4-76
FORT UNION
5925' - 6016' (20 PERFORATIONS)

FIGURE 7B
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 (12), 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 (13).

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 2.

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 2

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 X 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 (14). 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 (15).

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 (7) 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 capa[ble] of creating the extensive and large-scale fracture systems needed to produ[ce] 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 (8).

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 (7, App. C, D). More recent advances in the MHF technology have been described in various meetings (16, 17).

Shown in figure 8 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. 3/ It should be noted that early gas flow into a fractured well, as indicated by arrows in figure 8, 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 (18). 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 3. 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 $k_g h$, 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, $k_g h$, tends to be overestimated by a factor of 10 or thereabouts.

3/ 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 3.--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. 9). 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.4/

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. 8), 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.

4/ Provided by Amoco Production Company.

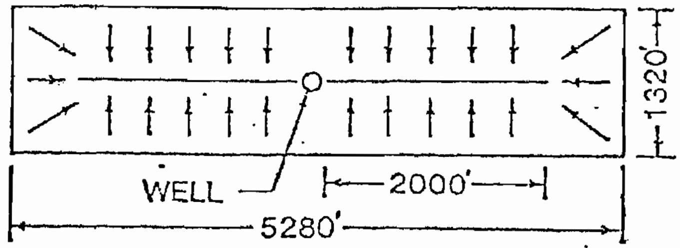


FIGURE 8.-Plan view of 160-acre-unit drainage area showing flow paths (arrows) into a symmetrical, double-winged fracture. Fracture length by definition is measured from the well outward along one wing; as shown, fracture length is 2000 feet (one wing); the total fracture length (two wings) for gas flow calculations would be 4000 feet.

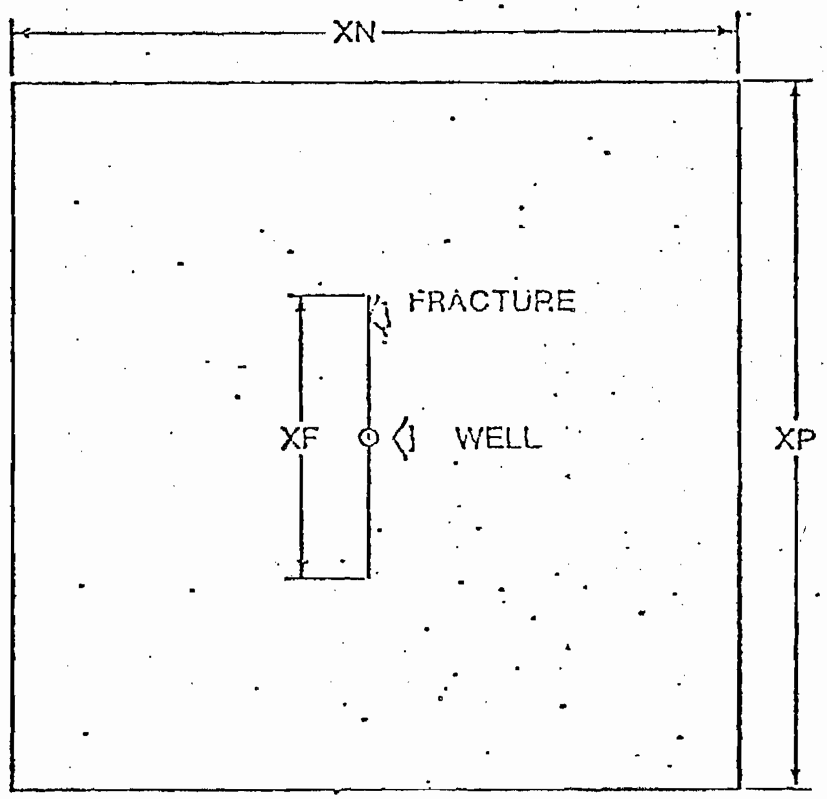


FIGURE 9.--DIAGRAM ILLUSTRATING DEFINITION OF WELL DRAINAGE AREA AND FRACTURE DIMENSIONS EMPLOYED AS INPUT DATA.

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 10--daily production, and in figure 11--cumulative production; and (2) 0.05 md in figure 12--daily production, and in figure 13--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 14, 15, 16, and 17. In figure 14, the production varies almost linearly with gas-filled porosity, but nonlinearly with permeability. In figure 15, production varies almost linearly with pay zone thickness. In figure 16, the production varies exponentially with depth, roughly by the square-root function. In figure 17, 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 18 and 19. 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. 18, 19) 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,

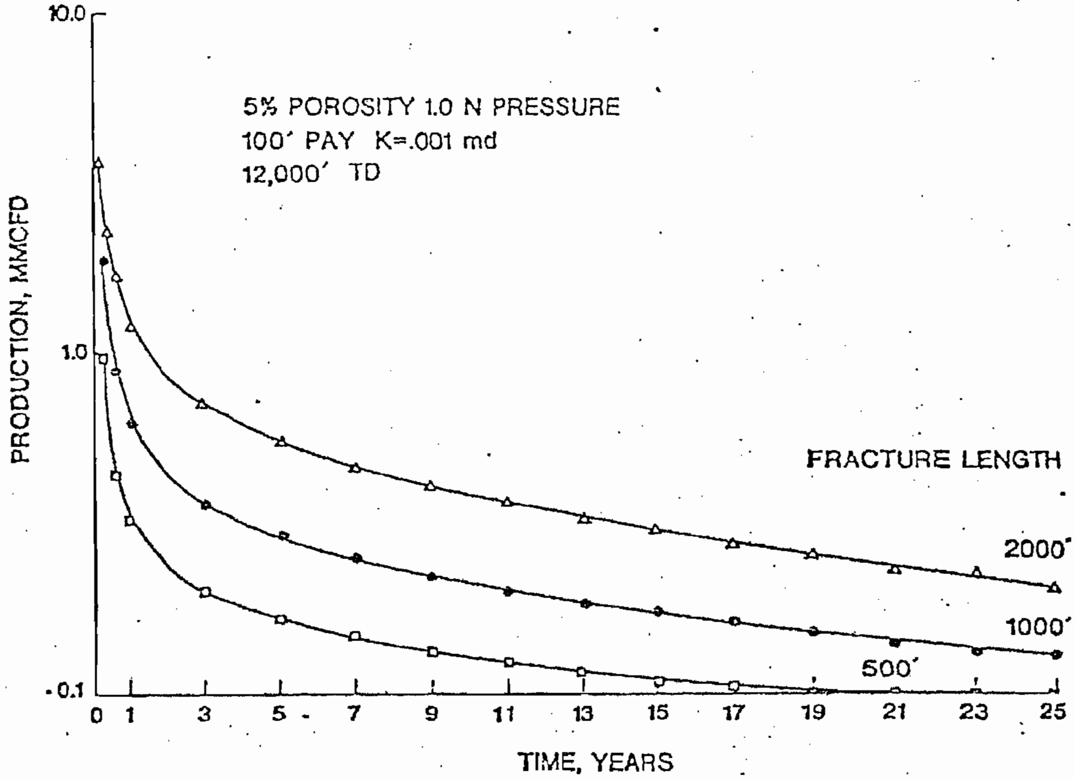


FIGURE 10-EFFECT OF FRACTURE LENGTH ON DAILY PRODUCTION

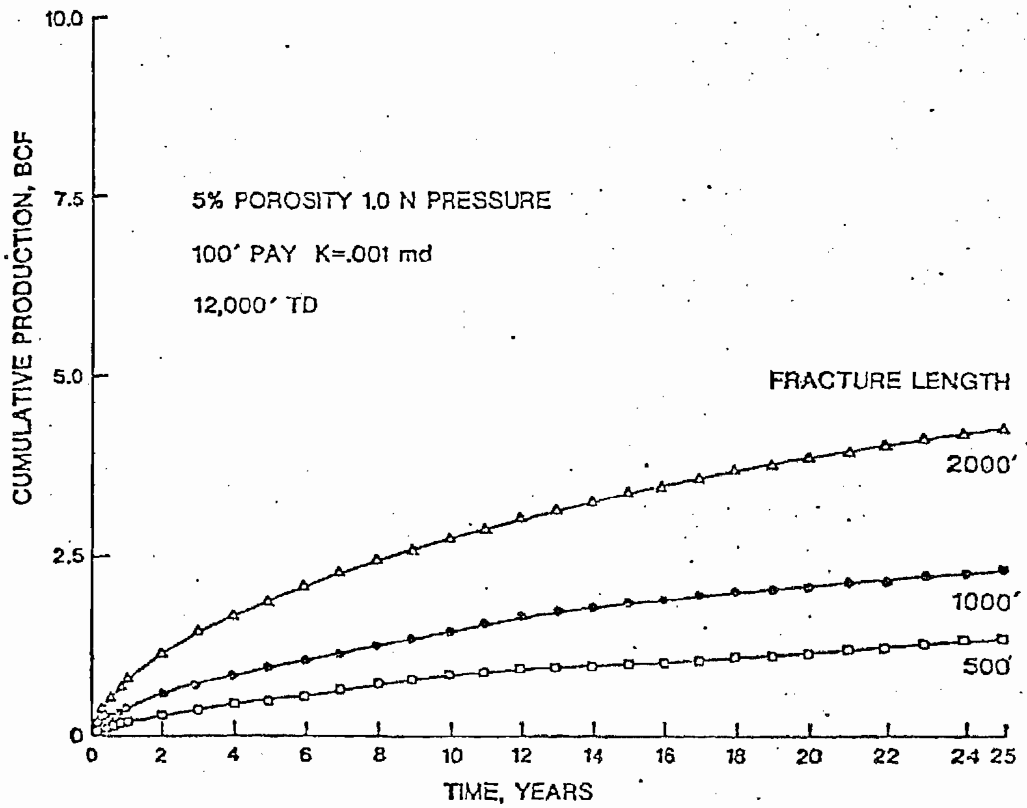


FIGURE 11-EFFECT OF FRACTURE LENGTH ON CUMULATIVE PRODUCTION

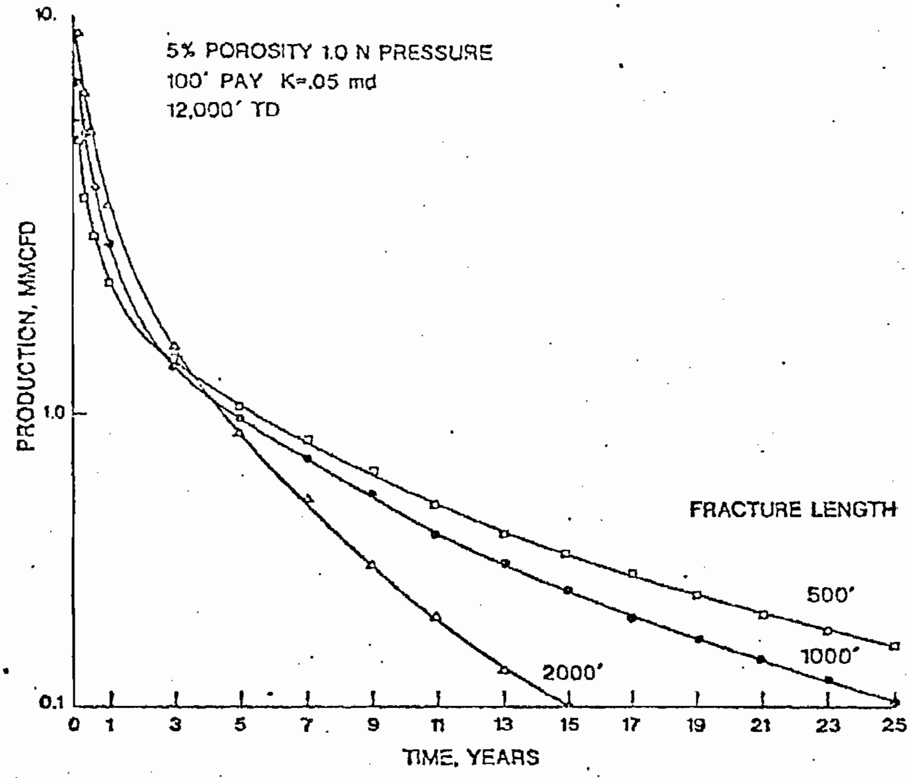


FIGURE 12.-EFFECT OF FRACTURE LENGTH ON DAILY PRODUCTION

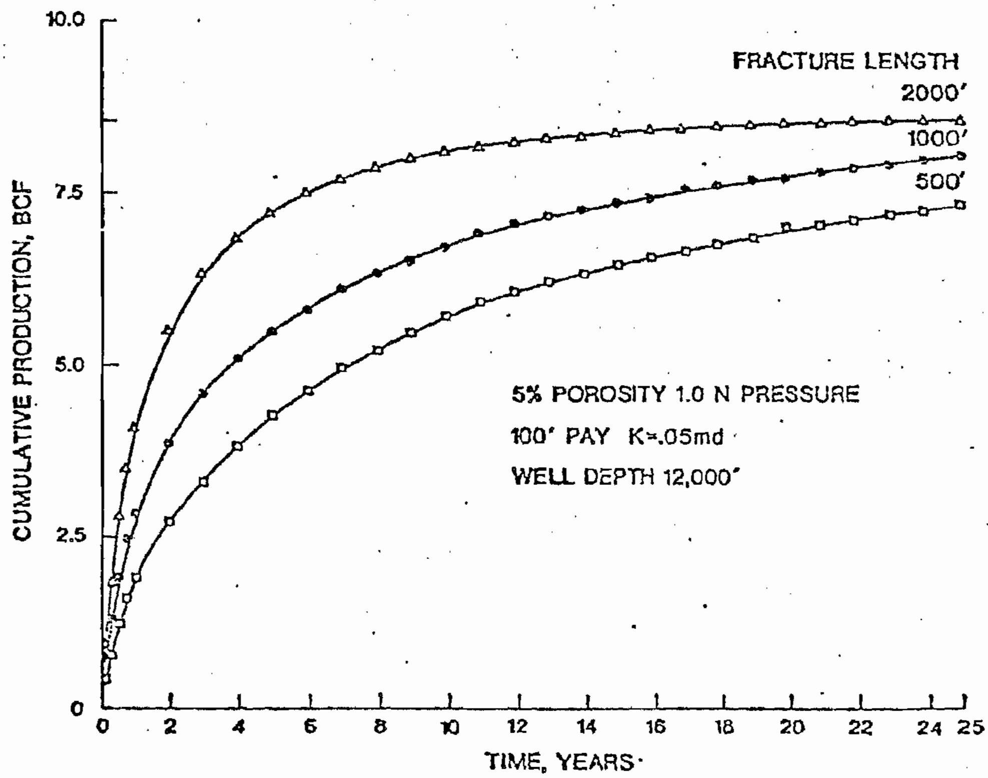


FIGURE 13.-EFFECT OF FRACTURE LENGTH ON CUMULATIVE PRODUCTION

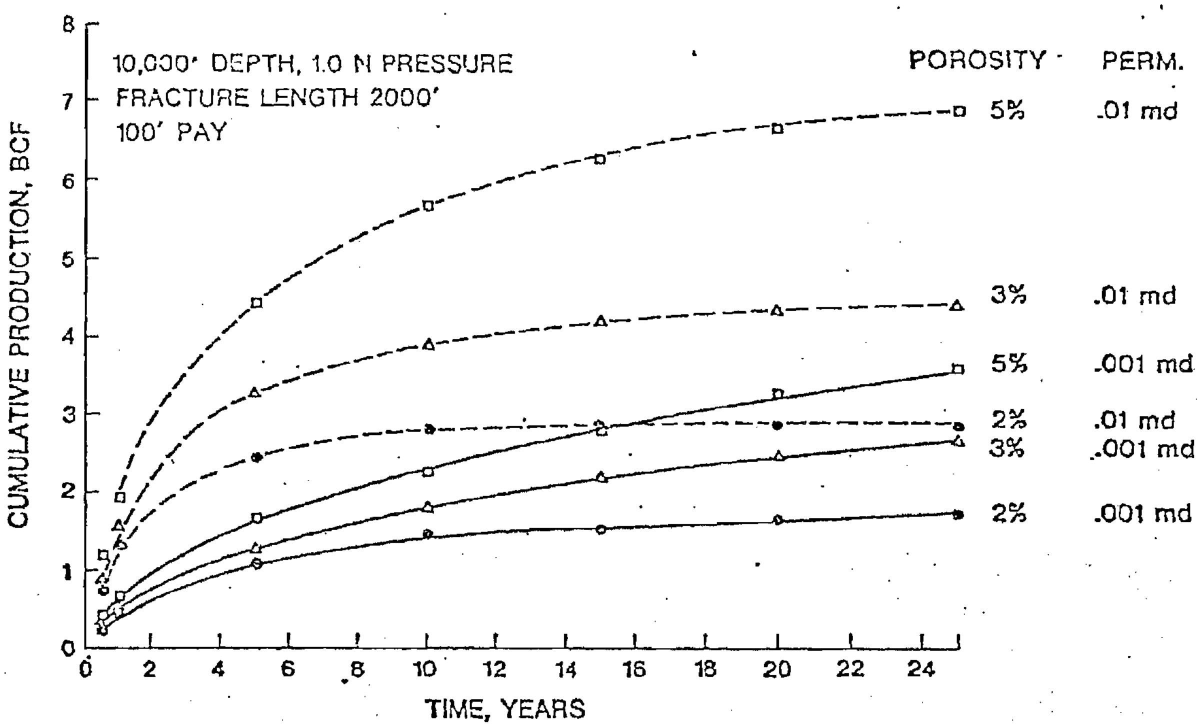


FIGURE 14.-EFFECT OF POROSITY AND PERMEABILITY ON CUMULATIVE PRODUCTION

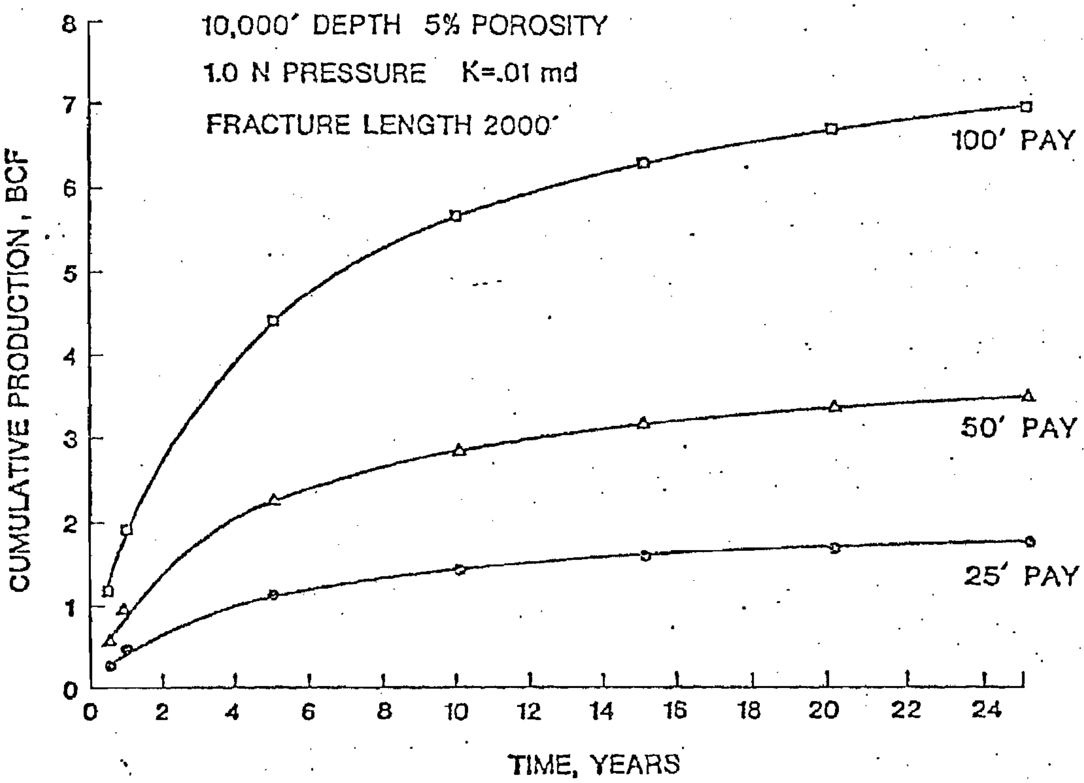


FIGURE 15.-EFFECT OF PAY THICKNESS ON CUMULATIVE PRODUCTION

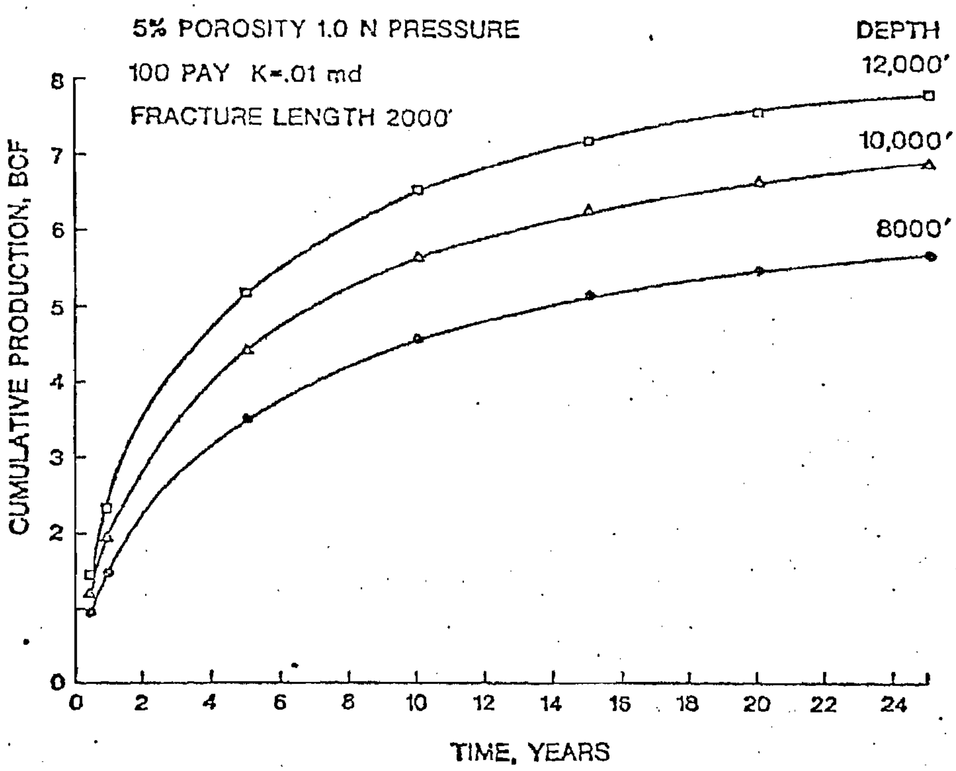


FIGURE 16.-EFFECT OF DEPTH OF PAY ZONE ON CUMULATIVE PRODUCTION

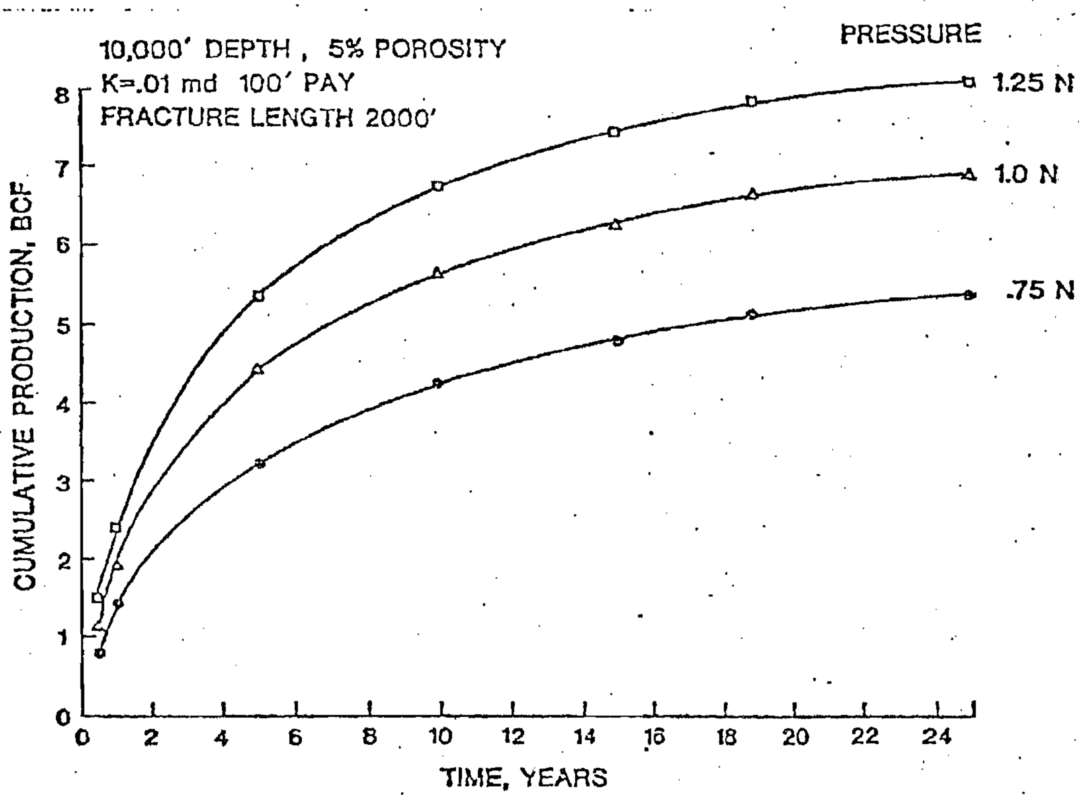


FIGURE 17.-EFFECT OF PRESSURE ON CUMULATIVE PRODUCTION

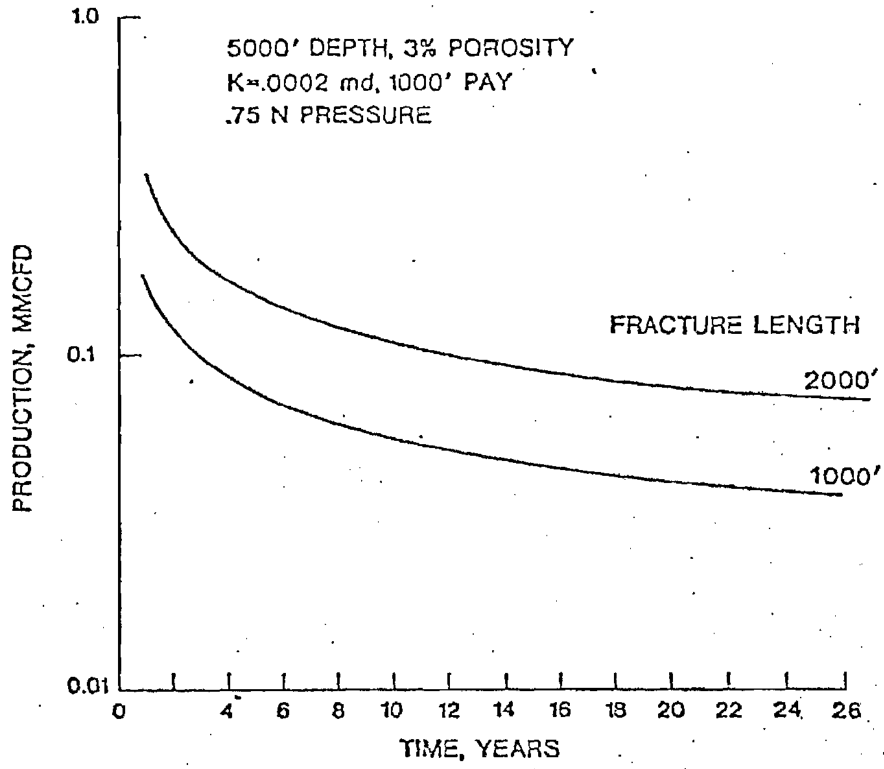


FIGURE 18.-EFFECT OF FRACTURE LENGTH ON DAILY PRODUCTION

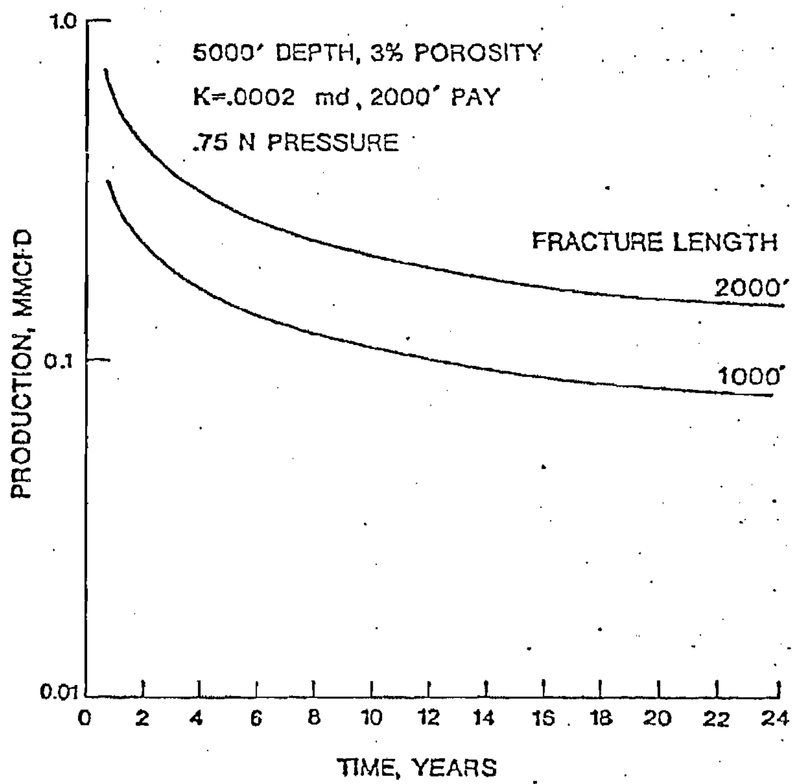


FIGURE 19.-EFFECT OF FRACTURE LENGTH ON DAILY PRODUCTION

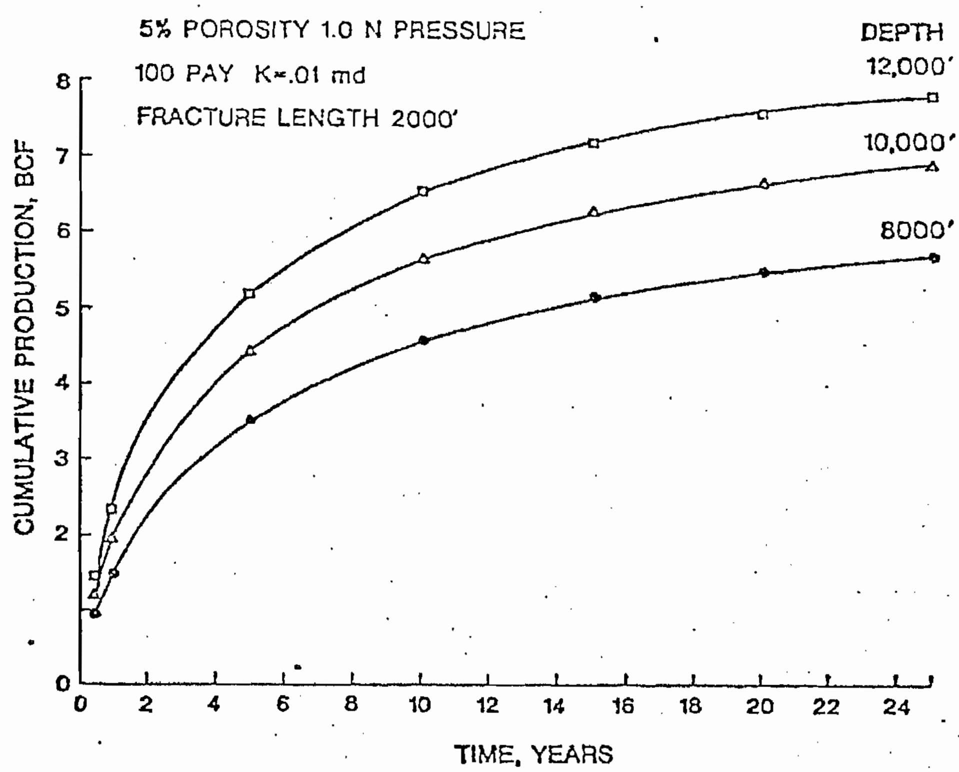


FIGURE 16.-EFFECT OF DEPTH OF PAY ZONE ON CUMULATIVE PRODUCTION

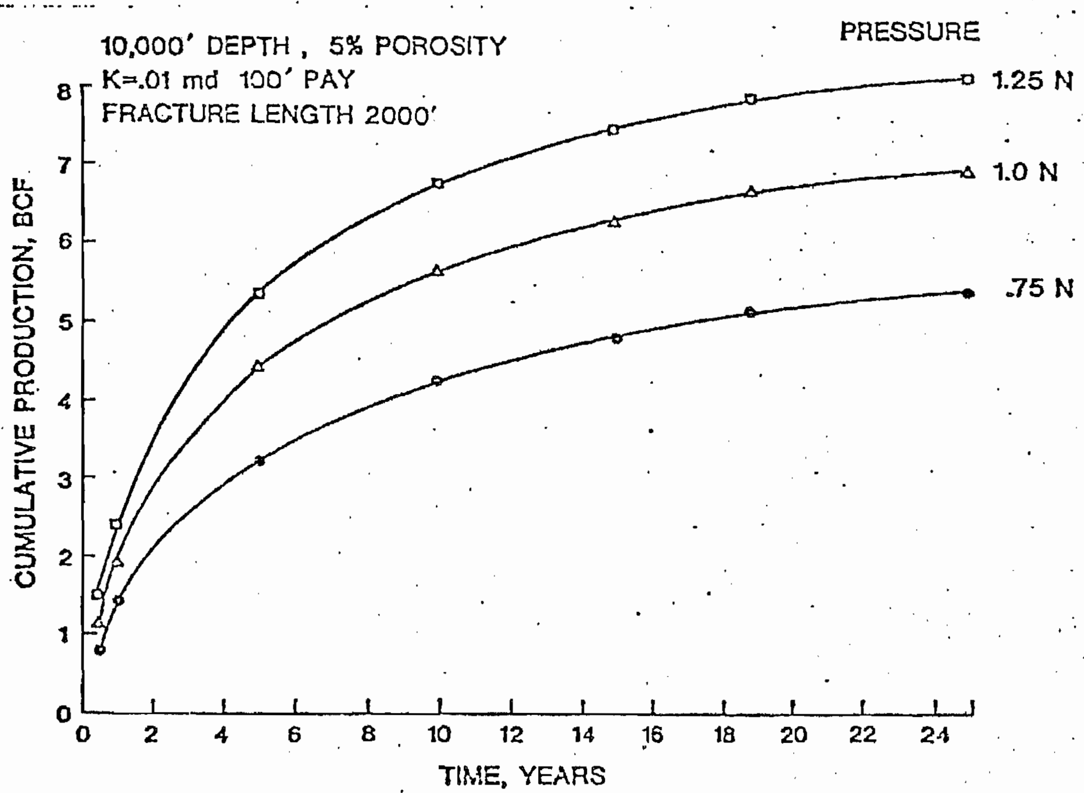


FIGURE 17.-EFFECT OF PRESSURE ON CUMULATIVE PRODUCTION

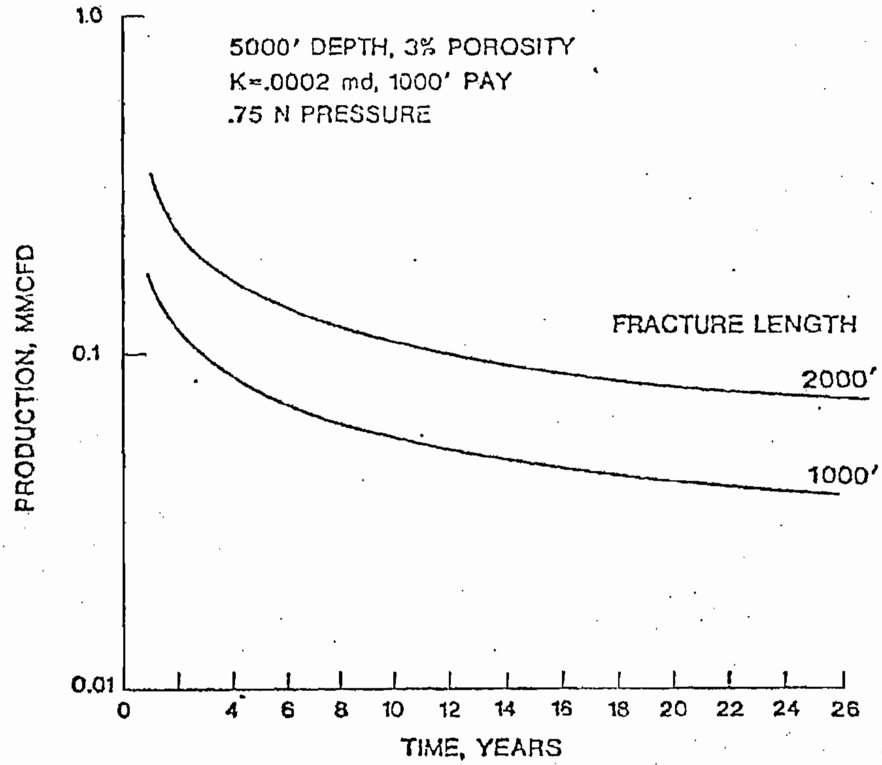


FIGURE 18.-EFFECT OF FRACTURE LENGTH ON DAILY PRODUCTION

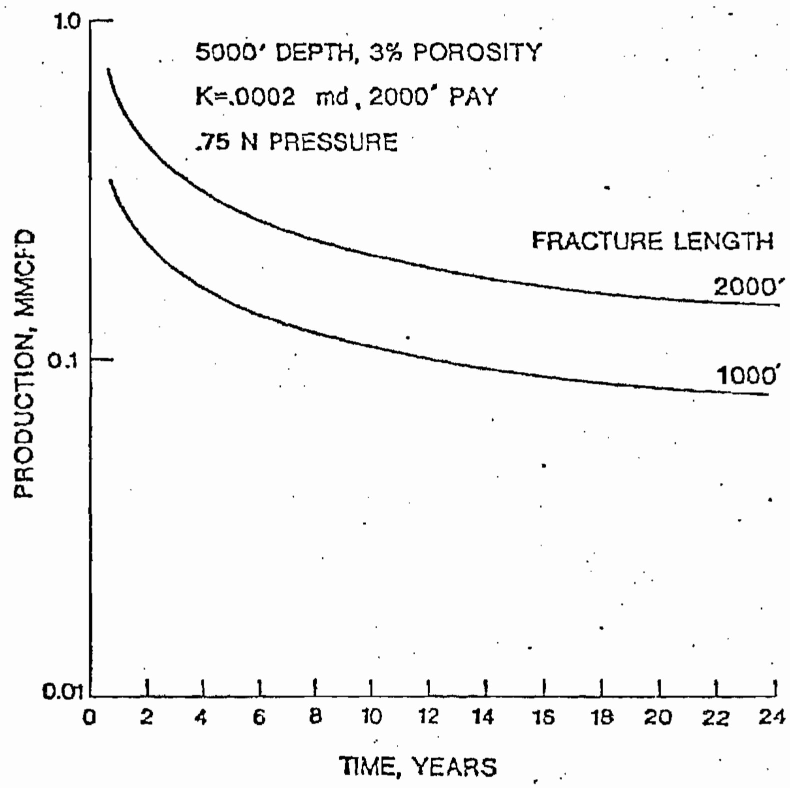


FIGURE 19.-EFFECT OF FRACTURE LENGTH ON DAILY PRODUCTION

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 20 for various in situ permeability and pay thickness, in figure 21 for various pressure and pay thickness, in figure 22 for various gas-filled porosity and pay thickness, and in figure 23 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 20, 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 21, 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 22, 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 23, 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.

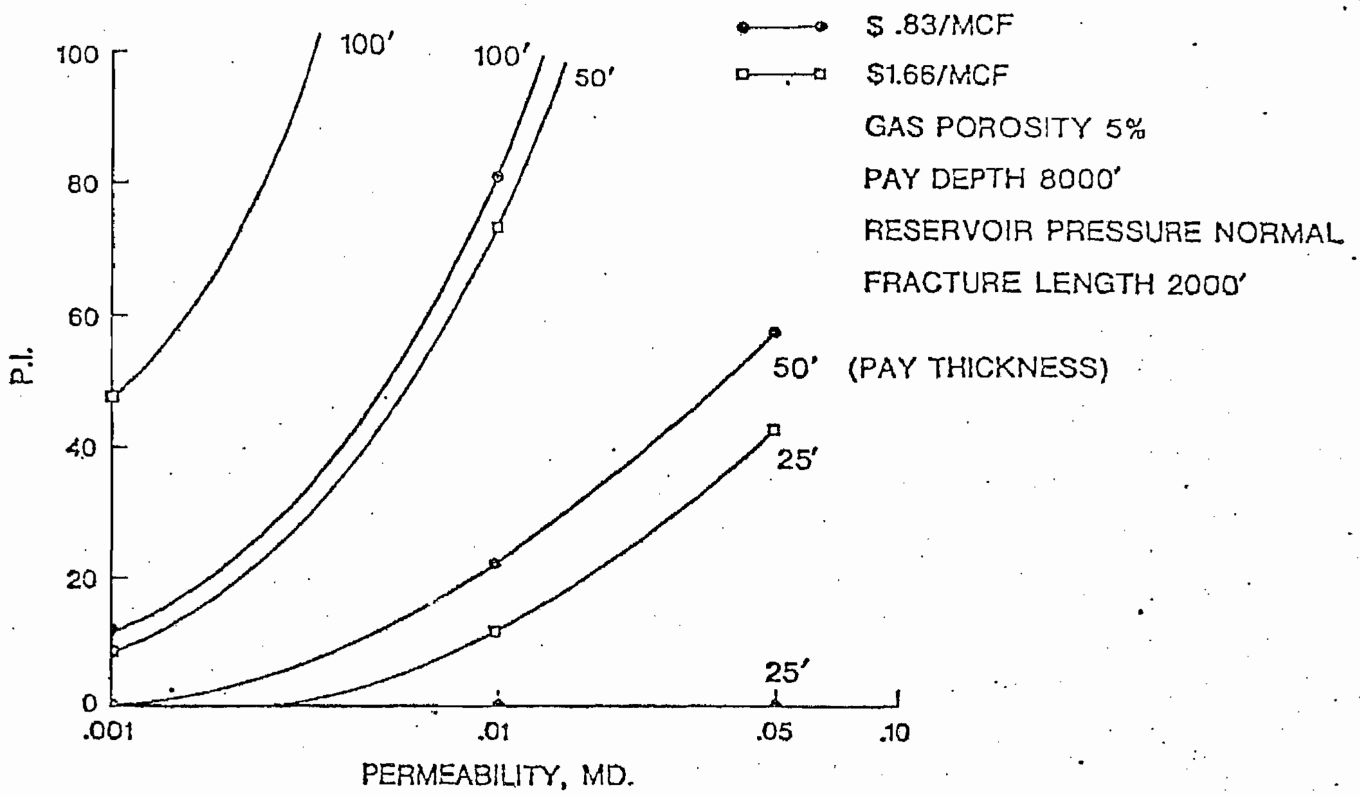


FIGURE 20.-EFFECT OF RESERVOIR PARAMETERS ON ECONOMICS

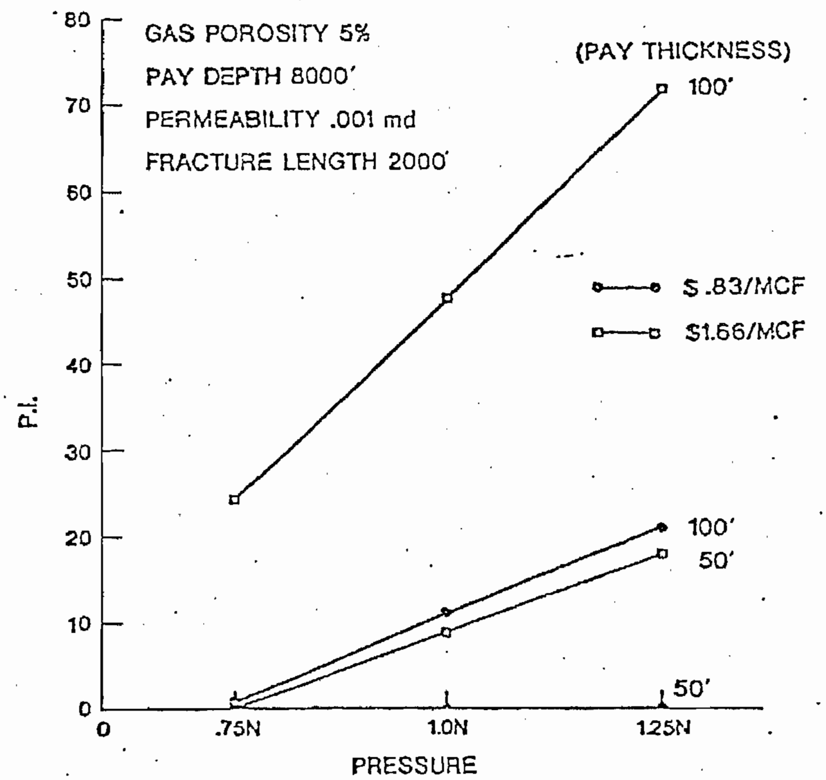


FIGURE 21.-EFFECT OF RESERVOIR PARAMETERS ON ECONOMICS

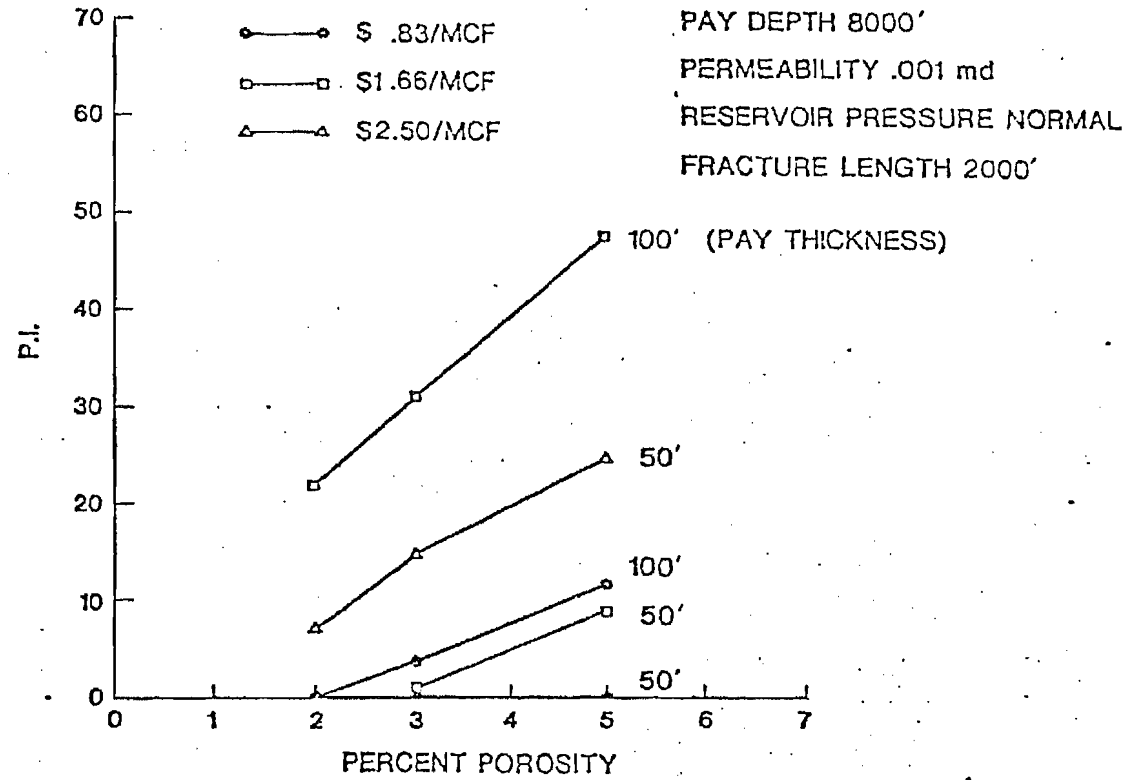


FIGURE 22.-EFFECT OF RESERVOIR PARAMETERS ON ECONOMICS

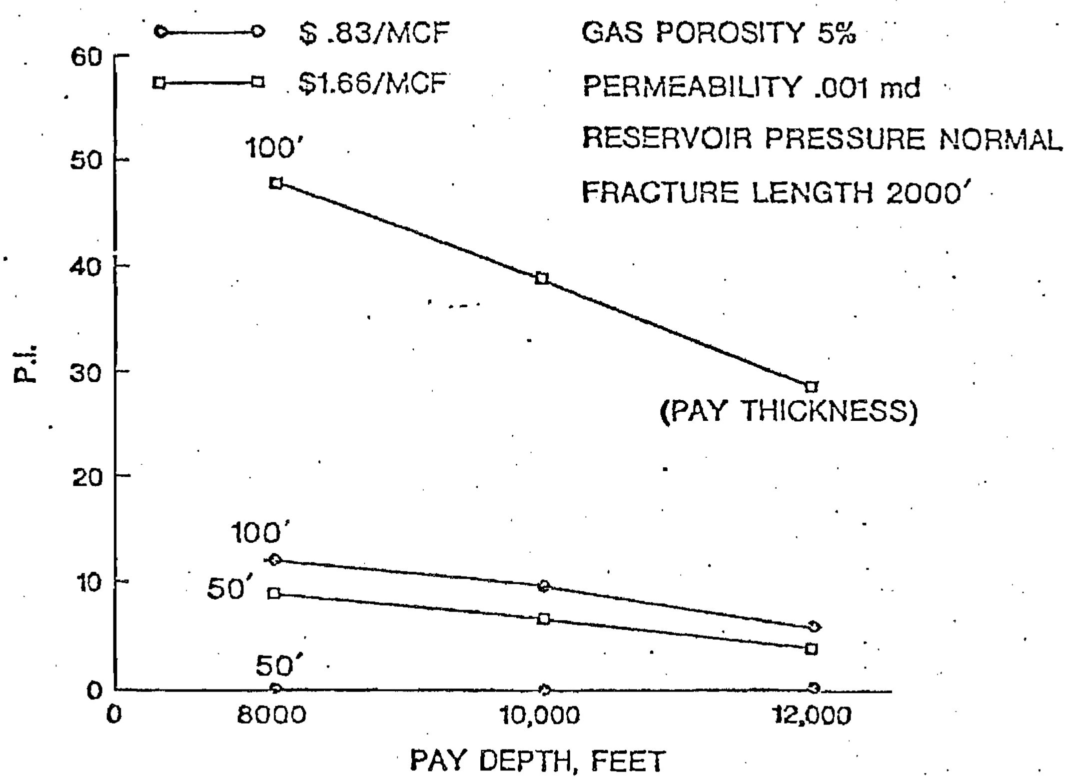


FIGURE 23.-EFFECT OF RESERVOIR PARAMETERS ON ECONOMICS

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 24 and 25 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 25 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 abvious that a 400-foot uniform pay zone with a 2,000-foot MHF treatment will produce gas at a slow rate (fig. 18) and at a high cost.

As shown in table 4, 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.

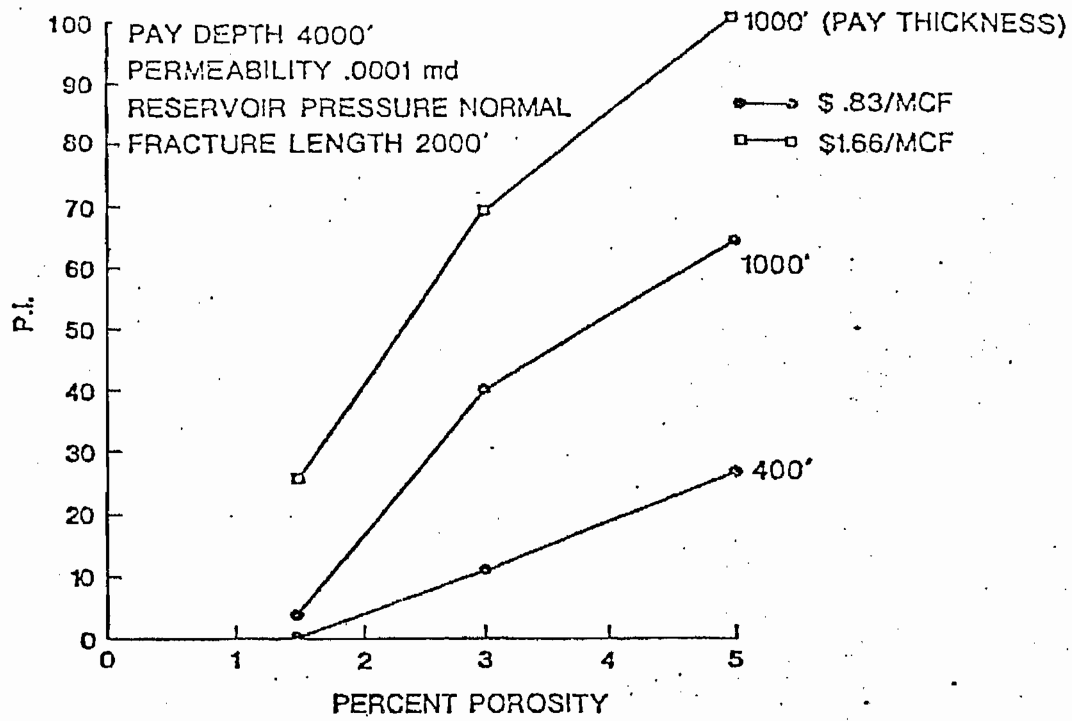


FIGURE 24.-EFFECT OF RESERVOIR PARAMETERS ON ECONOMICS

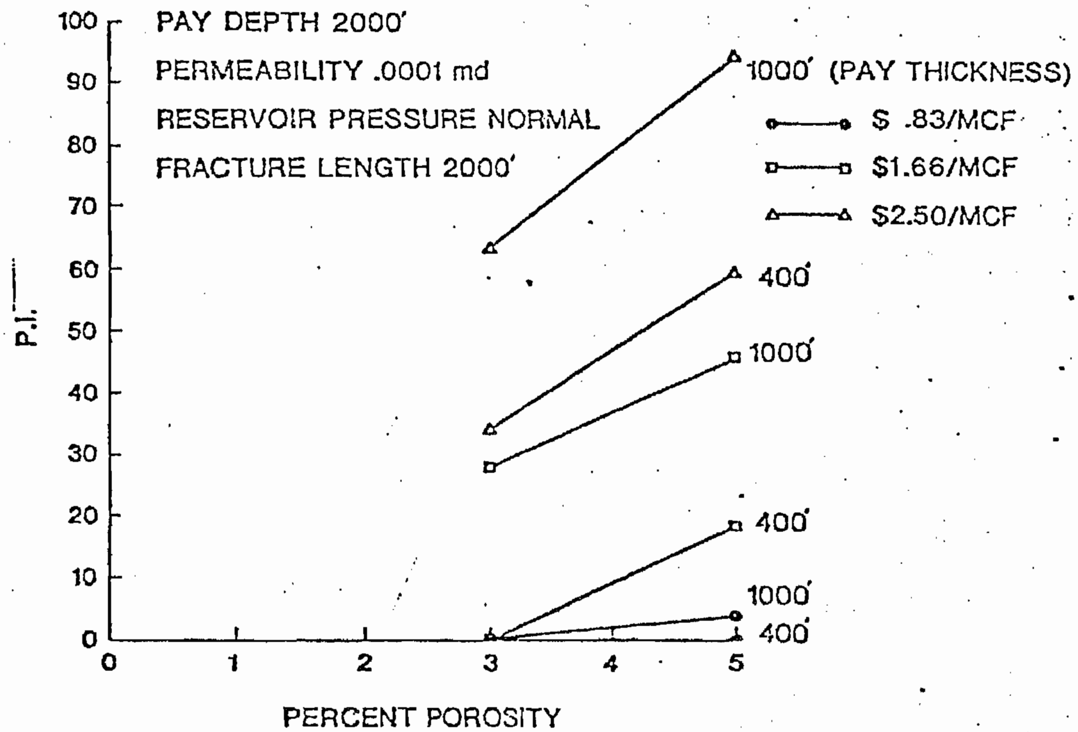


FIGURE 25. -EFFECT OF RESERVOIR PARAMETERS ON ECONOMICS

TABLE 4.--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. (2)	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 (7), 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 or infer 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 (19), 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 3, 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 attempt 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 (7), and are shown in detail in table 5 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" (7, App. E), because the reservoir flow capacity, $k_g h$, 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 (7, 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 5 • 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 2/	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 1/														
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	6,750 - 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)														
Fort Union	North	50	some characteristics as category 1								IVC + IVD	100	148.3	14.9
Mesaverde I	half	250									IA	50	239.6	12.0
Mesaverde II	of	150									IB	100	192.3	19.2
Mesaverde III	basin	250												
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	33.4
			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

1/ 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.

2/ 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(25) 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 3to 4 billion cubic feet per square mile.

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 (17). 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. 26) 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 26

Also indicated by the data in figure 26 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 (23) 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 (23, fig. 4); 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 (18), the pre-MHF in situ permeability would be 0.2 μd, within the range of physical properties shown in table 3.

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 (17, 20, 21, 22) at 285 trillion cubic feet for the Appalachian Basin (table 6) are accepted as the best fit with our present knowledge. Shown in table 6 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 6.--Reservoir characteristics and resources-Devonian Shales

	Appalachian Basin[1]	Well 20403 W. Va.[2]	Ohio, W. Va., Ky., and Ind.[3]	Appalachian Basin[4]
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	[5]491
Porosity(%)	2	---	---	---
Gas-filled porosity(%)	1.8	1.1	1-4	[5]1.3
Water saturation(%)	10	---	---	---
BHP(lb/in^2a)	400	800	---	---
BHT(°F)	---	112	---	---
Permeability, gas-k_g(μd)	---	[6]0.2-0.5	---	---
Flow capacity-k_gh(md-ft)	---	[6]0.4-1.0	---	---
Gas in place, SCF/ft^3	0.47	0.6	1.4-5.0	[5]0.35
Gas in place, $SCF X 10^9/mi^2$	2.6-5.2	3.38	40-140	0.9
Gas in place, trillion ft^3	285	---	---	149

[1] Estimates by ERDA (Reference: 17, 20, 21, 22).

[2] Data from MHF treatment, Well 20403, Lincoln Co., W. Va. (23).

[3] Data from figure 26.

[4] Data from Department of Interior News Release, Geological Survey, March 31, 1976.

[5] Based on gas production and other data from Big Sandy gas field, Kentucky.

[6] 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 (7) and can be modified to fit the changing reservoir conditions. Some data have been provided on the effect of reservoir parameters on economics (figures 20 through 25), which should permit an approximation of wellhead costs given the necessary reservoir properties. It should be noted that the Pinedale Unit MHF Experiments (12, 13) 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 (7), 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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