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A FEASIBILITY STUDY OF METHANE PRODUCTION FROM ROCKY MOUNTAIN COAL SEAMS USING "OIL-FIELD" TECHNIQUES

by

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ABSTRACT

This thesis determines that the degasification of the western coal seam models reviewed here are not economically feasible with the expected price of $1.50/MCF and the projected costs to drill and complete. With recent technological breakthroughs in well stimulation and the increased process for natural gas, coal demethanization is on the verge of economic viability.

The evaluation of the technology will include identifying, obtaining, and using the critical reservoir parameters in coalbeds to calculate gas reserves and design stimulation treatments. A review of the experience of other operators in drilling, completing, and producing coal seam reservoirs, mostly from the eastern United States, will be used in choosing the methods to be applied in the western coalbed models. The two economic models - a well with a single, 20-foot, sub-bituminous coal seam at 2200 feet and a well with three 20-foot, sub-bituminous coal seams at depths down to 3300 feet - are based on proposed projects in two Rocky Mountain basins.

Although the "most likely" initial average annual rate of 30 MCFPD is not economic in our models, recent unpublished data indicate this empirical rate is conservative. Sensitivity analysis shows that profitability is decreasingly dependent on the initial rate (a function of gas content, desorption rate, permeability, and fracture effectiveness) and the drilling and completion costs. Price becomes more

sensitive at higher production rates.

The depth of the coal seam, the operating costs, and the effective decline are increasingly less sensitive variables of profitability.

If the major legal consideration of gas ownership is resolved, methane-rich coal seams could be an additional source of an increasingly scarce natural resource.

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ACKNOWLEDGMENTS

Most of the work presented in this thesis was researched in preparation of a proposal to the Department of Energy on cost-sharing a Rocky Mountain coal degasification program. I would like to thank Kansas-Nebraska Natural Gas Company, Inc. for sponsoring this work and especially the staff of the gas exploration group in Lakewood, Colorado. I would also like to thank the members of both the mining and oil industries, and the government agencies, who filled the gap between published literature and present technology and experience. I am also appreciative of my thesis committee for their help in delivering this "baby."

NOMENCLATURE

A	area perpendicular to flow, cm^2
^oA	Angstrom, 1 $^oA = 10^{-7}$mm
a	radius of coal particle, cm
b	a constant, atm^{-1}
C	gas concentration, cc/g
C_1	gas concentration, g-mole/cm^3
D	diffusivity, cm^2/sec
Dn	nominal decline
De	effective decline, %/yr
K	empirical constant
k	permeability
L	length, cm
n	empirical constant
P	Pressure, atm
Pov	overburden pressure, psig
q	flow rate, cc/sec
q_1	first annual production, MMCF/yr
q_2	second annual production, MMCF/yr
T	time, years
t	time, sec
V	volume adsorbed at standard conditions, cm^3/g
Vad	volume of adsorbed gas, ft^3/ton

NOMENCLATURE (CONT)

Vj	constant, ft^3
Vm	the monolayer volume, cm^3/g
μg	gas viscosity, cp

WHY METHANE FROM COAL?

To the general public, the frequency and severity of coal mine disasters are the most noticeable effect of methane accumulating and exploding in coal mines. To the mining company, the emission of methane from coalbeds means an increase in ventilation costs, curtailed production, and a hazard to mine safety. To natural gas producers, methane-rich coal seams could be an additional source of an increasingly scarce natural resource.

With the increase in natural gas price, the once-dangerous wasted mine gas could become an economic supply of methane. The U.S. coal companies vent more than 200 million cubic feet (MMCF) of methane per day (Irani et. al., 1973) in operating their underground coal mines. The average daily use (1976) of natural gas in the U.S. is 53.5 billion cubic feet (BCF) (Amer. Pet. Inst., 1977). Based on Averitt's (1974) coal resource estimates and the calculated or postulated gas content of coal per ton, there are 300 trillion cubic feet (TCF) of natural gas alone in the 1.7 trillion tons of remaining identified coal resources with less than 3000 feet of overburden (strippable coal excluded).

The desires and priorities of the mining company, the natural gas producer, and the government are not always the same. The coal mining company wants to make money mining coal by: a) increasing coal production which, unfortunately, proportionally increases the amount of methane produced and b) reducing costs, including ventilation costs.

The methane's economic value is roughly 2% of the coal's economic value (Shupe, 1977). The natural gas producer wants a prospect with large reserves and high deliverability of a good quality gas. Although the in-place reserves are large and the coal gas is of pipeline quality, the actual recoverable reserves and the deliverability may not be economic for some coal seams. In the best interest of energy conservation, all three should utilize natural resources to their fullest. All three groups have contributed to the research that has been done so far, but due to the marginal economics, the government has been the major contributor.

The resources are tremendous, and with technologial breakthroughs and increasing prices, coal degasification is on the edge of economic viability. The scope of this thesis is to determine if western United States gas producers could drill coal degasification wells and make a reasonable return on their investment. As the most-promising completion technology has been developed in the past five years and the reservoir parameters of coal are not widely known, a comparatively larger technological evaluation than normal for an economics thesis is presented. As coal degasification matures, less discussion of the technology will be needed for feasibility studies.

An evaluation of the technology will include identifying, obtaining, and using the critical reservoir parameters in coalbeds to calculate gas reserves and design stimulation treatments. A review of the experience of other operators in drilling, completing, and producing coal seam reservoirs will be used in choosing the methods to

be applied in our western coalbed models. Our two economic models are used to determine profitability at a 20% discount rate before taxes. The models - a well with a single 20-foot seam at 2200 feet depth and a well with three 20-foot seams at depths down to 3300 feet - are based on actual projects in two Rocky Mountain basins.

Sensitivity analysis is run to determine to which variables the profitability is most responsive.

EVALUATION OF THE TECHNOLOGY

Although methane gas has been an inherent problem with the production of coal, it was not until the advent of high-productivity underground mining methods (i.e. continuous miners and long wall methods) that there was a concerted effort to try and understand methane gas emissions. In 1964 a comprehensive applied research program was initiated by the U.S. Bureau of Mines (Deul, 1964) to better understand and control methane emissions in coal mines.

Laboratory experiments were run on various coal samples to determine sorption and diffusion properties of various coal samples, which are the limiting reservoir parameters in coal seams. Methods for estimating the gas saturation of a coalbed from core samples were developed. Various reservoir parameters such as porosity, permeability, pressure, and temperature relationships were also experimented with in the laboratory. Field studies proved up technology for drilling horizontal as well as vertical holes and stimulating the vertical wells. Production histories were established from some wells and a comprehensive survey of the amount of gas emitted from U.S. coal mines was completed in 1972. The bulk of this work was done on coal in the eastern United States, where a higher percentage of the mines are underground (Young, 1977) and the coal rank is higher (Figure 1).

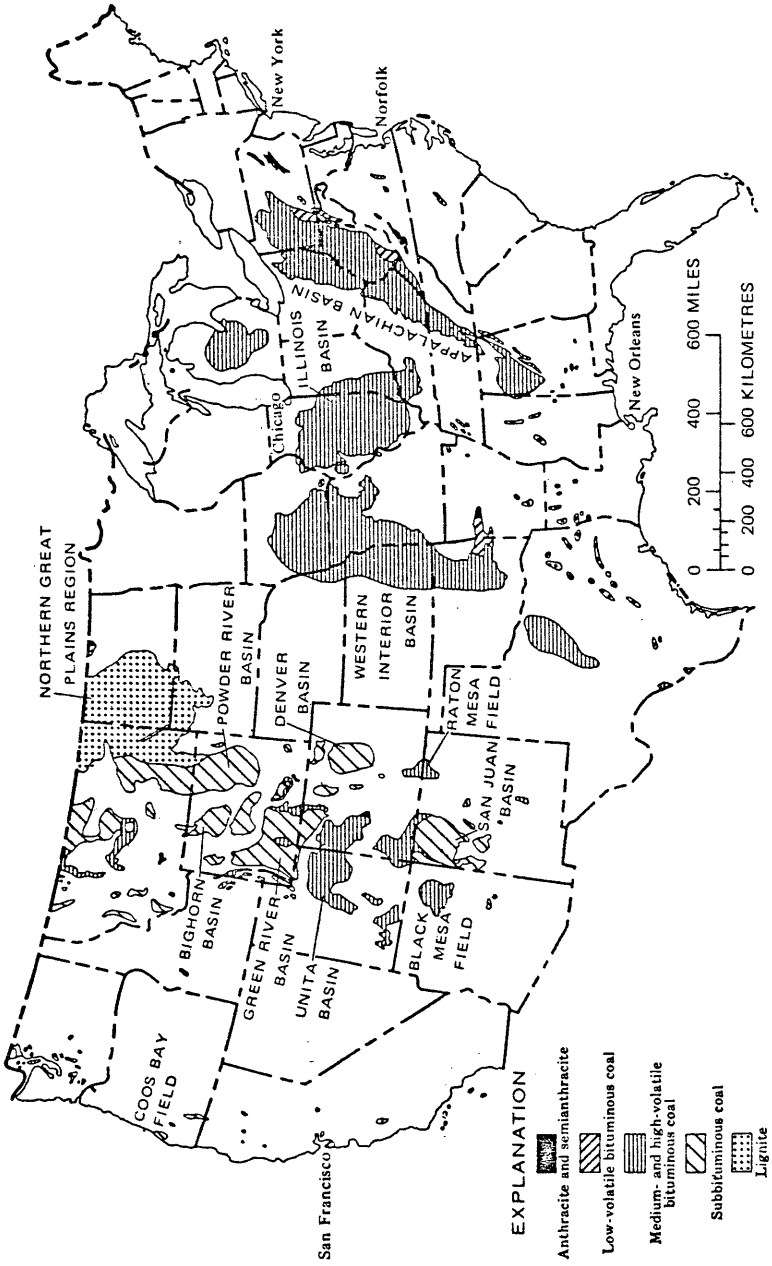


FIGURE 1 - Coal Fields of the conterminous United States from Averitt, 1974.

Composition of Coalbed Gas

Gas from coal seams is very similar in composition to natural gas. The primary constituent of coalbed gas is methane, which is usually in excess of 84% and can be as high as 99% (Kim, 1973). Other detectable hydrocarbons can include ethane through pentane in quantities of less than 2% each. The few impurities found in significant quantities consist of carbon dioxide (CO_2) and nitrogen (N_2), which may infrequently reach 15%. Trace amounts of hydrogen, helium, and oxygen may also be present. No hydrogen sulfide (H_2S) or sulfur dioxide (SO_2) has been detected in coalbed gas.

Pure methane has a heat content of 1012 Btu per cubic foot at 60°F (7.1 Kgcal per cu m at 15.55°C) and atmospheric pressure. The majority of coalbed gases tested in the range of 950-1050 Btu/scf, rendering them compatible with pipeline-grade natural gas.

Gas produced from gob areas can be 10 to 60 percent air by volume and therefore, oftentimes unsuitable for direct injection into pipelines without processing and upgrading. The more than 200 million cubic feet of methane vented each day from U.S. coal mines constitutes less than one percent of the ventilation exhaust and could presently be concentrated to usable proportions only at an "energy loss" (U.S. Department of Commerce, 1976).

Coal Seams as Gas Reservoirs

Although "tight" gas sands and coal seams have many similar reservoir characteristics, there are differences which affect the gas

rates and producing characteristics of the coal seam reservoir. An understanding of the reservoir and how it should be reached and stimulated are important in successfully completing a coal seam gas well.

A literature search revealed the following reservoir description and reservoir properties which had been investigated as possible critical parameters in evaluating coal seams as gas reservoirs:

a) Geologic Influences
b) Cleats (Inherent Fracture Systems)
c) Permeability ← Porosity
d) Pressure
e) Temperature
f) Water Saturation
g) Gas Saturation
h) Rate

Reservoir Description

In comparing coal to a "tight" gas sand reservoir the main differences are the cleat (fracture) systems, the large surface areas, and the very fine micropore system of the matrix. The micropore system is similar to a molecular sieve structure (Kim and Douglas, 1973) with an average pore diameter of 5 to 20 ^{o}A. The larger pores and hairline cracks are known as the macropore system. The micro-porosity of the coal accounts for the measured low porosities ranging from 2 to 10 percent, and the extremely high internal surface areas ranging from 200 to 300 m^2/g (Marsh, 1965). The combination of large surface area and the physical-chemical properties of gas and coal enables the coal to adsorb as much as 28 times its own volume in gas, much more than a normal sand reservoir of 10% porosity. The gases in

a coalbed can exist as free gas in the pore systems or as adsorbed gas on the surface of the micropores.

Chase (1977) has described the coal seam reservoir as:

> "..... a heterogeneous, low porosity, low permeability parallelpipeds, surrounded by an orthogonal system of continuous, uniform fractures of high permeability and porosity, similar to the Warren and Root (1963) model for naturally fractured reservoirs (Figure 2)."

Gas flow from coal then is a two-step process of slowly diffusing from the micropore system into the cleats and laminarly-flowing through the cleats to the wellbore.

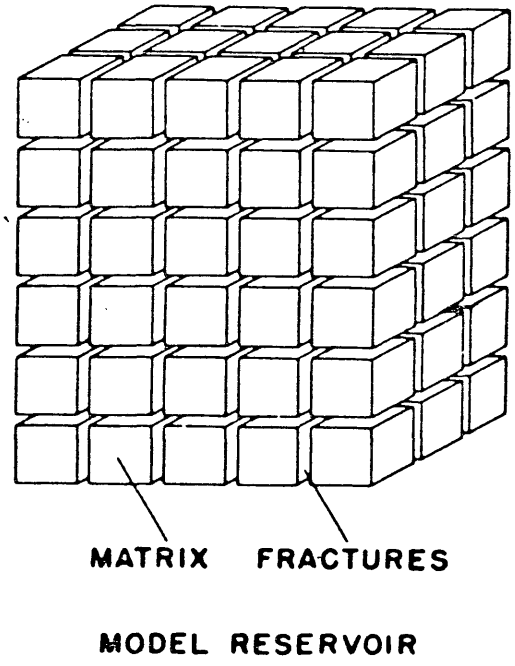


FIGURE 2 - Model Coal Reservoir
from Warren and Root, 1963

Geologic Influences

Depth is the most important geologic parameter in determining gas content. Although gas saturation increases with depth, the rate of gas saturation increase drops. Pressure and temperature increase with depth but gas content will tend to decline with higher temperatures. At a depth of 3500 to 5000 feet (1500 to 2250 psi) gas saturation reaches a maximum because at these pressures the rate of increase with pressure is less than the rate of decrease with temperature (Ruppel et. al., 1974). With the higher rank coals, the maximum could be slightly deeper and pressures could be slightly higher. Overburden also decreases porosity and permeability.

Coal is usually overlain by a thin slate, shale or sand. In fracturing a coal seam with a stimulation treatment, the brittle coal will contain the treatment between the other "more plastic" formations (Elder and Deul, 1975).

Steeply-dipping coal seams are more common in the intermontane basins of the Rockies. The high dips create many problems for mining but should not adversely affect methane extraction. One advantage could be the increased cleat system due to the more structurally-influenced coals.

Cleats (Fractures)

Cleats are perpendicular to the bedding plane of coal seams and are classified as either face or butt cleats. The face cleats are the longer and more continuous fractures which also occur more frequent-

ly. Butt cleats are perpendicular to the face cleats and are less developed and shorter. Mines are usually laid out to take advantage of the cleat systems as the coal breaks more easily that way (McCulloch et. al., 1974). Their origin is debated but cleats are probably either stress compensations occurring during the coalification process under high temperatures and pressures or caused by local structural forces. Cleats are related to coal rank and work by various authors (Komar et. al., 1973, Bench et. al., 1977) has shown correlations between cleat orientation and surface joints and lineaments.

The spacing of cleats is important to the rate of desorption as spacing determines the distance gas travels by diffusion. McCulloch et. al's. (1974) work on the blocky-type Pocahontas coal showed cleat spacing of 1/16 in or less and 1/2 in or more on the friable-type Pittsburgh seam.

The directional permeability of coal is also directly related to cleat. Holes drilled perpendicular to the face cleat yield from 2.5 to 10 times the amount of gas as compared with holes drilled perpendicular to the butt cleat (McCulloch et. al., 1974). Kissell (1972) noted that fluid production parallel to butt cleats yielded volumes up to ten times greater than those parallel to the face cleats because they intersected the longer, more continuous face cleats.

Permeability

Permeability is the ability of a gas or liquid to flow through a

formation. Some work has been done in the laboratory (Dabbous et. al., 1974) on the bituminous friable-type Pittsburgh and blocky-type Pocahontas coals. Their conclusions on permeability are:

1. Variations of more than four orders of magnitude can be expected for the single-phase (gas or water) permeabilities of samples from these two coals (Figure 3).

2. Both air and water permeabilities are greatly reduced by increases in the overburden pressure (Table 1). Both display significant hysteretic behavior.

Although permeability in coals does decrease with depth, permeability to methane appears to increase with time. Kissell (1972) noted that regions of coalbed adjacent to older areas of a mine were considerably more permeable than regions adjoining freshly-mined areas. Although "destressing" (Stewart, 1971) and coal shrinkage from the loss of methane (Moffat and Weale, 1955) have been proposed to account for this, the most probably explanation is a relative-permeability effect. The flow of methane is controlled in part by the degree of coalbed water saturation; the permeability to methane increases as the water in the coalbed decreases and makes more pore space available to the gas phase.

A similar phenomenon is seen in recent stimulation work in the blocky-type Mary Lee seam in Alabama. Vertical boreholes near mine workings have higher initial potentials than wells in virgin coal areas even with smaller stimulation treatments (Lambert, 1977).

Porosity

As stated in the reservoir description, coal has a very fine pore

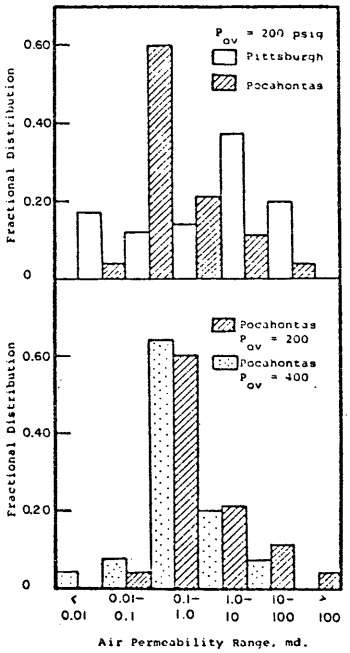


FIGURE 3 - Air Permeability Distribution for Pittsburgh and Pocahontas from Dabbous et. al., 1974

Sample Number	Coal Formation	Porosity* (percent of bulk volume)	Overburden Pressure (psig)	Permeability to Air (md)	Permeability to Water (md)
Poc.-2-1	Pocahontas	5.16	199	34.6	14.8
			599	12.3	8.70
			996	9.65	3.60
Poc.-2-2	Pocahontas	4.55	196	18.6	14.4
			596	5.83	5.70
			993	1.59	1.80
Poc.-2-3	Pocahontas	4.31	200	275	62.4
			600	19.5	20.3
			993	3.07	3.02
Poc.-2-4	Pocahontas	3.73	196	14.9	7.90
			596	3.10	2.56
			968	0.760	0.455
Pgh.-2-6	Pittsburgh	1.82	193	2.24	1.25
			593	0.814	0.547
			968	0.274	0.098

*Porosities determined at zero overburden pressure.

TABLE 1 -- Air and Water Permeabilities of Coal Samples at Various Overburden Pressures from Dabbous et al, 1974.

structure and the gas saturation is often very large. Porosity should not be thought of in the "traditional" sense due to adsorption properties and cleat space (Deul, 1977). According to Dabbous et. al. (1976), there are large differences between porosities measured with helium (ranging from 2.6 to 8.6%) and water (0.4 to 1.1%). Obviously helium is small enough to enter the micropores while water is not. This does not mean that all pores penetrated by helium are necessarily accessible to other gaseous molecules such as air or methane. The water porosities are more representative of the porosities of the macropore systems. The range of porosities for most seams investigated is generally 2 to 10%. It is important to remember that lab data were taken on disturbed samples where the confining stresses were relieved.

Dabbous et. al. (1976) also determined that porosity decreases significantly at higher overburden pressures (Figure 4), but pore compressibility appears to be constant at pressures above 1500 psig.

Pressure

Coals are normally underpressured with a pressure gradient of 0.2 to 0.4 psi per foot (these data were taken from eastern drill stem tests and they vary in the west). This underpressuring will hinder the diffusion of the gas system in the micropores (Bielicki et. al., 1972), but this is a minor influence compared to coal rank.

Another problem with underpressured reservoirs is that there is little reservoir energy to blow back water and "clean-up" wells after a stimulation treatment. For this reason a non-reactive gas is used to

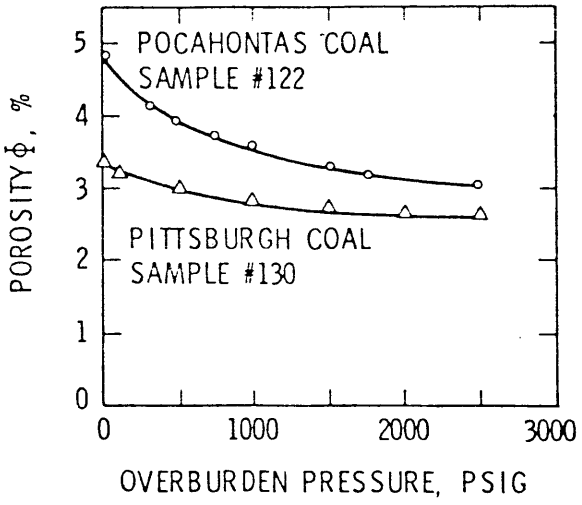


FIGURE 4 - Variation in Porosity With Overburden Pressure from Dabbous, 1976

create an artificial pressure in the reservoir.

Temperature

Coal adsorbs less gas at higher temperatures (Ruppel et. al, 1974); but the rate of sorption is faster at higher temperatures (Hofer et. al., 1966). Although these factors are important in a regional exploration sense, they will not affect our producing target coal seams which are assumed to be isothermal.

Water Saturation

Water is contained as free water in the cleat system as well as moisture in the micropores. The proof of free water in the cleat systems in virgin coalbeds is drill stem tests (DSTs) which recover only water and no gas. Also, the water rates of producing coal seams start high and decline, while the gas rate rises (Deul and Elder, 1973; Fields et. al., 1975).

The coal's sorption capacity decreases with increasing moisture content to a critical point, above which there is no effect on the isotherm (Jourbert et. al., 1973). Although methane content of coal seam is affected by moisture, moisture should have no effect on the time required to reach equilibrium.

In making capillary pressure curves for the Pittsburgh coal seam, Dabbous et. al. (1974) found the average "irreducible" or minimum water saturation for oven-dried coal samples was greater than 45%.

Gas Saturation (Sg)

A coal's methane capacity is a function of a coal's rank, pressure, and temperature, all of which generally tend to increase with depth (Kim, 1977). Coal rank is based on fixed carbon, volatile matter, and moisture (Figure 5). The moisture not only lowers the rank but also the methane adsorption capacity. The volumes of gas that can be retained at different pressures were plotted for six U.S. bituminous coals (Figure 6). At low pressures the volume adsorbed increases rapidly and at higher pressures it nearly stops as the adsorbed layer becomes more crowded. From these equilibrium adsorption isotherms, an adsorbed gas volume can be estimated at any depth.

Using the hydrostatic head to estimate pressure (Figure 7), Kim correlated gas content of various ranks of coal versus depth assuming a standard moisture and ash content.

Ruppel et. al. (1974) correlated the adsorption isotherms measured at several temperatures for various coals by the Langmuir equation. This equation is for the idealized monolayer adosorption of methane on a coal matrix. The equation is:

$$\frac{P}{V} = \frac{P}{Vm} + \frac{1}{bVm}$$

The values of the constants Vm and b are contained within a very narrow range. For the 15 coals identified, b ranged from about 0.05 to 0.2, and Vm varied from about 12 to 40 with the extremes falling at the low temperature where they would have little application. With the Langmuir equation, the equilibrium isotherm curve can be estimated from a single

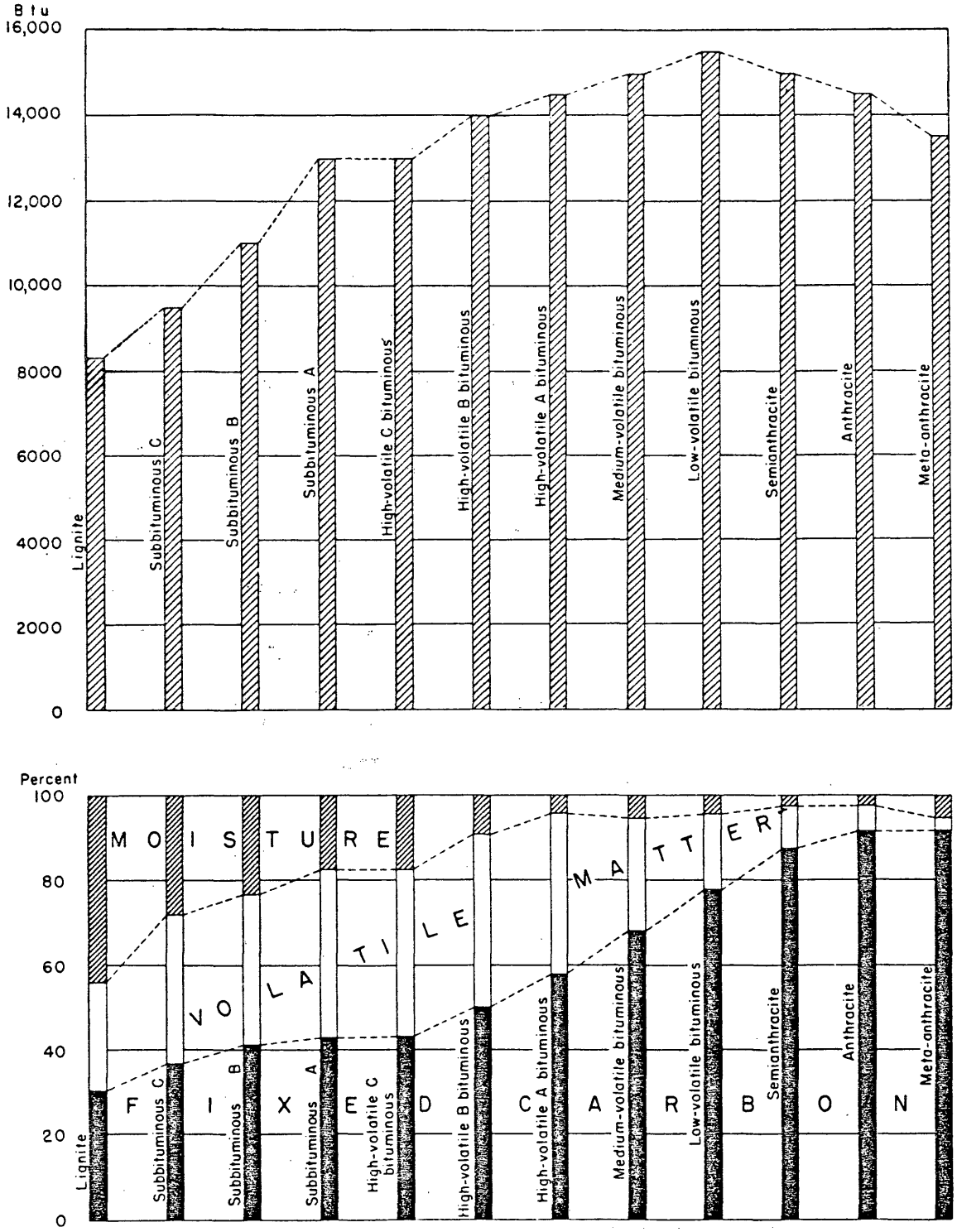


Figure 5 - Calorific Value of Coal Versus Rank from Hendrickson, 1975

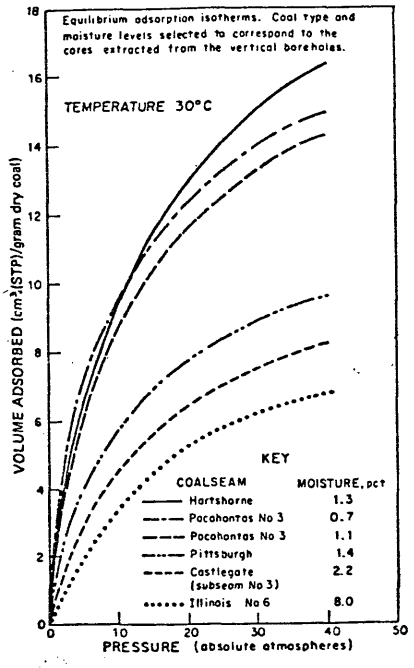


FIGURE 6 - Methane Content of Coal Vs. Pressure from Kissell et al., 1973

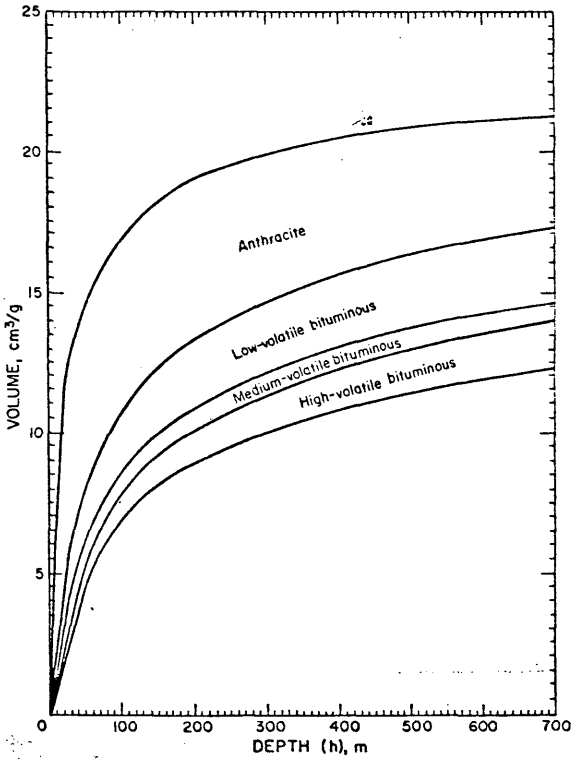


FIGURE 7 - Estimated Methane Content with Depth and Rank from Kim, 1977

field-measured point.

Rate

How will the coal seam actually produce? When the water is produced, the pressure drops and any gas in the cleats, fractures, or pores will expand. In addition, the differences in concentration of adsorbed gas will cause some of this gas to desorb. This is the reverse process of coalification, where gas escapes to coal surfaces and the coal-methane-water system remains at that equilibrium, temperature, and pressure (probably above the critical moisture content) until it is disturbed either by man or nature.

The flow along fractures and cleats is caused by the pressure gradient created by draining the water. The rate is very rapid compared to the very slow rate of diffusion.

The rate at which gas can be produced from coal is controlled by the desorption process in the matrix. The matrix is the solid, unfractured coal and its size is determined by the type of coal, cleat system, and geologic history. The desorption rate was studied by Hofer et. al. (1966) and their conclusions were:

1) The adsorption/desorption process appears to be diffusion controlled.

2) The rate curves for adsorption/desorption are the same. The process is reversible.

3) The rate of adsorption/desorption is dependent on the partial size of the sample.

The rate at which gas desorbs is the diffusion parameter (D/a^2) which

is a function of coal type and fracture spacing. The diffusivity equation mathematically defines the rate:

$$\frac{\partial C_1}{\partial t} = \frac{D}{a^2} \frac{\partial \left(a^2 \frac{\partial c_1}{\partial a}\right)}{\partial a}$$

or Fick's Law written without calculus (Cervik, 1967):

$$a = -DA \frac{dc}{dL}$$

The driving force in the diffusion process ~~will actually be a volumetric expansion in the micropore system.~~ is a concentration gradient

The free gas in the cleat system is controlled by Darcy's Law:

$$q = \frac{kA}{g} \frac{dP}{dL}$$

where the pressure gradient is the driving force and laminae flow is assumed.

Obtaining Reservoir Parameters

Obtaining accurate and useable reservoir data on coal seams is often difficult, time-consuming, and expensive. Most values can be obtained indirectly from either log data, local mine data, and extrapolation of the literature or directly from lab tests on cores, DST's, simulation, production, and pressure tests. It should be noted that core values obtained in the lab are rough approximations because confining pressures have been relieved and the exact in-situ conditions of temperature and pressure are difficult to duplicate. Indirect values are taken from well logs because there is no "gas-saturation log" or "permeability log" available. Much of the simulation and test results are also interpreted based upon various assumptions. The most important

parameters in a coal gas reservoir are gas saturation and permeability of the coal seams.

Desorption Tests for Gas Saturation

Several techniques have been developed for determining the gas content of coalbeds based primarily on the analysis of exploratory cores or on data obtained from drill stem tests.

Direct Method

This field method involves sealing a freshly-cored coal sample in an air-tight canister as quickly as possible. The canister is equipped with a low-pressure gauge and needle valve through which desorbed gas is periodically removed and measured by the quantity of water displacement. Because small increases in temperatures result in substantial increases in desorption rate, caution should be used to keep the sample at a fairly constant temperature. 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 (Figure 8) or by measuring directly the gas desorbed from the finely pulverized coal core. Extrapolation of the data is also made back to original cut time to estimate the gas lost in the core retrieval process (Kissell et. al., 1973; McCulloch et. al., 1975). If air, mist, or foam is used as the coring fluid, it is assumed that the coal begins losing gas immediately upon penetration of the coal seam by the core barrel. If water or mud is used as the drilling medium, gas desorption is assumed to commence when the core is halfway out of the borehole. The equipment

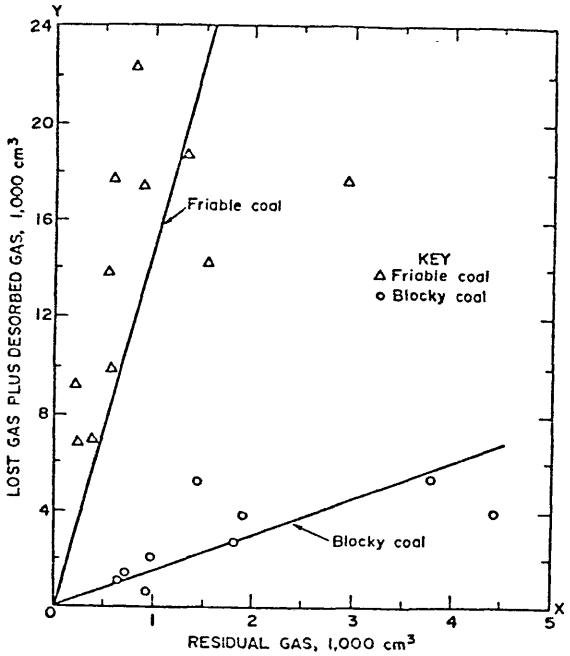


FIGURE 8 - Lost Gas Plus Desorbed Gas Vs. Residual Gas from McCullough et al, 1975.

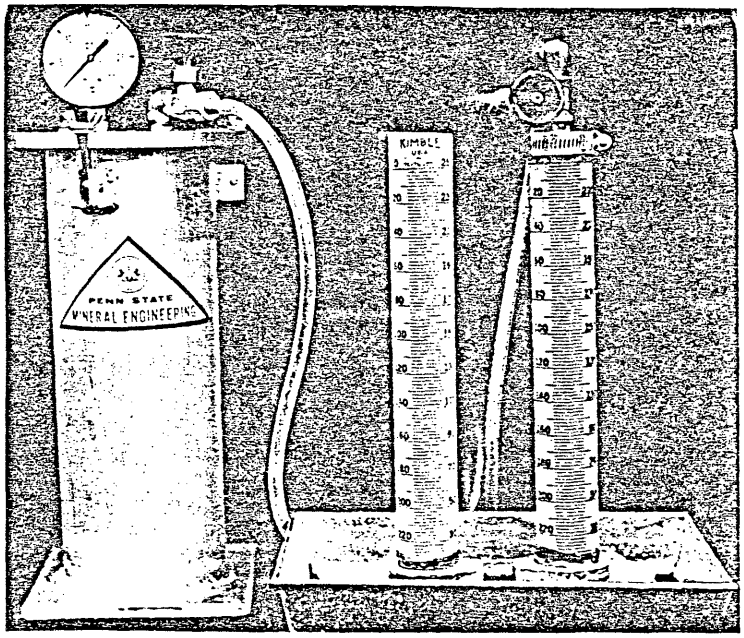


FIGURE 9 - Gas Content Determination Equipment from Chase, 1977.

and graph obtained from several core samples are shown in Figures 9 and 10. The total methane content of the coal can then be found by summing the values of lost gas, desorbed gas, and residual gas. This value is divided by the sample weight to determine the gas content in cc/g.

Indirect Methods

Gas content can be determined from pressures off of a drill stem test if an equilibrium adsorption curve (Figure 6) has been determined in the laboratory. A knowledge of moisture content of the coal is also necessary in using these curves.

A carefully preserved core sample from the seam is put in a high pressure container and pressurized in steps. These data points are used to develop the methane sorption isotherm (Ruppel et. al., 1969).

A second indirect method (Joubert et. al., 1973) proposes a specific application of the Langmuir adsorption isotherms:

$$Vad = \frac{VjbP}{1-bP}.$$

This describes the volume of gas adsorbed on the internal free surface of coal at a constant temperature. The constants Vj and b are determined experimentally for a specific coal seam and the pressure is assumed to be equal to the hydrostatic pressure of the coalbed.

In a third method, Kim (1977) has modified the adsorption equation even further to estimate content of in-place coal:

$$V = KP^n .$$

By correcting for temperature, moisture and ash content and determining pressure and temperature as functions of coalbed depth, the gas content

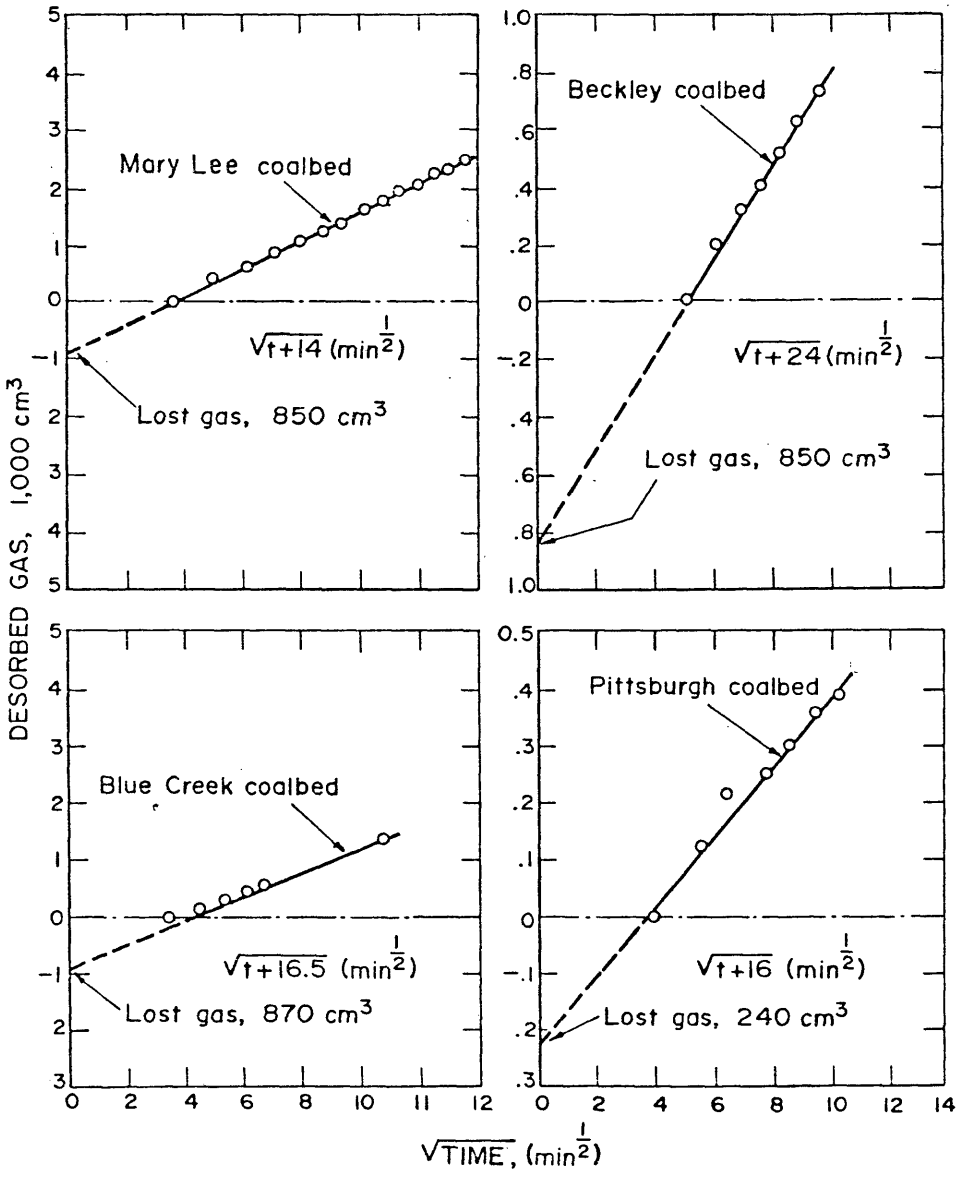


FIGURE 10 - "Lost" gas emission curves: Samples from the Mary Lee, Beckley, Blue Creek, and Pittsburgh Coalbeds from McCulloch et al, 1975.

of coal in-place can be determined from:

$$V=\frac{(100-\%\ \text{moisture}-\%\ \text{ash})}{100}\ (0.75)\ \left[k_o\ (0.096h)^{n_o}-0.14(1.8h/100+11)\right]$$

Decline Curve

Chase (1977) has outlined a method for determining the volume of desorbable gas from exploratory cores. His method eliminates the need for determining residual gas, since it is an irreducible gas in production. The "lost gas" and "desorbed gas" are found in the same manner as the direct method. An extremely low desorption rate cutoff (arbitrary) below which desorption measurements can no longer be justified will give us an upper limit on recoverable gas.

Figure 11 is a graph of desorption rate versus cumulative desorbed gas. At an arbitrary rate of .007 cc/gm/week (.001 cc/gm/day), 26,380 cc of cumulative gas will be desorbed from 5902 gm. This desorbed gas volume and the lost gas volume are added together and divided by the weight of the sample to determine recoverable gas in cc/gm.

Comparison of Methods

The direct method is the most widely used technique and has been adopted by the U.S. Bureau of Mines for determining the total gas content of coal cores. When the total gas of the direct method (lost gas + desorbed gas + residual gas) was compared to an extended desorbed gas (27 to 33 weeks) plus lost gas, the direct method was consistently low (Chase, 1977). The underestimation of methane content stems directly from the method of approximating residual gas. The residual gas estimation curves (Figure 8) are from a small statistical base and should be used with caution.

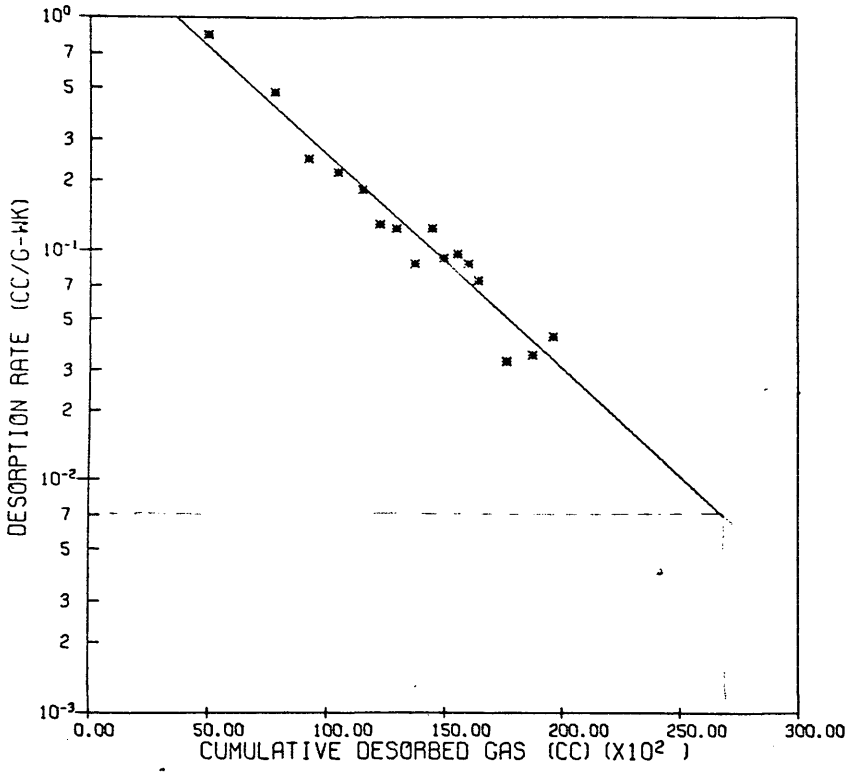


FIGURE 11 - Desorption Rate (CC/G-WK) Vs. Cumulative Gas (CC) Decline Curve for Sample from Chase, 1977.

The indirect method using the DST-pressure data may be in error because there is no way of knowing whether the pressure is from the gas or from the hydrostatic head on the water in the cleat system and larger pores (Kissell et. al., 1973). In addition, much of the gas is adsorbed on the internal free surface of the coal and is not measured by the DST, which is more likely to be reading the free gas pressure in the fractures and larger pores. Therefore, the pressure is not a true indication of the volume of gas in the coal. Also equilibrium adsorption isotherms are generally determined for powdered coal rather than from solid coal matrix

and the lab results may not be applicable to solid coal in-situ.

Joubert's technique also required equilibrium adsorption isotherms and moisture content determinations on new seams. Usually the final result of sorption analysis is an equation used to calculate gas content as a unique function of coalbed depth. But the depth does not necessarily reflect anomalies in gas content which may exist due to physical-chemical or geological differences in the environment of the coalbed.

Kim's method was replicated by Chase (1977) who stated that "the estimated methane content for most coals showed good agreement with values obtained using the most widely used technique, the direct method. However, gas content values obtained"

> "...using Kim's method were found to be consistently high for high-volatile bituminous coals from areas where the pressure was known to be less than hydrostatic."

Of all the methods, the Decline Curve is probably the most reasonable because it is based on the extrapolation of an established trend directly related to the mechanism of gas production from solid coal. Also the moisture content, equilibrium adsorption isotherms, and residual gas approximations need not be known. The decline curve methods results lie between the results of the direct and indirect methods (Chase, 1977).

Permeability

One of the most critical parameters in methane production from coal seams is the permeability of the matrix. It is used in designing frac jobs and spacing and determining whether a well is economical.

Permeability can be determined from DST's; but due to the "tight" reservoir, the low gas flow, the high water recovery from cleat drainage, possible wellbore damage, and the normally short shut-in periods, the results are a rough approximation at best.

Permeability lab tests are made on cores by gauging an air flow through a core plug. Lab tests are not in-situ conditions and should be correlated to other data. Also helium is normally used in core testing because coal adsorbs air, nitrogen, and water. Coal can swell when water is adsorbed.

Once a well is completed but before production tests are run, a water injection well test could be run to determine permeability (Ansell, 1977). A positive-displacement pump is used to "pressure up" the formation and these pressures are plotted against the log of time. Assuming single-phase radial flow, the slope of the line is proportional to permeability.

Also simulating ("history matching") actual production or good well testing procedures could get more accurate permeability values.

Porosity

Porosity can also be obtained from lab tests on cores. An effective porosity near the porosity from helium is probably more accurate than a porosity for air. Logs cannot define the low porosities (1-4% density) because of the low specific gravity (1.3-1.8 gm/cc) and poor resolution in this range of porosities. An acceptable porosity could be determined if the matrix characteristics were well-defined.

Pressure

Pressure-bomb tests and DSTs are the two methods available to determine pressures. The experience of the U.S.B.M. is that DST pressures are representative of the formation, but gas recoveries are low. Sample chambers should be run and any gas and water samples should be analyzed.

Temperature and Water Saturation (Well Logs)

By using well logs, many parameters can be obtained. The simplest are depth, thickness, and temperature. The recommended logging suite is a density, gamma ray, resistivity, sonic, neutron, and dipmeter in a water-drilled hole and an induction, sidewall neutron, and density in an air-drilled hole. The neutron log is hindered in coals because it reads hydrogen density and with the presence of volatile hydrocarbons in coal, the porosity erroneously reads 30 to 40%. But Lavers and Smits (1976) did suggest that coal lithologies could be determined from a gamma ray versus neutron-neutron cross-plot. A mechanical properties log could possibly be made from a sonic, density, and an adjusted neutron log to determine fracture pressure gradient and the shear modulus/bulk compressibility ratio. Water saturations can be calculated with a resistivity log and a density-porosity log. The dipmeter will not only determine the dip of the coal seam at the wellbore but is also a good fracture indicator. Although the well logs do not give a "direct value", they do examine the coalbed in-situ.

Cleats and Geology

Much of the work on cleats and geology can be obtained from the literature, photo work, outcrops, nearby mines, and exploration holes.

Using the Reservoir Parameters

Once the gas content and the other reservoir parameters of our coalbeds are established, reserves can be calculated and a stimulation treatment can be designed.

Although the reserves-in-place are large, the recoverable reserves may not be. Stimulation of "tight" gas sands many times not only increases the deliverability and the rate of recovery, but also increases the ultimate recoverable reserves (Brown, 1977).

Another advantage of stimulation will be the increased water rates as the cleat system drains. This not only drains the water faster, but also drains a larger area. After the cleat systems drain, the gas can more easily desorb from the micropore system.

Once the drilling and completion methods have been chosen, estimates of the costs can be determined. Not only the ultimate recoverable reserves, but also the deliverability rate and rate of recovery will be important to estimate. These latter two rates will drastically affect the cash flow of any future project. The profitability of a project can be estimated once these numbers are determined.

Reserves

From any of the desorption tests for gas saturation, a gas content

in cc/g is determined. Multiplying by 32 results in ft^3 of gas per ton of coal or multiplying by 57,600 converts cc/g to ft^3 of gas per acre-foot of coal. The coal reserves in the number of tons or acre-feet determines the gas reserves in-place. By using Chase's decline method the maximum recoverable gas reserves are estimated.

After determining the amount of coal, the amount of gas in the coal, and the amount of maximum recoverable gas, the questions can be answered of how many acres will one stimulated well drain, how long it will take to produce this gas, at what rates, and how effective will the stimulation treatment be.

Stimulation

Stimulation will be required because natural production rates from wells will not justify pipeline connection. There are many methods of "fracturing", but the main purpose is to open or extend existing fractures by injecting fluids at rates and pressures higher than can be injected into the formation matrix with permeability-controlled flow. The pressures have to be high enough to overcome the compressive stresses in the rock. The fracture at depth will theoretically be vertical or near-vertical parallel to the plane of maximum stress (parallel to the face cleats). The fracture must be propped open after the fluid pressure is released or the rock pressure will close it. Proppants are usually well-rounded, well-sorted sand or glass beads (Kohlhaas, 1977).

The fracture treatment increases the surface area that can flow and this takes the pressure drop further back into the reservoir. Even though

the flow velocities are low in the reservoir, the volumetric rates are higher. Once the reservoirs parameters are known, the size and type of treatment must be tailored for both engineering and cost-effectiveness. Computer programs can be run by service companies to determine the optimum volume of carrying fluid, amounts of proppant, and the required horsepower. Fracture width, length, conductivity, and effective fracture area can be calculated (Table 2). These results are based on the calculated and estimated reservoir parameters and are only as good as the original input data.

Once the optimum size of stimulation treatment has been calculated, an actual job is run. From build-up curves and production history, simulation is run which allows us to determine stimulation effectiveness. Larger spacing of gas wells (640 or 320-acre spacing) is used initially and with increased production history the spacing might be decreased by infill drilling. If a seam is to be mined in the near future, effective degasification could call for 40-acre spacing or less.

Decreasing Water Production and Increasing Gas Recovery

The initial production problem will be draining the water in the cleat system. Rates of over 115 and 150 barrels of water per day (BWPD) have been initially produced out of 5 and 7 foot seams respectively (Ansell, Chase, 1977). These rates were actually limited by pump size. The 115 BWPD-well pumped water for 45 days before producing any gas.

Ansell (1977) stated that a cleat system might be too good at depth, unless a large number of wells were completed and producing

Table 2
TREATMENT DOWN TUBING

INTEGER CONTROL VALUES	
Number of Perforations	50.00
Number of Volumes	8.00
Number of Injection Rates	4.00
Number of Sand Concentrations	4.00
Tubing Interval Length	50.00

WELL COMPLETION DATA	
Depth of Formation - ft.	910.0000
Depth of Packer - ft.	900.0000
Tubing I.D. - in.	1.9950
Tubing O.D. - in.	2.3750
Casing I.D. - in.	5.0000
Perforation Diameter - in.	.5000

RESERVOIR DATA	
Frac Gradient - psi/ft.	1.40
Formation Porosity - fraction	.04
Formation Permeability - md.	5.00
Well Spacing - acres	320.00
Well Bore Radius - ft.	.30
Reservoir Pressure - psi	400.00
Reservoir Fluid Viscosity - cp	.01
Reservoir Fluid Compressibility - psi-1	.0
Estimated Fracture Height - ft.	12.00
Estimated Formation Height - ft.	6.00
Modulus of Elasticity -psi	.30
Surface Temperature - f	70.00

FRAC FLUID DATA	
Foam Quality	.7500
Spurt Loss Coefficient - gal/sq.ft.	.0007
Fluid Loss Coefficient - ft/sq.ftmin	.0006
Water Viscosity - cp	1.0000
Pad Volume - Fraction of Total	.2500
Fraction of N2 Down Annulus - Mode 4	.0000

CALCULATED FRACTURE DIMENSIONS

Foam Injection Rate - bpm	10.00	Water Volume in Foam Flush - bbls	1.03
Water Injection Rate - bpm	2.50	Nitrogen Volume in N2 Flush - scf	1870.00
Nitrogen Injection Rate - scf/min	3500.00	Surface Closure Pressure with Foam - psi	1131.00
Surface Injection Pressure - psi	1630.00	Surface Closure Pressure with Nitrogen-psi	1221.00
Hydraulic Horsepower - hhp	100.00		
Required N2 Ratio - scf/bbl	1400.00		

(Continued on Next Page)

Table 2 (Cont)

Volume Gals	Foam Vis CPS	Created Width In	Propped Width In	Created Length Ft	Propped Length Ft	Propped Height Ft	Proppant Weight Lbs	Folds Incr	Frac Cond MD-FT	Effective Frac Area Ft**2
25000	218	.706	.095	1912	1576	12	34500	9.01	2367	37833
35000	303	.835	.114	2269	1871	12	49500	10.91	2862	44892
37500	324	.864	.119	2349	1937	12	53250	11.40	2973	46489
40000	345	.893	.123	2428	2002	12	57000	11.90	3079	48047
42500	366	.920	.127	2503	2064	12	60750	12.41	3183	49539
45000	387	.946	.131	2576	2124	12	64500	12.94	3283	50988
47250	406	.970	.135	2640	2177	12	67875	13.42	3371	52259
50000	429	.997	.139	2717	2240	12	72000	14.03	3475	53771

PROPPANT PUMPING SCHEDULE

Sand Concentration In Foam-PPG	Sand Concentration At Blender-PPG	Volume
0.0	0	25 Percent
0.5	2	1000 Gallons
1.0	4	1000 Gallons
1.5	6	1000 Gallons
2.0	8	Remainder

together. This could happen where permeability was in the range of darcies and steady-state flow was attained quickly. Some Powder River coals have permeabilities in the hundreds of millidarcies or even darcies, and are aquifers at depth.

To remove the water a pumpjack will be required. Water production will decrease with time and eventually the gas will be able to lift the small amount of water up tubing, but the pumpjack should be left on location. Gas production from the micropore system will not start until the fracture system is partially drained. Even a small pressure difference could slow the desorption rate significantly.

Problems have occurred with coal fines and propping sand clogging the water production string. Because of this problem and the intermittent use of water removal equipment (10-12 BWPD for 5-ft seam after 6 months), a pumpjack is recommended versus a down-hole pump.

The type of water will determine the disposal procedure. Open evaporation pits initially and small storage pits eventually will hold the produced water. A water sample from the DST should determine if the water is useable or whether it will cause disposal problems.

Experience to Date - Fall, 1977

To cover the entire history of demethanization of coal seams is not within the scope of this paper. A summary of techniques and results of the most promising methods and possible areas of technological breakthrough and problems are covered in this section. Much of the promising work has been done in the last year in the Mary Lee/Blue Creek seams in Alabama. As a result, completions and tests are still being run, and the data have not been released. Type-decline curves have been made for both near-mine wells and virgin coalbed wells.

From the degasification experience of operators in the eastern U.S. and the shallow, "tight" gas sand experience of Rocky Mountain operators, methods will be chosen to be used in our models. As coal seam gas wells are drilled in the Rockies, methods and models can be refined.

Much of the data and information about the methods mentioned in this section were obtained from inquiries with operators, service companies, consultants, and members of various government agencies.

Drilling and Completing Shallow Gas Wells

The methods for drilling and completing shallow gas wells are varied, but roughly the procedure follows as such:

1) A drilling rig capable of handling the proposed depth and hole size is moved on location. The rig could drill with air (using compressors) or be a conventional rig using a water-base drilling mud.

2) Surface casing is set and cemented deep enough to protect the local water table.

3) The well is drilled to the target interval and a core of the prospective zone is oftentimes taken in a new area.

4) Logs and drill stem tests (DSTs) are used to evaluate the formation and a decision to run casing and complete, or to plug and abandon is made.

5) If casing is run to total depth (TD), it is cemented through the target interval and far enough uphole to prevent lost production and contamination of any water zones. A well can also be completed open-hole by running casing to the top of the formation and cementing, and drilling through the target interval to TD.

6) The casing across the target interval is perforated and the well is either produced naturally or stimulated (acidized or fractured) down casing or tubing. Open-hole wells are stimulated through tubing using a retrievalbe packer assembly.

7) If production tests justify it, a pipeline is laid to connect the well.

Drilling and Completing Coal Seam Gas Wells

The common practice on coal demethanization wells presently is to air-drill to the top of the coal, log, and set casing. The coal is then cored and the wells are completed open-hole with any of various types of small fracture treatments (less than 10,000 gal fluid and 5000 lb sand). Recent stimulations of 50,000 gal foam (75 percent foam) and 25,000 lb sand have gone successfully and significant gas increases have been measured from virgin coal seams within the last year (Wallace, Lambert, 1977).

The disadvantages to this method are the inaccurate coal depths and thicknesses, no logs run over the cored interval, and the fines can more easily clog the water production string. Also, the oversize casing that has to be cored through adds to the cost.

The main advantage to open-hole completions is to the miners who later will mine through the seam.

Fracture Treatment Selection

The purpose of the fracture treatment is to stimulate the natural productivity of the formation. Various treatments have been developed for the wide ranges of oil and gas reservoirs. All have their advantages and disadvantages and fracture design will be very site specific. There are two rock-mechanics properties that are different in coal beds versus an "oilfield" sand reservoir. Poisson's ratio for coal is 0.4 to 0.5 versus 0.2 to 0.25 for an oil sand and Young's modulus for coal is approximately 1/10 of that for an oil sand (White, 1977). The first factor means the coal is more brittle and your fracture length should be greater; and the latter means the fracture width in the coal will be wider than expected for an oil sand.

Another recurring problem in stimulating a coal seam is the "leak-off" due to the cleat systems, which causes "sand-offs." The carrying agent has a tendency to escape into the microfractures (cleats) and "drops" the sand, causing a "sand-off." To circumvent this problem 100-mesh sand is used as a fluid-loss additive (FLA) in the stimulation treatment to pack-off these secondary fractures.

Gelled-Water

A gelled-water stimulation consists of pumping water at high rates into the formation and propping it open with sand. The purposes of the gel are to allow a greater concentration of sand per gallon of fluid, reduce friction, and prevent "leak-off." A "breaker" breaks down the gel and allows the fluids to flow back when the well is open after stimulation.

Various sizes of gelled-water fracture treatments have been run on bituminous coalbeds throughout the U.S. Results have been very poor to date (Trevits, 1977). Members of the U.S. Bureau of Mines are compiling a list of all the results which will be finished next year. Volumes as high as 20,000 gal of gelled-water and 35,000 lb of sand have been run (Wenzel, 1977).

The main problem seems to be that the "breakers" for the gel do not work as well at shallow temperatures and pressures as they do in deeper reservoirs. For this reason, the general concensus of operators is that gelled-water treatments are not suited for coalbed reservoirs.

Kiel

The design of a Kiel stimulation treatment is to fracture the reservoir with large volumes of only water and sand in pulses. The shock of the pulses cause "spall" or parts of the formation to chip off and act as a proppant further back in the formation. The pulses are also supposed to help fracture in a different direction when the preceding fracture is filled up with proppant sand and "spall."

An example Kiel job could be 10,000 BW (420,000 gal) and 100,000 lb sand, which would be injected in 8 stages (pulses). One-hundred-mesh sand is run in the initial stage as a fluid-loss preventer with 20/40-mesh sand. The bulk of the sand is run with the first 25 percent of the water in the first two stages. On the end of each sand/water stage a water flush is run. The pumps are shut-down and the well is allowed to flow back. The next stage is then started up. These high pressure changes and large volumes of sand and water cause the "spall" to move

further back into the formation with each stage.

An 80,000 gal water and 30,000 lb sand Kiel job was run in a 5-ft seam in Alabama in what looks like a very good well, but data are insufficient at this writing to conclusively decide on the Kiel treatments.

Foam

Since the formation energy is low, low-density fluids such as foam (using nitrogen) would seem to be the best carrying fluid for a fracture treatment. A base liquid, sand, and foaming agent are mixed with nitrogen gas and injected in a "shaving-cream-type" foam. Foam quality around 75 percent (75 percent N_2 volume/Total volume of gas and liquid) has been used with good results in coal (Wallace, 1977).

The advantages of foam are that only one quarter of the normal water volume is pumped into the formation at high pressures, and like the Kiel treatment, there are no additives. Foam vaporizes when the pressure decreases, which allows an artificial reservoir pressure to "blow back" the water and leave the proppant. Nitrogen gas is used because it expands more than CO_2 when the pressure is relieved and the well is "blown back." Foam-stimulated wells have cleaned up much faster than any other types of fracture treatment. The concensus of operators is that foam has shown the best results to date, but additional production hisotry is needed.

Carbon Dioxide/Water

There has been no production history on which to base this treatment as on the one job that was run, "sand-off" occurred at the perfora-

tions. Good results have been obtained with this treatment in various shallow shaley-sand reservoirs in the Rocky Mountains.

Recommended Treatments

The foam and Kiel treatments are presently the most-favored methods for stimulating a coalbed gas well at this time. Both are "clean fracs" (no additives) and seem to clean-up fairly well with the Kiel taking longer as it uses more water. One problem with treatments injecting large volumes of water at four or five times the normal pressure gradient is that the pores will take in water which they cannot expel when they return to their normal reservoir pressure.

A 50,000 gal, 75 percent quality, foam frac, with 25,000 lb sand will cost $16,000 to run at a 1000-foot depth in the southeastern U.S. For the same $16,000, the 420,000 gal, 100,000 lb sand in 8 stages can be run. Both jobs will run 100-mesh in the pad as a fluid-loss additive. A similar priced Kiel job in the Rocky Mountains will have to be smaller, depending on water costs and how far it has to be hauled to location.

Production History and Decline Curves

Coal degasification wells have been mostly drilled in the Mary Lee, Pittsburgh, and Pocahontas No. 3 seams of the eastern United States. To date there are two types of decline curves in the early production history of stimulated gas wells - the near-mining-activity well and the virgin-coalbed well. These curves are caused by the water saturation of the coal seam when initial production starts and the increased relative permeability of gas as additional production continues (Kissell

and Edwards, 1975).

Near-Mine Well

For a good near-mine well, there is a sharp decline in gas and water rates the first few months (Figure 12). The reason for the rapid decrease is the draining of the cleat system and the fracture system caused by the stimulation treatment. Any shut-in periods for build-up tests or downtime on the pump will cause an increase in production on start-up, which will then rapidly decline towards the old rate at Point A. If the production of water from the mine and the well drain an area between them (Figure 13), this area will be now desorbing more gas and producing very little water. There should be a decrease in water production and a corresponding increase in gas production as at Point B. An increase in productivity could also occur when other areas of the reservoir experience a large enough decrease in water saturation that the relative permeability of gas will increase and the rate will increase as at Point C.

The radius of influence of the mine face is a distance outside of which the coalbed is virgin (experienced no decline in water saturation or pressure). The distances are speculative for a month-old mine face in Figure 13.

The initial production rate on any stimulated well will depend upon the fracture length and conductivity. Some of the wells that have been mined through have shown that the induced fracture is parallel to the face cleats and the actual treatment is approximately equal to the calculated fracture dimensions.

FIGURE 12

Hypothetical Decline Curve of a Near — Mine Well

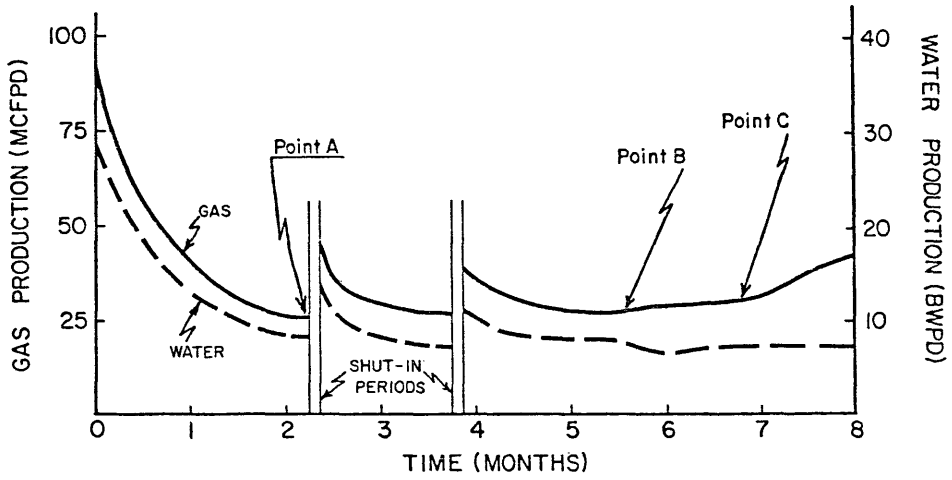
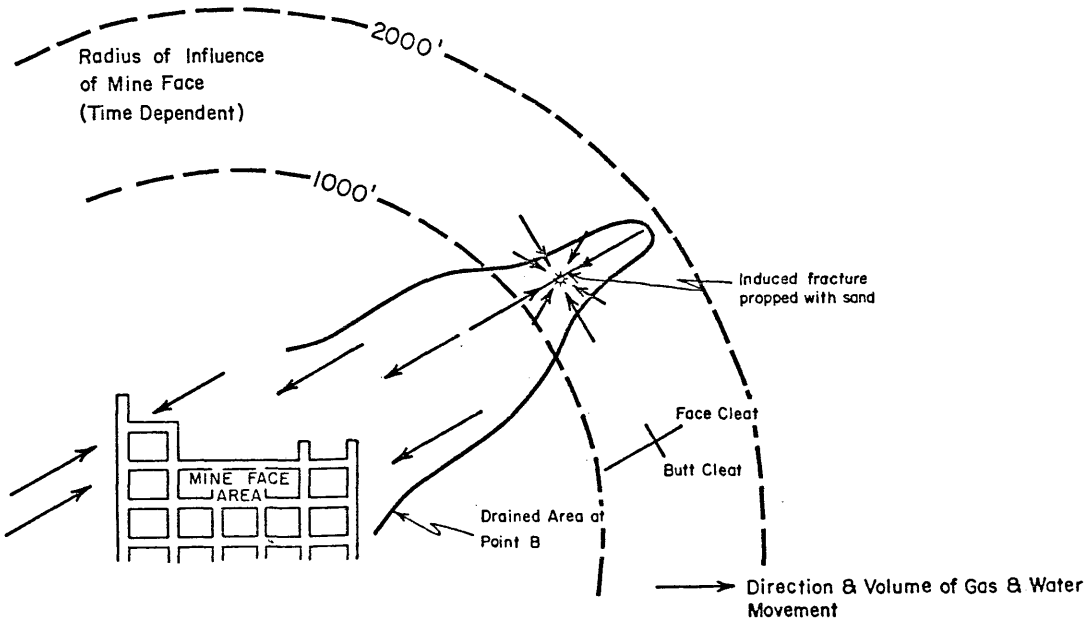


FIGURE 13

Gas Well Completed Near a Mine



Virgin Coal Seam Well

In a "good" virgin-coal seam well, water production will be five or six times the initial near-mine wells water production (Wallace, Stubbs, 1977). The water will hopefully produce at pump capacity for several months as it drains the microfractures (cleats) and the induced fractures (Figure 14). The more water produced, the larger the area of drainage and the larger the volume of coal that will desorb (Figure 15).

Because the initial water saturation is higher in the virgin-coalbed well, the initial-gas-relative permeability is lower (here it is zero), and the initial gas rate is lower. Within the first month, enough water has drained out that the relative permeability of the gas can begin to rise. The rate of gas production will rise and reach a maximum controlled by desorption in the dewatered volume of coal (Kissell and Edwards, 1975).

Type Decline Curves Versus Existing Computer Simulation

The gas rates of these type curves will change with initial water saturation, different relative permeability curves, and different capillary - pressure curves (Kissell and Edwards, 1975). Figure 16 is three hypothetical methane flow curves that were created on a two-phase flow simulator by Intercomp for the Bureau of Mines. Cases 1 and 3 are similar to our near-mine and virgin coalbed examples respectively. It is important to note that at the end of a year the rate of gas production is the same for all three cases and is controlled by desorption. Although the first year's cash flow will drastically be affected by the initial water saturation and initial gas production rates,

FIGURE 14

Hypothetical Decline Curve of a Virgin Coal Seam

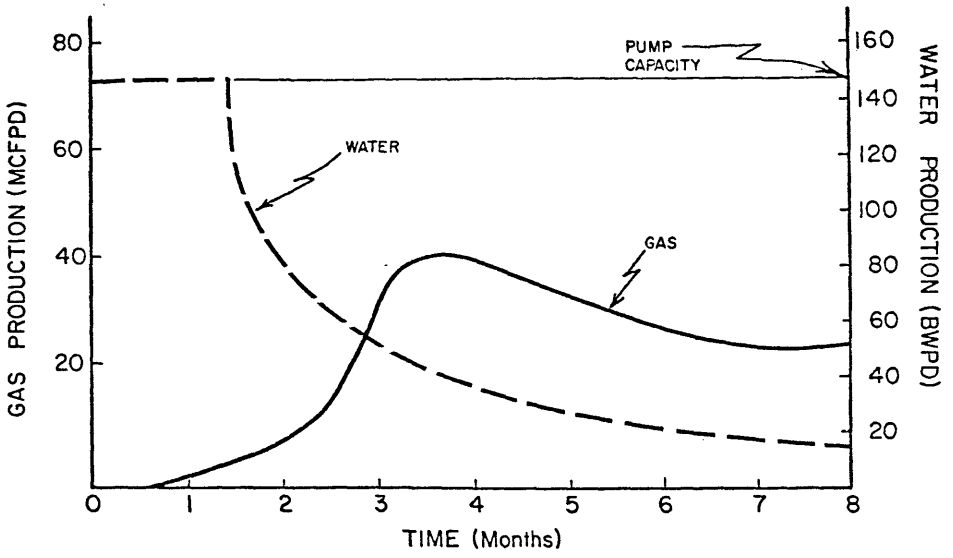


FIGURE 15

Gas Well Completed in a Virgin Coal Seam

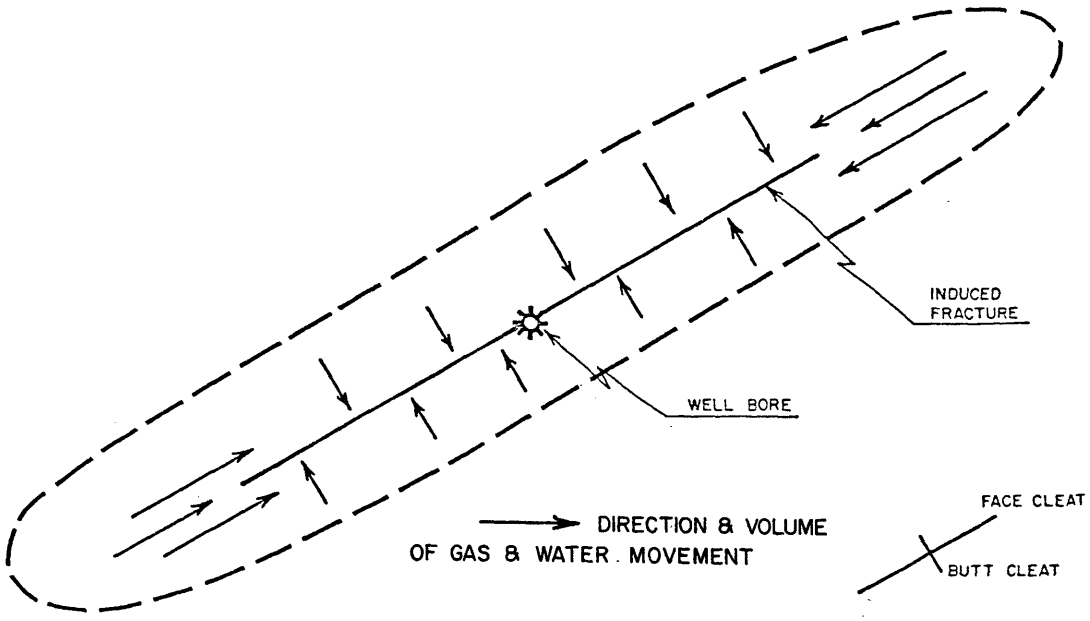
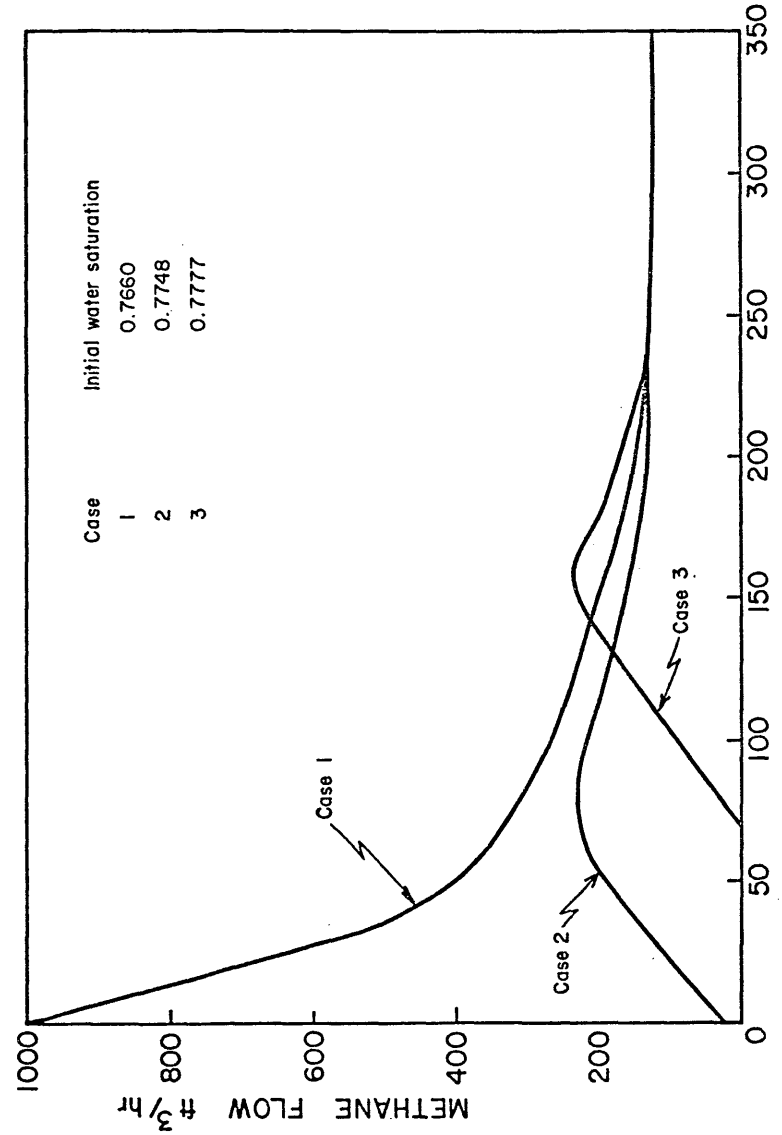


FIGURE 16

METHANE FLOW CURVES*

for three hypothetical cases with different initial water saturations.

* The curves in Figure 16 have been smoothed. Each curve also had several minor peaks & valleys that deviated about 10 or 15 percent from the smoothed curve shown.



from Kissell and Edwards, 1975

simplifying assumptions will be used in our model. For virgin coal seams, our type curve is expected. For our cash flow analysis, an average annual rate in thousand cubic feet per day (MCFPD) will be used.

Long-Term Production History

Over 2000 wells are producing methane from coal seams in the eastern United States (Tilton, 1977). Although many wells were once stimulated with nitroglycerin, the newer wells are being selectively perforated and stimulated.

One field that had a long production history which could be obtained is the Big Run Field, Wetzel County, West Virginia. This field has produced from the 9-ft Pittsburgh seam since the late forties (Figure 17). The wells were produced natural (never stimulated) because of the good permeabilities developed as tension cracks on the crest and lee flank of the Littleton anticline (Tilton, 1976). No water was produced because of the structural high. From the production curve, a nominal decline (Dn) and an effective decline (De) of a desorbing high volatile (blocky) bituminous coal can be determined.

$$Dn = \frac{\ln q_1 - \ln q_2}{T}$$

$$Dn = \frac{\ln 103 - \ln 56}{13} = .04688 \text{ (years 1956, 1969)}$$

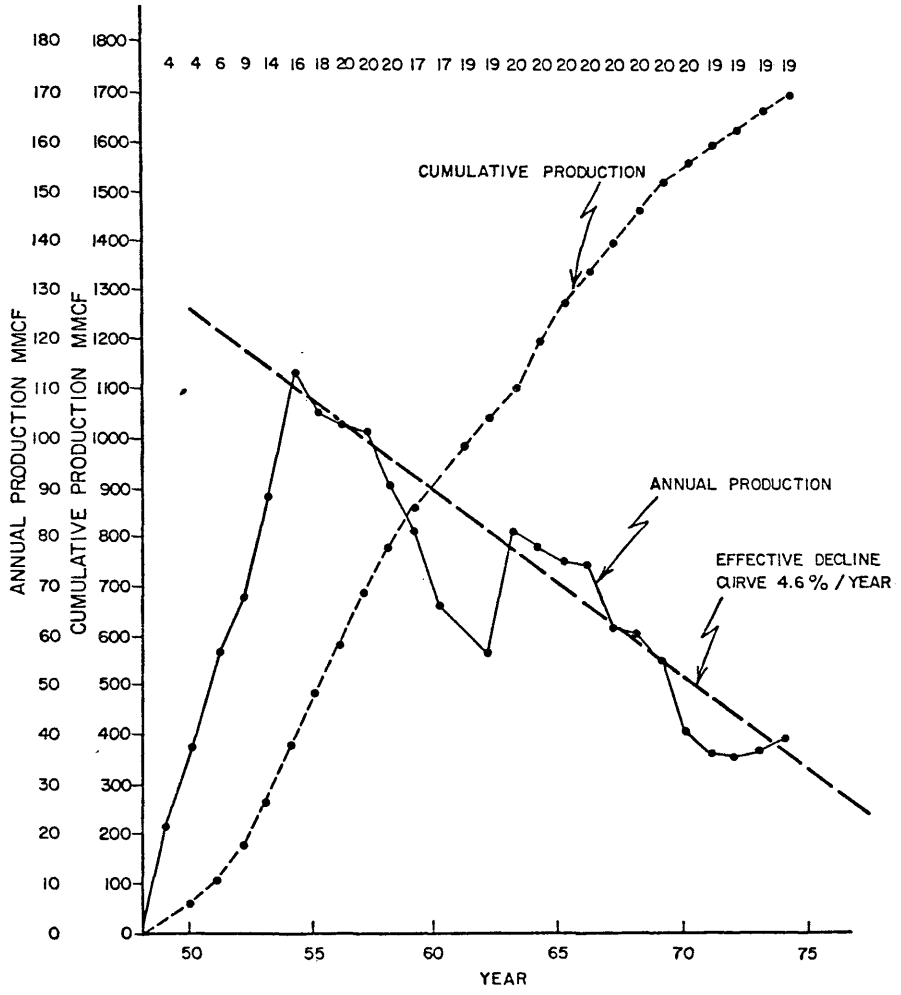
$$De = 1 - e^{-.04688} = .04579$$

$$De = 4.6\%/\text{year}$$

By choosing productions for various years, the effective declines

FIGURE 17

Annual & Cumulative Gas Production, Big Run Field,
Wetzel Co., W. Virginia (Natural production from Pittsburgh Seam)



Derived from records of Equitable Gas Company

From J.G. Tilton, 1976

range from 4.6 to 6.5%. These ranges are high to most of the effective declines of many of the fields, which range from 3 to 5% (Tilton, 1977). An effective decline of 4% will be used in our economic analysis. This decline will include not only the yearly decrease in desorption rates, but also the additional cleat and matrix drainage from the expanding drainage area with time.

Many of the Pittsburgh coalbed reservoirs have reservoir lives of 40 to 50 years. Also, an initial average annual rate of gas production for these wells would be 30 to 35 MCFPD (Tilton, 1977).

A recovery factor of 50% in 5 to 7 years is estimated for the low-volatile (friable) bituminous Mary Lee seam of Alabama (Wallace, 1977).

These averages and estimates with certain assumptions will be used in our economic analysis because there are no data of this type for Rocky Mountain coals.

ADDITIONAL CONSIDERATIONS

Legal Status

The one significant problem in drainage and conservation of methane in advance of mining is neither economic nor technical, but legal. Coal ownership and leases are separate from other minerals and surface rights. This separation of leases leads to a problem when the coal owner asserts that he owns the coal and everything in it. An oil and gas lease gives one the right to drill and produce oil and gas from any formation, while the ownership of the formations from which the gas or oil is being produced remains in the hands of the owner of the land. Ownership of the gas is not perfected until the gas is under control, i.e. in the casing at the wellhead (Tilton, 1976).

Draining methane is primarily a safety measure 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 grantor (Tilton, 1976). Although this is a valuable opinion, this position could be quickly overturned by a new court decision or by legislation.

It should also be remembered that if gas is not removed prior to mining, it is dissipated when the coal is mined, at which point nobody benefits.

The best way to avoid this controversy is to find both the gas and

coal leases under the same ownership.

Environmental

There is no difference between the environmental impact of a coal degasification well and a conventional oil and gas well.

The roads into the drilling location and the location will have to be properly graded and reseeded. If the produced waters are saline, an evaporation pit or storage tank and disposal wells will have to be used.

Horizontal Drilling Into the Coal Seam

If horizontal drilling is done from an air shaft that is drilled ahead of mining, a large volume of gas can be recovered (Fields et. al., 1975). It has already been shown that this method is not only justifiable and technically feasible, but economic as well. However, it is not applicable to the models in our Rockies feasibility study as our wells are drilled into virgin coalbeds and are not drilled in conjunction with producing underground mines.

EVALUATION OF THE ECONOMICS

Before economics can be applied, the technological background must be understood to create a model. The economic model will be defined by proposed methods and assumptions. Various factors can affect the methods and assumptions, and therefore, the model and the economics. Without an understanding of the technology the model is ineffective. An additional advantage of a good technological background will be a smaller, but more effective sensitivity analysis. The sensitivities of various parameters are established by changing one variable while holding all the others constant and making economic runs.

A background knowledge of the geology and reservoir parameters of coal, the methods of drilling and completing wells, and expected production rates and declines have been presented. By estimating prices, establishing costs, and extrapolating eastern data to western coals, economic models can be created for actual Rocky Mountain coal seams.

The ultimate goal of a feasibility study is a decision - "to go or not to go." The sensitivity analysis is used to determine critical parameters in the project and to aid in the decision-making process. The final outcome of the feasibility study is a decision.

Rocky Mountain Coals

Unlike the Appalachian and Interior Basin coals of Pennsylvanian age, the coals of the Rockies are Cretaceous in age. The eastern coals

are mostly anthracite and bituminous, while the younger western coals are sub-bituminous. This lower rank will lower the gas content (it is assumed roughly to one third) and therefore the reserves significantly (Figure 18). Another disadvantage is the higher moisture content in the western coals, which will also reduce the gas content (Kim, 1977).

The main advantages of the Rocky Mountain coals are the thicker seams, many of which can be three or more times thicker than the gas-productive 5-to-9-foot eastern seams (water will proportionately increase). The younger age, the lower rank of coal, and the large amount of tectonism will all contribute to greater permeability in the coal and increased gas rates.

The thicker coalbeds will also allow selective perforating and therefore control over the stimulation treatment. Also, through selective perforating, ways might be developed to control the expected increase in water flow.

Because strip-mining is the prevalent method of mining western coals, less near-mine wells will be needed, but the virgin seam wells will be allowed to produce for a long time. Figure 19 shows the rank and extent of the Rocky Mountain coal fields.

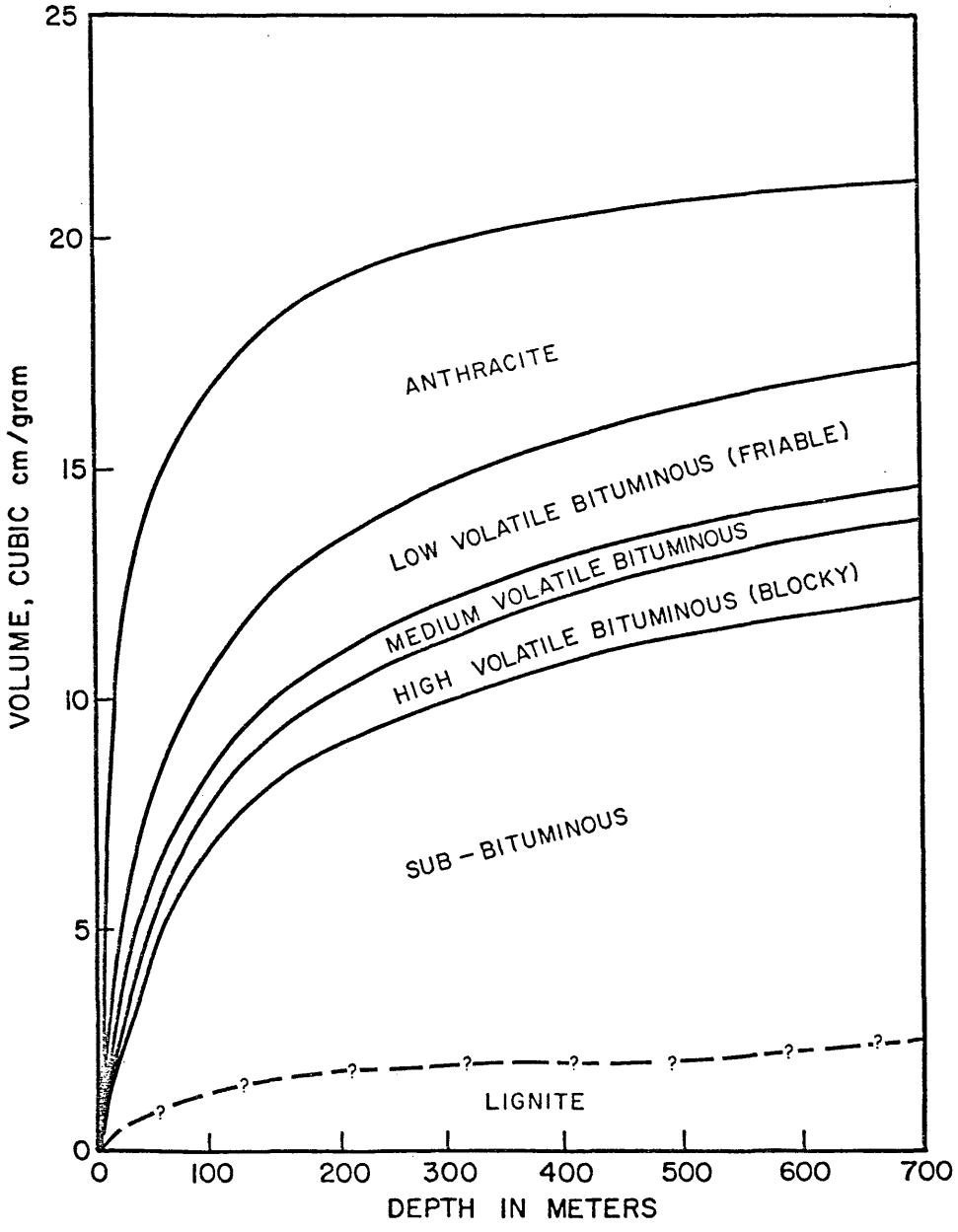
The steeper-dipping coals in the intermontane basins offer no real problem in coal demethanization.

Coal Degasification Models

The models used here are of actual coal seams that are being studied for application of demethanization programs in two Rocky Mountain basins.

FIGURE 18

ESTIMATED METHANE CONTENT WITH DEPTH & RANK
(from KIM, 1977)



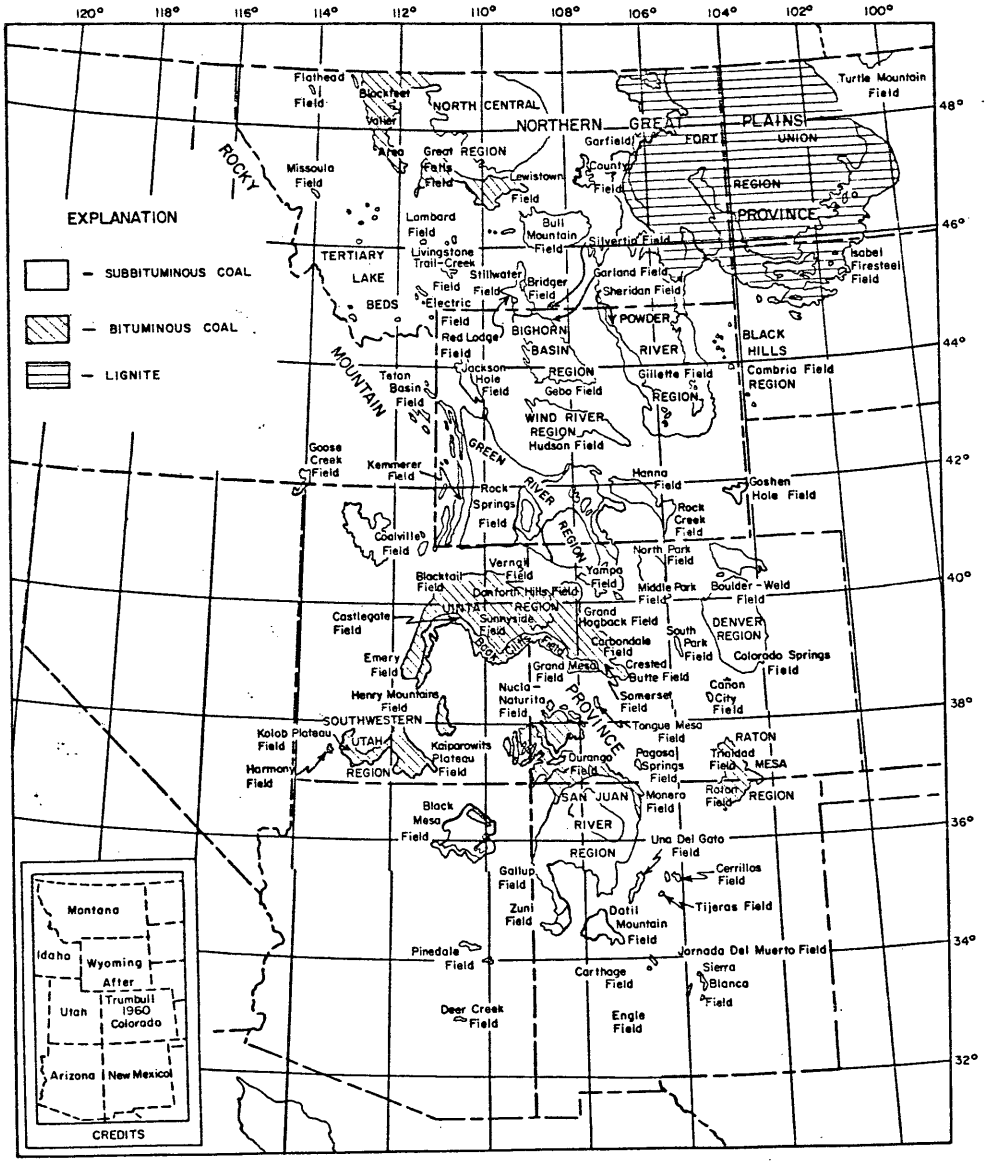


FIGURE 19
ROCKY MOUNTAIN COAL FIELDS

From: Geologic Atlas of the Rocky Mountain Region, 1972

They were selected on the basis of coal thickness, number of beds, depth, legal accessibility, and closeness to a pipeline, so that the wells could be properly tested.

The first model is 3 coal seams - all roughly 20-feet thick, at depths of 2400 to 3300 feet. The second model is a single coal seam, that is 20-feet thick at a depth of 2200 feet. All the seams are subbituminous at their respective depths.

Methods and Costs

The methods for drilling and completing wells and the estimated costs in our coal seam models are presented.

Drilling and Completing a Multi-Seam Well

After building the location and setting the surface casing, our well will be air-drilled to 3300 feet. The contract will be "turnkeyed" with most of the drilling expenses paid for on a "flat dollar/foot" basis. The "turnkey" equipment and services furnished by the contractor are listed in a drilling contract. The estimated costs in Table 3 were furnished by Kansas-Nebraska's drilling department for the fall, 1977 and are based on a "turnkey" contract. The three 20-foot coal seams in the interval between 2400 feet and total depth (TD) will be cored. Lab tests on the cores will include adsorption isotherms, methane content, chemical analysis for rank, volatiles, and moisture content. These costs are under formation evaluation and are not usually covered under the "turnkey" contract. Porosity and permeability tests should be run on the cores for fracture treatment design. Upon reaching

Table 3 DETAILED ESTIMATE FOR AUTHORITY FOR EXPENDITURE FALL 1977

ITEM	COMPLETED COST
1 Well - 3 20' seams	
DRILLING COST	
Roads and Location	$ 4,000
Fuel, Comp. Rig, Boilers, etc.	
Hauling, Move in, etc.	
Contract Drilling 3300' @ $10.50/ft	34,650
Daywork -- with Drill Pipe	
Daywork -- without Drill Pipe	
Completion Unit	
Bits	
Rentals, Down Hole and Surface	
Mud	
Chemicals and Additives	
Liquid Mud and Brines	
Air Compressor Rental, etc.	6,400
District Expense	1,000
Contingencies 10%	4,855
Cementing, Surface & Intermediate	2,500
Total Drilling Cost	53,435
FORMATION EVALUATION	
Rig Time 2 days @ $3,000/day	6,000
Coring 60' of core plug $5,000 testing	10,000
Drill Stem Testing	
Well Surveys	
Logging Induction, Density, Neutron	5,000
Contingencies 10%	2,100
Total Formation Evaluation Costs	23,100
COMPLETION COSTS	
Rig Time 8 days @ $750/day	6,000
Rentals and Labor	
Perforating	3,500
Acidizing and Frac 3-40,000 gal foam frac @ ($18,000)	54,000
Packers, BP, etc.	2,000
Trucking	600
Cement and Equipment	2,500
Wireline	
Contingencies 10%	6,860
Total Completion Cost	75,460
Total Intangible Cost	151,995
TANGIBLE COST	
Conductor Pipe	
Surface	
Intermediate	
Production 3300' (4½" Csg.) @ 4.50/ft	14,850
Tubing 3200' (2 3/8" Tbg.) @ 2.00/ft	6,400
Well Heads	1,000
Rods	2,000
Pumping Unit	8,000
Engine	1,500
Miscellaneous	1,000
Total Tangible Cost	34,750
LEASE EQUIPMENT	
Flow Lines	
Separator or Production Unit	
Heater Treater	
Tanks	
Construction Cost and Miscellaneous	
Total Lease Equipment	
Total Well Cost	$186,745

TD, logs which can be run in an air-drilled hole (induction, density, and pad-neutron) will be run. The above are all intangible drilling costs (IDCs) which would be expensed along with tangible costs in the event of a dry hole in an after-tax case. For a producing well, IDCs are expensed. Production casing will be set deep enough below the lowest coal seam to create a sump in which the water collects. This production casing will extend to surface and be cemented from TD to above the uppermost coal. A cement bond log will be run to check the cement job. After the log and core data have been analyzed, a stimulation treatment (frac job) will be designed. For our study an assumption that a 40,000 gal foam fracture treatment will be sufficient for each seam. The treatment will be through perforations and 100-mesh sand will be added to prevent leak-off. The well will be swabbed to the top of perforations and any remaining frac sand will have to be blown out. Retrievable bridge plugs will have to be placed below each of the upper two zones before they are stimulated.

After the bridge plugs are drilled out and the well has been cleaned out to TD, a water production string consisting of tubing and sucker rods will be run. The surface facilities will consist of a pumpjack, engine, and evaporation pits or storage tanks. All tangible cost items are listed together and would normally be depreciated by any reasonable method.

Drilling and Completing a Single Seam Well

The single seam well will be air-drilled to 2200 feet. The same

procedures for the multi-seam well will be used here - core, lab tests, logs, casing program, and stimulation treatment. Bridge plugs will not be needed. Table 4 shows a detailed cost estimate for a single seam well drilled and completed at 2200 feet.

Assumptions

The following assumptions were made to simplify our economic models. Sensitivity analysis will later be run to better understand the more influential parameters on our models, including some of the assumptions:

1) The discount rate will be 20% annually, end of the period, and all cash flow will be discounted back to 1978.

2) The runs are made on a before-income tax basis so as to give a measure of gross profitability. An after-tax run could include such unresolved complications as depletion allowances of coal versus gas, tax credits, mining development costs expensed versus the tangible and intangible costs of drilling.

3) The price of gas is $1.50/MCF, even though coalbed gas is not presently regulated by FERC of the Department of Energy. In the Rockies, the price of coalbed gas will be regulated by the availability of interstate gas and will have the interstate gas price of at least $1.50/MCF.

4) All costs are as of the fall, 1977.

5) Operating expenses will be $250/well/month. This is a normal maintenance charge on wells to cover both field and office overhead.

6) A washout of price increases and escalation of operating expenses will occur.

7) A one-eighth royalty will be taken out of gross production for the oil and gas mineral rights royalty. This is the normal oil field royalty.

Table 4 DETAILED ESTIMATE FOR AUTHORITY FOR EXPENDITURE FALL 1977			
ITEM	COMPLETED COSTS		
1 - 20 ft zone	1100'	2200'	3300'
DRILLING COST			
Roads and Location	4,000	4,000	4,000
Fuel, Comp. Rig, Boilers, etc.			
Hauling, Move in, etc.			
Contract Drilling $10.50/ft	11,550	23,100	34,650
Daywork -- with Drill Pipe			
Daywork -- without Drill Pipe			
Completion Unit			
Bits			
Rentals, Down Hole and Surface			
Mud			
Chemicals and Additives			
Liquid Mud and Brines			
Air Compressor Rental, etc.	5,600	6,000	6,400
District Expense	1,000	1,000	1,000
Contingencies	2,465	3,660	4,855
Cementing, Surface & Intermediate	2,500	2,500	2,500
Total Drilling Cost	27,115	40,260	53,435
FORMATION EVALUATION			
Rig Time $3000/day	3,000	same	same
Coring 20' of coring/testing	4,000		
Drill Stem Testing			
Well Surveys			
Logging Induction, Density, Neutron	5,000		
Contingencies	1,200		
Total Formation Evaluation Costs	13,200	13,200	13,200
COMPLETION COSTS			
Rig Time 3 days @ 750/day	2,250	same	same
Rentals and Labor			
Perforating	1,500		
Acidizing and Frac 40,000 gal foam frac	18,000		
Packers, BP, etc.			
Trucking	600		
Cement and Equipment	2,500		
Wireline			
Contingencies	2,485		
Total Completion Cost	27,335	27,335	27,335
Total Intangible Cost	67,650	80,795	93,970
TANGIBLE COST			
Conductor Pipe			
Surface			
Intermediate			
Production (4½" Csg) @ 4.50/ft	4,950	9,900	14,850
Tubing (2 3/8" Tbg) @ 2.00/ft	2,200	4,400	6,600
Well Heads	1,000	1,000	1,000
Rods	1,000	1,500	2,000
Pumping Unit	8,000	8,000	8,000
Engine	1,500	1,500	1,500
Miscellaneous	1,000	1,000	1,000
Total Tangible Cost	19,650	27,300	34,950
LEASE EQUIPMENT			
Flow Lines			
Separator or Production Unit			
Heater Treater			
Tanks			
Construction Cost and Miscellaneous			
Total Lease Equipment			
Total Well Cost	87,300	108,095	128,920

8) Production is in MMCFPD, the BTU is 950, and the maximum life of the field is 50 years unless operating costs exceed production revenue.

9) The production decline is exponential and the effective decline is 4% per year.

10) Although the Rocky Mountain coals have roughly one-third the methane content because of their rank, the seams are three times thicker. The "most likely" production rate for the first year will average 30 MCFPD per 20' seam. Compared to unpublished production rates from recently completed wells, this initial average annual rate is conservative.

11) The water production, although initially high because of our thicker seams, will drop as production has in the past and will be minimal after several months.

12) A 100% success ratio is assumed as the coals have been located by earlier drilling and there are no mechanical problems with the wells.

13) In the triple-seam model, the production rates are additive. In practice this rarely happens.

Computer Runs - POGO

The economic evaluation was run with a computer program written by Petroleum Software International Ltd. The program "Profitability of Oil and Gas Opportunities" (POGO) has the capabilities to handle most oil and gas models.

A sample input sheet (Table 5) is shown for 1 well with a 20-foot seam, producing an initial average annual rate of 30 MMCFPD (QGASI = .030, PRDTM = DAY). The operations costs are $250/well/month for 50 years (OEXDWM = 50 * 250) and the well's total cost is $108,095 (TANGA = 27.3, INTANGA = 80.795). As stated in the assumptions, the maximum field life is 50 years (MAXLIF = 50), the discount rate is 20 percent

Table 5 - Sample Computer Input Sheet

```
COAL6

100 COAL DEMETHANIZATION 1 WELL, 1-20 FOOT SEAM
101 30 MCFPD INITIALLY, OP. COST=$250/WELL-MONTH
102 TOTAL COST/WELL=$108,095
119 $DATA
122 FEDTX=NIL
124 OUTPUT=ANNL, WIDTH=WIDE
134 MAXLIF=50
138 PVINC=ANEP, PVICPC=.20
162 PRDTIM=DAY
217 BTU=950
250 DECG=EXP
252 QGASI=.030
254 DECPCG=.04
256 QGASF=.005
370 PRRES=50*1.5
475 ROY=50*0.125
617 OEXDWM=50*250.
700 INTAN=1*80.795,49*0
715 TANGA=1*27.3,49*0
999 $END
```

(PVICPC = .20), the calorific value of the gas is 950 (BTU = 950), the effective decline is 4 percent/year (DECPCG = .04, DECG = EXP) and the cutoff production rate is 5 MCFPD (QGASF = .005). The price is a nonescalating $1.50/MCF for 50 years (PRRES = 50 * 1.5) and the royalty is one-eighth for 50 years (ROY = 50* 0.125). The economic analysis is on a before-tax basis (FEDTX = NIL).

A sample print-out (Table 6) shows the year, number of wells, average daily production rate, gross yearly production, after-royalty yearly production, and the price/MCF adjusted for Btu-values on the first page. The life of the well ends in 37 years when the operating costs exceed the production revenue. On the second page of Table 6, the year, the net reserves revenue before royalty, the total net revenue after royalty, the net operating expenses per year, and the net operating income are presented in the first ten columns. In the last seven columns the net capital investments, the net cash flow, the cumulative net cash flow, and the discounted cumulative net cash flow are listed. In the summary, the interests in the well, the reserves, and project life are presented. The net present value (NPV) of discount rates of 0, 5, 10, 15, 20, 30 percent and our input rate of 20 percent are given. The rate of return, payout, and various other net profit indicators are also listed.

Using 57,600 for a conversion factor of cc/g to ft^3 of gas per acre-foot of coal, the total produced reserves of 209 MMCF, and a 50 percent recovery factor; the total acreage drained by this well in 37 years is 73 acres, which is reasonable.

Table 6

COAL DEMETHANIZATION 1 WELL, 1-20 FOOT SEAM
30 MCFPD INITIALLY, OP. COST=$250/WELL-MONTH
TOTAL COST/WELL=$108,095

OIL AND GAS LEASE ECONOMIC EVALUATION

		GAS WELL *			********** BEFORE INCOME TAX **********								OIL WELL *		
YEAR	WELL	GROSS RAW GAS/D MCF	GROSS YEARLY RES. MCF	NET YEARLY RES. MCF	RES. PRICE $/MF	GROSS COND. STB	COND. PRICE $/B	GROSS PROPAN STB	PROPAN PRICE $/B	GROSS BUTANE STB	BUTANE PRICE $/B	GROSS SUL. LT	SUL. PRICE $/LT	GROSS DAILY OIL STB	OIL PRICE $/B	GROSS SOLN GAS MCF
1978	1	29	10730	9388	1.42	0	0.	0	0.	0	0.	0	0.			
1979	1	28	10300	9013	1.42	0	0.	0	0.	0	0.	0	0.			
1980	1	27	9888	8652	1.42	0	0.	0	0.	0	0.	0	0.			
1981	1	26	9493	8306	1.42	0	0.	0	0.	0	0.	0	0.			
1982	1	25	9113	7974	1.42	0	0.	0	0.	0	0.	0	0.			
1983	1	24	8749	7655	1.42	0	0.	0	0.	0	0.	0	0.			
1984	1	23	8399	7349	1.42	0	0.	0	0.	0	0.	0	0.			
1985	1	22	8063	7055	1.42	0	0.	0	0.	0	0.	0	0.			
1986	1	21	7740	6773	1.42	0	0.	0	0.	0	0.	0	0.			
1987	1	20	7431	6502	1.42	0	0.	0	0.	0	0.	0	0.			
1988	1	20	7133	6242	1.42	0	0.	0	0.	0	0.	0	0.			
1989	1	19	6848	5992	1.42	0	0.	0	0.	0	0.	0	0.			
1990	1	18	6574	5752	1.42	0	0.	0	0.	0	0.	0	0.			
1991	1	17	6311	5522	1.42	0	0.	0	0.	0	0.	0	0.			
1992	1	17	6059	5301	1.42	0	0.	0	0.	0	0.	0	0.			
1993	1	16	5816	5089	1.42	0	0.	0	0.	0	0.	0	0.			
1994	1	15	5584	4886	1.42	0	0.	0	0.	0	0.	0	0.			
1995	1	15	5360	4690	1.42	0	0.	0	0.	0	0.	0	0.			
1996	1	14	5146	4503	1.42	0	0.	0	0.	0	0.	0	0.			
1997	1	14	4940	4323	1.42	0	0.	0	0.	0	0.	0	0.			
1998	1	13	4742	4150	1.42	0	0.	0	0.	0	0.	0	0.			
1999	1	12	4553	3984	1.42	0	0.	0	0.	0	0.	0	0.			
2000	1	12	4371	3824	1.42	0	0.	0	0.	0	0.	0	0.			
2001	1	11	4196	3671	1.42	0	0.	0	0.	0	0.	0	0.			
2002	1	11	4028	3524	1.42	0	0.	0	0.	0	0.	0	0.			
2003	1	11	3867	3384	1.42	0	0.	0	0.	0	0.	0	0.			
2004	1	10	3712	3248	1.42	0	0.	0	0.	0	0.	0	0.			
2005	1	10	3564	3118	1.42	0	0.	0	0.	0	0.	0	0.			
2006	1	9	3421	2994	1.42	0	0.	0	0.	0	0.	0	0.			
2007	1	9	3284	2874	1.42	0	0.	0	0.	0	0.	0	0.			
2008	1	9	3153	2759	1.42	0	0.	0	0.	0	0.	0	0.			
2009	1	8	3027	2648	1.42	0	0.	0	0.	0	0.	0	0.			
2010	1	8	2906	2543	1.42	0	0.	0	0.	0	0.	0	0.			
2011	1	8	2790	2441	1.42	0	0.	0	0.	0	0.	0	0.			
2012	1	7	2678	2343	1.42	0	0.	0	0.	0	0.	0	0.			
2013	1	7	2571	2249	1.42	0	0.	0	0.	0	0.	0	0.			
2014	1	7	2468	2159	1.42	0	0.	0	0.	0	0.	0	0.			
2015	1	7	308	270	1.42	0	0.	0	0.	0	0.	0	0.			
TOT.	1	15	209314	183150	1.43	0	0.	0	0.	0	0.	0	0.			

Table 6 (Cont)

YEAR	NET OIL REV. BEFORE ROYLTY $	NET RES. REV. BEFORE ROYLTY $	NET SUB. REV. BEFORE ROYLTY $	TOTAL NET REV. BEFORE ROYLTY $	TOTAL NET REV. AFTER ROYLTY $	OTHER NET INCOME $	NET OP. EXP. $	TOTAL NET LOCAL TAXES $	NET OP. INCOME $	*** CAPITAL BONUS $	****** NET ****** INVESTMENTS INTANG $	TANG $	*** TOTAL $	NET C FLOW $	CUM. NET C FLOW $	DISC. CUM. NET C FLOW $
1978	0	15290	0	15290	13378	0	3000	0	10378	0	0	27300	108095	-97717	-97717	-99446
1979	0	14678	0	14678	12843	0	3000	0	9843	0	0	0	0	9843	-87873	-92611
1980	0	14091	0	14091	12329	0	3000	0	9329	0	0	0	0	9329	-78544	-87212
1981	0	13527	0	13527	11836	0	3000	0	8836	0	0	0	0	8836	-69708	-82950
1982	0	12986	0	12986	11363	0	3000	0	8363	0	0	0	0	8363	-61345	-79590
1983	0	12467	0	12467	10908	0	3000	0	7908	0	0	0	0	7908	-53436	-76941
1984	0	11968	0	11968	10472	0	3000	0	7472	0	0	0	0	7472	-45964	-74856
1985	0	11489	0	11489	10053	0	3000	0	7053	0	0	0	0	7053	-38911	-73215
1986	0	11030	0	11030	9651	0	3000	0	6651	0	0	0	0	6651	-32260	-71926
1987	0	10589	0	10589	9265	0	3000	0	6265	0	0	0	0	6265	-25995	-70915
1988	0	10165	0	10165	8894	0	3000	0	5894	0	0	0	0	5894	-20101	-70121
1989	0	9758	0	9758	8539	0	3000	0	5539	0	0	0	0	5539	-14562	-69500
1990	0	9368	0	9368	8197	0	3000	0	5197	0	0	0	0	5197	-9365	-69014
1991	0	8993	0	8993	7869	0	3000	0	4869	0	0	0	0	4869	-4496	-68635
1992	0	8634	0	8634	7554	0	3000	0	4554	0	0	0	0	4554	58	-68340
1993	0	8288	0	8288	7252	0	3000	0	4252	0	0	0	0	4252	4311	-68110
1994	0	7957	0	7957	6962	0	3000	0	3962	0	0	0	0	3962	8273	-67931
1995	0	7638	0	7638	6684	0	3000	0	3684	0	0	0	0	3684	11956	-67793
1996	0	7333	0	7333	6416	0	3000	0	3416	0	0	0	0	3416	15373	-67686
1997	0	7040	0	7040	6160	0	3000	0	3160	0	0	0	0	3160	18532	-67603
1998	0	6758	0	6758	5913	0	3000	0	2913	0	0	0	0	2913	21446	-67540
1999	0	6488	0	6488	5677	0	3000	0	2677	0	0	0	0	2677	24122	-67491
2000	0	6228	0	6228	5450	0	3000	0	2450	0	0	0	0	2450	26572	-67454
2001	0	5979	0	5979	5232	0	3000	0	2232	0	0	0	0	2232	28804	-67426
2002	0	5740	0	5740	5022	0	3000	0	2022	0	0	0	0	2022	30826	-67405
2003	0	5510	0	5510	4822	0	3000	0	1822	0	0	0	0	1822	32648	-67389
2004	0	5290	0	5290	4629	0	3000	0	1629	0	0	0	0	1629	34276	-67377
2005	0	5078	0	5078	4444	0	3000	0	1444	0	0	0	0	1444	35720	-67369
2006	0	4875	0	4875	4266	0	3000	0	1266	0	0	0	0	1266	36985	-67362
2007	0	4680	0	4680	4095	0	3000	0	1095	0	0	0	0	1095	38081	-67358
2008	0	4493	0	4493	3931	0	3000	0	931	0	0	0	0	931	39012	-67354
2009	0	4313	0	4313	3774	0	3000	0	774	0	0	0	0	774	39786	-67352
2010	0	4141	0	4141	3623	0	3000	0	623	0	0	0	0	623	40409	-67351
2011	0	3975	0	3975	3478	0	3000	0	478	0	0	0	0	478	40887	-67350
2012	0	3816	0	3816	3339	0	3000	0	339	0	0	0	0	339	41226	-67349
2013	0	3663	0	3663	3206	0	3000	0	206	0	0	0	0	206	41432	-67349
2014	0	3517	0	3517	3077	0	3000	0	77	0	0	0	0	77	41509	-67349
2015	0	439	0	439	385	0	384	0	1	0	0	0	0	1	41510	-67349
TOT.	0	298273	0	298273	260989	0	111384	0	149605	0	0	27300	108095	41510	41510	-67349

Table 6 (Cont)

********** SUMMARY **********

INTERESTS *

INTL WORKING INT (PCT) =	100.00000
INTL CAPITAL INT (PCT) =	100.00000
INTL ROYALTY INT (PCT) =	12.50000
AVG. ROYALTY INT (PCT) =	12.50000

RESERVES + PROJECT LIFE *

LIFE (YRS) = 37.13

RESERVES

	OIL (MSTB)	SOLN GAS (MMCF)	RESIDUE (MMCF)	COND. (MSTB)	PROPANE (MSTB)	BUTANE (MSTB)	SULPHUR (MLT)
GROSS	0.	0.	209.3	0.	0.	0.	0.
NET	0.	0.	183.1	0.	0.	0.	0.

NET PRESENT VALUE *

DISC. RATE	*** BEFORE INCOME TAX *** OP. INC (M$)	INV. (M$)	C FLOW (M$)
0.	149.6	108.1	41.5
5.00	93.1	108.1	-15.0
10.00	65.8	108.1	-42.3
15.00	50.4	108.1	-57.7
20.00	40.7	108.1	-67.3
30.00	29.3	108.1	-78.7
20.00	40.7	108.1	-67.3

NET PROFIT INDICATORS *

*** BEFORE INCOME TAX ***

RATE OF RETURN (PCT)	3.24
PAYOUT (YRS)	14.99
INTL. OP. INC ($/DAY)	28.43
AVG LSE OP CST ($/UNIT)	0.68
AVG LS PROD VAL ($/UNT)	1.35
UNDIS C FLOW/UNDIS INV	0.38
DIS C FLOW/DIS INV	-0.62
DIS C FLOW/UNDIS INV	-0.62
CAPITAL EXPOSURE (M$)	0.
UNDIS C FLOW/CAP EXPOS	0.
DIS C FLOW/CAP EXPOS	0.
SUCCESS CAPACITY	0.

$$\frac{209 \text{ MMCF}}{50\% \quad \frac{57{,}600 \text{ ft}^3\text{g}}{\text{acre-ft(cc)}} \quad \frac{5\text{cc}}{\text{g}} \quad (20 \text{ ft})} = 73 \text{ acres}$$

All computer runs are listed in Table 7 with their input data and the net present value at 20 percent.

"Most Likely" Runs

Using a "most likely" average first year production of 30 MCFPD/seam, the single-seam and the triple-seam wells both have negative net present values (NPV) at 20% before income tax (BFIT). These are -$67,300 and -$34,500 for the single and triple-seam wells respectively (Runs 6 and 1 on Table 7). Based on these initial figures, the prospects for coalbed gas wells are poor; but it must be remembered that these are "exploratory" wells and their costs will be 20-30% higher than a "development" well. It is not uncommon in the petroleum industry for the discovery "wildcat" in a field to never payout because of the high costs of additional precautions and the additional evaluation needed. By drilling additional gas wells, economies of scale and better methods will hopefully make the additional wells economical and help payout the original "discovery."

Sensitivity Analysis - Economics

The factors involved in making a commercial coalbed gas well are numerous, from the reservoir parameters to the drilling and completing of the wells. Models have been developed to simplify most of these factors based on the present "oilpatch" technology and experience of producing eastern U.S. coalbed gas well. By using sensitivity analysis

Table 7 - Data for Economic Analysis

	Run	Intan	Tang	Total	Effec. Decline	Initial Yearly Rate	Operating Cost	# Wells	# Seams	Price ($/MCF)	Depth (ft.)	NPV @ 20% ($M)
1.		151.995	34.750	186.745	.04	90	250	1	3	1.50	3300	-34.5
2.		123.852	34.750	158.602	.04	90	250	1 of 25	3	1.50	3300	- 6.4
3.		143.195	34.750	177.945	.04	90	250	1 of 4	3	1.50	3300	-25.7
4.	Not Run	149.610	34.750	184.000	.04	45	250	1 of 4	3	1.50	3300	
5.		80.795	27.300	108.095	.04	15	250	1	1	1.50	2200	-95.2
6.		80.795	27.300	108.095	.04	30	250	1	1	1.50	2200	-67.3
7.		80.795	27.300	108.095	.04	45	250	1	1	1.50	2200	-39.5
8.		80.795	27.300	108.095	.04	60	250	1	1	1.50	2200	-11.3
9.		80.795	27.300	108.095	.04	75	250	1	1	1.50	2200	16.3
10.	Not Run	151.995	34.750	186.745	.04	45	250	1	3	1.50	3300	—
11.		151.995	34.750	186.745	.04	135	250	1	3	1.50	3300	49.1
12.		151.995	34.750	186.745	.04	180	250	1	3	1.50	3300	132.7
13	Not Run	151.995	34.750	186.745	.04	225	250	1	3	1.50	3300	—
14.		67.650	19.650	87.300	.04	60	250	1	1	1.50	1100	9.2
15.		67.650	19.650	87.300	.04	45	250	1	1	1.50	1100	-18.7
16.		93.970	34.950	128.920	.04	75	250	1	1	1.50	3300	- 4.6
17.		93.970	34.950	128.920	.04	60	250	1	1	1.50	3300	-32.4
18.		80.795	27.300	108.095	.02	60	250	1	1	1.50	2200	- 0.2
19.		80.795	27.300	108.095	.06	60	250	1	1	1.50	2200	-21.2
20.		80.795	27.300	108.095	.06	75	250	1	1	1.50	2200	4.2
21.		80.795	27.300	108.095	.02	75	250	1	1	1.50	2200	30.5
22.		80.795	27.300	108.095	.04	60	250	1	1	2.00	2200	25.6
23.		80.795	27.300	108.095	.04	45	250	1	1	2.00	2200	-11.6
24.		80.795	27.300	108.095	.04	45	250	1	1	2.50	2200	16.3
25.		80.795	27.300	108.095	.04	45	250	1	1	3.00	2200	44.1
26.		123.852	34.750	158.602	.04	90	150	1	3	1.50	3300	- 0.4
27.		123.852	34.750	158.602	.04	90	350	1	3	1.50	3300	-12.4
28.		80.795	27.300	108.095	.04	30	250	1	1	3.00	2200	-11.6
29.		80.795	27.300	108.095	.04	60	250	1	1	3.00	2200	99.9

the parameters which will affect our economics the most can be determined. Sensitivity analysis will cover the following parameters:

1. Rate
2. Effective Decline
3. Depth
4. Economies of Scale
5. Operating Costs
6. Price

Rate

By increasing the initial average annual rate (IAAR) of our single-seam model at 2200 feet, the net present value increases (Figure 20). For IAARs of 15, 30, 45, 60, and 75 MCFPD, respective NPVs of -$95,200, -$67,300, -$39,500, -$11,600, and +$16,300 are calculated. At a rate of 66 MCFPD our model will reach a 20% rate of return (ROR) before tax.

For the triple-seam model, IAARs of 30, 45, and 60 MCFPD result in respective NPVs of -$34,500, +$49,100, and +$132,700 (Figure 21). The breakeven point is 36 MCFPD per seam or 108 MCFPD for a $187,000 well. The slope of the line is much steeper in the triple-seam case as the well is producing three times the initial rate.

The steep slope for both analyses indicates that the net present value is very sensitive to the initial average annual rate. Because all the vertical axes (Net Present Value) are on the same scale, the slope of the line will indicate sensitivity.

The rate will be mainly a function of coal rank, gas content,

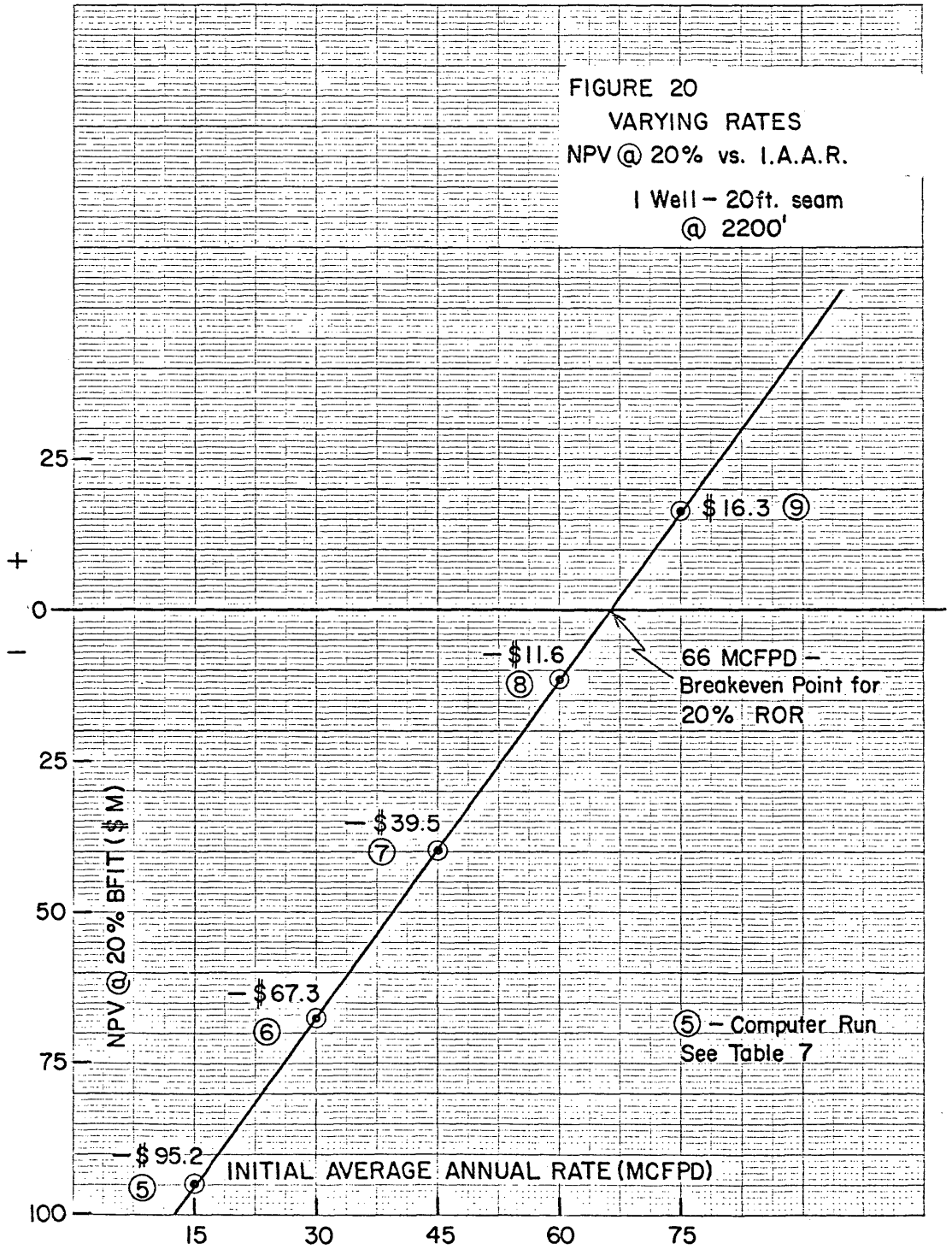


FIGURE 20
VARYING RATES
NPV @ 20% vs. I.A.A.R.
1 Well – 20ft. seam
@ 2200'
+
0
–
25
25
50
75
100
NPV @ 20% BFIT ($ M)
$16.3 ⑨
–$11.6
⑧
66 MCFPD –
Breakeven Point for
20% ROR
–$39.5
⑦
–$67.3
⑥
⑤ – Computer Run
See Table 7
–$95.2
⑤
INITIAL AVERAGE ANNUAL RATE (MCFPD)
15
30
45
60
75

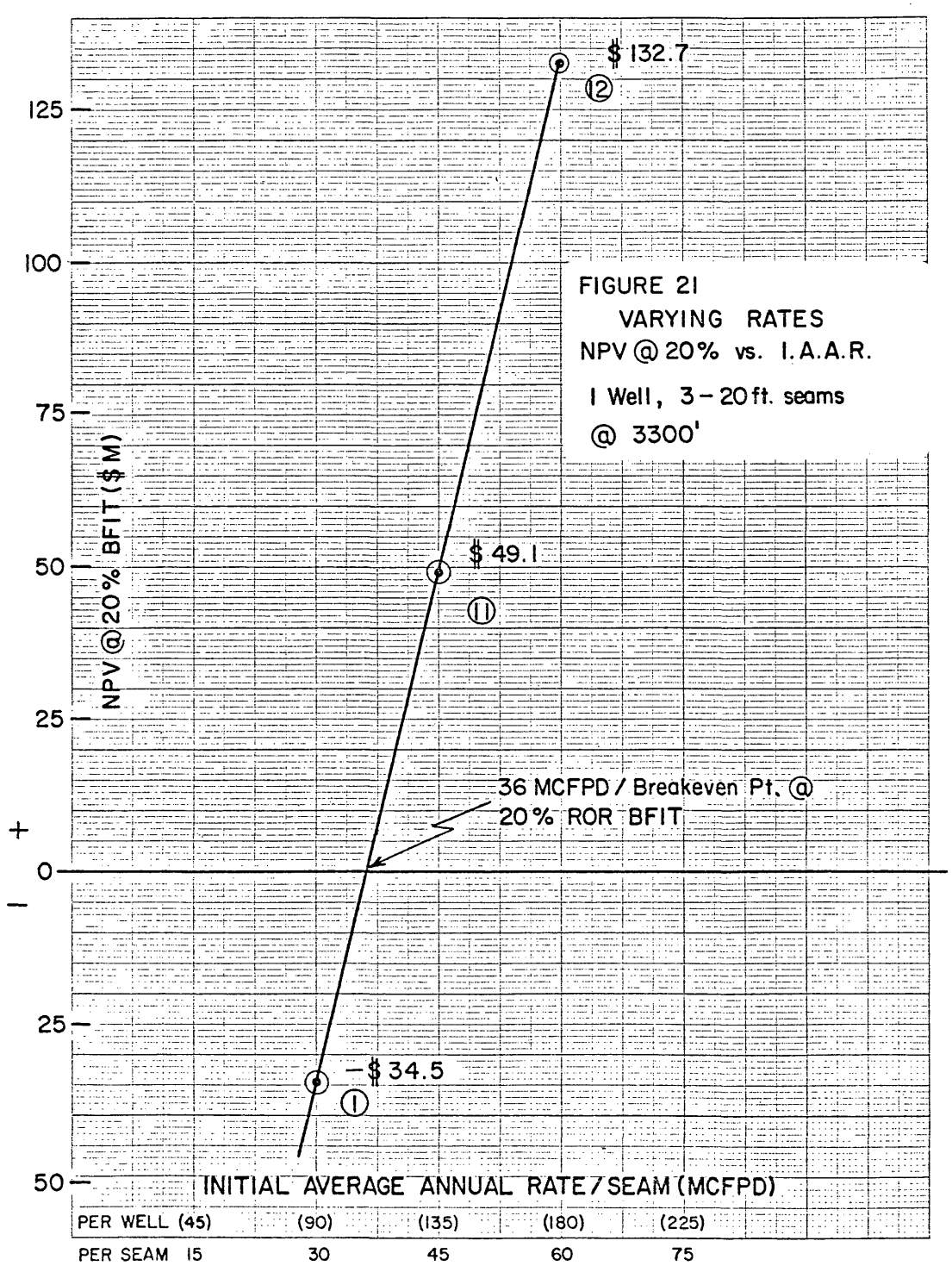


FIGURE 21
VARYING RATES
NPV @ 20% vs. I.A.A.R.
1 Well, 3 – 20 ft. seams
@ 3300'

permeability, desorption rate, and fracture treatment effectiveness as covered earlier in the technical evaluation of this report. The probability of the rates being near these "most likely" values is good but with production rates dependent on so many variables, the range could be very wide, say from 0 to 100 MCFPD.

Effective Decline

Using 60 and 70 MCFPD as the IAAR on the single-seam model, the sensitivity of the effective declines can be analyzed.

Assuming the effective decline is 2 percent higher (6 percent) than our "most likely" effective decline of 4 percent the net present values will decline (Figure 22). The inverse is true using an effective decline of 2 percent, where the NPVs improve.

The effective declines could easily be in the ranges presented here. Although the effective decline does affect our cash flow, it is less sensitive than the effect of varying rates.

Depth

Using the single-20-foot-seam model at 2200 feet and estimating costs for completing the same zone at 1100 feet and 3300 feet (Table 4), the rates at which a 20% ROR is obtained can be calculated (Figure 23). The breakeven points for the IAARs of 55, 66, and 77 MCFPD are lower for the seams at 1100, 2200, and 3300 feet, respectively as the wells are less costly at the shallower depths.

The depths of coal seams can of course, cover a wide range. For

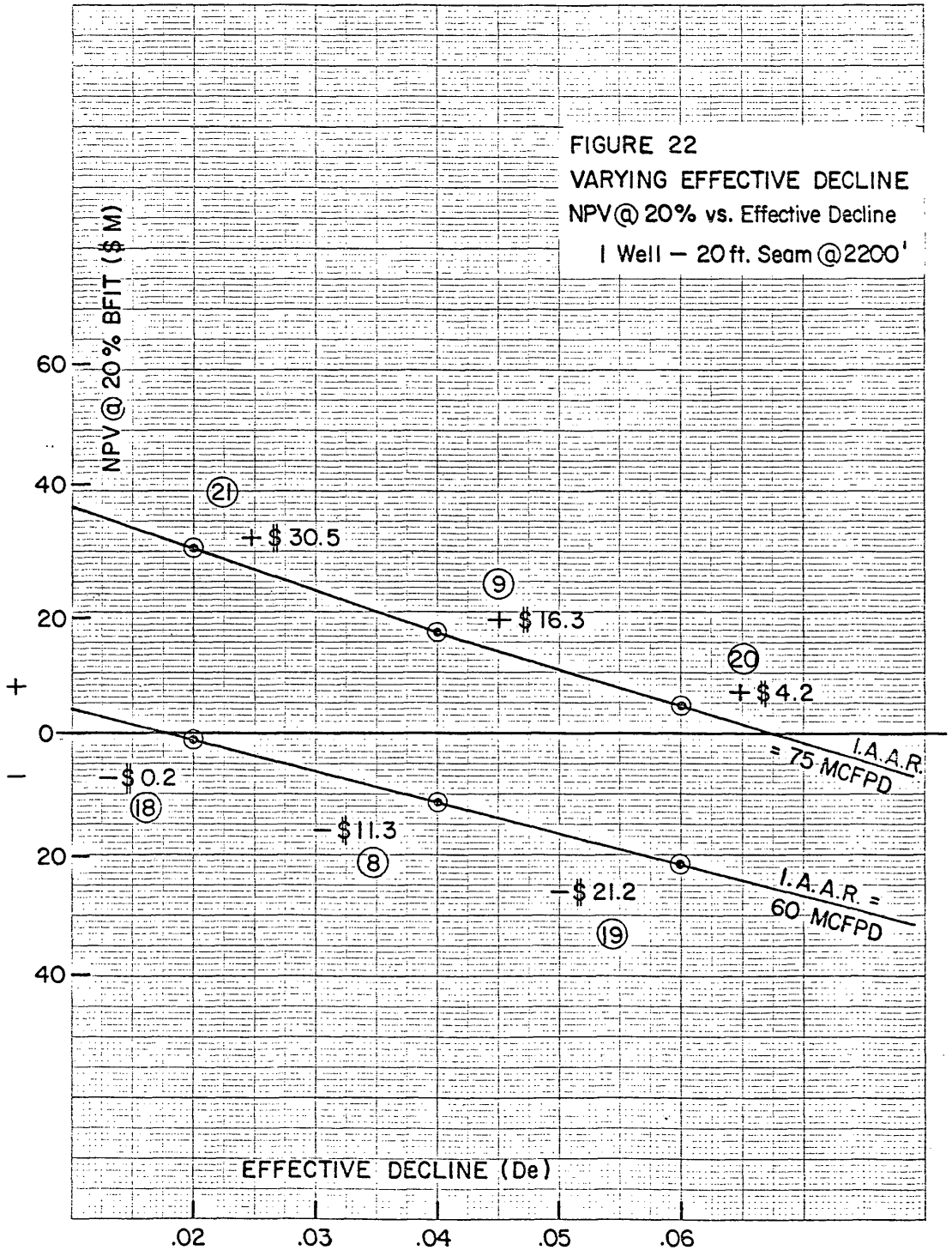


FIGURE 22
VARYING EFFECTIVE DECLINE
NPV@ 20% vs. Effective Decline
1 Well — 20 ft. Seam @2200'
NPV@20% BFIT ($M)
60
40
20
+
0
—
20
40
21
+$30.5
9
+$16.3
20
+$4.2
I.A.A.R. = 75 MCFPD
−$0.2
18
−$11.3
8
−$21.2
19
I.A.A.R. = 60 MCFPD
EFFECTIVE DECLINE (De)
.02
.03
.04
.05
.06

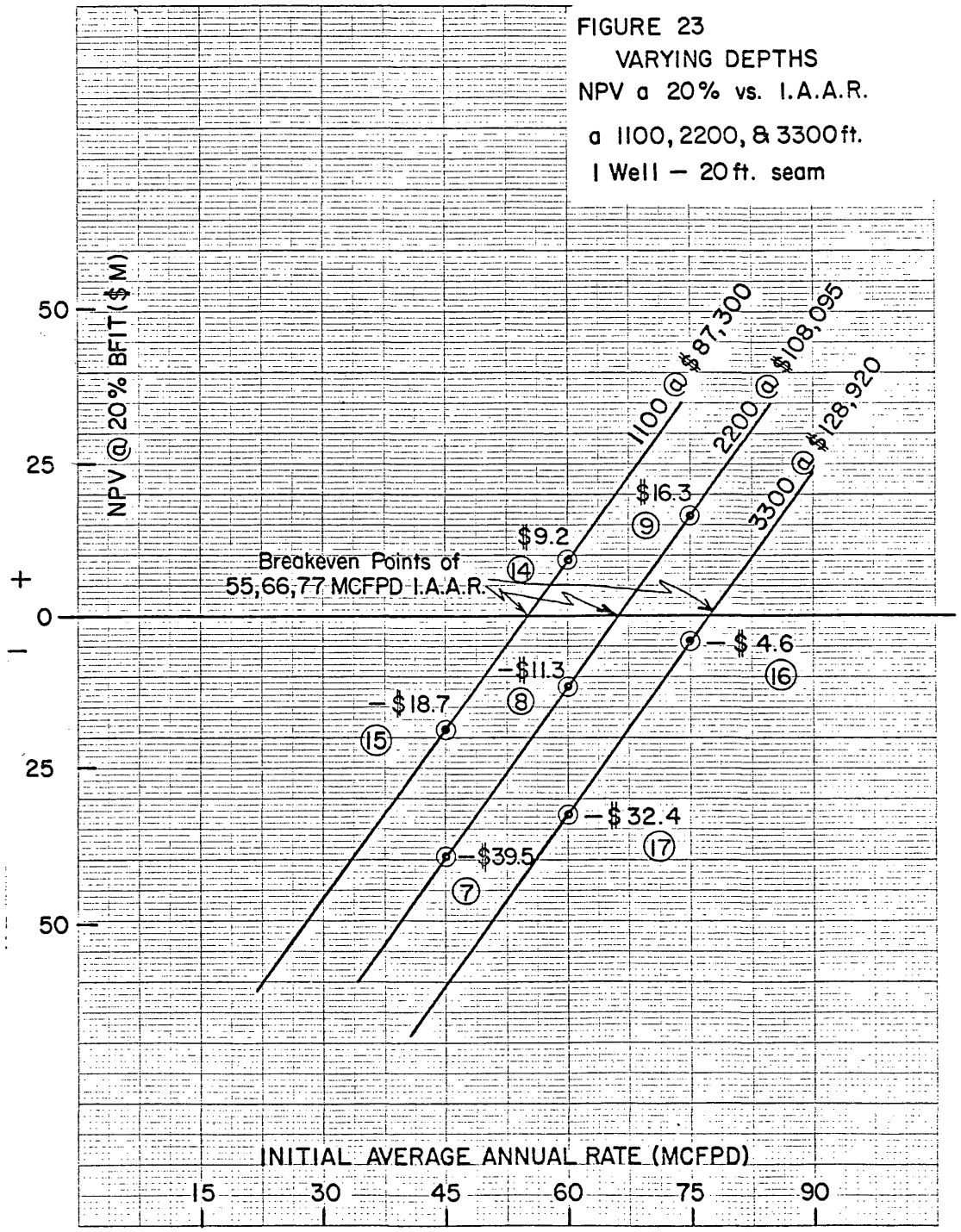


FIGURE 23
VARYING DEPTHS
NPV a 20% vs. I.A.A.R.
a 1100, 2200, & 3300 ft.
1 Well — 20 ft. seam
NPV @ 20% BFIT ($ M)
50
25
+
0
—
25
50
1100 @ $87,300
2200 @ $108,095
3300 @ $128,920
$16.3
⑨
$9.2
⑭
Breakeven Points of
55,66,77 MCFPD I.A.A.R.
— $4.6
⑯
—$11.3
⑧
— $18.7
⑮
— $32.4
⑰
—$39.5
⑦
INITIAL AVERAGE ANNUAL RATE (MCFPD)
15
30
45
60
75
90

the well operator trying to produce virgin-seam gas wells, the greater the depth (down to the maximum gas content depth of 3500 to 5000 feet), the better the gas saturation. The increased costs of drilling deeper holes at these shallow depths increases linearly.

If the "most likely" rate of 30 MCFPD holds true, it will not be economic to drill and complete a 20 foot seam. The depth of the well directly affects the cost and the net present value will be less with the increased costs.

Economies of Scale

By drilling more wells, the average cost/well will decline. Additional wells do not have to be cored and tested and savings on drilling costs can be as high as 20-30%. For 25 wells, a 25% saving per well on drilling costs will be assumed. The 4-well program's drilling costs will equal the 1-well cost (Tables 8 & 9). For 4 and 25 wells, cores will be taken on 2 and 4 wells respectively. The cost/well in a 25-well program will be roughly 85% of the 1-well cost.

Using the "most likely" case (IAAR = 30 MCFPD) on the "triple-seam" well, the project looks increasingly better with the lower costs (Figure 24). The rate of return of 20% (BFIT) is reached if well costs can be cut to $150,000 per well. The size of the project will be based largely on operator size, acreage position, cash flow, and success ratio.

The curve of the line indicates that the net present value is affected more in the lower range of savings per increased number of

Table 8 DETAILED ESTIMATE FOR AUTHORITY FOR EXPENDITURE ITEM	COMPLETED COST	1 Well Cost
4 Wells - 3 Seams 3300'	4 wells	(Average)
DRILLING COST		
Roads and Location		Same as 1 well
Fuel, Comp. Rig, Boilers, etc.		
Hauling, Move in, etc.		
Contract Drilling 3300' @ /ft		
Daywork -- with Drill Pipe		
Daywork -- without Drill Pipe		
Completion Unit		
Bits		
Rentals, Down Hole and Surface		
Mud		
Chemicals and Additives		
Liquid Mud and Brines		
Air Compressor Rental, etc.		
District Expense		
Contingencies		
Cementing, Surface & Intermediate		
Total Drilling Cost	$213,740	$ 53,435
FORMATION EVALUATION (For all 4 wells-Core 2)		
Rig Time 4 days @ 3000/day	12,000	
Coring 120' of core plug $10,000 testing	20,000	
Drill Stem Testing		
Well Surveys		
Logging (4 wells @ $5,000)	20,000	
Contingencies	5,200	
Total Formation Evaluation Costs	57,200	14,300
COMPLETION COSTS		
Rig Time		Same as 1 well
Rentals and Labor		
Perforating		
Acidizing and Frac		
Packers, BP, etc.		
Trucking		
Cement and Equipment		
Wireline		
Contingencies		
Total Completion Cost	301,840	75,460
Total Intangible Cost	572,780	143,195
TANGIBLE COST		
Conductor Pipe		Same as 1 well
Surface		
Intermediate		
Production		
Tubing		
Well Heads		
Rods		
Pumping Unit		
Engine		
Miscellaneous		
Total Tangible Cost	139,000	34,750
LEASE EQUIPMENT		
Flow Lines		
Separator or Production Unit		
Heater Treater		
Tanks		
Construction Cost and Miscellaneous		
Total Lease Equipment		
Total Well Cost	$711,780	$177,945

Table 9 DETAILED ESTIMATE FOR AUTHORITY FOR EXPENDITURE ITEM	COMPLETED COST 25 Wells	1 Well Cost (Average)
25 Wells - 3 seams 3300'		
DRILLING COST Economies of Scale - 75% of 1-well cost of $53,435		
Roads and Location		
Fuel, Comp. Rig, Boilers, etc.		
Hauling, Move in, etc.		
Contract Drilling		
Daywork -- with Drill Pipe		
Daywork -- without Drill Pipe		
Completion Unit		
Bits		
Rentals, Down Hole and Surface		
Mud		
Chemicals and Additives		
Liquid Mud and Brines		
Air Compressor Rental, etc.		
District Expense		
Contingencies		
Cementing, Surface & Intermediate		
Total Drilling Cost	$1,001,900	$ 40,076
FORMATION EVALUATION (Core 4)		
Rig Time 8 days @ $3,000/day	24,000	
Coring 240' of core plus $20,000 testing	40,000	
Drill Stem Testing	-	
Well Surveys	-	
Logging 25 wells @ $5,000	125,000	
Contingencies	18,900	
Total Formation Evaluation Costs	207,900	8,316
COMPLETION COSTS		
Rig Time		Same as 1 well
Rentals and Labor		
Perforating		
Acidizing and Frac		
Packers, BP, etc.		
Trucking		
Cement and Equipment		
Wireline		
Contingencies		
Total Completion Cost	1,886,500	75,460
Total Intangible Cost	3,096,300	123,852
TANGIBLE COST		
Conductor Pipe		Same as 1 well
Surface		
Intermediate		
Production		
Tubing		
Well Heads		
Rods		
Pumping Unit		
Engine		
Miscellaneous		
Total Tangible Cost	868,750	34,750
LEASE EQUIPMENT		
Flow Lines		
Separator or Production Unit		
Heater Treater		
Tanks		
Construction Cost and Miscellaneous		
Total Lease Equipment		
Total Well Cost	3,965,050	158,602

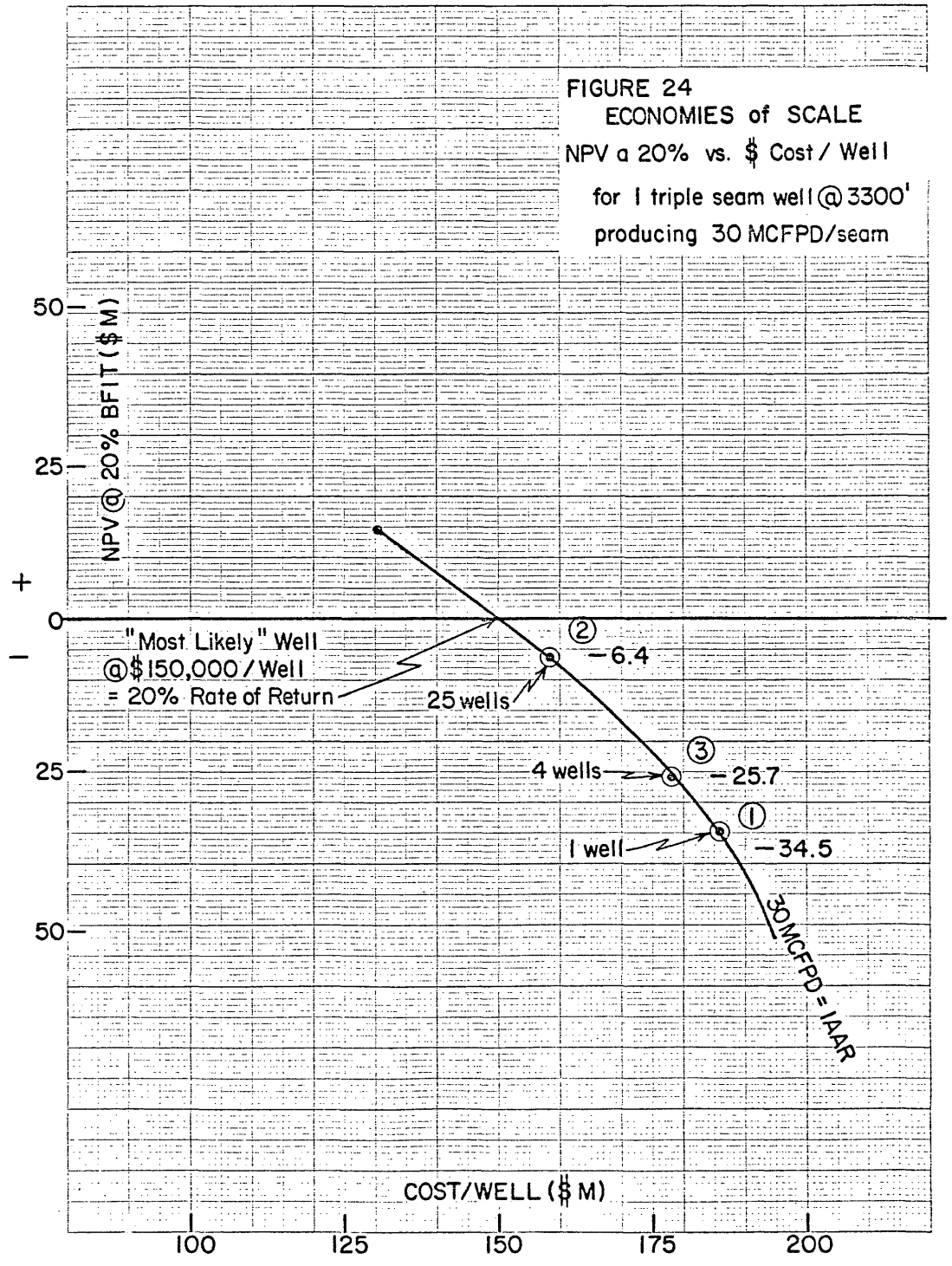


FIGURE 24
ECONOMIES of SCALE
NPV @ 20% vs. $ Cost / Well
for 1 triple seam well @ 3300'
producing 30 MCFPD/seam
NPV @ 20% BFIT ($M)
50
25
+
0
−
25
50
"Most Likely" Well
@ $150,000 / Well
= 20% Rate of Return
25 wells
②
−6.4
4 wells
③
−25.7
1 well
①
−34.5
30 MCFPD = IAAR
COST/WELL ($M)
100
125
150
175
200

wells (1 to 25) versus an upper range (25 to 50 wells) where the slope is less.

Operating Costs

If a large number of wells are drilled in an area, the cost/well for maintenance will drop. If water production is greater than expected or the water more saline, operating costs will rise.

For the triple-seam well producing a "most likely" rate of 30 MCF/seam in a 20-well program, a 20% ROR could be reached with approximate operating costs of $143/month/well (Figure 25).

The very shallow slope on this economic parameter indicates that the net present value is not very sensitive to operations costs.

Price

By raising prices (through market demand if this gas remains unregulated), the lower rate wells begin to be economical (Figure 26). Higher prices from intrastate pipelines or commercial users could also ease some of the lower-rate wells into commercialability. Using the various rates for our single-20-foot-seam at 2200 feet, the 30, 45, and 60 MCFPD wells will make a 20% ROR at the approximate gas prices of $3.30, $2.20 and $1.66/MCF, respectively.

The changing slopes indicate that the NPV is more sensitive to prices at higher rates than lower rates.

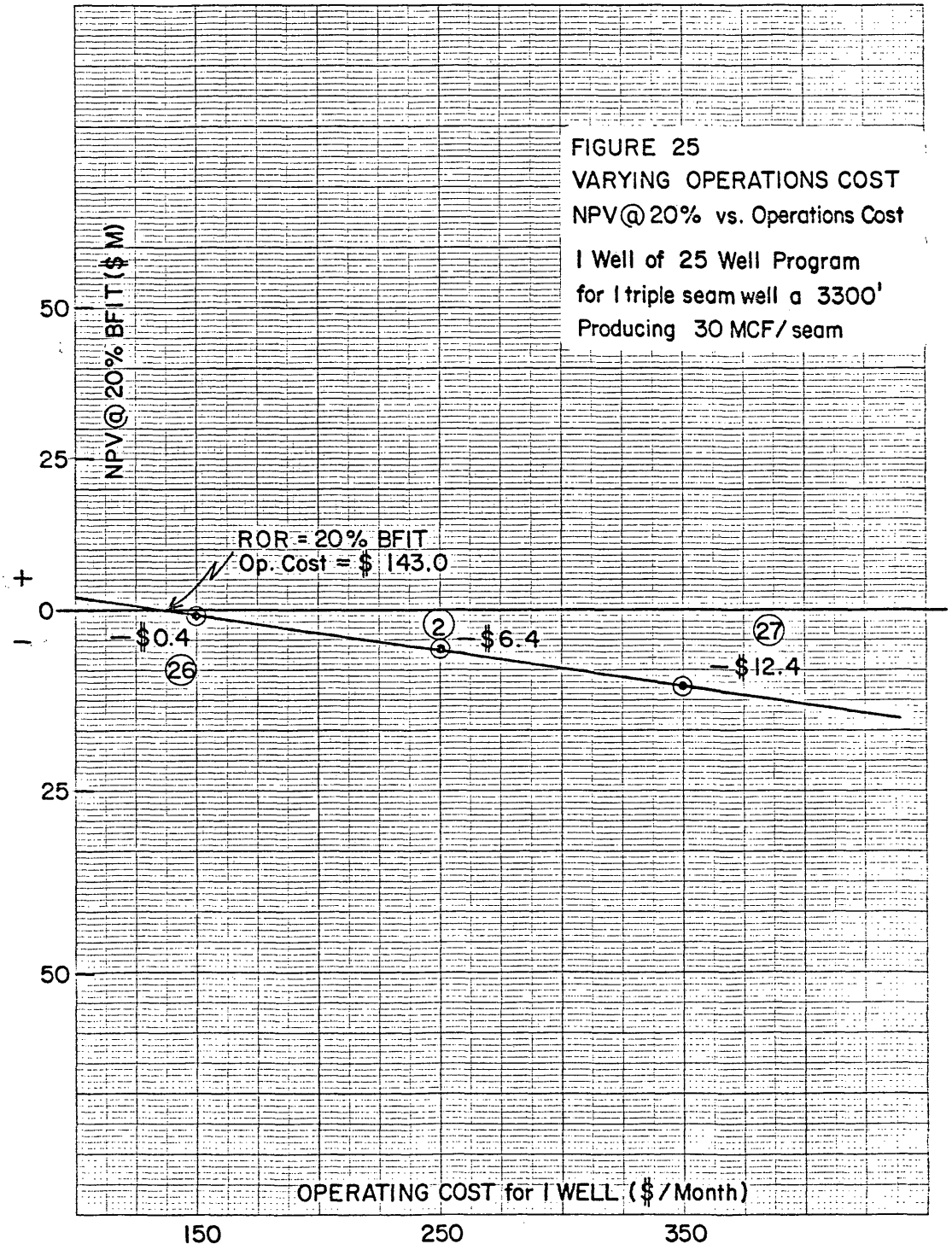


FIGURE 25
VARYING OPERATIONS COST
NPV@20% vs. Operations Cost
1 Well of 25 Well Program
for 1 triple seam well a 3300'
Producing 30 MCF/seam
NPV@20% BFIT ($M)
50
25
+
0
−
25
50
ROR = 20% BFIT
Op. Cost = $ 143.0
−$0.4
26
2
−$6.4
27
−$12.4
OPERATING COST for 1 WELL ($/Month)
150
250
350

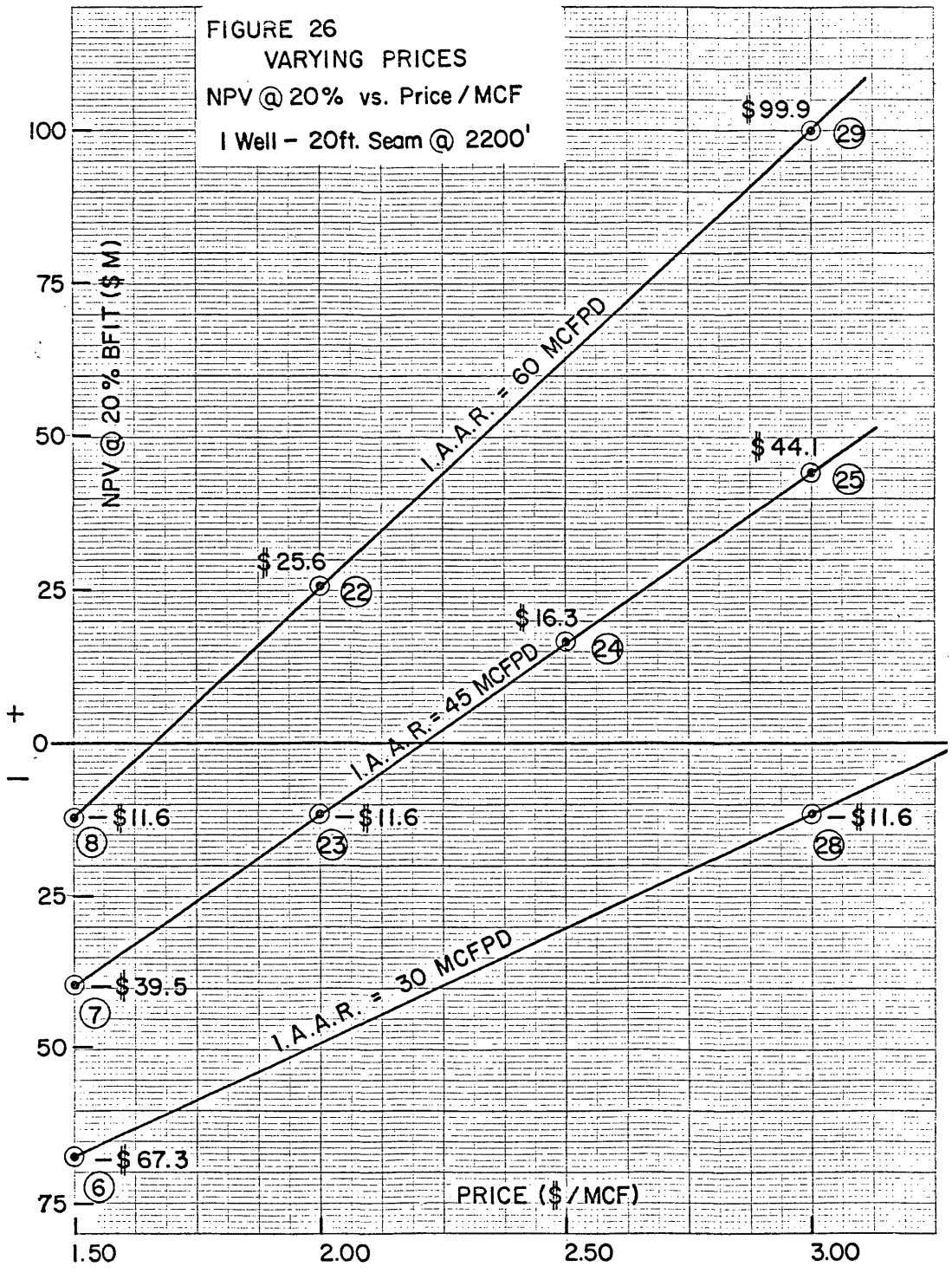


FIGURE 26
VARYING PRICES
NPV @ 20% vs. Price / MCF
1 Well – 20ft. Seam @ 2200'
NPV @ 20% BFIT ($ M)
100
75
50
25
+
0
–
25
50
75
I.A.A.R. = 60 MCFPD
I.A.A.R. = 45 MCFPD
I.A.A.R. = 30 MCFPD
$99.9
29
$44.1
25
$25.6
22
$16.3
24
–$11.6
8
–$11.6
23
–$11.6
28
–$39.5
7
–$67.3
6
PRICE ($/MCF)
1.50
2.00
2.50
3.00

Economic Overview

Degasification of coalbeds in the target areas/models reviewed here is not economically feasible with the expected price of $1.50/MCF and the projected costs to drill and complete. This is also based on extrapolating a "most likely" initial average annual rate of 30 MCFPD, an empirical rate, from eastern coal seams for one well.

Recent work in the southeastern United States may indicate substantially higher initial rates, but the data are insufficient at this time. The initial rate is the most sensitive parameter in our economic analysis, and is a function of gas content, desorption rate, permeability, and fracture effectiveness. Besides higher production rates, reduced costs through economies of scale would help the profitibility of the well. Better technological methods could be developed with time, to increase rates and lower costs. Deeper wells will increase the cost of drilling, which will require a higher initial average annual rate to obtain the desired rate of return.

The price has a varying sensitivity on the net present value, increasing at higher gas rates and becoming less sensitive at lower rates. Economic incentives by government, i.e. price supports, tax credits (Wall Street Journal, December 5, 1977) or ERDA grants, would encourage more than near-mine degasification in the Rockies. From the additional knowledge obtained in western coals, better and less costly methods could be developed.

The effective decline is less sensitive to the net present value than those variables listed above. In the expected low range of

declines, the wells will have a field life of greater than 20 years with our "most likely" rate of 30 MCFPD or more.

The least sensitive of the tested variables was the operations costs, but it should not be ignored. After a well is completed, the only things the field personnel can do to help the cash flow is to maintain the gas production rate and lower the operations costs.

CONCLUSION

Although the degasification of the coal seams in our target areas/models are not economically feasible with our proposed assumptions, price increases, cost savings, or tax credits could make the models marginally economic. Additional western experience could bring the drilling and completion costs down. From unpublished production data on recently completed wells in Alabama, the empirical initial average annual rate is conservative.

Degasification wells of virgin coal seams might only breakeven or be marginally economic. But if wells are drilled ahead of underground mining resulting in increased coal production, the degasification program will more than pay for itself.

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