MERC/SP-78/1

METHANE GAS FROM COALBEDS—DEVELOPMENT, PRODUCTION AND UTILIZATION

Co-Sponsored by:

Region III
Philadelphia, PA

and

Morgantown Energy Research Center
Morgantown, WV

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Morgantown, W.Va.

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JANUARY 18, 1978

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"WELCOMING REMARKS"

by

Robert M. Tomar
Director, Operations Division
Region III Office
U. S. Department of Energy
Philadelphia, Pa. 19102

Good Morning, I am Robert Tomar, Director of Operations for Region 3. Bernard Snyder who was to open this conference cannot be present due to illness. On his behalf and that of his staff I want to extend a warm welcome to you on an otherwise miserable day, to this first Regional Methane Conference ever held under the auspices of the U. S. Department of Energy.

I hope this will be more than a meeting to exchange ideas and information. I think this presents an opportunity for us to meet on an informal basis and to establish working relationships that will carry on into the future.

There is much to be done if we are to solve our energy problems, and methane gas certainly appears to have the potential to play an important role in the solution of those problems.

Our nation is rich in coal, and if we can economically capture only one third of the almost 800 trillion cubic feet of methane gas associated with coalbeds, and use it as a substitute for natural gas, we could supply for about 10 years the nations entire demand currently being experienced for natural gas.

The figures I've just cited dictate the need to know how to place methane on stream as a fuel and to be ready to turn the "valve" by prior resolution of the numerous and complex problems which will be addressed here today.

If I may digress for a moment. From an organizational standpoint, this meeting is the first joint effort within this region by an office formerly part of the old Federal Energy Administration and by a research center formerly part of the old Energy Research and Development Administration. So, it has added meaning to some of us.

I am sure you are aware of the deliberations within the Congress concerning the specifics of a national energy program. Hopefully, their action will be completed soon. There is much at stake.

But, as Congress deliberates, it is essential that research continues. We are dealing here with national security. Our vulnerability as a nation increases in direct proportion to our increasing reliance on foreign oil to maintain our economy and our standard of living. We can ill-afford to continue as the most energy-wasteful nation in the free world. We cannot continue to rely on our economic life's blood to be shipped half way around the world. And we cannot expect to be able to sustain the tremendous financial drain that imported oil places upon us. . . .more than 46 billion dollars in 1977.

That is why this meeting is important. Not only does methane hold a promise of vast new energy, it represents, in its final form, an environmentally desirable energy source. Methane meets the double objectives of our national goal --- adequacy of energy supply and maintenance of our ecology.

Thank you for being with us today. This is an important symposium. I hope you will find it informative, helpful and productive.

And now, I would like to turn the program over to Dr. Brian Butz who supervises Region III's Energy Resource Development Programs within its Division of Energy Conservation and Resource Development.

"REMARKS ON THE REGIONAL ROLE IN METHANE RECOVERY"

by

Brian P. Butz
Region III Office
U. S. Department of Energy
Philadelphia, Pa. 19102

Good morning, I am Brian Butz and I am certainly pleased to be here with you today at this symposium on "Methane From Coalbeds." William Kaplan could not be with you today because of the inclement weather.

As you know this symposium is being co-sponsored by the Department of Energy's Region III Office and its Morgantown Energy Research Center. Many of you, I am sure, are aware of some of the energy research programs carried out by the Department's Morgantown Facility. However, you may not be familiar with the Department's Region III Office and its role in Methane Utilization. I hope to remedy that situation.

First let me say what Region III is. Federal Region III is populated by more than 24 million persons living in the States of Maryland, Pennsylvania, Virginia, West Virginia, Delaware and the District of Columbia. We feel that Region III is America in miniature. To gauge the impact of any national energy policy on the nation, measure its impact on Region III. Coal, natural gas, offshore drilling sites and a nuclear energy commitment comprise the energy portrait within the region.

A closer look at this region's energy resources is quite revealing. Over one-third of the coal produced in this country is produced in the five state area comprising Region III. Over one-quarter of our nation's oil refinery capacity is found within our region. However, just as important as what is produced now is what is capable of being produced in the future. Coal is this region's most abundant energy resource. In fact over 150,000 million tons of coal are located within the geographical confines of this region. This translates to about 250 years worth of coal for the entire country at the present rates of consumption.

Region III is a large consumer as well as a large producer of energy. Over 12% of the nation's energy is consumed in this region. But of more significance than consumption total figures is the region's consumption of scarce domestic fossil fuels.

Transportation alone accounts for over half of the petroleum usage in Region III. Industrial use accounts for another 14%. Natural Gas, while primarily used for heating homes, is still used in large amounts by industry, in fact, over a third of the natural gas used is used by industry. Finally, the industrial and commercial sectors account for 24% of the petroleum used in Region III and 53% of the natural gas. Clearly, effective conservation measures in these sectors can prolong the availability of these scarce fuels.

As you can see Region III encompasses a geographical area containing many energy resources. Today we are here to discuss one of the Region's abundant and valuable resources - Methane.

Approximately 35 trillion cubic feet of methane is projected to exist in the coalbeds of Region III - or enough for over 80 years of usage as natural gas within this region at the present rate of consumption.

But just the existence of this coal and its associated Methane Gas does our nation little good. Both resources must be utilized. That's where the regional office comes in. One of our primary functions is to ensure the timely development and utilization of our region's resources. This brings me to my second point - the role of the regional office in the methane development.

As you will hear today we are facing a future natural gas shortage in this part of the country. Methane gas from coalbeds may help alleviate that shortage. You will hear talks from Federal Government Representatives, today, who will tell you about the research, development and demonstrations that the Federal Government has been sponsoring in the areas of Methane Extraction and Utilization. The Regional Office's role is to let the public know the state of the technology and, when feasible, assist in getting the technology used.

One purpose of this symposium is to provide some needed data, to you, the potential users and developers of methane gas.

Is methane competitive with other fuels? Why isn't it used more? What should potential developers look for? What are the State and Federal Governments doing to bring methane from coalbeds into the market place? These questions will be addressed here today.

Another purpose of this symposium is to bring together individuals who have different and sometimes conflicting points of view on Methane Gas Development and Utilization. I think a discussion of these points of view will be beneficial to all of us.

We hope this is the first of many interactions we will have together. Our job is to get technology out of the lab and onto the street, so to speak, and this is one of our first attempts.

I hope that you find this symposium beneficial and that you have many of your questions answered. If you have any suggestions for any other efforts of this kind please let us know.

Before we begin with our speakers I would first like to take a few moments to acknowledge the efforts of some of those people who helped make this meeting possible. I want to thank Anthony Pontello of the Region III Office who sought out our speakers and did a great deal of work putting the program together. I would also like to thank Leo Schrider of MERC for his co-operation and would especially acknowledge Hilma Barlow of MERC who has done such a wonderful job handling the symposium logistics.

Now let us begin the symposium.

THE METHANE CONTENT OF COALBEDS IN REGION III

by

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ABOUT THE AUTHOR

Maurice Deul earned his Bachelor of Science degree in Geology from Union College in 1942 and a Master of Science degree in Mineralogy from the University of Colorado in 1947. From 1948 to 1957 he worked with the U. S. Geological Survey on the geology and geochemistry of uranium and coal; from 1957 to 1960 he worked on methods for reducing sulfur in coal at Bituminous Coal Research Incorporated; from 1960 to 1963 he worked on novel approaches to coal beneficiation with the Consolidation Coal Company. In 1963 he joined the Bureau of Mines, where he is now Research Supervisor of the Methane Control and Ventilation group. He has authored and coauthored over 60 publications during his professional career.

ABSTRACT

The deep bituminous coalbeds of Region III, with an estimated 150 billion tons of coal, probably contain at least 30 trillion cubic feet of methane. Bureau of Mines research has demonstrated that it is possible to recover pipeline-quality gas from several bituminous coalbeds in Region III for less than $0.50 per thousand cubic feet. Ultimately, most of the gas can be recovered from the deepest coalbeds at costs that are well below the $3.25 to $4.50 per million Btu that LNG imported from Algeria will cost. More than 2 billion cubic feet of gas has already been drained from coalbeds in Region III in Bureau experiments and demonstrations; an additional 250 million cubic feet have been drained by others using similar techniques.

The 20 billion tons of anthracite in eastern Pennsylvania may contain an additional 4 to 6 trillion cubic feet of methane. However, preliminary tests indicate that commercial production is not now feasible from anthracite.

Supplemental natural gas supplies need not be derived only from the coalbeds in Region III. Any coalbed gas produced commercially in the United States increases the total available amount and, consequently, eases the demand on the conventional sources of supply. Fuel resources should not be treated as a parochial problem.

INTRODUCTION

All that I have to say about the gas content of coalbeds in Region III is included in the abstract of this paper.

Of the 30 trillion cubic feet of gas estimated to be in the bituminous coalbeds of this region, probably about 10 trillion cubic feet can be recovered easily by methods already developed by the Bureau of Mines. The gas is simply drained from the coalbeds by vertical gas wells or by a system of holes in the coalbed drilled parallel to the bedding. By these direct means, much of the gas can be recovered from permeable coalbeds.

Enough about Region III. With all due respect to the Federal Administrative Region Structure, we who are concerned with fuel supply should shun a provincial solution to the problem of providing pipeline gas to consumers.

Since more than 18 minutes remain of the allotted time, I am taking this opportunity to discuss some real problems in commercial gas production from coalbeds that I feel that are not likely to be discussed formally at this symposium.

Utilization is not a problem since we already have more demand than supply; a major national problem is to reduce the demand.

Technical problems do exist, and will be solved in time, but they are not now the major deterrents to putting coalbed gas into pipelines.

The real problems are found in trying to explain why billions of cubic feet of pipeline-quality coalbed gas is being wasted, and wasted at the rate of several million cubic feet per day from pipes bringing gas to the surface from holes already drilled into coalbeds for purposes of degasification. This gas is captured; it is flowing through pipe. I do not include the few thousand cubic feet per day from experimental wells drilled in the early years of the Bureau of Mines research program.

More than 5 years ago, the Bureau of Mines drilled long holes horizontally into the Pittsburgh coalbed from a shaft drilled specifically to gain access to the coalbed for that purpose. These holes began producing gas at a rate of nearly 1 million cubic feet per day. They are still producing gas at a rate of more than 400,000 cubic feet per day. That test resulted in the first gas drained from coalbeds into a commercial gas distribution system in advance of mining. The test was so successful that a shaft at the same mine, constructed but not in use, was pumped free of water so that a similar drainage test could be conducted. Here, also, gas was readily produced.

With two such successful tests (which have produced nearly 2 billion cubic feet of gas), so well documented and publicized (1-4), one would reasonably expect future efforts to drain gas from the deep Pittsburgh coalbed to be coordinated with utilization of the produced gas.

But that didn't happen!

One coal mining company, conducting a similar independent research program, has produced more than 250 million cubic feet of gas, without using or selling any of it (5). The Bureau is conducting another demonstration of drainage from horizontal holes drilled from mine entries in the Pittsburgh coalbed. At this moment, gas is flowing freely from a pipe to the surface at the rate of about 400,000 cubic feet per day. What is particularly difficult to explain about this waste is that the exit pipe is scarcely 2,000 feet from a gas distribution line and neither the coal mining company nor the gas company has moved decisively to arrange for compression and hookup.

One progressive coal mining company, opening a new mine less than 40 miles from this meeting place, expended nearly $500,000 to drill eight vertical degasification holes into the Pittsburgh coalbed. In a cooperative effort, the Bureau of Mines funded experimental studies of stimulation methods to increase gas production. This research proved so successful that flow rates of more than 100,000 cubic feet per day were achieved from two holes, and a sustained total flow rate of 500,000 cubic feet per day from all eight holes was anticipated. Thus encouraged, plans were made to sell the produced gas and to lay a pipeline to conduct the gas to a transmission line. But none of this happened. Suddenly, the mining company was confronted with FPC rules and regulations, applications for permits and public hearings, and a myriad of multiple forms. A right-of-way for a pipeline could not be obtained easily. Then came a loss of personnel, and now, more than 15 months later, no gas has been utilized from this site. Approximately 360 million cubic feet of the gas has been lost or not produced; and at the current selling price of natural gas, this operation would have returned, to this date, more than the $500,000 expended on the degasification holes.

Nearly 5 years ago an entrepreneur proposed to a coal mining company that the gas mixed with air drained from underground gob areas be purified cryogenically to produce LNG for a supplemental pipeline gas. The proposition was premature, but we must ask why it has taken until now for a pilot project to be agreed upon. No new technology is required, there is an insatiated market for LNG, and the price is right.

Incidentally, all these examples are from Region III. I will not bore you with references to similar experiences in Alabama, Oklahoma, and Utah.

Certainly we need better drilling technology, reliable and simple continuous in-hole surveying systems, more data on the gas content of coalbeds, and better methods of producing gas from coalbeds of low permeability. But I do not believe that the lack of this advanced technology is a deterrent to producing more gas from coalbeds now.

Coalbed gas is not going to solve the Nation's or even this region's gas supply problem; but wasting the gas produced does not contribute to the solution. The gas produced from coalbeds can be compared with petroleum production from stripper wells in that each well produces only a small amount, but the aggregate is more than 10 percent of domestic crude oil production; that is significant.

It has been predicted that by 1986 methane drainage from coalbeds could contribute about a half trillion cubic feet of gas annually, rising to 1 trillion cubic feet by the end of the century (6). This is a conservative but realistic estimate. However, we must recognize that for the immediate future--today, in fact--every million cubic feet of gas wasted each day deprives 1,600 domestic consumers of their average daily requirements. All of us--mine operators, gas company engineers and executives, bureaucrats, businessmen, scientists, engineers, and the citizens that pay the bills--all of us must question why this waste continues, why this gas is not being recovered when there is a long-established history of production and sale of gas from coalbeds in western Pennsylvania and in northern West Virginia (7).

We can expect other participants in this meeting to help resolve some of the questions I have raised. There is a need for the gas that can be produced from coalbeds; there is a market for it. Reservoir engineers will show that extensive production is feasible, and the problems of commercialization will be addressed. And, finally, we will recognize that the impediments to significant gas production from coalbeds are not due to a lack of technology but, rather, to a lack of appreciation for the simplicity of the methods of recovery.

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MARKET PROSPECTS FOR COALBED METHANE

by

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ABOUT THE AUTHOR

Joseph Pasini, III, Senior Staff Specialist, Advanced and Special Projects, Morgantown Energy Research Center, U.S. Department of Energy, received a B.S. degree in petroleum and natural gas engineering from the Pennsylvania State University in 1958. Since joining the Morgantown Energy Research Center, he has conducted research on petroleum and natural gas reservoir evaluation, enhanced recovery of crude oil, stimulation of natural gas reservoirs, deep well disposal of waste liquids, ground control in mining operations, well plugging and mining through, underground gasification of coal, methane removal prior to, during, and after mining operations, and systems studies of coal mining through utilization.

His major contributions have been the development of techniques for elimination of old oil and gas well support pillars which have caused safety problems in coal mines, controlling fluid flow in crude oil reservoirs to increase production by the use of various polymers, directional drilling for reservoir stimulation, fluid flow control for underground coal conversion, methane drainage from virgin coalbeds, and utilization of methane produced from coalbeds.

Mr. Pasini holds patents on oil recovery techniques, methane drainage, underground coal conversion, is listed in American Men of Science and Who's Who in the East, and has published and presented numerous papers related to petroleum production and mining operations. He served as part-time instructor in petroleum engineering at West Virginia University for three years and is a member of Pi Epsilon Tau, the petroleum engineering honorary, and the Society of Petroleum Engineers. He was a Distinguished Lecturer for the Society of Petroleum Engineers 1975-76. He is presently serving as Energy Advisor to the Governor of Ohio.

MARKET PROSPECTS FOR COALBED METHANE

ABSTRACT

The marketplace will demand greater volumes of methane both in 1985 and the year 2000 than at present. This increasing demand for gas will be met by both conventional and unconventional sources, with unconventional sources such as methane being the principal contributors to increased reserves to production ratios. In addition, methane/natural gas will be the cheapest end use fuel available at the turn of the century.

INTRODUCTION

Methane has been vented from coal mines almost from the time of initial coal mining efforts. Increasing volumes of methane have been vented as mining operations have gone deeper into the earth's crust. In Europe this gas has been utilized for many years; however, their costs for energy have forced this situation to occur. As for the U.S., no one was interested in utilizing this gas, except in isolated cases, because most of the liberated methane was exiting the mine through the ventilation system. However, with the advent of the 1969 Federal Coal Mine Health and Safety Act and the subsequent "tightening" of regulations concerning methane concentrations in the mine atmosphere, it became necessary to predrain the coalbeds through vertical and horizontal holes and to drain "gob" areas with wells. Now the situation has changed because the vented gas contains greater quantities of methane (heating value ranging from 100 to 1000 Btu per cubic feet). Thus the reason for increased efforts in utilization of this gas. This paper deals with the author's perception of the prospects for utilizing coalbed methane in the future - between now and the year 2000.

COALBED METHANE UTILIZATION

The utilization of methane produced from coalbeds does not depend on the wellhead price, that is to say, for gas produced from minable coalbeds wherein the methane is being removed to allow mining operations to proceed under safer and more efficient conditions. Since these operations will be conducted to enhance mining operations, the economics of drilling and completing wells will not depend on the wellhead value but rather on the cost of the purification/transportation/utilization/conversion system plus profit required to move the gas to the marketplace. In the case of unminable (coal that will not be mined in the next five to ten years, if ever) coalbed methane projects, the wellhead price will control not only the feasibility of production but the system for moving the gas to the marketplace just as in the case for natural gas production.

Minable Coalbeds

It presently appears that methane production from minable coalbeds will for the most part be controlled by coal mine development and not by companies and/or entrepreneurs interested only in gas production -- in which case lead times will be as indicated in Figure 1, somewhere between that for privately owned surface coal and federally owned underground coal development. Thus anywhere from three to eight years will be required to see substantive methane production from the minable coalbeds, assuming that major roadblocks do not occur. This production will come from development activities related to the opening of new mines and will include predrainage gas from vertical wells completed in the coalbed and horizontal holes drilled from ventilation shafts sunk in advance of mining. The estimated yearly production in 1985, as projected in the MOPPS[1] study and as constrained by the required lead times, ranges between 0.1 and 1.0 trillion cubic feet. The MOPPS estimates for equivalent wellhead prices with zero profit will be less than $0.15 per MCF for methane produced wherein the costs of wells, shafts, etc., are charged to the mining operation. The cost of methane wherein the wells are drilled for gas production alone prior to mining and costed as if they were conventionally drilled and stimulated gas wells was estimated to range from $0.50 - $3.00 per MCF. The actual availability of methane to the marketplace from the minable coalbeds will depend on the concerted efforts and cooperation between federal, state, and local governments, gas and mining companies, and capital investment by enterprising individuals.

Unminable Coalbeds

Methane production from unminable coalbeds is constrained only by the lack of gas resource data and production information for the various coalbeds that could be "drilled up." Therefore, lead times would be comparable to those for onshore oil and gas and as indicated in Figure 1 require one to three years to see substantive production. The MOPPS study indicates that by 1985 the production of methane could range from 0.03 to 0.3 trillion cubic feet at wellhead costs ranging from $1.00 to $4.50 per million Btu's from unminable coalbeds. There would be zero tradeoff between mining operations and gas production in the case of gas from unminable coalbeds. However, in areas where no mining is in progress and unminable coalbeds exist below minable coal reserves, it may be possible to consider the tradeoffs of extracting methane from the minable coalbed while producing from the other unminable coalbeds. However, the questions of well support pillar requirements and the hydraulic fracturing of adjacent strata could complicate these operations to the point that lead times would be increased to at least that of offshore Atlantic oil and gas of from eight to ten years. Resolution of the problems associated with this effort could greatly enhance predrainage efforts in unminable coalbeds through development of technology that would allow adjacent strata to be hydraulically fractured around minable coalbeds and thus allow completions of wells in both minable and unminable coalbeds.

MARKET PROSPECTS

With the foregoing in mind, what can one say about methane or natural gas with respect to the marketplace? Presently, it provides about 25% of the end use energy; however, due to the uncertainties of future supply, as projected by the MOPPS study, demand will decrease to nearly 15% of end use by 1985, or about 17 Quads. This is about 5 Quads below Gas Research Institute projections[2] for possible natural gas supply in 1985, which would have us believe there will be an oversupply. I believe the supply of natural gas will be in excess of Gas Research Institute estimates and that the demand in excess of supply will be met by unconventional gas sources in which methane from coalbeds is included. In addition, I believe that the cumulative production of methane from coalbeds between now and the end of this century will be greater than that from all other unconventional sources. This is predicated on (1) the "wellhead price" of unconventional gas sources being deregulated; (2) tax credits for unconventional sources of methane; and (3) the fact that there is no fuel available to replace methane in the marketplace.

In conclusion, an "all out" effort at developing methane production from coalbeds and other unconventional sources must be initiated if we are to continue providing energy to the marketplace at "reasonable costs"; obviously, electricity at $60 per barrel (crude oil equivalent) is not the answer.

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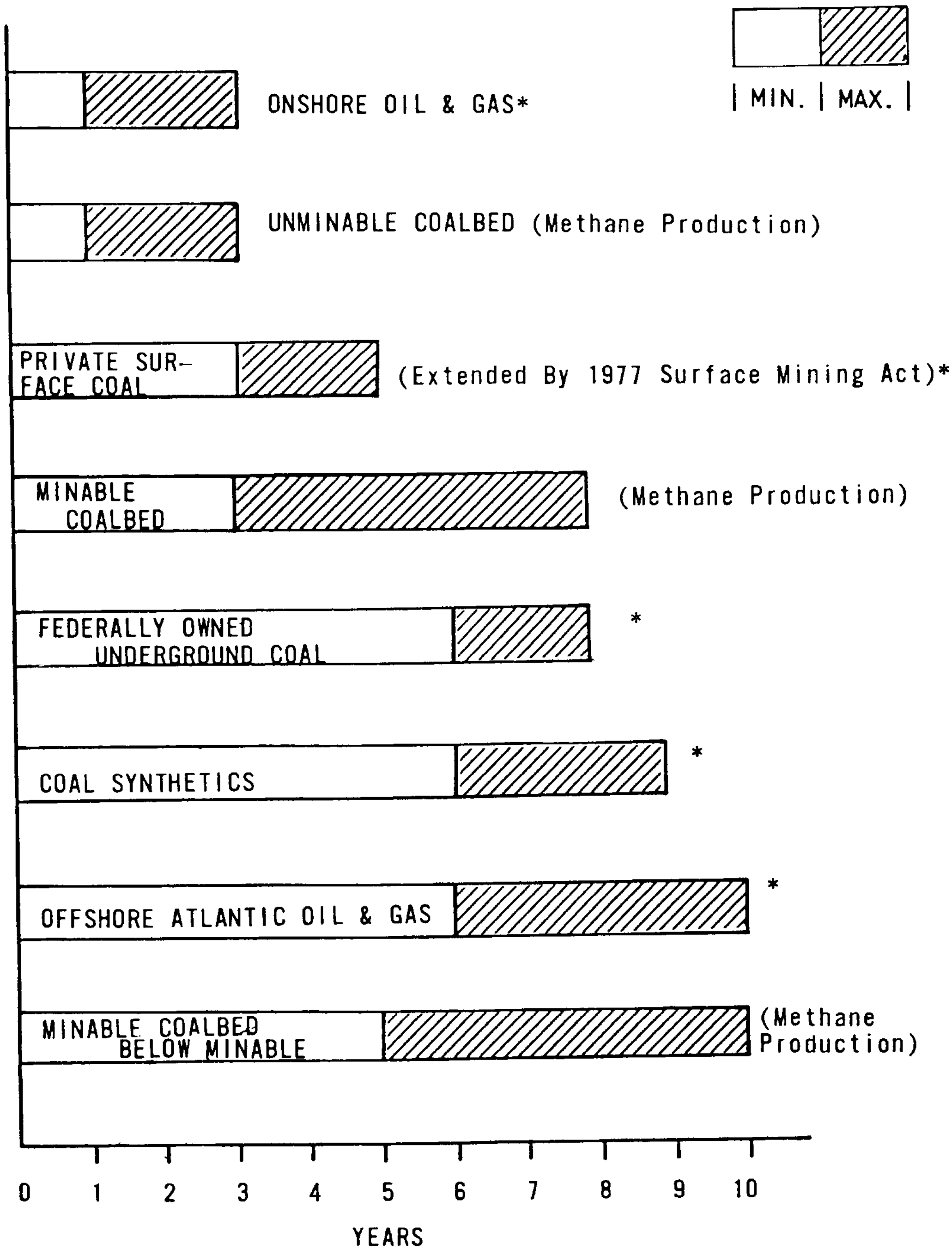
2. Oil and Gas Journal, November 21, 1977, pp 76-77.

FIGURE 1. LEAD TIMES FOR INITIAL PRODUCTION



NOTE: LEAD TIMES SHOWN BEGIN WHEN DEVELOPMENT OF THE ENERGY SOURCE BECOMES ECONOMIC. THE MINIMUM LEAD TIMES ASSUME APPLICATION OF CURRENTLY AVAILABLE TECHNOLOGIES WITHOUT ANY GOVERNMENTAL DELAYS.

METHANE DRAINAGE FROM COALBEDS: RESEARCH AND UTILIZATION

by

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ABOUT THE AUTHOR

Ann G. Kim earned her Bachelor of Arts degree in Chemistry from Carlow College in 1964 and a Master of Science degree in Earth and Planetary Science from the University of Pittsburgh in 1972. She has been employed by the U.S. Bureau of Mines since 1964. She worked as an analytical chemist in the Coal Analysis section from 1964 to 1966. From 1966 to 1969, she did research on the rate of ferrous iron oxidation in acid mine water. Since 1969, she has been involved in research on the origin, control, and utilization of methane in coal. Mrs. Kim has authored and co-authored 20 publications on the origin, composition, analysis, and potential resource value of coalbed gases. She is a member of the American Chemical Society and the Geochemical Society.

ABSTRACT

Since it is very similar to natural gas, methane from coal can be recovered and used as a substitute for natural gas. Research by the Bureau of Mines has demonstrated several methods of draining methane from coal, such as horizontal holes at the bottom of shafts, vertical boreholes from the surface, and vertical boreholes to gob areas.

Utilization of methane drained from coalbeds depends on many factors, including the drainage method, the expected rate and duration of the drainage project, access to pipelines or other surface facilities, and market demand. The simplest and currently most popular use of coalbed methane is its direct addition to natural gas pipelines.

The minable bituminous coalbeds of the United States contain an estimated 300 trillion cubic feet of methane. The location and extent of most coalbeds is known, and most coalbeds are located in close proximity to commercial gas pipelines and existing markets. Drainage and utilization of methane from coal could play a significant role in immediately increasing domestic energy supplies.

INTRODUCTION

Methane drained from coalbeds is an excellent substitute for natural gas. Drainage and utilization of coalbed methane could supplement U.S. gas supplies, particularly in Region III, which produces less than 30 percent of the gas consumed there.

If the average gas content of coal is estimated at 200 cu ft/ton, minable coals in the coterminous United States contain more than 300 trillion cubic feet of gas and all U.S. coal resources could contain over 750 trillion cubic feet of gas (table 1). On a local basis, the Beckley coalbed in Raleigh County, W. Va., contains an estimated 0.1 trillion cubic feet of gas; and the Pittsburgh coalbed in southwestern Pennsylvania contains an estimated 0.5 trillion cubic feet of gas.

TABLE 1. - Estimated U.S. coal and coalbed gas resources

	Coal, billion tons[1/]	Coalbed gas, tcf
Coal reserves		
Surface mining	137	-
Underground mining	297	59
Identified coal resources		
0-3,000 feet	1,297	259
Hypothetical coal resources		
0-3,000 feet	1,849	370
3,000-6,000 feet	388	78
Total	3,968	766

1/ Averitt, P. Coal Resources of the United States, January 1, 1974. U.S. Geol. Survey Bull. 1412, 1975, p. 1, 33.

Although the gas in coal is called methane, it is actually a mixture of gases: methane, other hydrocarbons, CO_2, N_2, O_2, and helium (table 2). It does not contain CO or sulfur compounds. Its heating value is similar to that of natural gas.

TABLE 2. - Composition and heating value of coalbed gas and natural gas, pct

Source	CH_4	CH[1/]	H_2	Inerts[2/]	O_2	Btu/scf
Pocahontas No. 3	96.87	1.40	0.01	2.09	0.17	1,059
Pittsburgh	90.75	.29	-	8.84	.20	973
Kittanning	97.32	.01	-	2.44	.24	1,039
Lower Hartshorne	99.22	.01	-	.66	.10	1,058
Mary Lee	96.05	.01	-	3.45	.15	1,024
Natural gas[3/]	94.40	4.90	-	.40	-	1,068

1/ Other hydrocarbons.
2/ N_2, CO_2, and He.
3/ Moore, B. J., R. D. Miller, and R. D. Shrewsbury. Analyses of Natural Gases of the United States. USBM IC 8302, 1966, 144 pp.

Methane drainage was developed as a safety technique, a means of reducing methane emissions, and thus explosion hazards, in underground bituminous coal mines. The methane emission rate during mining is related to gas pressure within the coalbed. Reducing the gas pressure by removing some of the methane lowers the rate at which methane enters a mine. Originally, no plans were made to recover methane drained from coal. In coal mining, methane is a nuisance and, as such, adds to the cost of mining. However, in drainage tests, the sustained drainage rate and purity of drained gas were comparable to those of a small gas well. As the need for gas increased, the research effort was directed toward not only the most effective methods of removing methane, but also the best methods of recovering and using it. Methane drainage is probably one of the few safety measures that is effective and produces a usable product.

DRAINAGE METHODS

The Bureau of Mines has developed and/or demonstrated several methods of draining methane from coalbeds:

Horizontal boreholes from shafts,

Vertical boreholes to virgin coal,

Vertical boreholes into gob areas,

Directional slant hole, and

Horizontal boreholes from underground mine workings.

Methane Drainage Through Shafts

In this procedure a shaft, or group of shafts, is sunk to the coalbed, a minimum of 3 years before needed for mining. At the base of the shaft, horizontal holes 500 to 2,000 feet long are drilled into the coalbed. Each hole is connected through a mechanical packer and water trap to receiver tank; pipes carry the gas to the surface.

This procedure has been used twice: at the multipurpose borehole (8 feet diameter) and the Honey Run shaft (18 feet diameter) of Federal No. 2 mine in the Pittsburgh coalbed. In both these trials, the methane drained from the coal was compressed on the surface and added directly to commercial natural gas pipelines. Gas was drained from the coalbed through the Honey Run shaft between August 1973 and May 1977 (3.7 years). Gas production totaled 889 MMcf, of which 121 MMcf was sold. Total daily production from the horizontal boreholes averaged 650 Mcfd or approximately 110 cfd per foot of drainage hole.

Between September 1972 and January 1977, 907 MMcf of methane was drained from the coal through the multipurpose borehole. Average daily production was 567 Mcfd or about 125 cfd per foot of drainage hole. Between January 1974 and January 1977, 463 MMcf of gas was sold as pipeline gas. In January 1977, a pump malfunction caused extensive flooding and gas production ceased. Repairs to the underground installations were completed in October 1977, and gas sales resumed. The production rate is now 426 Mcfd. As of December 1977, a total of 967 MMcf of gas has been drained from the coalbed at this site.

Over 1.8 billion cubic feet of methane has been drained from the Pittsburgh coalbed at these two sites. The area subtended by the horizontal drainage holes contained only an estimated 0.3 billion cubic feet of methane. Evidently, the area of effective drainage is much larger than the area penetrated by horizontal boreholes. When the demonstration at the Honey Run shaft was terminated after 3.7 years, it was producing gas at the rate of 390 Mcfd. After 5 years, gas production at the multipurpose borehole remains at 424 Mcfd. Apparently, reducing the gas pressure near the shaft and dewatering the coalbed causes methane to migrate through the natural fractures in the coalbed toward the boreholes. Sinking shafts for methane drainage, although relatively expensive, is effective. The quantity and quality of recovered gas make this technique economically feasible, even when subsequent benefits in coal mining are not considered.

Vertical Boreholes to Virgin Coal

In this technique, small-diameter boreholes are drilled to the coalbed and cased. The hole is extended into the coalbed; as the water that accumulates in the hole is pumped off, methane flows out of the coalbed. Since coal has a relatively low permeability, flow rates from coal to small-diameter vertical boreholes are low, generally between 500 and 10,000 cfd. To overcome this problem, the Bureau of Mines has adapted stimulation techniques used in gas and oil fields for use in coalbeds. Stimulation involves pumping water, gelled water, or foam into a coalbed under pressure to widen and extend the natural fracture system. Sand is used to prop the fractures open. After stimulation and dewatering, gas production increases substantially, by 6 to 60 times the original flow rate. Methane drainage from coal through vertical boreholes has been tried in the Pittsburgh, Pocahontas No. 3, Hartshorne, Mary Lee, anthracite, and Castlegate coalbeds.

This technique works very well in some coalbeds, particularly in coalbeds that are deep, blocky, and moderately gassy. For example, production rates of more than 100,000 cfd have been obtained from stimulated holes in the Pittsburgh and Mary Lee coalbeds.

However, this technique works poorly in some coalbeds, particularly those with low gas contents and low permeability. Exploratory efforts by the Bureau of Mines at drilling and stimulation in anthracite only demonstrated the difficulty of obtaining gas from anthracite. The Castlegate coalbed has a low gas content and after stimulation produced only 800 cfd. The Pocahontas No. 3, although deep and gassy, has a low permeability at the site of the first tests; a factor reflected in low flow rates even after stimulation. The Bureau has also found that errors in well completion and/or stimulation will result in low production rates even from deep, gassy coalbeds with good permeability. Sustaining high production from the Pittsburgh and Mary Lee coalbeds requires that these boreholes be serviced and maintained like gas wells.

Using arbitrary production goals to determine the feasibility of vertical boreholes may actually obscure potential areas of utilization. For example, wells that produce over 100 Mcfd are obvious candidates for commercialization. However, wells that produce 10 Mcfd could fill a mine's gas requirements for space heating, coal drying, and heating coke ovens. A borehole that produces 1 Mcfd or even less, might be a boon to a farmer who is dependent on high-priced electricity or propane for heating and crop drying. Potential for utilization depends not on production rate itself, but rather on whether the production rate can satisfy the requirements of a specific user.

Vertical Boreholes to Gob Areas

Vertical boreholes are also used to drain methane from strata above the coalbed. A hole is drilled to the coalbed ahead of mining. When it is intersected by mining, the overburden fractures and the methane that would normally be released into the gob area is drawn to the surface. Such holes can remove as much as 1 MMcfd of methane from a mine and reduce underground emission by more than 50 percent. However, flow rates from such holes tend to drop rapidly; for example, the decrease may be from 1 million cubic feet to 0.1 million cubic feet over a period of 1 year. The concentration of methane also decreases with time, from 100 percent to 50 percent or less within several months. The use of an exhauster will increase flow rates, but by entraining air from the mine, it may decrease the concentration of methane. The amount of air in the gas can be reduced by the use of a "short hole," a hole that terminates in the strata above the coalbed. Since it is not directly connected with the mine workings, the amount of air in the gas is reduced.

Any system to use gob gas must be designed to handle the variable quantity and quality of the gas. The gas can be used as boiler fuel or in gas turbines. Gob gas can also be upgraded to provide consistent quality fuel or feedstock gas.

Directional Slant Hole

Slant-hole drilling combines the horizontal drainage holes and vertical boreholes from the surface. In the directional slant hole, holes are drilled from the surface at an angle to intercept the coalbed horizontally. In one test of this method, a hole was drilled to the Upper Freeport coalbed 930 feet deep. The borehole penetrated the coalbed along a slanted trajectory and continued horizontally for 390 feet. Erratic coal thickness caused the test to be discontinued, indicating that adequate exploratory drilling is essential to successful slant-hole drilling. The cost of the project, which was almost double that anticipated, was increased by mechanical failures and directional control problems.

In addition to problems in bit control and downhole surveying, a method to dewater the coalbed must be developed before slant holes can be used routinely since most pumps will not operate effectively in the horizontal portion of the slant hole. One possible solution is that instead of a pump in the slant hole, exploratory coreholes be used to dewater the coalbed.

When problems in this technique are solved, it can be used where conventional vertical or horizontal holes are not feasible. Also, sites can be used for slant-hole drilling that are unsatisfactory for other types of methane drainage, and several holes can be drilled from a single site.

In-Mine Drainage

In this method, horizontal holes are drilled into the coalbed within a mine. The methane drained from the coal is conducted by pipeline to the surface. Safety regulations require that the pipeline be intrinsically safe and incorporate fail-safe leak detectors and shutoff controls. In-mine drainage has been tried in the Pittsburgh and Sunnyside coalbeds where rates of 100 Mcfd were typical. Production rates from horizontal holes in the Pocahontas No. 3 coal were low because of low permeability. However, this technique was used to drain gas from the overlying Pocahontas No. 4 coal through a mine in the Pocahontas No. 3 at the rate of 200 Mcfd.

Widespread utilization of this technique will depend to a large extent on overcoming resistance to having a gas pipeline in the hazardous environment of a coal mine. However, large-scale underground pipeline systems have been extensively used in the United Kingdom and Europe.

Utilization of Methane From Coal

There are no major technical problems in the utilization of methane drained from coal. It can be used in any system in which natural gas is normally used:

Pipeline gas,

LNG,

Chemical feedstock,

Boiler fuel, and

Gas turbine power generation.

The simplest method of using methane from virgin coal is direct addition to natural gas pipelines. The most practical use of gob gas is as boiler fuel, or in gas turbines. Utilization of gob gas does require that an alternate fuel be available to handle variations in quantity and Btu value.

Problems in utilization of methane from coal are related primarily to market demand and the availability of surface facilities. For example, use of methane as boiler fuel or in gas turbines is feasible when the coal mine itself is the consumer. Converting methane to LNG is practical in areas where a demand for LNG already exists, and the price of LNG from coalbed methane, including transportation costs, is competitive with other sources. Even adding drained methane to a natural gas pipeline requires that the boreholes be located close to a pipeline or that right-of-way can be obtained and a pipeline constructed at reasonable cost.

Utilization of coalbed methane requires evaluation of many factors, technical, economic, political, and legal. A primary consideration is a realistic estimate of methane resources. Then, as in any type of gas production, a number of questions, like the following, must be considered. Is gas production the sole objective or is methane drainage an adjunct to coal mining? What drainage method will be most effective in a particular situation? What is the best method of using the gas? Are supporting facilities available? What will be the cost of service and maintenance? How much money can be invested and over what period of time must it be recovered? Over what period of time should wells and surface facilities be amortized? Can a depletion allowance be claimed? What is the minimum acceptable price for which the gas can be sold? Who owns the gas rights and how can any ambiguities in ownership be handled? What state and Federal regulations will apply to the production and sale of methane from coalbeds? These are some of the questions that must be answered in order to successfully drain and utilize methane from coalbeds. It seems obvious that the Bureau of Mines cannot provide a simple blueprint for the utilization of methane from coal; there are too many nontechnical variables involved. Our areas of expertise are primarily in quantifying methane resources and in technology of drainage methods. In these areas, we provide information and assistance. Other factors must be considered by those familiar with the individual situation.

CURRENT RESEARCH

The Bureau of Mines is currently involved in research on improving the effectiveness of all the drainage methods discussed. Demonstration projects are being conducted in order to test drainage techniques in various coalbeds and to improve the technology, to test modifications of developed methods and to determine the effect of geological factors. Research in improving methane drainage from coalbeds with low permeability, in dewatering coalbeds penetrated by slant holes, and in quantifying resources will make methane drainage from coalbeds easier, more effective, and more efficient. But at present, increased utilization of methane drained from coalbeds is not dependent totally, or even primarily, on research aimed at improved technology. Rather, realizing the potential inherent in methane drainage from coalbeds requires comprehensive planning and the application of currently available technology.

COMMERCIALIZATION OF METHANE GAS FROM COAL BEDS & THE PROBLEMS INVOLVED

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Service with the U.S. Army Construction Agency, France. Responsible for the first 100 miles of the DONGEMETZ pipeline. Also served for 17 months in Parks as Chief Design Engineer for three major depots with design costs of $1,250,000 and construction costs of $32 million (at prices of 20 years ago).

Other routine staff and command assignments in the United States Army.

ABSTRACT

Natural gas supply is critically short and getting worse. Reliable estimates reveal that minable bituminous coalbeds in the United States contain approximately 300 trillion cubic feet of methane. Removal of this methane before mining reduces major safety hazards while producing pipeline quality gas to augment seriously diminished reserves. Demethanization can be profitable.

Doesn't that sound great! If it's so great, why hasn't commercial enterprise grabbed the ball and capitalized on these attractive benefits and all the glamour of adding to energy resources while making coal mining safer?

The reasons are good, numerous and complex - also surmountable. They are:

1. The coal companies are ultra-conservative.
2. The gas companies are not convinced of the economic viability of coalbed methane as a commercial source of gas.
3. Ever-proliferating red tape, rules, regulation, policy, and law all generate legitimate fears.
4. The economics of reduced ventilation cost, reduced "down time", reduced probability of catastrophic accident and increased productivity can't be reliably quantified.
5. Gas prices remain regulated.
6. Legal problems associated with gas rights.
7. Coal companies fear the adverse effects of demethanization on later mining operations.
8. Surveying and drilling control techniques are not sufficiently reliable.
9. Methane represents roughly 1% (by BTU content) of the energy value of a given volume of coal. The coal company therefore applies its resources to the coal.
10. There are other (seemingly) better and safer opportunities for the limited capital available.

TEXT

INTRODUCTION

Let me start by saying I am not technically expert in either mining or methane recovery. When one is not an expert, it becomes much easier to talk like one, not being hung up on knowledge and expertise. A possible advantage exists in circumstances like this because sometimes it becomes easier to see the woods instead of the trees.

KEY FACTORS

- The largest single safety problem in coal mining is methane.
- The amount of recoverable methane in known U.S. coal reserves is estimated conservatively at over three trillion cubic feet--a resource roughly equal to or exceeding known domestic natural gas reserves.
- This gas is currently being wasted by venting it to the atmosphere at a rate of 200 to 250 million cubic feet per day.
- The technology required to recover and use this gas is substantially available now.
- All that sounds great. You've heard it before and you've heard it repeated this morning. If it is so great, why hasn't commercial enterprise grabbed the ball and capitalized on these attractive benefits and the associated glamour of adding to energy resources while making coal mining safer.

The reasons (or problems involved) are good, numerous, and complex. All we can do in twenty minutes is to put them into "whole perspective." It is necessary first, however, to define that term "whole perspective."

WHOLE PERSPECTIVE

I think the best way of explaining the word "whole" is to tell you a parable about the six blind men who stood by the roadside everyday begging for pennies from passersby. All six had heard of elephants, but had never been close enough to come to understand the concept of an elephant. As luck would have it, an elephant stopped before them one day, and they asked the elephant driver if they could touch the elephant in order to learn what kind of an animal it is. The first blind man touched the elephant's side, and proclaimed that an elephant is like a wall. The second blind man felt the elephant's tusk, and said..."An elephant is not like a wall--he is hard, round, smooth and comes to a point. An elephant is obviously like a spear." The third blind man touched the trunk, declared his first two comrades to be wrong, and described the elephant as being very much like a snake. The fourth blind man touched a leg, and determined that an elephant is like a large tree trunk. The fifth blind man felt the ear, and decided an elephant is like a fan. Finally, the sixth blind man touched the tail and said that an elephant is not like a wall, spear, snake, tree, or fan, but is rather very similar to a rope. The elephant moved on with his driver, and the blind men argued for days about the elephant's appearance. So you can see, the whole, although it consists of its parts, must really be seen in its entirety in order to get the picture.

The best way I can define "perspective" is by reading a letter that a friend of mine recently received from his daughter away at college.

> "Dear Mother and Dad:
>
> It has now been three months since I left for college. I have been remiss in writing, and I am very sorry for my thoughtlessness in not having written before. I will bring you up to date now, but before you read on, please sit down. You are not to read any further unless you are sitting down... Okay?
>
> Well, then, I am getting along pretty well now. The skull fracture and the concussion I got when I jumped out of the window of my dormitory when it caught fire shortly after my arrival, are pretty well healed. I only spent two weeks in the hospital, and now I can see almost normally and only get three headaches a day.
>
> Fortunately, the fire in the dormitory and my jump were witnessed by an attendant at the gas station near the dorm, and he was the one who called the Fire Department and the ambulance. He also visited me at the hospital, and since I had nowhere to live because of the burnt-out dorm, he was kind enough to invite me to share his apartment with him. It's really a basement room, but it is kind of cute. He is a very fine boy, and we have fallen deeply in love and are planning to get married. We haven't set the exact date yet, but it will be before my pregnancy begins to show.
>
> Yes, Mother and Dad, I am pregnant. I know how much you are looking forward to being grandparents, and I know you will welcome the baby, and give it the same love and devotion and tender care you gave me when I was a child. The reason for the delay in our marriage is that my boyfriend has some minor infection which prevents us from passing our premarital blood tests and I carelessly caught it from him. This will soon clear up with the penicillin injections I am now taking daily.

I know you will welcome him into our family with open arms. He is kind and although not well educated, he is ambitious. Although he is of a different race and religion than ours, I know your expressed tolerance will not permit you to be bothered by these facts. I am sure you will love him as I do.

Now that I have brought you up to date, I want to tell you that there was no dormitory fire, I did not have a concussion or skull fracture, I was not in the hospital, I am not engaged, I do not have syphilis and there is no man in my life.....However, I am getting a "D" in history, and an "F" in Science....and I wanted you to see these marks in the proper perspective.

Your loving daughter,

Futilla"

There you have the definition of "Whole Perspective."

THE PROBLEMS

The problems that must be put in "Whole Perspective" are as follows:

1. The coal companies are ultra-conservative.
2. The gas companies are not convinced of the economic viability of coalbed methane as a commercial source of gas.
3. Ever-proliferating red tape, rules, regulation, policy, and law all generate legitimate fears.
4. The economics of reduced ventilation cost, reduced "down time", reduced probability of catastrophic accident and in-increased productivity can't be reliably quantified.
5. Gas prices remain regulated
6. Legal problems associated with gas rights.
7. Coal companies fear the adverse effects of demethanization on later mining operations.
8. Surveying and drilling control techniques are not sufficiently reliable.
9. Methane represents roughly 1% (by BTU content) of the energy value of a given volume of coal. The coal company therefore applies its resources to the coal.
10. There are other (seemingly) better and safer opportunities for the limited capital available.

Each problem requires a bit of explanation and elaboration.

PSYCHOLOGICAL

It seems natural for operators of coal mines to venture into the methane recovery business. Yet they have not done it, except for cooperating in several instances with demonstration programs, largely capitalized by the U.S. Bureau of Mines, and more recently, by other departments of the Federal government and some state governments. One must recognize first that the energy content of methane adsorbed in a coal deposit represents only one percent of the total energy content of the coal deposit. It is, therefore, reasonable and prudent for the coal operator to apply 99 percent of his capital, people, equipment, and time resources to the extraction of coal rather than methane. This is exactly what he does. In addition, there is some legitimate apprehension of methane recovery procedures adversely affecting the structure of the coal bed, particularly when fracturing techniques are employed as part of the recovery process. At this time it appears that the fracturing technique is most applicable to vertical drilling. Also, it is by no means proven that the structure of the coal bed is indeed affected by the use of this technique. Nevertheless, if methane recovery is to become part and parcel of coal mining operations, more work is needed to prove that mining operations will not be hampered by fracturing, holes, pipes, etc.

Coal operators are also affected in their thinking of methane recovery by a natural tendency to be ultra-conservative. Underground mining continues to be dangerous and expensive in spite of many advances in safety and mining technology over the years. Nevertheless, the danger and the expense force the mine operator into a frame of mind that results in extreme reluctance to employ new methods, procedures, and equipment until these are established and proven by others. Someone, somewhere, somehow must stick his neck out, as the proverbial turtle, in order to start something new.

ECONOMIC

The economics of methane recovery have not yet been firmly established and accepted on a credible basis. The cost of a methane recovery system can be estimated reliably, as can the cost of delivery of the methane to the market. The price of natural gas, fortunately or unfortunately, is known because of government regulation. Best theoretical estimates at the moment lead to the general conclusion that, with gas prices at their current regulated levels, cost of methane recovery is approximately equal to revenues that may be expected from its sale or use on the site. These calculations will show a much more favorable picture on the profit side with either deregulation or, more probably, substantial raises in the regulated price of natural gas in the relatively near future.

Another favorable aspect of the economic picture is the reduction in cost of the mining operation itself after demethanization is accomplished. Unhappily these economics are difficult to pin down, believably. It has been estimated that a well-conceived and well-executed methane recovery program can reduce ambient methane in the mine on the order of 70 percent. This would result in reduced ventilation cost, and reduced time, now engendered by all too frequent instances of methane concentrations in excess of the legally established amount of one percent. Such decreases in down time would obviously increase productivity. The economic benefit of this increased productivity is difficult to estimate as to its precise magnitude. It is even more difficult to put a price tag on the reduced probability of a catastrophic accident by virtue of the fact that there would be less methane in the mine after an efficient demethanization program.

Lastly, there are many competing opportunities for investment of the limited capital available. Many of these opportunities involve purchase of expensive equipment that would increase production at less ultimate cost. Until it is proven that methane recovery is more productive financially, these other opportunities will continue to take precedence.

TECHNOLOGY

The next general conclusion, or problem, involves technology. It seems generally recognized that the technology for methane recovery is at hand now. After all, the U.S. Bureau of Mines demonstrations have largely proved technical feasibility. Also, methane recovery has been employed for many years in coal mining operations in Europe. There are significant differences between European mining practice and U.S. practice, but we cannot dispute the fact that coal-mine methane has been a source of energy in Europe for a long time. If they can do it, why can't we? One of the more attractive methane recovery techniques that you have already heard about, or will hear about during this seminar, is the slant-hole drilling method. This method does require further research and development in underground surveying and drill guidance in order to become efficient, reliable, and effective.

LEGAL

There are also significant legal problems to be surmounted. First, we have the well-known problem associated with contending ownership of coal rights versus gas rights. It is an unfortunate fact of life that the gas rights are seldom owned by the same entity that owns the coal rights. Since the law is not clear, present confusion is the result. It is also a fact, however, that the law not only allows, but requires coal operators to keep ventilating air in the mine at methane concentrations of less than one percent. Should these concentrations exceed one percent, the mining operation must be discontinued until the problem is resolved. Consequently, methane is currently wasted to the air through expensive ventilation procedures. Since the coal operator not only may, but must, get rid of the methane, it would appear he holds the upper hand. If the gas owner does not wish to cooperate in a methane recovery program and obtain a small royalty for this cooperation, his alternative is to get nothing from the methane at all. Therefore, it appears that there is adequate ground for sensible people to compromise at the negotiating table with or without help from legislation. In the meantime, there are coal mines where the coal rights and gas rights are owned by the same entity. Certainly we can start with methane recovery programs in those mines.

A coal operator today must also contend with a tremendously complex and often contradictory body of rules, regulations, procedures, and law. The gas operator is faced with similar problems; but the rules, regulations, procedures, and law for him are different. Aggravating the matter further is the ever-increasing tendency of government to proliferate these complications and change them almost on a daily basis. It is a monumental task for the coal operator to keep up with his own red tape much less learn what the gas operator has to know and vice versa. This results in a reluctance to take on a program which requires learning the other's red tape.

INERTIA

Last, but certainly not least, is the general problem of corporate inertia. The companies that might logically get involved in methane recovery are large, complex organizations. The decision-making process in such organizations is complicated and time-consuming. The creative dreamers must not only come up with the new ideas, they must also be able to convince management by overcoming corporate inertia thru sound, logical arguments, facts, and figures.

THE FUTURE

The problems outlined above are not insurmountable, and they will be overcome. In my innocence as a "non-expert," I can see a scenario where government one day, pernaps very soon, will wake up to the fact that a precious natural resource is being wasted at a time when this resource is scarce and becoming scarcer. Public clamour and logic will require government to react firmly and positively. I hope and pray that the government reaction will not be legislation that forces methane recovery as it has forced many safety measures in the past. Hopefully, the result of the "wake-up" will be the provision of incentives that will make it very difficult for the coal and gas industries to ignore demethanization and other methane recovery procedures as a part of normal operations. I predict that this will come to pass in the next several years, and perhaps sooner than we think.

UTILIZATION OF GOB GAS FOR POWER GENERATION

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1.0 INTRODUCTION

Under Department of Energy Contract EY-77-C-21-8098 the Advanced Energy Systems Division, Westinghouse Electric Corporation, will install and operate a system for the conversion of gob gas to electricity. The conversion device is a gas turbine which serves as the prime mover for an electrical generator. The system outputs 4160/2400 Volt, 3-phase, 60 Hertz power which is distributed back into the mining operation. The turbine/generator to be used is a portable (trailer-mounted) unit provided by the Corps of Engineers, United States Army, Fort Belvoir, Virginia. The unit has a nominal rating of 750 kW, and was designed and built for the Army by SOLAR Turbines International, San Diego, California. The site selected for the operation of the system, under a contract currently being negotiated, is the Revloc No. 32 Mine, Bethlehem Mines Corporation, Ebensburg, Pennsylvania.

2.0 SYSTEM

Figure 1 is a block diagram of the system as it will be operated at the Ebensburg Site. The major elements of the system are seen to be:

- The fuel source, i.e., the gob gas degasification borehole.
- The interface equipment which regulates the borehole flow to deliver a fixed fuel flow rate to the turbine combustor.
- The turbine/generator, which is mounted in a tractor-trailer van, and fully portable.
- The power distribution network, which routes the turbine/generator output power to the existing mine power grid.

The operational concept of the system at this site is one which is based on fueling the turbine from a single degasification borehole and moving the system from hole-to-hole as new fuel sources come on line and older degasification boreholes cease to produce. This design approach is necessary at this mine because the nature of the land surface ownership is such that a multiple degasification borehole collection system cannot be easily implemented here. This factor also limits the size of the turbine which may be used, i.e., the fuel mass flow rate required by the turbine must be compatible with the rate of flow of the degasification well. The latter is of course determined by the underground mining operation and normally varies from hole-to-hole. These boreholes are not opened in advance of the underground mining operation and their productive lives (insofar as turbine requirements are concerned) vary from a few months to three or four years. There are approximately seventy-five degasification boreholes at the Cambria 32/33 mining operation to date. The age of these holes varies from 1968 to the present time. Over the years this approach to degasifying the mine has prevented a build-up of unacceptable concentrations of methane in the underground work areas. On an overall basis, about 50 percent of the total methane released by the mining operation passes through the degasification boreholes and the remaining 50 percent is swept out of the mine by the mine ventilation system.

For the Ebensburg project, the Saturn Model gas turbine engine being supplied by the U. S. Army is about the largest unit which can be employed in a single degasification borehole application at this mine. This conclusion is supported by an evaluation of the flow rate characteristics of several of the degasification boreholes, which are on recorded data documented by Bethlehem personnel at Cambria 32/33. Given the system design flexibility to install a pipeline collection system from multiple degasification boreholes, larger systems(1) could be considered. With these larger engines it would generally be desirable to modify the combustion systems for a more optimized operation with gob gas as the fuel, or using a combination of gob gas and other fuels.

A pipeline collection system would also permit flexibility in physically locating the turbine. For a large mining/coal processing operation, such as Cambria 32/33, this is significant, because the turbine generates a great deal of heat in the stack exhaust process, and this heat could be used in coal drying, for example, or in co-generation schemes. Both approaches greatly increase the overall efficiency of the total system operation, and this can be directly translated into additional dollars saved.

The Saturn engine being used for the Ebensburg program has not been extensively modified for this program. The two major modifications for the demonstration project include:

- A dual fuel capability which allows the turbine to be operated from either gob gas or conventional liquid hydrocarbon fuels.
- Special gaseous fuel hardware to handle the increased fuel mass flow rate required for gob gas operation.

The Saturn engine will be operated in a parallel mode with the existing mine power grid. Mixing will be done at 13,000 volts after transformation of the 4160 volt turbine-generator output. Electrical phase matching controls are built into the turbine electrical system. The level of power to be delivered to the mine power grid, presently estimated at 625 kW, is significant considering that the turbine fuel to be used is normally vented to the atmosphere as waste. It should be noted, however, that this represents a small fraction (less than 5 percent) of the power normally used at the Cambria 32/33 mining complex.

(1) The Centaur and Mars engines manufactured by SOLAR Turbines International are in the 2.5 to 9.0 Megawatt class. Larger units (10 Megawatts and up) are available from Westinghouse.

3.0 PROGRAM STATUS/OBJECTIVES

Under the sponsorship of the Department of Energy and the State of Pennsylvania, Westinghouse initiated work on Contract EY-77-C-21-8098 in September of 1977. We presently plan to be in operation in late April or May of 1978 at the Ebensburg site. The specific program objective is to experimentally evaluate the technological and economic implications of using methane associated with coal mining as a fuel for gas turbine electrical power generation. Earlier preliminary Westinghouse evaluations of this type of system have suggested that the technology is well within the state-of-the-art and that the economics should be attractive. These earlier evaluations have suffered from the lack of a hard core, experimentally derived, data base. Contract EY-77-C-21-8098 is expected to provide this data base.

4.0 THE FUEL SOURCE

Bethlehem Mines Corporation personnel have recorded extensive data on the present seventy-five degasification boreholes at the Cambria 32/33 mining operation. This data includes rate of flow, methane concentration and overall lifetimes. Approximately 20 percent of these boreholes have lifetimes exceeding one year, and some exceed four years. Borehole 32-07, for example, is more than six years old and is still being pumped. Presently this borehole does not produce a sufficient quantity of methane for operation of the turbine, however. A typical sequence of events in the development of one of these degasification boreholes is as follows.

- The borehole is drilled to the depth of the anticipated mining operation, which may be either an advancing longwall face or the retreat phase of a continuous miner operation.
- The borehole is cased and set to a depth of approximately 100 feet above the mining operation.
- The underground mining operation passes through the borehole area and the roof of the mined out area is collapsed, creating a gob area. This action actually opens the borehole for venting the methane which is stored in the strata immediately above the coal seam being mined.
- After opening, the borehole is allowed to "free flow" until mine management deems it necessary to start the electric exhaust blower. This may occur as early as the first day the borehole is intersected with the face. Pumping is continued until the rate of flow is greatly reduced and the methane concentration is 25 percent or less. This period of pumping may last for an extended period, i.e., up to four years in some cases. The well is monitored daily (frequently several times daily) for rate of flow and methane concentration.

5.0 FUEL QUALITY-QUANTITY

As a source of turbine fuel, the characteristics of the flow from the degasification borehole of primary interest are the rate of flow, methane concentration, the degree of dryness/cleanliness and freedom from hydrogen sulfide. The life cycle of individual degasification wells at this location can be considered as consisting of three distinctively different phases:

- The initial, or "free flow" phase in which the rate of flow is often as high as 2×10^6 cubic feet per day and the concentration of methane is high, i.e., 80 - 90 percent. This period may last for several days, several weeks or, in some cases, two months or more.
- A pumping phase which is required to accelerate the degasification of the underground area being mined. During this period both the rate of flow and the concentration of methane are reduced somewhat. The pumping is continued and may be required for an extended period, e.g., in some cases for as long as four years.

- A terminal phase in which both the rate of flow and the concentration of methane are further reduced. The criteria used by Bethlehem mines personnel for termination of the pumping is a methane concentration(2) of 25 percent or less.

Within the above three-phase life cycle of the degasification borehole, it is the second phase which will be used for the turbine operation. Evaluation of recorded data on individual degasification boreholes, and independent laboratory analysis of fuel quality have shown that twelve to fifteen of the present seventy-five degasificaton boreholes at this mining operation could have provided fuel for the Saturn engine at full power operation. Borehole 32-10, for example exceeded 1.75×10^6 cubic feet per day for the first two months following the initial, or free flow phase. Within the next ten months (which would have satisfied the schedule constraints of the present program) the minimum daily flow exceeded 6×10^5 cubic feet per day. In addition, the fuel is clean, dry and free of contaminants such as sulfur. During this same period the average heating value of the fuel exceeded(3) 600 Btu/ft^3. During normal operation (with commercial grade natural gas) the Saturn engine requires a fuel flow rate of slightly more than 300,000 cubic feet of fuel per 24 hours of operation. The equivalent heat rate of degasification borehole 32-10 exceeded this by a substantial margin during this period.

6.0 FUEL QUALITY CONSTRAINTS

There are two major constraints on the extent of dilution which can be permitted during operation of the gas turbine from gob gas:

- Safety considerations as specified by the Mining Enforcement and Safety Administration.
- Engine manufacturer (SOLAR Turbines International) and U. S. Army experience with the engine.

In the case of MESA, it will be necessary to monitor both the methane concentration and the oxygen content of the fuel on a continuous basis. This feature has been provided for in the system design. MESA prefers that the oxygen level of the fuel source be no greater than 10 percent by volume, which would fix the lowest permissable volume mixture ratio at about 50/50 (Methane/Air).

Direct experience with the Saturn engine with fuels other than commercial grade is extremely limited. SOLAR Turbines International has accumulated some test data on a similar combustion system with fuels down to heating values of 600 Btu/ft^3, which sets the lowest permissable volume ratio somewhat higher than the 50/50 requirement set by MESA. From a purely technical point of view the engine should operate below this level, however the Ebensburg program cannot be based on technical speculation and we will set a lower limit of 600 Btu/ft^3 for the turbine gob gas fuel. As part of Contract EY-77-C-21-8098, SOLAR Turbines International is evaluating (on an experimental combustor) much leaner mixtures (down to 30/70, approximately) in a simulated gob gas situation. The results of this work and the extent to which those tests can be applied to the Saturn system are not yet completed by SOLAR. Any considerations of extending the 600 Btu/ft^3 criteria downward would require prior experimental verification and advance agreement between all parties.

In normal operation (with commercial grade natural gas) the system mixes(4) 210 cubic feet/minute of fuel with a portion of the air supplied from the turbine air compressor in the primary combustion zone of the combustor. The air mass flow rate from the turbine compressor is 768 lbs/minute, of which only approximately 20 percent is used in the combustion process. Combining this with the above fuel flow rate, and considering natural gas as having a density of 0.0452 lb/ft^3, the fuel/air mixture ratio is seen to be(5) 0.061.

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(2) With specialized design of the combustion systems, gas turbines can be operated on fuels with heating values considerably less than 250 Btu/cubic foot. The Saturn engine to be used at Ebensburg was not designed for such fuels, however, and will be operated at somewhat higher levels of methane concentration.

(3) Based on 1000 Btu/ft^3 for pure methane.

(4) Date Source - SOLAR Turbines International

(5) The stoichiometric fuel mixture ratio is that mixture ratio corresponding to complete combustion. It can be computed from the combustion reaction equations at 16.132 lb of air per pound of fuel.

The substitution of gob gas for commercial grade natural gas as fuel obviously introduces additional air into the primary combustion process. This moves the mixture ratio to the lean side of stoichiometric, corresponding to a reduction in output electrical power. To compensate for this trend, and without making major hardware changes in the design of the system, two modifications have been made to the operation of the turbine:

- Injection nozzles for supplying gob gas fuel to the primary zone of the combustor have been enlarged, facilitating an increased fuel flow rate. The skid mounted interface equipment is adjustable, but can deliver up to 500 cubic feet/minute through the gas compressor.

- The volume of air normally supplied by the turbine air compressor to the primary combustion zone has been slightly reduced.

In combination, these modifications are expected to maintain the fuel mixture ratio near stoichiometric, permitting a system operation near normal. The electrical transient response of the system is expected to be slightly reduced due to the lower heating value (600 Btu/ft^3) of the fuel. However, two additional factors which minimize this problem are:

- The system initial start-up will always be on liquid fuel prior to switching to gob gas fuel.

- The turbine electrical power output is in parallel with the existing mine power grid, i.e., an infinite bus, and large transient power demands on the turbine system power are not expected.

7.0 TURBINE PERFORMANCE

Figure 2 summarizes the input/output relations of the Saturn engine. Continuous operation, including the effect of power factor, is at 800 kW. The latter is reduced in normal operation by the influence of altitude (Ebensburg elevation is approximately 2000 feet) and inlet/exhaust pressure losses. In addition, a portion of the output turbine power is used to operate the skid mounted interface equipment. Total system losses are estimated to be 175 kW. Of these losses the local use of power(6) represents approximately 100 kW, and normally this would be additional power supplied to the mine power grid. Power delivered to the mine power grid is presently estimated at 625 kW.

From Figure 2, it should be noted that turbine exhaust heat produced (approximately 28,000 cubic feet/minute and 860°F) is extensive. This exhaust heat is normally about 78 percent nitrogen, 18 percent oxygen and 4 percent carbon dioxide and water, by volume. Operation on gob gas is not expected to change this composition. As previously noted, waste heat cannot be used at the Ebensburg Site because of the location of the turbine.

8.0 INTERFACE EQUIPMENT

As shown in Figure 1, the skid mounted components which comprise the interface equipment provide the following functions:

- Accepts what is normally a varying rate of flow from the degasification borehole venting system and provides a relatively fixed rate of flow to the turbine.

- Provides for the venting of excess fuel, since the boreholes normally produce a flow in excess of that required to operate the system.

- Provides for purging the system (N_2 Purge) when initially filled with fuel, to avoid the 5 - 15 percent flammability range of Methane/Air mixtures.

- Through a combination of the accumulator tank, gas compressor, and gas receiver elements, provides a "mixing" function which tends to minimize short term variations in fuel quality.

(6) This system power loss is unique to the Ebensburg system design - it is not a loss normally associated with the Saturn engine.

- Provides a base for physically attaching all components of the interface equipment. This base, or skid, is fabricated from a combination of structural steel and concrete. Potential vibration problems are thus minimized, and the entire assembly can easily and quickly be moved to another site.

- Provides a number of built-in safety features described in more detail in Section 10.0, below.

9.0 POWER DISTRIBUTION NETWORK

The power distribution network runs from the turbine generator output at the site to an existing power sub-station at the Revloc No. 32 mine. The network includes a transformer and additional (beyond that protection built into the turbine) circuit protection at the site, and a pole/line type of construction to transfer the power to the Revloc No. 32 sub-station. The distance from the site to the sub-station is approximately 500 yards. Power mixing at the sub-station is at 13,000 volts and electrical phase matching is provided by controls built into the turbine control panel (located in the rear section of the trailer). Additional system safety features are discussed in Section 10.0, below.

10.0 SYSTEM SAFETY

The safety features built into the overall system are extensive. They may be summarized here into five areas:

- General
- The Fuel Source
- The Interface Equipment
- The Turbine/Generator
- The Power Distribution Network

10.1 GENERAL

The design and operation of the total system will be closely coordinated with Bethlehem Mines Corporation and MESA. In the final analysis, the safety requirements of these agencies must be satisfied in operation of the system. This philosophy is reflected in several areas:

- The rate of flow from any individual degasification borehole is determined by mine ventilation needs rather than by turbine requirements. In this case we believe the two requirements can be compatible.

- A minimum of two people must be present at any time the turbine is operated. A fast reliable means of communication must be provided.

- Such features as electrical grounding techniques must comply with local practices.

10.2 THE FUEL SOURCE

Over the past ten years Bethlehem has developed a method of pumping individual degasification boreholes to insure continuous venting. The operation of this device depends primarily on the uninterrupted operation of a motor which is powered from the local utility company. This feature for venting the borehole has been retained in the operation of the system, and simply feeds the fuel to the accumulator tank where it may either be vented to the atmosphere or fed to the gas compressor. In addition, excess fuel may be vented from the gas compressor. Pressure relief valving is provided in both the gas compressor and the gas receiver tank.

10.3 THE INTERFACE EQUIPMENT

With reference to Figure 1, the interface equipment includes all skid mounted components. The major safety features included in this sub-system are as follows:

- Testing of all components for pressurized gas service prior to assembly.
- Flame arresters located inby the gas compressor and the turbine fuel inlet orifice.
- Pressure relief valves for pressurized components.
- A nitrogen purge sub-system.
- Elevated "stove pipe" sections for dumping fuel to the atmosphere.
- NEMA class equipment enclosures.
- MESA approved gas sampling instrumentation.
- Remote control and monitoring of the skid mounted system from the control center (the control center is located in the rear section of the trailer van).

10.4 THE TURBINE/GENERATOR

Protection for this element of the system is discussed(7) in terms of:

- Protection While Starting
- Protection During Running

10.4.1 PROTECTION WHILE STARTING

Protection provided during the starting sequence includes:

- Low Oil Pressure

  If the pre/post lubrication pump discharge pressure fails to reach a preset limit within ten seconds, the start will be aborted and the Pre/Post Lubrication light will illuminate.

- Fail to Crank

  If the engine fails to reach 13 percent speed within a preset time, the engine will shut down and the Start Fail light will illuminate.

- Fail to Light

  If the turbine inlet temperature fails to reach 400°F (204°C) within a preset limit, the engine will shut down and the Start Fail light will illuminate. This feature prevents excessive fuel accumulation in the combustor prior to light off.

- Fail to Start

  If the engine fails to reach 90 percent speed within a preset limit, the engine will shut down and the Start Fail light will illuminate. This is to prevent excessive cranking in case the engine stalls because of weak batteries or an improper fuel schedule.

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(7) Data Source - SOLAR Turbines International (Saturn Engine Handbook)

In addition to the preceeding protective features, a fuel topping circuit in the control system (on a liquid fueled operating mode) provides a signal to reduce the fuel input if the turbine temperature exceeds a preset limit and the engine is below 60 percent speed. If this temperature exceeds a second preset limit, the engine will shut down and the High Turbine Temperature light will illuminate.

10.4.2 PROTECTION WHILE RUNNING

Protection provided during the running sequence includes:

- Turbine Overspeed

  If the turbine speed exceeds a preset limit, the unit will shut down and the Overspeed light will illuminate.

- High Turbine Temperature

  If the turbine exhaust temperature or the turbine temperature exceed preset limits, the unit will shut down and the High Turbine Temperature light will illuminate.

- Low Oil Pressure

  If the oil pressure in the engine supply header drops below a preset limit, the unit will shut down and the Low Oil Pressure light will illuminate.

- High Oil Temperature

  If the oil temperature in a supply header exceeds a preset limit, the unit will shut down and the Lubrication Oil Temperature light will illuminate.

- Turbine Underspeed

  If the turbine speed drops below a preset limit because of governor malfunction or a turbine flameout, the unit will shut down. This shutdown is initiated by the circuitry provided for start/failure protection; therefore, the Start Fail light will be illuminated by the underspeed condition.

Contact points are provided to interlock with the main power circuit to trip the breaker, removing the generator set from the bus when the unit is shut down for any reason.

In addition to the protective features, another safeguard when operating a generator in parallel with other units, is reverse power relay in the switchgear to prevent motoring the unit in the event of a malfunction.

Control of the entire system, including the interface sub-system, is from the central control area in the aft section of the trailer van housing of the turbine/generator.

10.5 POWER DISTRIBUTION NETWORK

The interface between the turbine output power and the distribution network is a four wire cable from the turbine generator. Bethlehem personnel interconnect this cable through a junction box, a transformer (4160/13,000 volts) and an additional circuit breaker. From this breaker the power distribution wiring is routed via pole/line construction to the existing mine power sub-station. Local electrical grounding (in the turbine area) standards will be followed.

Two additional safety features built into the system include the following:

- Protection from lightning strokes is built into the system housing the turbine/generator.

- Mine operating conditions frequently require disconnecting external power to certain areas of the underground operation. This must often be done on short notice (15 minutes). As part of the power distribution network, Bethlehem will provide for interconnecting the existing mine warning system for such a condition into the turbine operating site.

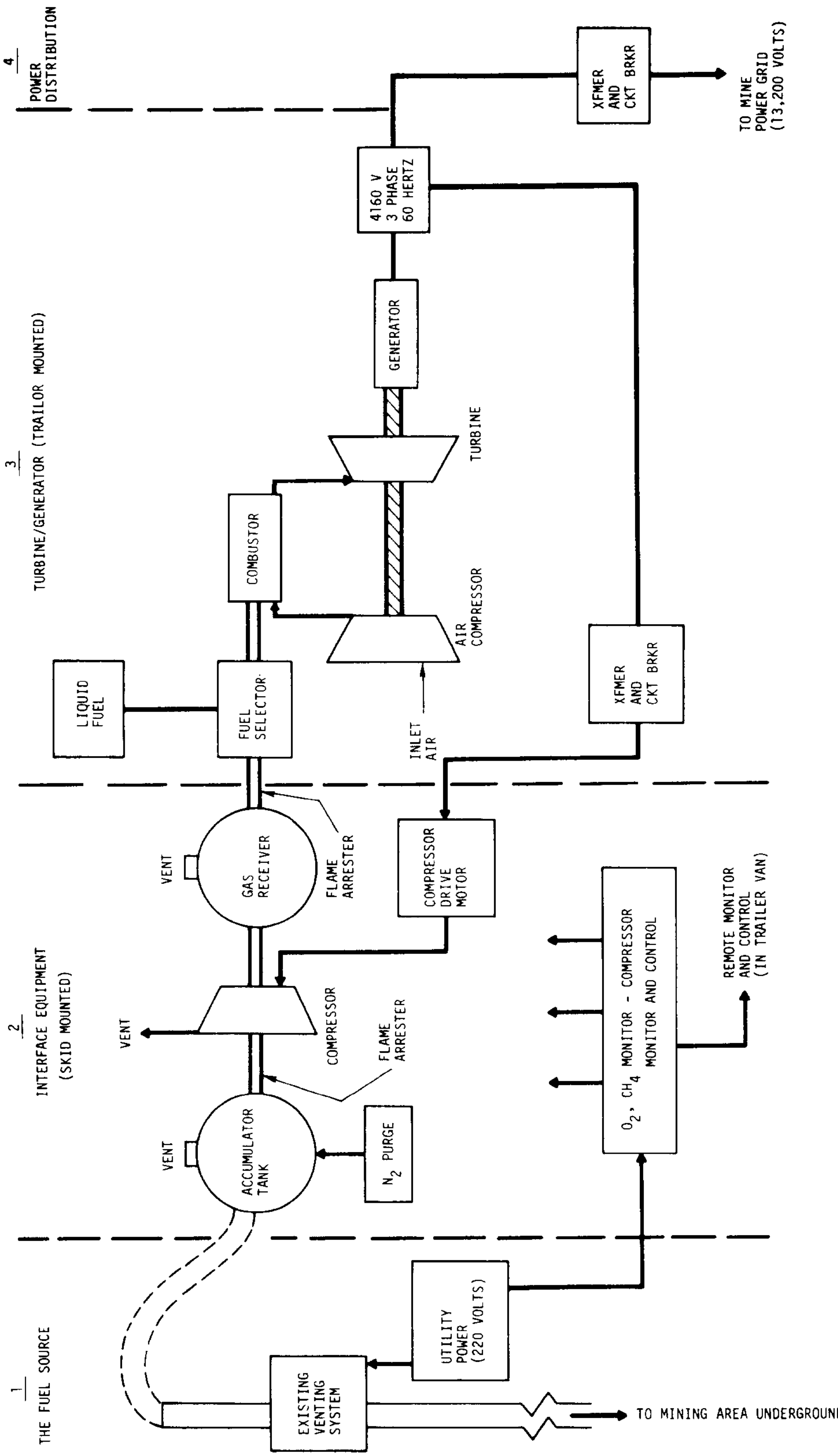

Figure 1. System Block Diagram

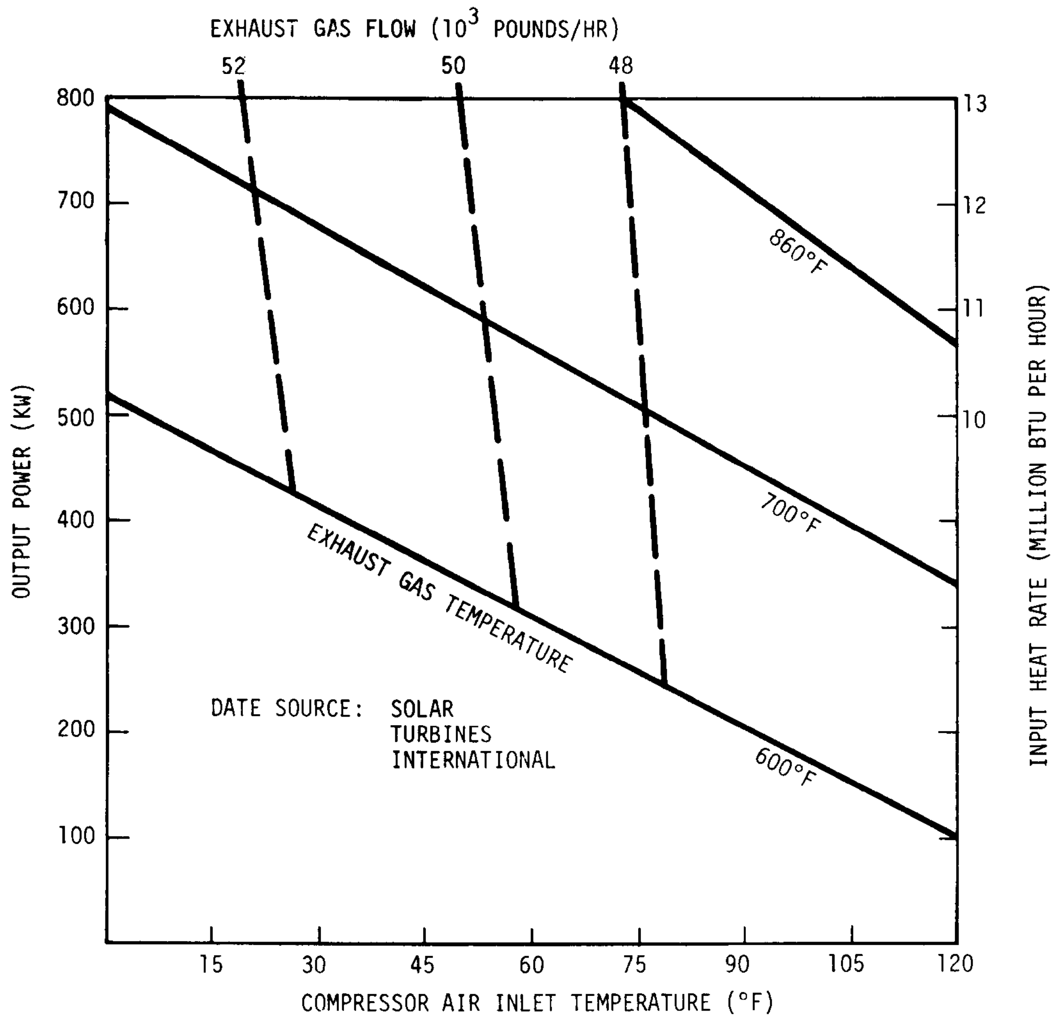

Figure 2. Saturn Engine Performance (at sea level)

THE FEASIBILITY OF METHANE PRODUCTION FROM COAL

by

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ABOUT THE AUTHOR

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ABSTRACT

The emission of methane from coal beds has caused problems for coal mining since the inception of the industry. At best, the methane problem is merely a nuisance, and at worst it can literally cause the closing of mining operations. Regardless of its severity, methane in coal mines is a detriment to mine safety, increases mining costs and curtails coal production. On the other hand, methane is the principal component of natural gas, a product that has ever increasing value and is in very short supply. Therefore, the "trash" of the coal industry is the "treasure" of the gas industry. This paper directs its attention at the feasibility of methane production from coal, and presents some results which have already encouraged industry to begin to actively seek this treasure.

The paper begins by describing the development and validation of a mathematical model which simulates the flows of methane and water in coal beds. Some examples are presented which demonstrate the ability of the model to accurately predict measured methane and water flows from actual systems once the properties of the coal beds are described to the model.

Following these examples, the paper is concluded by presenting some typical deliverability curves for vertical wells producing gas from coal along with an economic analysis that clearly indicates that this gas can be profitably delivered to pipelines at today's prices. In order to place the deliverability curves, generated by the model, into proper perspective, some data from an actual vertical well is presented to show that the generated curves are realistic.

INTRODUCTION

During the process of coalification, considerable quantities of gases are evolved from the indigenous carbonaceous material. These gases include methane and heavier hydrocarbons, carbon dioxide, nitrogen, oxygen, hydrogen and helium.[1, 2] The primary constituents are methane and carbon dioxide, and these gases have been observed in coal mines since the inception of the industry.

Quantities of methane and air in proper proportions (5 to 15 percent methane) result in explosive mixtures[3]. It is these mixtures that when ignited cause the disastrous explosions in coal mines. For many years, the only method of controlling the accumulations of explosive mixtures was a combination of increasing the ventilation and decreasing the extraction rate. These activities are costly and reduce productivity. With the advent of the energy shortage, the waste of the valuable gas resource makes the practice even more undesirable.

While there were some early U.S. efforts to study the problem, the most productive endeavor to study the phenomenon was an applied research program initiated by the U.S. Bureau of Mines in 1964.

These investigations have resulted in some very useful information and techniques that are identified throughout this paper.

GAS CONTENT OF COAL BEDS

Gas can be contained in coal either as free gas in the joints and fractures or as an adsorbed layer on the internal surfaces of the coal.[4] It is important to understand that the free gas contained in the fracture system will behave according to Boyles and Charles Laws just as gas accumulations in any reservoir rock. On the other hand, the gas which is adsorbed onto the internal surfaces does not behave according to Boyle's and Charles' Law, but in a very distinctive manner.

It is common knowledge that carbonaceous substances such as charcoal, coke and coal can adsorb gases preferentially, and this is what gives these substances their filtration properties. It is this same mechanism that stores methane and other gases in coal. In the adsorbed state, the gas molecules are "tightly packed and closely held" to the walls of the minute sized pores in the structure of the coal.[4]

The packing is thought to be only one molecule thick and its density increases with pressure. The large surface area available because of the very fine pore structure of the coal makes it possible to hold large quantities of gas. Figure 1 is a plot that shows the relationship of the volume of gas that can be retained as a function of pressure for several U.S. coals. This plot is shown as volume in cm^3/g of coal as a function of pressure shown in atmospheres and is known as the equilibrium sorption isotherm. At low pressures, the volume adsorbed increases rapidly and almost linearly. At higher pressure when the adsorbed layer becomes more crowded, the adsorption slows and finally at extremely high pressures it nearly stops.

Figure 2 is a plot in more conventional units which shows the relative magnitude of the amount of gas that can be stored in U.S. coal beds compared with that which can be stored in conventional reservoir rocks at the same pressures. As can be seen, coal contains methane in quantities of five to ten times the amount that can be stored in conventional reservoir rocks at the pressure range of interest.

It is interesting to note that even for a low to moderately gassy coal such as the Pittsburgh that the gas in place per section is about 1.4 billion cubic feet. If half of this gas is recoverable, then this gas source is as good or better, from a recovery point of view, as the Austin chalk in south Texas or the Milk River formation in Alberta, Canada. Since both of these areas are currently being exploited, this is a strong indication that we should be looking harder at gas production from coal.

The methane capacity of coal is a function of coal rank, pressure and temperature. A quantitative correlation has been developed by Kim of the U.S. Bureau of Mines[5]. The correlation was built on the basis of correlating the methane isotherms of various ranks of coal measured on a dry-ash free basis. These values were then adjusted for temperature, ash content and moisture content. Correlations for pressure and temperature with depth were applied and estimates of field values for methane capacity were made as a function of depth. This correlation is shown on Figure 3.

Some discussion is necessary to explain the use of Figure 3. This chart assumes that moisture plus ash is 10 percent by weight and that the effect of moisture on sorption capacity reduces the capacity 25 percent. These values are very reasonable for the high rank coals. Moreover, for the lower rank coals with high moisture content, the moisture correlation presented by Joubert[6,7] seems to be realistic. This, of course, needs further testing. Figure 3 assumes that a hydrostatic pressure gradient of .433 psi/ft exists and a temperature gradient of 1°C/100 feet of depth prevails.

SORPTION KINETICS OF COAL

While the measurement and prediction of the gas that can be stored in coal is very important, it does not tell the complete story of production of methane from coal. If it is accepted that all coal beds are subjected to an internal fluid pressure and that the coalification process makes gas available to the coal surfaces, then the coal-methane system will exist in equilibrium at that temperature, pressure and very probably above the critical moisture value because free water exists as a water saturation in the coal fractures.

If the pressure is lowered by the removal of some of its fluids, the coal will desorb some of its adsorbed gases. The amount that would ultimately be desorbed is calculated by the difference between equilibrium volume at initial conditions and that at the reduced pressure. However, the rate at which this happens is a function of another set of parameters which describe the kinetics of the system.

The emission of gas from coal requires the movement of fluids from their storage place, i.e. the micropores of the coal to a surface, i.e. a well, mine face, outcrop, etc. Patching[4] and others[3,8,9,10] postulate that flow in coal can occur in two ways. In solid unfractured coal, the flow is thought to be the very slow diffusion of gas molecules through the pores in response to differences in concentration. In fractured coal, the flow is through fractures in response to pressure gradients. The flow through fractures is much more rapid than the diffusion through solid coal. In large size samples of coal, both types of flow occur simultaneously.

Thimons and Kissell[11] demonstrated this postulation by flowing methane through very small discs of coal. Their results showed that where fractures existed the flow was laminar flow and could be described by Darcy's Law, and when fractures did not exist the flow was by diffusion.

A system of fractures commonly referred to as "cleat" exists in all coal beds.[12] This has meaning in the sense that all coal particles are surrounded by fracture planes at some distance. Conclusions from the above references lead to the development of equations which describe the diffusion flow from the solid coal or matrix into the fracture system. Crank and others[13, 14] have shown that utilizing Fick's Laws the differential equation for diffusion into or out of a sphere is

$$\frac{D}{r^2}\frac{\partial}{\partial r}\left(r^2\frac{\partial C}{\partial r}\right) = \frac{\partial C}{\partial t} \tag{1}$$

where C = concentration, cm^3/g

r = distance from the center of sphere, cm

D = diffusion coefficients, cm^2/sec

t = time, sec

An analytic solution of Equation (1) for the amount of gas entering or leaving the sphere is given by

$$\frac{M_t}{M_\infty} = 1 - \frac{6}{\pi^2}\sum_{n=1}^{\infty}\frac{1}{n^2}\exp(-Dn^2\pi^2t/a^2) \tag{2}$$

where M_t = amount sorbed at time, t

M_∞ = amount sorbed at equilibrium

a = radius of the sphere, cm

Further, it is shown by Crank that that shape of the particle is relatively unimportant and the above equation for a sphere adequately describes the flow for many other shapes as well.

Laboratory investigations of these parameters have been performed by several authors[15, 16, 17]. Some of the more important results were presented by Hofer et al[16]. They showed data that led to the following conclusions:

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

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

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

It is important to note that the solution of the differential equation (1) required the data of diffusion coefficient, D, and the effective fracture spacing, a. However, the system is adequately described by the ratio, D/a^2, so that a single measurement is all the data necessary. For this paper, D/a^2 is referred to as the diffusion parameter and is a function of the coal type and the fracture spacing.

RESERVOIR CHARACTERISTICS OF COAL BEDS

Although coal beds have several unusual characteristics, the only unique feature about the coal reservoir is the manner in which the gas is stored in the adsorbed state. The mechanisms for the release of the adsorbed gas were discussed in the previous section. Once the gas exists as free gas, the equations applicable to conventional petroleum reservoirs apply[3]. These equations are based on Darcy's Law of fluid flow in porous media and the continuity equation. These are discussed in detail later. A discussion of the more important properties of coal beds follows.

1. Cleat in Coal

Coal beds universally exhibit a natural system of fractures. Except in areas of high tectonic activity, the fracture system is generally perpendicular to the bedding planes of the coal. This system of joints and fractures is commonly referred to as cleat. The origin of cleat in coal is the subject of much discussion; however, it has been observed for many years. Coal mines are traditionally planned to take advantage of the cleat by mining in the direction in which coal breaks most easily.[12]

Frequently there exists a direction in which the cleat system is much better developed than the other. This direction of more frequent fracture spacing and longer, more continuous fractures is called the face cleat. The less developed, shorter fractures are called the butt cleats. The face and butt cleat directions are frequently separated by about 90°.

The variable frequency of fracture spacing with direction yields measurable differences in permeability. Holes or other conduits parallel to the butt cleat direction yield fluid productions up to 10 times greater than those parallel to the face cleat.[8]

2. Porosity of Coal

When determining the porosity of coal, it must be specified that we are looking for the fractional volume of the coal that is capable of being occupied by free gas and not adsorbed gas. This presents somewhat of a problem when measuring porosities of core samples. Taber et al in nearly the only laboratory investigation of coal reservoir properties[18, 19, 20, 21] reported large differences in porosities between those measured with helium and those measured with water as saturating fluids. Helium porosities on five samples varied from 2.5 to 8.6 percent while water porosities varied from 0.4 to 1.1 percent.

It is thought that this is a function of pore size that the respective molecules could penetrate. The water porosities probably are a better representation of the porosity of the fracture or cleat system. This is consistent with work done by the Bureau of Mines personnel in water infusion experiments. Porosities of fracture systems of about 1 to 4 percent are the best estimates that have been found to date. Kneuper[2] predicts an effective porosity of 1.3 to 3.9 percent for European coals.

3. Permeability of Coal

Again, the best work on permeability of laboratory samples is by Taber et al[21]. However, it is simply not possible to accurately measure permeabilities of fracture systems in laboratory samples. Cores taken in a virgin coal bed have been broken by the drilling process, and confining stresses have been relieved.

To date, the best estimates of permeability have been made by "history matching" observed production data. This is discussed in a later section. Absolute permeabilities of from 1/10th to 250 millidarcies have been postulated for various coal beds in the U.S.

4. Saturation Distributions in Coal

There are several keys available that lead to the conclusion that initially the cleat system is saturated with water in virgin coal beds. Drill stem test data (unpublished) show recoveries of water with little or no gas. Nearly all data available on vertical wells show that water rates initially start at high levels and decline while gas rates start at near zero and increase[22, 23, 24, 25, 26].

Further, field studies have shown that permeabilities to gas must increase with time.[27] This has been consistently demonstrated in several mines in different coal beds. This is readily explained by the concept of relative permeability. As water is produced and gas is desorbed, the water saturation in the fracture system decreases and gas saturation increases. Increased gas saturation with time results in higher permeability to gas.

5. Relative Permeability and Capillary Pressure of Coal

Again, the only recent work has been done by Taber et al[21]. This work is limited to Pittsburgh and Pocahontas coal, but fortunately these coals cover the range of friable and blocky type coals. Gas relative permeability curves are shown as Figures 4 and 5. Their resulting capillary pressure curve is shown as Figure 6.

6. Pressure-Depth Relationships in Coal

Reservoir pressures increase with depth in coal beds just as in any other geologic formation. What data is available[22, 23, 8] indicates that the pressure gradient is generally somewhat less than a hydrostatic gradient. Several examples tend to indicate a gradient of 0.2-0.4 psi/ft based on some drill stem test data (unpublished) and horizontal holes with packers.[8, 27, 9]

Caution should be used when using the hydrostatic gradient because most of the data available is from the eastern United States, and other geological basins are likely to show different pressure depth-relationships.

7. Gas Quality of Coal Beds

The gas produced from coal beds is of high quality. In the most comprehensive study on the composition of coal bed gas, Kim[1] reports that all samples contain large amounts of methane. Quantities do vary from 84 to 99 percent methane. Heating value varied from 840 Btu/cu.ft. to 990 Btu/cu.ft. when calculated at 30 inches of mercury, saturated with water vapor.

Quantities of carbon dioxide do exist in nearly all samples, and in some cases there are measurable quantities of heavier hydrocarbons, oxygen, nitrogen, helium and hydrogen. It is interesting to note that no sulfur dioxide or hydrogen sulfide has been found in any of the coal bed gas samples, even in high sulfur coal beds.

DEVELOPMENT OF SIMULATION MODEL

The previous sections contained a discussion of individual parameters that determine the flow of gas in coal beds. This section relates the parameters to one another in a mathematical manner that allows quantitative evaluation and validates the calculations with field data.

1. Mathematical Description of the Coal Gas Process

The production of methane from coal beds is believed to be dependent upon two distinctly different physical processes--(1) diffusion from the interior of a solid coal particle to a crack or macropore in the coal, and (2) two-phase (gas-water) Darcy flow through the fracture or macropore structure to a shaft or production well[3, 9]. The two-phase aspect of the fracture flow in coal beds is evidenced by the increase in permeability with time that has been consistently observed[27]. This phenomenon is readily explained by the relative permeability concept used to describe flow in oil and natural gas reservoirs.

a. Methane Diffusion

Diffusion of methane through solid particles of coal is a much slower process than the fracture flow. Depending on particle size, it may or may not be the controlling factor in production[30]. Diffusivities have typically been measured by grinding coal particles to a uniformly small size and comparing rates of desorption to analytical solutions for diffusion in a sphere of comparable diameter.

The differential mass balance describing diffusional transport in a sphere is as follows:[13]

$$\frac{D}{r^2}\frac{\partial}{\partial r}\left(r^2\frac{\partial C}{\partial r}\right) = \frac{\partial C}{\partial t} \qquad (3)$$

(The nomenclature defining each of the symbols used is found earlier in this paper.)

The concentration of methane, C, is expressed as moles/unit volume of coal. The boundary conditions for this equation are as follows:

$$\frac{dC}{dr} = 0 \quad \text{at } r = 0 \qquad (4)$$

$$C = f(p_g) \quad \text{at } r = a \qquad (5)$$

The rate of methane desorption at the surface of the sphere is given by

$$N = (M.W.)4\pi r^2 D \left.\frac{\partial C}{\partial r}\right|_a \tag{6}$$

or expressed on a unit volume basis:

$$N_v = \frac{3(M.W.)D}{r} \left.\frac{\partial C}{\partial r}\right|_a \tag{7}$$

b. Two-Phase Fracture Flow

The differential equations describing the flow of gas and water in a coal bed's fracture system result from combining continuity equations with the Darcy expression for flow in a porous medium:

Continuity Equations

$$-\nabla\cdot(\rho_w v_w) - q_{wv} = \frac{\partial}{\partial t}(\phi\rho_w S_w) \tag{8}$$

$$-\nabla\cdot(\rho_g v_g) + N_v - q_{gv} = \frac{\partial}{\partial t}(\phi\rho_g S_g) \tag{9}$$

Darcy Equations

$$v_w = -\frac{kk_{rw}}{\mu_w}(\nabla p_w - \rho_w g\nabla h) \tag{10}$$

$$v_g = -\frac{kk_{rg}}{\mu_g}(\nabla p_g - \rho_g g\nabla h) \tag{11}$$

Substitution of Equations (10) and (11) into (8) and (1) yields

$$\nabla\cdot[\frac{\rho_w kk_{rw}}{\mu_w}(\nabla p_w - \rho_w g\nabla h)] - q_{wv} = \frac{\partial}{\partial t}(\phi\rho_w S_w) \tag{12}$$

$$\nabla\cdot[\frac{\rho_g kk_{rg}}{\mu_g}(\nabla p_g - \rho_g g\nabla h] + N_v - q_{gv} = \frac{\partial}{\partial t}(\phi\rho_g S_g) \tag{13}$$

These two equations contain five dependent variables--p_w, p_g, S_w, S_g and N_v. Two additional equations are required to complete the coal gas model[9]

$$p_g = p_w + P_c \tag{14}$$

$$S_g = 1 - S_w \tag{15}$$

Equation (14) relates the gas phase pressure to the water phase pressure through a capillary pressure, P_c, which is a measured function of water saturation, S_w (see Figure 6). Equation (15) just states that the pore space is filled with water and gas.

In order to calculate the gas desorption term, N_v, that appears in Equation (13), it is necessary to solve Equation (3) for concentration. The desorption rate is then calculated from the concentration gradient in accordance with Equation (7).

APPLICATIONS OF SIMULATION MODEL

Validation of the simulation model was achieved by the analysis of laboratory and field studies. The desorption calculations were compared against laboratory measured desorption experiments. The results were identical with the results obtained by Bielicki[30] and Hofer[16]. Further, the coupling of the desorption calculation with the reservoir was tested against the analytic solution to the diffusion equation. The results were that the laboratory experiments, as well as the analytic solution, could be described by the model.

Several field applications have been studied which show that the simulation model is valid and does simulate actual field conditions. These applications or problems were chosen to address the range of problems reported in the literature and to point out the application of the model to applications that vary widely in objectives, location, etc.

It should be pointed out that most of the field data were taken with the objective of establishing ranges of results in a semiquantitative manner. The use of the data in such a rigorous manner as is done here is an extension of its precision and in no way reflects on the procedure or conditions by which it was recorded.

1. Mine Face Problem - Pocahontas Coal

This data set was recorded by the Bureau of Mines to study the effects of an advancing face, drilling degasification holes outside the headings and conducting a methane emission rate study in the Pocahontas coal bed. The results were published by Krickovic and Kalasky[28]. It is the methane emission rate study that is of interest to this application.

The study area consisted of a set of five headings and breakthroughs advancing in a north direction into virgin coal. Figure 7 shows the configuration of the immediate monitoring area. This area is several thousand feet from other mine workings. During the study period, the annual miners' vacation occurred which resulted in a two-week idle period. It is this idle period which is the subject of the simulation period.

Ventilation air was circulated to the mine face down headings 2, 3 and 4. Headings 1 and 2 were used for air returns. Monitoring of methane emissions was accomplished by recording air volumes and methane content both upstream (point E) and downstream (points C and D) of the face. Differences between the methane in the return air and incoming air were calculated to be the emission from the face. Monitoring was discontinued for several days during the period because of a holiday.

During the first few days of the idle period, a horizontal hole was drilled 108 feet into the face and a series packer assembly was installed which enabled the pressure at that depth to be monitored. The pressures measured are shown in Table 1 below, and flow rates from the face are shown in Table 2. It is thought that the first two days' pressures were affected by the drilling process and that the pressure continued to build toward the initial pressure of about 655 psig before the pressure started to fall due to production at the face.

Table 1

In Situ Gas Pressure at 108 Feet

Time, Days Into Idle Period	Pressure, psig
5	649
6	650
12	645
13	642
14	640

Table 2

Gas Emission from Face

Time, Days of Idle Period	Rate, Mcf/d
1	234
2	182
3	161
4	102
5	115
6	127
11	82
12	75
13	67
14	56

The simulation was accomplished with a one-dimensional simulation grid which extended about 400 feet with the coal face assumed to be one boundary that is 376 feet wide and maintained near atmospheric pressure.

The data used was the equilibrium sorption isotherm for Pocahontas coal shown earlier on Figure 1. The initial pressure was assumed to be 670 psia and the value of D/a^2 was used as $5x10^{-6}$ sec^{-1}. A gas relative permeability curve developed for Pocahontas coal shown in Figure 4 was used. The gas properties were calculated assuming methane as the major constituent of the gas.

These data leave the primary unknown variables to be coal porosity and permeability. The best fit of the data was found to be 2.2 percent porosity and 5 md permeability. The results of this simulation run are shown graphically in Figure 8. These results are called a history match which is the set of parameters that most closely fits the observed behavior.

The fit of the gas production data is quite good. The original reported data had an apparent error in four points. Adjustment of the data to reasonable limits yields the data shown. The production anomaly for the fourth day remains unresolved unless the methanometer reading was erroneous for that day.

While it is impossible to measure water production from a face such as in this problem, the calculated volumes are not at all unreasonable. If the water vapor capacity of the ventilation air is calculated, far more water could be evaporated by the ventilation air than is calculated to be produced. This would account for no water accumulation on the floor of the mine.

The boundary conditions were examined by adding additional dimensions of coal in the three directions from the face. The result was little change in the calculated results. This means that the coal some distance removed from the immediate face area contributed very little to the flow from the face.

The initial condition was assumed to be a uniform pressure of 670 psia and 100 percent water saturation in the fracture system. At time zero, the pressure at the face was lowered to atmospheric and the gas and water rates were calculated. Time zero was the time at which mining ceased. Obviously the face did not instantaneously appear in virgin coal, but the data does show that it takes in excess of ten days to materially affect the pressure at about 100 feet. Additional data in the report shows that the mining equipment can mine at a faster rate than the pressure wave can move through the coal. This means that the mining activity is very close to virgin coal after any extended mining period. This means that the initial conditions assumed are close to reality.

The significant things demonstrated by this problem are that (1) the simulation model can be used to give accurate estimates of the performance of coal reservoirs and (2) the data generated by several independent sources is accurate enough to explain the phenomena observed in the field.

2. Vertical Well with Hydraulic Stimulation - Pittsburgh Coal

The subject of this simulation problem is a vertical well drilled into the Pittsburgh coal bed. The description was obtained from Duel and Elder.[23] The well was part of a pattern of five wells drilled by the Bureau of Mines. After 18 months of production, the well had stabilized at about 8 Mcf/d and 4 bbl/d of water. The well was stimulated with a small hydraulic fracture treatment. The treatment was 10,000 gallons of gelled water and 6,000 pounds of 10-20 mesh sand. After the pump was reinstalled, the gas production peaked at about 35 Mcf/d and declined thereafter.

The simulation was done in radial coordinates in two dimensions of r-θ, as shown in Figure 9. The fracture was simulated with a small angle with permeability equivalent to a sand pack of 10-20 mesh sand or 800,000 md and a fracture width of 0.1 inches. Equilibrium sorption isotherm data as shown on Figure 1 and gas relative permeability as shown on Figure 5 were used to describe the coal. Initial pressure was 180 psia. A diffusion parameter of 5×10^{-9} was used for D/a^2. This made the primary unknown parameters to be reservoir porosity, permeability and effective fracture length.

The procedure used was to obtain the best pre-stimulation history match by adjusting the porosity and permeability, then holding these constant, adjust the fracture length to match the post-stimulation performance.

Figure 10 shows the best results obtained. The data indicate some problem getting the pump in proper working order as evidenced by the fact that the peak water production was not observed until about 3 months after the stimulation. To account for this, production from the model was restricted to what was actually produced for this 3-month period. The result is that the simulation predicts an absolute peak of about 42 Mcf/d with the 30-day average very close to the 35 Mcf/d observed. The simulation shown was obtained with 1.0 percent porosity, 5 md and a total fracture length of 330 feet (165 feet each way from the well). It is interesting to note that the fracture treatment design predicted a total fracture length of 309 feet.

The largest difference between the observed and simulated data exists in the water production. However, it is felt that the problems with the pump make the exact scheduling of the rates uncertain and further refinements are not warranted.

Again, the boundary conditions were checked and it was found that the well was not experiencing interference from the other wells in the pattern and that the computation grid was adequate to describe the flow.

The results of this problem show that the simulator can be used to evaluate individual wells and that the behavior can be adequately described by the theory and data that have been developed.

3. Well Pattern Problem - Mary Lee Coal

This last example is a problem described by Duel and Elder[22]. The problem is a five-well pattern in Jefferson County, Alabama. Five wells were drilled and completed in the Mary Lee coal bed. The data was somewhat incomplete with production data from only four wells reported. The wells produced with markedly dissimilar characteristics.

Well #3 was hydraulically fractured, but there is apparently an error in the post-stimulation production data so the fracture treatment was not simulated. Also, Well #2 produced for only a short time and was not simulated, but it is very similar to Well #4.

Wells #1 through #4 were drilled at the corners of a square with sides of 1,500 feet. Well #5 was then drilled in the center. Analysis shows that there was no interference between wells during the period studied.

Well #3 produced the largest volumes of gas starting at near zero and increasing to nearly 5 Mcf/d over a 20-month period. Well #4 was nearly constant at about 200 cf/d and Well #5 shows a behavior that was intermediate, but also shows evidence of some production problems.

Sorption characteristics of the Mary Lee were estimated from data reported by McCulloch, et al[29]. This data indicated a 6.55 cm^3/g gas content and a low desorption rate; a value of $1x10^{-9}$ was used for D/a^2. Porosity was found to be about 4 percent with permeability being the primary variable. Relative permeability was assumed to be similar to the Pocahontas curve from Taber et al[21] with a 10 percent critical gas saturation.

The results of the simulation are shown in Figure 11 which is a plot of cumulative gas production with time for the three wells considered. All parameters were the same in all three cases except permeability. As can be seen, the differences in production characteristics can be explained by a difference in a single variable. Experience in other fractured gas reservoirs indicates that the range of 0.1 md to 2.5 md is indeed not unreasonable even over the relatively short distances involved here.

Another explanation of this data could be achieved by assuming that the wells were damaged during drilling and that some skin factor should be applied to each well. This was not done here, but more recent information from this area of Alabama indicates that permeabilities in the Mary Lee are higher than the 2.5 md calculated above and that wellbore damage is the most probable explanation for the low measured flow rates.

TECHNOLOGY APPLICATION - GAS PRODUCTION

We are now in a position to use the mathematical model which has been developed and validated in order to look at the feasibility of producing methane from coal. The deliverability curves displayed in Figures 12 and 13 are examples of what the model predicts to be typical of a Pittsburgh type and Pocahontas type coal.

The curves on Figure 12 were generated using data that is typical of the Pittsburgh coal seam. That is, we used a characterization of the coal-methane system and of the reservoir that we would expect to find in the actual Pittsburgh coal seam. You will note that these curves vary from very pessimistic to very optimistic to allow for the data uncertainties that still exist. In order to establish some reality to these predictions, we have plotted an "x" on Figure 12 which is the production from an actual well in Greene County, Pennsylvania, producing from the Pittsburgh coal seam. It is unfortunate that more data is not available; however, this data point certainly indicates that the model generated curves are realistic and that more actual data should be gathered.

Figure 13 presents the model generated deliverability curves for a coal that was characterized using data which is typical of the Pocahontas coal seam. These deliverability curves are considerably more optimistic than those obtained for the Pittsburgh type coal; however, no actual substantiating data is available for this coal seam. There is, however, some work currently being done by U.S. Steel and the Bureau of Mines in the Mary Lee coal seam, which is similar to the Pocahontas coal, and indicates that these deliverability curves are realistic.

COST ESTIMATE

In order to evaluate the feasibility of gas production from coal, we need to look at some kind of economics. We therefore, have included here projected economics for the typical deliverability curves shown on Figures 12 and 13. The first step in projecting economics is to make some cost estimates.

The capital and operating costs for the various components of potential systems were estimated. These cost estimates are intended only to test the feasibility of the process and do not represent projected costs for any specific application. The costs are based on early 1977 prices.

The cost of drilling, completing, equipping and producing will vary widely between areas. This effort is made to make reasonable estimates of costs which can be used to test the economic viability of the degasification technology. Variables that can affect the costs dramatically are such things as freight on pipe and equipment, terrain, the difficulty of drilling, etc.

The costs are broken down into several categories. The drilling function includes drilling the hole and running the surface and production casing. The casing and tubing costs include the costs of the pipe and the wellhead. Pumping equipment includes the cost of pump, rods and pumping unit. Cementing and perforating are estimated as is logging. One of the largest costs is for a stimulation treatment. While the treatments have not been optimized, the allowance of $15,000 per well is thought to be realistic. The production unit costs include an individual wellhead compressor, as well as separator and an allowance for connecting the piping. A nominal allowance of $5,000 is made for site preparation and electric power.

Some of the costs are variable with depth and others are fixed. To demonstrate the variability, Figure 14 was prepared which shows the capital costs of drilling wells as a function of depth. Table 3 itemizes the costs for a nominal 800 ft. well.

Table 3

Vertical Well Costs

Depth - 800 Feet

Drilling	$ 8,000
Casing	1,600
Tubing	1,200
Pump, Rods, Pump Jack	3,500
Cementing and Perforating	3,000
Logging	1,500
Stimulation	15,000
Surface Equipment (Production Unit)	15,000
Site Preparation and Electric Power	5,000
	$ 53,800

Operating costs were estimated to include labor, maintenance and repair, and electric power. Labor was estimated on the basis of one man for each 16 wells. Repair and maintenance was estimated as 5 percent per year of installed costs of the production equipment, pumping equipment, and pipeline.

Electric power used for compressors and pumps was estimated at two prices, \$.02 and \$.05 per kwh. These costs are displayed on Figure 15.

One potential operating cost that was not included is water disposal costs. This varies from zero to over \$1 per barrel. If the produced water is poor quality, the cost of disposal goes up, but several operators report no appreciable cost for water disposal.

In an attempt to make the economics of gas production applicable to different size projects, a unit development module was used. This unit module consists of sixteen wells and its associated facilities. The module would cover 4 square miles on 160-acre spacing, 16 square miles on 640-acre spacing and 640 acres on 40-acre spacing.

The deliverability curves used for the economic calculations are shown in Figures 12 and 13.

Tangible costs were estimated to be \$23,500 per well with the balance as intangible drilling cost. Depletion allowance is assumed to be zero. Depreciation is calculated on a unit of production basis. Production and severance taxes are estimated to be 6 percent and ad valorem taxes are 5 percent. Corporate income tax was assumed to be 48 percent. Economic indicators chosen for analysis are payout and rate of return. The heating value of the gas was assumed to be 1,000 Btu/scf.

Several cases were calculated assuming different gas prices for the various deliverability curves. The results of these calculations are shown on Figures 16 and 17 for the Pittsburgh type coal and Figures 18 and 19 for the Pocahontas type coal. The results show the economics to be very exciting for most cases at realistic gas prices. However, the curves do show the reason that this gas has not been developed previously when gas prices were less than \$1 per Mcf.

It should also be noted that the costs used for the gassier Pocahontas type coal assumed that wells would be drilled to 2,000 feet, while for the less gassy Pittsburgh type coal well depths were assumed to be 800 feet.

When using these curves, care must be exercised to note that all the assumptions inherent in the deliverability calculations flow through directly.

The cases presented point out that certain variables are significant to the coal gas process. The most significant variable to the economic calculation is the gas deliverability. Once again it is pointed out that the ability to create gas wells that can produce in the range of 50-300 Mcf/d is critical. It will be immediately pointed out that this ability has been demonstrated only partially. However, in all fairness, extrapolation of stimulation treatments to larger sizes should result in substantially higher rates.

Further, all the calculations are for a single coal seam. The assumed coal thickness can be increased by completing multiple beds. Even if the beds have to be stimulated separately, the costs will not go up in proportion to the increase in thickness and larger deliverabilities should be possible.

CONCLUSIONS

It is clear from the results presented in this paper that it is currently feasible and economic at reasonable gas prices to begin to produce gas from coal if we can believe the model generated deliverability curves. As we indicated, there is some limited data which indicate that these predictions are realistic; however, more field testing is badly needed.

Industry and government are now moving rapidly to obtain this field data and before the end of 1978 there will be dozens of test wells drilled into U.S. and Canadian coal seams. INTERCOMP is now actively involved in seven such test projects with many more probable.

If these projects are as successful as we believe they will be, we can project that many trillions of cubic feet of gas can be recovered for under 2.00/Mcf.

Since there are estimates that the gas trapped in coal exceeds 800 trillion cubic feet, it is clear that the incentives to exploit this resource are large and that even a higher level of effort than that currently going on is desirable.

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Figure 1. **EQUILIBRIUM ADSORPTION ISOTHERMS.** Coal type and moisture levels selected to correspond to the cores extracted from the vertical boreholes.

(FROM KISSELL ET AL, USBM RI 7767)

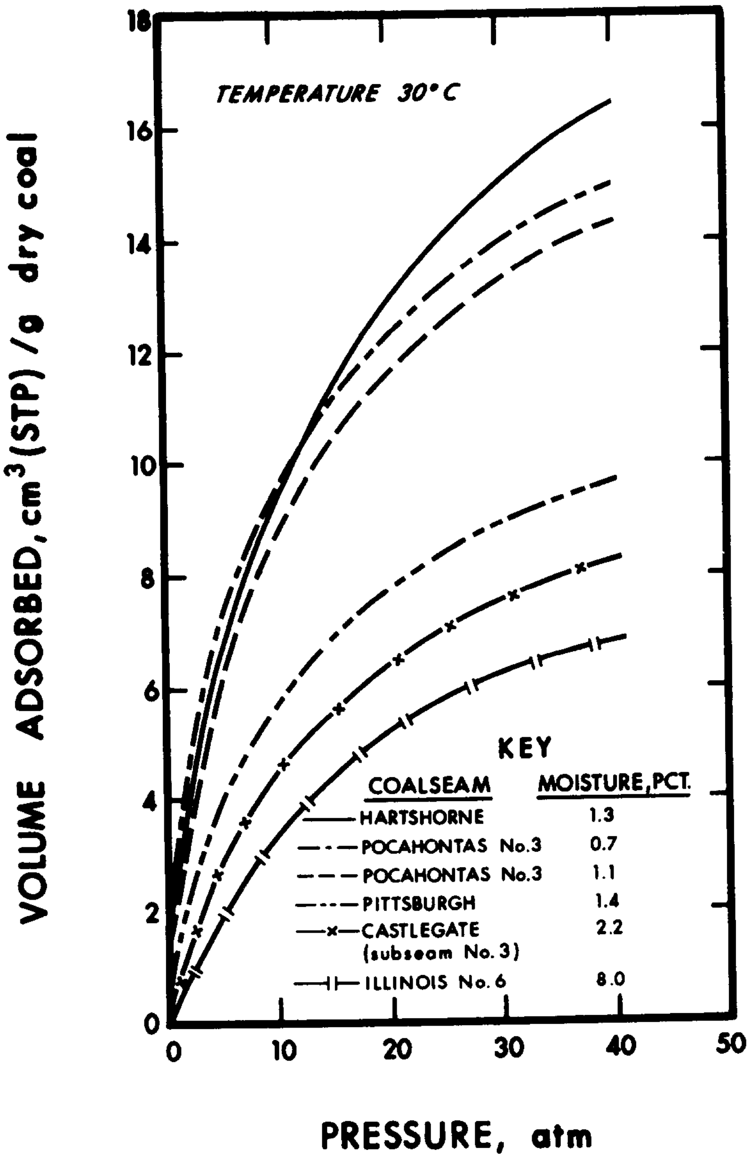


Figure 2. **METHANE CAPACITY OF COAL AND ROCK**

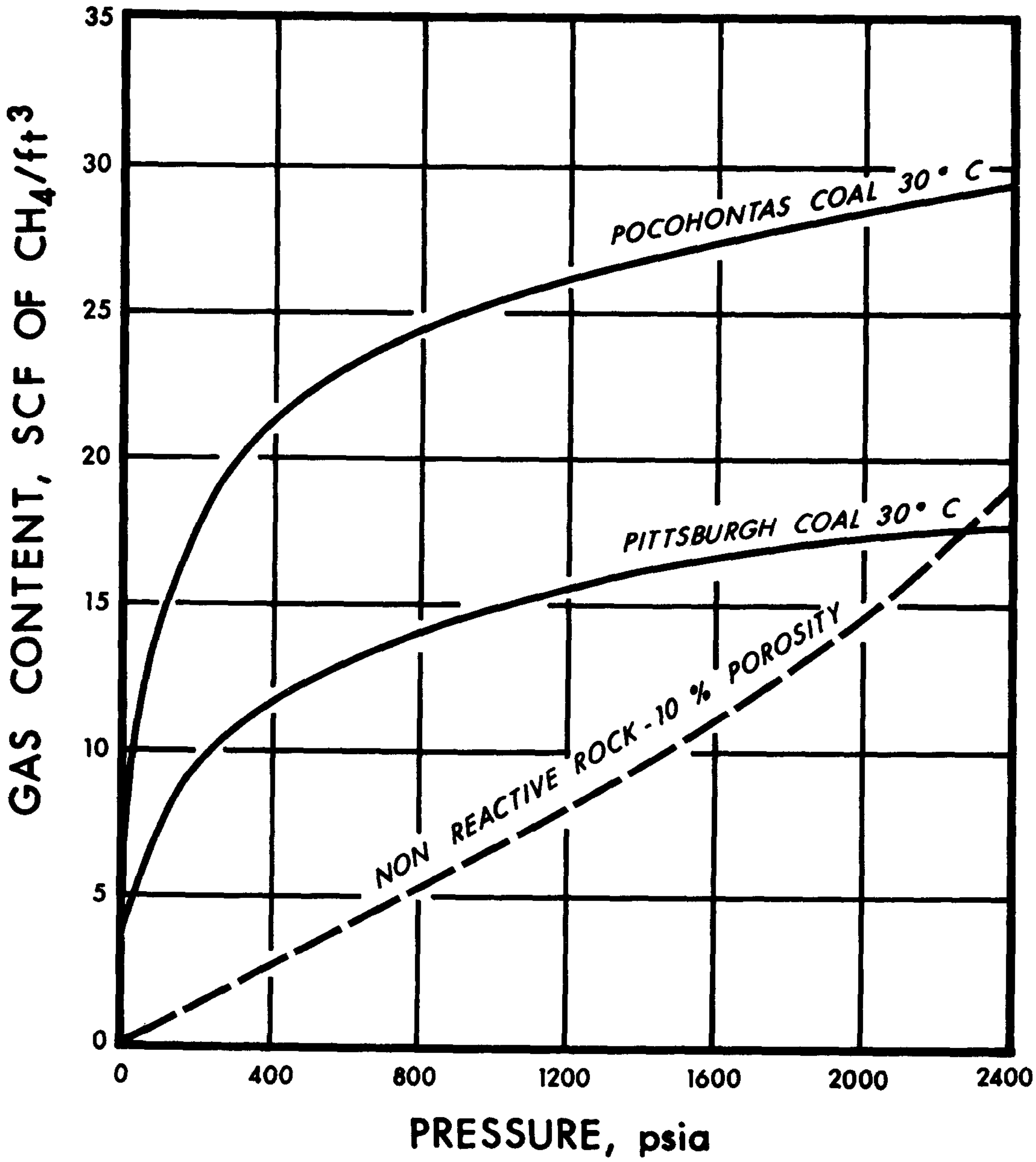


Figure 3

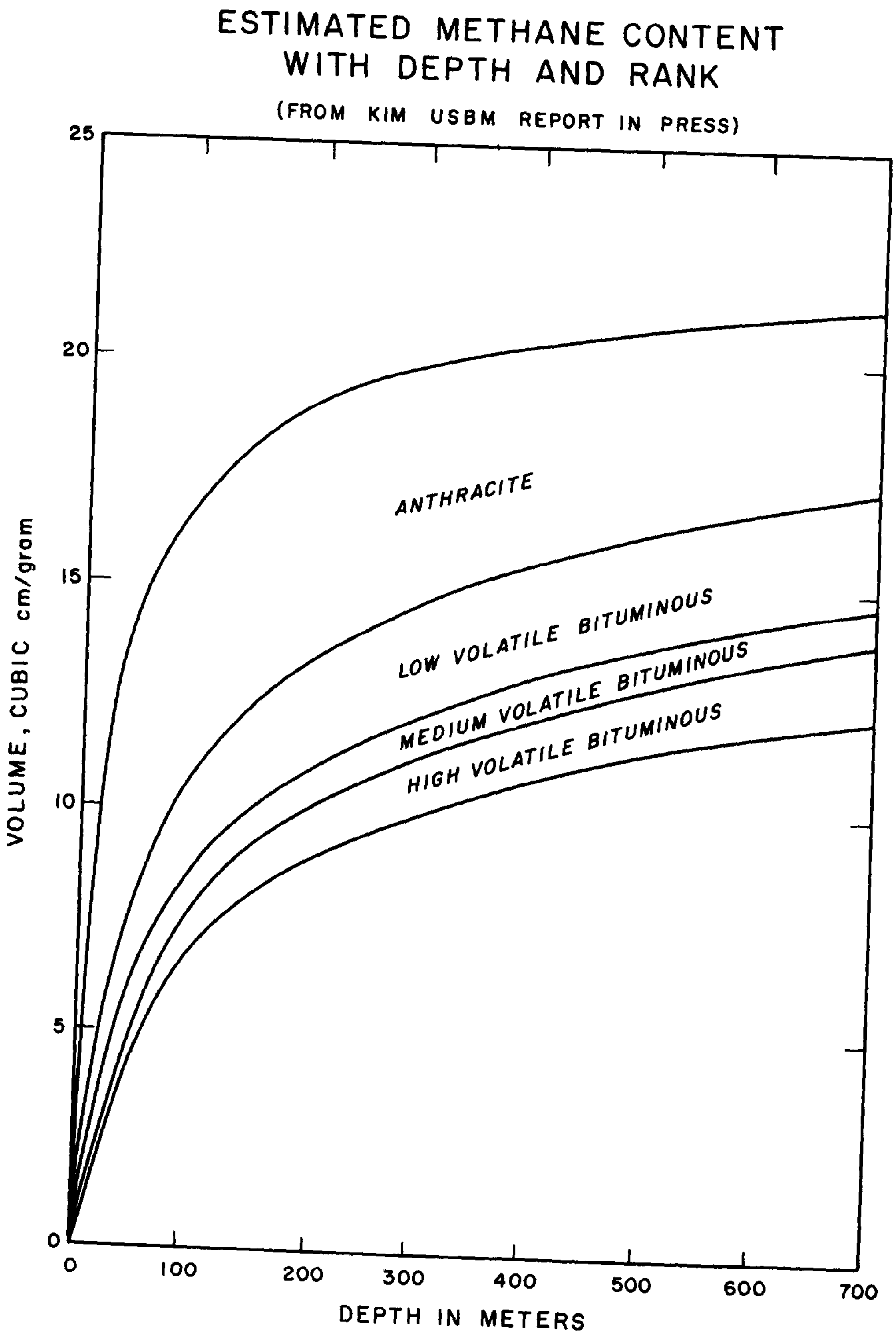

ESTIMATED METHANE CONTENT
WITH DEPTH AND RANK
(FROM KIM USBM REPORT IN PRESS)
ANTHRACITE
LOW VOLATILE BITUMINOUS
MEDIUM VOLATILE BITUMINOUS
HIGH VOLATILE BITUMINOUS
VOLUME, CUBIC cm/gram
DEPTH IN METERS
0
5
10
15
20
25
100
200
300
400
500
600
700

Figure 4

Drainage relative permeability curves for Pittsburgh Coal.

(FROM TABER ETAL, SPE JOURNAL, DEC. 1974)

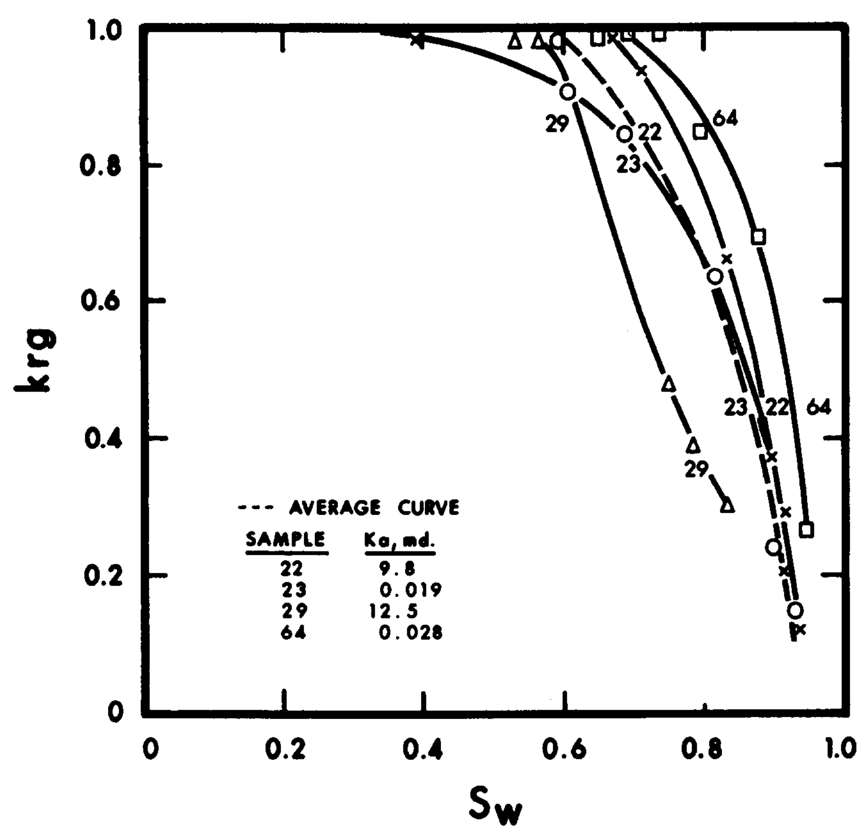


Figure 5

Drainage relative permeability curve for Pocahontas Coal.

(FROM TABER ETAL, SPE JOURNAL, DEC.1974)

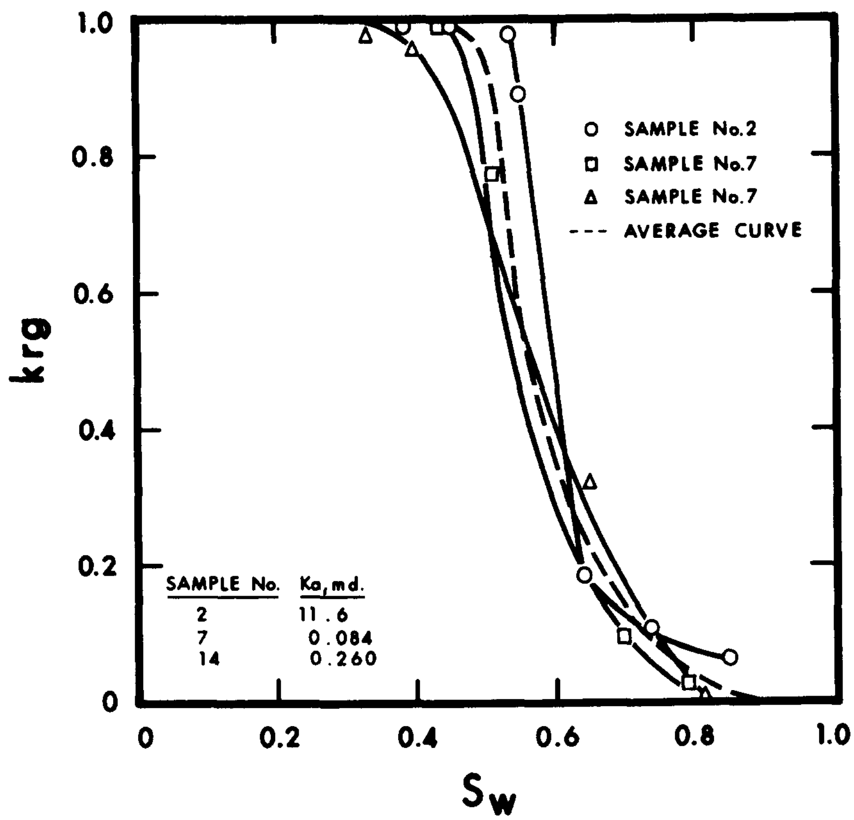


Figure 6

Capillary pressure, Pc, VS water saturation, Sw

(FROM TABER ETAL, SPE JOURNAL, OCT. 1976)

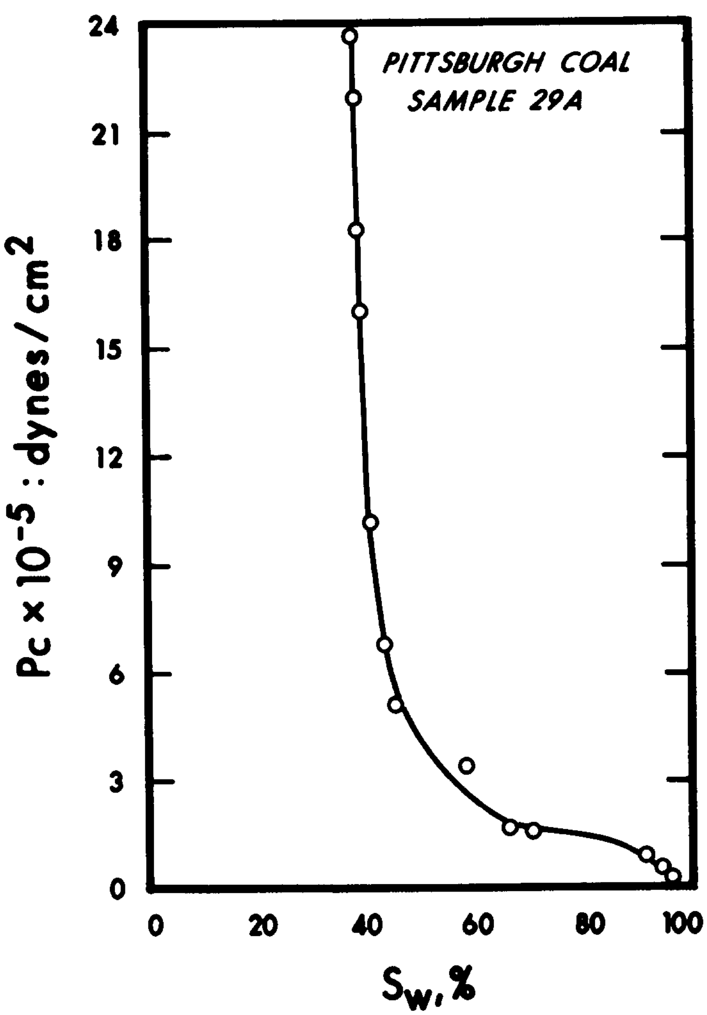
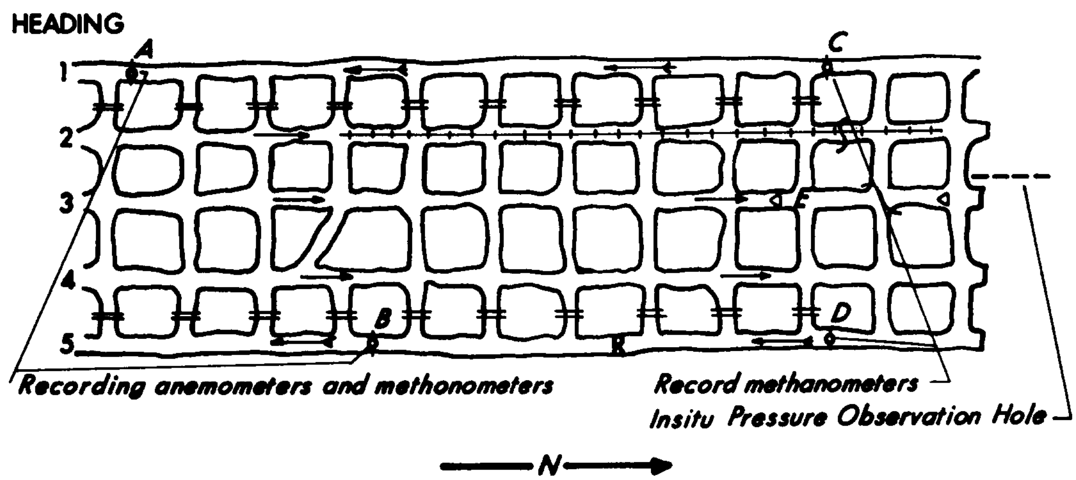


Figure 7

CONFIGURATION OF HEADINGS DURING MINERS VACATION

(FROM KRICKORIC ETAL, USBM RI 7703)



LEGEND

- 1-5 ENTRY NUMBER
- PLASTIC STOPPINGS
- R REGULATOR
- PERMANENT STOPPING
- INTAKE AIR
- RETURN AIR
- HORIZONTAL DRILL HOLE
- BOLT LOADING STATION
- TRACK

SCALE

Figure 8

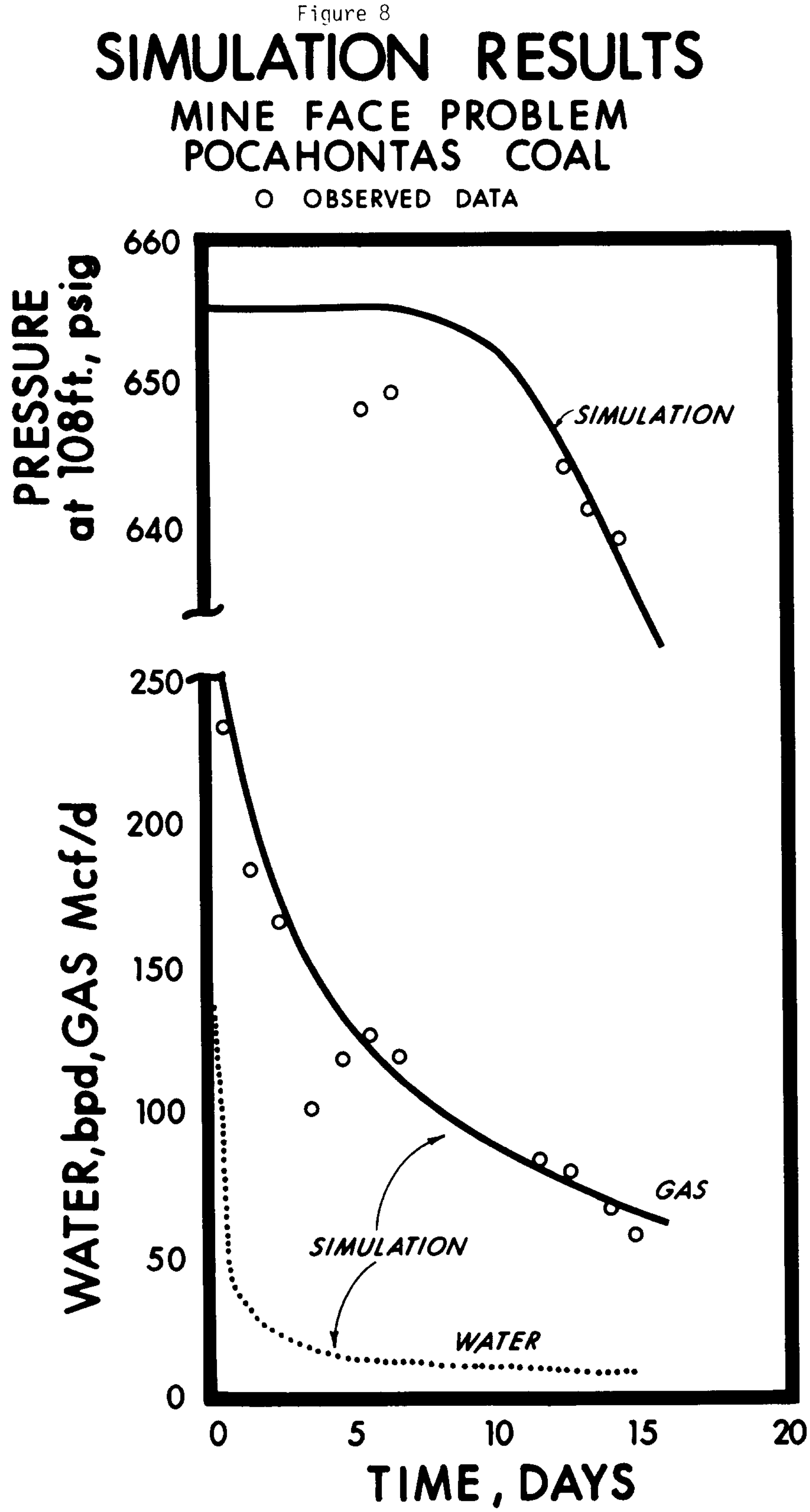

SIMULATION RESULTS
MINE FACE PROBLEM
POCAHONTAS COAL
O OBSERVED DATA
PRESSURE at 108ft., psig
660
650
640
SIMULATION
250
200
150
100
50
0
WATER, bpd, GAS Mcf/d
GAS
SIMULATION
WATER
0
5
10
15
20
TIME, DAYS

Figure 9

SINGLE WELL COMPUTATION GRID IN RADIAL COORDINATES

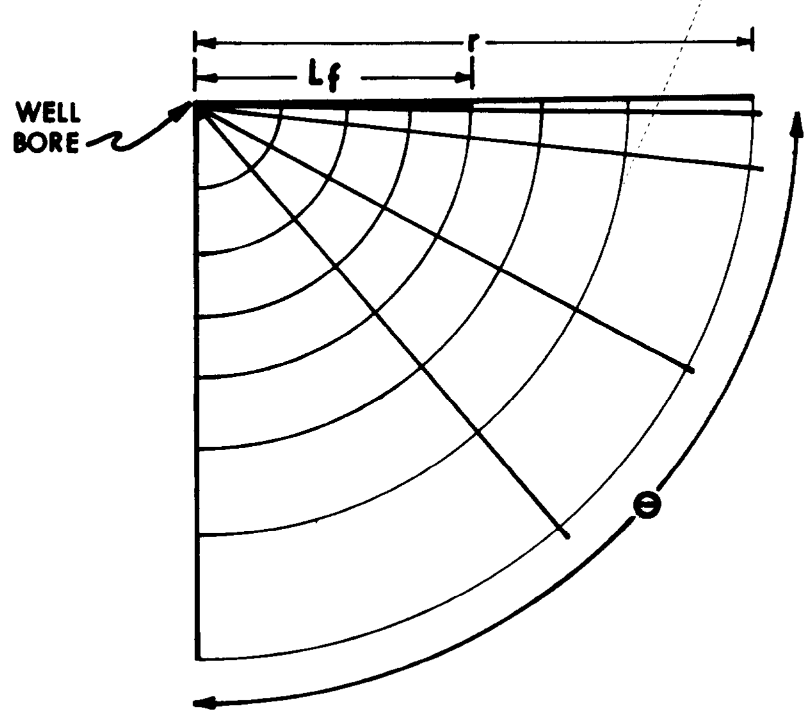


Figure 10

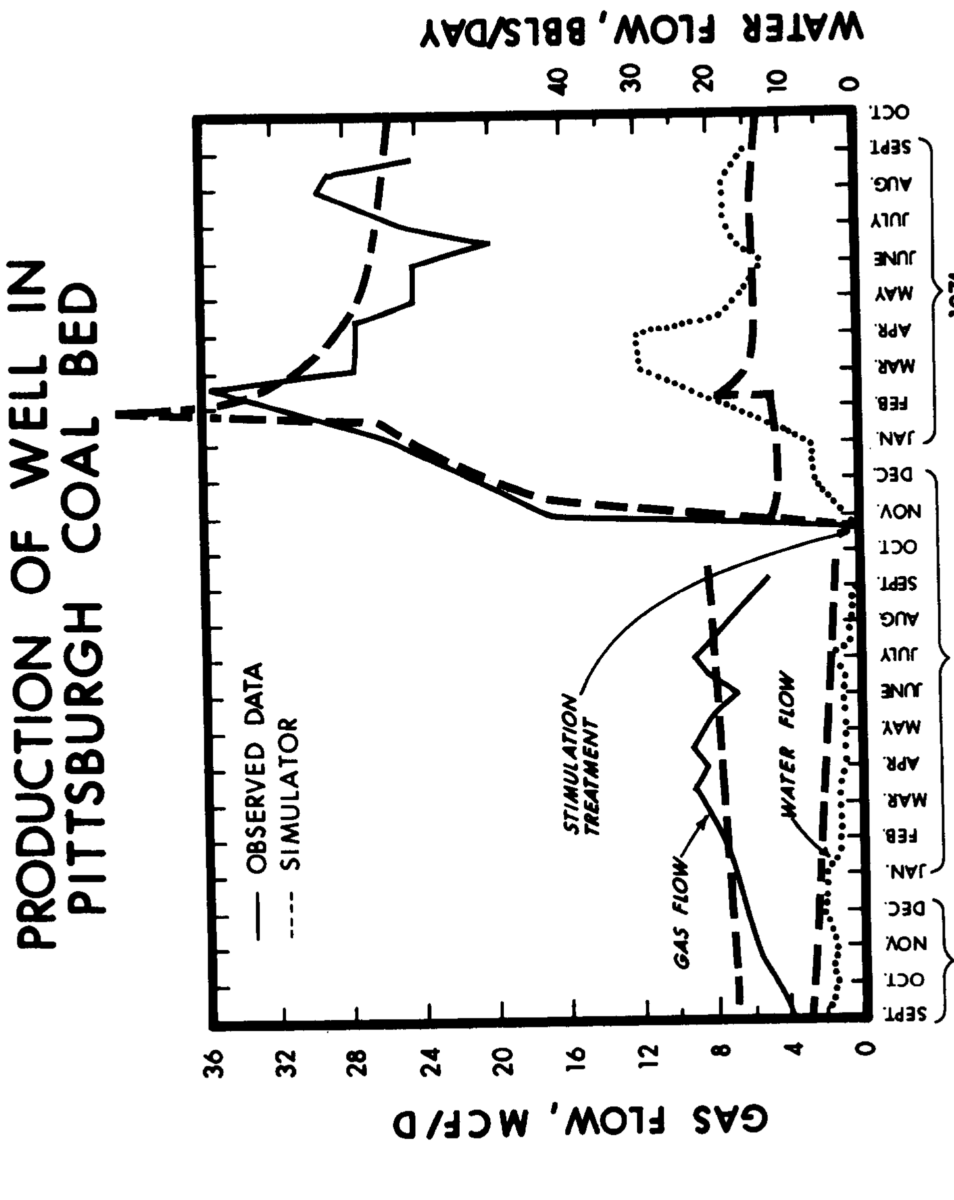

PRODUCTION OF WELL IN
PITTSBURGH COAL BED
— OBSERVED DATA
--- SIMULATOR
STIMULATION TREATMENT
GAS FLOW
WATER FLOW
GAS FLOW, MCF/D
WATER FLOW, BBLS/DAY
36
32
28
24
20
16
12
8
4
0
40
30
20
10
0
SEPT.
OCT.
NOV.
DEC.
JAN.
FEB.
MAR.
APR.
MAY
JUNE
JULY
AUG.
SEPT.
OCT.
NOV.
DEC.
JAN.
FEB.
MAR.
APR.
MAY
JUNE
JULY
AUG.
SEPT.
OCT.
1972
1973
1974

Figure 11

INDIVIDUAL WELL PRODUCTION
MARY LEE COAL

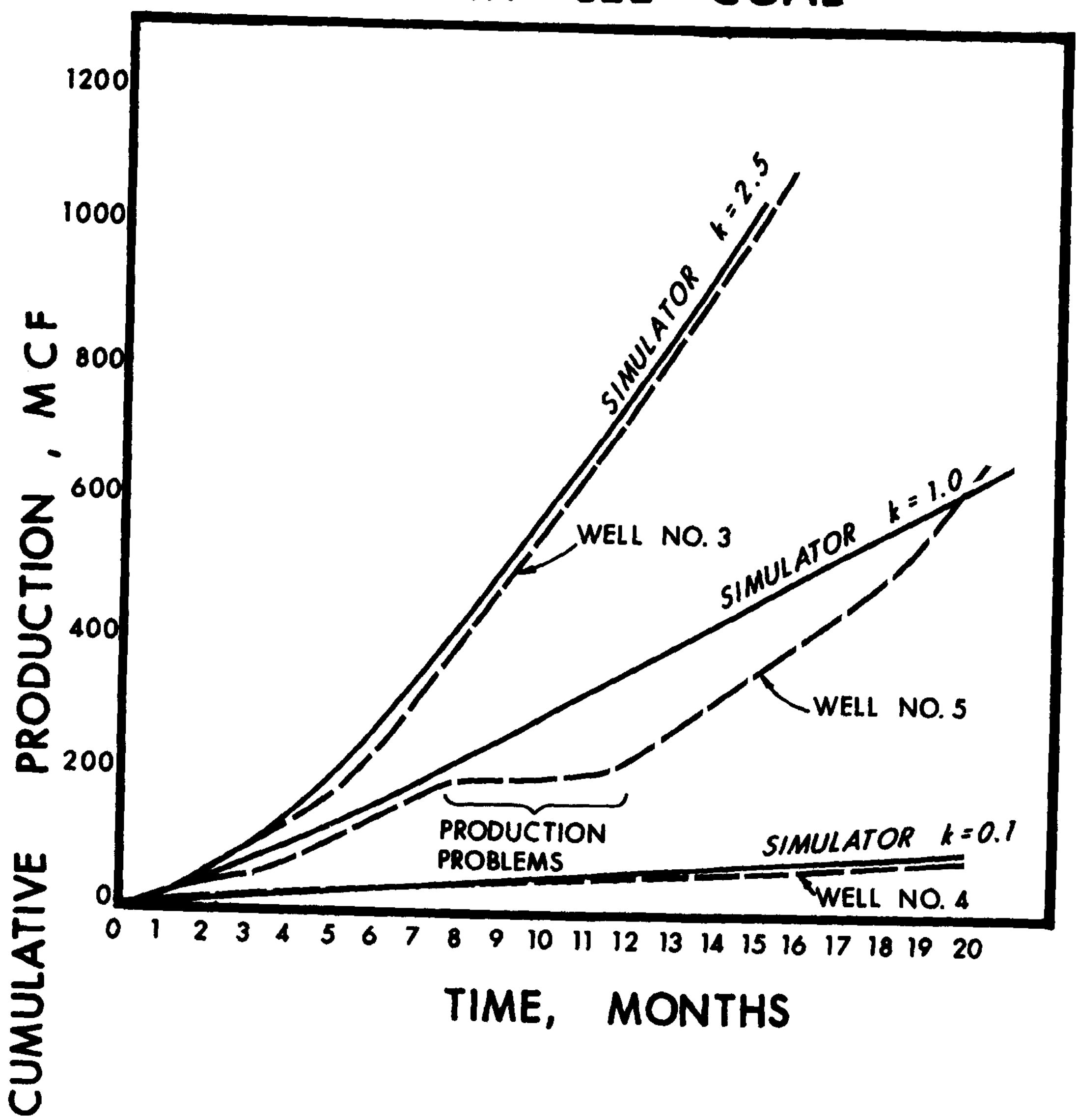


Figure 12

PROJECTIONS OF WELL DELIVERABILITY

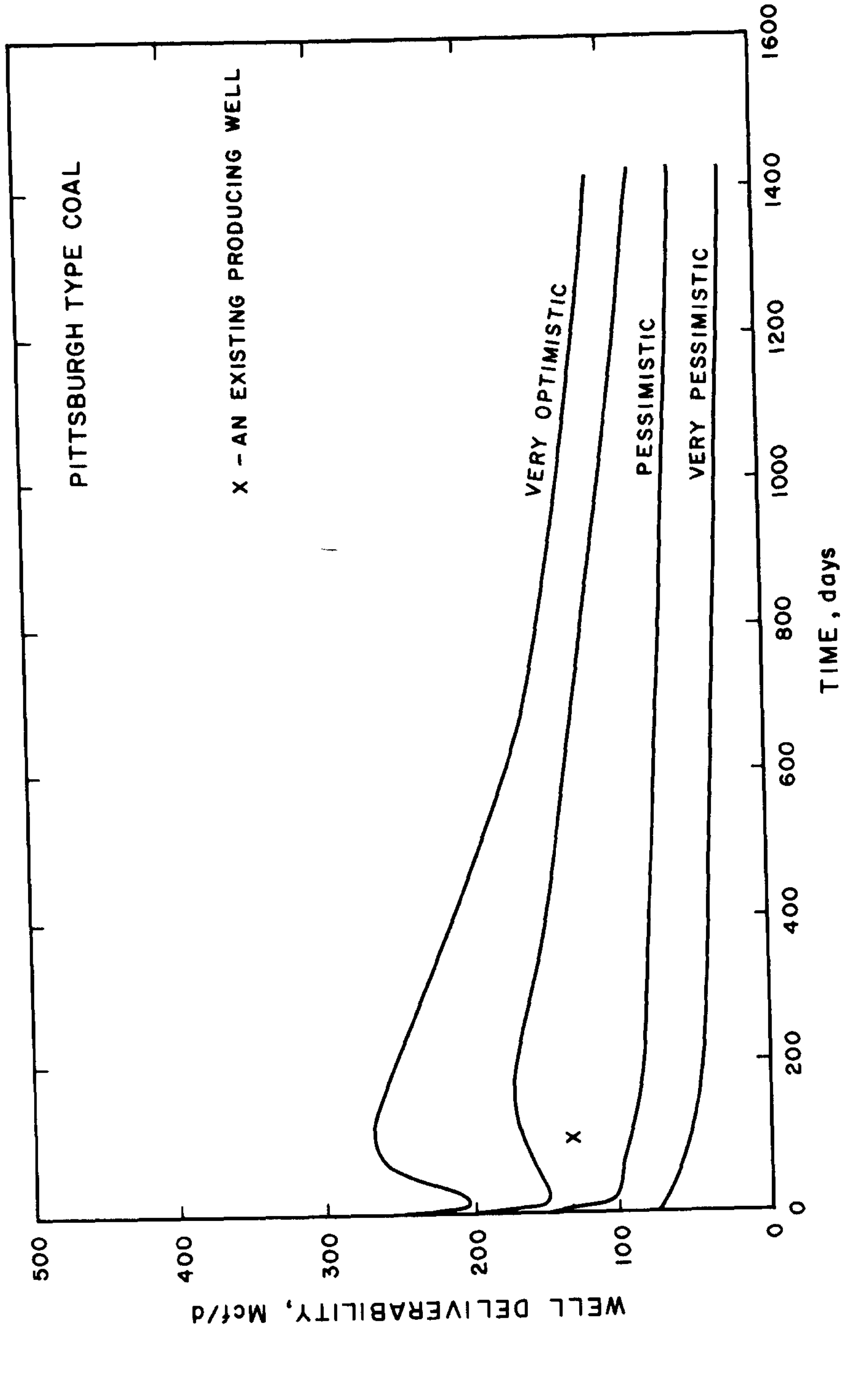


Figure 13

PROJECTIONS OF WELL DELIVERABILITY

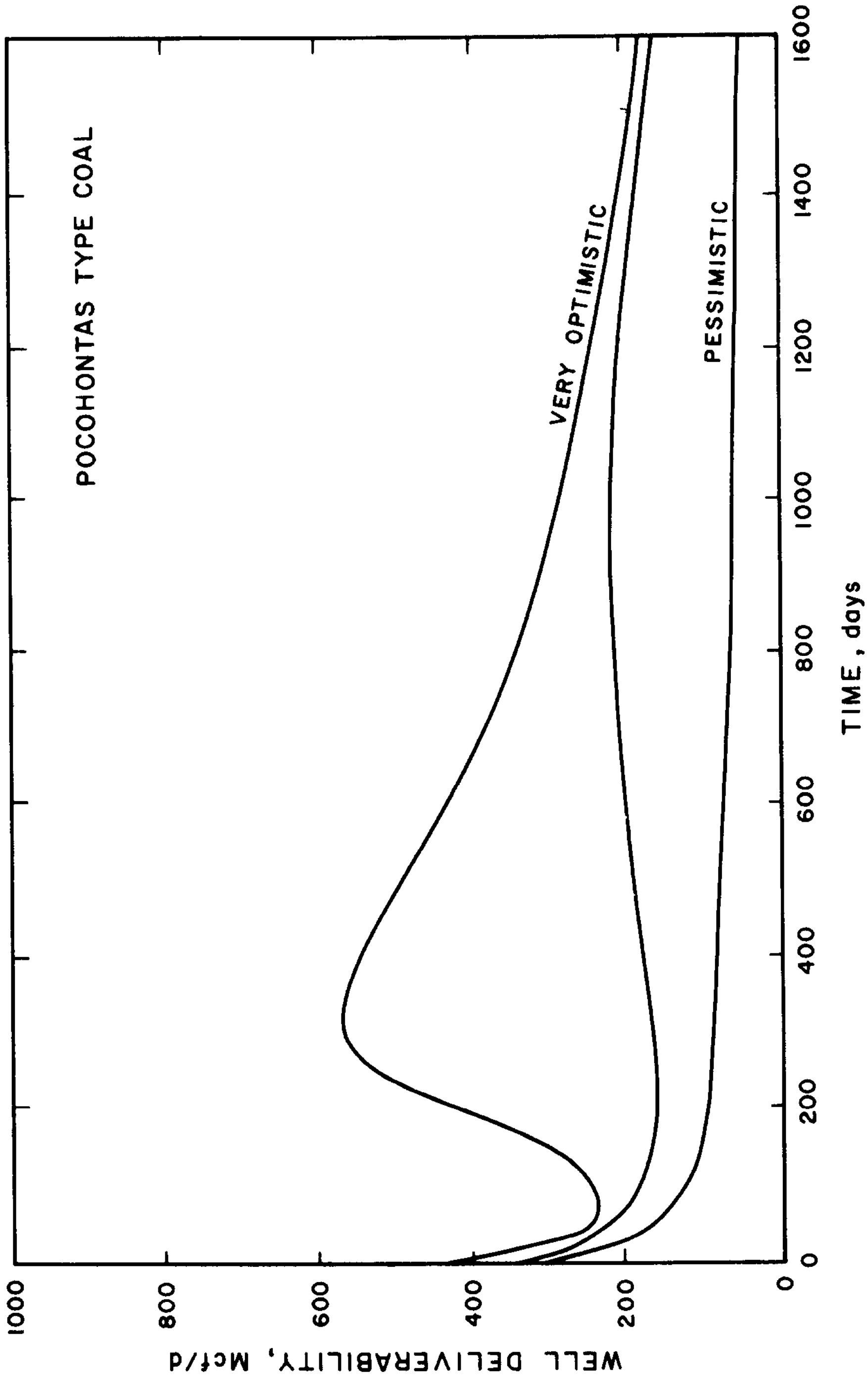


Figure 14

INDIVIDUAL WELL CAPITAL COST

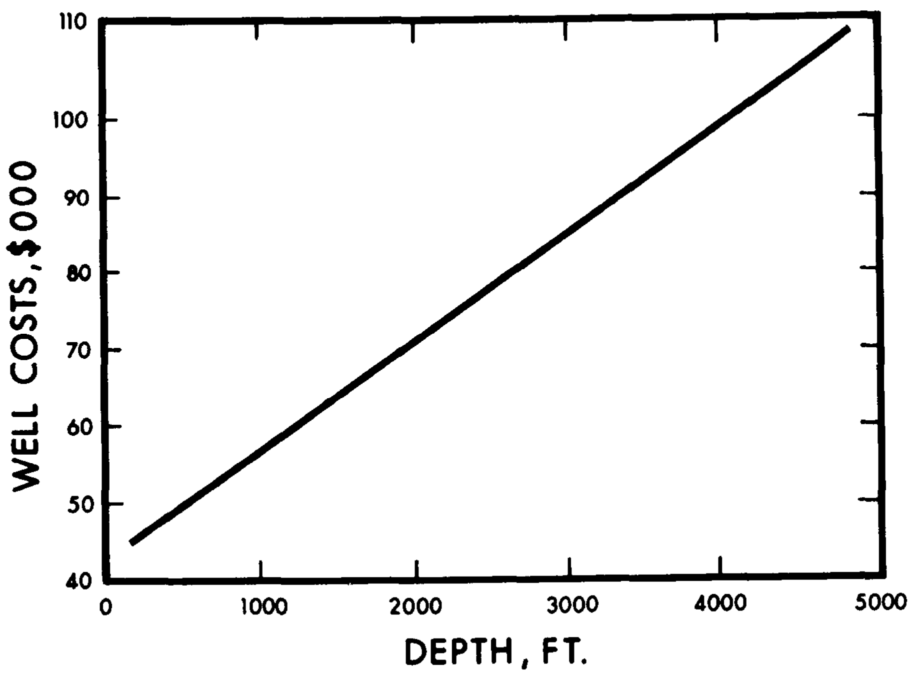


Figure 15

INDIVIDUAL WELL OPERATING COSTS

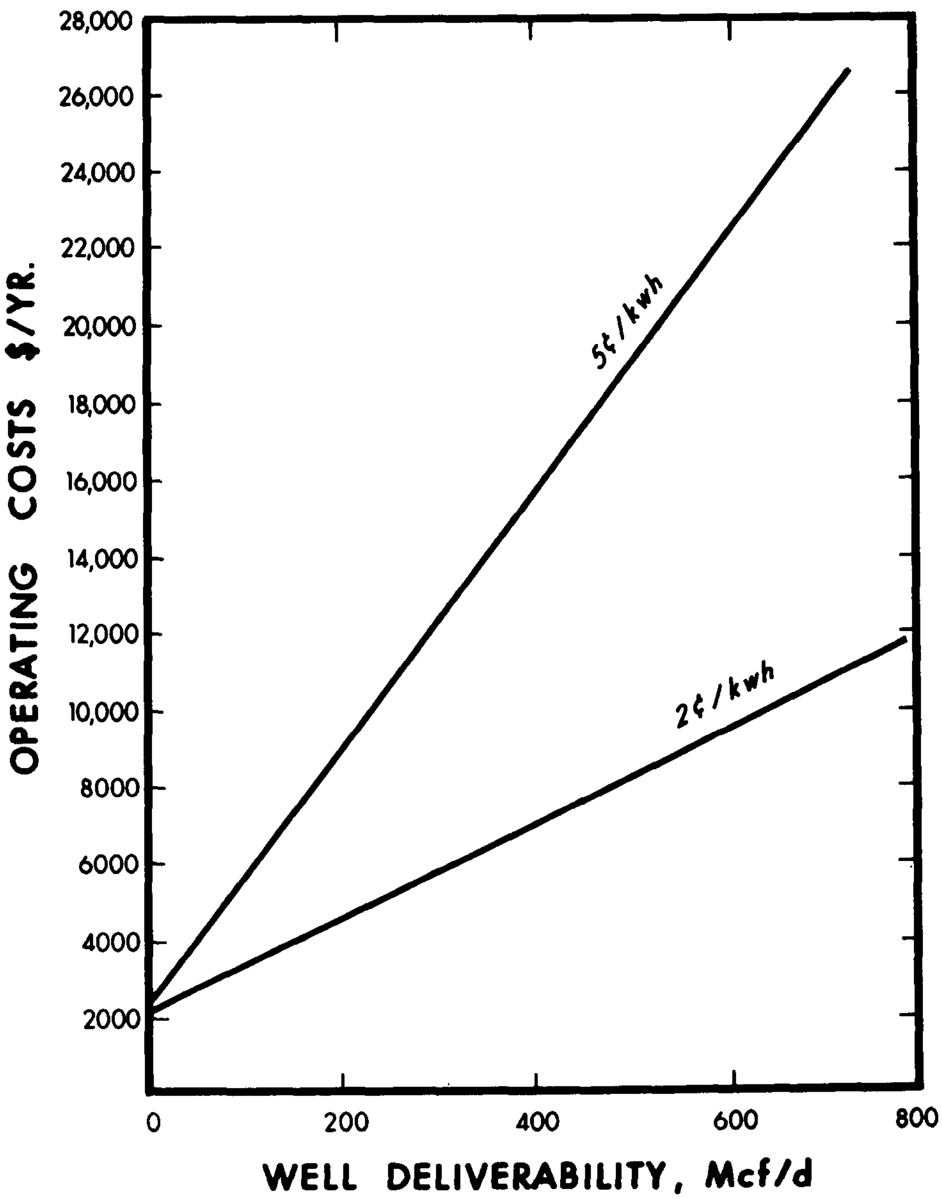


Figure 16

PAYOUT AFIT BASED ON DELIVERABILITY CURVES FOR A PITTSBURGH TYPE COAL

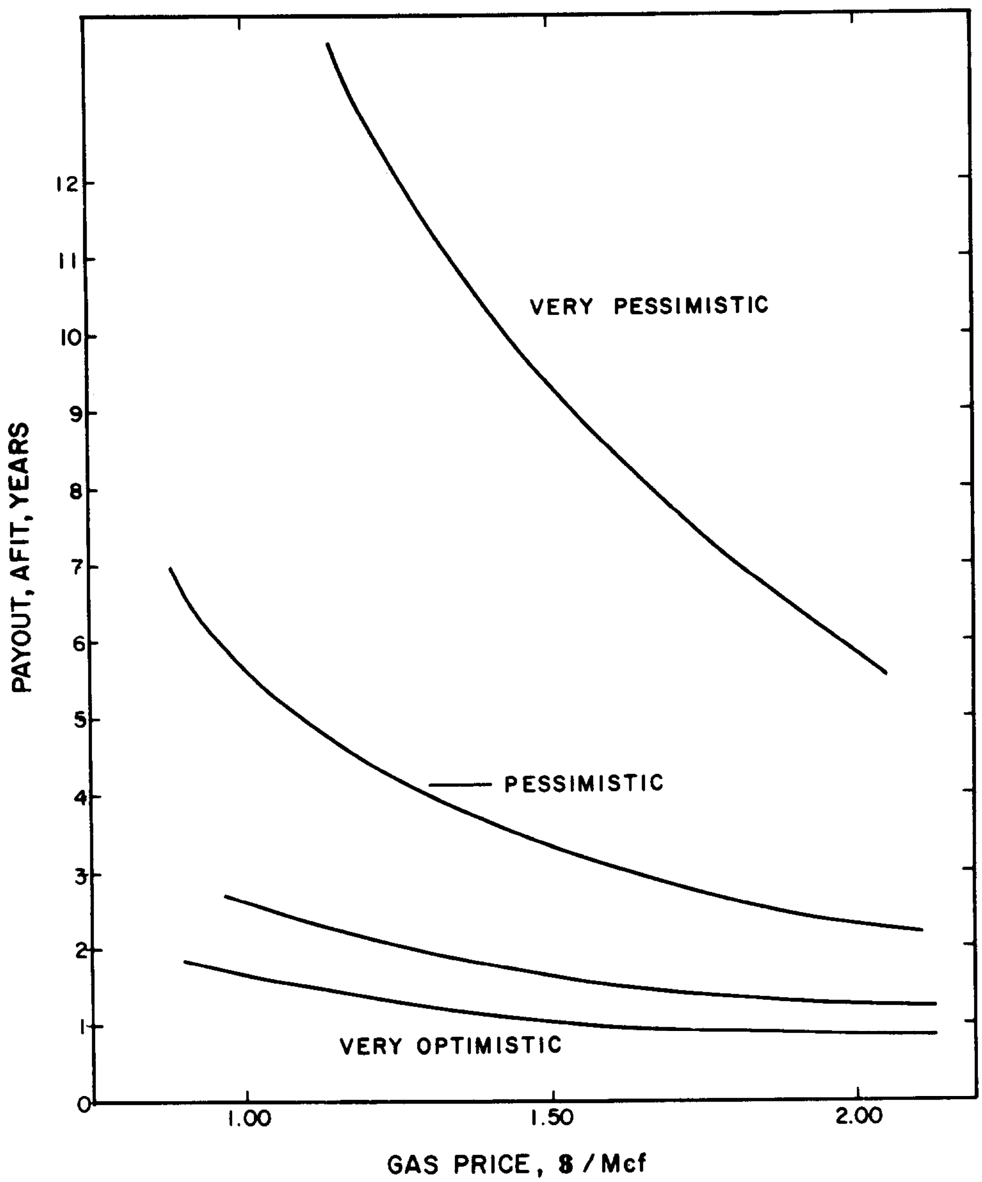


Figure 17
RATE OF RETURN AFIT (BASED ON DELIVERABILITY CURVES FOR A PGH TYPE COAL)

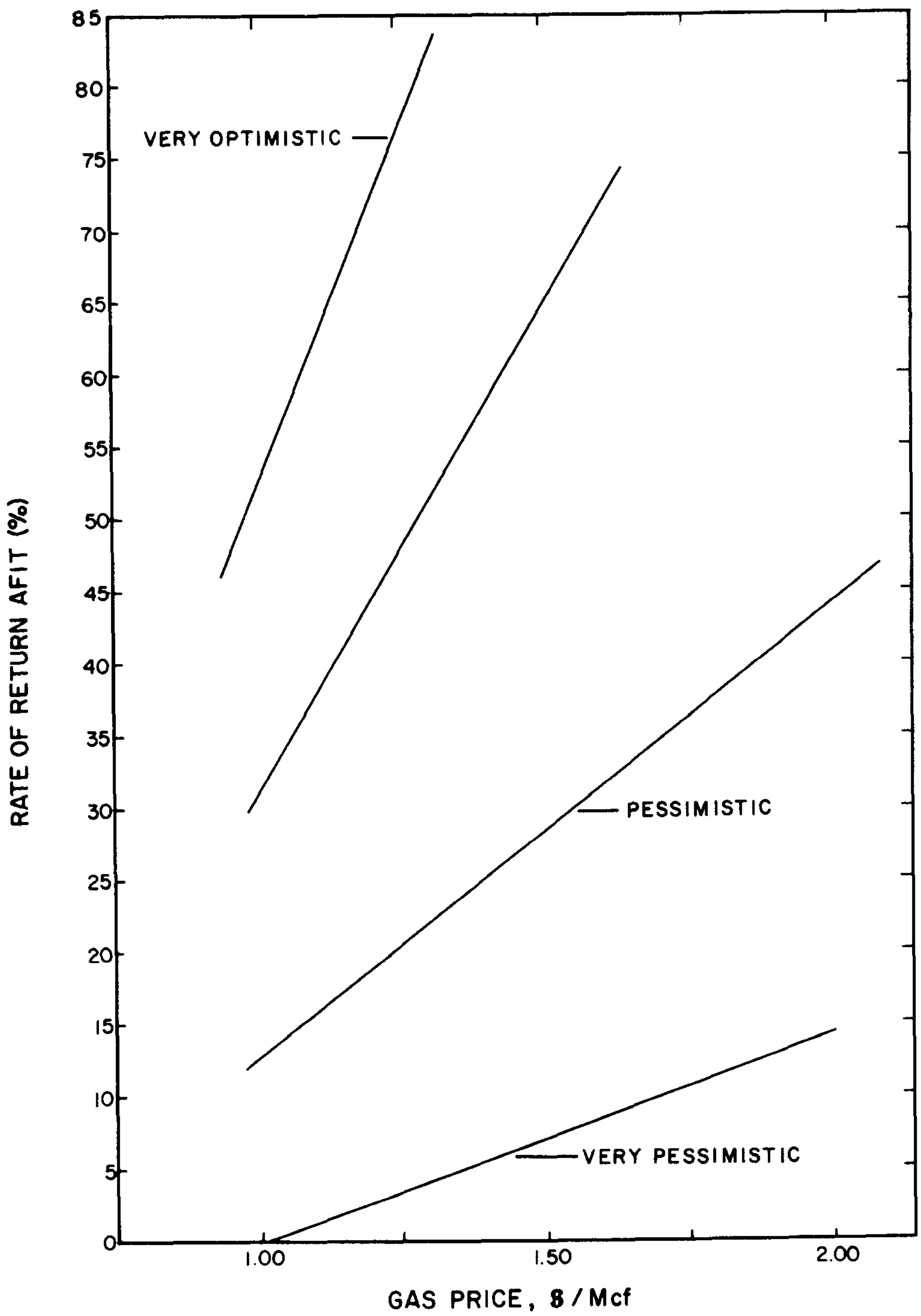


Figure 18

POCOHONTAS TYPE COAL PAYOUT AFIT

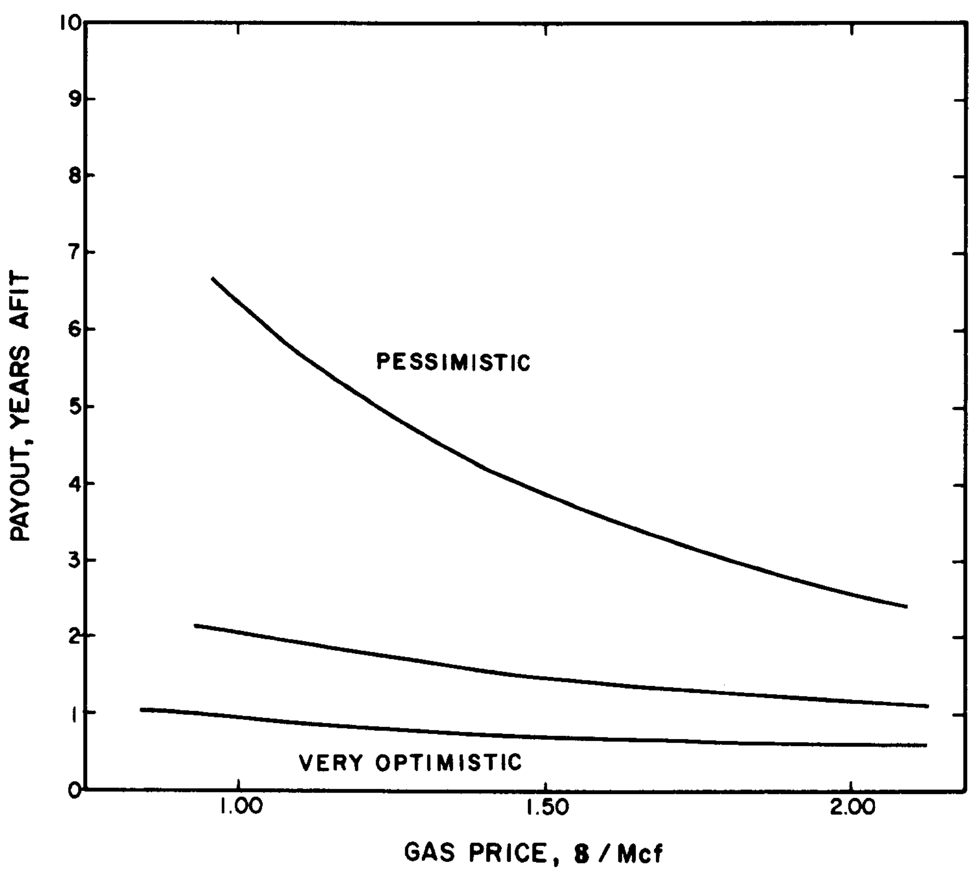
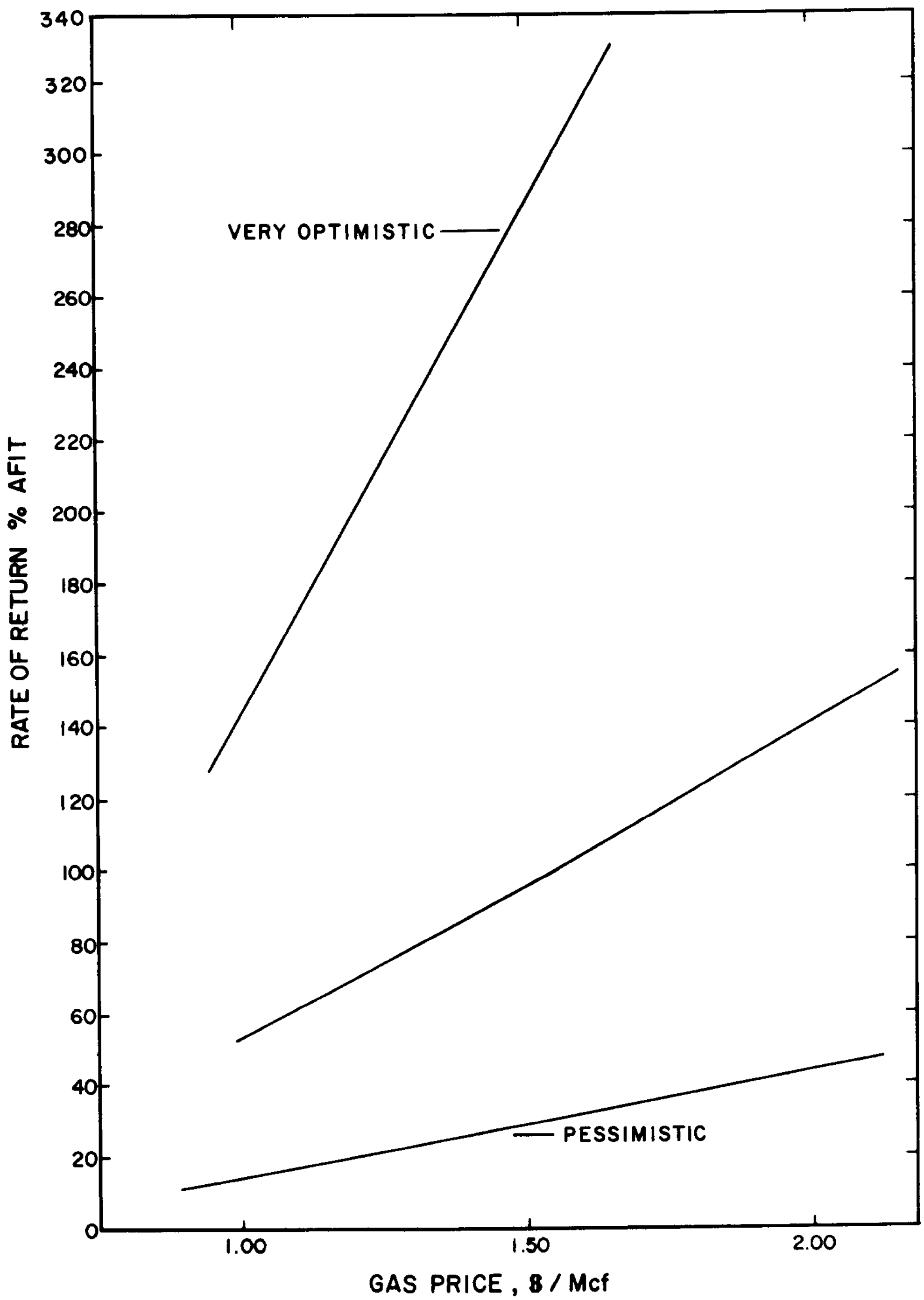


Figure 19

POCOHONTAS TYPE COAL RATE OF RETURN



LUNCHEON ADDRESS

by

Augustine A. Pitrolo

Acting Deputy Program Director for Fossil Energy

ABOUT THE AUTHOR

Augustine A. Pitrolo, Acting Deputy Program Director for Fossil Energy, Department of Energy, Washington, DC, and Director, Morgantown Energy Research Center, Department of Energy, Morgantown, WV, graduated from West Virginia University in 1952 with a B.S. degree in mechanical engineering. Subsequent education included graduate work at the University of Pittsburgh, University of Cincinnati, Xavier, and Pennsylvania State University.

He began his professional career with the Joy Manufacturing Company in design and development of underground mining equipment. He then joined General Electric as a power plant engineer involved in the design and development of aircraft gas turbines. Subsequently he served as systems manager in various advanced space programs, followed by manager of GE's space nuclear radioisotopic thermoelectric generator (RTG) programs. He managed the research, technology, development, and production of SNAP-27 RTG's flown and deployed on each Appollo flight. He later became involved in the design and development of commercial gas turbines.

He joined the Energy Research and Development Administration (now the Department of Energy) as Director of the Morgantown Energy Research Center in 1975, where he has been engaged in research and technology development of coal conversion into synthetic gas and oil, direct coal combustion, and extraction of oil and gas. In October 1977, he was named Acting Deputy Program Director for Fossil Energy, Department of Energy.

Mr. Pitrolo is author of a number of papers, their subjects ranging from systems for auxiliary devices to heavy duty gas turbines. He was awarded the NASA Public Service Award in 1972.

Good Afternoon. I am pleased to have this opportunity to speak to you today. I will discuss the newly created Department of Energy (DOE) -- its role and organization and then relate to the Department's Methane from Coalbeds Program.

As I was drafting this speech, I thought about columnist George F. Will, who once wrote that the three most unbelievable statements that anyone can make are:

1. "My check is in the mail."
2. "Of course I'll respect you as much in the morning."
3. "I'm from the Federal Government and I am here to help you."

To this we should add a fourth:

"I can solve the energy crisis."

Because clearly there is no one solution, the Department of Energy is not the advocate for any single energy technology. Our mission is to create as many promising options as possible. It may take all of the promising options, implemented to the degree that available capital, materials, and manpower permit, plus many great improvements in energy-use efficiencies to allow us to achieve our energy goals. Methane from coalbeds is one such option.

I'm reminded of the ancient Chinese proverb that states: "A journey of 1,000 miles begins with a single step." If that is true, then by sponsoring this First DOE Symposium on Methane Recovery from Coalbeds, an important first step will have been taken that we hope will lead to early commercialization of this resource.

A little background that led to this Symposium is in order. As everyone knows, methane from coalbeds is not a new subject. Prime interest for years was vested in the Bureau of Mines, whose primary concern was mine safety. Accordingly, the Bureau focused on this technology to minimize the gaseous hazard to coal miners. It is this work that provided the springboard for a major program by the Department of Energy.

In early 1976, interest expressed by the Keystone Bituminous Coal Association (H. Brown) led to the creation of a five-state Methane Development Conservation Committee (MDCC) and a program thrust by ERDA's Division of Conservation Research. The MDCC, comprised of five states, Pennsylvania, West Virginia, Ohio, Kentucky, and Virginia, was chaired by Dennis Seipp of Pennsylvania. ERDA's examination of the resource potential added an additional program element, "Methane from Unminable Coal Seams." Since this latter program dealt with an unknown resource, it was assigned to ERDA's Fossil Energy group and categorized as unconventional gas research.

You may recall that the Department of Energy was created to provide a single focus for critical technologies. When DOE was formed, the two ERDA groups previously mentioned, along with elements of methane recovery relating to mining production from the Bureau of Mines, came together under DOE's Fossil Energy program Directorate. While the Bureau will continue to work on health and safety aspects of methane recovery, DOE will focus on methane recovery. It will be approached from the standpoint of enhancing mining productivity, identifying the resource magnitude, establishing a reserve base, and assuring that efficient use of the resource is made.

With that background, I want to describe a few key facets of the Department. The organization has a corporate structure--work flows across the Department. The Office of Energy Research, under Dr. John Deutch, deals with fundamental approaches. Those research elements that appear promising move to Energy Technology, which is managed by an Assistant Secretary. This group develops new technologies to the demonstration stage. Even though a program reaches technology demonstration, it is of no value unless it reaches the commercial development that benefits all. That aspect of the task is the responsibility of the Assistant Secretary for Resource Applications whose concerns include institutional barriers as well as providing suitable financial incentives to bring about commercialization.

I represent the Fossil Energy group in Energy Technology; Resource Applications is represented here today by Marian Olsen, who will take on Institutional Problems. You may be aware that Resource Applications has just completed a task force study examining commercialization aspects of coalbed methane.

It is appropriate to discuss the relationship of government and the private sector, because without a partnership approach all our efforts to develop solutions to energy problems will fail. I have been with the government for a little over 2 years and before that worked some 24 years in the private sector, so I believe I can view current typical relationships rather objectively. A summary of the situation might go like this:

A. View of government - bureaucratic morass, uninterested in profit, insensitive to what it takes to get a job done; interference in free enterprise system, fails to react.

B. View by government - unresponsive to national needs, protective, wants grants and funding; does not want accountability.

These attitudes must change. There is a role for both, and both must accept these roles if new energy technologies are to be brought into the marketplace - technologies that benefit our way of life.

We view our role as working in the area of high risk technologies - those normally not sponsored by the private sector and also providing means to introduce emerging technologies in a proper manner to the marketplace. The thrusts of our programs require major inputs from the private sector in program formulation and implementation.

As we all know, conservation is the cornerstone of the National Energy Plan. It carries as its theme, "Conserve energy and reduce oil imports in such a way that the quality of life will not be significantly impaired." The Plan did not highlight supply but supply was implicit as was a drive toward coal.

For those of you who are unfamiliar with the government's mode of operation, we are now formulating our FY80 budget. This says the FY78 program is in place and running, the FY79 program will take final shape in the budget hearings in Congress late this month and that FY80 activities will be cast by mid-summer. It is very difficult for us to form budgets without having contributions from each of you through symposia such as this one today and through direct contact of your companies with us in the Department. So I encourage you to let us know how you view this program, how you view both roles.

With that background, let's briefly discuss the Fossil Energy organization, the focus for the technology aspects of the Methane from Coalbeds Program. With reorganization, Fossil Energy now has the following program thrusts:

- Solid fuel mining and preparation - this acquired from the Bureau of Mines
- Coal gasification and liquefication
- Power systems technology
- MHD
- Oil shale technology, enhanced oil recovery, enhanced gas recovery
- Drilling and offshore technology

The Enhanced Gas Program is primarily directed at gases from unconventional resources, including the Eastern Gas Shales, which treats the gas trapped in Devonian and Mississippian shales of the Appalachian, Michigan, and Illinois Basins; the Western Gas Sands Project, which treats the tight sands of the Rocky Mountains and other western areas; and the geopressured aquifer project, which treats the methane trapped in the deep, faulted sediments of the Gulf Coast. The remaining element is the Methane from Coalbeds Program, the subject of today's Symposium.

How much resource is there? A recent DOE study shows a coalbed methane resource of over 800 trillion standard cubic feet, of which we think 300 TCF are recoverable. The fact that this gas is not now used and is sometimes wasted, together with its strategic location relative to gas requirements in the East, makes its potential very great.

We see this program as having near-term impacts both from a supply and from a regional point of view. We estimate that approximately 8 billion cubic feet a year by 1981 could be available in this area. By 1986 this could increase to 150 billion cubic feet.

The gas produced by 1981 could provide the region with $14 million of additional income a year, and the estimated 1986 production could provide $263 million additional income to the area. Labor directly associated with methane recovery would be 300 jobs by 1981 and 5,400 jobs by 1986. Moreover, each new job also supports additional service jobs, making the beneficial effects even wider-ranging.

In the Methane from Coalbeds Program we will: (1) characterize the resource; (2) develop specific technologies to produce, collect, convert, or use coalbed methane more efficiently and cheaply; and (3) remove potential institutional constraints that preclude its use.

The program will build on current information and capabilities. For example, industry and the BOM have studied coalbed methane production for over a decade. Maurice Deul, who spoke this morning, was a major factor in that effort. His program generated data and a technology base to remove methane in conjunction with mining and in advance of mining in virgin coal.

There is excellent knowledge of the resource in this region; however, much is to be learned about methane from coalbeds on a national scale. Considerable emphasis will be given to drilling projects both east and west to determine methane content, reservoir conditions, types of coals, geographic location, proximity to distribution systems, and end-use potential.

The cornerstone of the program will be demonstration of actual recovery and use - this to ascertain technical and economic viability. We will see many programs of this nature highlighted today by Carl Sturgill. We will look for propositions for joint ventures and will also make calls for unique R&D, plus demonstration ventures in various targets of opportunities.

For 1978, we have the following in place:

A. DOE budget of approximately $10 million

B. Two management field sites - MERC and Pittsburgh mining reserach operation

C. Westinghouse project with Bethlehem Steel, State of Pennsylvania underway

D. A second Westinghouse project just negotiated

E. Major R&D efforts:

   1. Directional drilling
   2. Drilling instrumentation
   3. Conversion and utilization equipment

The program is just beginning - success rests with the manner in which the private sector and government enjoin this challenge.

I would like to close by quoting the last two paragraphs of a speech given by Governor Richard Lamm of Colorado on October 13, 1977.

"To meet the challenges proposed by the energy crisis, we must develop creative mechanisms of working with other levels of government and with private industry. I have worked at great lengths with other Western Governors to develop a strong and united voice for the West on energy matters. This effort will continue and we are beginning to see some tremendous dividends from it within the State of Colorado. A meaningful partnership must be created between the state government, local government, and private industry. No one level of government nor one sector of the economy can solve the energy crisis. We must work together in a creative partnership. The importance of energy issues to the preservation of our democratic institutions cannot be overstated nor can the impacts that the energy crisis will have on our state. Our approach to energy issues in Colorado must transcend personal and partisan political considerations. This nation and this state may be seriously underrating the effects of and the impacts of the energy crisis. We are not talking about anything short of survival of our institutions, and nothing in our experience has prepared us for the magnitude of the challenges ahead.

"The energy problem, like the environmental problem, refuses to comply with our human and institutional desires to divide things into narrowly defined and easily managed pieces. Leadership aimed at resolving the energy problem must consider this broad perspective of energy and respond in ways that match its magnitude and complexity, rather than relying solely on traditional approaches."

TECHNICAL AND ECONOMIC PROBLEMS IN METHANE DEGASIFICATION OF COAL SEAMS

by

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University Park, Pennsylvania

ABOUT THE AUTHOR

Dr. Robert Stefanko is professor of mining engineering and associate dean of the college of Earth & Mineral Sciences at The Pennsylvania State University. After serving with the U.S. Navy in World War II and graduating from Penn State with a B.S. degree in mining engineering in 1948, he worked for the Westmoreland Mining Company until 1954. Since 1955, he has been at Penn State where he has also earned his M.S. and Ph.D. degrees and has held numerous positions including head of the then Department of Mining Engineering from 1964-69 when he assumed his present position.

His research interests are broad and he has published extensively, reporting results of his work in rock mechanics, mine electrical power, mine systems analysis, mine ventilation, mine health and safety, and, of course, methane degasification. He received the 1970 AIME Howard Eavenson Award in 1970 for his rock mechanics research efforts, and in 1977 received the Mineral Industry Education Award from the same organization. He has been an advisor or a consultant to a number of government agencies and is very active in the Society of Mining Engineers and the American Institute of Mining, Metallurgical, and Petroleum Engineers, serving on the board of directors of both organizations. Also he is presently president-elect of the Society of Mining Engineers.

ABSTRACT

Four vertical boreholes into virgin coal seams for methane degasification purposes are reported upon in this paper. One intersected anthracite coal seams near Nanticoke, Pa. while the other three intersected the Pittsburgh coal seam south of Waynesburg, Pa.

The anthracite well showed a flow of 85,000 cubic feet per day of high purity methane gas in an open hole configuration (uncased). In an attempt to improve upon this yield, two stimulation procedures were employed, first hydrofracing and then an explosive treatment. Neither proved successful since there was a reduction in gas yield and the well was blocked. It remains idle.

Neither of the three vertical wells in the Pittsburgh coal seam showed significant gas flows after being drilled and completed. Two were subsequently foam fraced, one through an open hole treatment and another through perforations. While the gas flows improved, they were insufficient to justify placement into commercial gas lines even though the gas was of high purity.

Since gas analyses of cores taken from the Pittsburgh seam revealed the high gas content of nearly 200 cubic feet of gas per ton of coal in place, the results were disappointing. Furthermore, a considerable amount of water was produced after stimulation procedures. The work reveals an inadequate understanding of methane gas flow and effective stimulation procedures in coal seams and thus attests to a need for improvement.

Others have reported similar results with vertical boreholes into virgin coal seams. Research and development are needed to determine whether this is a problem of siting the holes in less susceptible locations for gas flow or a deficiency in the stimulation procedure that may be corrected. While vertical boreholes in virgin coal seams cannot be ruled out on such limited data, the work suggests the need for guarded optimism. Other degasification techniques such as horizontal long holes and vertical holes tapping gob gases might prove to be more attractive alternatives.

INTRODUCTION

While in high school I was intrigued by my initial introduction to the well-known quotation "a little learning is a dangerous thing," which was posted in my chemistry laboratory. My experiences and observations of others through the years have given me a deeper insight into the meaning of this quotation. I can't help thinking of it now as I observe the methane degasification scene. People with just a little learning of the subject are providing glowing accounts of the future of this "untapped" energy source. I will not be critical, however, because, three or four years ago, I, too, was a wild-eyed optimist on the subject. While I am not going to paint a pessimistic picture now, my optimism has been dampened by my experiences, and I have a more realistic perspective of the role of methane degasification in the future. In short, I recognize the potential that exists, but I also recognize the many problems to be overcome in developing these processes to the commercial stage.

There is a potential for commercial demethanization for our vast coal deposits do contain considerable gas within them, but this is the subject of another paper. However, the potential must be transformed into performance before commercialization can become a reality. Mother nature holds on firmly to her treasures and gives them up only begrudgingly. Still, the gas potential is so impressive, and the need so great, that it cannot be ignored.

Vertical boreholes, slant-holes, and horizontal holes in virgin coal seams have been tried as well as the collection of gob gases from vertical boreholes over mined workings. Each technique has its advantages and disadvantages, and at this stage none can be ruled out since refinements are possible in all areas. Of these techniques, the primary one used has been the boring of vertical holes into virgin coal seams; probably close to 100 such holes have been bored. An accurate survey of the results from these holes would be very helpful at this time in assessing their true potential. Unfortunately, most of the holes have been drilled by mining companies who consider the information of a proprietary nature and are reluctant to divulge it. This is too bad because public funds (tax dollars) will have to be spent to obtain data that are already available from previous projects. Thus, a carefully conceived, large-scale demonstration project will have to be initiated. While it does not necessarily have to be conducted by a single group, any such development among various organizations must be well coordinated so that there is a common reference base. Otherwise, it will be difficult to interpret the data and arrive at some universal conclusions.

REPORTED RESULTS

Results have been reported from vertical boreholes into virgin coal seams through: (1) standard publications such as U. S. Bureau of Mines, Reports of Investigations or Information Circulars and (2) by oral communication. While the printed reports have tended to be positive and will be reported elsewhere in this symposium, the orally reported results which cover the major part of the work have been spotty. For every hole that produced 50,000 to 80,000 cfd, ten reported 2,000 to 1,000 cfd or even less. Furthermore, while most mined-through holes revealed the fracture was confined to the coal seam, in one case, there was migration of the frac fluid into the roof. However, it was not established whether migration occurred into a pre-existing crack, resulted from the fracture procedure itself or even adversely affected subsequent mining. Finally, the amount of water encountered has been surprising. Thus many problems have been encountered, and one company, after having drilled approximately thirty holes in the Pittsburgh seam, is no longer considering the vertical borehole technique as viable and are concentrating on horizontal drilling. Since it appears that this information will not be quantified and reported publicly, a larger controlled demonstration project will have to be conducted to obtain this information.

EXPERIMENTAL VERTICAL HOLES

In the last three years, a methane degasification project has been conducted in the Department of Mineral Engineering at The Pennsylvania State University. From this project complete data are available on four wells. Three were located at the Cumberland Mine Site of U. S. Steel Corporation in Greene County and the fourth was located one-half mile east of Nanticoke, Figure 1. While the first three holes were to assist ventilation for subsequent mining activity as well, the fourth one was strictly a commercial venture with the sole benefits to be derived from the sale of gas.

Anthracite

The Nanticoke hole was financed entirely by the Pennsylvania Energy Research Incorporated (PERI) to produce methane gas for the customers of The Pennsylvania Gas & Water Company, the parent company. While Penn State personnel worked closely with the group offering technical services and advice, the well was strictly under the control of the corporation.

The PERI hole was spotted in seams dipping approximately 15° to the SW on the flank of a small anticline in one of the few remaining blocks of coal in an otherwise extensively mined area. A 7-7/16-inch hole was drilled 1,651 feet deep. While it had been reported that as many as ten coal seams existed at the well site, the targets were the two bottom seams initially identified as the Ross and Red Ash. Later, these two seams were designated as the Middle and Bottom Red Ash, Figure 2, although there is still some disagreement about them. The well was designed to be closed, that is, it would be fully cased and subsequently perforated and stimulated at the two seams which were each estimated to be around ten feet thick.

A 60-foot section was drilled below the deepest seam, the Bottom Red Ash, to provide for a sump for dewatering. Before production casing was cemented in the hole, a pressure buildup was created at the well. Over a period of several days, a static wellhead pressure of 86 psig was developed and a flow of 85,000 cubic feet of gas was recorded daily. While this quantity represented the cumulative effects of all the seams exposed by the well, about ten in number, and was sufficient to provide a payoff for the well, a decision was made to complete the well and stimulate it as originally planned with the expectation of improving the yield. During the process of drilling the hole, a 2-1/2-inch-diameter core was taken of a seam encountered between the 1,480 and 1,487-foot levels designated as the Ross seam on Figure 2. While the core was of the lower portion of this coal seam and contained considerable shale, it nevertheless indicated 96.7% methane and 3.3% hydrogen with a content of 500 cubic feet of gas per ton of coal in place. This was the only core taken from the borehole and analyzed for the quality and quantity of gas.

Subsequently, the well was completed as shown in Figure 2. Along with the 1,642 feet of 4-1/2-inch production casing, it had 440 feet of 8-7/8-inch surface casing. Finally a 25-foot section of 12-inch conductor pipe was placed near the surface of the hole. Wellhead measuring gages and a pump jack for dewatering the well completed the development. A siphon string placed in the well originally proved unsuccessful and was replaced by a pump.

The lower seam (Bottom Red Ash) was perforated using conventionally fired projectiles and then stimulated hydraulically. Unlike the other wells to be reported upon, this was strictly a water-sand frac. A mixture of 17,500 gallons of water and seven tons of 20-40 mesh sand was pumped into each of the two formations at a wellhead pressure of 2,200 psig. The formation fracture pressure was indicated at 1,800 psig. Then a removable plug was placed between the lower and upper seam (Middle Red Ash) and the upper seam was hydraulically stimulated. To speed up the return flow of the frac fluid, an attempt was made to retrieve the plug, but the equipment proved inadequate for removing the wedged contrivance. It was a month later before a larger rig removed the plug but only a small amount of frac fluid returned at a slow rate. Because gas pressure and flow rates did not increase as expected, continued swabbing and bailing to clean up the well continued for several days without any apparent success. Also, problems were encountered with dewatering the well due to a rod separation in the pumping string. In spite of all efforts, a pressure buildup of only 53 psig and a flow of 4,000 cubic feet of gas per day were obtained, far below what was obtained prior to stimulation. Of course, because of the closed nature of the well after casing, only the two seams were being drained of gas, all others being effectively blocked off by the casing.

PERI officials decided that the well needed additional stimulation. It was deduced that an explosive treatment would be most effective in promoting additional gas flow. In addition to providing increased permeability to gas flow, it was believed that this treatment would increase the movement of the stagnant fracing fluid which was thought to be causing gas blockage.

The Joyce National Powder Company was contacted to employ its "orbit penetration system" to stimulate the well. The technique employed the placing of 5-foot-long sections of sheet metal tubes at the elevation to be treated and then detonating them. These cylinders contained shaped directional charges which were arranged to form a continuous horizontal circle and were packed in a dry blasting powder called Judymite. Four sections, or 20 feet, were placed near the lower seam with three sections or 15 feet at the upper seam. A squib was dropped in the borehole to detonate the charges.

Subsequently, a bailer made numerous unsuccessful attempts to reach the bottom of the borehole, but a blockage in the frac zone prevented it from doing so. Fragments of sheet metal from the explosive charge and production casing were withdrawn by the bailer when it was brought to the surface. All attempts to dislodge the blockage failed and all work was suspended on the well.

The final results for the PERI well can be summarized in a few words. Gas production is negligible and the well is blocked and apparently badly damaged. It remains idle.

Analysis and Conclusions

Because it had shown a probable high gas production rate initially as an open hole, the present status of the PERI well is especially disappointing. This substantial initial quantity of gas would have made a viable commercial gas producer possible. The gas analysis from the one core obtained indicates that at least one seam contained 500 cubic feet of methane gas per ton of coal. Not only was the potential of the well not exploited, but it has been so badly damaged in the two stimulation procedures that significant restoration of it is problematic.

Since two different types of stimulation techniques were counterproductive, alternatives do not appear to be simple. The inability to achieve successful backflow of fracing fluid is puzzling. At this time, it cannot be concluded whether it is representative of the behavior of the hydraulic fracturing in anthracite coal or a result of deficiencies in the procedure itself. One expert in the hydraulic fracturing of oil and gas reservoirs contends that because of the peculiar physical characteristics of anthracite, he believes that a backflow of fracing fluid will not occur in anthracite. If this is true, then the procedure cannot be employed with anthracite and the use of propane as a fracing fluid is suggested. However, there are obvious hazards in handling such an explosive material and perhaps the investigation of the use of another type of fluid is desirable.

The use of an explosive treatment may have merit, but it probably should be done in an open hole rather than a cased one. Certainly, the results of an explosive treatment under the conditions of PERI proved disastrous.

If PERI proved nothing else, it showed that the use of a stimulation technique does not insure improved gas yields, but, in fact, can destroy an otherwise viable commercial venture. It points to an inadequate understanding of stimulation procedures for coal seams and suggests an area of need for considerable research and development. It also points to the desirability of placing holes and collecting gas from a number of coal seams in an open-hole arrangement. Of course, partial production casing could be utilized to prevent sanding-out and caving of vulnerable strata.

BITUMINOUS COAL

Site Selection Criteria

Plans were made to drill vertical boreholes into significant coal seams and evaluate their gas-producing potential. Because the Commonwealth of Pennsylvania was a co-sponsor of the project, public land locations were considered along with private sites. Obviously, this included a wide variety of situations.

Most of the parameters that were used to make the site selection were developed by a review of the status of methane degasification in this country. Thus, the choice was made on the following considerations: (1) minimal legal problems in methane gas ownership; (2) advantages of methane recovery in a multiple-seam area; (3) opportunity to stimulate; (4) opportunity to observe the results of stimulating and degasifying that would be provided by an area to be mined; (5) accessibility; (6) availability of logistic and financial support; (7) virgin coal area; (8) probability of reasonably high methane flows; and others.

Site Selection

After reviewing sites in the anthracite and bituminous coal areas, a location south of Waynesburg, Greene County, Pennsylvania, was chosen because it had a number of advantages: (1) coal and gas leases, as well as some surface rights, were held by United States Steel Corporation and its subsidiary, Carnegie Natural Gas Corporation; (2) the major mineable seam in the area was the Pittsburgh, which had shown emission rates of 100 to 200 cubic feet per ton of coal in many areas; (3) the site was in virgin territory, that is, it had not been extensively mined; (4) a portion of the leased area (Pittsburgh seam) was expected to be mined through in several years; this was an especially important factor, for the mining of the coal seam would have made it possible to observe the effects of degasification and hydraulic stimulation, both in the coal seam and the adjacent layers, especially the roof rock; (5) without being stimulated, one of the holes could be used as a reference or observation and monitoring hole for several years, if so desired; (6) there were a variety of coal beds in the area besides the Pittsburgh; it was planned to get as many cores of coal seams as reasonably possible, even though some of the seams would probably never be mined; also, this situation provided the possibility of stimulation and studying the cumulative effect on multiple seams; (7) low-pressure gas lines were already available in the area so that the methane gas could be put into commercial lines with reasonable gathering costs: (8) logistic support would be supplied by the United States Steel Corporation and a subsidiary, Carnegie Natural Gas Company.

Well Description

Three gas wells were located in hilly terrain about eight miles south of Waynesburg, Pennsylvania, which is located less than ten miles from the northern West Virginia border, Figure 1. Thus the elevations of the tops of the collars of the three holes varied: (1) CNG 1034 at 1,195.95 ft, (2) CNG 1035 at 1,110.90 ft and (3) CNG 1036 at 1,394.00 ft. The holes were given Carnegie Natural Gas identification and numbered in the order they were planned to be drilled. In reality, right-of-way difficulties due to a surface ownership change resulted in a delay to CNG 1035 and thus CNG 1036 actually was drilled ahead of it. These holes were spotted on a Carnegie Natural Gas lease as shown in Figure 3 on which future mine entries are projected as well.

A maximum amount of information was sought from the three holes so two were planned to be stimulated after a short monitoring period and testing while the third (CNG 1036) was planned as a long-term observation hole unstimulated. Two different stimulation procedures were conducted-open-hole hydrofracturing for CNG 1034 and closed-hole, perforated hydrofracturing for CNG 1035. A foam fracing procedure was planned for each stimulation utilizing a mixture of 5,000 gallons of water, 182,000 cubic feet of nitrogen and 22,000 lbs of 100-mesh and 20/40-mesh sand to be pumped at a static wellhead pressure of 1,200 psi.

There were many similarities in the way the holes were developed. Each had a 5-1/2-inch production casing placed in a 7-5/8-inch-diameter hole, which had been drilled with a rotary roller bit. Production casing was cemented almost completely in each hole as shown in Figures 4, 5, and 6. Additionally, well completion equipment including a pump jack, gas flowmeter, water meter and recording gas pressure meter were placed at the top of each hole. All were subjected to multiple logging and a variety of gas flow tests, and two ultimately underwent stimulation treatment. Finally, with the exception of weekends, all were monitored daily.

Drilling for CNG 1034 began on November 11, 1975, and was completed to a depth of 825 feet including a sump. A 6-inch-diameter core was obtained from the Pittsburgh seam and tested for gas content. Later, a bottled sample was also taken of the gas emitting from the hole. Subsequent tests indicated the following composition of the gas sample: 96.7% methane; 2.98% hydrogen; 1.67% carbon monoxide and 0.60% carbon dioxide. A gas content of 190.05 cubic feet per ton of coal in place was revealed from the core sample. Gamma, density, caliper, temperature, and neutron logs were run on the hole, providing evidence that the Washington, Waynesburg A, Waynesburg, and Sewickley had also been intersected by the hole. The production casing was cemented into the hole in early December 1975 and completed as shown in Figure 4. Well completion equipment subsequently installed included a recording temperature gage, a recording pressure gage, gas flowmeter and a pump jack. A 5/8-inch pump rod, operated on 220 volts, removed water through a 2.375-inch tubing connected to the hole bottom. Power had been extended to the hole by February 1976 and the well was completely operational in April 1976 and observed as an open hole until stimulated in May 1977. During April 1977, the gas flow of CNG 1034 ranged from 122 cubic feet to 256 cubic feet per day, with water influx ranging from 42 to 246 gallons per day. Figure 7 provides a record of flows over a period of months.

While planned as the second hole to be drilled, CNG 1035 was actually begun on December 22, 1975, as the third hole. While designed to intersect the Freeport seam below the Pittsburgh at an estimated depth of 1,300 feet, Figure 5, the bit was lost at the 1,250-foot level and no amount of fishing could remove it. Two and one-half-inch cores were obtained for the Waynesburg A, Waynesburg, Sewickley, and Pittsburgh coal seams for gas analyses. Since the exact location of the Freeport was in doubt, it was decided to core the section between the depth of 1,236 and 1,276 feet. Coring between 1,236 and 1,250 feet produced shales at which time the ill-fated bit mishap occurred. Since the project had to assume the fishing costs, and these were mounting drastically, it was decided to abandon the hole, and 1,201 feet of production casing was cemented in place by January 29, 1976, after some cementing difficulties. Figure 5 shows the hole completion.

On November 4, 1976, the casing was perforated at the level of the Pittsburgh seam using steel carrier shots to produce twenty-six 0.41-inch-diameter holes in the casing. Subsequent gas and water flow measurements revealed no appreciable water or gas flows even after the hole was swabbed. An acid treatment was conducted on November 8, 1976, to remove what appeared to be a blockage. After treatment and placement of the pump, gas pressures measured 12.0 psi with a flow of 5.0 cubic feet of gas over a two-day period; 28 gallons of water were also produced. The well was completed in a manner similar to CNG 1034.

Drilling for CNG 1036 was started December 8, 1975, and was completed as shown in Figure 6 on December 15, 1975, without interruption. Since power could not be secured to the site until November 1, 1976, and thus the well had remained idle for nearly a year, the well had to be cleaned out of accumulated debris on November 8 before the well was completed with measuring and pumping apparatus. Prior to stimulation of any of the holes, between 317 to 497 gallons of water and 398 to 1,364 cubic feet of gas were obtained daily from CNG 1036. This compares with a top gas flow of 250 cubic feet of gas and 100-200 gallons of water daily for CNG 1034 during the same period, and with 400 to 500 cubic feet of gas and 15 gallon of water daily for CNG 1035.

Stimulation

CNG 1034 was hydraulically stimulated on May 5, 1977, at the Pittsburgh seam level after the 60 feet sump below the seam had been closed with a calcite-limestone mixture. The foam frac planned was conducted without incident at an injection pressure of 1,200 psi without any indication of a fracture level. Table 1 lists the total amount of materials employed during the stimulation procedure. By the middle of June 1977, gas flows were 1,900 to 5,400 cubic feet and water flow was 1,500 to 5,100 gallons daily.

The stimulation of CNG 1034 affected both CNG 1035 and CNG 1036. CNG 1035 was producing approximately 400 cubic feet of gas daily but dropped to less than 50 cubic feet following the CNG 1034 treatment; it gradually built back up to 430 cubic feet by the latter part of June 1977. The water flow remained consistent at 10-14 gallons per day, however.

Gas flow from CNG 1036 increased appreciably for several weeks following treatment of CNG 1034, but the water flow of between 200 to 400 gallons daily did not change significantly. For example, gas flows of 400 to 1,400 cubic feet daily prior to CNG 1034's stimulation jumped to nearly 4,000 cubic feet per day for several days following treatment.

CNG 1035 was stimulated on June 30, 1977, utilizing the same foam frac plan employed with CNG 1034. While 5,000 gallons of water had been planned for use, only 2,580 gallons were injected with 112,000 cubic feet of nitrogen at a pressure of 1,200 psig prior to blockage occurring. When pressures built up to 3,000 psig, hydrofracturing was suspended. Thus in Table 1, CNG 1035 had completed the injection of item 4 and was proceeding with item 5 when the stimulation treatment halted.

At the time of the last measurement on June 27, 1977, prior to stimulating, CNG 1035 was producing 410 cubic feet of gas and 11 gallons of water daily. Immediately following stimulation, the highest rate of gas reached was 13,120 cubic feet with a daily flow of 3,150 gallons of water on July 7, 1977. However, the production rates at this well were 5,000 cubic feet of gas and 5,091 gallons of water on July 29, 1977.

While the stimulation of CNG 1034 had a quick and temporarily adverse effect on CNG 1035, the foam fracing of CNG 1035, the foam fracing of CNG 1035 did not soon affect CNG 1034. From a gas flow of 3,746 cubic feet of gas and 3,212 gallons of water recorded for CNG 1034 on June 27, 1977, its rates changed to 3,346 cubic feet and 3,963 gallons of water on July 7, 1977.

There was a change in CNG 1036 as a result of the stimulation treatment of CNG 1035. From 852 cubic feet of gas and 483 gallons of water produced on June 27, 1977, it went to 1,122 cubic feet of gas and 345 gallons of water on July 7, 1977.

Analysis

The gas production from the Pittsburgh coal seam prior to stimulation was disappointing considering that the cores revealed such a high gas content per ton of coal in place. While stimulation improved the initial yield, it was still far too insufficient to justify the expense of connecting to the nearby gas lines. Thus the results of these three holes were very disappointing. Also, the amount of water encountered after stimulation was much greater than one would anticipate if it were contained entirely in the coal seam. Thus there is a suspicion that hydrofracturing was not confined entirely to the coal seam but penetrated outside it, possibly intersecting aquifers. This has ramifications not only because of the water which will thus have to be pumped but because it could contribute to adverse roof conditions upon subsequent mining. However, the hypothesis will have to await mining through the area for confirmation.

Costs

Table 2 is a condensation of the costs in drilling the three vertical wells at the Cumberland mine site. Note the high cost per foot of drilling, especially CNG 1035 which reflects the large amount of fishing time in a vain attempt to extract the lost bit, and the problems encountered in cementing the production casing during completion. The standard drilling contract protects the driller against all mishaps, even ones resulting from worker negligence. As far as the driller is concerned, all delays are "acts of God" and the costs are assigned to the project. Thus an intolerable situation such as CNG 1035 can occur where cost overruns become prohibitive and the target area cannot be reached. In defense of the driller, CNG 1035 was drilled during January 1976 which was the coldest month ever recorded in the area and not conducive to effective drilling. Incidentally, the drilling contract called for a cost of $10.25 per foot. But note that even with CNG 1036 where the drilling went smoothly without any mishaps, the cost of drilling was $15.85 per foot, nearly a 55% overrun. The disparity results from the additional payments stipulated in the contract for initial mobilization, moves,drill steel changes, and any other standby time incurred. Incidentally, a lower bid had initially been received from another drilling contractor who has an excellent reputation. However, during contract negotiations,the demands of the lawyers from the University and U. S. Steel so discouraged him that he withdrew his bid. Also, his insurance covered a liability less than the $1,000,000 required by the University although this was not a permanent obstacle since additional insurance could have been purchased with the bid still remaining substantially lower. Regulatory processes also discouraged the small driller.

In any event, the total cost of $180,259 represents a sizeable investment in the holes that would require a far greater gas yield than was obtained from them for successful amortization. The costs reported are direct costs only and do not include the salaries and travel expenses of engineering and technical manpower assigned to the project which nearly equal the indirect costs. Of course, this was not their only assignment, and therefore these costs would have to be prorated over all assignments. Since this did represent their primary assignment, however, it would have taken a good portion of the total amount.

CONCLUSIONS AND RECOMMENDATIONS

The data on the four wells reported indicate there is no assurance that high yields will be obtained from vertical boreholes drilled into virgin coal seams even though core samples indicate high gas contents. One must be impressed by the high purity of methane in the gas samples, however, which would allow it to be placed virtually directly into commercial gas lines. However, because of the large amounts of water produced after stimulation, the energy required to pump the water to keep the seams clear for gas emission almost equals the amount of energy recovered, making the operation uneconomical. Thus four vertical boreholes into seams with high potential could not be translated into commercial performance. Discussions with others having similar experiences indicate that this is not an unusual condition.

While one hole out of ten drilled might pay for itself because of good gas yield, a realistic cost assessment would require that the other nine unsuccessful low-yield holes would have to be amortized by the successful one. In the natural gas industry, where yields for holes are high, several hundred thousand cubic feet of gas daily or more, such low success rates can be successfully amortized. Since I know of no hole in a coal seam that produces as much as 100,000 cubic feet of gas daily, commercialization of methane gas from unmined coal seams will become viable only if a much higher rate of successful wells are produced.

Therefore, as I view the present interest and activity in methane coal seam degasification, I believe the emphasis is being misplaced. Too much concern is being expressed for the utilization aspects rather than the recovery procedures. I think this is because a too optimistic assessment has been made of the recovery problems and there is a lack of understanding of the low success rates achieved to date. Unfortunately, the successful wells have received widespread publicity, but the far greater number of unsuccessful ones have been quietly filed away.

Therefore, it is my opinion that a large research and development effort must be concentrated on recovery techniques. This appears only logical because the development of the best end use will be to no avail if the gas isn't available. Thus a verdict on the commerical use of methane gas from unmined coal seams is still out and hinges on a vast improvement in recovery techniques. While most wells drilled to date have been sited with relationship to mine working since they have been drilled to improve mine health and safety, a better understanding of the geologic structure conducive to high recovery rates must be obtained and utilized.

Whether or not methane commercialization of unmined coal seams proves viable, there is no doubt in my mind concerning the need for methane degasification of coal seams in conjunction with mining to improve not only health and safety but productivity as well. Because of the higher degree of mechanization and mining at greater depth, conventional mine ventilation is no longer sufficient and will become even less so in the future. Therefore, if our vast coal deposits are to be mined, and I fervently believe this is absolutely necessary considering our present national energy posture, methane degasification will have to be practiced. Therefore I believe that degasification of blocks of coal from outside entries using long-hole horizontal drilling will be necessary, accompanied by the drainage of gob gases from vertical holes extending from the surface. I am impressed by the large gas flows available from gob areas in the Bethlehem project being conducted with Westinghouse. I believe the development of an automatic guidance system for horizontal holes is necessary to keep the bit in coal, following an undulating seam and permitting longer holes and higher drilling rates.

In spite of all the problems and poor results I have reported upon in this paper, I remain optimistic. My experiences merely have given me a more realistic perspective of the situation and a better understanding of where the research and development priorities must be concentrated. The potential is there but a large job must be done before it is translated into performance. However, I would doubt that the recovered methane gas from coal seams will ever be a significant energy source in the future in this country. Its greatest contribution to our energy posture can only come by permitting the mining of coal seams more safely and at higher productivity rates; it will remain a by-product. Of course, every little bit helps, and if presently wasted energy material becomes an asset, so much the better for conservation purposes. Still, let us keep the significance of this source of energy in proper perspective.

ACKNOWLEDGEMENTS

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DISCLAIMER

The views expressed in this paper are solely those of the author, and there is no implicit endorsement or assumed liability for any statements by the sponsors of this project.

TABLE 1
DEGASIFICATION FOAM-FRAC
CNG1034 CUMBERLAND MINE OPERATIONS, GREENE COUNTY, PA
MAY 5, 1977

Item	Sand Concentration (lbs/gal)	Foam (Gallons) Increment	Foam (Gallons) Total	Water (Gallons) Increment	Water (Gallons) Total	Sand (lbs.) Increment	Sand (lbs.) Total	Injection Rate Foam* (BPM)	Injection Rate Water** (BPM)
(1) Foam Pad	-	2,000	2,000	500	500	-	-	10	2.5
(2) Sand-Laden Foam 100 Mesh	1/2	2,000	4,000	500	1,000	1,000	1,000	10	2.7
(3) Sand-Laden Foam 100 Mesh	1	2,000	6,000	500	1,500	2,000	3,000	10	3.0
(4) Sand-Laden Foam 20/40 Mesh	1	4,000	10,000	1,000	2,500	4,000	7,000	10	3.0
(5) Sand-Laden Foam 20/40 Mesh	1 1/2	10,000	20,000	2,500	5,000	15,000	22,000	10	3.2
(6) Sand-Laden Foam Dyed Sand	1 1/2	1,000	21,000	250	5,250	1,500	23,500	10	3.2
(7) Flush with Foam	-	840	21,840	210	5,460	-	-	10	2.5
(8) Flush with Water	-	-	-	640	6,100	-	-	10	10

*75 Quality foam

*Down-hole foam injection rate = 7.5 BPM Nitrogen + 2.5 BPM Water

**Water injection rate = 2.5 BPM 6L-C Pump Truck pumping water + foam agent at 1/2 BPM
HT-400 Pump Truck pumping water + sand at 2.0 BPM

**Water rate increased with each increase in sand concentration to compensate for additional volume due to high sand concentrations in blender tub

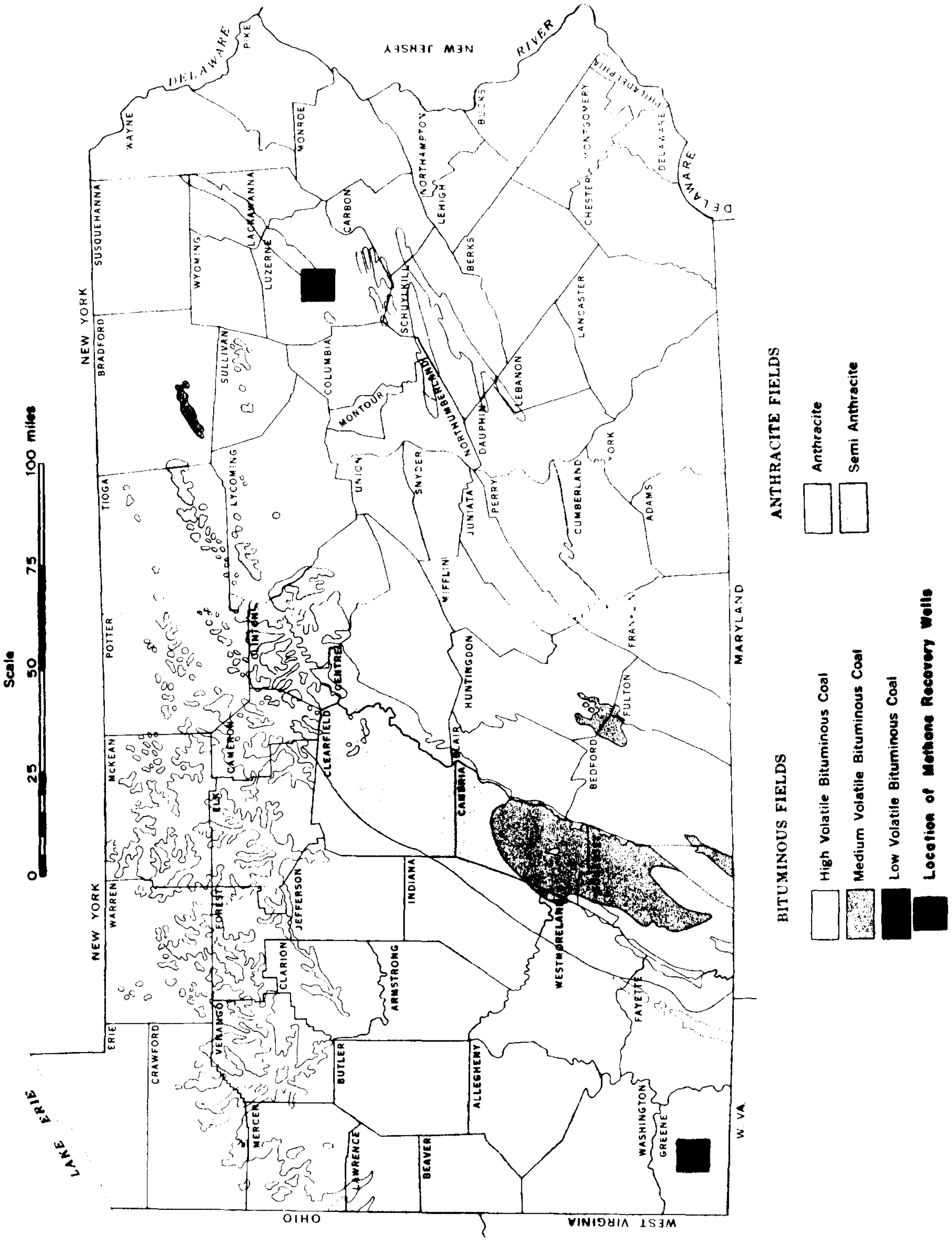
TABLE 2

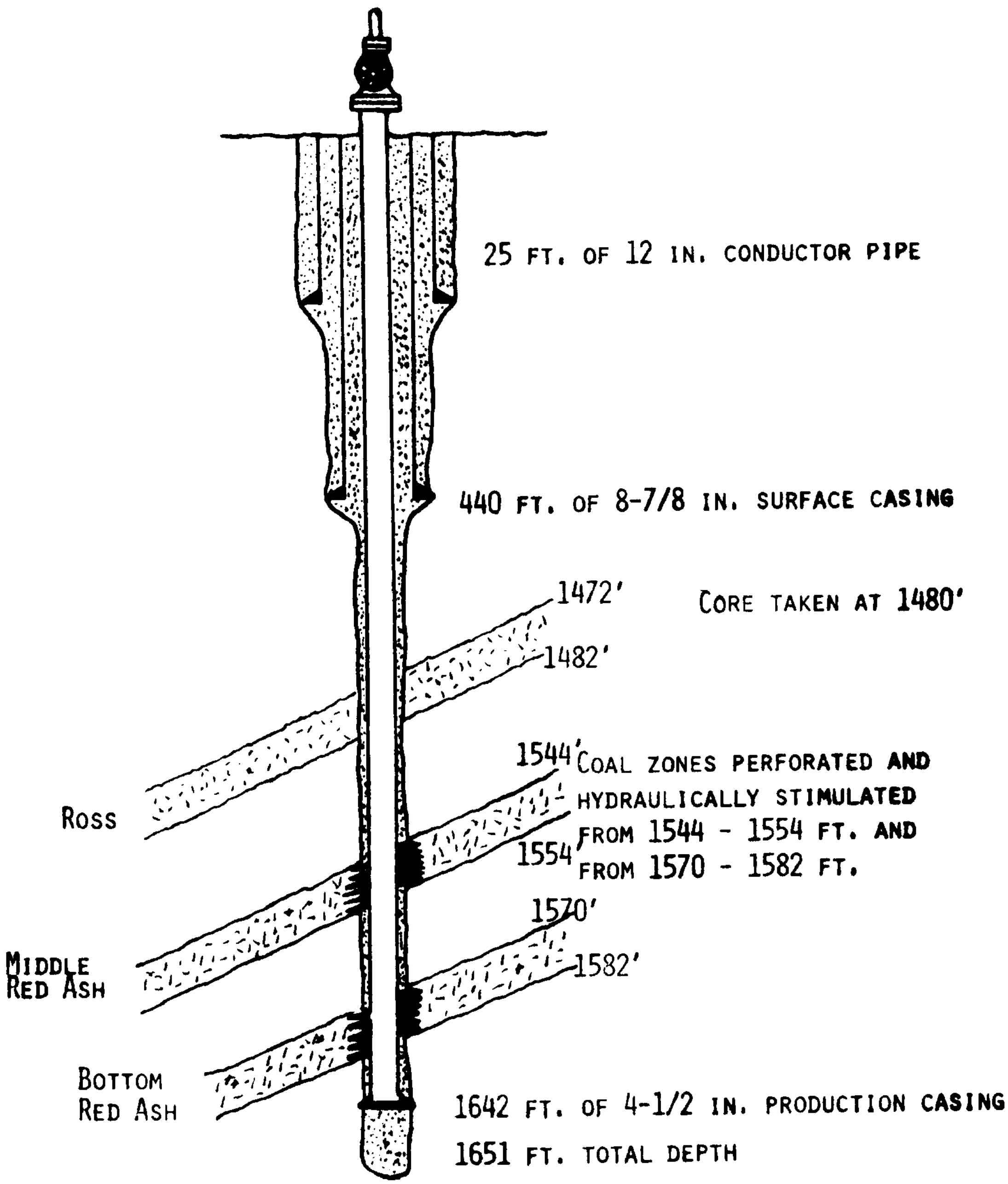
DIRECT COSTS FOR CUMBERLAND WELLS

	CNG 1034 (825')	CNG 1035 (1250')	CNG 1036 (1025')	TOTALS (3100')
DRILLING	$14,235.00	$44,671.00	$16,243.00	$75,239.00
DRILLING PER FT	17.25	35.74	15.85	24.27
CORING (FT)	3,088.00(10')	6,907.00(103')	3,506.00(20')	13,501.00(133')
COMPLETION	7,505.00	19,804.00	7,216.00	34,525.00
SUBTOTAL (A)	24,828.00	71,382.00	26,965.00	123,175.00
SUBTOTAL (A) PER FT	30.10	57.11	26.31	39.73
FRACING (B)	13,000.00	10,000.00		23,000.00
SERVICES (MOVING, MATERIAL, BULLDOZING, CNG, ETC.) PRO-RATA (C)	7,000.00	7,000.00	6,000.00	2,000.00
(A) + (B) + (C) =	44,828.00	88,382.00	32,965.00	166,275.00
OTHER SERVICES - U.S. STEEL (D)	2,700.00	4,300.00	3,000.00	10,000.00
(A) + (B) + (C) + (D)	47,528.00	92,682.00	35,965.00	176,175.00
POWER LINES (CAN BE RETURNED IN FUTURE POWER PAYMENTS) (E)				3,027.00
POWER COSTS TO END OF PROJECT (PUMPING) WATER - LARGELY) (F)				967.00
TOTAL (A) + (B) + (C) + (D) + (E) + (F)				180,169.00

DISTRIBUTION OF PENNSYLVANIA COALS

FIGURE 1





WELL COMPLETION - PERI NO. 1

FIGURE 2

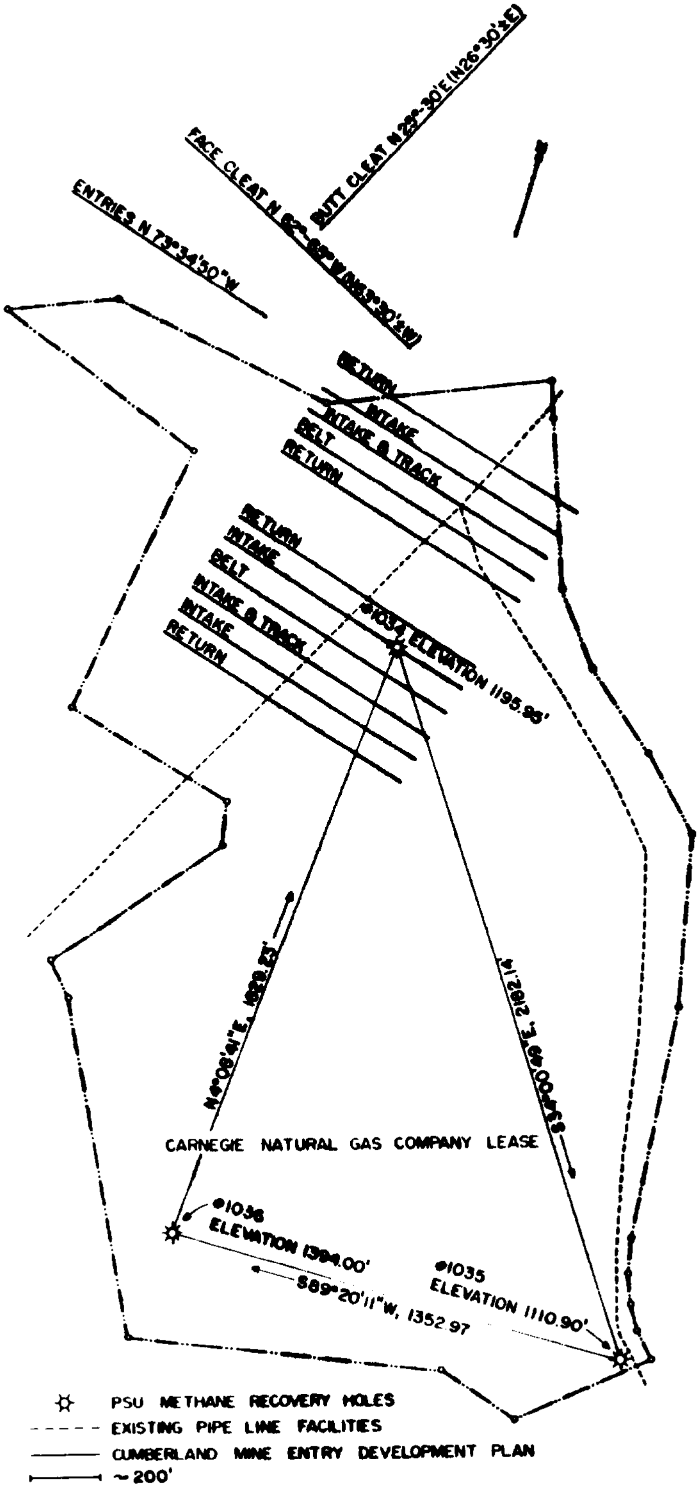
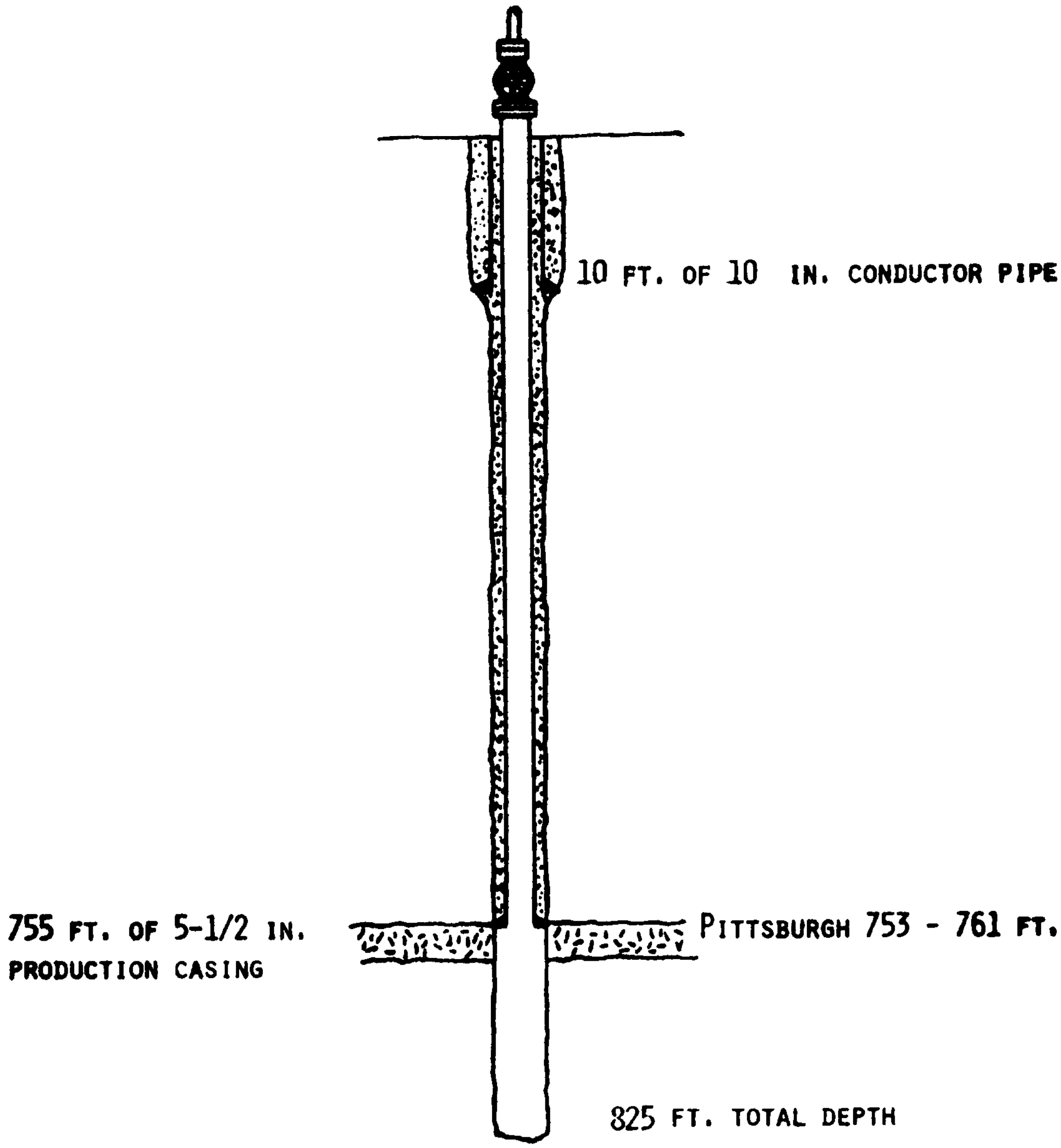
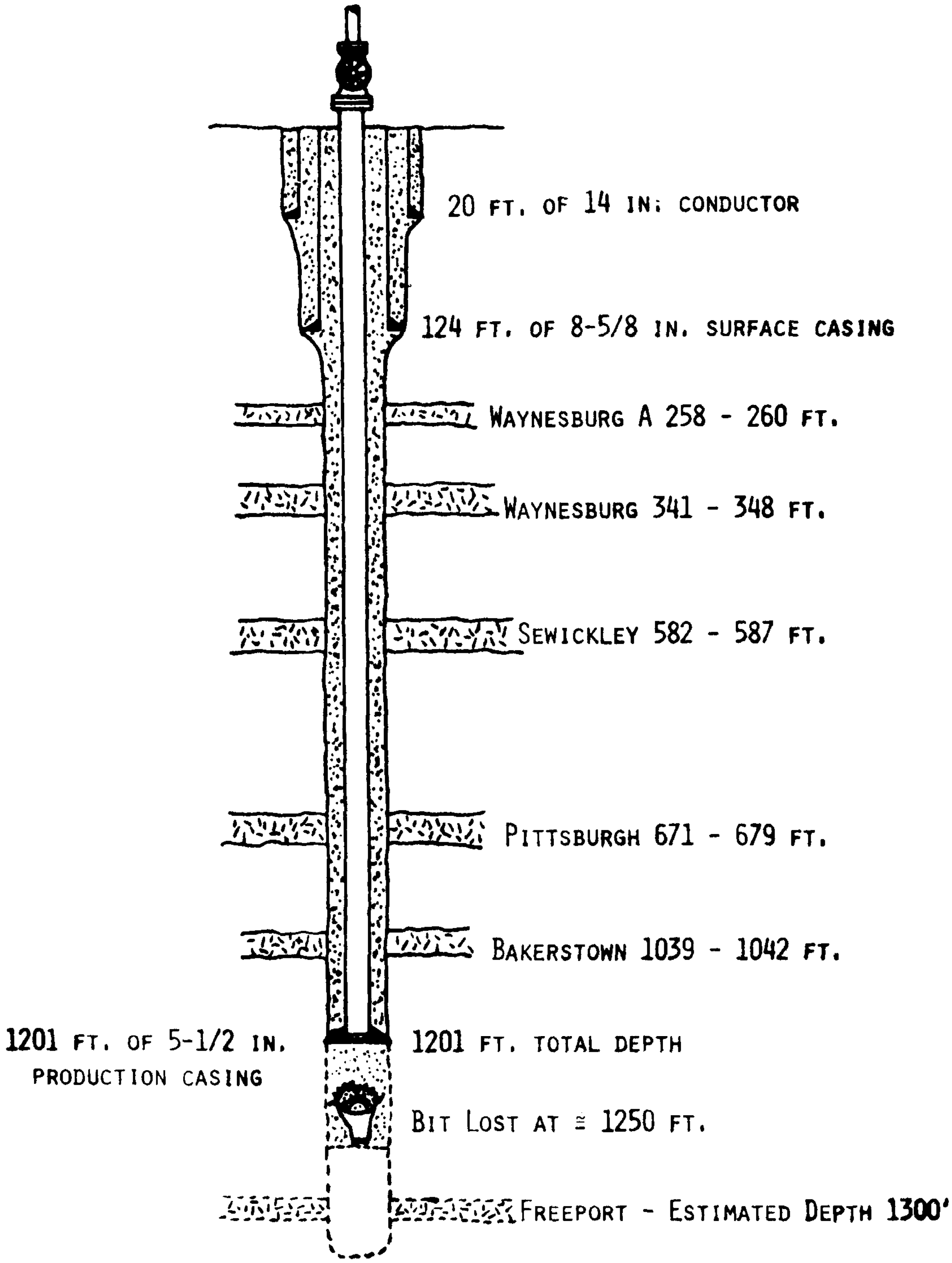

BUTT CLEAT N 23°-30'E (N26°30'±E)
FACE CLEAT N 62°-66°W (N63°30'±W)
ENTRIES N 73°34'30"W
RETURN
INTAKE
INTAKE & TRACK
BELT
RETURN
RETURN
INTAKE
BELT
INTAKE & TRACK
INTAKE
RETURN
#1034 ELEVATION 1195.95'
N14°08'41"E, 1629.23
S14°00'49"E, 2162.14
CARNEGIE NATURAL GAS COMPANY LEASE
#1036
ELEVATION 1394.00'
S89°20'11"W, 1352.97
#1035
ELEVATION 1110.90'
PSU METHANE RECOVERY HOLES
EXISTING PIPE LINE FACILITIES
CUMBERLAND MINE ENTRY DEVELOPMENT PLAN
~200'

FIGURE 3



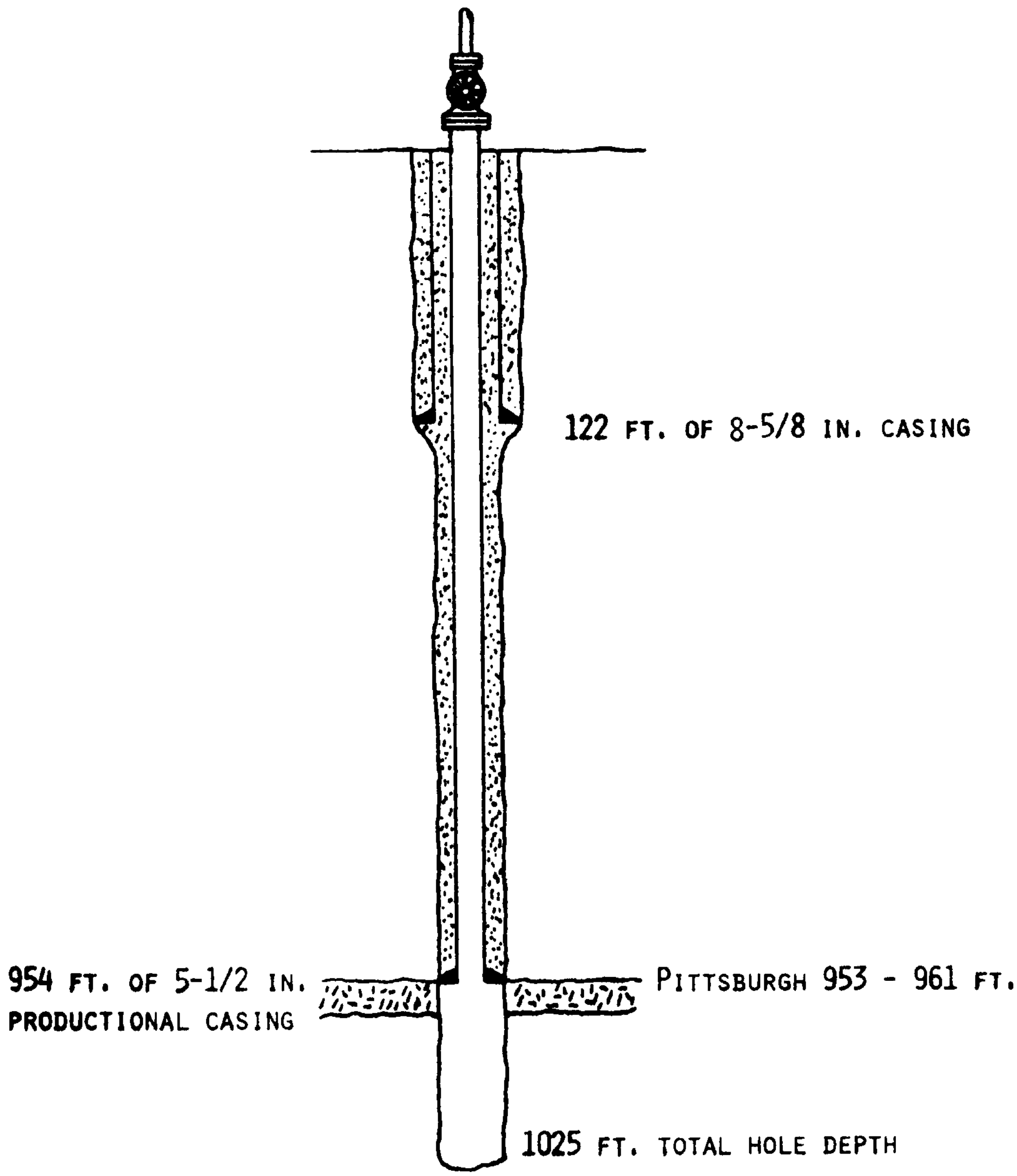
WELL COMPLETION - CNG No. 1034

FIGURE 4



WELL COMPLETION - CNG NO. 1035

FIGURE 5



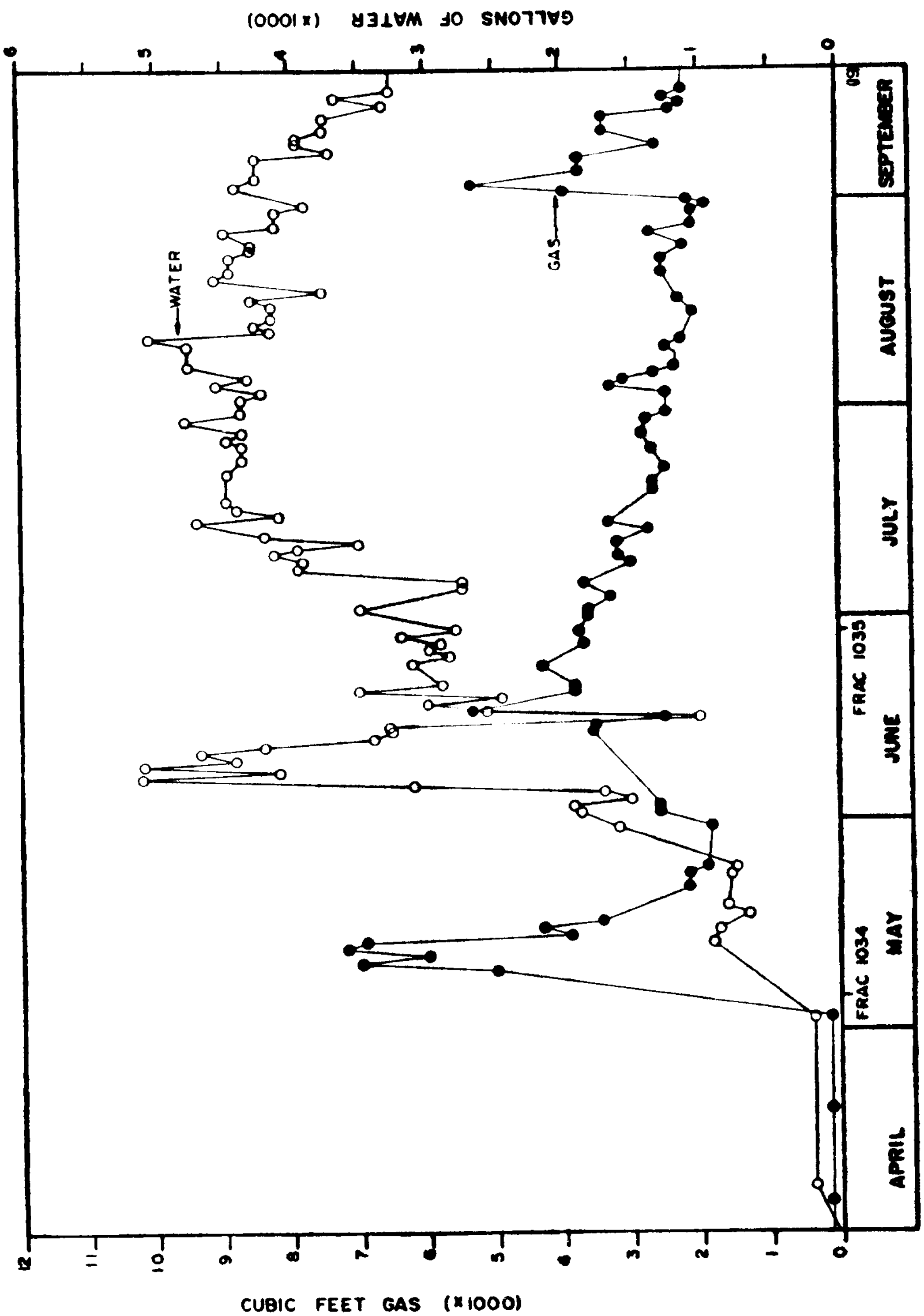
WELL COMPLETION - CNG No. 1036

FIGURE 6

FIGURE 7

CNG 1034

CUBIC FEET GAS & GALLONS OF WATER vs. TIME



INSTITUTIONAL CONSTRAINTS TO THE DEVELOPMENT OF COALBED METHANE

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ABOUT THE AUTHOR

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She taught schools in Wyoming, Colorado and Montana for nine years, then spent two years as a Teaching Fellow, Adjunct Instructor in Education, and Associate Director of an Urban Affairs Studies Program at the University of Tulsa. She taught at Eastern Montana College and from July of 1970 to June of 1975 served as a Program Associate in Research Administration at Montana State University. She was on leave from this position for 14 months while she served with the White House Energy Policy Office and in the Federal Energy Administration.

In June of 1975, Mrs. Olson joined the Division of Coal Conversion and Utilization of ERDA as a Staff Assistant, became a Technical Assistant for Planning and Budget in this Division in June of 1976, and is now a Program Analyst in the Division of Commercial Applications in the Department of Energy.

She is a senior member of various project management teams to develop the alternative fuels commercial demonstration program, especially in the area of fossil fuels and their conversion and utilization.

ABSTRACT

Constraints to the development of coalbed methane as an energy resource may arise as a result of (1) an interest in keeping information about coal or gas resources confidential; (2) the Federal and State regulations affecting development of most energy resources; (3) taxation and pricing policies and practices of Federal and State governments; and, of basic significance, (4) legal questions related to the status of the resource and the rights of interested parties.

Issues related to status and rights include the question of methane ownership, definitions of natural gas, the role of State and Federal regulatory agencies and the position of the Federal Energy Regulatory Commission (FERC, formerly the Federal Power Commission).

A review of these matters indicates that both judicial decisions and legislative action will play roles in the modification of these constraints. Speculation is made as to the direction court decisions may go and the basis on which these decisions will be made. The problems of regulatory agencies as they attempt to deal appropriately with methane are discussed. Some suggestions are made as to actions they may consider pursuing. Legislative language is proposed that could assist in clarifying the status of the resource and the rights of interested parties.

INTRODUCTION

It has been shown that both recovery and utilization of coalbed gas is technically feasible. Now the need for increased gas production, for energy conservation, and for mine safety are combining with feasibility to make coalbed methane an outstanding candidate for immediate development.

In order to promote the development of this potentially large methane resource, State and Federal government agencies can work together to minimize or eliminate, if possible, institutional problems that may act as deterrents to that development. Constraints to development may take many forms. Individuals who have information about their coal and gas resources may wish to keep that information confidential for reasons independent of interest in coalbed methane extraction and utilization. Many State and/or Federal regulations affect the rate of development of most energy resources. Economic constraints may arise out of pricing and taxation policies and practices of either State or Federal government.

Basic to many problems associated with the development of this resource are legal questions. What is the status of the resource? What are the rights of interested parties? Four issues related to status and rights tend to be raised when the subject of coalbed methane is discussed. One revolves around the question of methane ownership - whether it lies with ownership of the coal or natural gas. This issue has not been resolved legislatively or in the courts. There have been decisions in related areas that suggest a direction that the court might take. In this paper, some of these problems are reviewed and legislative language is suggested which might contribute to clarification of ownership problems.

Second, various legal definitions of "natural gas" or "gas" are reviewed to determine if they are broad enough to include gas from unconventional sources, particularly methane from coal seams. A definition is then suggested that might serve this purpose.

Third, some consideration is given to the role of regulatory agencies in ensuring fairness to all interests and safety for miners as this resource is developed. Fourth, there is a discussion of the role of the Federal Regulatory Commission (FERC, formerly the Federal Power Commission) and the direction it is moving with respect to this resource.

OWNERSHIP

Where oil and gas rights and coal rights are held in common, production could begin with few problems. In the many cases where ownership is fragmented, the right to remove and market methane from coalbeds could become a significant deterrent to development.

Legal problems arise primarily in areas where coal rights have been leased and mining operations are underway or planned.

Methane migration into coal mines constitutes an explosion hazard and increased and deeper bed mining has been paralleled by increased fatalities due to ignitions and explosions in underground coal mines.[1]

Because the gas has been generally considered to be a nuisance, it is not surprising that few if any, deeds or leases transferring interest in coal rights make any reference to the methane contained in the coal.

Even though our one hundred fifty years of coal mining transactions have produced a great many such deeds and leases, there has been little judicial attention given to the ownership of coalbed methane. The recent expressions of interest in the problem of rights to coalbed methane have not been sufficient to stir such states as West Virginia and Pennsylvania, where activity has been most intense, to come to a legislative resolution of it.

Some coal companies view the ownership of coalbed methane as concomitant with ownership of the coal. This is contrary to the view held by the petroleum industry and that expressed in several court opinions that an oil and gas lease confers on the holder the right to drill and produce oil and gas from any formation, with ownership of the reservoir remaining with the owner of the surface rights.[2] Similarly it was held in Lynch v. Alworth-Stephens Co.[3] that while a lease of the right to extract ore from a mine does not convey title to ore deposits in place, it does give to the lessee exclusive possession of the deposits and the right of removing and reducing the ore to ownership. Further, the property of the owner of oil and gas is not absolute until the oil or gas is actually in his grasp, and brought to the surface.[4]

The hazardous nature of coalbed methane has resulted in various Federal and State regulations requiring that methane concentration in mines be kept to less than one percent. To accomplish this, operators pump fresh air into the mines thereby forcing methane through a ventilating system and into the atmosphere. The question then arises as to what impact this necessary activity has on the relationship between the coal grantee and title to the methane gas. The Attorney General of Pennsylvania addressed this question in 1974.[5] In so doing, he looked to the opinion of the court in the case of Chartiers Block Coal Co. v. Mellon.[5] In this case, oil and gas were discovered as new resources after the grant of the coal rights had been made. This presented the question of the right of the vendor to reach strata underlying the coal. The Court took the position that

> It is impossible for him to reach his underlying estate, except by puncturing the earth's surface and going down through the coal which he has sold. While the owner of the coal may have an estate in fee therein, it is at the same time an estate that is peculiar in its nature. Much of the confusion of thought upon this subject arises from a misapprehension of the character of this estate. We must regard it from a business, as well as a legal standpoint. The grantee of the coal owns the coal but nothing else, save the right of access to it and the right to take it away. Practically considered, the grant of the coal is the grant of a right to remove it.[6]

The Attorney General subsequently wrote,

> This is not to say, however, that the coal mine operator may not expel methane gas into the atmosphere. To deprive him of this right would, in effect, be depriving him of his access to the coal, since coal cannot be mined without expelling the methane gas from the mine shaft. Thus, the right to mine for coal necessarily includes the right to perform those actions necessary to insure the safety of such mining. Since the coal owner or grantee only retains the right to extract coal, however, the right to access to, and economic control of, the methane gas belongs to the owner or grantee of the gas rights.[7]

In the Texas case of Halbouty v. Railroad Commission,[8] the appellants sought to restrain the Railroad Commission from continuing in effect an allocation formula for a field in which they had an interest. An issue at the heart of the case was whether the owner of a small tract, being entitled to one well to prevent confiscation of the gas underlying his tract, was entitled to confiscate gas from adjacent properties sufficient to pay the cost of drilling and to provide a reasonable profit. In discussing this issue, the Court referred to an earlier decision:

> In Marrs v. Railroad Commission, 142 Tex. 293, 177 S.W.2d 941, we held that "Under the settled law of this State oil and gas form a part and parcel of the land wherein they tarry and belong to the owner of such land or his assigns...; and such owner has the right to mine such minerals subject to the conservation laws of this State. Every owner or lessee is entitled to a fair chance to recover the oil or gas in or under his land, or their equivalent in kind, and any denial of such fair chance amounts to confiscation."[9]

The appellees, in arguing that the proration formula was valid, claimed some benefit or protection under the "rule of capture." The Court again quoted from an earlier decision:

> ...we said in Eliff v. Texon Drilling Company (1948), 146 Tex. 575, 210 S.W.2d 558, 4 A.L.R. 2d 191, that "In our state the landowner is regarded as having absolute title in severalty to the oil and gas in place beneath his land.... The only qualification of that rule of ownership is that it must be considered in connection with the law of capture and is subject to police regulation.[10]

The Oklahoma Statutes treat ownership of gas as follows:

> All natural gas under the surface of any land in this state is hereby declared to be and is the property of the owners, or gas lessees, of the surface under which gas is located in its original state.[11]

RULE OF CAPTURE

In Bingham v. Corporation Commission,[12] the Corporation Commission had approved a Plan of Unitization for secondary recovery operations. The protestants challenged the order on the grounds that it would permit the operator to pay part of the expenses of the operation from the royalty reserved to the lessors. The Oklahoma Court, in considering the relevance of the "rule of capture" in this case, referred to a previous decision:

> However, the law of "capture" is not strictly applied and there are exceptions in Oklahoma for in Gruger v. Phillips Petroleum Co., 192 Okl. 259, 135 P.2d 485, we said: "The law of capture, under which oil and gas is owned by the one lawfully reducing it to possession, still obtains in Oklahoma, except as it has been or may be regulated or restricted under laws passed in the exercise of the police power, such as the proration and spacing statutes.... Those laws do not abrogate the law of capture. They are not self-executing. They simply authorize administrative boards to issue orders that have the effect of regulating or abrogating in a measure the law of capture."[13]

In Bogges v. Milam,[14] the plaintiff contends that, in effect, a unitization agreement, so far as the rights of the lessee and its lessors - his cotenants - are concerned, destroyed the identity, as separate tracts, the two acreages involved, making him a tenant in common, but not a colessor, all persons having an interest in the oil and gas underlying both boundaries. The West Virginia Court discussed the change in interpretation of ownership in that State and, addressing recent cases on the subject, had this to say:

> ...the recent decisions are all to the effect that the owner of the fee is vested with title in the oil and gas underlying the boundary to which he holds title, although it is admitted that due to the nature of both or either they may not remain in place and are not the subject of actual possession until brought to the surface, because until that occurs there is no way to determine positively that oil and gas does, in fact, lie under a designated boundary.[15]

A number of other cases similarly deal with ownership and "capture." Among them are: Walls v. Midland Carbon Co. 254 US 300, 41 S Ct 118; Ohio Oil Co. v. Indiana, 177 US 190, 20 S Ct 576; and Champlin Ref. Co. v. Corporation Commission, 286 US 210, 52 S Ct 559, 86 ALR 403.

It is a rather common position, then, among the states that the owner or lease holder of the surface rights (or gas rights, if they have been separated) is entitled to attempt to recover the gas and once he has reduced it to his possession to claim it as property. It would appear that the coal mine operators, in their efforts to rid mines of this dangerous substance, do not exercise a kind of control and have not affected the type of possession that would constitute "capture" as described in the above cases. It would appear instead that the operators are merely instruments of escape of the gas thus severing title of the gas owner but in no way creating a right of ownership in themselves.

MINERAL RIGHTS

It is quite common for mineral rights, including the right to explore or prospect for, develop and produce gas or coal, to be contracted for separately from surface rights. The owner of the rights may transfer acreage by deed or lease and the intent of the parties determines what is conveyed.

Therefore, each deed or lease must be examined for its effect on and relationship to the mineral right. Normally, oil and natural gas leases are held separately from coal leases when the land is held in fee simple or owned by a unit of government.

In the course of development of these resources, the courts have been asked to interpret deeds and leases related to minerals. Judicial interpretation of mineral leases and deeds dates back to at least the middle of the nineteenth century when, in what may be the first reported case on this issue, a landowner's interest in oil and gas was before a Kentucky court. There it was held in Hail v. Reed[16] that the landowner could recover damages for the illegal conversion of oil and gas.

Quite often the deed or lease names one or more specific substances such as coal, clay or limestone and then generalizes to include "other minerals." Sometime later a substance not known to have value at the time of the transaction may be discovered or become economically attractive. This has occurred in the case of oil and gas as well as other substances such as uranium and oil shale. Because each lease or deed has had to be examined in light of the circumstances under which it was written, differing conclusions have been reached by the courts and no easy test has emerged by which to judge the inclusion or exclusion of coal in an instrument involving "oil, gas, and other minerals" or of gas in an instrument involving "coal and other minerals."

One problem arises from inconsistency in the use of the word "mineral."

> It has been correctly pointed out that the word 'mineral' has been said to have no definite or certain meaning. It is not capable of a definition of universal application, but is susceptible to limitation or expansion according to the intention with which it is used in the particular instrument or statute, 54 Am Jur 2d, Mines and Minerals B 6. However, it has been further stated that 'substances which are minerals within the scientific, geological, and practical meanings of the term (legally) constitute minerals within the purview of a clause reserving all oil, gas, and minerals.'[17]

In most states, "minerals" includes in its meaning oil, gas, and petroleum products unless a contrary meaning is stated in the instrument. For example, the reservation of "any mineral on said land" was found in Branham v. Minear (1947, Tex Civ App) 199 SW2d 841, to include oil and gas as part of all minerals. It was the Court's statement that inclusion of oil and gas in the term "minerals" was so well settled that no authorities need be cited. Applying the rule that under normal circumstances a conveyance or reservation of mineral included oil and natural gas in place, unless there was proof of a contrary intent, the Court held in Warren v. Clinchfield Coal Corp. (1936) 166 Va 524, 186 SE 20, that a conveyance of "all the coal and minerals of every description" included oil and gas. In a West Virginia case, Burdette v. Bruen (1937) 118 W Va 624 191 SE 360, it was noted that an exception or reservation provision in a deed conveying minerals, not limited or qualified as to intention elsewhere in the instrument, included not only solid minerals but oil and gas as well. In those states, where the meaning of "minerals" is uncertain, therefore, the facts and circumstances that existed at the time of the transaction must be examined in an effort to determine intent of the parties.

In Pennsylvania, in the case of Dunham v. Kirkpatrick[18] the court laid down the "Dunham rule" or the "Pennsylvania rule" saying that a deed conveying all coal and other minerals of every kind and character under a described tract of land did not include natural gas subsequently discovered on the land.

This rule has been applied fairly recently (1960) in a Pennsylvania case although the document in question was executed in 1887. Due to the diversity of citizenship of the parties involved, a dispute over ownership of the natural gas underlying a tract of land in Pannsylvania came before the Federal Court in the case of New York State Natural Gas Corp. v. Swan-Finch Gas Development Corp. Observing that the real property law of Pennsylvania was "applicable and controlling" in this case, the Court restated the rule citing Dunham and several other cases.

> The rule is that such a general reservation of minerals without specific mention of natural gas does not suffice to reserve natural gas, at least unless such intention is affirmatively and convincingly proved in the particular case.[19]

Arguing that this rule applies to language used in reservation but not granting clauses, the appellants attempted to avoid it. The Court, however, pointed out that that distinction had

> ...been rejected by the Supreme Court of Pennsylvania and the rule of reservation

> cases has been authoritatively applied to language in a grant. Highland v. Commonwealth of Pennsylvania, Pa., 161 A.2d 390. That case contains an explicit ruling that the fact "that the word 'minerals' appears in a grant, rather than an exception or a reservation, in nowise alters the rule." [20]

Although this rule is occasionally cited in other jurisdictions, its application is generally limited to Pennsylvania.[21]

To add the new element of coalbed methane to this confusion is to compound the difficulty of interpreting the meaning of "minerals." Some clear, precise definitions and legislative language would do much to clarify the status of this resource and its ownership.

NATURAL GAS

This presents a related question of whether coalbed methane gas is natural gas in the conventional sense. The main constituent of conventional natural gas is methane. Both gases have a similar heat of combustion range. They are compatible in the pipeline. From the chemical and end use points of view the differences are not normally significant. What then about the legal point of view? Natural gas is defined in the Natural Gas Act: "(5) 'Natural gas' means either natural gas unmixed, or any mixture of natural and artifical gas."[22]

As this definition is rather general, it is not surprising that questions have arisen requiring a more specific interpretation of it. Notes of Decision appearing in the United States Code Annoted shed some additional light on its intended meaning.

2. Natural Gas

> Liquefied natural gas is "natural gas" within the meaning of this chapter. Distrigas of Massachusetts Corp. v. Federal Power Commission, C.A.1, 1975, 517 F.2d 761.
>
> Jurisdiction of the Commission under this chapter does not extend to production, transportation, and sale of unmixed synthetic gas produced from coal; such gas is "artificial" within meaning of this chapter. Henry v. Federal Power Commission, 1975, 513 F.2d 395, 168 U.S. App. D.C. 137.
>
> "Casinghead gas" produced from a well, was "natural gas" within meaning of this section defining natural gas as either natural gas unmixed, or an mixture of natural and artificial gas. Deep South Oil Co. of Tex. v. Federal Power Commission, C.A.5, 1957, 247 F.2d 882.
>
> "Natural gas" is a mixture of gaseous hydrocarbons found in nature in many places connected with deposits of petroleum, to which the gaseous compounds are closely related. Id.[23]

In many states, the definition of "gas" is dependent on the definition of "oil" which preceeds it. For example, the West Virginia Administrative Regulations state these definitions as follows:

> (8) "Oil" means natural crude oil or petroleum and other hydrocarbons regardless of gravity, which are produced at the well in liquid form by ordinary production methods and which are not the result of condensation of gas after it leaves the underground reservoir;
>
> (9) "Gas" means all natural gas and other fluid hydrocarbons not defined as oil in subdivision (8) of this section.[24]

The Oklahoma Statutes express an almost identical definition:

> (e) The word "Oil" shall mean crude petroleum oil, and any other hydrocarbons, regardless of gravity, which are produced at the well in liquid form by ordinary production methods;
>
> (f) The word "Gas" shall mean all natural gas, including casinghead gas, and all other hydrocarbons not defined as oil in the subsection above.[25]

In his Official Opinion No. 53, the Attorney General of Pennsylvania addressed the question:

> It is our conclusion that methane gas must be classified as a natural gas. Under the Gas Operations, Well-Drilling, Petroleum and Coal Mining Act, 52 P.S. §2102 (10), gas is defined as "any natural, manufactured or byproduct gas or any mixture thereof," this necessarily includes methane. Furthermore, in Emerson v. Commonwealth, 108 Pa. 111, 126 (1884), the court defined natural gas as a gaseous fuel "which may be converted into heat by combustion with atmospheric air." As such the conclusion is inescapable that methane is a natural gas.[26]

It appears that there would be little difficulty in interpreting definitions of "gas" or "natural gas" to include coalbed methane. However, a definition that expressly includes this resource would minimize the likelihood of litigation over it.

REGULATIONS

Removal of methane from coalbeds can be under two different sets of circumstances. One is in association with an underground mining operation that is underway or in coal seams that can reasonably be expected to be deep mined at some future date. The other is associated with seams that normally would not be candidates for deep mining. Such seams may be too thin - less than twenty inches, too deep, or otherwise not suited to deep mining techniques. The objectives in each case are also different. Where mining is a factor, the objectives are to conserve the methane that would otherwise be wasted and to clear the potential mining area of the dangerous gas in a rather short period of time, perhaps three to five years. Where mining is not expected to be involved, the objective is to develop a production field that has a reasonable economic life - probably at least twenty years. The differences in timing, spacing and mode of operation in these two situations, methane conservation and methane production, could realistically call for differences in types or applications of existing or new regulations.

In methane production from non-mining areas, it could generally be expected that regulations that apply to natural gas from conventional sources would be equally appropriate. Recognition would have to be made by the regulating agency, be it State or Federal, that production from these wells is normally much lower in volume than wells in conventional sources. This may call for some special arrangements with regard to spacing, collection systems, and pricing. Illustrative of this is a bill recently proposed in the West Virginia legislature. The bill, which did not pass, called for spacing of gas wells a mile apart. Had such a bill been enacted and applied to coalbed methane, it could virtually eliminate the prospects for development of this resource either for conservation or production.

Methane removal from minable coalbeds presents distinct and unique problems that will require more specific management and regulation development. A number of regulatory organizations will be concerned and involved in this activity. Federal agencies such as the Mining Enforcement and Safety Administration (MESA) and state oil and gas and mining agencies will surely be among them.

Acknowledging the high safety and conservation value of removing methane from minable coalbeds, the ownership rights of both the coal and gas must be fairly protected. Arrangements must be made for just compensation where the advantage to one works to the disadvantage of the other.

State agencies have regulations that apply to oil and gas activities and they have other regulations that apply to coal mining activities. Will the oil and gas regulations apply directly and absolutely to methane removal or will a separate set of regulations be required? Using West Virginia as an example, it is notable that no permits are required for air shafts or ventilation holes in mining activity yet permits are required for holes or shafts made for gas production. Coal mine operators are encouraged to vent gas to the atmosphere by the safety requirement for air quality in the mine. At the same time, the oil and gas regulations read, "Waste of oil or gas is hereby prohibited."[27]

A number of regulations dealing with spacing, completion, abondonment, etc. may not be appropriate to either vertical or horizontal boreholes in coal seams. Fracturing to increase gas production is a commonplace technique, however, this activity must be controlled in some manner. Fracturing could damage the roof structure where mining is to follow methane removal thus endangering the safety of the miners. All this suggests that a separate set of regulations would be more suitable than trying to force fit existing gas regulations to methane recovery operations.

FEDERAL ENERGY REGULATORY COMMISSION

A final question asks what the jurisdictional position of the Federal Energy Regulatory Commission (FERC, formerly the Federal Power Commission) would be. The definition of natural gas in the Natural Gas Act and the subsequent interpretations of it leave little doubt that FERC would consider coalbed methane to be a "natural gas." As a "natural gas," FERC would have jurisdiction over the methane when it was stored, transported or sold for resale in interstate commerce. This agency, too, would have to recognize the peculiarities of recovering the resource, particularly in the mine-related situation in applying regulations such as those for abandonment, collection systems, and pricing. Evidence that this recognition is taking place will be discussed later.

SUMMARY

To summarize, we have identified four legal problems that may inhibit development of coalbed methane recovery: Ownership of the methane, the definition of "natural gas," the applicability of regulations as dictated by various agencies, and the involvement of FERC. Regarding the ownership issue, there are no cases directly in point. The indications from closely related decisions are that in most jurisdictions ownership would be determined to be with the owner of the natural gas. At the same time, rights of the owner of the coal will be protected. There is presently on the books no legislation that addresses this problem and there is a need for appropriate statutes clarifying ownership and doing so in a general applicable way. The alternative, of course, is the development of law through the decisional process. As events unfold, both procedures may very likely occur.

The definition of "natural gas" is quite similar in the states and at the Federal level. By going one more step in these definitions to include gas from unconventional sources, future problems about the real and full meaning of the term can be avoided.

Regulatory agencies need to distinguish between recovery of coalbed methane from mining and non-mining situations. The mining-related situation will call for a unique set of regulations so that the gas may be removed while protecting the rights of both coal and gas owners and providing for the safety of the miners.

FERC claims jurisdiction over any form of gas entering the pipeline for interstate commerce. Unconventional sources of gas will require some special consideration, particularly where mining is involved.

Finding the ownership problem solvable, Maurice Deul of the U.S. Bureau of Mines discussed the issue in an article in the Mining Congress Journal:

> The problem of ownership of the gas in coalbeds could be solved in several ways. Legislative action or judicial decision could grant the owner of the coal the right to remove the gas and dispose of it in any appropriate manner. If legal title to the gas is in doubt, the mine owner could drain and market the coalbed gas, placing in escrow sufficient funds to cover claims for gas royalties. Cooperation by owners of the coal and gas rights in draining the coalbed gas is another possibility. Investment/profit could be adjusted, insuring an equitable return to both parties, taking into account that the coal owner derives benefits from gas drainage in addition to the return from the sale of the gas. In any case, the legal ownership of coalbed gas should not impede efforts to improve mine safety, increase productivity and conserve a valuable energy resource.[28]

As noted by Deul, a number of options are available in approaching the ownership problem. A reading of various definitions of "natural gas" and decisions dealing with ownership suggests that the court would tend to keep the ownership of coalbed methane with the ownership of other naturally formed gases. To legislate otherwise and place ownership of this gas with the ownership of the coal would probably precipitate more court action and problems than not dealing with the question at all and, ultimately, ownership would most probably be awarded to the natural gas owner. It would seem most prudent then, if legislation is developed, to legislate ownership in the natural gas owner so that the issue would be clearly stated and resolved.

Using the treatment of ownership from the Oklahoma Statutes that was quoted earlier, we have the beginning point that

> All natural gas under the surface of any land in this state is hereby declared to be and is the property of the owners, or gas lessees, of the surface under which gas is located in its original state.[29]

Making some logical modifications that reference all strata underlying the surface, acknowledge the "rule of capture," and allow for the necessary exercise of the police power, we might use a statute that reads as follows: The right to all natural gas (assuming the definition of "natural gas" now includes gas from unconventional sources) in any strata under the surface of any land in this state is hereby declared to be and is the property of the owners, or gas lessees, of the surface under which gas is located in its original state. The gas is owned by the one lawfully reducing it to possession, however, this ownership may be regulated or restricted under the laws of the State.

As has been noted, there is a need for a definition of "natural gas" or "gas" that includes naturally formed gases from any strata underlying the surface, thereby including coalbed methane. A Pennsylvania definition of "gas" in its oil and gas conservation rules and regulations could easily be construed to include the methane in coalbeds.

> (5) Gas - All natural gas and all other volatile hydrocarbons not herein defined as oil, including condensate because it originally was in a gaseous phase in the reservoir.[30]

It is the phrase "...all other volatile hydrocarbons" that clearly includes the methane resource. One additional phrase can sharpen the interpretation giving us a definition that reads: Gas - All natural gas and all other volatile hydrocarbons not herein defined as oil, including condensate (some states go into more detail here or use terms such as "casinghead gas"), regardless of the strata in which they originate.

Assuming the coal and gas owners to usually be different parties, the range of functional arrangements is wide. A commission or other such body would be required to ensure appropriate and fair investment/profit arrangements, maintain escrow accounts for gas owners who are unknown or cannot be found, approve drilling plans, and perform other such functions necessary to the successful operation of methane removal activities. Each state will have to develop rules and regulations appropriate to its own situation. It is obvious that safety will be of prime importance where miners may at any time be involved. Also of major concern will be environmental matters and financial arrangements. In some cases, the rules and regulations will have to be unique to this resource. In others, they can be adopted directly from most existing oil and gas regulations. One regulation that exists in many states would have considerable impact if applied to coal mine operators as it applies to gas developers. That is the rule forbidding the waste of gas. Considering that over two hundred million cubic feet of gas are vented from coal mines daily and safety requires that a minimum of methane be present in mine air, a prohibition on the waste of this gas would create great pressure on mine operators to adopt the practice of removing methane from the coal seams in advance of mining. In any event, the states will have to make the decisions about the most appropriate and useful regulations to apply to coalbed methane.

In the case of FERC, it has recently been made clear that it claims jurisdiction over any gas entering the interstate market and, further, that it recognizes the peculiarities of obtaining gas from this unconventional source. A Notice of Proposed Rule-Making was issued July 7, 1977, by FERC. If approved, a new Section 157.41 would be added to read as follows:

> § 157.41 Exemption of Sales by Coal Mining Operations
>
> Public interest does not require the issuance of a certificate authorizing the sale of natural gas produced as a byproduct of coal mining operations provided that any jurisdictional pipeline company, or other person undertaking such a purchase, shall so advise the Commission immediately by telegram or letter stating briefly the circumstances and shall within ten (10) days file a statement in writing and under oath, together with four (4) conformed copies thereof, setting forth the purpose and character of the purchase, the rate being paid, the estimated volumes to be delivered, the seller of the gas, the date of initial delivery, the location of the sale, the facts warranting invocation of this section, and, upon completion of the sale, shall advise the Commission of the actual volumes delivered and the price paid pursuant to this section.[31]

The obvious difficulty with this well-intentioned proposal is that the coal mine operators very well may not own the methane. If they do not, then there can be little incentive for them to do anything other than vent the gas into the atmosphere as they now do. Here again the Pennsylvania Attorney General's opinion is directly in point with the issue.

> Any attempt by the owners or grantees of coal rights to convert methane to profitable use could be challenged by those individuals who have acquired the gas rights.

In the light of this disincentive, it is not likely that the FERC effort will produce any pipeline coalbed methane until there is a further resolution of the ownership questions.

Having thus reviewed the matters of ownership, "natural gas" definitions, rules and regulations, and the role of FERC, it appears that none of these that might still be construed as a problem is severe enough to prevent the development of the coalbed methane resource. There are a number of approaches to dealing with the problems. Quite possibly legislative action would be the most time-efficient and most far reaching. It is therefore important, if not urgent, that state legislatures in coal bearing states take the necessary steps suitable to their various circumstances that will serve to encourage the removal and utilization of a valuable and accessible resource, coalbed methane.

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UTILIZATION OPTIONS FOR COALBED METHANE

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ABSTRACT

Derivation of Energy from coalbed methane in significant quantities will depend upon availability of utilization options which are technically feasible and economically attractive. Many options can be defined in terms of the gas source (predrainage gas, gob gas, ventilation gas) and the use category (on-site, local, distant). The Coalbed Methane Utilization Program of the U.S. Department of Energy is designed to identify utilization options, to develop utilization technology, and to demonstrate the technical and economical viability of selected options. Through the Program, institutional barriers to coalbed methane utilization are addressed and coalmine operators are informed of the potential benefits of methane recovery and utilization.

At the present time the economic viability of coalbed methane utilization is unclear. Certain options, such as on-site or local utilization of gob gas, appear favorable and demonstration projects are underway. For other options, uncertainties arise over the extent of the resource and the costs of recovery and delivery to the user. Reduction of these uncertainties is a primary objective of the Department of Energy Program.

INTRODUCTION

This paper describes the options which currently are available for utilization of methane derived from coalmines. Principal topics addressed in the paper are:

- Gas supply for utilization
- Utilization technology
- Economics of utilization
- Current DOE utilization program

The source of information and data for this paper is the report entitled "Systems Studies of Energy Conservation: Methane Produced from Coalbeds" produced by the TRW Energy Systems Group in January 1977.

GAS SUPPLY FOR UTILIZATION

The quantity and chemical content of gas obtained from predrainage of virgin coalbeds or gob areas indicates feedstock requirements for the utilization system. Furthermore, steady production rates and variations in gas content over time are important considerations in choosing an appropriate application for gas utilization. As an indication of the difficulties involved, available Bureau of Mines data show that in one instance gas production, obtained by predrainage from a well ahead of the mine face, decreased by approximately 70 percent over a two-year period although methane content remained at approximately 90 percent during that time. In another example, gob gas methane composition was reported to have declined from a concentration of 90 percent to 40 percent over a one-year period. Along with methane concentration, the gob gas production rate also declined.

UTILIZATION OPTIONS FOR COALBED METHANE

In order to maintain a steady gas supply and relatively uniform composition, consideration must be given to the blending and production phasing of individual wells. Accumulator tankage will provide adequate mixing and elimination of short duration fluctuations, thereby providing a reasonably steady flow, uniform composition and supply pressure for the utilization system feedstock. Feedstock flow rates identified for potential commercial ventures lie between 1 and 2 MMCFD. Analyses obtained from the systems study of predrainage gas and gob gas from the Pittsburgh seam are shown in Tables 1 and 2, respectively. Although gases from various geographic areas, seams and sites will vary, these data show illustrative values together with concentration ranges and fluctuations that might reasonably be expected to be used as feedstock for the various utilization systems. Of particular importance in the data is the sulfur content of the gob gas. This sulfur, in the form of methyl mercaptan and hydrogen sulfide, was less than 1.5 PPM total for all cases analyzed.

The gas compositions shown in Tables 1 and 2 are on a dry basis. At the wellhead these gases will contain water which must be removed. Water separators at the wellhead will be used to dewater the gas before injection into collection pipelines. However, this may not reduce moisture to a sufficiently low level to meet requirements for all of the utilization systems, and therefore must be considered when analyzing the utilization system feedstock requirements.

UTILIZATION TECHNOLOGY

Potential Utilization Categories

Five potential utilization categories have been identified for predrainage gas and gob gas:

- Pipeline injection
- Power generation
- Heating applications
- LNG production
- Chemical production

The technological feasibility of each of these categories will be discussed in this section.

Pipeline Injection

Gas produced from coalbeds can be utilized by direct injection into a commercial pipeline. However, the gas must meet certain requirements set by the pipeline gas companies in order to be suitable for this purpose. A specification for the quality of purchased gas set by the Equitable Gas Company is summarized as follows:

The gas quality shall:

a. Be in its natural state as produced.

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

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

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

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

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

g. Have at least nine hundred and fifty (950) British Thermal Units per cubic foot calculated as the gross saturated value at 14.73 psia and $60^{o}F$.

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

i. Be in conformance with any existing regulatory standards.

It is evident from these specifications that gob gas, which for a Pittsburgh seam coal can typically average 77 percent methane, will be unsuitable for direct pipeline injection without substantial upgrading. The significant amounts of inerts contained in the gob gas must be removed before pipeline injection to meet the inert and heat of combustion requirements. Upgrading methods include both chemical and absorption techniques, and tradeoffs will be required to determine if the gas volumes to be treated make these methods economically attractive. Rectification and subsequent vaporization would be feasible but economically unattractive, as the resultant LNG would be of greater economic value than pipeline gas. Nitrogen removal in the case of the average Pittsburgh seam gob gas (Table 1) would still leave the CO_2 specification limit for pipeline gas. In addition, the oxygen concentration would exceed that allowed and, depending on the efficiency of moisture removal by the wellhead separator, water contained in the gas may also exceed the specification limit.

Gas obtained by predrainage of coalbeds approaches the specification requirements for pipeline quality gas and can therefore be injected directly into a commercial pipeline. In cases where CO_2 content is higher than the specification allows, direct pipeline injection may be acceptable because sufficient dilution may occur in the pipeline to bring the total CO_2 level below the required 3 percent. Moisture removal may be required although the combination of wellhead water separation and pipeline dilution may suffice. Other than CO_2 and H_2O content (as typified by the Pittsburgh seam gas analysis) predrainage gas meets specifications for pipeline quality gas. Water and CO_2 removal from such gases is established technology. Water can be removed by absorption or solution processes. Solid desiccants include calcium chloride, activated alumina or "molecular sieves," generally in alternate dehydration and regeneration cycles. CO_2 removal can be accomplished by any number of systems, such as treatment with monoethanolamine (MEA) solution, carbonate-based systems, physical absorption system or molecular sieves.

A utilization system configuration for pipeline injection collects gas at the wellhead where water separators remove water contained in the gas streams. The steady-state gas pressure, measured at the wellhead, varies with time and from coalbed to coalbed. Therefore, small compressors are provided to raise the gas pressure before injecting the gases into a gathering pipeline network which accumulates the gases and feeds them into the commercial line. This system would appear to be most suitable when no upgrading is required. Should additional water and CO_2 removal be necessary, the gathering pipeline network would be used to feed central accumulator/storage tankage used to eliminate short duration fluctuation of feed rate. The gas from these surge tanks can then be used to feed the system for removal of CO_2 and/or water. Although the processes for H_2O and CO_2 removal are developed, tradeoffs and possible development problems may arise due to the small gas throughput of 1 to 2 MMCFD.

Power Generation

The fuel requirements of a gas turbine/generator unit can be met by both predrainage and gob gases. The use of gob gases is particularly attractive because need for upgrading is obviated. The combustor section of the turbine/generator can readily burn gas having as low as 50 percent methane, and can handle reasonable fluctuations in methane concentration. No pretreatment of the gases should be necessary beyond wellhead water removal and possibly filtration of the gas to prevent entry of any particulates into the turbine. Because of the low sulfur content in gob gases, no blade corrosion should occur.

The process flow for power generation using turbine/generators is as follows: gases from the wellhead are dewatered, collected into a gathering pipeline system, and then fed into accumulator/storage tanks. These tanks eliminate short-term fluctuations in flow rate, gas composition and pressure, and ensure steady flow of gas to the process system for power generation. The gases from the accumulator are subsequently compressed to approximately 150 psig and fed into the turbine combustor. The generated power is fed to an electrical distribution system which includes transformers, switchgear, and distribution system. This power could be used to operate mine equipment such as pumps, fans, lighting, etc. Alternatively, it could be collected into the mine power grid for general use or even fed into a utility grid.

Turbine/generator units are available off-the-shelf in small sizes, can be skid-mounted for mobility, and require low maintenance. Units rated as low as 800 KW are suitable for gases having production rates of approximately 1 MMCFD and have delivery times of 6-7 months. No developmental problems are anticipated in the use of turbine/generator utilization systems.

Heating Applications

Several applications are possible for using gas as a fuel to supply heat. They include coal drying, thawing of railway cars, space heating, and ventiltion air heating. The fuel requirements of burners used for these applications can be met by both predrainage and gob gases. For these applications upgrading is unnecessary beyond removal of water at the wellhead. Burners for the various heating applications can easily accommodate fuels having a methane content as low as 50 percent, and are not unduly sensitive to large variations in composition.

The utilization system would typically consist of accumulator/storage tankage required to receive and store dewatered predrainage or gob gases from the collection pipeline network. The accumulator provides adequate mixing and damping of fluctuation in production and composition, and ensures an ample reservoir of fuel supply as well. A reasonably steady gas supply from the collection network can be maintained by phasing well production and by blending of production streams. Fuel from the accumulator/storage tankage is subsequently compressed for distribution to the drying burner.

With regard to coal drying, various equipment types are used but fluidized bed dryers are the most common. For Eastern coals, these dryers typically process approximately 250 tons/hour and require some 2,300 million Btu/day. One to 2 MMCFD production of predrainage gas could not meet this requirement, much less gob gas production rates. Current drying facilities are primarily stoker-fired using middling coals as fuels. Partial conversion of these dryers to use the 1 to 2 MMCFD gas production is practicable.

LNG Production

Both gob and predrainage gases are suitable for LNG production. In the case of predrained gas, existing LNG process technology can be employed, while some modification of the air separation technology is needed for gob gases. Both predrainage and gob gases, as given for a Pittsburgh seam in Tables 1 and 2, must be treated to provide a dry stream, free of CO_2 and filtered to remove any dust.

The liquefaction of coalbed gas involves removal of its sensible and latent heats, either by using an adiabatic expansion process (the "expander" cycle) or by multi-stage mechanical refrigeration (the "cascade" and "mixed refrigerant" cycles). The expander cycle utilizes the energy produced by expansion of the gas as it passes from a high to low pressure. In an illustrative example, incoming gas at 300-400 psig and $60^{\circ}F$ is first stripped of its moisture and CO_2 content and then passed through a heat exchanger which cools it to approximately $-140^{\circ}F$. The pressure is then reduced to approximately 50 psig by passing the vapor through a single or series of compressor-loaded expander turbines, a process that reduces the temperature to approximately $-250^{\circ}F$. Part of the stream is then removed as LNG (which boils at approximately $-258^{\circ}F$ at 14.7 psig) with the remainder flowing through a heat exchanger to cool the inlet gas. Although the efficiency possible with this cycle is rather low, both capital and operating costs can be less than for other systems.

The cascade cycle typically consists of a number of compression refrigeration cycles operating at temperatures which are successively lower. Each lower temperature cycle rejects heat to the next warmer cycle. Cascade cycles have the disadvantage of requiring a large number of heat exchangers and a compressor for each stage. Because of its complexity, a high degree of ingenuity is required to keep the cost of the plant down.

The mixed refrigerant process was developed to simplify design of the compressor and piping and obviate most disadvantages of the cascade cycle. It does not require more than a single compressor. In this cycle the refrigerant is a single fluid composed of hydrocarbons and/or nitrogen which condense or evaporate continuously over the required temperature range in a single heat exchanger or series of heat exchangers. Supplemental refrigeration is also used for some applications. The nitrogen-rich inert content of the stream is removed and pure LNG is produced from the bottom of the lowest temperature heat exchanger. The nitrogen-rich stream is used for precooling the warm feed-stock. Although the power requirement for the mixed refrigerant process may rise to 20 percent higher than for the most efficient cascade system, the capital costs are notably less.

Although the LNG plant is small, certain site considerations must be reviewed. Right-of-way must be obtained for road building for truck transport to the plant site. Additionally, the plant location must be near enough to a major highway to permit easy access to the plant.

Chemical Production - Ammonia

The use of both gob gases and predrainage gases for producing ammonia has been identified as attractive from a technical point of view. For predrainage gas, the existing technology for ammonia production can be employed. For gob gases, the question of upgrading depends upon its methane concentration and the economic factors involved. The lowest methane concentration for which an ammonia plant has been designed is about 80 percent, which is very close to the average methane content of gob gas from Pittsburgh seam mines. In this instance upgrading would seem not to be required. Although methane concentrations as low as 50 percent can be handled, the heat load on the reformer increases as does cost of the plant.

Commercial plants currently are sized down to about 50 tons ammonia production per day, although in special instances plants having a capacity of 15 tons per day have been built. Assuming 2 MMCFD gas feed, the ammonia production rate would be approximately 53 and 45 tons/day for predrainage and gob feedstock respectively. If gas-engine drivers are employed in the plant the total ammonia production is reduced, respectively, to 44 and 38 tons/day. These quantities definitely place such plants within proximity of current commercial practice. For less than 2 MMCFD feed the production rates would be proportionately lower, but even at the rate of 1 MMCFD, considered the lower limit for demonstration gas production, the lowest plant capacity would still be within existing technology. It should be noted that commercial plants in the 50 ton per day range very often do not operate at design capacity due to shortage in feedstock supply or demand variation. Indeed, a plant can be run over a range of from 50 percent to 110 percent design capacity.

Water requirements for a plant are large and its availability must be considered when selecting a location site. Typically, 2,000 gallons are required for each ton of ammonia produced. Assuming a 45 ton per day plant, 90,000 gal./day would be required at the site. Of this, approximately 10 percent is process water for steam production, the balance being used for cooling. Air cooling can be used to partially offset this requirement, but it has disadvantages such as large equipment, high costs, and a reduced plant efficiency of approximately five percentage points.

Although a 45 ton/day plant would occupy a large plot area and contains extensive equipment, it can be skid-mounted for portability. Modularization would be essential, however, with each module separately skid-mounted. The design and construction of such a plant does not represent any development problems as the technology of ammonia production is well in hand. Some ingenuity in design will be required to ensure efficient production from a relatively small (by commercial standards) capacity plant and to provide the required modularity for portability, but basically no new technology is involved.

A typical installation would receive dewatered gas from the gathering pipeline network into accumulator tanks for the purposes of providing adequate mixing and eliminating short duration fluctuations. The resultant ammonia plant feed will be reasonably uniform in supply and composition. The overall supply and composition can be controlled by the phasing and blending of gas production from the well. Gas from the accumulator is subsequently compressed and fed into the gas treatment module of the ammonia plant.

The product ammonia can be stored at the site in cryogenic tanks in anhydrous form. Vapors are compressed, cooled and recycled back. Alternatively, ammonia may be stored in pressurized bullets and transported directly.

The plant is envisioned to be automated, thereby typically requiring only two operators per shift to monitor its operation and record data. In addition, one maintenance craftsman and one supervisor will be required, bringing the total complement to 10 for full-time round-the-clock operation.

Certain site requirements must receive careful considerations. The necessity of water availability has already been mentioned. Right-of-way for a road suitable for truck transport must be obtained. The plant location must also be near a major highway to permit easy access to the site.

Chemical Production - Methanol

The minimum size for a conventional methanol plant is 100-150 tons of methanol per day (315,000-470,000 scf/d methane feed). This is due primarily to the fact that below this capacity, centrifugal compressors are uneconomic and capital costs become such a large part of the product cost that even "free" methane may not be enough to make the plant profitable. Gas production from coal mine seams is generally between 500,000 and 1,000,000 scf/d. In cases where the gas production rate is low and the methane content of the gas is low, the methane feed to the plant may be too low to keep the methanol plant above the "minimum" size of 100-150 tons per day.

It should be noted that the gas from coal mine degasification can contain a large fraction of inerts with nitrogen as the primary component. This is a problem because the inerts are diluents which reduce the partial pressure of the reactants and decrease the already low conversion per pass. A high concentration of inerts would be unacceptable in a conventional methanol plant and would have to be removed from the feed gas. This could be a costly step depending on the amount of inerts in the gas.

In a conventional methonal plant, methane is steam reformed to CO and H_2 at 250 psi and the synthesis gas is then catalytically converted to methanol between 1,500 and 3,000 psi. Coal seam methane is at atmospheric pressure and would have to be compressed for the reforming step. This is normally not needed in conventional methanol plants where the feed gas is already at pressure. Some cost penalty would have to be assessed for this extra compression for the coal seam methane case.

Since the gas supply for a coal mine seam is not long term, the portability of the "plant" must be considered. Methanol plant equipment is generally too large to be transported by truck but transportation of "temporary" plants by rail might be possible. Many coal mines have rail lines close by so that only a spur would be needed if the plant were located near an active mine. The practicality of such a temporary plant would depend primarily on the amount of gas available at any given source.

In summary, the viability for using methane from coal seam degasification as a feed for methanol plants depends on a number of factors including: gas cost, gas production rate, long term gas supply and concentration of methane in the gas. Transportation costs and plant proximity to methanol markets are other factors to be considered. In certain cases methanol production may be an attractive option but no general statement can be made about the economic viability. An analysis would have to be done on a case-by-case basis.

ECONOMICS OF UTILIZATION

Methane contained in most deep coalbeds in the Eastern United States may be recovered economically (20 percent ROI) at the currently regulated price of $1.50/MCF by using the horizontal boreholes established by directional (slant) hole drilling technology. When using the stimulated vertical well technology, gas may be recovered economically from deeper, gasier coalbeds with the specific economics highly dependent upon cost of the wells. Recovering gas in the Pittsburgh bed, shallower parts of the Mary Lee bed, and in parts of the Beckley bed, will generally require that the degasification process also result in moderate coal mining cost savings. For the Pittsburgh bed, the required savings would be about $.50/ton for room-and-pillar mining methods and about $.30/ton for longwall methods.

The projected cost of establishing and operating the pipeline connecting the degasification boreholes to a commercial pipeline ranges from about 10 to 50 cents per MCF, depending upon distance to the pipeline and the necessity to remove the CO_2 from the gas before sale. When such pipelines are impractical, the gas may be converted economically to LNG or ammonia for the size of projected plants required, with the ammonia plant being applicable to the larger mines (2 MMCFD) or to combinations of adjacent smaller mines.

When considered as a separate system, gob gases may be collected for economical use in local heating and power generation applications, depending upon the specific siting factors. When considered as a part of a total system to recover gas in the virgin coal, wherein the well is used both for draining the coal seam and for removal of the gob gases, these gases may be converted econmically to LNG.

The differences previously described require that a very careful selection of subsystems be made for each proposed site under consideration for methane drainage and utilization. It is believed that sufficient options are available so that a combination of subsystems offering favorable economics is possible for any mine in the country.

The projected rates of return (before taxes) for typical large system configurations (using 2 MMCFD of gas from the virgin coal or 2 MMCFD of gob gas) located at mines in the Pittsburgh Seam are summarized in Table 3 and the parameters used in making economic analyses and projections are summarized in Table 4. In general, for the same product market values, the investment rates of return will be somewhat less for smaller systems. The most sensitive of the configurations are those using the ammonia plants which are not considered practical for sizes less than 2 MMCFD gas capacity for the projected market price of $100/ton for ammonia. When used, the ammonia plant should be configured to use a combination of the gob gases and the gas drained from the virgin coal.

As the market value of the gas or products are considered volatile and highly area dependent, and since specific piping distances required will vary from mine to mine, the rates of return that are indicated are considered to represent nominal values but not necessarily typical for any specific mines.

CURRENT DOE UTILIZATION PROGRAM

The DOE Fossil Energy Program includes a Coalbed Methane Program with the overall objective of promoting the recovery and utilization of methane from coalbeds. The princiipal thrusts of the Coalbed Methane Program are:

- Location and characterization of the resource
- Development of improved recovery and utilization technology
- Demonstration of the technical and economic viability of selected recovery and utilization options
- Establishment of the benefits of methane drainage on mining safety and productivity
- Transfer of technical and economic information to industry.

Through this program, the DOE expects to reduce the loss of the coalbed methane resource and to augment conventional supplies of gaseous fuels.

Gas Supply
Predrainage Gas

	Average	Range	Avg. Var.
CH_4	90.7%	84.4 - 95.9%	$\pm$ 0.8 %
C_2H_6	0.3	0.04 - 1.1	$\pm$ 0.06
CO_2	8.2	2.5 - 14.8	$\pm$ 0.76
O_2	0.2	0.04 - 0.5	$\pm$ 0.1
N_2	0.6	0.05 - 1.2	$\pm$ 0.36

TABLE 1

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Gas Supply
GOB Gas

	Average	Range
CH_4	77.1%	37.3 - 98.1%
C_2H_6	0.4	0.02 - 0.8
CO_2	3.4	0.03 - 8.6
O_2	1.2	0.09 - 3.4
N_2	17.8	0.7 - 55.3
Other*	0.1	Trace - 0.7

*Propane,Butane,1-Butane -Trace to 0.7 Total
H_2S,CH_3HS - >1.5 PPM Total

TABLE 2

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Economic Projections

Percent Rate of Return on Investment Before Tax

	Stimulated Vertical Boreholes	Horizontal Boreholes-Deviated Boreholes	Horizontal Boreholes-Vent Shafts'	Vertical Boreholes to GOB Area	Unified System for GOB Gas Collection
Direct Sale of Gas	26	58	26	—	—
LNG	24	47	24	21	39
Ammonia	20	33	20	10	17
Power Generation	—	—	—	15	120
Space Heat	26	58	26	222	530
Coal Drying	—	—	—	74	273
Gas Vented to Atmosphere	11	33	11	100	—

TABLE 3

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Parameters Used for Economic Projections

Coal Mining Cost Savings[1]		$1.00/Ton
95% Methane Market Value		$1.50/MMBTU
LNG Market Value		$2.50/MMBTU
Ammonia Market Value		$100/Ton
Electrical Power Value		20 Mills/KWH
Space Heat Value		$1.50/MMBTU
Coal Drying Value		$ .40/MMBTU
Room & Pillar Mining — 2 Million Tons/Year		
Virgin Coal Area Drained/Borehole - Acres		
Stimulated Vertical Boreholes	— 8.3	
Horizontal Boreholes-Deviated	— 115	
Horizontal Boreholes-Vent Shaft	— 230	
Coal Recovered /Borehole - 1000 Tons		
Stimulated Vertical Boreholes	— 51	
Horizontal Boreholes-Deviated	— 706	
Horizontal Boreholes-Vent Shaft	— 1432	
Gas Recovery Rate		
Virgin Coal		2 MMCFD
GOB Gas		2 MMCFD

[1]Savings for Predrainage: $.25/Ton for GOB Gas Removal

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TABLE 4

THE STATE'S FORECAST FOR GAS DEMAND NEEDED IN THE FUTURE
AND
HOW METHANE IS EXPECTED TO MEET THIS DEMAND

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THE STATE'S FORECAST FOR GAS DEMAND NEEDED IN THE FUTURE AND HOW METHANE IS EXPECTED TO MEET THIS DEMAND

Within the Commonwealth of Pennsylvania our energy consumption pattern is made up of the following:

COAL -----------45%
PETROLEUM ------34%
NATURAL GAS ----17%
NUCLEAR & HYDRO- 4%

Even though the Commonwealth only depends upon 17% of its energy from natural gas, it differs from region to region. For example, 95% of the homes in the Pittsburgh area rely on natural gas for their heating needs.

Natural gas consumption in Pennsylvania had increased by 57% from 1960 to 1972, but since 1972 has been curtailed due to supplies reduced by 22%. In Pennsylvania, five major interstate pipelines provide 87% of the state's natural gas. These interstate pipeline companies sell their gas to distribution companies which in turn supply consumers. Approximately 99% of all gas sold within Pennsylvania comes from the 12 largest distribution companies.

In 1975 Pennsylvania's total gas consumption was 653.7 BCF, of which 42% was residential, 15% commercial, and 42% industrial. In 1976, Pennsylvania's total gas consumption was 665.3 BCF with the projected total gas consumption for 1977 being 658.5 BCF, and 652.7 BCF projected for both 78 and 79.

Residential customers throughout the Commonwealth of Pennsylvania consumed more natural gas during the 76-77 heating season than all other combined sectors. Eastern residentials used 84.2 BCF versus 45.5 BCF for commercial/industrial sectors. In the west residential customers used 142.4 BCF versus 116.3 BCF for commercial/industrial.

During the 76-77 heating season the industrial customers bore the largest share of gas curtailments. A gas curtailment of 51.0 BCF was applied to industrial customers out of the total 54.8 BCF curtailment for the Commonwealth of Pennsylvania.

Projections for the 77-78 heating season indicates a decrease in the % rate of curtailments by 28% in the east and 68% in the west of the Commonwealth. However, it is also projected that our total requirement of gas for the heating season will be less by 27.8 BCF. These lower requirements are attributable to smaller residential heat loads as a result of energy conservation and the weather forecast.

So, with all these projections of natural gas consumption and curtailments to industry and commercial facilities where does methane gas fit in? Well, it is the policy of the Governor's Energy Council to promote the conversion of natural gas end-users to alternate sources of energy where economically and technologically possible. Some of the types of alternate sources of energy we are promoting are direct coal combustion, coal gasification and the use of Methane Gas.

Coal gasification and coal combustion technology are well proven and can readily be implemented in industry. However, methane gas does not presently share that status, but in my opinion it soon will.

Today we have a great deal of interest in the development of methane gas from coal seams. We have to thank individuals such as Maurice Deul and Robert Stefanko for the work they have done which has led to this industry/government interest. I believe we are on the threshold of a new industry developing hand-in-hand with the coal and gas industries for the development of methane gas. I feel this is possible if we can work out some of the man-madeinstitutional problems simultaneously as we prove the commercial technology for methane gas, as we are presently doing at the Westinghouse-Bethlehem Mines Corporation project at Ebensburg, Pennsylvania.

In summary, I just would like to say the future of methane gas technology and end use in Pennsylvania looks very favorable. However, I don't see methane playing any real significant role in supplementing our natural gas needs for at least the next 5 years.

Nevertheless, I would like to assure you that our five (5) state committees as well as our individual states will continue to promote methane development from coal seams. Mr. Ron Potesta, our West Virginia Representative on the MDCC, will provide some general information on our committee's activities during his presentation.

I would like to conclude my remarks by making an analogy of methane gas to my son, whom I talk about all the time if you know me. When Brad was begining to walk, he had a difficult time in getting started; he even fell on his backside a few times, but once he found his balance and took that first step, it wasn't long before he was off and running I think we can say the same thing about methane gas from coal seams development.

THANK YOU.

WEST VIRGINIA METHANE PRESENTATION

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ABSTRACT

With the progressive action taken thus far by the Department of Energy in methane recovery and utilization, the Methane Development Conservation Committee feels that the future is brighter than ever for methane commercialization. However, we also find an element of discontinuity in the DOE program. The Bureau of Mines originally instigated its study of methane gas to help alleviate the safety problems associated with mining gaseous areas. It was soon realized that the dual goals of both safety and conservation could be served if the gas drained to aid in the safe production of coal could also be utilized as a supplemental fuel. It was this purpose that stimulated such a high interest from the Appalachian states which belong to the Committee. Now, we find that the DOE is directing a portion (how much has not been stated) of its methane recovery effort to determining the potential capabilities of draining methane gas from unmineable coal seams.

At a time when the nation is relying more and more on coal from all coal producing areas, it seems incomprehensible why the greatest portion, if not all, of the revenue devoted towards methane recovery would not be in conjunction with normal mining operations. West Virginia and all underground coal producing states deserve a justification of these new methane recovery initiatives that are not associated with coal production.

The Committee realizes that certain issues must be resolved simultaneously as a methane recovery/utilization program develops. Some of these issues are:

1. Legal interpretation of methane gas ownership;

2. Federal Energy Regulatory Commission (FERC) natural gas regulation of methane gas; and

3. Pipeline rights-of-way.

Good afternoon. It is a pleasure to be on the agenda today among such a distinguished group of experts. It is the relatively small size, though, of this group that concerns me, particularly when one considers that the U. S. Bureau of Mines initiated their methane recovery program at least 13 years ago. The good word is simply not spreading as rapidly or extensively as we feel it should.

You have heard very knowledgeable testimony concerning the technological feasibility of methane recovery and also of the pressing national need to develop supplementary sources of natural gas. Still, we have yet to see any strong commitment on the part of the nation as a whole to begin to utilize methane gas from coal seams.

Dennis Seipp's presentation of Pennsylvania's historical and future natural gas demands and the known and expected curtailments of those demands is a situation shared and reiterated in many of the states, West Virginia being one of them.

To additionally complicate the problem, a recent report by the Department of Energy, "1977 - 1978 Heating Season, Projected Natural Gas Curtailments and Potential Needs for Additional Alternate Fuels" estimates that, given a colder than normal winter, this area of the country could experience shortages of propane and other alternate fuels. Concerned about this problem of alternate fuel shortages at an early stage, the West Virginia Legislature funded a study to investigate the feasibility of converting public buildings from natural gas to coal usage. This feasibility study was performed by the West Virginia University College of Engineering. The results are now in and they are not favorable. The study showed that, due to the necessary redesigning of boilers and recent increases in coal prices, such a conversion of public buildings is not economically desirable.

We knew beforehand of the scarcity of petroleum-derived alternate fuels, but there was always the prevailing thought that West Virginia's abundant coal supplies could, in some way, be directly utilized as a natural gas substitute. Although the direct combustion of coal may not hold the answer, coal, itself, represents the reservoir from which the very viable supplemental fuel, methane gas, could flow. I might add here that the first methane recovery/utilization program to be demonstrated in the United States was by Eastern Associated Coal Company in northern West Virginia.

The Methane Development Conservation Committee was formed in April of 1976 to prosper the commercial development of methane gas. The Committee, consisting of the States of Pennsylvania, West Virginia, Kentucky, Ohio and Virginia, lobbied for the adoption of a national methane conservation plan.

The plan was envisioned having at least the following elements: 1. A research/development program for the economic recovery and utilization of methane gas from coal seams which would include both a data collection and an R & D technological development section; 2. A technological development program on recovery techniques based on the substantial experience of the Bureau of Mines; 3. Demonstration for commercial use of methane gas from coal seams including a performance assessment of the overall program.

In testimony before the U. S. House of Representatives' Subcommittee on Energy, Research and Demonstration, the Methane Committee stated its opinion that techniques and new technologies either now in existence or which can be developed, will allow collection of this valuable resource and simultaneously improve mine safety and increase coal production.

With the progressive action taken thus far by DOE in methane recovery and utilization, we feel that the future is brighter than ever for methane commercialization. However, we also find an element of discontinuity in the DOE program. The Bureau of Mines originally instigated its study of methane gas to help alleviate the safety problems associated with mining gaseous areas. It was soon realized that the dual goals of both safety and conservation could be served if the gas drained to aid in the safe production of coal could also be utilized as a supplemental fuel. It was this purpose that stimulated such a high interest from the Appalachian states which belong to the MDCC. Now, we find that the DOE is directing a portion (how much has not been stated) of its methane recovery effort to determining the potential capabilities of draining methane gas from unmineable coal seams.

At a time when the nation is relying more and more on coal from all coal producing areas, it seems incomprehensible why the greatest portion, if not all, of the revenue devoted towards methane recovery would not be in conjunction with normal mining operations. West Virginia and all underground coal producing states deserve a justification of these new methane recovery initiatives that are not associated with coal production.

The Committee realizes that certain issues must be resolved simultaneously as a methane recovery/utilization program develops. Some of these issues are:

1. Legal interpretation of methane gas ownership;

2. Federal Energy Regulatory Commission (FERC) natural gas regulation of methane gas; and

3. Pipeline rights-of-way.

We feel these issues can be resolved since they are man-made problems and, therefore, manageable. The Committee has already begun deliberation on these issues and is willing to work with all interested parties in resolving them.

Dennis and I will now attempt to answer any questions you may have.

Thank you.

METHANE RECOVERY AND THE REGION III OFFICE

by

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ABOUT THE AUTHOR

Tony Pontello is a graduate engineer of Pennsylvania Military College and holds a Master's degree (MBA) from Widener College. In addition to his degrees, he has received certificates of instruction in lasers, holography, statistical analysis, solid waste management, and infrared thermography. He also attended, and completed, a management program at the Middle Management Institute. Mr. Pontello belongs to several technical organizations including membership to their various committees.

Mr. Pontello has presented and published a number of technical papers related to research, development, testing, and evaluation of: fuels derived from coal, shale, and tar sands; oils, fuel service problems, fuel handling and filtration equipment, effects of additives in fuels, fuel reclamation, oil/waste pollution abatement equipment, energy conservation, and resource development. The highlights of these publications were the selection of two of his papers for presentation at the 1971 and 1972 NATO meeting in Brussels, Belgium. In 1973, Mr. Pontello was selected as one of only two authors, chosen from the United States, to present a paper on nondestructive testing of fuel filtration equipment in Warsaw, Poland. His work has been cited in a hard-back book, Practical Applications of Infrared Techniques, by Dr. Vanzetti. Also, Mr. Pontello had a technical article on synthetic fuels published in a British journal in 1976 and an article on energy conservation (covering the results of tests he performed in Philadelphia) was published in a United States technical publication in 1977.

Mr. Pontello holds several patents in the areas described above.

Tony Pontello was selected by the Federal Energy Administration, Region III, in 1976, as their nominee for the national "William Pecora" award sponsored jointly by the Department of Interior and the National Aeronautics and Space Administration (NASA).

Prior to joining FEA, Mr. Pontello was employed by the Navy and worked in the area of research and development.

INTRODUCTION

Planning, organization, direction, monetary assistance, public communications, visibility, and application of developed energy resources are the functions of an energy coordinator. An energy coordinator may be defined as one who combines into a harmonious relation or action, the results of research and development and arranges these results in due order or proper relative position so as to obtain the maximum benefits possible.

Region III of the Department of Energy can serve this role as an energy coordinator for enhancing methane recovery. Region III is populated by more than 24 million people living in the states of Pennsylvania, Maryland, Delaware, Virginia, West Virginia, and the District of Columbia. To gauge the impact of any national energy policy on the nation, measure its impact on Region III. Coal, natural gas, offshore drilling and a heavy nuclear energy commitment comprise the energy portrait within the region.

About two-thirds of the U. S. coal reserves, and therefore, methane from coal, is in the West. The remainder is in the Appalachian region of the eastern U. S. However, the eastern methane may be more significant in the near-term since it is in a region which is highly dependent on natural gas for its industries, but which is subject to shortages and interruptions in the pipeline supply. A closer look at this region's energy resources is quite revealing. Over one-third of the coal produced in this country is produced in the five-state area comprising Region III. Over one-quarter of our nation's oil refinery capacity is found within our region. However, just as important as what is produced now is what is capable of being produced in the future. Coal is this region's most abundant energy resource.

Region III is a large consumer as well as a large producer of energy. Over 12% of the nation's energy is consumed in this region. But of more significance than total consumption figures is the region's consumption of scarce domestic fossil fuels.

Transportation alone accounts for over half of the petroleum usage in Region III. Industrial use accounts for another 14%. Natural gas, while primarily used for heating homes, is still used in large amounts by industry. Finally, the industrial and commercial sectors account for 24% of the petroleum used in Region III and 53% of the natural gas. Clearly, effective conservation measures in these sectors can prolong the availability of these scarce fuels.

Region III encompasses a geographical area containing many energy resources. One of the region's abundant and valuable resources is methane. To facilitate the development, production and utilization of methane gas requires the cooperation and coordination of all the principals involved in this energy making process.

REGIONAL METHANE POTENTIAL

The coal reserves in Region III are estimated at 174,458 million tons. Assuming on the average, there is about 200 cubic feet of methane per ton of coal, the associated methane with these reserves is estimated at approximately 35 trillion cubic feet. If the current regional natural gas consumption rate averages 424,068 million cubic feet per year, there would be enough methane gas available for the next 82 years in Region III. Even if only 30 percent of the coal was recovered, methane would be available for approximately 25 years.

In West Virginia alone, the coal reserves are estimated at 100,150 million tons. Based on West Virginia's 1975 natural gas consumption rate of 194,395 million cubic feet, there is enough methane available for 103 years. If only 30 percent of the coal is recovered, there still would be enough methane gas for approximately 31 years. In Pennsylvania, where coal reserves are estimated at 63,940 million tons, the natural gas consumption rate was 653,742 million cubic feet. Based on this consumption figure, and the quantity of coal reserves, in a highly industrialized state, there is enough methane available for approximately 20 years. With the quantity of potential methane available in Region III, exploration and production are attractive incentives for waiting markets.

Planning:

Region's III role in the planning stage of methane recovery can be to ascertain, through an information survey, what development programs are being undertaken by government, industry and universities and organize the results of these programs into a framework designed to provide accessible information for those participants engaged in fostering methane gas utilization.

The information survey would consist of collecting technical reports, publications, news articles, and related articles on methane recovery from coalbeds, reviewing and analyzing the gathered information and cataloging the end results by finished product and subject titles. As an energy coordinator Region III would lend itself to assisting on the preparation of plans for methane researchers by pointing out what areas in methane recovery need to be explored as a result of the information survey.

Organization:

In the area of organization, Region III can develop a structural system capable of directing the results of methane research centers and related activities, and answer the most relevant questions frequently asked by potential end-users. These people must be assured of continued exploration in methane development and refinement of processes so that utilization, when initiated, will not be interrupted due to technological, supply, or governmental constraints.

Some of the questions that must be answered include: the progress made in methane recovery during the past three years; approximate number of demonstration plants, in operation, for recovering methane gas from coalbeds; expected time-table, for bringing on-line successful demonstration plants; success ratio between methane recovered from bituminous mines versus anthracite mines, venting systems of existing mines versus unopened mines; practicality of utilizing methane gas now as a limited replacement for natural gas currently being utilized in industry; quality of methane gas derived from venting systems, unopened mines, gob areas, and other sources of methane extraction; what constraints other than financial have limited production of methane (have these constraints been identified and can they be resolved?) and what alternatives in recent methane gas development offer the most advantageous method in advancing utilization.

Coordination:

As an energy coordinator, Region III's role could be expanded, not only to give visibility to new developments in methane recovery, but to coordinate the state's and industry plans for utilizing methane gas and their forecast for future gas supplies needed to spur economic growth. In order to meet future demands and enhance utilization Region III's role will be to organize committees, by state, to meet at scheduled dates and present results of the states progress in methane recovery, their methods of publicizing utilization and what incentives they plan to offer for encouraging increased production of methane gas. The regional office would also organize workshops, in conjunction with experts in the field of methane, to train and advise local, state and federal personnel how to chart methane gas availability, number of producers and suppliers, methane quality, new and/or closing of demonstration plants, and report any other pertinent information needed to keep abreast of new technology in methane gas development.

Community Involvement:

In teaming with the states and industry, Region III's expanded role would be to assist in energy planning for community needs. Communities themselves can plan together to avoid future energy crises by de-emphasizing petroleum-based fuel sources and concentrating their efforts towards enhancing methane utilization. With assistance from Region III, a concept of integrated community energy systems planning can be developed to locate new residential homes and industrial parks in areas rich with methane gas potential. The location of such energy community parks in methane gas territory would minimize gas transportation costs, and possibly consumer costs, ensure adequate supplies of a resource, encourage industry relocation to coal mining areas where coal could possibly serve as a secondary energy source in the event methane gas was used mainly for home consumption, and finally, with new industry, revitalize social and economic development in the coal regions where methane gas exists.

Fiscal Responsibility:

To continue methane gas exploration and research, develop methodologies for enhancing methane utilization, and stimulate methane commercialization, requires large amounts of money. It is within the framework of the Department of Energy that the regional office could best serve this purpose by acting as a catalyst in expediting federal monies, where available, to those sources engaged in methane gas activities. With the Regional Office directing their efforts towards monitoring of contracts concerning methane development, duplication of effort could be avoided, wide scale publicity given to new developments in methane recovery-as received from periodic reviews of programs, and data collection could be facilitated for developing both trend and annual forecasts for methane utilization.

An additional role that the Regional Office could undertake in methane recovery includes the role of a symposium originator where states, federal agencies, and industry are solicited for ideas that are oriented towards initiating methane end-use utilization. These ideas would be grouped together and presented at a symposium for optimum visibility. This type of a symposium would differ from those kind of seminars which report on strictly technical informative type results. The symposium must be action oriented and aimed at motivating increased production of methane recovery. No symposium on methane development can be complete without following up the results by sampling the community reactions, responses, and initiatives. It is this latter action that constitutes the responsibility of the regional office.

CONCLUSIONS

The role of the region will, and can, continue to play an important part in shaping the characteristics of methane gas development, production and utilization. Using its legislative education, gained during the formative years of the energy crisis, the region could review legislative bills aimed at "speeding" up methane recovery and make recommendations and prepare testimony for their inception.

In summary, it can be stated that the objective of the Regional Office, of the Department of Energy, is to foster meaningful actions in the commercialization of methane gas. It is <u>not</u> the intent of the Regional Office to interfere, retard, hinder, or delay research and production of methane projects undertaken by private industry and other government agencies. It is in fact, essential that the regional office, industry, and state and local government rely on teamwork to bridge the gap between what has been accomplished in research and development and how best to "sell" these results to the consumer for increasing utilization.

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SUMMARY REMARKS

by

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ABOUT THE AUTHOR

Leo A. Schrider is the Assistant Director, Oil, Gas, and In Situ Coal Division at the Morgantown Energy Research Center. He received his B.S. degree in petroleum engineering from the University of Pittsburgh in 1962. Subsequent post graduate work has been completed in operations research at West Virginia University. After graduating in 1962, he was employed by Shell Oil Company in southern Louisiana as an exploitation engineer. In 1964 he joined the staff of the Bureau of Mines, Morgantown Energy Research Center, as petroleum research engineer. He worked in this capacity for several years and became project leader for the project titled, "Susceptibility of Eastern U.S. Oil Reservoirs to Newer Recovery Techniques." In 1973 he transferred to the Laramie Energy Research Center as the program manager for the Underground Coal Gasification program being conducted by the U.S. Bureau of Mines. He managed the reserach and technology development for the in situ coal gasification experiments being conducted near Hanna, Wyoming. In July 1976, he transferred back to Morgantown to assume his present duties.

I 'd like to summarize some of the important points that have been made today be our speakers.

The overall program of the Department of Energy for Coalbed Methane Recovery was explained by Mr. Pitrolo at our luncheon. I'd like to reemphasize a few of the points that he made during his talk. The Department of Energy has underway a research, development, and demonstration program that is focused on four unconventional gas resources. One of these areas is represented by the Methane from Coalbeds Program.

METHANE FROM COALBEDS PROGRAM EMPHASIS

- NEAR-TERM GOAL
  - -PROVIDE GAS ENERGY FROM COAL TO CONSUMERS
- MAJOR OBJECTIVE
  - -DEMONSTRATE TECHNICAL AND ECONOMIC VIABILITY OF RECOVERING AND UTILIZING COALBED METHANE
- STRATEGY
  - -NEAR-TERM, LOW-RISK, COST-SHARED PROJECTS
  - -PROGRAM INTEGRATION
  - -CONCENTRATION ON CONSERVING WASTED RESOURCE

Vu-Graph 1

The near-term goal of the Methane from Coalbeds Program is to provide gas energy from coal to consumers. This is important, first, because gas and other forms of energy are needed, particularly in this region, and second, the gas that is currently being released during or in advance of mining is being wasted. The primary objectives of the DOE program is to demonstrate the technical and economical viability of recovering and utilizing coalbed methane. The purpose is to develop the information and confidence industry needs to commercialize these technologies. If the technology is viable and is not commercialized, then we have missed a unique opportunity which is unlikely to come along again.

To stimulate this industrial interest, we are fielding near-term, low-risk, cost-shared projects using currently available technology to develop the information we feel is needed to provide the confidence that industry will require prior to commercialization. The role we see the government adopting in this technology area is to catalyze the R&D activities in order that the transfer to Industry will be swift. The risks are high; however, the projects are designed to answer technology issues in a meaningful way for ultimate industrial implementation. We are depending on cooperative industry partners with a sufficient number of coalbeds to define projects using a number of production technologies and conversion or utilization options to satisfy most requirements which will be found in the commercial world.

As another point of our strategy, we are depending on program integration which allows us to quickly identify requirements for additional efforts, to get them underway, and to provide the technology transfer to industry.

METHANE FROM COALBEDS PROGRAM

- IMPLEMENTATION
  - WESTINGHOUSE PROJECTS
  - TRW - ADDITIONAL PROJECTS
  - PROPOSALS ON UNMINEABLE COAL DUE JANUARY 23

Vu-Graph 2

As shown on the next chart, our coal resource is extremely vast. Mineable coal in general represents 10-15 percent of the coal resource while unmineable coal is 85-90 percent of the coal resource. Also shown is the fact that most of the dollars spent by the DOE are in the utilization of the methane prior to mining the coal. Mr. Duel explained that the Bureau of Mines has focused their efforts on the removal of gas from coalbeds to enhance production and to reduce hazardous emissions during mining.

This work has been underway for over ten years, and is still functioning as part of the Government's overall effort.

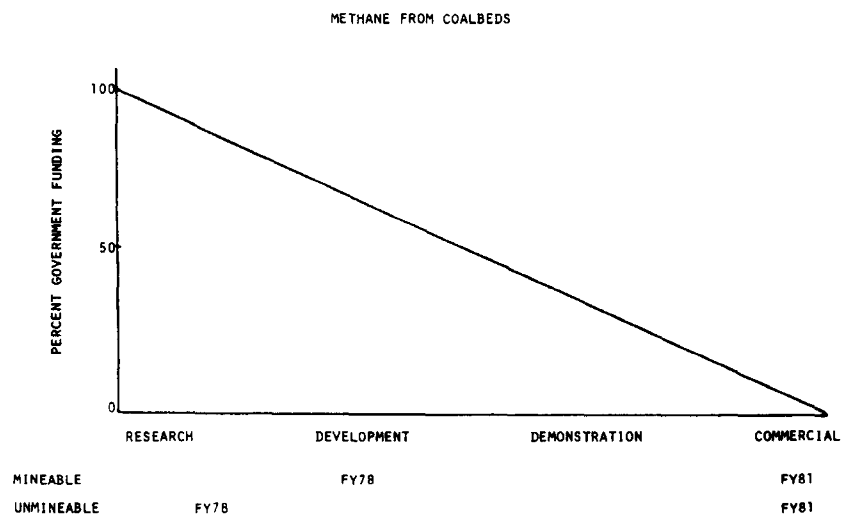
FY78 RESOURCE ALLOCATION

COAL		METHANE PROGRAM
4.2 TRILLION TONS RESOURCE IN PLACE		APPROX. BUDGET $5.0M
MINEABLE	10-15% OF RESOURCE	70%
UNMINEABLE	85-90% OF RESOURCE	30%

Vu-Graph 3

Westinghouse, represented today by Carl Sturgill, is ready to go on one project in Ebensburg, Pennsylvania, and is negotiating another with DOE. Other programs are being defined and selected by TRW. Proposals for identifying the unmineable sources are due later this month.

The Methane from Coalbeds Program is utilizing the same basic approach as other fossil energy programs to move technologies into commercialization as shown in the next vu-graph.



Vu-Graph 4

Funding for research efforts generally is 100 percent Government funded. Industry often contributes toward development efforts and is expected to support demonstration in a significant manner. At the present time, we feel the mineable coal aspect of our program is sufficiently advanced to encourage participation by industry in demonstrations. The unmineable coal activities are just getting underway but we expect them to advance more quickly since they do not require close coordination with mining efforts. Hopefully the next few years will lead to many projects becoming commercial.

Well, where do we go from here?

The problem, particularly here, is that gas is needed. This is both a regional and a national problem. In our opinion, coalbed methane can be an important part of the solution, which leads us to a second problem. Generally, industry is not developing the coalbed methane resource. Edward West pointed out the concerns of the coal industry and Harvey Price, the initial enthusiasm of some oil and gas companies. All are important. All must be addressed to allow industry to make coalbed methane recovery a normal part of their activities. Jorgen Birkeland described some of the institutional problems that are associated with the coalbed methane resource while Bob Stefanko, Joe Pasini, Ann Kim, and Karl Bastress addressed the R&D and utilization aspects. All must be addressed in the DOE program to ensure industry that the problems don't outweigh the benefits in recovery of this gas. William Kaplan and Ron Potesta mentioned some further federal and state concerns. These, too, must be addressed.

What is "the next step"? The DOE program contains many of the elements necessary in our opinion to recovering and utilizing coalbed methane.

"The next step" is obtaining the cooperation from industry to fielding both a sufficient number and sufficient scope of projects to be sufficiently representative of the possible commercial applications. "The next step" also includes public support for the Methane From Coalbeds Program from institutions, associations, committees, and other organizations interested in the development of this resource and its application to providing industry, commercial, and residential energy users with various forms of coalbed methane derived energy. The public can help in defining requirements for various forms of energy and identifying various locations for tests. They can encourage industrial support and they can provide support to related efforts, for example, legal studies directed at the question of gas ownership in all of the states of interest. We, of the Department of Energy, are looking forward and working towards, "the next step."

I'd like to take this opportunity to once again thank our moderators and our speakers for a fine program today and would like to know if there are any further questions.

SPEAKER: MAURICE DEUL

QUESTION: (Harvey Price) Do you think the legal issue regarding the ownership of gas and coal is part of the detriment of why some of this gas has not been sold today?

ANSWER: I really don't know, Harvey, that might be it for research efforts where people are very much concerned about getting the rights to the surface and to the coalbed gas so that there won't be any litigation in terms of pilot programs. I know we're faced with that all the time. But as an opinion, and that's all I can give you and that's all that any attorney or judge will give you until a suit is brought. But as an opinion, it's my feeling that where there is a profit to be made, where gas is to be produced and sold, where there are royalties to be paid, people who are businessmen can come to agreements. I think reasonable people can come to agreements. And if you are dealing with unreasonable people, it doesn't matter what the situation is, you're not going to be able to come to an agreement. So I would hope that litigation is brought so that it can be decided once and for all that any of us who have been concerned with legal actions known that one case doesn't do anything but set a precedent; that doesn't necessarily mean that it is going to be the same situation in every State of the Union. I don't believe that where people have a will to produce gas used as technology and the expertise of land and lease people to go out and get leases to develop farm out agreements, to unitize properties that this would be a problem. It is just a matter of getting the right people to do the job.

QUESTION: In your opinion, are the reserves adequately described that it would cover the economic cost of the compresser stages in the pipelines necessary?

ANSWER: For certain coalbeds it is. I don't think anyone should go into the deep Pittsburgh coalbeds to drain gas without being prepared immediately to produce that gas. Similar situations exist in certain other coalbeds in the country. I think deep Harshhorn is one like that. I think the Beckley coalbed is probably a similar situation, but now let's get down to a discussion of technology. I'm a strong advocate of non-conventional methods of producing gas from non-conventional sources. We are used to putting down a vertical well to a gas field to a gas horizon and producing gas by stimulation or not. Coalbeds are tabular deposits. It's not very effective or efficient to drill a vertical hole into a coalbed where the producing zone is only five or at most 10 feet thick. It's a hell of a lot easier to put a horizontal hole in, maybe someday to be able to develop a slant hole and be in thousands of feet of producing zone. But this is where a good sharp pencil, a few facts and some conservative thinking would apply as to whether the venture should be developed. If the coalbed is going to be mined, certainly if it's a gassy coalbed that gas will be wasted and this is a problem these days. Every coalbed that is going to be mined will lose it's gas. When you drill a hole into a coalbed that's going to be mined you don't have the option of capping that well and waiting. Waiting for investors, waiting for the right market, waiting for the right moment, when you've got all of these complex variables to put together, and you drill a hole into a coalbed, you've got to produce gas. You have to produce the gas because you want to mine that coal safely. And that's, of course, the main basis as to why the Bureau of Mines got involved in these compensation problems and until six years ago nobody gave a damm what happened to that gas. We could hardly give it away.

SPEAKER: JOE PASINI

QUESTION: You mentioned that you saw the future of gas production from unminable coalbeds. I don't see what different problems you are going to have with unminable coalbed gas than you have with gas in minable coalbed gas?

ANSWER: The Uniontown paper I picked up had a little clipping about a legal battle, now being instituted over the drilling of wells into the Pittsburgh coalbed. I'm not sure of all the particulars. These things will be coming up left and right and there is a great difference (between minable and unminable). Mining companies in a lot of areas can't lay a pipeline five feet outside their present right-of-way associated with the mining operation because they can't get the right-of-way. We've been told many times that the relationship between the landowners and the mining companies is kind of ferocious in a lot of areas.

QUESTION: Well, how does this check with the unminable coal?

ANSWER: There are no mining companies in those areas.

QUESTION: You still have the problem of property ownership?

ANSWER: A lot of it is owned by the Federal Government and this could create a bigger problem. I think that is solvable in a shorter timeframe (in minable coal areas). I see these battles going on over permits. It's only my personal opinion, but I know what kind of problems we got into in trying to set up a system whereby permits would be gained from one source in each state. If you wanted to go in to drill a well or open a coal mine you would go to one location and turn in one piece of paper and it would be up to the bureaucracy, Federal, State or otherwise to get those permits together to give back to you. I know what kind of problems we had just with that little try at simplification and I realize that was in the bureaucracy. Now you've got that bureaurcracy associated with company bureaucracy, union bureaucracy, together those things that separate entrepreneurs and major companies and I just don't see it.

SPEAKER: ANN C. KIM

QUESTION: What is the carbon dioxide content in the gas in the Pittsburgh coal seam?

ANSWER: It's less than 10 percent but, I can't give an exact answer right now. It's about 6 percent.

QUESTION: That's considerably more than what you showed on the chart.

ANSWER: The coalbed composition I gave were composites. They're meant to show a comparability with natural gas. You may get less or you may get more.

QUESTION: Do you think fracturing the coal seam constitutes a safety hazard?

ANSWER: No. If you do it right in a minable coalbed. Here again, if you're not going to mine the coalbed you don't have to consider the dangers inherent in stimulation. But if it's done right; no. We've found that fractures don't extend into the roof or floor.

COMMENT FROM THE FLOOR: I would like to make a comment -- there are some companies that have been hydraulically stimulating coal that have some very significant roof damage from the hydraulic fracture.

ANSWER: My rejoinder is that in properly stimulated coalbeds and this implies knowing what you are doing and being concerned with what you are doing.

QUESTION: I have a couple of questions. Ann, in one of your slides you have 776 trillion cubic feet of methane in all coalbeds. I assume that this is in-place, that is not recoverable.

ANSWER: No, it's in-place. Because right now depending on coalbed we don't know the recovery.

QUESTION: And in another place, Ann, you use 259 trillion from zero to three thousand feet.

ANSWER: That's minable coal reserves.

QUESTION: Now has any of that gas been produced or vented.

ANSWER: In proportion to 259 trillion you might get a .00001 percent. It would be an insignificant amount.

QUESTION: One last thing I'd like you to comment on. Let me lay a little bit of ground work for you. My work has been for a pipeline company where we produce what we call natural gas into pipelines and transport it back. Now our gas, for example, comes from say a limestone quarry or it might come from sandstone. The thing that strikes me (is that) supposingly at this meeting we are taking the same type of thing and we are making of it a seemingly legal problem by saying here we are demethanizing a coal seam. Well, here we've gone on in our business and we might say we are demethanizing a limestone quarry. I hate to see us, the technical people involved in this see a legal precedent, saying that we're doing something unusual when in fact we are doing the very same thing that has gone on in the natural gas business for years and years. Why are we unnecessarily emphasizing demethanizing a coal seam?

ANSWER: For one thing I think this technique is unusual in this country even though it was proposed 30 to 40 years ago and done for 200 years in England. So gas recovery from coalbeds is not new, but I think as far as we have seen the legal problems come in when rights are sold. I can't get involved in this. I don't know enough about it. I assume if you own the gas rights you have a right to it. I don't know, I keep insisting, as Maury said, reasonable men should produce reasonable solutions. Thank you.

SPEAKERS: EDWARD WEST, CARL STURGIL, HARVEY PRICE

QUESTION: I would like to ask Mr. Pasini to comment further on the tax credit provision.

ANSWER: I don't think I have to come forward to talk about that because I think everybody can hear me. The tax credit provisions says you can write off 10% of the total tax against the production. This is not much, if you are a gas company, but if you happen to be some kind of a mining company or manufacturing company, then this is written off against your total tax bill. OK, and so, in other words, the total production operation could be written off against this. So, I think that's the crux of it. I think it was in the Federal Register, no it was in the Congressional Hearings. I'm trying to think what the date was on it. I don't have it right off hand. If you call me, I have the Congressional Record that states this part of the tax credit in specifics, OK, and this was for unconventional sources and the unconventional sources were considered to be methane, Devonian shale and Western tight sands. No, it didn't say Western tight sands, it said tight sand. OK. That got some people excited in Ohio because obviously some of the formations that are producing from over there are just as tight as the ones out West. OK.

QUESTION: I'd like to ask Harvey -- as I understood you said the rock fracture permeability data came from actual measurements rather than a map. Is that correct? In a word, what I'm asking is what kind of measurements did you use to measure the permeability?

ANSWER: Well, there are a number of ways this can be done. It can be measured in the laboratory; these measurements are generally unreliable. The best way to measure permeability is through some kind of flow test. This might be the drilling of horizontal holes out of entries, the flow of water between these; these can be actual flow tests from wells, water injection tests and things of this sort where forced permeability has to be calculated from the actual observed data.

QUESTION: Is that how you got those numbers?

ANSWER: The permeabilities that were used were the simulator generated curves taken from the numbers that the Bureau of Mines had estimated the permeability in these areas to be. They were given over a range. In other words, the Bureau has many measurements of permeability may be as low as five millidarcies and as high as a few hundred millidarcies and within that range what we did, was just take numbers and adjust them until they actually matched the data. The same thing was true with the data that we reproduced in other coals. So yes, the curves were generated by a history matching within a reasonable range of variation of the parameters that are uncertain, permeability being one.

QUESTION: But the information originally came from the Bureau of Mines?

ANSWER: It gave us the indication of where it began and I can tell you the adjustments that were required were extremely normal. In all cases we used a constant permeability for the coal seam, in no way, shape or form attempted to curve fit this data; we really attempted to show that the model could generate it, given the right information.

QUESTION: Harvey, what was the size and cost of Kiel frac and were those costs included in your completed costs?

ANSWER: Yes. The size of the Kiel frac I believe was 40,000 gallons of water. Ken, is that right? (55 I think) 55,000 gallons of water, it's pure water stimulation and service company charges were about $3,800.00.

QUESTION: What about Kiel's charges?

ANSWER: Kiel's charges for that type of service are $3,000.00. The total cost would have been $6,800.00 - $6,900.00. In our costs we estimated $15,000.00 for the cost of stimulating the coal. So as you can see that's considerably less than what we used in our economic projections. We think also that treating as I said, is moderate to small. He has also designed a treatment in a well in Alabama where we injected about 80,000 gallons in a thinner coal seam and feel that we obtained a much more highly conductive and longer stimulation which when we get the water pumped off we hope will give substantially higher flow.

QUESTION: But in effect the Kiel frac in Greene County didn't really produce any more gas than the gel water frac.

ANSWER: That's right.

QUESTION: There are three questions I would like to ask Mr. Sturgil. Your slide indicated that the Gob gas content was about 60% methane. What is the cutoff point? In other words, how lean, also the Gob area you were talking about, is that from longwall mining, and the third question is have you considered enriching a lean fuel with pipeline gas?

ANSWER: The first question regarding the concentration of methane. Normally after the predrainage stage, the concentration will vary quite a bit, from day to day, from hour to hour. The lowest limit that we plan to operate at is going to be determined by safety considerations. MESA representatives are currently saying that they would like to see us stay above a 50-50 concentration. It will be somewhere above that just from safety margins. We have yet to determine exactly where we will decide to shut down the engine. Your third question about the types of mining that are going on, at this particular mining operation both longwall and continuous mining are going on, and Gob areas have created in both cases. Both kinds of mining are going on, at this mining operation at these wells that I refer to, are created by both types of mining operations. Generally longwall mining creates better Gob.

QUESTION: Mr. Stefanko, I understand that just to the north seven miles on one Lykes Resource property they have drilled similar wells into the Pittsburgh seam and the production rates have been considerably higher. Are you aware of the differences in drilling techniques and recovery they have used to get those recorded differences?

ANSWER: (Bob Stefanko) Most of these have been fraced by Halliburton or Dow. This is a standard technique. Lykes has done it. I wish they would document it, get some data together and publish this. This is just north of us and there are other companies who have drilled just south of us. This is the point I'm trying to make; the disparity of results in the Pittsburgh seam in that general area. You have 100,000 cubic feet per day and then you have a thousand, two thousand cubic feet per day. I don't know what it is. Maury?

ANSWER: Well, the Lykes wells that were stimulated, we used a much larger treatment and the treatments generally were in the order of 40 and 50,000 gallons equivalent volume and we are pretty certain that in most of these we did get (interrupted)

QUESTION: Were those hydraulic or foam?

ANSWER: Foam. There were several different kinds of treatment. There is a report practically in press right now on that. It was held up for three months, for what reason I don't know, but it is going to press and will be out very shortly. We were hoping that would be put on continuous production so we would get some better data on it. But, since it is not going into a pipeline, the data is sporatic but to provide a comparison and to give the technical details of what the stimulation is worth. That is all in the paper and it'll be out very shortly.

QUESTION: You said that the rates are better. How better?

ANSWER: The rates of production are over 100,000 cubic feet a day.

QUESTION: In what psia range were the foams?

ANSWER: For the nitrogen pressure, I don't know. I don't think it exceeded 3,000 lbs. Bob, did it exceed 3,000 lbs?

ANSWER: In several instances we did sand out in very similar circumstances to what Bob Stefanko was talking about. In those cases, the first time we did we aborted because we had all our treatment in, the next several times that it occurred we flowed back and went back in and had no trouble going back in. Normal treatment was between 11,000 and 13,000 lbs.

QUESTION: Has this frac been documented?

ANSWER: Oh, yes.

QUESTION: In line with that the hydraulic fracturing is not a standard procedure -- I would very strongly urge you to document details of what company -- you can't learn the chemical composition -- you've got to put in a company and company tradenames you haven't documented what you did. Hopefully you can break that barrier and put that kind of stuff in your report. Each company has 10,000 different rules on what they put in. List those tradenames or you'll never be able to compare results, frac to frac. No two are alike, really.

ANSWER: I realize that, but the basic technique is what I've got to understand. I realize the different pumping pressure. (interruption)

QUESTION: In the oil and gas business?

ANSWER: The burden of having confidence in the detail in the design of the frac lies upon the operator of the well or owner of the property. The frac company gives you the standard oil field guarantee. If you don't like the results we will be happy to do the same thing again for the same price again. Operator beware!

COMMENT: I found that to be true in the drilling, the fracing and everything else. That's the way the industry works.

COMMENT: (Phil Randolph) I'd like to express some observations to some of the material covered by a number of the speakers on the controls and invitations for comments relating to the FY80 budget, the abstract of Joe Pasini's paper, which, thank God he abandoned. Some comments by K. Bastress, by R. Potesta of West Virginia and others. Particularly in the context of why isn't the industry taking up coalbed gas. I would suggest that from the point of view of supply to an interstate gas transmission company, expenditures and the programs of DOE to date have been little-bitty microscope studies. Far too small to provide a basis for a company to decide to move forward and spend a hundred million bucks to develop enough gas to warrant a 24 inch pipeline. You know, kind of a minimum increment insignificance to a major interstate company or major gas consuming area, such as the State of Pennsylvania. The research so far, for real good reasons, talking about -- I'll say what could be here by the 1980's, real good reasons, all of the Federal Government research funding has been tied, virtually all of it, has been tied very closely to existing mines. They arm-wave about 300 or 800TCF, but the research is tied to a location where, hell, what percent of the energy in-place is methane? You follow it with the West Virginia recommendation natural gas production from coalbeds is never going to exceed one percent of the energy

COMMENT: (Phil Randolph Con't) production from direct coal utilization for all types of mining. That doesn't turn on any gas company. From the point of view of defining the unminable resource base, go to 95% of what you're talking about. The first real deal we step is the RFP unit where responses as due next Monday. That RFP specifies that during Phase I, thou shall prove that methane is producable from the coal seam but under this contract thou shall not drill any holes until Phase III. There is no damm way you can respond to the RFP unless you are intimately tied to a seam at which there is existing mining. I may get a surprise, somebody may come in with a proposal with a vast deep thick seam which is known to exist out West. I know a bunch of companies who are about to go with the ground rule where somehow they could prove their methane where there has never been a mine or never been a hole. If you can't drill a hole until Phase III, we don't have a program that addresses establishing the producability of the large hypothized resource. I would suggest that by FY1980 very serious consideration be given not to phasing out the expenditures in 81 as I just saw on a graph, but rather to putting together a program that's big enough to address whether or not this hypothetical, enormous resource base really exists or if detailed engineering characteristics so that the economics is something besides a bunch of arm waving nonsense. That magnitude of a deal which we program is many tens of millions per year, it's not phasing down from the microscopic studies that are going on now.

RESPONSE: (Leo Schrider) OK, Phil. I won't say I agree with everything you said but you have certainly raised a lot of points there. One of the things, of course, as far as the dollars go, is controlled by the Congress and by the Office of Management and Budget as to the types of things that we can do and start to do. We have always been restrained to some degree by those dollars. I mean, we like to feel that, yes, we could do other things given different levels of funding. So with that kind of consideration, perhaps we do take on a bit much in trying to do the best of all things. That is essentially the kinds of answers that we are trying to find. We felt a very strong commitment to make some attempt at what was there as far as the unminable resource goes, and we wanted to get some initial indication from people on what needed to be done. Prior to the issue of the RFP and I know it's hard to see all these things, we asked through the Commerce Business Daily to get opinions of people, as to what should be done in the area of unminable coal seams. We got several responses, we tried to take into consideration those concerns that people had prior to issuing an RFP. This was done, so I don't know.

COMMENT: (Bob Wise) The RFP is directed at specific projects. We have at the same time a program tied in with USGS, Colorado Geological Survey and Penn State which is for identifying possible sites. We are doing that to find areas for various contractors and other Government agencies and state agencies to supplement the RFP. The RFP is intended for specific projects.

COMMENT: (Phil Randolph) I think you've done a hell of a good job. You haven't had enough money to do it right. We're talking about the fiscal '80 budget. We still have presentations that complain we haven't been able to do the job right. We've done the best we can, it's damn good. But it isn't very much in relation to what it takes to further a large-scale commercialization of these hypothized hundreds of thousands of feet of natural gas.

COMMENT: (Leo Schrider) Well, it's really your direct input, both to your people in Washington from wherever you might reside and to us that tells us the way you feel. I think when Augie said that he was asking for you to put your concerns down he meant for you to send it to him -- I know he'll read it and consider it.

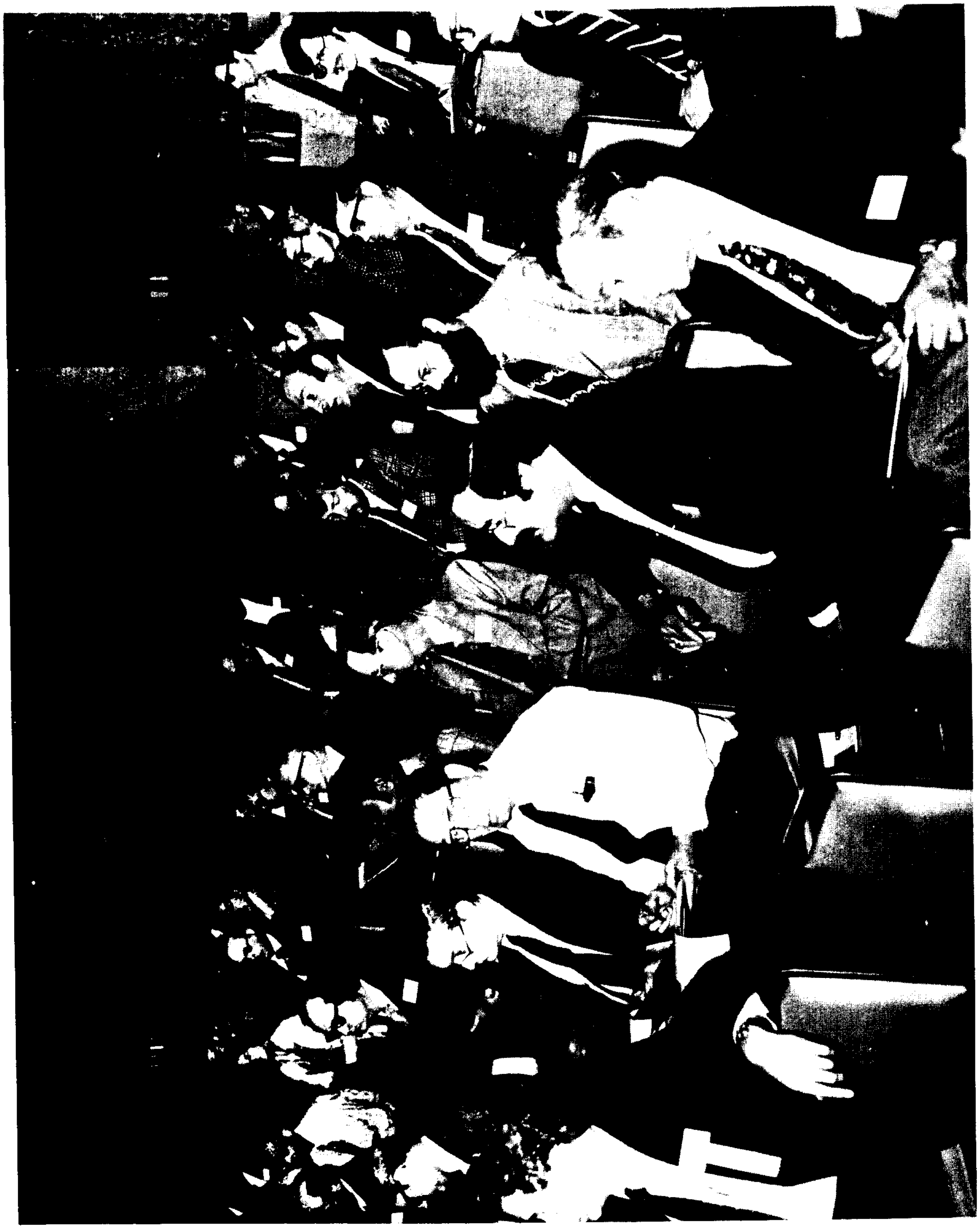
COMMENT: (Phil Randolph) There's a little concern that we are producing studies which compare LNG, ammonia, and pipelines. Specifically projects like LNG or ammonia production, scare me. The national picture clearly determines a need for natural gas and we crank out these studies in an added value context, this kind of terrifies you. We're saying we take methane out of coal mines to make electricity. Well, that guy who owns a house has to pay thirteen dollars a million BTU to heat his hot water for his house, the methane project seems very viable. But if we put in a pipeline so that he can heat that water for his house for two and half a million BTUs, I worry about these option studies that stop before you get to an end-use. We generate electricity, a high priced commodity but the guy out there that owns that house he can't get a natural gas hookup -- he's got to buy that electricity. The LNG is the same thing. All LNG is in a high priced transport scheme for a project that's so damn small it's not worth the trouble to get the right-of-way to put in the pipeline. Focus on bigger projects and that alternative thing would go away. Pipeline

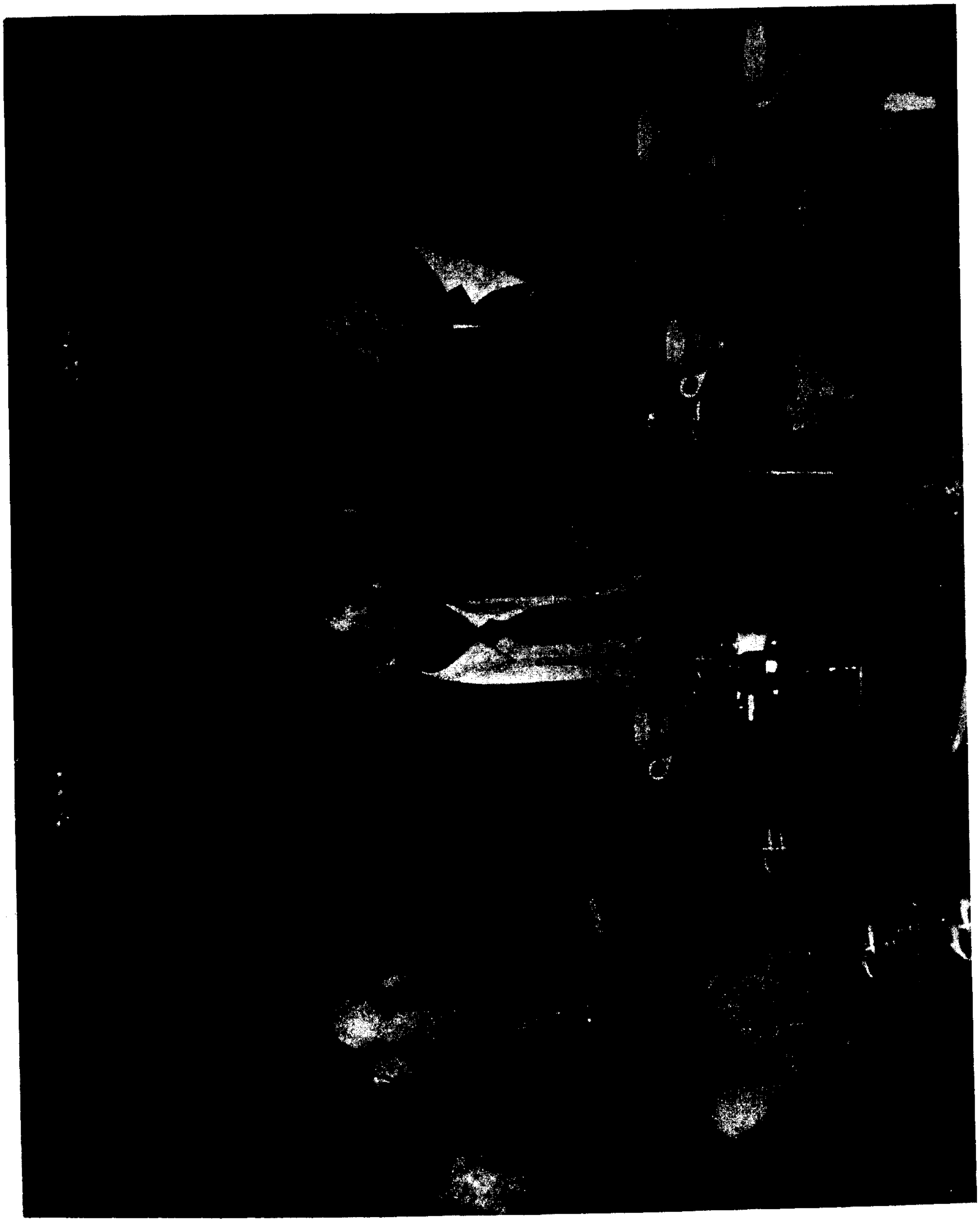
COMMENT: (Phil Randolph Con't) transportation is phenomenonly less expensive than LNG transportation if the project is big enough to justify the trouble and use the existing right of imminent domain to solve the right-of-way problems, and so on. Nobody is going to take on the legal problems of playing that game, if they're talking about laying a small pipeline. The LNG is an advantage not because of the added value of the methane, but you've got what's practical for small projects. If you've got enough gas you build pipelines. Right-of-way wouldn't be a problem anymore. Anytime a new natural gas field is discovered the right-of-way problems get solved. It costs a lot of money to solve them. You turn on a big staff of lawyers, regulatory affairs types, if the project is big enough to carry those costs, they get solved very quickly. A guy drills a gas well to produce $10 million a day you'll get a pipeline 90 days later. It just ain't worth the trouble for a little-bitty project.

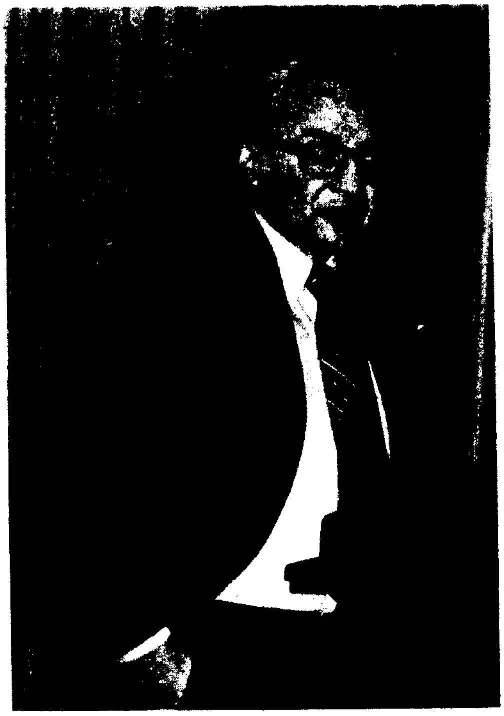
COMMENT: I'd like to add to that comment based on our experience at U.S. Steel. One of the reasons it's kind of difficult to make a big project is because of the number of wells that have not been successes. We've no idea prior to turning on the valve how much gas is going to come out of the ground. In spite of the pioneering work done by the Bureau, far more production-type research needs to be done as well as utilization.

COMMENT: (Leo Schrider) Any comments? OK, thanks again.

APPENDIX A2
CANDID SHOTS







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APPENDIX A2
CANDID SHOTS

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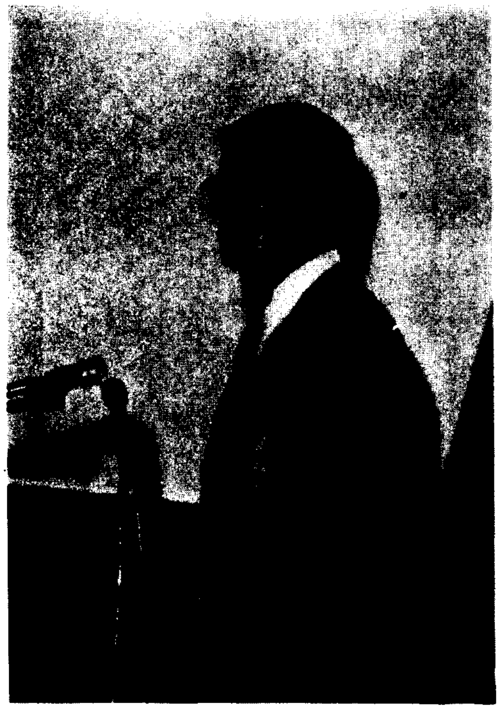
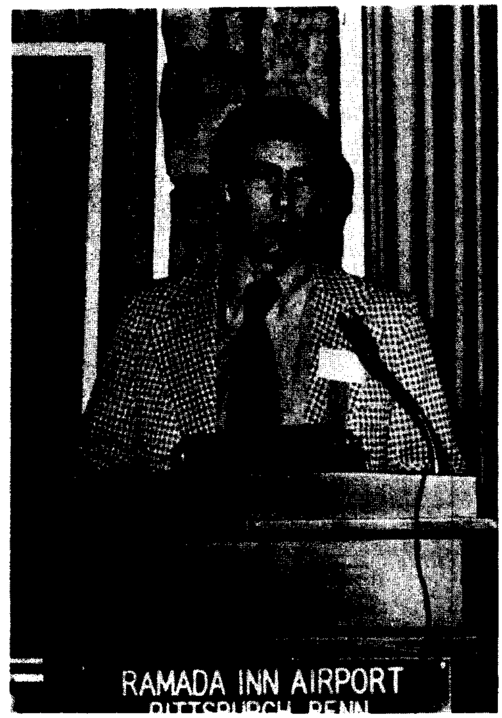
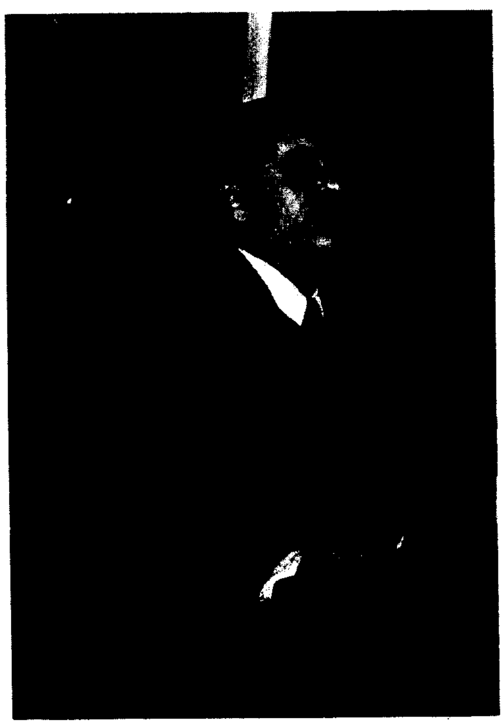


Carl L. Sturgill



Robert Wise



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APPENDIX A2
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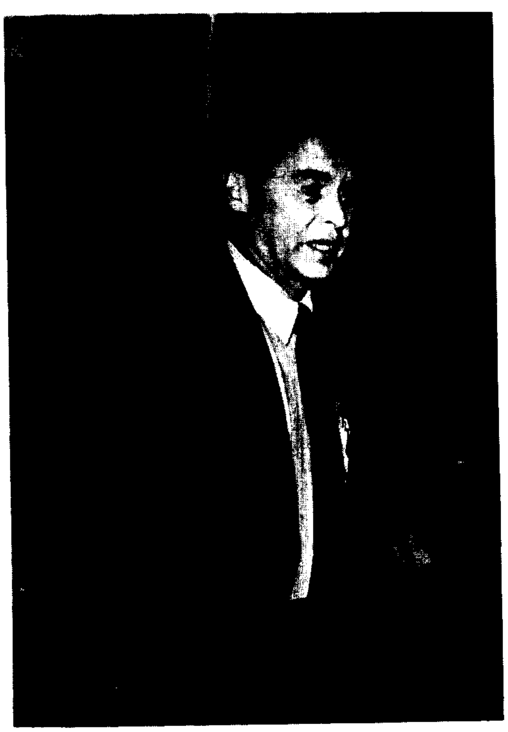
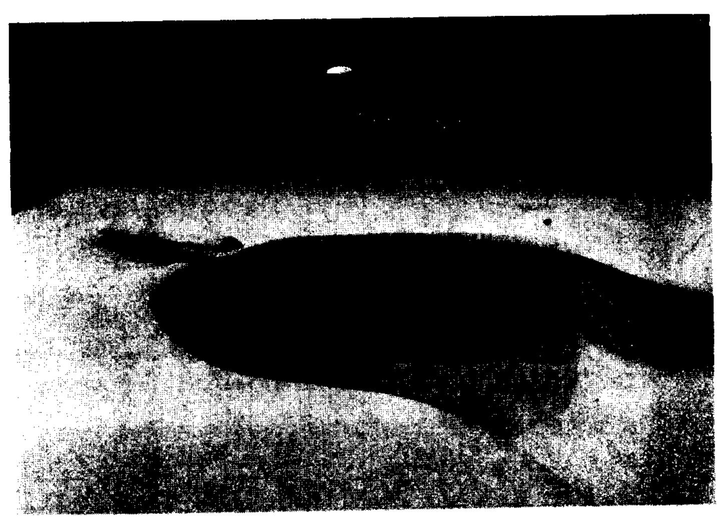


E. Karl Bastress



It snowed and snowed and snowed....

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