METC/SP-79/9
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Proceedings of the 2nd Annual METHANE RECOVERY FROM COALBEDS SYMPOSIUM

Sponsored by

MORGANTOWN ENERGY TECHNOLOGY CENTER

Morgantown, W. Va.

GATEWAY HILTON HOTEL

Pittsburgh, Pa.

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OPENING REMARKS

BY

LEO A. SCHRIDER

ASSISTANT DIRECTOR, EXTRACTION DIVISION
MORGANTOWN ENERGY TECHNOLOGY CENTER

ABOUT THE SPEAKER

Leo A. Schrider is the Assistant Director, Extraction Division at the Morgantown Energy Technology 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, Mr. Schrider 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 research and technology development for the in situ coal gasification experiments being conducted by the U.S. Bureau of Mines. He managed the research and technology development for the in situ coal gasification experiments being conducted near Hanna, Wyoming. In July 1976, Mr. Schrider transferred back to Morgantown to assume his present duties.

EDITOR'S NOTE: Mr. Schrider presented the opening remarks instead of the introduction of Mr. George Fumich, the scheduled keynote speaker. Mr. Fumich was unable to attend the Symposium due to the development of other business which conflicted with the Symposium schedule.

OPENING REMARKS

By

Leo A. Schrider

Good morning. I am Leo Schrider, Assistant Director of the Extraction Division at the Morgantown Energy Technology Center. On behalf of METC, I would like to welcome all of you to the Second Annual Methane Recovery from Coalbeds Symposium. The weather this year is certainly much better than that we experienced last year; as some of you may recall, we had about 18 inches of snow at the time of our first annual symposium, so in planning this year's, we decided to hold it in the spring, and our decision, weather-wise, seems to have been a good one.

We have a 1½ day meeting planned for you; technical papers will be presented all day today, as well as tomorrow morning. If everything goes according to the schedule, we will be through around noon tomorrow.

Our scheduled keynote speaker, Mr. George Fumich, the Program Director for Fossil Energy, for the Department of Energy, regretfully could not attend the symposium due to the pressures of some urgent business. I would like to therefore take this opportunity to talk briefly about the DOE Unconventional Gas Recovery Program, perhaps conveying some of the thoughts Mr. Fumich may have made.

Unconventional gas resources can make significant contributions to the national gas supply in both the near- and the long-term. The potential of these resources can be realized at a lower cost than most other supplemental gas sources, mainly through a balanced combination of technology development, resource characterization, and economic incentives.

The goals of the UGR program are to:

- Accelerate the development of an improved scientific, engineering, and economic basis for prompt, orderly development of enhanced recovery technologies to accelerate production of natural gas resources.

- Transfer DOE-developed technology in UGR to those sectors of private industry that need such information to establish reserves and production goals and significantly reduce investment risks.

In addition to the Methane Recovery from Coalbeds Project (MRCP), the UGR program includes the Western Gas Sands Project (WGSP) and the Eastern Gas Shales Project (EGSP).

The Eastern Gas Shales Project is aimed at recovery and utilization of the Devonian age, gas-bearing shales of the eastern United States. Studies show that gas occurs in natural fracture systems within the Devonian shales. The fractures serve as reservoirs and also as channels for movement of the gas to producing wells. Because the gas production rates associated with unconventional wells have been too low to be economically attractive, efforts of this project have been directed toward developing fracture, stimulation, and drilling techniques to connect more gas-containing fractures to the wellbore.

The Western Gas Sands Project is aimed at exploitation of gas in the low-permeability, "tight" sandstone reservoirs of the Rocky Mountain region. The low-permeability gas sands contained in basins of the region contain as many as a hundred or more reservoirs with an estimated 730 trillion cubic feet of gas in place. Because low deliverability is a problem with the wells in that region, R&D effort is directed toward improved stimulation, such as repeated massive hydraulic fractures, which will induce economic production.

Figure 1 shows the U. S. known natural gas reserves, production, and additions. In 1970, the country started to see a rapid decline in our natural gas reserves which, according to latest estimates, amounts to approximately 210 tcf. Due to conservation as well as switching to other fuels, our consumption rate has stabilized to approximately 20 tcf per year. However, the feeling among the Department of Energy is that the drop is temporary and will rise again in just a short time. Therefore, DOE is using the time to look at the so-called "unconventional" sources of natural gas, namely the tight gas sands of the western U. S., the Devonian shales of the eastern part of the country, the coalbed methane, and the methane from the geopressured aquifers of the Gulf states.

Figure 2 shows where the resources are in the continental United States. It is important to point out that the gas, like coal, is located all over the country. The amount of energy recoverable from the unconventional sources is currently highly debated. The lower bound is a few tcf; on the other hand, estimates have been stated at approximately 2000 tcf. Needless to say, defining the resource and estimating the reserves are principal goals of the Unconventional Gas Recovery program.

Another aspect of the UGR program is research and development for recovery of the natural gas. Much of the R&D is directed toward advanced stimulation techniques by hydraulic fracturing and other treatments. The emphasis is to understand the gas reservoir and releasing and obtaining the gas at rates that are economically attractive.

Figure 3 shows some of the reasons for the limited production from unconventional sources. Basically, we do not fully understand the technology and the economics. Because the gas does not behave like gas obtained from conventional sources, attempts will have to be made to understand and predict its behavior pattern. Until the technology is understood, recovery of gas from unconventional sources will probably continue to be limited. Instead, producers will continue to seek and exploit conventional sources, even though it involves deeper wells, staying with a technology they understand rather than increasing risk by adopting a technology not fully understood.

Figure 4 shows some of the unresolved technological issues. The first, obviously, is the size of the reserves. Understanding the gas flowthrough matrix and natural fracture patterns is another. Of course, utilization of the gas, environmental and institutional impacts, and regulatory implications are areas of concern to the Department of Energy, and particularly, to the Morgantown Energy Technology Center, which is the lead center for the Unconventional Gas Recovery program.

Figure 5 shows the current budget for the three UGR projects under the Fossil Energy Program. In addition to the $33 million total for Methane Recovery from Coalbeds, Eastern Gas Shales, and Western Gas Sands, approximately $25 million has been allotted for FY 1979 activities of the Geopressured Methane project. The total for UGR activities, therefore, is approximately $58 million. The budgets for FY 1980 have not been generated as yet; funding will probably be approximately the same as the level for the current year.

Briefly, that is what the Unconventional Gas Recovery program is all about. The Methane Recovery from Coalbeds Project plays a vital role toward solution of the energy problem, and sessions like these are all intended to help understand and develop the technologies. Thanks for attending the symposium; I hope you find it helpful.

At this time, I would like to turn the symposium over to the first session chairman, Bob Wise. Bob is the Project Manager for both the Methane Recovery from Coalbeds Project and the Eastern Gas Shales Project. He will also present the first paper of the day, a Status Report of the Methane Recovery from Coalbeds Project.

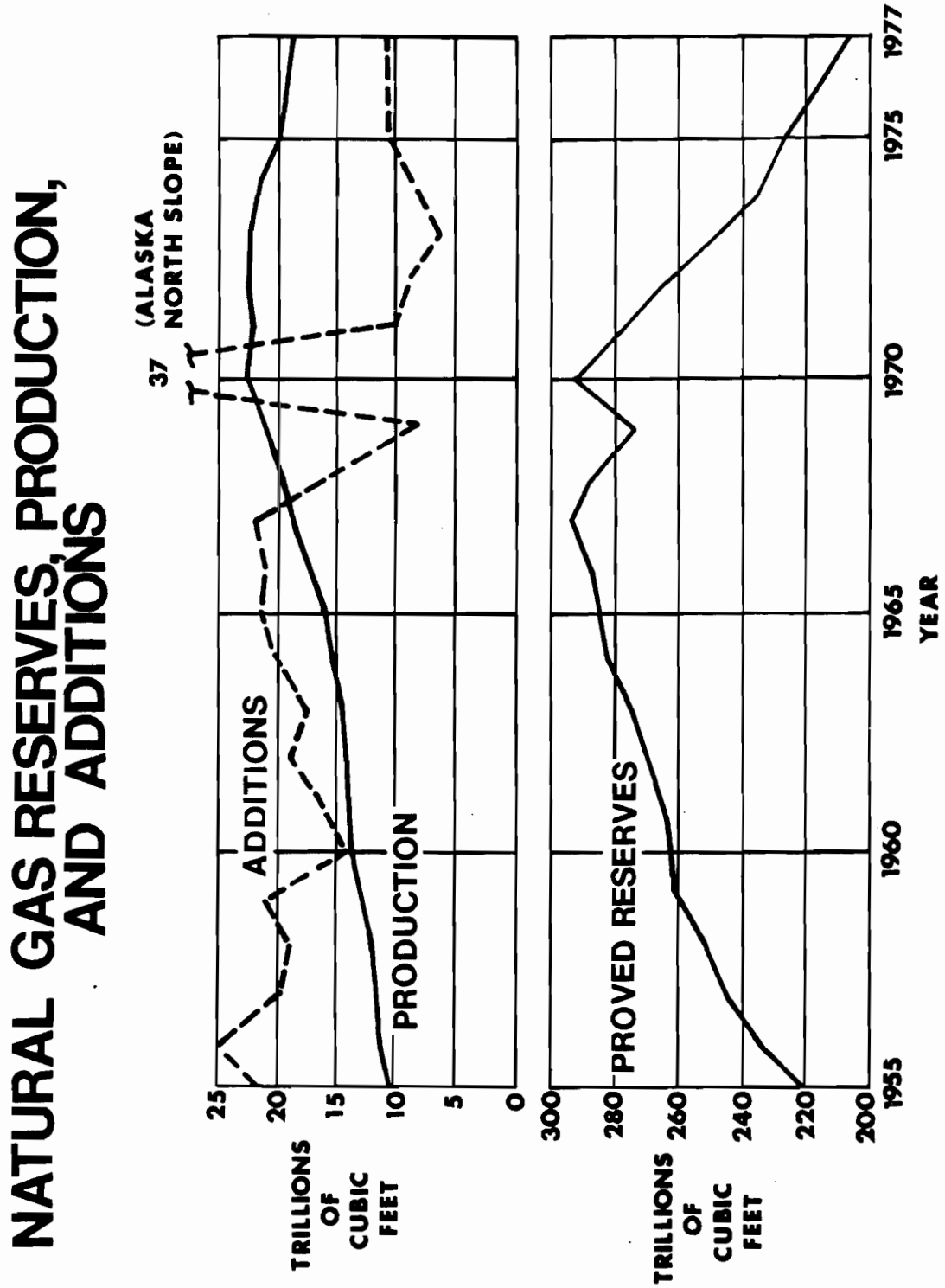

Figure 1. U. S. Known Natural Gas Reserves, Production and Additions

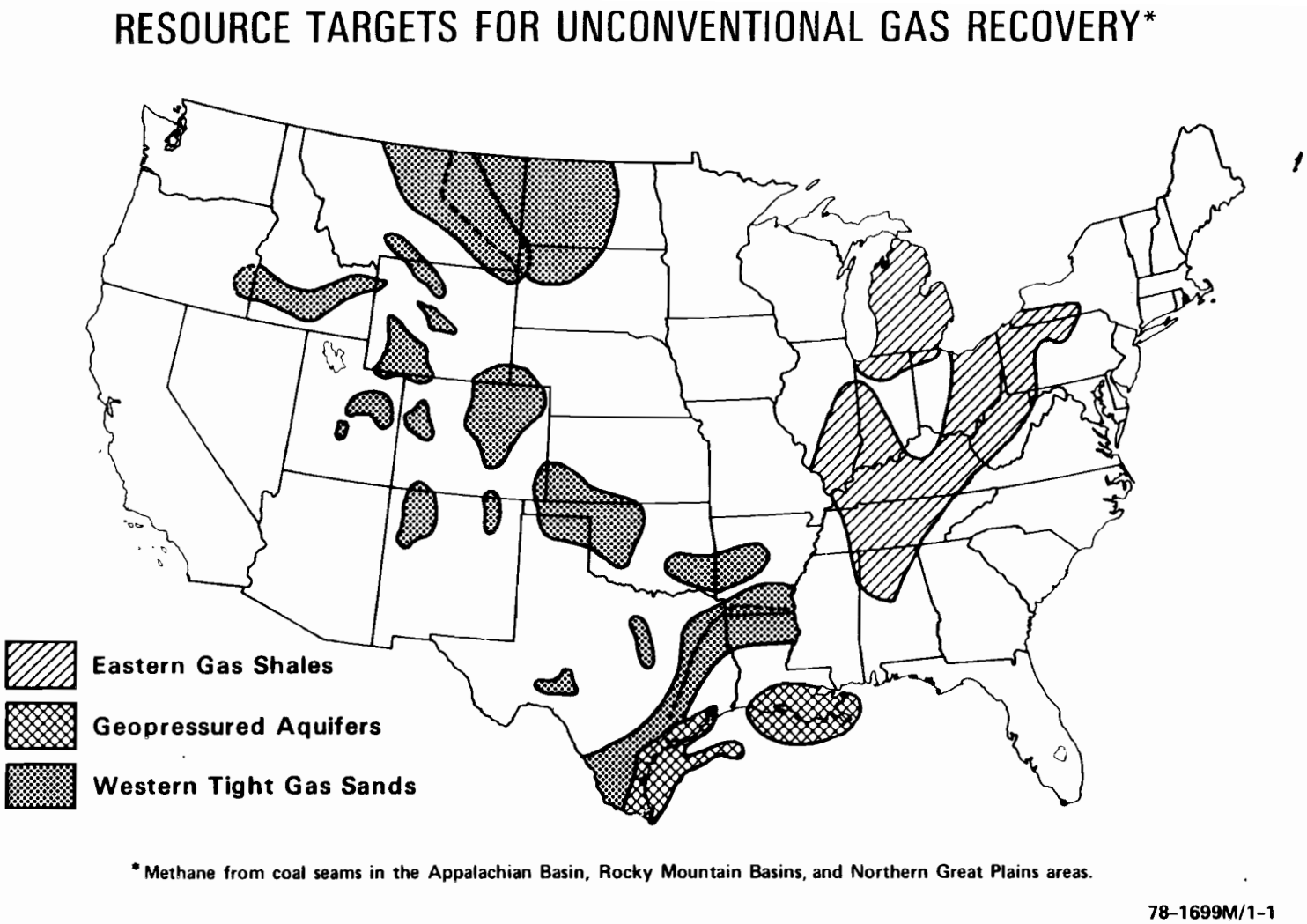

Figure 2. Resources in the 48 Conterminous United States

UNCONVENTIONAL GAS

- *REASONS FOR LIMITED COMMERCIAL PRODUCTION*
  - *— RECOVERY TECHNOLOGIES & ECONOMIC ANALYSIS NOT DEMONSTRATED*
  - *— GAS QUALITY IS VARIABLE*
  - *— LOW PRODUCTION & REMOTE LOCATION*
  - *— HISTORICALLY LOW GAS PRICES*
  - *— REGULATORY/INSTITUTIONAL IMPLICATIONS*

Figure 3. Reasons for Limited Commercial Production of Unconventional Gas Resources

UNCONVENTIONAL GAS PROJECTS

ISSUES WHICH NEED RESOLUTION

- *TECHNOLOGY*
  - *SIZE OF NATURAL GAS RESERVE (COST TO PRODUCE)*
  - *GAS FLOW THROUGH THE RESERVOIR*
  - *NATURAL FRACTURE PATTERNS*
  - *IMPROVED PRODUCTION RATES*
    - *DRILLING*
    - *STIMULATION*
    - *COMPLETION*
  - *UTILIZATION*
  - *ENVIRONMENT*
  - *REGULATORY/INSTITUTIONAL*

Figure 4. Unresolved Technological Issues of Unconventional Gas Resources

DOE FUNDING FOR UNCONVENTIONAL GAS RECOVERY
(Millions of Dollars)

RESOURCE TARGET	PRIOR FY'S	FY 76	FY 77	FY 78	FY 79
TIGHT SANDSTONES	2.0	5.1	4.5	4.3	7.5
DEVONIAN SHALES	0.2	11.5	10.0	14.0	18.0
COALBED METHANE			.5	4.7	6.0
GEOPRESSURED AQUIFERS				1.5	24.7
TOTAL	2.2	16.6	15.0	24.5	56.2

Figure 5. Current DOE Budget, Unconventional Gas Resources

STATUS REPORT
METHANE RECOVERY FROM COALBEDS PROJECT

BY

ROBERT L. WISE
PROJECT MANAGER
METHANE RECOVERY FROM COALBEDS PROJECT
MORGANTOWN ENERGY TECHNOLOGY CENTER

ABOUT THE AUTHOR

Robert L. Wise is the Project Manager for the Methane Recovery from Coalbeds and the Eastern Gas Shales projects at the Department of Energy's Morgantown Energy Technology Center, Morgantown, West Virginia. The Center is engaged in the management, research and development of projects associated with the recovery of energy values from oil, gas and coal resources.

Mr. Wise earned a Bachelor of Science degree in Chemical Engineering from the University of Wyoming. Prior to joining the Morgantown Energy Technology Center, he worked as a consulting engineer with the Denver Research Institute and as a senior engineer with the Laramie Energy Technology Center. He was also involved in oil shale research and was a plant metallurgist for the molybdenum and uranium minerals industries.

Mr. Wise is a past member of the Veterans Honorary Society. He is the author of many technical articles dealing with unconventional gas and oil shale research activities.

STATUS REPORT
METHANE RECOVERY FROM COALBEDS PROJECT

By

Robert L. Wise

Project Manager
Methane Recovery From Coalbeds Project
Morgantown Energy Technology Center

ABSTRACT

In 1977, the Morgantown Energy Technology Center added to its Unconventional Gas Recovery activities, the Methane Recovery from Coalbeds Project. Based on U.S. Bureau of Mines data, the project was directed at the recovery and utilization of methane associated with active mining operations and the resource verification of the gas potential associated with unmined coalbeds. A summary of project progress and current status is presented.

INTRODUCTION

The Methane Recovery from Coalbeds Project (MRCP) is a planned sequence of resource characterization, research and development, and technology systems tests, designed to predict and test the technical and economical extraction and utilization of gas associated with coalbeds. The project examines methane resources and matches extraction with utilization subsystems to determine total system capability. Initially, state-of-the-art technology and off-the-shelf equipment are being utilized. Project results will guide ongoing R&D to advance the technology and develop appropriate equipment to maximize economic viability.

Project efforts are expected to result in significant advances in the state-of-the-art including:

- Location and delineation of coalbed gas resources, indicating economically feasible recovery possibilities,
- Coalbed methane productivity prediction techniques, and
- Technology systems and methods for commercial extraction and utilization of coalbed methane.

Although not part of the project per se, increased coal productivity and improved coal mine safety are anticipated through removal of gas which might seep into the mine, thereby avoiding shutdowns to eliminate dangerous methane buildup.

The MRCP is structured for implementation employing the following primary elements considered essential for success:

- Resource Engineering - Identification and definition of the coalbed methane resource so the most attractive targets may be selected.
- Research and Development - Development of improved, more cost-effective methods and subsystems for recovery/utilization of coalbed methane.
- Technology Systems Tests - Demonstration of the technical and economic viability of a number

of different system-coalbed combinations to accommodate the variety of specific site conditions that will be encountered in large-scale commercialization, and

- Project Integration - Coordination of project functions: technical overview, systems planning, support studies/analyses, information management, and technology transfer.

The interrelationships of these elements over the project lifetime are designed to build on state-of-the-art technology and encourage eventual commercialization, as shown schematically in Figure 1.

RESOURCE ENGINEERING

Delineation of the methane content of the nation's coalbeds has been done on a very limited basis, mostly in conjunction with active mining. Previous work includes only a very small percentage of the coal resource and does not provide the knowledge needed to locate recovery and utilization projects in coalbeds with the greatest potential for methane production.

A resource delineation plan was developed which shows the MRCP approach to providing a data base for determining the national resource and the reserve; disseminating the information that is developed; and guiding management of the overall effort.

Areas of study were selected on the basis of the following general criteria:

- Physical and chemical characteristics of coal
- Seam depth
- Total effective coal thickness
- Individual seam thickness
- Areal extent

Cooperative drilling, coring, logging, and test activities were initiated in 1978 in an effort to extend the data base. The locations of 1978 tests are shown on Figure 2. Figure 3 shows location of the tests planned for 1979. Details of the testing are reported in the paper "The Delineation of Methane Resources in Minable and Unminable Coalbeds" by A. A. Lee of the TRW Energy Systems Planning Division.

RESEARCH AND DEVELOPMENT

The MRCP Research and Development (R&D) effort is being directed at development of improved, more cost effective methods and systems for methane extraction and utilization from coalbeds. Currently, four MRCP research and development projects are underway:

Contractor	R&D Project
Maurer Engineering	Turbodrill development
Physics International	Coal fracturing
Sandia Laboratories	Water jet drilling
West Virginia University	Fracture mechanics

TECHNOLOGY SYSTEMS TESTS

While research is being done, a series of technology systems tests to develop and demonstrate technical and economic viability has also been started. The projects' locations are shown in Figure 4; the project titles and contractors are listed in the following table. Some of the projects are still in the conceptual design stage, while others are quite well developed.

WISE

Project	Contractor
• Gas turbine power generation	Westinghouse
• Space heating/fuel cell	Westinghouse
• Pipeline injection from deep coal seams	Mountain Fuel Supply Company
• Pipeline injection from deep coal seams - multiple hydraulic fractures	Intercomp/Coseka
• Long horizontal holes	TRW/Occidental Research
• Multiseam coal stimulation for local usage	TRW/Waynesburg College
• Anthracite coal drainage	TRW/Pennsylvania Energy Resources, Inc. (PERI)

PROJECT INTEGRATION

The project integration element provides for project planning, data analysis, and the technology transfer of project results. Routine project information documents are prepared and include:

- Project Planning Document - project information for implementation and field management by Morgantown Energy Technology Center. The document is prepared annually.

- Technical Information Releases - summarized significant project accomplishments. This information is prepared as warranted.

- Unconventional Gas Recovery Semi-Annual Report - status report of the technical progress of the four conventional gas resources: Methane Recovery from Coalbeds Project, Eastern Gas Shales Project, Western Gas Sands Project, and Geopressured Aquifers (Solar/Geothermal).

- Methane Recovery from Coalbeds Symposium - proceedings of the annual Methane Recovery Symposium.

This information, as well as significant contractor reports and well data, are available for inspection at the Morgantown Energy Technology Center's open file. The open file also includes information and data for the Eastern Gas Shale and Western Gas Sands Projects. In many cases, extra copies of various reports are available at no charge.

SUMMARY

Resource Engineering activities are beginning to provide the necessary data to more accurately assess the gas resource associated with the Country's coalbeds. Initial results in the unmined coalbeds indicate a high potential gas source. Development of this resource, as well as that associated with active mining operations are being advanced through complementary R&D efforts and the testing and verification of applicable technologies in the field.

The development of this resource, as well as the other unconventional gas projects, requires close cooperation between government and industry. The Federal Government must make policy decisions which determine the priorities of a variety of potential energy sources. Industry input is necessary to this decision making process to effect the proper priority scheme. In addition, their willingness is needed to provide the necessary technical and economical support for commercialization. The unconventional gas resource represents a large potential energy source that can reduce our nation's dependence on foreign imports with a minimum impact on the environment.

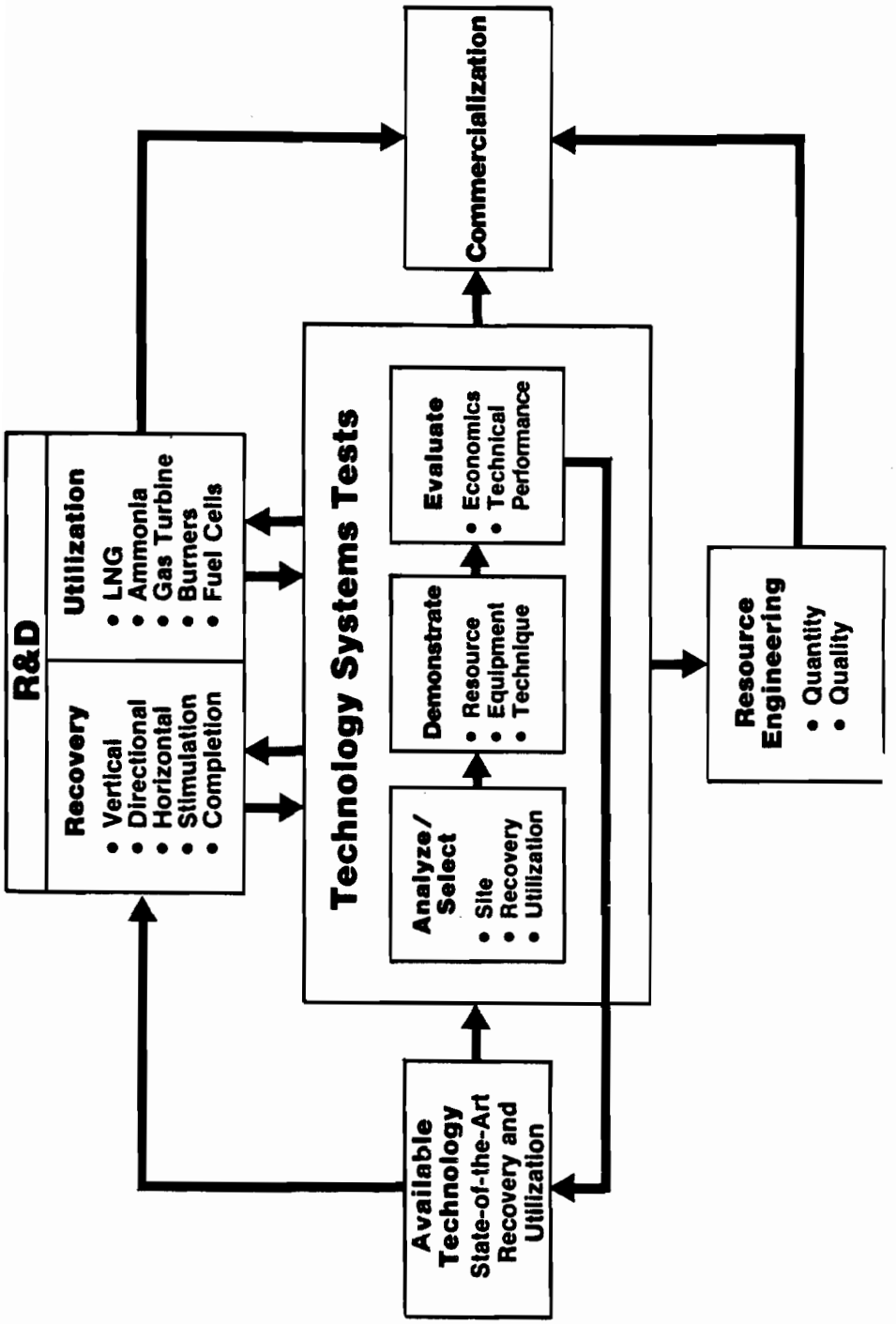

Figure 1. Methane Recovery from Coalbeds Project Overview

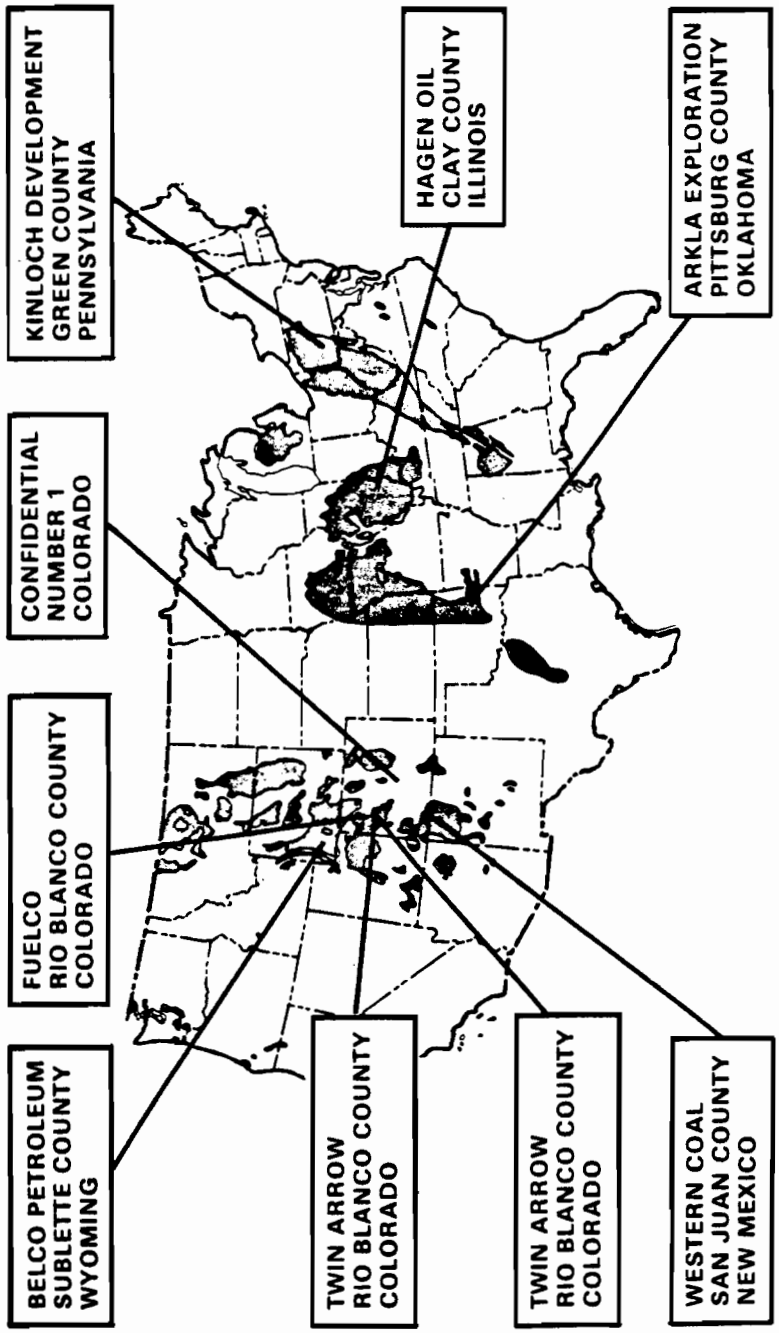

Figure 2. Wells Tested in 1978

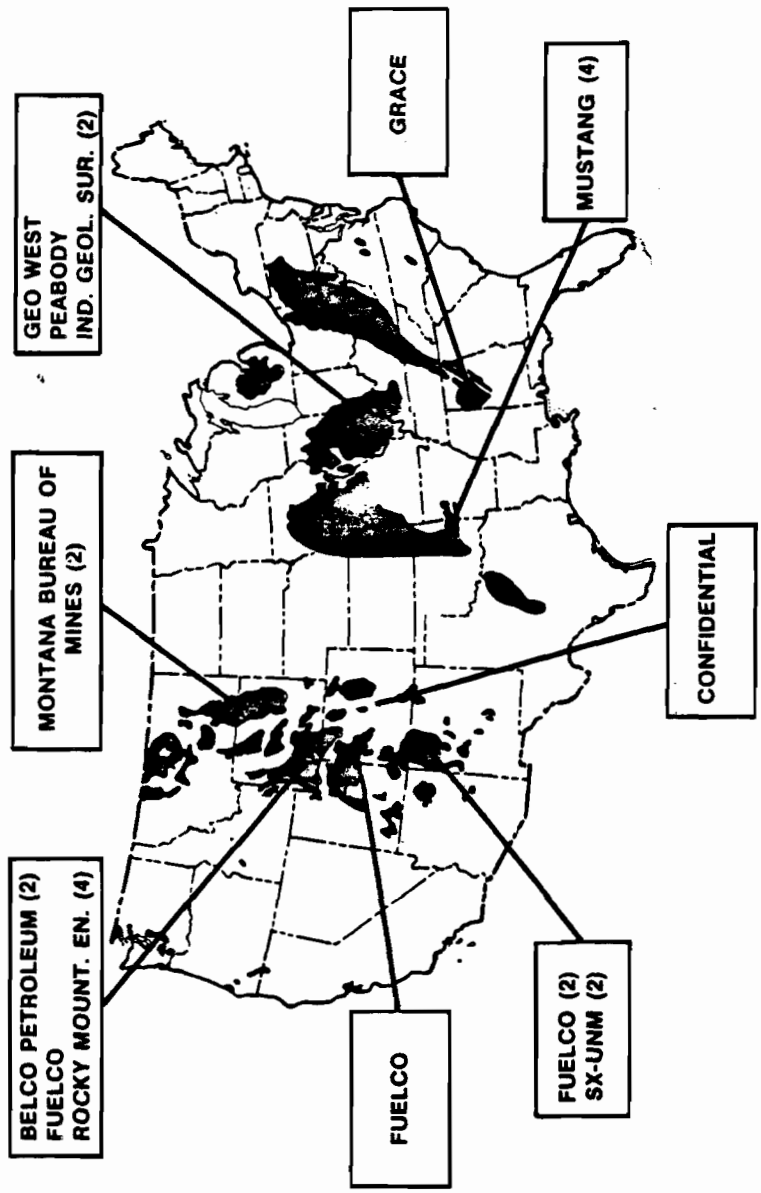

Figure 3. Wells to be Tested in 1979

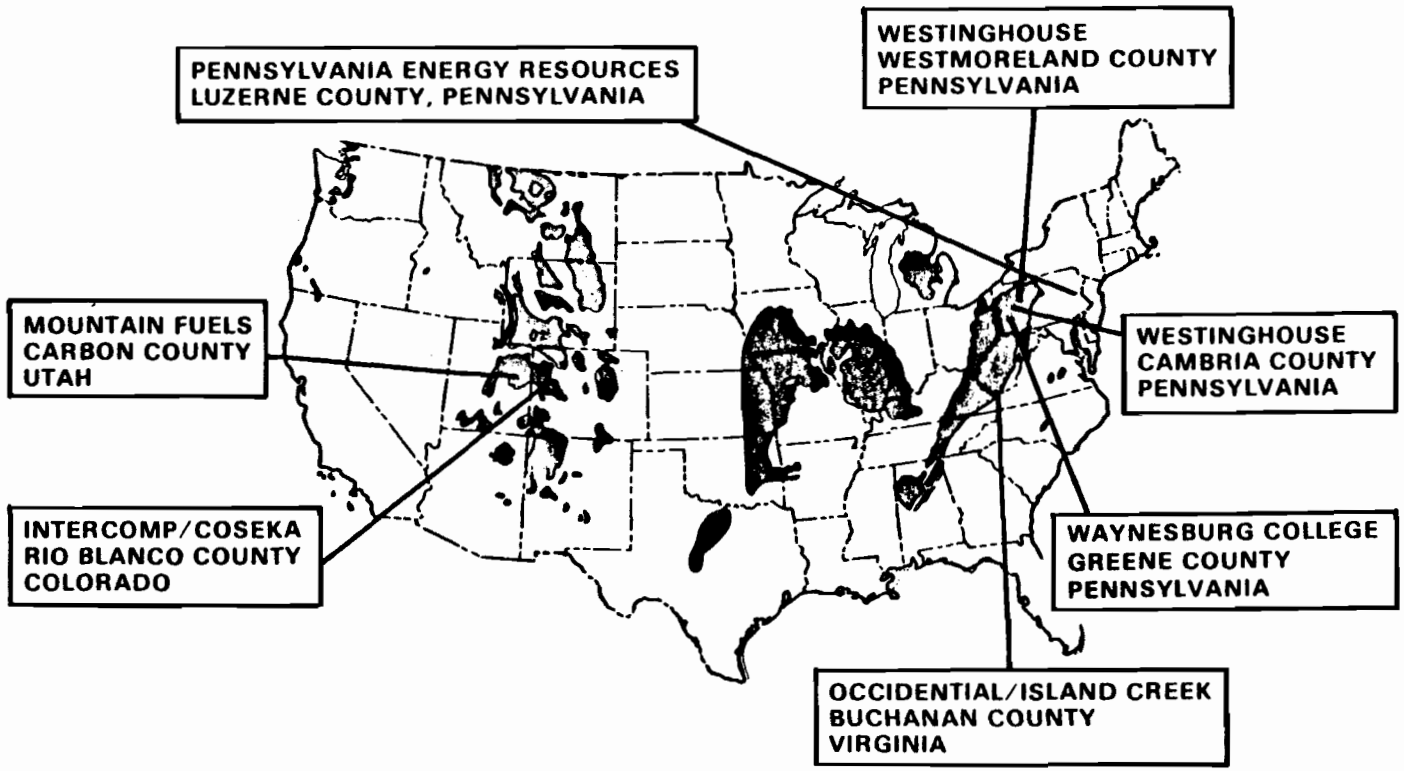

Figure 4. MRCP Technology Test Project Sites

COMMERCIALIZATION OF COALBED METHANE

BY

TROYT B. YORK

RESOURCE MANAGER/UGR
DEPARTMENT OF ENERGY

ABOUT THE AUTHOR

Troyt York is the Resource Manager and Acting Director of the Division of Natural Gas in the Office of Oil and Natural Gas Supply Development. His responsibilities involve formulating and implementing programs that result in the accelerated development and commercialization of natural gas from the marginal and unconventional resources. Major functional areas of work include: Gas Resource Assessment; Alternative Gas Production Technologies; Gas Collection and Processing; Waste Resource Recovery, Disposal and Environmental Management; Gas Transportation and Storage; and Marketing and Utilization.

Mr. York has BS and MS degrees from Eastern Illinois University. His undergraduate training was in the fields of geology and resource management. His graduate study involved academic concentrations in each of the areas of regional planning, economics and public administration. He is the founder of the American Society for Public Administration. Mr. York publishes occasionally in the general fields of community and resource development.

EDITOR'S NOTE: Mr. York was unable to attend the symposium; therefore, his paper was presented by Dr. Marian L. Olson.

ABOUT THE SPEAKER

Dr. Olson received her BA and MA degrees in Political Science and Education respectively at the University of Colorado, and her PhD at the University of Tulsa.

Prior to joining ERDA in June 1975, Dr. Olson was affiliated with various educational institutions in Wyoming, Colorado, Montana, and Oklahoma. She was granted a leave from the position of Program Associate in Research Administration at Montana State University to serve on the staff of the White House Energy Policy Office and in the Federal Energy Office.

Dr. Olson is currently a Program Analyst in the Division of Natural Gas in the Department of Energy and participates in various project management team efforts to develop the alternative fuels commercial demonstration program.

COMMERCIALIZATION OF COALBED METHANE

ABSTRACT

A series of energy technologies with near-term potential have been studied by the Department of Energy to determine barriers to their immediate commercialization and to consider the range of Federal actions that could potentially overcome the barriers. Where R&D is "complete," responsibility for "marketing" is transferred to an appropriate Assistant Secretary for commercialization. Unconventional gas recovery, including coalbed methane, is to be commercialized under the Assistant Secretary for Resource Applications.

Part of the strategy of the Commercialization Plan for Recovery of Natural Gas from Unconventional Sources is to make development of coalbed methane more attractive to the local use market. Of particular significance is a proposed project to demonstrate the technical and economic feasibility of local gas utilities to produce and distribute natural gas from coalbeds.

INTRODUCTION

Over the past several months, a series of energy technologies with near-term potential were studied at the Department of Energy in order to determine what barriers exist to prevent immediate commercialization of these technologies and what range of Federal actions could potentially overcome the barriers. During this time, a philosophy has developed concerning how best to insure the accelerated movement of such candidates to full commercialization. Where applicable, Resource Managers have been established to provide a DOE-wide point of focus for the integration of all activities required to achieve the earliest possible data for commercialization for specific technology.

In general, where the R&D for a technology is "complete, " responsibility for "marketing" activity is transferred to the Assistant Secretary responsible for commercialization. Among the technologies moved to the Assistant Secretary for Resource Applications and to which a Resource Manager has been assigned is Unconventional Gas Recovery.

Until recently, conventional sources have produced enough natural gas to meet the normal demands of the United States. Now, with declining production from domestic energy supplies, it is essential to develop the "unconventional" sources of gas.

There are two primary marketing targets for the commercialization of unconventional gas: the pipeline supply market (applies primarily to tight sands and geopressured zones) and the local use market (applies primarily to coalbed methane and Devonian shale). The strategy presented in the Commercialization Plan is designed to make development of the unconventional resources more attractive to these markets.

As this meeting is specifically concerned with coalbed methane, focus will be placed on that gas with references to Devonian shale gas where the Plan deals with the two simultaneously.

COMMERCIALIZATION PLAN

The Plan enumerates barriers to production and activities to overcome these barriers. For coalbed methane, barriers to production include: low flow rate of wells resulting in marginal profitability; limited public knowledge of the resource; mine safety; mineral rights, especially in active mining areas; and undefined utilization/market. Activities to overcome these barriers include; demonstrate feasibility of developing coalbed methane for local use; clarify institutional issues; and maintain currency with efforts of ET to determine the impact of methane drainage on coal production.

The Plan then sets forth program goals and objectives and activities to attain objectives. GOAL - to promote and increase the recovery of gas from unconventional sources to exceed 2 Tcf per year by 1990. OBJECTIVES AND ACTIVITIES - Coalbed methane and Devonian shale gas, by location, distribution and resource character, lend themselves to local or onsite development. They are extensively co-located throughout the country. Geologically the coal overlies the shale. Both resources have low flow rates, low pressure and produce for long periods of time. There has been limited experience producing and utilizing these gasses - particularly at the local level.

1. Accelerate local development and utilization of gas from these sources: The greatest exploitation of gas from these dispersed sources may ultimately be utilized by small communities and commercial/industrial firms located nearby. While some of these potential users have expressed interest, broad involvement is not likely without demonstrating the economics, reliability, environmental and

social feasibility of the concept. (a) Prepare a Program Opportunity Notice (PON) for qualified public and private applicants to demonstrate the technical and economic feasibility of developing coalbed methane and Devonian shale gas for local use. The PON will require a comprehensive approach to assessment, production, and utilization. (b) Begin projects to demonstrate technical and economic feasibility of developing coalbed methane and Devonian shale gas for local use, utilizing existing technology. (c) Promote rural and municipal development through utilization of unconventional gas resources by developing a memorandum of understanding with the Departments of Agriculture and Commerce and others. These departments have funds or loan guarantee authority for projects of this type. MOU will support this approach to development and outline working relationship as agencies utilize DOE for technical assistance. (d) Prepare a comprehensive information package that deals with the legal, technical, economic and managerial aspects of developing and utilizing natural gas from Devonian shale and coalbed deposits. This will be used for in-house reference and for public distribution.

2. Identify, investigate, and mitigate institutional barriers. (a) Seek to clarify ownership issue for coalbed methane. (b) Determine physical characteristics of coalbed methane and its marketability requirements.

3. Encourage the capture of methane vented during normal coal mining operations. (a) Determine the potential and desirability of using existing EPA and/or State environmental regulations to require that methane vented from coal mines be captured. Feasibility studies and cost benefit anaylses need to be done to determine if new or existing regulations should be used to encourage drainage rather then standard venting practices. (b) Review potential for modification of Federal tax laws to encourage recovery of methane from operational coal fields.

Program Coordination and Performance Monitoring

1. Determine expected impact of Natural Gas Policy Act of 1978 on projected recovery of gas from these sources. (a) Report on impact of NGPA. (b) Review progress in deregulating these gases under NGPA.

2. Establish commercialization planning for DOE R&D activity. Cooperate with other DOE offices to coordinate R&D efforts toward commercialization. (a) Work with ET, ER, EV, and industry to determine the technical aspects of UGR requiring resolution, which can justify Federal participation. (b) Perform state-of-the-art reviews with ET at regular intervals to determine which RDT&E activities should be terminated, and whether the technical information learned should be disseminated to industry via a technical transfer program. (c) Maintain currency with UGR efforts in ET to understand their objectives and to provide recommendations through the R&D Coordinating Council and other forums to focus their efforts on end products. (d) Encourage the adoption and utilization of State self-help programs.

3. Establish a monitoring activity . Provide comprehensive monitoring and work toward mitigation of major problems to commercialization or continued production. (a) Establish a baseline of private sector activity against which Government actions can be measured for effectiveness. (b) Develop a sample survey mechanism which may be used to determine industry reaction and interest in proposed and affected programs. (c) Stay abreast of efforts by industry in respective resources. (d) Identify potential impediments to commercialization of a resource as revealed by survey activity; refer to appropriate element of Gas group. (e) Monitor regulatory activity.

PROGRAM OPTIONS

The major basis for the strategy embedded in this program plan is the different levels of technical and commercial readiness among the unconventional sources.

Devonian shale deposits and coalbeds have potential in an inexperienced market. It is therefore, assumed that development of these resources can benefit most from government involvement at this time.

As both resources frequently are in the same geographical location they may be developed simultaneously at a given site. Much of the work done by the Office of Oil and Natural Gas will be applied to both resources simultaneously, thus resources available for this work are divided equally as a matter of convenience.

Resource Assessment and technology improvement are roles assumed by ET. It is the strategy of this program to begin where we are with what we know. As ET reports achievements we will modify the plan to reflect these changes.

COMMERCIALIZATION OF COALBED METHANE

Commercialization of coalbed methane and gas from Devonian shales is not so much a technical obstacle as locating and developing users of this decentralized resource. Funding is not available from the DOE budget in FY 1979 to provide financial support to any demonstration project. However, by identifying a few sites where use of these unconventional sources could be utilized, and by obtaining from industry Expression of Interest requests, financial support could be obtained from other Government agencies such as Department of Agriculture and the Economic Development Administration.

There are also a number of other issues peculiar to coalbed methane whose solution should enhance the recovery potential of this resource. Institutional impediments include ownership issues, and marketability of the gas. There may also be some reasonable actions which would encourage recovery of methane that is vented prior to coal mining operations.

MANAGEMENT APPROACH

DOE's Office of Energy Technology has a program designed to develop needed technology to stimulate and increase the production of natural gas. The Office of Oil and Natural Gas Supply Development program in Resource Applications is designed to meet the stated objectives through the development of DOE policies and actions to encourage commercialization, through analytical studies of primary constraints to development and through actions to mitigate these barriers.

APGA PROPOSAL

In November of 1978, the American Public Gas Association initiated contact with DOE expressing their interest in submitting an unsolicited proposal to demonstrate the technical and commercial feasibility of utilizing gas from coalbeds and Devonian shale for purposes of community and rural development. They submitted a formal proposal January 8, 1979.

In reviewing the proposal, the RA Commercialization objectives were considered:

RA COMMERCIALIZATION OBJECTIVES

Coalbed Methane and Devonian Shale Gas, by Location, Distribution and Resource Characteristics, Lend themselves to Local, On-site Development. The RA Commercialization objectives are to:

- Accelerate Local Development and Utilization.
- Initiate Projects to Prove Commercial Feasibility.
- Prepare Comprehensive DOE Technical Assistance and Technology Transfer Program.
- Seek Interagency Participation With Departments Of Agriculture, Commerce, Interior and the CSA to Implement Development Program.

Also considered was the potential for gas use in rural development.

RURAL DEVELOPMENT PRIORITIES AND NATURAL GAS USE

1. ENERGY, WATER AND FOOD PRODUCTION: Electric Power Generation (REA/Municipal Systems); Water Pumps For Irrigation; Farm Fuel (Equipment, Processes, & Grain Drying); and Fertilizer Production.

2. RURAL INDUSTRY & TRANSPORTATION DEVELOPMENT: Industrial Process; Industrial Heating & Cooling; Automotive Fuels; and Diesel Systems Fuel.

3. IMPROVED COMMUNITY FACILITIES & SERVICES: Local Pipeline Injection (Residential/Commercial Use); and LNG Production (Storage For Seasonal & Peak Use).

With this infomation in mind, the proposal was reviewed:

WHO IS THE SPONSOR? _ The American Public Gas Association; Private, Not-For-Profit Organization; Represents 1200 Municipally Owned Gas Systems In 32 States; Principal Charter: Technical Assistance To Municipally Owned Gas Systems; Eligible To Recieve Financial Assistance Under Federal Procurement Rules; and Prohibited From Lobbying Activities.

WHAT IS PROPOSED? - The APGA proposes to develop a demonstration program to acquire and use natural gas from coalbeds and Devonian shale utilizing technologyPresently considered technically and economically feasible.

TROYT B. YORK

OBJECTIVE: To demonstrate the technical and economic feasibility of local, publicly owned and operated gas utilities to produce and distribute natural gas from coalbeds and Devonian shale deposits. The project will develop a prototype that can be replicated in small communities and rural areas around the country, with the goal of accelerating the availability of this resource.

Phase I - $75,000 9-11 Months Duration

- Many communities will be evaluated with sebsequent selection of a "pilot" community from each of the major coal and Devonian shale bearing regions of the country.
- One exploration well drilled and resource evaluation done for each community.
- Identification and planning for resolution of legal and institutional issues.
- Go, no go decision for phase II.

Phase II - $2,729,000 9 Months Duration

- Drilling and completion of 3 test wells and 1 reinjection well in each community.
- Technological and market/economic evaluation to determine feasibility of using natural gas from coalbeds and Devonian shale deposits as a supplemental energy source.

Phase III - $86,000 7 Months Duration

Based on experience gained from demonstration, a technical and financial assistance program ("Cookbook") will be developed to provide continuing information and assistance to smaller communities and rural areas thoughout the Nation in the development of this underutilized resource.

Is The Proposal Representative of What Can Be Done? - The proposal targets small communities and the drilling would be sited in selected communities. While certain experience and information gained would be community specific, the resource assessment; drilling and completion; legal and institutional issues; technological and market/economic experience and information developed through the project would be transferable to a wide variety of settings and circumstances.

The Project Is A Catalyst Intended to Accelerate The Rate of Technology Transfer.

- Project directly involves six communities. Potentially, there are over 6000 small communities representing 24 million people co-located with coal and shale resources, many of which could become candidates for future development.
- Other potential rural and community users of information expected to be developed by this project: Industrial Parks; Electric Cooperatives; Small Industry; Agricultural Units (Crop Drying, Pumping, Heating); Compressed Gas Distributors; Indian Reservations; and Community Institutions (Schools, Hospitals, Community Buildings). There is significant potential for diverse and widespread technology transfer and resource development for community and rural purposes.

Are The Economics Attractive: To the consumer; the community; the Department of Energy; and the United States?

For a sample community, the annual gas bill under a private utility contract would be $871,500+. With a municipally owned supply, the annual bill would be $572,000+. The annual savings would be about $300,000 or 34%.

For $3.7 million, DOE purchases: First-of-a-kind demonstration of commercial production and utilization of natural gas from coalbeds and Devonian shale for local markets; Experience in encountering and dealing with related institutional issues; Technological and market/economic data to be used in determining feasibility of using natural gas from these sources; and, "Cookbook" for use of others interested in developing these resources.

A $3.7 million DOE investment in this project can provide information and experience that will allow other agencies such as USDA (Farmer's Home Administration, REA), DOC (Economic Development Administration), Community Services Administration to consider funding unconventional gas development projects. Funding which could be dedicated to such projects exceeds $1 billion.

COMMERCIALIZATION OF COALBED METHANE

HOW DOES UNCONVENTIONAL GAS COMPARE IN COST TO OTHER SOURCES?
(COST PER 1000 CUBIC FEET -* 1978)

Electricity**	$14.65
Coal Gasification	$ 5.50
Distillate Oil (Equivalent)	$ 4.43
LNG	$ 4.27
Alaskan Gas	$ 4.20
Mexican Gas	$ 3.25
Domestic Gas (Conventional)	$ 2.26
Coalbed Methane & Devonian Shale***	$ 1.05

* ERA, June, 1978
** Price Quote - Pepco, March, 1979
*** NGPA - March, 1979

Will The Project Trigger Interagency Cooperation? - A memorandum of understanding is being drafted that will lead to the joint funding of a technical and financial assistance program for small business, community and rural development. The participants are: The Department of Agriculture. (FmHA - REA - Rural Development); the Department of Commerce (Economic Development Administration); Community Services Administration; and the Department of the Interior (Geological Survey).

The successful completion of the APGA project is the trigger that could channel these interdepartmental resources into a rural energy development program.

Why We Should Support This Project? - It is not likely that the gas will be produced otherwise in the short-term because: Coal and shale resources are too regionally dispersed to be of interest to industry; this is an advantage to 6400 municipalities; Gas from coalbeds and shales is produced at low pressure, low volume and over a long period of time; not economically viable for interstate gas industry; compatible nd economically attractive for local, low pressure, low volume users; Small business, rural users and municipal Governments have no traditional experience in gas production; They are extremely interested but are taking a wait-and-see attitude.

Why Should RA Support This Project? - The project Fits the RA commercialization Plan; There is a very low level of national awareness of the resource and technology; Will not happen soon otherwise, (Industry and local government are taking a wait and see attitude); Limited expenditure has potentially large payoff, very low risk; Information acquired will accelerate technology transfer; We need a larger scale test of current economics and technology to prove the case; Opportunity exists to harness technical and financial resources of industry and other government agencies; High degree of interest. (DOE - USDA - DOC - DOI - CSA - Congress - Whitehouse - Producers - Consumers - Environmentalists); Negligible environmental impact; Utilize an otherwise dispersed and wasted resource; and Promotes competition between producers and between consumers.

Why shouldn't we support this project? - The mortage may be higher than expected, up to 10% (result of inflation); Resource might not sustain production estimates - if wells produce less than 25 MCF/day project probably uneconomic; The proposal may unleash a host of "me, too" applicants; and In some cases the project may be viewed unfavorably by pipeline companies.

To minimize negatives - Contract for project for fixed budget. Cut back on number of wells or communities if necessary to avoid cost overruns; Work closely with USBM to select communities that are over known gas producing coals and shales; Work closely with other agencies on MOU to provide technical and financial assistance to subsequent applicants; and coordinate the project through the gas Research Institute so that gas industry is kept advised on developments, seek their cooperation.

Recommendation - It was recommended that stage I be funded by RA at a level of $735,000 to carry out all pre-development work.

SUMMARY

The Commercialization of coalbed methane is in its infancy. The Department of Energy is pursuing a plan aimed at reducing barriers to commercialization of this resource. A significant activity that will contribute to the plan is the APGA project to demonstrate the technical commercial feasibility of utilizing gas from coalbeds and Devonian shale for purposes of community and rural development.

THE U. S. BUREAU OF MINES PROGRAM FOR METHANE DRAINAGE TO REDUCE SAFETY HAZARDS IN COAL MINES

BY

MAURICE DEUL

RESEARCH SUPERVISOR, PITTSBURGH MINING AND SAFETY RESEARCH CENTER

U. S. BUREAU OF MINES

ABOUT THE SPEAKER

Maurice Deul is the Research Supervisor for Methane Control and Ventilation at the Pittsburgh Mining and Safety Research Center of the U.S. Bureau of Mines. He joined the Bureau of Mines in 1963. From 1960 to 1963 he was employed by the Consolidated Coal Company where he worked on novel approaches to coal beneficiation. Mr. Deul worked on methods for reducing sulfur in coal at Bituminous Coal Research Incorporated from 1957 to 1960.

Mr. Deul worked with the U.S. Geological Survey from 1948 to 1957 in the geology and geochemistry of uranium and coal. He earned his Bachelor of Science degree in Mineralogy from the University of Colorado in 1947. He has authored and coauthored more than 60 publications during his professional career.

EDITOR'S NOTE: The following text is a transcript of Mr. Deul's talk at the symposium.

Fortunately, I don't have any slides either. Nor do I have an abstract of the paper, nor do I have a written presentation, for several reasons. Talking about the current program of the Bureau of Mines with regard to reducing the hazards of explosions of methane in coal mines has been the business of the Bureau since its inception, and most of the development has followed sort of an orderly pattern. I've just outlined a few highlights to present to you in the context of this meeting. One of the things we ought to recognize is that most federal agencies operate based on budgets which are prepared with genuine requirements for funding to do planned work. We are not given a pot of money which we dip into and distribute as largesse to people who come up with some ideas. That's not the way we operate. The ideas that the Bureau has worked on were generated in the Bureau, not entirely uniquely and independently, but as part of a work plan. As a consequence of that, the work that has been done by the Bureau currently is directed in a number of directions.

First of all, we want to promote the use of methane control techniques that have been developed by the Bureau. These techniques have been rather well established. They're simple and direct, and where they can be applied, we're proposing their use. Recognizing that these are not entirely perfect, we are working on improving these techniques, especially for application in mines where the coalbed physical properties and the geologic conditions are unfavorable if not downright hostile.

We are also working on developing, through contract research, inhole surveying instrumentation to make drilling more efficient and more productive.

We're promoting improved drilling machine and tool design either by direct contracts or by modifications which we've worked on ourselves or in cooperation with other drilling companies.

We're testing novel methods - novel to the coal industry - of drilling to drain gas from coalbeds. You will hear more about that from Pat Diamond.

We are continuing to determine the gas content of bituminous coalbeds that are now being mined, or soon will be mined, and determining geologic factors that control methane migration and retention.

We are managing research and demonstration and development contracts that were originally planned by the Bureau or are now broadly administered by the DOE. Some of those have already been mentioned by Bob Wise.

One of our more important activities is that of providing information to the public, to industry, to research organizations, universities, to other federal and state agencies, and DOE and their contractors so the Bureau's work is not needlessly duplicated. In essence, these are our activities. Most of them are focused on our primary mission of reducing the hazards of explosions of methane-air mixtures in coal mines, which still continues to be probably one of the most difficult problems to cope with in the newer, deeper mines being opened. As an aside, we feel that methane drainage will be practiced by the mining companies only when they must do it. They must do it to survive, for their investment in a new mine is extremely precarious because they cannot produce coal and get a cash flow if the commitment to operation is not economically sound. Now it's a sad commentary, but those are the facts of life as we see them. I really doubt that there will be a substantial thrust by the mining companies to begin to drill and produce gas independently of their needs to develop a safe operating environment, except for a notably few cases. In fact, even where money has been invested and drilling has been ostensibly done to develop the gas resource, some of the constraints to putting that gas into a pipeline for commercial use have been so severe that hundreds of thousands of dollars have been spent without a cent of return except for the benefits that accrue in operating a mine safely and productively, and that is not a small matter. I think there are people here who would attest to that statement.

Well, getting back to the program of the Bureau of Mines, the major thrust of investigation is to develop techniques that can be used easily by coal mine operators. We have developed a lot of techniques in the past that were expensive and very complicated, and we did not really try to push those for an acceptance by the coal mine operators because we recognize that in drainage of methane from coalbeds, if a process isn't direct, isn't simple, and can't be done with the minimum of management, it will not be used. That's something for people to consider in trying to get coal mine technology expanded to work on these ancillary problems. Because we're talking about methane drainage from coalbeds, I won't discuss here the research and development on improved and novel methods to make ventilation more efficient and more effective that have been developed by the Bureau of Mines, and now independently, under a dust and ventilation research program now headed by Floyd Kessell, a research supervisor in the Pittsburgh Mining and Safety Research Center. All the methods of methane drainage that we have developed and that are used broadly (and everyone knows what they are) involve drilling. I'll just go over the list very quickly.

- drilling horizontal holes from shaft bottoms
- drilling horizontal holes from outside mine entries
- drilling vertical drainage holes, as we will discuss later on in this program
- drilling directional slant holes from the surface to intersect coalbeds at a glancing angle and then stay parallel to the bedding
- drilling gob degasification holes which are drilled down to the vicinity of the advancing longwall face or retreating longwall face, to relieve the methane when there is a collapse of the overlying strata.

We are also engaged in an exploratory program for drilling holes from mine entries diagonally upward over the strata overlying an advancing longwall face. This is an attempt to apply European technology, and there are only a few places now in the United States that this can be done. We are trying to develop the techniques so it can be applied easily by the mining companies where they are indicated. Finally, research is being done in drilling and packing holes in the coalbed in order to infuse water to provide a water flood; a lot of water to prevent the flow of methane into the immediate face area. Where there is inadequate ventilation to dilute the methane, where there is not a

good situation to provide the pipeline to the surface, or where it is too costly or inconvenient to drill a vertical borehole down to intercept mine entries so that the gas can be piped to the surface, it becomes necessary to use water flooding to prevent the emission of methane into the base area and to allow mining to continue productively and safely. Recognizing that methane control techniques are dependent upon the capability to drill very longholes effectively (we are talking now about the prospect of drilling holes five thousand to six thousand feet long, since we have already been able to demonstrate that we can drill holes one-half mile long, without even beginning to tax the drilling equipment we use) we feel that being able to drill a hole a mile long which will drain a lot of methane from a gassy coalbed which has good permeability, while technically possible, has some real problems in coalbed discontinuities, there are rolls, small displacement faults, sand channels, sand bars, etc., the economics of which would preclude drilling a long hole that will do any good.

So it's useless to have the capability of drilling a hole five thousand feet long or two thousand feet long when only two hundred feet from the drilling site you will run into one of these barriers to long hole drilling. All too often, the geological data to define the coalbed parameters which enable us to predict drilling effectiveness is too sparse and sometimes totally absent or nonexistent. Most coal mining companies drill holes to determine only quality and perhaps quantity since they are only trying to find the resources as they understand it. But getting around to mining it effectively and safely is of secondary importance. Very often, they have totally inadequate means of determining the exact location of the hole. So what we have to do now is come up with a criteria that will allow us to establish confidence levels for drilling horizontal holes or holes parallel to the bedding for some given length. If we are in the situation that we are often in the Pittsburgh coalbed, where it is possible to drill a hole two-, three-, or four thousand feet long without running into a discontinuity of more than five, or six percent of the time, this is fine. Perhaps we would establish a 95% confidence level. But there are other areas where we work, like the Beckley coalbeds and others, where the confidence levels for drilling a hole a thousand feet long may be only 60%. That means that 40% of the time we wouldn't be able to drill a hole five- or six hundred feet long. That may do some good, but certainly does not help when your mine degasification plans on holes that are going to be 1500 feet long. So that is the next area we currently are starting a program, our next area of major investigation.

In essence, that is the Bureau's program. I would like to get into philosophy a little bit and begin to worry about progress and how progress is maintained in an R&D effort, and this holds true not just for methane control research. I think once an investigation is planned in an orderly and rational manner, and supported modestly, and if it is supported by permitting a staff to be assembled that consists of a smattering of imaginative thinking, the project will probably be successful, because the work will be planned in such a way that goals are set up, at least initially, so an accomplishment can be reached. In the methane control research program, we have been particularly blessed with that kind of enlightened management. The Department of Interior, when they did decide in 1964 to invest in a methane control research program, funded it modestly and gave us time to develop the program. We have had the time to get it reviewed by people who can give us critical input. We were allowed to staff up modestly with people who were independent thinkers. Within about three years, Joe Cervick published a paper that I wanted to have titled "Methane Can Be Controlled". That title was shot down because we were then deferential to the people in Health and Safety, who operated independently from the research people and who thought that was just too blatant a statement to make. But I still say the methane can be controlled. We changed the title of that paper to something innocuous like "An Investigation Into the Behavior Migration of Gas in Coalbeds". The first paragraph had a couple of differential equations in it, and that paper lay dormant for years because nobody would ever read it. We have found out since that people in the mining industry, and often elsewhere, are just too busy to read scientific papers. They want answers, and they want answers that are clearly defined. They want them simple. We gradually developed a trend toward writing "shin kicking" papers, the kind of paper that tells just what you can do in one particular instance. If the title is not clear, people do not even open the cover. We do have a communications problem and the proliferation of issues and papers given on methane that say nothing and add nothing new to the body of knowledge, and that merely gives us another reference we have to include when we get a contractor to review what goes on in the field. It really does a disservice to those people who want to get in and really begin to do something. Most of the important concepts we have now have been published by 1967. Almost everything we have done since then, although it has been added to the literature and has developed more techniques and more tools, have not been very "earth shaking". It is very simple to establish what has to be done if you want to operate a safe mine, as far as methane control goes. You first have to determine how much gas is there, and you can do that very easily by the methods that have been written and published and are widely used. What we do with the data afterward is another problem. Even if you know you have a gassy coalbed, people will argue, just like they argue about how many angels will dance on the head of a pin, what constitutes a gassy coalbed. A rough rule of thumb is that if you have a coalbed that contains five or six cc

per gram of methane in the coalbed in place you can anticipate problems, especially if you have ground control conditions such that the entries cannot be very wide, and such that where the depth is great, since it is costly to put down lots of ventilation shafts, then you have a methane problem. If you have good engineering, good conditions so that you can make use of every last bit of ventilation air that comes down, you might be able to handle as much as three or four million feet of methane emitted in the base area. If it goes beyond that, generally, the ventilation efficiency of engineering does not permit one to operate the mine safely without extremely costly shafts without excessively high velocities, and sometimes mines had to go to a drainage technique. One of the worst things that can happen to an engineering operation is to be surprised. Management does not like it. Stockholders do not like it. It raises some very serious problems when you have designed the mine, that is supposed to operate with the existing shafts for four to five years and produce six or seven million tons of coal before you open up the new shaft. But when it turns out that you have the timescale very briefly condensed and before you even begun to get a decent cash flow you have got to begin putting down more air shafts, people begin to wonder. This is where methane drainage should help. This is where methane drainage should be planned. We have iterated and reiterated that methane drainage should be planned well in advance of opening a mine. Techniques are there to allow you to make those plans, and if you are so unfortunate as to be opening a mine in a coalbed where the physical properties of the coal would not allow free flow of methane from the drainage holes you have an additional problem. Knowing about that problem perhaps does not make your life particularly easier in terms of operating the mine productively and properly. But you should not be surprised when you begin to extract coal and find that you cannot do with it the way you want to. Those are these areas that we are seeking cooperators who will generally want to work with us, in terms of developing the methodology and in testing the techniques that we are developing and want to develop and continue to develop in making gas drainage work in coalbeds where the problems are extremely difficult. The kind of tests that we do, the kind of work that we do can not be done in vitro; it cannot be done in a test tube. The place where it has to be done is in the mine. It has to be done in the mine that is having problems. The mine having problems sure as hell does not want a bunch of Federal men around poking holes in their coalbeds. Yet, unless the mining company is willing itself to do the development, and to do that work, I think ultimately they're going to have to depend upon the cooperative efforts that we make with them.

THE CONTROLLING PRODUCTION MECHANISM OF METHANE GAS FROM COALBEDS

BY

VELLO A. KUUSKRAA, EDGAR HAMMERSHAIMB
DR. TODD M. DOSCHER

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VELLO A. KUUSKRAA

Mr. Kuuskraa is Vice President of Lewin and Associates, Inc. and as such directs efforts in resource economics and energy technology for their Energy Practice. Recently he directed the firm's efforts in analyzing the potential of unconventional gas sources; recommending R&D programs and conducting regulatory of oil production, including enhanced oil recovery, offshore production, and other high cost oil production; and providing analytic assistance in assessing the potential of domestic tar sands. Mr. Kuuskraa was selected as a representative of the U.S. to the UN/IIASA conference on the "Future Supply of Nature-Made Petroleum". Mr. Kuuskraa holds a bachelors degree in applied mathematics from North Carolina State University and a MBA from the Wharton School of the University of Pennsylvania.

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THE CONTROLLING PRODUCTION MECHANISM OF METHANE GAS FROM COALBEDS

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ABSTRACT

Methane occluded in coal seams constitutes a large resource of natural gas which has remained essentially untapped. In the last few years, interest in this resource has increased, but the physical parameters and technical aspects governing its recovery are still not well understood.

This paper investigates the production characteristics of methane from coal and describes a framework for evaluating the physical mechanisms controlling the production of this resource.

An understanding of the controlling production mechanism is necessary when considering which recovery method to use. This choice may well depend on whether recovery is limited by fracture permeability or by the amount of gas that can diffuse from the coal face into fractures.

This paper provides a framework for evaluating recovery under two production mechanisms and over a wide range of physical parameters, such as the diffusion coefficient and coal seam permeability. After reviewing the basic theory, an analysis will be presented of the controlling production mechanism for the Pittsburgh and Pocahontas coals.

GAS PRODUCTION MECHANISMS

Since coal is not a porous medium, the methane in coal seams must be located either in the fractures or be adsorbed in the coal matrix. Thus, the two physical mechanisms controlling the recovery of methane from coal are:

- Diffusion - the propagation of absorbed methane from the coal matrix into the fracture system.
- Permeability - the flow of gas through the fracture system.

Assuming the total fracture system in the drainage area is connected to the wellbore, the simple recovery model postulated by these two mechanisms is that, upon commencing production, gas and/or water is produced from the fracture network.(1) Initial production is thus limited by the reservoir permeability or the relative permeability of two-phased gas/water flow. As the gas and water present in the fractures are produced, the equilibrium gas concentration in the fractures falls below the gas concentration within the surface layer of the coal and gas will diffuse out of the coal and into the fractures for subsequent flow through the permeable fracture system. Thus, the recovery rate will depend on an interplay between diffusion and permeability, with ultimate recovery depending on the concentration of methane and the effective drainage volume of the wellbore.

The recovery rate is constrained by permeability (permeability is controlling) when gas can diffuse from the coal into fractures faster than it can flow through the fracture network.

THE CONTROLLING PRODUCTION MECHANISM OF METHANE GAS FROM COALBEDS

Diffusion is controlling when gas can flow faster than it can desorb from the coal matrix into the permeable network.

To evaluate recovery in a given time period, the controlling mechanism can be estimated from initial physical parameters and then analyzed using reservoir engineering methods.

DIFFUSION CONTROLLED RECOVERY

Basic Recovery Equation

The equation characterizing diffusion is:

$$dQ/dt = D*A* (dc/dx)$$

This equation states that the flow rate of gas out of the matrix depend on the diffusion constant (D), the area from which gas is diffusing (A), and the methane concentration gradient from the surface into the coal matrix (dc/dx).

Assuming zero concentration in the fractures and a finite amount of gas sorbed in the matrix, the concentration gradient will decrease as gas is removed from the matrix. The flow rate is thus a decreasing function of time. To maximize recovery when diffusion is controlling requires a large surface area and a rapid removal of desorbed gas from the matrix face.

Since the coalbed tends to fracture in slabs that are uniformly spaced, the model used for evaluating diffusion recovery consists of fractures running the length and height of the coal seam with slab thicknesses of 2L.

Under this geologic configuration, the diffusion equation can be solved as described by Carslaw and Jaeger.(2) The resulting recovery efficiency, R_e, for desorption from this type of slab geometry, is as follows:

$$R_e \text{ (at fracture pressure of 0 psi)} = f(Dt/L^2)$$

The solution is shown graphically on Figure 1. Recovery as a fraction of the sorbed gas is plotted as a function of Dt/L^2 where D is the diffusion constant (cm^2/sec), L is the half-width of the slab (cm), and t is time (sec).

Measured Diffusion Constants

The diffusion constant for methane in coal has been reported to vary from $1*10^{-13}$ cm^3/sec to $5*10^{-8}$ cm^3/sec.

The lower end of the range was reported by Sevenster(3) in 1959, who reduced the coal to a powder before measuring the diffusion constant.

Other investigators(4) have reported estimates ranging from 10^{-10} cm^3/sec to $5*10^{-8}$ cm^3/sec. However, these results appear to depend on particle size, decreasing with decreasing superficial size, which casts doubt on the accuracy of the large diffusion coefficients measured from large particles.

The analyses in the following sections will cover the range of reported diffusion constants.

PERMEABILITY-CONTROLLED RECOVERY

Basic Recovery Equation

The second physical process controlling recovery is permeability. This parameter determines the rate at which the gas already in the fractures will flow toward a pressure sink (wellbore). Recovery depends on the reservoir pressure, the porosity, the drainage volume, the temperature,

and time. The radial-flow unsteady state equation, assuming constant pressure, used for estimating the cumulative volume of recovered gas is:

$$Q_{MSCF} = \frac{0.111*\phi*h*r_{we}^{2}*c*(P_i^{2}-P_w^{2})Q_{td}}{Z_{avg}*T_f}$$

Where Q_{td} is a function of dimensionless time (t_d) and dimensionless drainage radius (r_d), as shown in Figure 2. The equation for dimensionless time is a function of key reservoir properties, such as permeability, gas viscosity, and porosity.(5)

Limiting Reservoir Parameters

To determine recovery, one must define a pseudo porosity and establish the effective in-situ gas permeability.

- Porosity. The actual porosity of the coal is low. However, to account for the methane sorbed in the matrix, a pseudo-porosity can be defined, equal to the porosity the coal would have if all the dissolved methane were located in a porous structure.(6)

- Permeability. Natural fracture systems, the presence of clay seams, and the effect of water are variables that influence permeability. Although permeability varies widely among individual coal seams, a few data points are available. In-situ measurements have been reported in one mine in Canada and one in Australia.(7) Permeabilities were measured to be 5 millidarcies for the Canadian mine and between 0.001 and 0.01 millidarcies for the Australian mine. Indirect measurements of permeability for Pocahontas coal gave values between 0.05 and 250 millidarcies, and an indirect average value of 0.75 md. (8-9) The analysis covered an average permeability range of 1 to 5 millidarcies.

RECOVERY-LIMITING PROCESS

For a chosen period of time, either diffusion or permeability will limit recovery. Using the equations presented earlier, the lower recovery can be calculated and thus the limiting process determined.

A qualitative analysis of the recovery-limiting process is illustrated on Figure 3. Permeability-limited recovery is shown to increase as permeability increases. Should the reservoir properties be such that diffusion-limited recovery is the horizontal line on Figure 3, a permeability less than the point at which the curves cross will result in ultimate recovery being permeability-limited, and a permeability larger than this will result in diffusion being the limiting factor.

Over shorter periods of time, the diffusion and permeability mechanism will interfere with one another, and the recovery equations must be refined. A major assumption is that the concentration of methane in the fracture system is zero for estimating diffusion-limited recovery. For the initial recovery period this is not the case, and diffusion will be less than the maximum shown on Figure 1. As the fracture pressure is reduced, diffusion of gas into the fractures will increase and approach the theoretical diffusion curve as a limit.

The interaction between permeability and diffusion recovery is shown qualitatively on Figure 4. The flow rate for diffusion and permeability is shown as a function of time. Initially, the flow is permeability limited and the gas does not diffuse out of the matrix as fast as the theoretical maximum. The rate of diffusion drops to the permeability-constrained rate of production. The volume difference between this theoretical maximum and actual is shown as the hatched area on Figure 4.

After a sufficient amount of time, t_1, recovery would have become diffusion-limited. However, the concentration gradient is higher than the theoretical value and permeability will control recovery as the volume of gas that was constrained earlier is produced. When the concentration gradient has decreased such that the rate of desorption is less than the fracture flow capacity, diffusion becomes limiting.

EXAMPLE ANALYSIS

An analysis of the controlling production mechanism will be illustrated for two dominant Eastern coal seams, the Pittsburgh and the Pocahontas.

1. The only reported data on fracture spacing is that the Pittsburgh and the Pocahontas coals have slab thicknesses of 1/2" and 1/16", respectively.(10) Under these values, the 10-year recovery from diffusion is shown on Table 1 over a range of diffusion constants and for different time periods, assuming this dense natural fracture system.

   - Pittsburgh. For the Pittsburgh coal seam, a negligible amount of gas is recovered with a diffusion constant of $1*10^{-13}$ and essentially all the gas can be recovered with a diffusion constant of $5*10^{-8}$.

   - Pocahontas. A negligible amount of gas is recovered from Pocahontas coal if the diffusion constant is 10^{-13}. Seventy-four percent of the gas in place can be recovered the first year with D equal to 10^{-10}, and essentially all if the diffusion constant is $5*10^{-8}$.

2. Ten-year recovery from Pittsburgh and Pocahontas coal is shown on Tables 2 and 3, respectively, for a range of permeabilities, a range of drainage areas, and two wellbore radii. The larger wellbore corresponds to fracturing. Reservoir parameters used to calculate the recoveries are also shown on Tables 2 and 3. The major findings are:

   - Pittsburgh. This coal seam has a low gas content and a low initial pressure (Table 2). To produce a quarter of the gas over 10 years, a permeability of 5 millidarcies and a drainage area of 80 acres is required. If stimulated, the recovery increases to 35 percent.

   - Pocahontas. This coal seam has a higher gas content and pressure than Pittsburgh coal (Table 3). Consequently, the gas recovered as a percent of gas in place is higher. With a permeability of 1 millidarcy and a drainage radius of 80 acres, about a third of the gas is recovered in 10 years. With fracturing, recovery increases to 42 percent.

   To interpolate between the permeabilities shown on the tables, graphs of the recovery are shown on Figures 5 and 7 for the Pittsburgh and Pocahontas coals, respectively. Similar graphs can be drawn showing ultimate recovery as a function of the diffusion constant.

3. By comparing the recovery from permeability and diffusion at any point in time, the limiting process can be determined. (The combination of parameters that result in either diffusion or permeability-limited recovery can also be graphically determined by comparing Table 1 with Figures 5 and 6.) The analysis of which production mechanism is controlling leads to the following results for Pittsburgh and Pocahontas coals:

- Pittsburgh. Ten-year recovery from diffusion varies from a negligible amount with a diffusion constant of $1*10^{-13}$ to essentially 100 percent for a diffusion constant of $5*10^{-8}$. Ultimate recovery is thus diffusion-limited at the lower diffusion constant and permeability-limited at the higher. Between these two extremes, ultimate recovery changes from being diffusion- to permeability-limited. With a diffusion constant of $1*10^{-10}$, diffusion-limited recovery is 31 percent. Figure 7 repeats the earlier shown graph of permeability recovery for Pittsburgh coal, but now the diffusion recovery of 31 percent is also shown. As can be seen on the graph, permeability is the controlling variable on ultimate recovery for the cases examined, except for a fractured well on 80-acre spacing and a permeability greater than about 4 millidarcies.

- Pocahontas. Over the range of diffusion constants examined, ultimate recovery ranges from essentially zero with a diffusion constant of $1*10^{-13}$ to nearly 100 percent with a diffusion constant of $1*10^{-10}$. As shown on Table 3 and Figure 6, recovery becomes permeability-limited for diffusion constants larger than $1*10^{-10}$ cm^3/sec.

INCREASED RECOVERY POTENTIAL

The potential for increasing ultimate recovery depends on the mechanism controlling recovery. If diffusion is the controlling mechanism, additional recovery can only be obtained by increasing the area for methane desorption or insuring that the pressure in the fracture system is as low as possible. However, since the addition of one more fracture plane to increase the area for desorption can add only a small amount to ultimate recovery, methods will need to be developed for inducing numerous fracture planes deep into the coalbed.

If permeability is the limiting mechanism, additional recovery could be obtained by increasing the wellbore radius and the effective permeability through propped fractures. However, it may not be technically possible to induce fractures orthogonal to the dominant face cleat systems.

CONCLUSION

This analysis has shown that methane recovery from coal seams can be either diffusion- or permeability-limited, depending on the physical parameters of the coalbed.

At the lower end of the range reported for diffusion constants, recovery is limited by diffusion, and increasing production will require connecting large additional surface areas to the wellbore.

At the upper range of the reported diffusion constants, recovery is permeability-limited. Increased recovery might then be obtainable by increasing the wellbore radius or the permeability.

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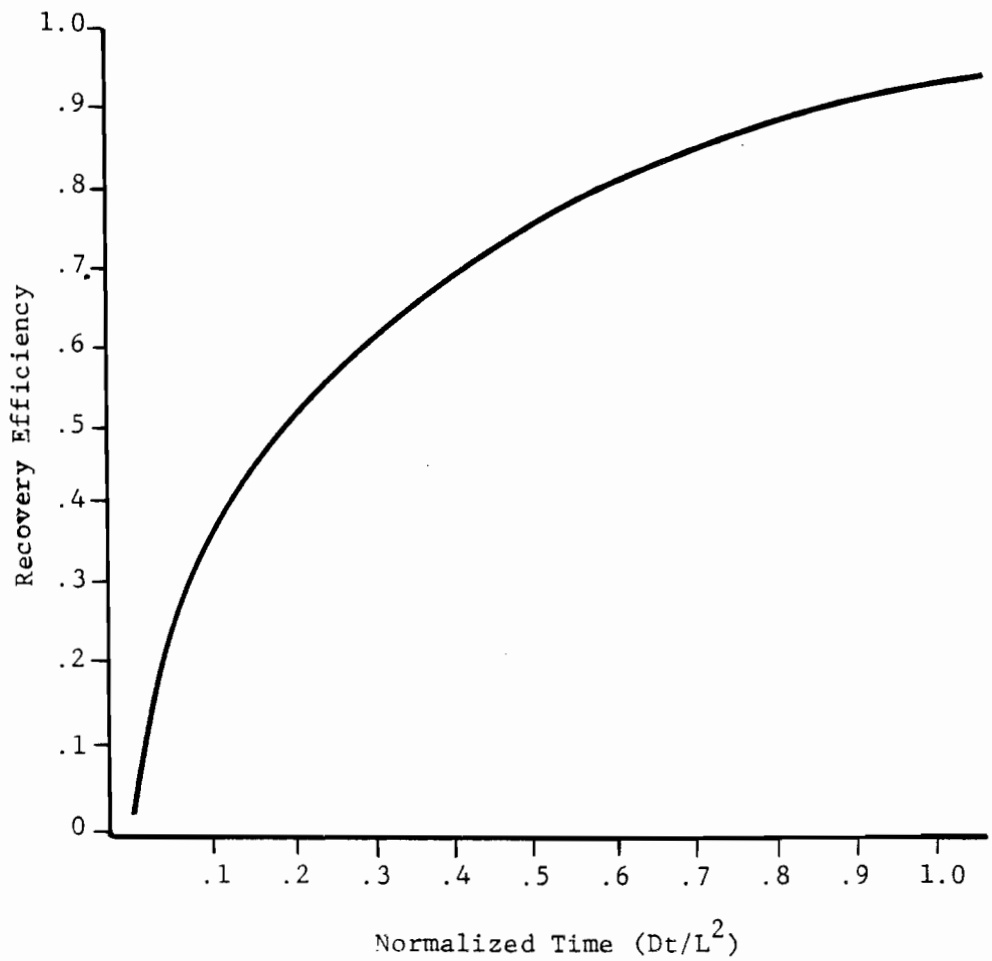
FIGURE 1

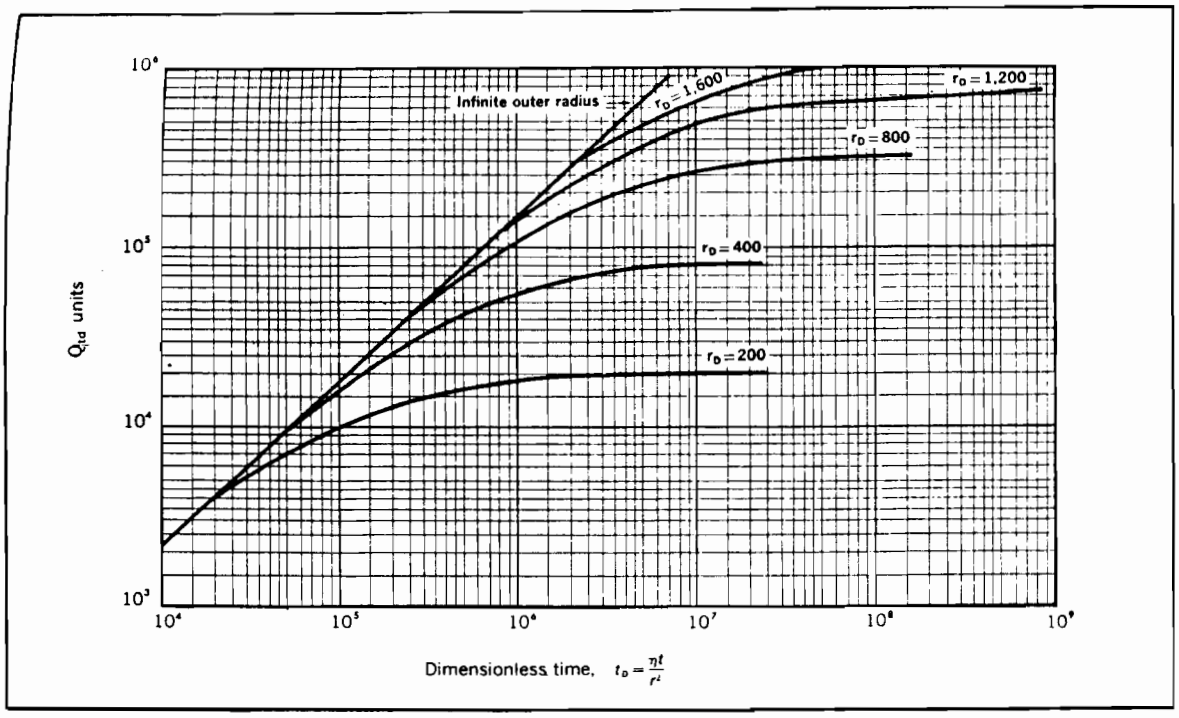
DIFFUSION RECOVERY EFFICIENCY



SOURCE: Derived from Carslaw and Jaeger, Conduction of Heat in Solids, Oxford, 2nd Edition, 1959, Chapter III, pp. 92-102.

FIGURE 2

RELATIONSHIP BETWEEN Q_{td} AND DIMENSIONLESS TIME



SOURCE: Practical Petroleum Reservoir Engineering Methods, H. C. Slider.

FIGURE 3

DIFFUSION VERSUS PERMEABILITY CONTROLLED RECOVERY

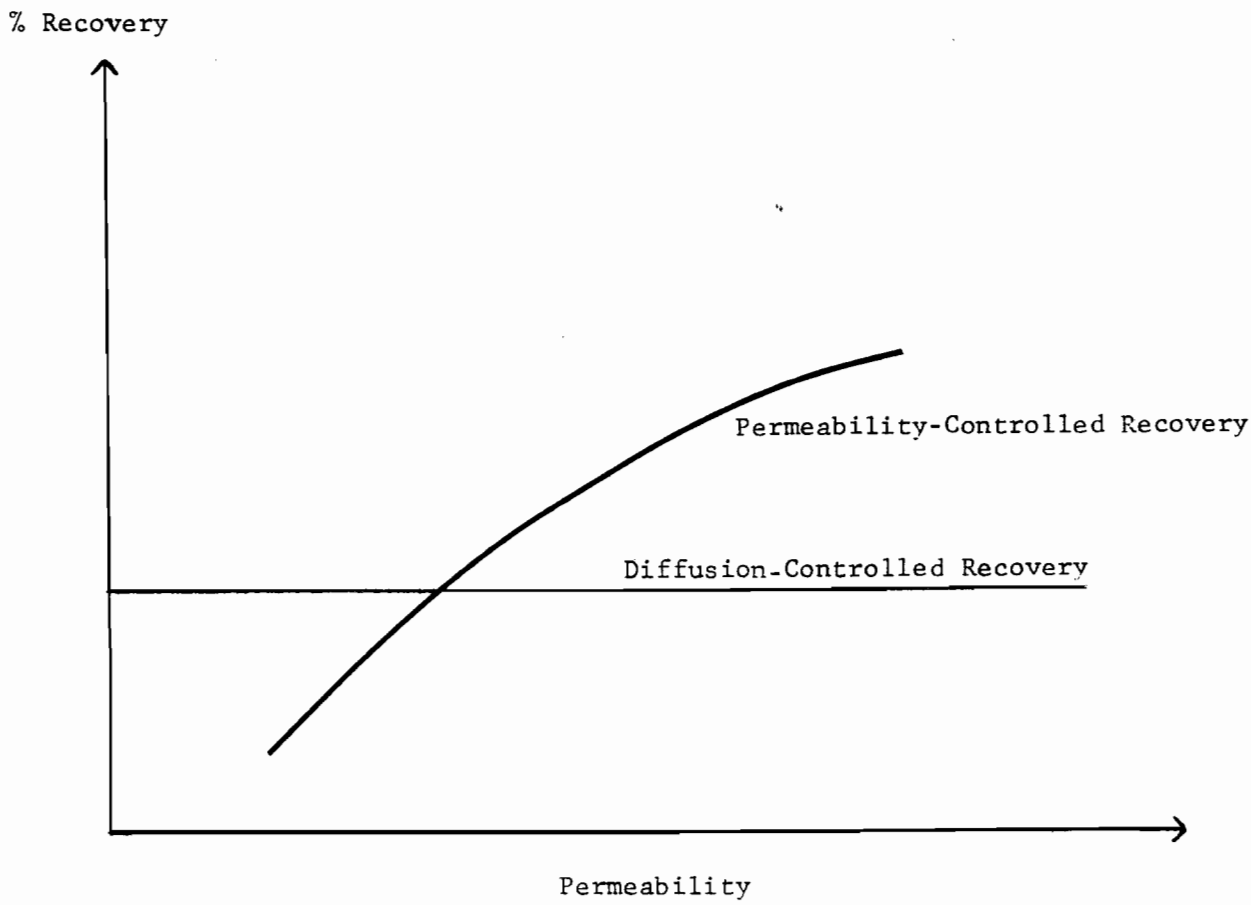


FIGURE 4

INTERACTION BETWEEN RECOVERY MECHANISMS

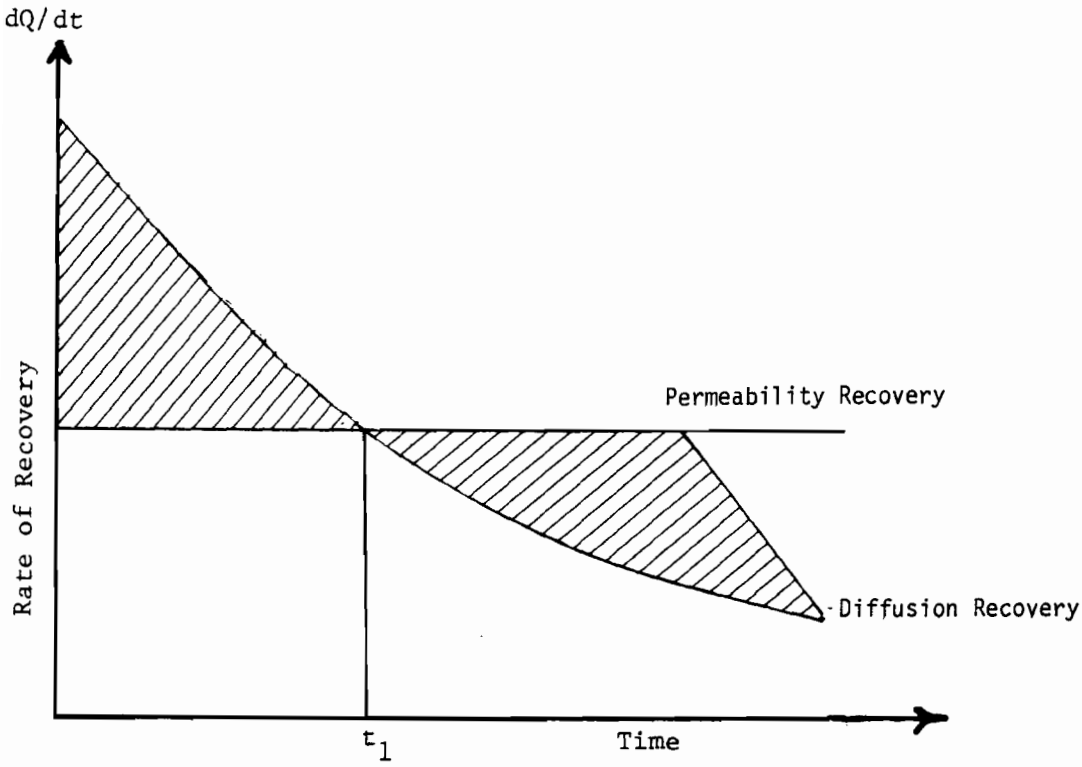


TABLE 1

METHANE RECOVERY FROM DIFFUSION

- Pittsburgh Coal Seam (assuming slab thickness of 1/2"):

Diffusion Constant (cm^2/sec)	Percentage of Gas in Place Liberated		
	1 Year	5 Years	10 Years
1×10^{-13}	N/A*	N/A	N/A
1×10^{-10}	N/A	16	31
5×10^{-8}	≈100	≈100	≈100

- Pocahontas Coal Seam (assuming slab thickness of 1/16"):

Diffusion Constant (cm^2/sec)	Percentage of Gas in Place Liberated		
	1 Year	5 Years	10 Years
1×10^{-13}	N/A*	N/A	N/A
1×10^{-10}	74	≈100	≈100
5×10^{-8}	≈100	≈100	≈100

*N/A = Negligible Amount

TABLE 2

TEN-YEAR RECOVERY OF METHANE FROM PITTSBURGH COAL USING VERTICAL WELLS

	Gas Recovered, Percent of Total					
	r_{we} = 1 foot			r_{we} = 10 feet		
Permeability, mds.	80 acres	160 acres	640 acres	80 acres	160 acres	640 acres
1	9	4	1	13	7	2
2	16	9	2	22	13	3
5	27	20	5	35	27	8

	Gas Recovered, MMSCF					
	r_{we} = 1 foot			r_{we} = 10 feet		
Permeability, mds.	80 acres	160 acres	640 acres	80 acres	160 acres	640 acres
1	14	14	14	23	25	28
2	26	28	28	39	46	43
5	48	71	71	62	96	114

Pittsburgh Coal:

Gas Content	160 SCF/Ton
Pressure	176 psia
Depth	607 feet
Thickness	8 feet
Temperature	80°F
Pseudo-porosity	34%
Gas Content in 80 acres	178 MMSCF
Producing Well Pressure	50 psig
Compressibility	7.83×10^{-3} psi^{-1}

TABLE 3

TEN-YEAR RECOVERY OF METHANE FROM POCAHONTAS COAL USING VERTICAL WELLS

	Gas Recovered, Percent of Total					
	r_{we} = 1 foot			r_{we} = 10 feet		
Permeability, mds.	80 acres	160 acres	640 acres	80 acres	160 acres	640 acres
1	31	17	4	42	23	6
2	49	33	8	59	40	12
5	66	53	18	74	64	25

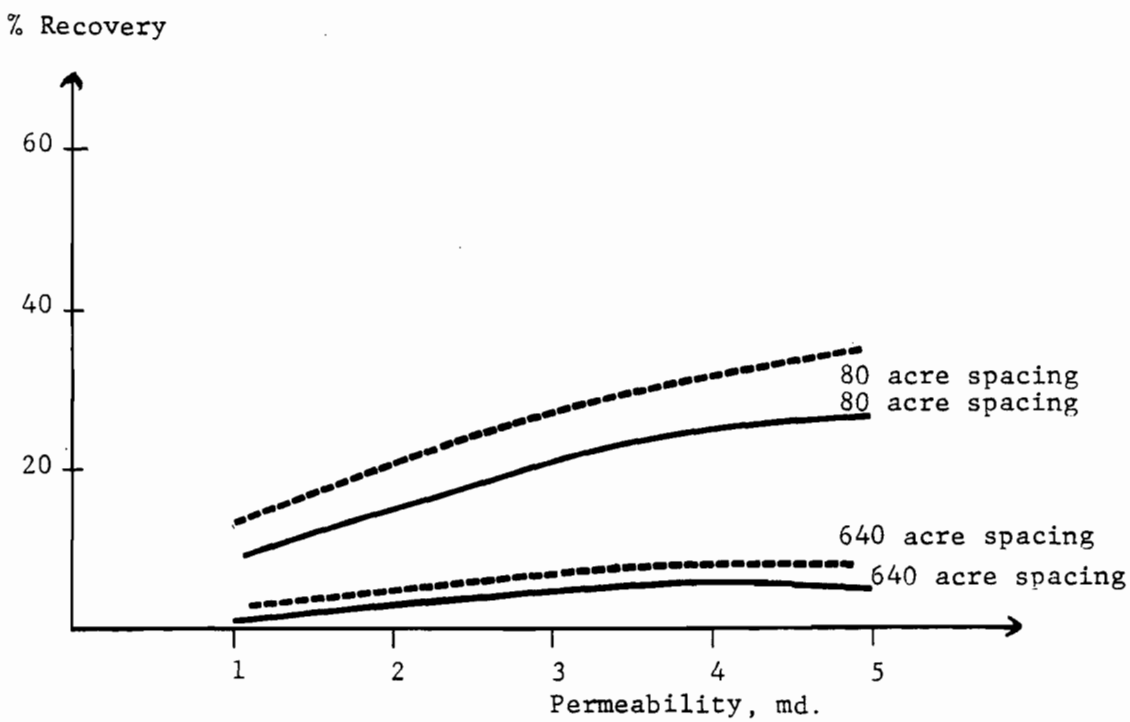
	Gas Recovered, MMSCF					
	r_{we} = 1 foot			r_{we} = 10 feet		
Permeability, mds.	80 acres	160 acres	640 acres	80 acres	160 acres	640 acres
1	85	93	93	113	128	128
2	134	180	180	162	216	245
5	180	289	395	202	351	543

Pocahontas Coal:

Gas Content	435 SCF/Ton
Pressure	588 psia
Depth	1600 feet
Thickness	54 inches
Temperature	100°F
Pseudo-porosity	38%
Gas Content in 80 Acres	273 MMSCF
Producing Well Pressure	50 psig
Compressibility	2.95×10^{-3} psi^{-1}

FIGURE 5

TEN-YEAR RECOVERY OF METHANE FROM PITTSBURGH COAL USING VERTICAL WELLS



r_{we} = 1 foot effective wellbore radius

r_{we} = 10 feet effective wellbore radius

FIGURE 6

TEN-YEAR RECOVERY OF METHANE FROM POCAHONTAS COAL USING VERTICAL WELLS

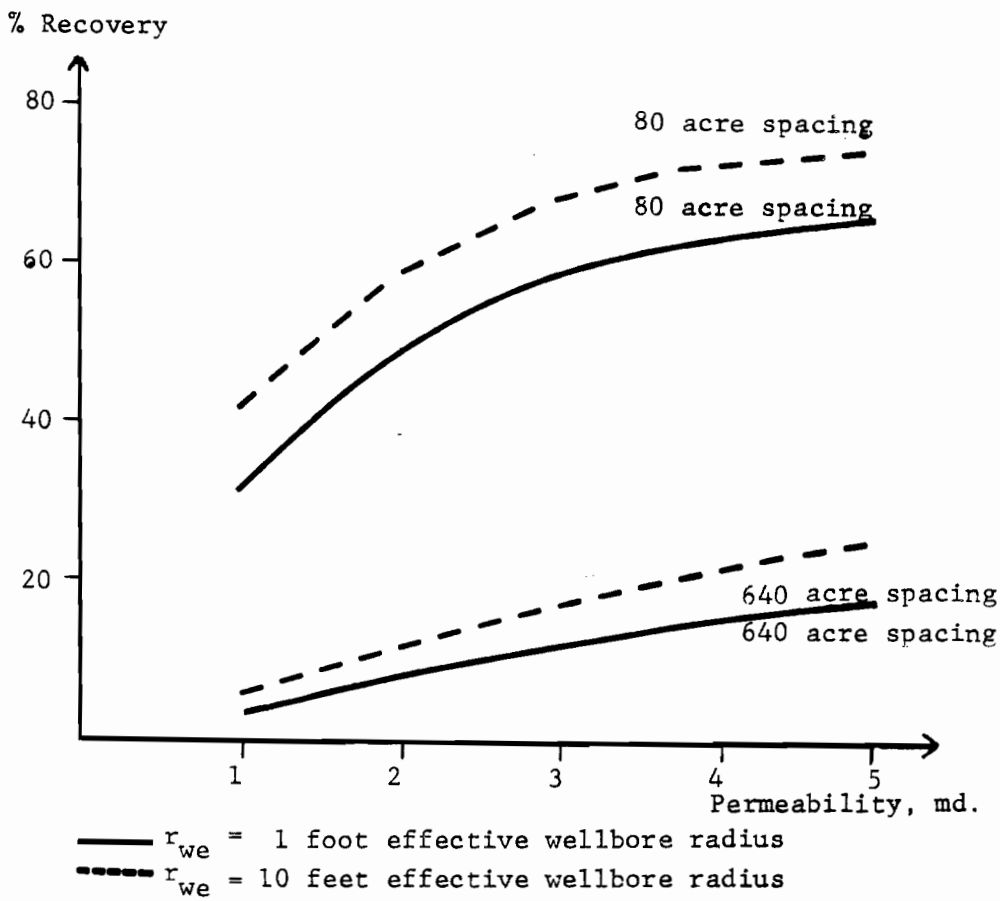
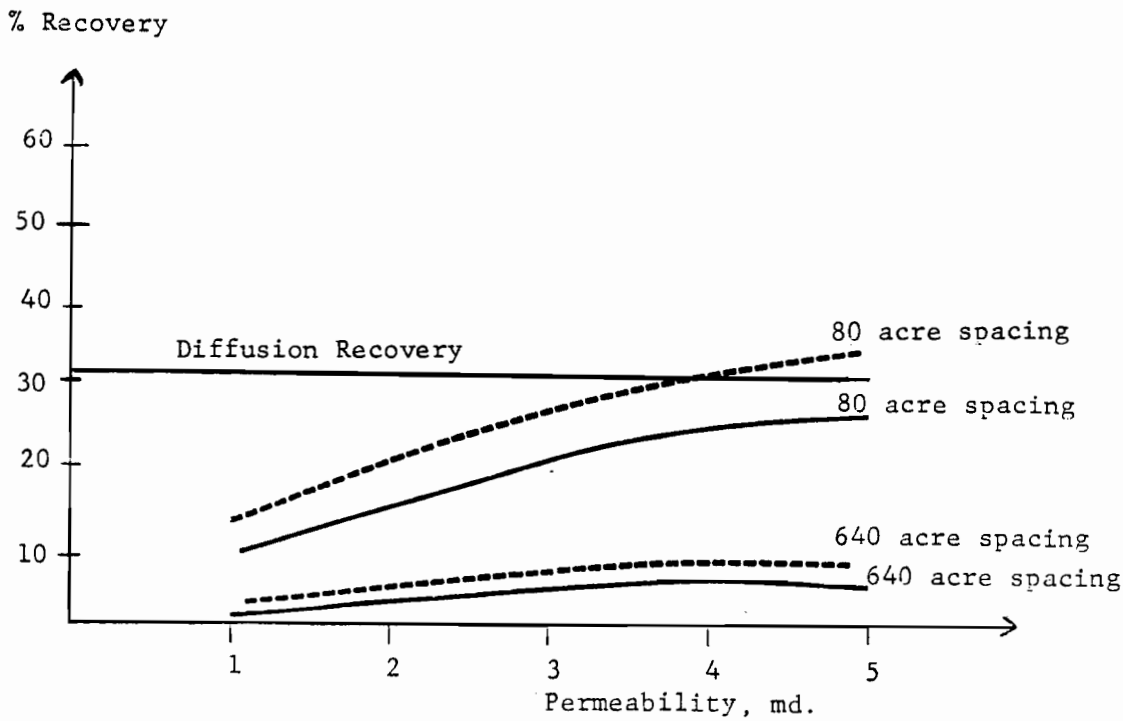


FIGURE 7

COMPARISON OF TEN-YEAR DIFFUSION AND PERMEABILITY LIMITED RECOVERY FOR PITTSBURGH COAL



——— r_{we} = 1 foot effective wellbore radius

- - - - - r_{we} = 10 feet effective wellbore radius

THE VAGARIOUS NATURE OF METHANE GAS FROM COALBEDS

BY

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Dr. Stefanko is the 1979 President of the Society of Mining Engineers of AIME.

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ABSTRACT

This paper is a progress report on three vertical wells drilled into the Pittsburgh Coal Seam in Greene County (southwestern Pennsylvania) on U.S. Steel's Cumberland Mine Property. Additionally, the results from these wells are compared with others in the general area to show the erratic results one can obtain. There appears to be no way of predicting the results "a priori" with any degree of accuracy nor can satisfactory explanations be given of the different performances noted. A discussion of possible explanations of the varying nature of methane flow from beds is given, along with the author's perspective of what the future holds for this technique with recommendations for future work.

INTRODUCTION

As part of the research contract sponsored by the U.S. Bureau of Mines (USBM) and the Pennsylvania Science and Engineering Foundation (PSEF), from November 11, 1975, to January 5, 1976, three vertical boreholes were drilled into the Pittsburgh Coal seam at the Cumberland Mine of United States Steel Corporation in Greene County, Pennsylvania, and are designated CNG 1034, 1035, and 1036, Figure 1. The holes were 808, 1201, and 1025 feet deep. Each has a 5-1/2-inch production casing cemented in a roller bit, 7-7/8-inch diameter, rotary-drilled hole in which was placed a 2-3/8-inch tubing and pump jack for dewatering. CNG 1034 was subjected to open-hole stimulation, 1035 was fully-cased, perforated, and stimulated, while CNG 1036 has a casing to the top of the coal seam but remains unstimulated. Complete details of the well's completion were given in earlier reports.(1,2)

Because of delays incurred in obtaining right-of-way access, the holes were not simulated until the year following their drilling, at which time, two were stimulated with the third kept as a base monitoring hole. Figures 2, 3, and 4 trace the water and gas flows from these holes from April 1, 1977 to February 1, 1979.

ANALYSIS OF RESULTS

Figure 2 gives the results obtained with CNG 1034. It was purposely located so that it would be mined through at an early date in order to see if there were any adverse effects to the mine structure as the result of stimulation, and also to be able to assess the benefits, if any, to mining as a result of methane degasification. Presently, the face of the mains is about 2,000 feet away from CNG 1034, and it is predicted that 6 to 7 months will elaspe before the workings penetrate the borehole area. As can be seen, both gas and water flows from the hole were minimal prior to stimulation in May 1977. After stimulation, water flow increased tenfold with about a fivefold increase in gas. The water inflow continued to increase slowly until a peak of close to 4500 gallons per day was realized; throughout the latter part of 1977 and early part of 1978, the water

flow fluctuated into a near sinusoidal fashion from approximately 2000 to 4500 gallons per day and then slowly dwindled until today (February 1, 1979) it is only about 150 gallons per day. As the seam was dewatered, the gas flow continued to increase gradually until it has been fluctuating around 5000 cubic feet per day. However, all of these early readings are suspected of being on the low side because of the manner in which the wells were dewatered; it is believed that a considerable amount of gas was ejected with the water and remained unmeasured. Therefore, these early figures are considered to be too low and the more recent figures are considered more reliable. Dewatering such boreholes is not as easy as might appear with many degasification projects encountering difficulties with what would appear to be a simple problem to solve with today's technology. The caving of the hole in the sump area can cause blockages, and maintaining pumps and equipment in severe winter climates is not easy. For example, the water meter froze during January 1979, and pumping of CNG 1034 was suspended. At the time of the preparation of this paper in February, no final decision had been made regarding the restoring of pumping.

Figure 3, which gives the results of CNG 1035, shows a behavior similar to but more dramatic than that of CNG 1034. There were virtually no water and gas flows prior to stimulation, but, after stimulation in June 1977, both increased initially before dropping off; however, the gas flow dropped off more quickly before increasing again during the early part of 1978, and increasing more dramatically during the summer of 1978. Notice that around May 1, 1978, there was a decrease in daily water flow with a correspondingly large increase in gas flow that reached nearly 34,000 cubic feet per day during October and November 1978, and jumping up to 45,000 in January 1979. The water flow has stabilized at nearly 350 gallons per day. This well, placed on line commercially in June 1978, continues to produce. It should have a life expectancy of several years before being mined through.

Figure 4 provides similar data for CNG 1036. Since the hole has never been stimulated, no dramatic changes in gas and water flows have been noted. However, on June 1, 1978, there was a better than twentyfold increase in gas flow, from a negligible 100 cubic feet per day to over 6000. Much of this increase probably resulted from a change in the dewatering technique that minimized the amount of gas ejected with the water since it was at this time that the technique was assessed and changes were made in the pumping cycle. The well's flow continues to vascillate around 5000 cubic feet per day

CNG 1036 will have a very long life, on the order of ten years or more, before being mined through; it was placed on stream commercially in November 1978 and continues to produce. At some later date, it will probably be stimulated.

What can be said from the results of these three holes? One obvious observation is that improved gas flows result from the dewatering of the coal seam. Upon stimulation, not only does the improved seam permeability result in an increased gas inflow but also in an increased flow of water. This is noted immediately upon stimulation. The dewatering of the seam is a very long and drawn out process that is accompanied by a corresponding continuously increased gas flow. This is understandable since both gas and water are fluids and compete for the same voids within the coal. As the volume of one is reduced, it allows more room for other. The surprising aspect is how long it takes the dewatering to occur. The author thought that the maximum effect of seam dewatering would be realized within a matter of three to four months and not require nearly the year it did.

The results with these holes indicate the necessity of providing a sizable, intact sump hole below the seam at all times. Unfortunately, during the early part of this study, a timing mechanism, which proved unreliable was employed for starting the pumping cycle rather than a float valve. The result was that the pumping cycle did not begin soon enough to keep the water off the seam and thus gas which was not measured, was ejected with the water.

OTHER RESULTS

There have been quite a few vertical holes drilled into the Pittsburgh seam just a few miles north of the Cumberland Mine on the Lykes property and a few miles south by Consolidation Coal Company. A comparison with these holes is worthwhile.

Seven holes were drilled into the Pittsburgh seam in 1976 on the Lykes property which is approximately 20 miles north of the Cumberland site. All used a nitrogen foam frac similar to that used at the Cumberland site. The reported results are given in Table 1. As can be seen, the range of gas flows is considerably greater than obtained with the Cumberland wells. Yet, there was not that much

difference in coal seam gas analysis in cubic foot per ton of coal in situ from the Lykes well site (200 cubic feet per ton) to Cumberland (144-168). Since the difference seemingly cannot be explained by stimulation procedural differences or gas potential in situ, it can only be assumed that it must be related to geologic structure although the different sites were not evaluated on this bases.

The Consolidation Coal Company well was drilled to the south across the border in West Virginia. It showed an initial peak production of 28,000 cubic feet per day with a recent or final figure of 8000 cfd. The prefractured gas flow was 5200 cfd. Neither the Lykes nor the Consolidation holes have been tapped commercially.

One of the principal factors determining the commercial quality of methane gas from coal beds, apart from the yields, is the quality, which determines what must be done (and the cost) to place it into a commercial line. The gas from the Pittsburgh Coal bed has a very high purity; typical gas analyses collected from the three Pittsburgh seam boreholes at the Cumberland mine site are shown in Table 2. The methane content is very high with a minimal amount of other impurities, and the heating value is comparable to that of commercial natural gas. Such a gas can be placed directly into a commercial pipeline after proper compression.

ANALYSIS OF DEVELOPMENTS IN METHANE COAL BED DEGASIFICATION

Just a year ago at the First Annual Methane Symposium, a sense of extreme emergency existed for development of methane gas from coal beds, Devonian shales, and other unconventional, high-cost sources. Manufacturing plants had had to suspend operations for lack of adequate gas supplies, the gas shortage was being widely felt by all, and exploration and drilling for new sources was being rapidly accelerated. Today, just a little over a year later, the situation has been reversed with supplies exceeding demand, and new drilling has been drastically curtailed. All this needs to be kept in proper perspective, however, or the public is misled.

While it is true that supplies exceed demand at this moment, this is because demand is down, not because supplies have increased that substantailly. We continue to consume more gas annually than is found. Thus the situation is temporary at best and in three or four years, or perhaps even sooner, we will be scurrying about looking for additional gas supplies. Therefore, this is no time to relax, especially since so much remains unknown.

Direct commercial use of methane gas from coal beds will probably never be a primary source of gas, but the benefits it can have on mining may be highly significant. New, deep mines in Appalachia are encountering great difficulties with excessive gas inflows, jeopardizing safety and requiring the suspension of mining activity over long periods of time. Therefore, some method of degasification is almost certainly going to be required if we hope to have a viable deep mine industry. Yet, scientific determination of the beneficial effects of degasification on subsequent mining have not been made. Thus pre- and post-degasification effects must be assessed and compared at a mine operation in conjunction with the well development process. More needs to be known about the location of holes, effects of geologic structure on flows and stimulation techniques. These are all in their infancy. The thousands of natural gas and oil wells do not provide the same information since the mechanism of gas flow from the coal seams is different.

Further research and development with methane degasification in virgin coal seams from vertical surface boreholes might result in increased yields and thus improve the economic feasibility of such ventures. Certainly, with an impact on coal production in active mines located in seams undergoing degasification, the cost benefits might prove favorable. However, based on this study, and those of others, the benefits, both in the commercial sale of gas and improved coal production, do not indicate economic viability for this technique. However, the effect on coal production has not been fully assessed with a sufficient number of studies and thus this is a preliminary observation that could change with further study. This is an area requiring a more scientific and complete assessment.

There are seams that are not mineable and where surface boreholes are the only technique to be employed. For these seams, perhaps additional research on this technique might result in improvements that would give it greater viability. Presently, the results are generally unfavorable although there are a few wells in the Pittsburgh seam that are highly productive. While the well spacing, life, price of gas, return on investment, location of pipelines, and quantity and quality of the gas all enter into an economic analysis, it has been estimated that upwards of 75,000 cubic feet per day are required over a period of ten years at a price of $2.00 per thousand cubic feet for economic viability.(3) Using these criteria, the most favorable gas well on the Lykes property (No. 4 hole in Table 1) falls short. Since none of the wells on the Cumberland property produce this much, none are commercially viable. The only

reason that the two are being placed in a commercial pipeline is that the cost of drilling and well development were amortized by the research project. Otherwise, revenue from gas sales would not recover the complete cost of these wells.

Since the energy crisis continues in this country and promises to get worse, we must turn to our most plentiful energy source-coal—at least for the remainder of this century. There are two primary sources: the shallow, strippable coals which abound in the west and the very deep coal seams in the east and midwest. For the latter, some method of degasification will be essential if they are to be mined.

Recognizing this, coal companies are planning on the use of the in-mine, horizontal-hole seam degasification technique. For the Cumberland site, no additional vertical holes are being planned. However, since severe gas problems are being encountered underground, a horizontal drill has been ordered and horizontal, long hole degasification will take place in the mine. Furthermore, Consolidation Coal does not plan on the further use of vertical boreholes but also plans to use the horizontal hole technique.[4] In fact, they have spent a lot of time and effort to develop a suitable guidance system to keep the drill hole positioned in seams that undulate. It is anticipated that many such degasification projects will be started in active mines in the near future.

ROBERT STEFANKO

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Table 1.

RESULTS FROM BOREHOLES DRILLED ON THE
LYKES PROPERTY IN GREENE COUNTY

Holes							
Initial Peak Production, cfd	26,200	42,000	40,000	117,000	134,000	140,000	210,000
Recent Inflow Production, cfd	1,000	28,000	22,000	60,000	55,000	13,000	37,000

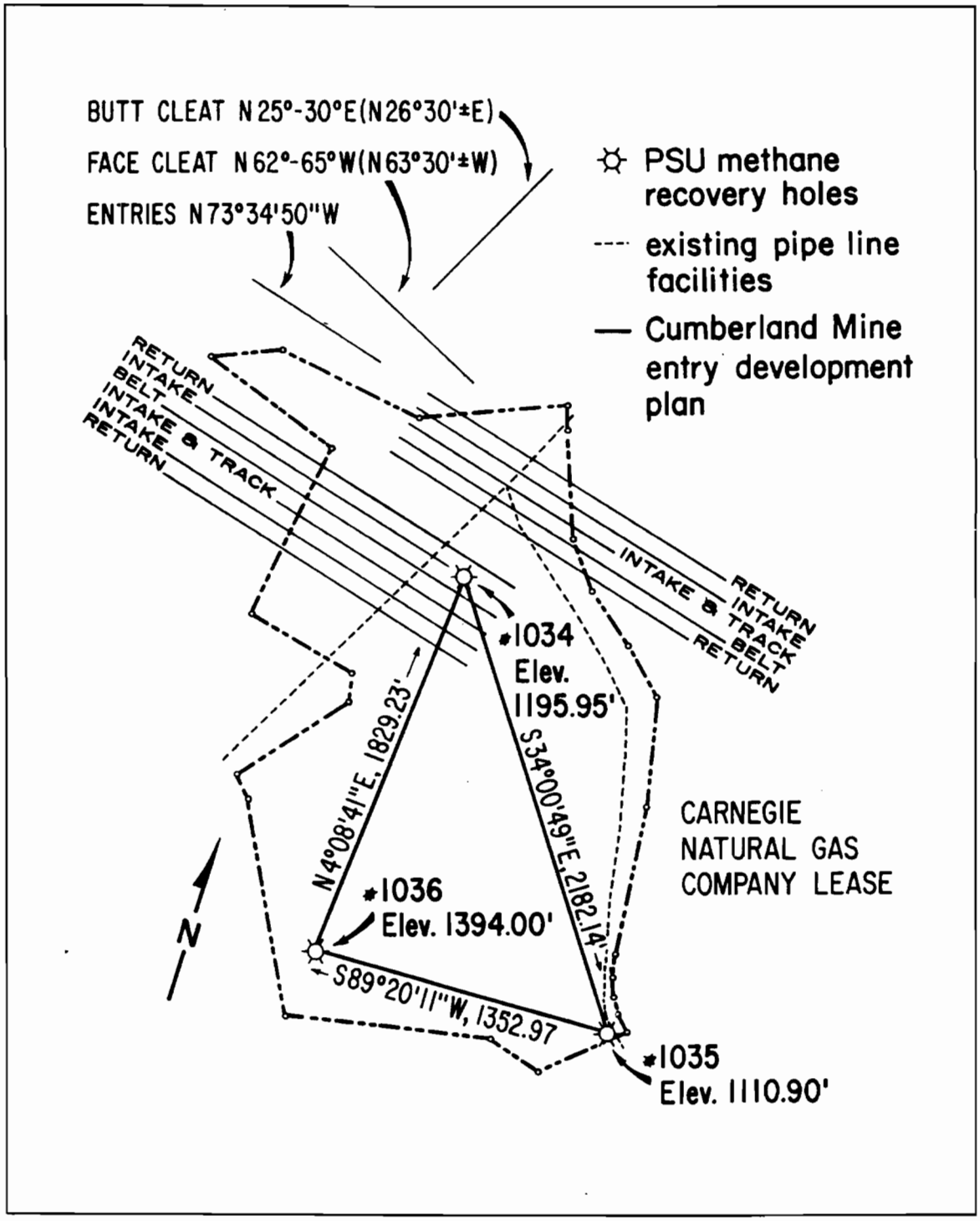
Table 2.

CUMBERLAND MINE DEGASIFICATION BOREHOLES
METHANE GAS ANALYSES

	CNG 1034	CNG 1035	CNG 1036
CONSTITUENT	Percent	Percent	Percent
1. Methane	95.51	95.81	93.80
2. Ethane	TRACE	0.02	0.31
3. Propane			0.09
4. Butane			0.05
5. Pentane			0.01
6. Hexane			
7. Oxygen	0.05		
8. Nitorgen	1.55	0.54	1.63
9. Carbon Dioxide	2.89	3.00	4.11
10. Hydrogen		0.49	
11. Helium		0.14	
12. Carbon Monoxide			
TOTAL PERCENT	100.00	100.00	100.00
HEAT VALUE (DRY) BTU/SCF	968	974	962
DATE OF SAMPLE	6-3-76	11-22-76	7-1-77

Figure 1

DEGASIFICATION HOLE ARRANGEMENT AT CUMBERLAND MINE



THE VAGARIOUS NATURE OF METHANE GAS FROM COALBEDS

Figure 2

CNG 1034 GAS AND WATER FLOWS

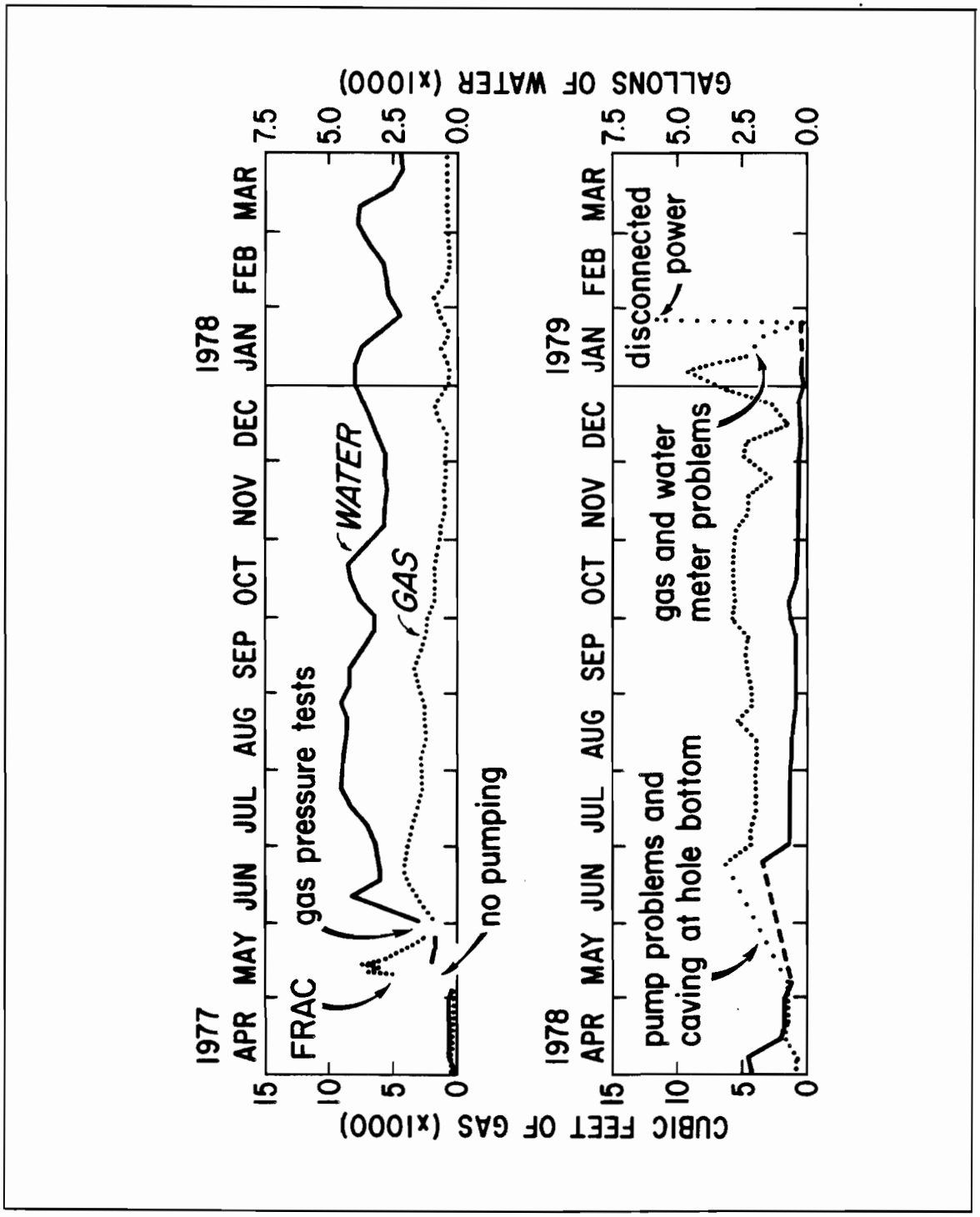


Figure 3

CNG 1035 GAS AND WATER FLOWS

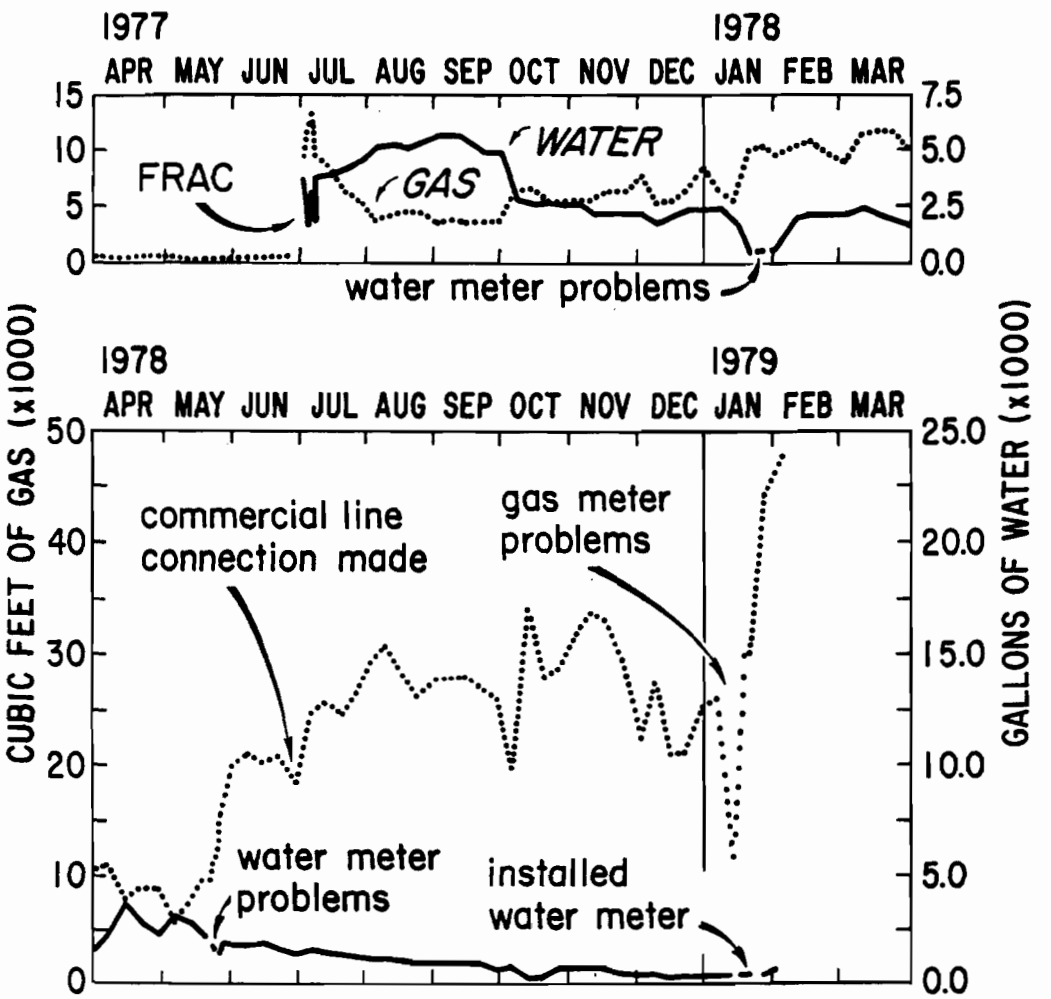
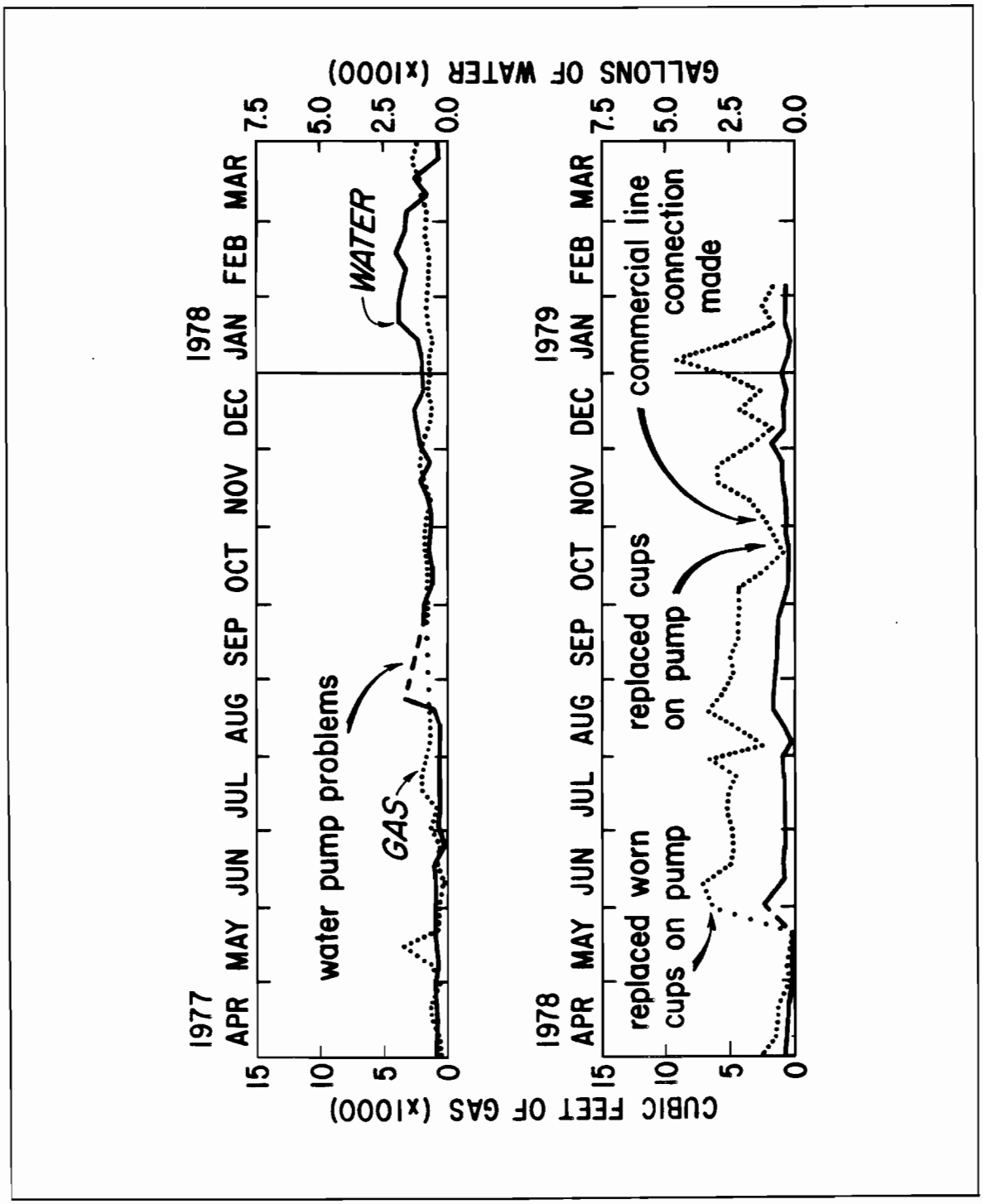


Figure 4

CNG 1036 GAS AND WATER FLOWS



A REVIEW OF UTILIZATION OF METHANE GAS FROM COALBEDS IN THE UNITED KINGDOM

BY

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ABOUT THE AUTHORS

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A REVIEW OF UTILIZATION OF METHANE GAS FROM COALBEDS IN THE UNITED KINGDOM

ABSTRACT

In the United Kingdom methane has been brought to the surface of coal mines by bulk ventilation and in later years also by the technique of methane drainage developed to aid the longwall mining methods employed in deep seams. An historical overview of gas sales by the National Coal Board (NCB) is presented to demonstrate how market forces initiated the approach to local industries; first to develop a medium BTU gas market for coke oven gas, and subsequently how this experience was applied to gob gas as economic and world political factors altered the relativity of fuel prices.

The development of drainage of the U.K. coalbeds is reviewed giving insight into how the application of high safety standards concurrent with new improved mining methods has affected the removal of methane. The necessity for effective face drainage has led to the adoption of gob gas extraction techniques to bring methane to the surface at zero attributed value.

Utilization schemes in operation in the U.K. for on-site and local industry sales options are examined and figures for current annual business are quoted. The paper concludes with a review of utilization technology within the U.K. Particular emphasis is given to consideration of quality control and reliability of the source of supply. Both features contribute to the success or failure of an industrial scheme. Some of the techniques adopted by the NCB to ensure continuity of fuel supply to the point of use are described.

The annual turnover of the NCB is currently running at 6.0 billion dollars. This includes a significant contribution from the utilization of mine methane and coke oven gas. The utilization of these mine gases in the U.S.A. could well have a small but significant effect on maximising benefit to industry whilst using a valuable resource which would otherwise not be recovered.

HISTORICAL PERSPECTIVE

The development of utilization options in the U.K. occurred with the NCB's involvement in the medium BTU gas supply business. To highlight the current position, the NCB are suppliers of 8 trillion BTU's annually of manufactured coke oven gas to industrial users through 60 miles of private pipelines, and of 3 trillion BTU's per year of methane drained from coalbeds sold for industrial use. NCB (Coal Products), a wholly owned subsidiary of the NCB, set up in 1963, manages the coke making, fuel and chemical activities. They are merchant suppliers of coke to the British Steel Corporation and the major suppliers of hard cokes to the foundry trade both home and abroad. They design and engineer the gas utilization schemes for the sale of coke oven gas and coalbed methane on behalf of the NCB.

In the manufacture of coke, 7 to 8½ million BTU's of gas is produced in association with each ton of solid product. Between 45 and 50% of this energy is required for the manufacturing process. The net surplus is available for external utilization. Until the late 1960's whilst the gas industry used coal or oil to manufacture medium BTU domestic gas, there was a ready market for every unit of gas that could be produced. Coke oven gas was completely compatible with medium BTU gas. In the case of coalbed methane having substantially different burning characteristics only small quantities could be blended for sale. Historically, the utilization of gob gas commenced with burning in boilers at mines early in the 1950's. This was followed by the development of coalbed methane gas pipeline grids in Scotland, South Yorkshire, Staffordshire and South Wales in the early 1960's mainly for the sale of gob gas to the gas supply industry, coke ovens and for inter-mine transfers. The availability of North Sea natural methane resulted in a substantial reduction in coke oven gas and gob gas external sales in the late 1960's.

So the pattern of utilization of coalbed methane over the twenty years 1950 to 1970 had been for optimum local utilization, for coke making, and for steam raising and power generation at the mines.

The U.K. gas industry did an excellent job in converting from medium BTU gas to the newly discovered methane resource. This was available at a price attractive in comparison with the costs of bulk conversion of UK coal or imported oil. The gas industry secured new markets and accelerated the trend from solid and liquid fuels to gas.

The NCB was left with a surplus of coke oven gas and gob gas and no prospect of further sales to the gas industry. The hydrogen rich coke oven gas was incompatible with pipeline methane as was the gob gas having a calorific value of only 500 BTU per cubic foot. Consideration had therefore to be given to alternative uses for this fuel. Steam raising and power generation would make the producers self sufficient in energy but still have left them with tremendous surplus. The objective was to find large industrial users with continuous, steady load fuel requirements within economic distance of the gas sources. Intensive activity from 1968 to 1972 enabled about 70% of production to be placed with little waste, closely phasing the activities with the gas industry's conversion programme. The next four years saw the securement of additional outlets until, in the Spring of 1977 for example, 95% of all coke oven gas production was utilized.

In the early years it was difficult to justify expenditure on pipelines and new facilities due to the low gas revenues that were achieved in the face of competition with low priced oil and natural gas. In 1972 pipeline methane was selling at an average price of $0.60/MM BTU. To achieve new markets it was necessary to undercut this value and still show an economic return on capital.

World events of 1973 and 1974 which gave rise to the fuel price explosion came as a welcome and unexpected bonus when the market related prices escalated beyond all expectations. Low profit schemes began to show substantial returns on investment. The turning of this corner enabled the remaining business to be secured with longer pipelines and short term contracts which previously could never have been justified.

With this intensive activity in the highly competitive U.K. fuel market the NCB had, by 1973, built up the competence within NCB (Coal Products) to market, engineer and manage a substantial gas supply business. At the same time increased relative value of medium BTU gases inspired a renewed interest in the utilization techniques of gob gas in two ways. The first objective was to optimize the internal use of gob gas at the mines with capital schemes which would show an acceptable return on investment. Secondly, to capitalise on coke oven gas sales expertise, attention was turned to the expansion of the use of coalbed methane as a fuel for local industries. The leap in fuel prices had made it attractive to consider schemes for the sale of quantities as low as 300 MMBTU's per day from a single mine and this led to the small user, small supplier conceptual package.

The first of the new generation of projects for the further use of gob gas as a local industrial fuel was completed in 1975 at the Grimethorpe mine in Yorkshire. An over-the-fence sale was negotiated with a small brick-making company producing 500,000 quality facing bricks per week. They have successfully used gob gas now for four years on a continuous tunnel kiln originally designed for gas oil firing.

To understand further the approach adopted to utilization by the NCB it is necessary to consider the development of coalbed gas drainage techniques in the U K. mining industry.

A REVIEW OF UTILIZATION OF METHANE GAS FROM COALBEDS IN THE UNITED KINGDOM

DEVELOPMENT OF COALBED GAS DRAINAGE IN THE U.K.

The coal measures currently worked in the U.K. are generally at depths ranging from about 600 to over 3,000 feet. The techniques employed are almost exclusively by advancing or retreating long-wall mining of coal seams of widely varying rank from high grade low volatile anthracite to lower grade, high volatile bituminous coals. Increasing rates of extraction, depth of working, and further exploitation of deeper virgin areas with relatively high seam density (inches of coal per foot of strata) have required further development of fundamental knowledge and skills to enable coalbed methane drainage schemes suitable for such situations to be installed.

Incidents and coal mining history have demonstrated potential risks associated with methane in coal mines and have led to progressive legislation in the U.K. over a period of some 130 years. Dilution by ventilation provides the basic method of removing methane from the mine and thereby containing methane concentrations within acceptable limits. For example, current U.K. Coal Mining Acts and Regulations require the isolation of electric power if the methane concentration adjacent to men working in the mine exceeds 1¼%, and the withdrawal of men when the methane concentration exceeds 2%. These and other limits indicate general body levels of methane concentration in longwall mining where methane emission rates can range from about 50 to over 2,000 cfm. Seam thickness, depth of working, dust control, tolerable air speeds and other factors may limit the total ventilating air quantities employed in working places and, therefore, the degree of dilution attainable in certain U.K. regional coalfields. In these and other situations, methane drainage has been applied under widely varying conditions.

Methane drainage is practised at 114 mines in the U.K. to reduce methane concentrations in working and old parts of mines, to increase safety and security and in many cases to allow higher production and productivity to be achieved. It has been employed successfully in the U.K. for some 30 years on a systematic basis specifically to make direct contact with methane sources within relaxed or disturbed zones above and below the worked seam and to extract as much methane as practicable before it enters the ventilating stream. In particular, it is used to reduce local and general body methane concentrations in roadways and to deal effectively with situations liable to spontaneous methane emissions and outbursts.

Conventional methods of methane drainage involve the drilling of roof and/or floor holes at centres ranging from 15 to 120 feet in one or both gate roadways of longwall faces. These boreholes may have unlined lengths ranging from about 40 to 250 feet and are sealed by a casing over the initial 5 to 40 feet. Borehole suctions range from about 0.5 to 5 inches mercury, typical qualities of borehole drained gas ranging from 90 to about 20% methane. Borehole flow rates vary from a few cubic feet per minute to over 1000 cfm gob gas in some cases. Gob gas is drained by suction generated by electrically driven water seal pumps with suction pressures ranging from about 5 to 20 inches mercury (2.5 to 10 psi gauge) through steel pipes over distances ranging from approximately 0.5 to over 5 miles. Drilling, commissioning and isolating of boreholes takes place continually.

In other situations methane is drained from abandoned underground workings or from abandoned mines. In a limited number of cases, methane has been drained in advance of mining from narrow workings or headings, and in some cases by using surface boreholes. Considerable advances have taken place in the development and production of special equipment, including drilling machines, and methane drainage hardware. New techniques are continually being evolved which are also applied to other problems such as certain types of spontaneous gas outbursts. In recent years, monitoring of drained gob gas has played an important and essential part in planning and achieving effective methane drainage systems. A high level of understanding, expertise and experience has thus been acquired during the continual and challenging demands of practical situations.

Methane drainage from gob areas is practised in the U.K. on about 60% of the highly mechanised longwall faces to contribute to the achievement of the necessary safety and legislative requirements whilst maximising machine utilization and productivity.

In assessing the economics of extraction, recognition must be given to the high degree of mechanisation on all U.K. coal faces where it is essential to maximise the use of machines during the shift. This is coupled with the impracticability of re-deploying manpower from face to face as may be adopted with room and pillar techniques. All these factors have contributed to methane drainage being an accepted essential cost of mining coal. It is treated in the same way as mine air ventilation cost so that U.K. accounting procedures show coalbed methane at the surface at zero attributed value.

This is an important concept to grasp contributing significantly to how economics of utilization are appraised. However, an indication of cost of surface plant to meet U.K. standards at a 1 million ton per year mine may be about $1 million, whilst the cost of supplying and installing piping underground may be about $2 million. There is an on going cost for underground work as coal faces advance or retreat and new faces are developed. This demonstrates that the case for recovering coalbed gas in the U.K. cannot be made on its fuel value alone. The incentives of safeworking and continuity of high coal production rates are the prime reasons why the capital costs are absorbed in the cost of coal extraction.

UTILIZATION SCHEMES FOR COALBED GAS

An important secondary objective associated with methane drainage schemes is energy conservation and the income or value obtained from the utilization of quantities of drained gob gas brought to the surface. Gob gas is currently brought to the surface at 60 mines. Of the 12 trillion BTU's drained to the surface, about 7 trillion BTU's are utilised annually.

Existing U.K. Methane Drainage Regulations restrict the utilization of gob gas to that containing more than 40% methane. A number of mines, however, drain gob gas with lower concentrations or in uneconomic quantities. For these reasons about 5 trillion BTU's are not used. Recently a number of exemptions have been obtained from the relevant Mine Regulations to utilize gob gas down to 30% methane. This,with other measures being adopted,will raise the annual quantity of drained gob gas used to between 8 and 8½ trillion BTU's.

The distribution of available drained gob gas varies widely over the various U.K. coalfields and over the life of individual mines. The largest individual producer in the U.K. is in the North-West of England, currently brings to the surface about one trillion BTU's per year of 530 BTU per cubic foot gob gas. About thirty other mines produce from 0.1 to 1 trillion BTU's per year of 300 to 700 BTU per cubic foot gob gas. At some of these mines gob gas is subject to supply and quality variations.

On-site utilization

Developments in combustion technology and equipment have enabled significant advances to be made in the range of on-site utilization applications which cover boilers, dual fuel engines, gas engines and gas turbines.

This equipment is used for on-site utilization in the fields of :

Steam raising and hot water production
Power generation.

Steam raising and hot water production - packaged boilers with outputs ranging from 2 to 20 MM BTU's per hour are employed using one or two burners, double-block and bleed, nitrogen proving and flue gas sampling systems. Quality control and gas flow monitoring systems are applied. Progress in control and monitoring technology has led to simple unmanned, low power demand and highly profitable installations. Gob gas containing down to 30% methane is currently being burnt in packaged boilers. This marks a significant advance in the utilization of lower quality gob gas.

Electric power generation - gob gas is used in dual-fuel engines, gas turbines and gas engines. A dual fuel reciprocating engine generating 500KW has been operating for about 15 years using about 4 MM BTU's per hour of gob gas. Another installation comprises four dual-fuel generating sets in parallel, each generating about 1300 KW of electric power from about 15 MM BTU's per hour of gob gas. Three of the generating sets produce about 70% of the total electrical consumption of the mine and a heat recovery scheme enables about 10,000 lbs per hour of hot water to be produced. A small amount of electric power is sold to the local utility.

Power is also generated using a small gas turbine which utilizes 30 MM BTU's per hour of gob gas at concentrations down to about 40% methane with the capability of utilizing gob gas down to 30% methane. The 1300 KW alternator is driven through a gear box, the turbine itself being provided with gob gas at a pressure of 120 psig. The generator set is used to provide base load. With a heat recovery scheme, hot water could be provided at the rate of 14,000 lbs per hour.

Sales to Local Industry

The changes in price relativity referred to earlier have made local industrial sales a very attractive proposition for coalbed methane and coke oven gas. Whilst the markets for coke oven gas were being established a diverse range of industry was investigated.

The main criteria were :

- Continuous processors or seven days users
- Proximity to the source of fuel
- Energy intensive industrial sector.

Coke oven gas now sells into markets for brick making, glass melting, dolomite calcining, general steel making and metal processing, industrial steam raising and process heating and finally hospital and institutional heating.

Geographic and geological factors will contribute greatly to the types of industry local to a mine. The U.K. mining industry has been fortunate in that the heavy clay industry has been located close to major coal fields providing substantial outlets for coalbed gas sales from North Wales, Staffordshire and Yorkshire to clay users consuming individually 150 to 300 billion BTU's per year at a plant. The economics of transmission distance, 1 to 2 miles, and the alternative fuel cost, LPG at $3.0/MM BTU and pipeline methane at $3.5/MM BTU, have made these attractive customers.

Where substantially higher quantities of gas are extracted from the mine a market can be sought at greater distance. The most ambitious single supply/single user project to date will be the sale of gas from a mine in North-West England to a Unilever factory, 7 miles distant. The supply, expected to commence in Spring 1980, will satisfy 75% of the factory's process steam requirements equivalent to 850 billion BTU's per year. Stand-by fuels will be heavy oil and pipeline methane. The capital cost of this scheme is around $7 million and a ten year contract has been signed with the customer.

A concept that the NCB is now exploring is the identification of potential users whose business is sufficiently energy intensive to justify re-development or the construction of new facilities alongside a mine or coke works with surplus gas for sale. This may overcome some of the problems of economy of scale whereby the U.K. maximum economic transmission distance, valuing gas at zero cost at the point of supply, is about ten miles for 1 trillion BTU's per year.

Currently the possibility of a joint venture with the glass industry is being evaluated. A new manufacturing facility alongside a coke works with a projected surplus of 700 billion BTU's/year in 1980/81 might be built. This promises to show a better return on investment than piping the gas to a potential customer some 10 miles distant.

A further option available to gas producers is the establishment of a gas grid linking a number of mines to one or more users. There are a number of examples of this development in the U.K. now being operated by the NCB. In South Wales eight mines and three coke works feed gas to a pipe grid system. One coke works uses the major proportion of coalbed methane from the mines and then blends the surplus with its own production for sale. The grid is linked to a central boiler plant on an industrial site where steam and hot water are sold to small factory units. In Staffordshire five mines situated on the perimeter of an industrial town feed gas to a 11 mile grid. There are three brick makers on different sites taking gas at rates of between 150 and 300 billion BTU's per year. The mines produce in total 1.8 trillion BTU's per year. On-site use accounts for 300 billion BTU's and the brick industry another 600 billion BTU's. The balance of 900 billion BTU's is currently sold to a steel rolling mill in the centre of the town but will, following a recently concluded contract, be sold to a tyre manufacturing plant for process steam raising. Both grid systems operate with a manned compressor and grid control station, and gas storage facilities for 1 million cubic feet of gas in conventional holders.

REVIEW OF GOB GAS UTILIZATION TECHNOLOGY

This section reviews the utilization technology applicable to local industrial use. The techniques described have been specifically developed for use with gob gas by the NCB. It has been essential to adopt a consumer-oriented technology for the utilization of lean, variable quality gas available only in low and varying quantity. A number of features are considered, including pretreatment at the mine, transmission to the user, reception facilities at the user's plant, quality control and continuity of supply.

Pretreatment at the mine

Cleaning - the method of extraction adopted in the U.K. using water sealed vacuum pumps ensures that there are no particulate contaminants in the gas leaving the surface plant. No special provision has to be made for filtering prior to transmission. The major contaminant is water.

De-watering - gas leaves the extractor pumps saturated with water vapour at 100°F. Cooling by a simple heat exchanger will reduce the temperature to 75°F and a knockout drum will remove the entrained droplets. This is sufficient for short transmission distances of up to two miles where facilities can be built into the pipeline for dropout collection and regular blow-down. For pipelines of 5 to 10 miles, costs are reduced by further removal of water at source. This has been achieved by a number of methods to ensure that no further dropout occurs during transmission.

Storage - schemes for conventional gasholder and high pressure storage have been considered for utilization systems. A waterless gasholder of 250,000 cubic feet capacity costs in excess of $1 million. Costs of this magnitude to enable the user to carry out a smooth changeover to an alternate fuel cannot be justified on small contracts. It can become marginally economic when the user's process requirements are taken into consideration. Thus in cases of excess of supply over demand the surplus must continue to be vented and in situations of shortfall against demand the user must have a standby fuel instantaneously available for make up.

Compression - in the U.K., wherever practicable, advantage has been taken of the pressure available at the outlet of the extractor pump to transmit to the user. Above certain distances the economics favour a reduction in pipeline diameter and the use of reciprocating compressors.

Transmission to the user

Ductile spun iron pipe - this piping system with mechanical, self-anchoring joints has been adopted in preference to welded steel which is used for pipeline methane. The inherent ductility of the pipe and the flexibility of the mechanical joints show benefits in high subsidence areas. The pipe is bitumen coated internally and externally at the factory and no further internal protection is necessary against corrosion from the oxygen rich, moist gob gas. Substantial savings are made on purchase and installation costs. In the U.K. at pressure up to 50 psig a saving of 40% can be made against the cost of an equivalent diameter steel line. External protection by wrapping backed up with inert sand fill adjacent to the pipe has proved as effective as the cathodic protection techniques used on steel pipelines.

Polyethylene pipe - this material, developed in the United States for domestic gas distribution, has rapidly found favour in the U.K. for low pressure methane use. Being light and strong it shows a small cost advantage over ductile iron. Its chief benefit is that it is totally unaffected by aggressive soil conditions. Internal corrosion is eliminated and it is an ideal choice for conveying wet methane air mixtures. The major limitation of this material is that its pressure rating at larger diameters is suitable for only 15 psig when U.K. standards are applied.

Reception facilities at the user's plant

The gas arriving at the customer's site can fluctuate in pressure, quality and quantity because of the nature of the source of supply. Pressure variations and metering are the responsibility of the supplier and it is customary practice in the U.K. to construct a reception terminal which will house filters, pressure regulators and the billing meter.

Filtering - whilst all particulate matter has been removed at the mine, it has been found necessary to filter the gas to remove pick-up from the pipeline and reduce crystalline salt deposition from the vapour phase moisture. Fine mesh pipeline filters are adequate for this purpose and minimise the downtime on regulators and burners.

Pressure regulators - users throughout the U.K. have generally found that a controlled pressure of 5 psig is adequate at the point of supply into the works from the reception terminal. Twin regulator trains are provided each with its own high pressure trip valve to cater for regulator failure in the open position.

Metering - the positive displacement meter has proved the most successful with wet gases. Turbine meters are used, however, where large volume supplies of dry gas are used since the capital and installation requirements are substantially lower.

The features described form part of a standard design package developed by the NCB which can be utilized by clients with diverse requirements.

Quality control

The nature of gob gas collection schemes, the variability in rates of mining advance and the fluctuation in barometric pressure, all contribute to the production of a methane-air mixture of changing composition. It has been possible in the U.K. to determine the acceptable range of variation and to design quality control schemes to cope with a range, in general from 40% to 60% methane content. As the major incentive for mine drainage is safety it has proved impractical to control quality at source. The control function is therefore carried out at the point of use.

Two methods of approach have been adopted. For small supplies where the nature of the user's process, e.g. brickmaking, requires a gas of consistent calorific value, the gas is conditioned prior to combustion. For large supplies where the fuel is to be used for process steam raising, burner technology has received attention since large amounts of working capital may be at risk if the user's steam supply fails.

Control of calorific value - the techniques devised by the NCB are based on reducing the calorific value by the addition of further dilution air. Calorimetric control of dilution air addition is provided as a standard package at the reception terminal. The alternative approach of increasing the calorific value has been rejected since it does not maximise the sale of gob gas. Fuel addition is undertaken, however, in order to control calorific value closely provided a supplementary energy source is available on site. In the U.K. many users have pipeline methane or LPG storage facilities. We have found it advantageous to arrange for the addition of small quantities of LPG vapour or methane if the gob gas quality starts to fall from the mine specification of 40% by 2 or 3%. This avoids the user having to change fuels on a pressure/calorific value sensitive process. The type of control system used is based on Wobbe index to ensure a consistent input of fuel to the user's process independent of the LPG - gob gas mixture ratio.

Use of gas as received - the techniques of calorific value or Wobbe index control are particularly relevant to circumstances where the user has a process with a large number of small individually controlled burners such as a tunnel kiln for clay products or a tempering furnace for metal or glass. The cost of burner control systems to accept a fuel of varying quality would in this case be prohibitive.

For process steam raising or steam raising for power generation, where the total thermal input may be ten times that of a brick or ceramic kiln, the number of burners may be only six or eight. It then becomes practical to consider modification of the fuel-air ratio control system to the combustor. A sophisticated arrangement has been developed for the Unilever factory referred to previously. The control system used has the ability to monitor gob gas quality and pressure and also adjust primary combustion air. If the pressure decreases due to mis-match of supply and demand, a supplementary fuel is fed to the same burner through a separate line. Heavy oil or pipeline gas can be used and primary air is adjusted accordingly. An alternative has been adopted on other sites where the stand-by or support fuel is introduced through separate burners to accommodate gas quality variation.

Continuity of supply

The most important factor for the fuel user is the reliability of the fuel source. It has already been stated that U.K. experience of gob gas extraction has shown the quantity of gas available can be variable. Added to the variation imposed by mining and natural causes must be the variability of demand, affected for example by shift working and ambient temperature changes. The mis-match of supply and demand becomes an important consideration in arranging the sale to local industry.

The possibility of cessation of supply from the mine must also be covered. The supply cannot be guaranteed at the same level of certainty as pipeline methane. This makes the use of standby fuels inevitable.

Use of standby fuels - the techniques of utilization must depend upon the type of fuel available and the process. Liquid hydrocarbon fuels generally have to be burnt on a separate spud or burner. This makes the control relatively simple but can be costly if a multiburner installation has to be converted. LPG and methane offer a more convenient alternative if available since a synthetic mixture of fuel and air can be pre-mixed to supplement or replace gob gas. The synthetic fuel mixture can then be handled through the same pipework and controls without alteration to process conditions.

Design of standby and make up fuel systems - the NCB have put extensive effort into the design of standby systems. Pipeline methane can easily be diluted in a carburretor to produce a substitute gob gas. Recent development effort has concentrated on the utilization of LPG to produce a synthetic mix compatible with gob gas at the users premises.

Recently, the design, engineering and commissioning of a LPG tank farm and fuel gas production unit has been completed at a cost of $500,000. This was funded by the user to enable him to burn gob gas or LPG in the production of clay tiles. The supply was rated at 400 billion BTU's per year. This facility automatically adds LPG in the event of shortfall and is sized to completely replace gob gas in the event of a supply failure. At this same plant LPG is added in order to upgrade weak gob gas.

CONCLUSIONS AND SUMMARY

The paper has shown how geological, geographical and market forces have shaped the nature and direction of coalbed methane utilization in the U.K.

The depth of coal measures and predominance of longwall mining techniques have led exclusively to the extraction of gob gas at around 45 to 50% methane content by the technique of continuous methane collection progressing with the mining of coal from longwall faces.

Safety and mining requirements and a high degree of mechanization have led to the extracted gas at the mine surface being available at zero attributed value.

Coal output and the nature of the strata determine extraction rates. These rates are generally between 100 and 600 billion BTU's per year and rarely exceed one trillion BTU's from a single mine.

At the lower rates on-site use is the only option, whilst above 200 to 300 billion BTU's sales to local industry within a radius of about two miles are currently attractive.

At the one trillion BTU level it is economic in the UK to transmit the gas over a distance of ten miles.

Combination of outputs from several mines into a pipeline serving a multiplicity of customers is becoming more common and has many practical advantages.

Increased utilization of coalbed methane in the U.K. will be accomplished by the on-site use of gas down to 30% methane content, by blending outputs from mines and possibly by the development of industry adjacent to coalbed methane sources.

The picture overall is one of a mature industry, highly mechanized with methane drainage established securely as a major contributor to the safe production of coal. Markets for the gas are diverse and well established with sales to local industry giving an attractive payback on capital investment. The technology of practical mine drainage and gas utilization have been well proven in the U.K. and can be offered worldwide through Coal Processing Consultants, a subsidiary of the National Coal Board, with offices in London and Pittsburgh.

DEGASIFICATION PARAMETERS AND WELL COMPLETION PROCEDURES FOR THE MARY LEE/BLUE CREEK COALBEDS IN TUSCALOOSA COUNTY, ALABAMA

BY

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DEGASIFICATION PARAMETERS AND WELL COMPLETION PROCEDURES FOR THE MARY LEE/BLUE CREEK COALBEDS IN TUSCALOOSA COUNTY, ALABAMA

Kenneth L. Ancell, INTERCOMP

John W. Stevenson, Jim Walter Resources

INTRODUCTION

The Mining Divison of Jim Walter Resources is developing three new mines in the Warrior Basin in Tuscaloosa County, Alabama. The coalbeds to be developed are the Mary Lee and Blue Creek seams. In the area being developed the parting between the two seams is thin enough that both seams are being mined at once. Total coal height is between six and seven feet of coal in an interval of nine to ten feet. The mines are planned for the use of long wall mining methods.

Development mining has resulted in severe methane emissions in the mines. This paper reports the analysis of these emissions at the most advanced of the three new mines, Mine No. 4, and the status of a project to degasify the coal using vertical wells. One well has been drilled, completed and is currently producing. Four additional wells are planned and will be drilled in the next few weeks.

The mines are deep with overburden ranging from approximately 1950 ft to 2100 ft. The coal is low volatile bituminous. Primary use is for metallurgical purposes.

ANALYSIS OF EMISSIONS

The early emissions from Mine No. 4 were analyzed using a reservoir simulator that calculates the transient flow of reservoir fluids in three dimensions. The model includes the calculation of desorbtion of methane by the process of diffusion. The basic equations for the flow of gas and water in porous media are:

$$\nabla \cdot \left[\frac{\rho_w k k_{rw}}{\mu_w} (\nabla p_w - \rho_w g \Delta h) \right] - q_w = \frac{\partial}{\partial t} (\phi \rho_w S_w) \quad (1)$$

$$\nabla \cdot \left[\frac{\rho_w k k_{rg}}{\mu_g} (\nabla p_g - \rho_g g \Delta h) \right] - q_g = \frac{\partial}{\partial t} (\phi \rho_g S_g) \quad (2)$$

where

ρ = fluid density

k = permeability

k_r = relative permeability

μ = viscosity

g = acceleration of gravity

p = pressure

q = volumetric flow rate

ϕ = porosity

S = saturation

t = time

h = height above datum

Subscripts:

g = gas

w = water

The simulator assumes that the coal is made up of small particles that contain adsorbed gas in equilibrium with the fluid pressure around the particle. Desorbtion from each particle is calculated by the equation:

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

where:

D = desorbtion coefficient

r = radial distance from center of particle

C = concentration of methane

t = time

The simulation solves these equations in three dimensions and calculates distributions of pressure, saturations, gas concentrations and flow rates and pressures at the boundary conditions at specified points in time.

To simulate the growth of the mine, a boundary condition of atmospheric pressure was established at the point mining started. The area subjected to this atmospheric pressure boundary condition was allowed to grow with time. Figure 1 illustrates this growth. Flow is calculated from the faces and ribs exposed as well as from the pillars left behind. Because of the nature of the model, this was done incrementally; however, the conditions at the end of each month were approximately current. Figure 2 shows the results for the year 1977. The simulator gas production is averaged over each month for simplicity of illustration. Actual calculations show short time variations in the same order as the day-to-day variations in the observed data. The parameters used to calculate this performance are shown on Table 1.

To July 15, 1977, Mine No. 4 had produced about 250 MMCF of methane. By calculating the amount of gas originally in the coal, it is estimated that about 150 MMCF of gas migrated into the mine from areas outside the confines of the entries themselves. Figure 3 shows a pressure profile and gas desorbed as a function of distance at mid-July 1977. This data shows that significant methane drainage is confined to within 500-1000 ft from the existing ribs, although some drainage has come from as far as several thousand feet. What this means is that had there been any activity beyond that 500-1000 ft limit during the year there would have been little effect on the mine emissions. Further, if vertical wells had been drilled on 40 acre spacing (1320 ft between wells) and production commenced at the same time mining started, there would have been minimal effect on emission. The wells would have had to be in place considerably longer than one year.

EXPERIMENTAL WELL

Since the analysis of the mine emissions indicated parameters of the magnitude that would make vertical well degasification attractive, one experimental well was drilled to establish the parameters for an extended pattern of wells. The well was drilled approximately one-half mile southwest of the existing mine. The location was selected to place the well in the first long wall panel so that it can be mined through at the first opportunity.

The well was drilled and cased to a depth of 1968 ft. The casing was 4-1/2 inch O.D. casing and was designed to be set just above the coal. The drilling experienced some problems creating some sharp directional deviations. To complicate matters further, the casing pulled out of a collar while running, causing additional consternation. The problems caused by these complications will be discussed later. The interval below 1968 ft was cored through the 4-1/2 inch casing. The top of the Mary Lee coal was found at 1985 and the base of the Blue Creek was found at 1995 ft. Total depth drilled was 2010 ft. The schematic of the well is shown on Figure 4.

The coal cores were desorbed using the U. S. Bureau of Mines Direct Method. Results of the samples showed gas contents of 14.08 and 14.88 cm^3/g. In addition, a sample of coal from a nearby mine was taken to the laboratory and a methane adsorbtion isotherm was run. Results of this are shown on Figure 5. Both these methods tend to confirm the estimates of 500 cuft/ton (15.6 cm^3/g) which was the initial estimate of gas content. The laboratory isotherm tends to predict somewhat higher gas contents but the handling and drying of the sample all tend to make the measurements higher for the isotherm than would be expected from the raw cores themselves.

The well was then jetted with a sand water slurry in preparation for stimulation. Because of the 17 ft of laminated sandstone and shale open to the well between the bottom of the casing and the top of the coal, an inflatable packer was set at the top of the Mary Lee coalbed and the interval below the Blue Creek was filled with sand and debris from the jetting operation.

With the well in the above described configuration, the water level was allowed to come to equilibrium and a water injection test was run. The static water level was found at 102 ft below ground level. Using a water gradient an initial pressure of 820 psig at the top of the Mary Lee coalbed was calculated. This yields an overall pressure gradient of about 0.41 psi/ft. This is just slightly higher than what had been estimated earlier. The injection test was run for a 24 hour period with an injection rate of 16 barrels per day. Permeability was calculated to be about 35 md. This value is considerably higher than what was estimated from the emission study.

The well was then stimulated using 1000 bbl of water containing a small amount of friction reducer and foaming agent with 4,000 lb of 20-40 mesh sand and 5000 lb of 100 mesh sand. This was followed with 30,000 gal of foam of 75% quality and 30,000 lb of 20-40 mesh sand. Injection rate was restricted to between 8 and 9 bpm because of the tubing size and packer opening. Surface injection pressure averaged about 1200 psig during the water stage and about 2000 psi during the foam stage because of the light column of fluid.

Because of the restrictions of having to fracture down tubing and through a packer, one very important observation can be made. The annulus above the packer was left open to atmospheric pressure. Had the roof rock fractured, the fluid would have bypassed the packer and communciated with the annulus. This did not happen; therefore, the stimulation treatment did not fracture the roof rock.

After the flow back from the treatment died, the well was swabbed through the tubing for several days. Particular attention was paid to the amount of water swabbed and the resulting water level drawdown. The results of swabbing at the rate of 150 to 180 bbl/day could not appreciably affect the water level. Swabbing at that rate could not lower the level below 180-200 ft below ground level.

At this point, several artificial lift systems were contemplated. High volume positive displacement pumps were ruled out because of high cost and excessive wear caused by the crooked hole. Submergible pumps could pump high volumes but are subject to gas lock and with the well completion the way it is the pump could not be placed below the coal. The close tolerance for submergible

pumps in 4-1/2 inch casing made this option impractical. The lift method selected was an airlift using compressed air injected down the tubing and back up the annulus.

Unfortunately, because of equipment availability, a small compressor was utilized initially with a maximum discharge pressure of about 350 psig. This limited the initial lift to be from only 1200 ft. However, large volumes of water were removed from the well and as the injection pressure declined, additional tubing was installed. This method succeeded in lowering the tubing to only about 1600 ft. Problems developed with the compressor engine, and this process was terminated.

A second set of compressors was installed which has three stages of compression and a maximum discharge pressure of in excess of 1000 psig. This system has been operating for about two months with a minimum of problems. The performance of the airlift system has been very good. Approximately 75,000 bbl of water have been produced with no stoppages for downhole problems. During this time the well has produced a considerable amount of sand, coal particles, and coal fines. The well blew out one time and resulted in an excessive amount of water and solids, but the production system continued to operate. This performance is shown on Figure 6.

Gas production has been somewhat disappointing. Because of the mixture of air, methane, and water, methane production has not been measured to date on a continuous basis. However, during periods when the compressor is shutdown for maintenance or some other stoppage, the well does produce measurable quantities of relatively pure methane. These flow periods have been measured at rates of 45 Mcf/d. Sustained production is thought to be in the range of 5 to 15 Mcf/d based on the methane content of the air stream and is increasing with time.

Immediate plans call for purging the system with vaporized propane to eliminate explosive mixtures, producing the gas-water mixture into a phase separator, and recycling the gas. As the methane is produced, the pressure will increase and a stream will be taken out of the system for measurement, thus creating a closed rotative gaslift system. Such a system is shown as Figure 7.

WELL PATTERN

Because of the higher permeability than initially suspected, it is impossible to dewater this coalbed using a single well. Recent shut-in pressure tests indicate that the well will build back close to initial pressure within a few hours after shut-in. This indicates an aquifer that is infinite acting and the only way to get the pressure down and hence desorb gas is to place a pattern of wells such that interference is created between wells and the resulting pressure depression will cause the coal to desorb gas in large quantities.

After analyzing the early data from the experimental well, such a pattern of wells was developed. Using the recent data obtained, a series of simulations was made using the simulator discussed earlier. The primary variables were the permeability and the external radius for the various spacing sizes. The current mine emissions were analyzed and it was determined that a 40% reduction in the gas content should result in significantly reduced mine emissions. Using the 40% drainage and the sensitivity runs described above, Figure 8 was developed which shows the time required to remove 40% of the methane for the various spacings at various levels of permeability.

Utilizing Figure 7, and the mining plan, a pattern of five wells was developed to create sufficient interference to desorb the gas in quantities large enough to make degasification feasible. This pattern is on approximately 40 acre spacing and makes maximum use of the planned development mining. This pattern is shown on Figure 9.

The wells are planned to be in the long wall panels so that they can be used for gob drainage wells after mining if necessary. Completion procedures will be markedly different with casing set through the coal to be mined and cemented. A section of fiberglass is planned for across the immediate coal zone. This fiberglass can be mined through with no danger of sparks or problems with the mining machinery. The gaslift production system is planned to be expanded to two compressor sets that will handle two and three wells each.

This pattern is in the process of being installed.

CONCLUSIONS

The Mary Lee/Blue Creek coals have properties that make degasification by wells attractive. In order to achieve effective degasification, a multiple well pattern is necessary. Further, each well must be capable of lifting large volumes of water.

A high volume airlift can be used to lift large volumes of water in a hostile environment producing some solids. This high volume airlift can be converted to a closed rotative gaslift system when wells begin to produce sufficient quantities of gas.

A pattern of wells can be planned such that the mining plan can be utilized to enhance the interference created by individual wells. The wells can be planned for multiple use as gob drainage holes after mining.

ACKNOWLEDGEMENT

The authors express sincere appreciation to Jim Walter Resources Corporation for permission to present this paper. This effort has been funded entirely by Jim Walter Resources and the Company had no obligation to allow its presentation.

TABLE 1

ESTIMATED COAL PARAMETERS AT MINE NO. 4

Coal Thickness	6 ft
Gas Content	500 cuft/ton
Permeability	7 md
Porosity	1.5%
Sorbtion Coefficient	5×10^{-8}
Pressure	750 psia
Gas Relative Permeability	$k_{rg} = 4(1-S_w)$

FIGURE 1

MINE DEVELOPMENT - JIM WALTER RESOURCES, MINE NO. 4

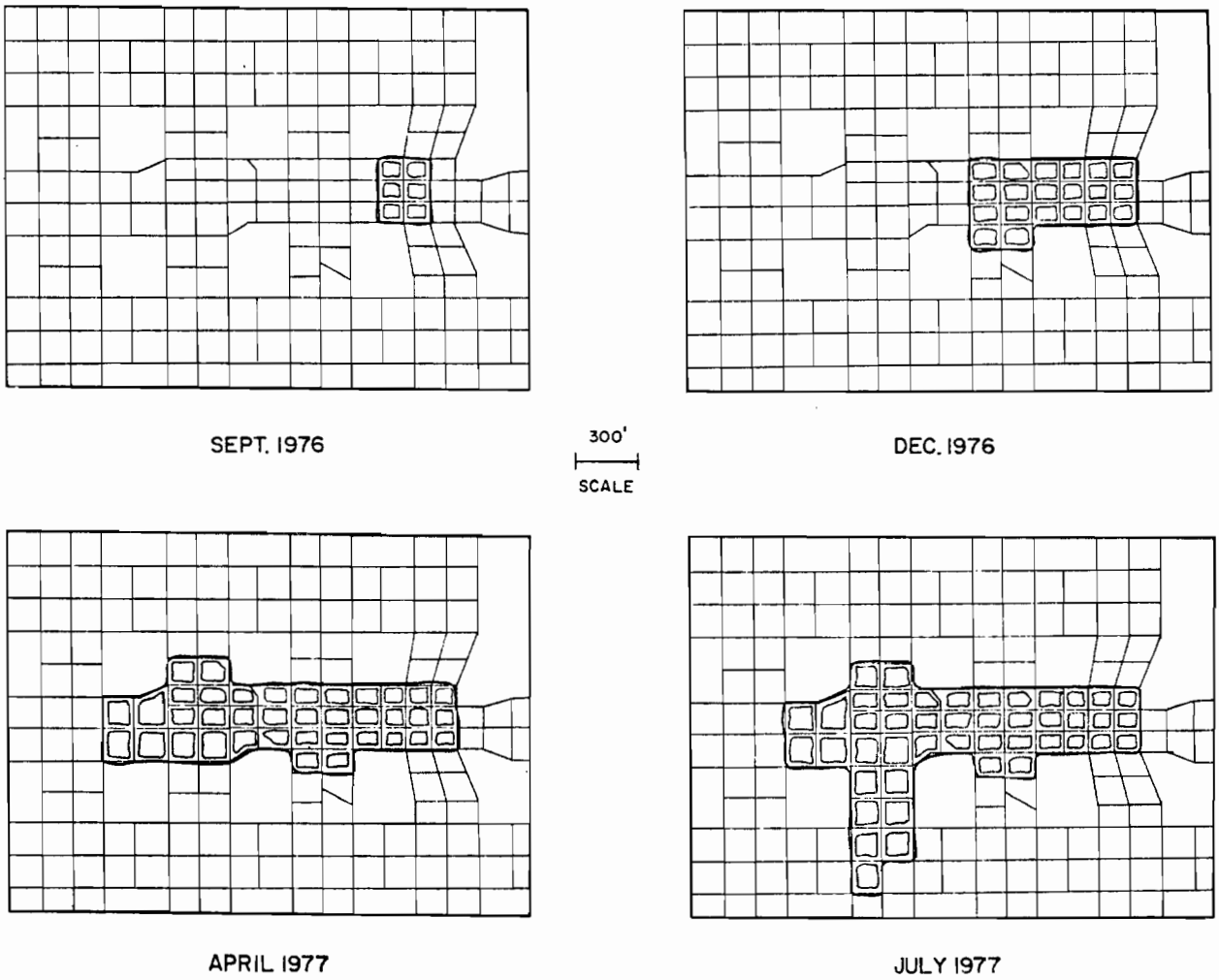


FIGURE 2

GAS EMISSIONS JIM WALTER RESOURCES MINING DIVISION MINE NO. 4

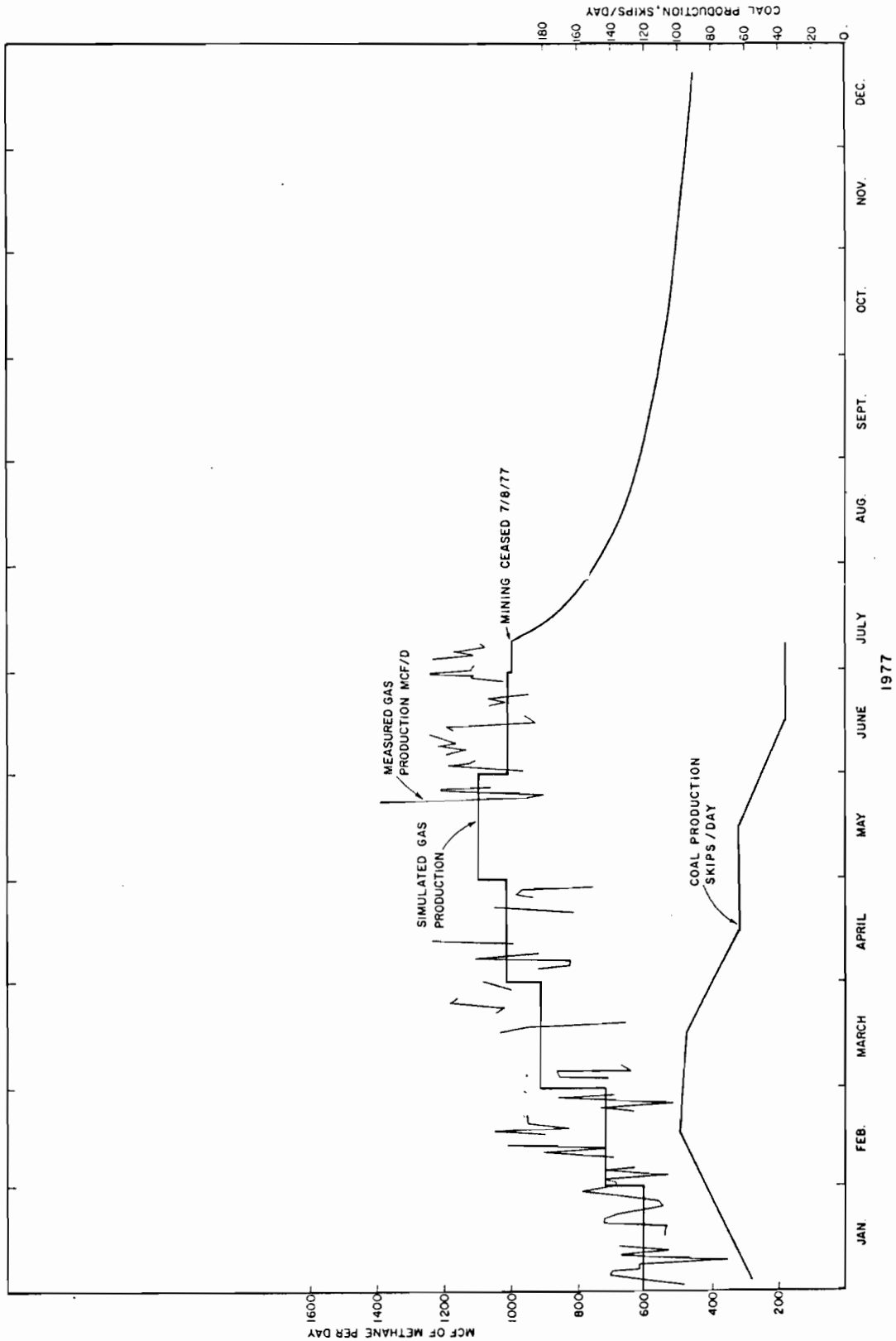


FIGURE 3

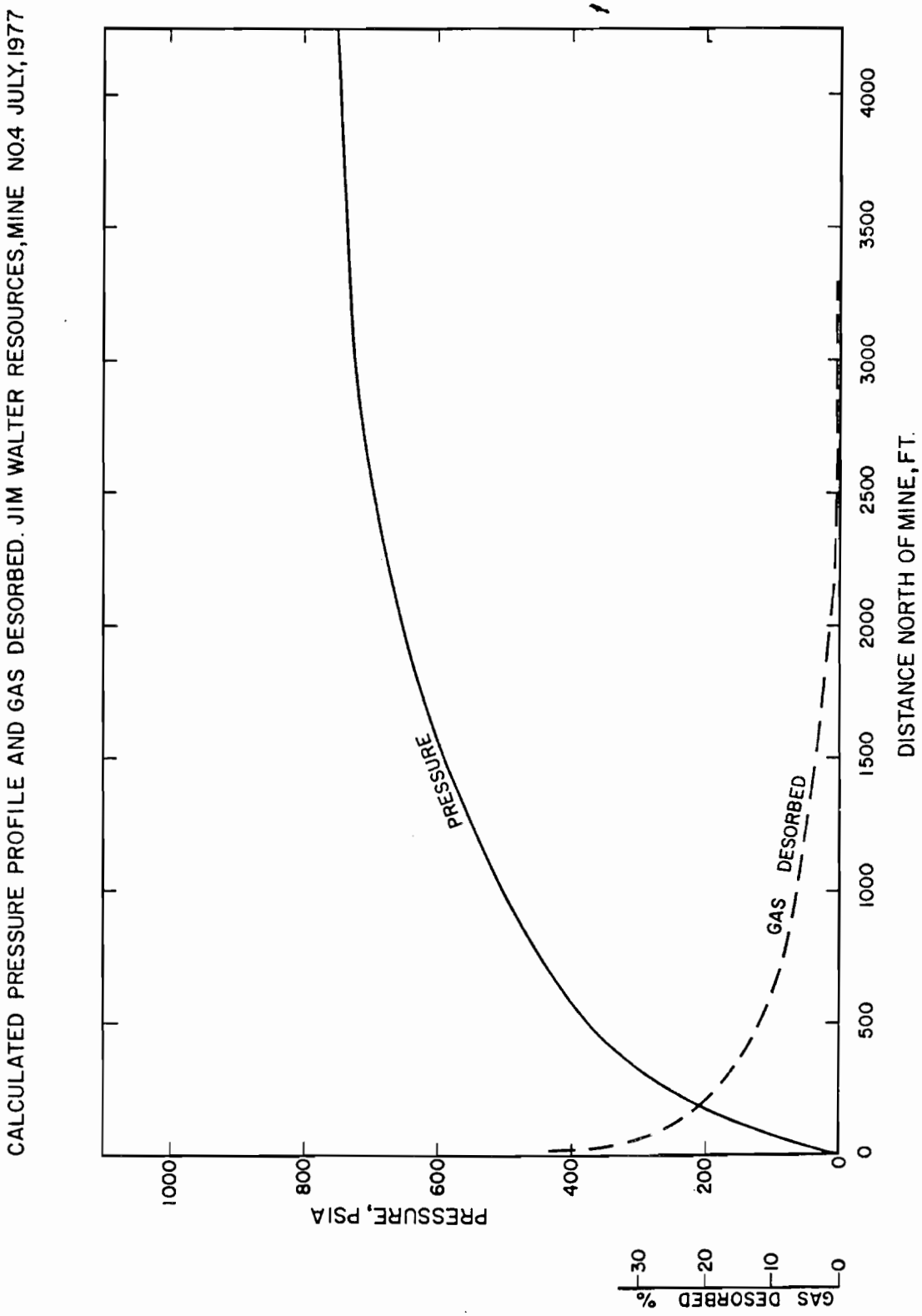

CALCULATED PRESSURE PROFILE AND GAS DESORBED. JIM WALTER RESOURCES, MINE NO.4 JULY, 1977
PRESSURE, PSIA
1000
800
600
400
200
0
PRESSURE
GAS DESORBED
GAS DESORBED %
30
20
10
0
0
500
1000
1500
2000
2500
3000
3500
4000
DISTANCE NORTH OF MINE, FT.

FIGURE 4
DIAGRAMITIC SKETCH
JIM WALTER RESOURCES-DEGAS NO. 1

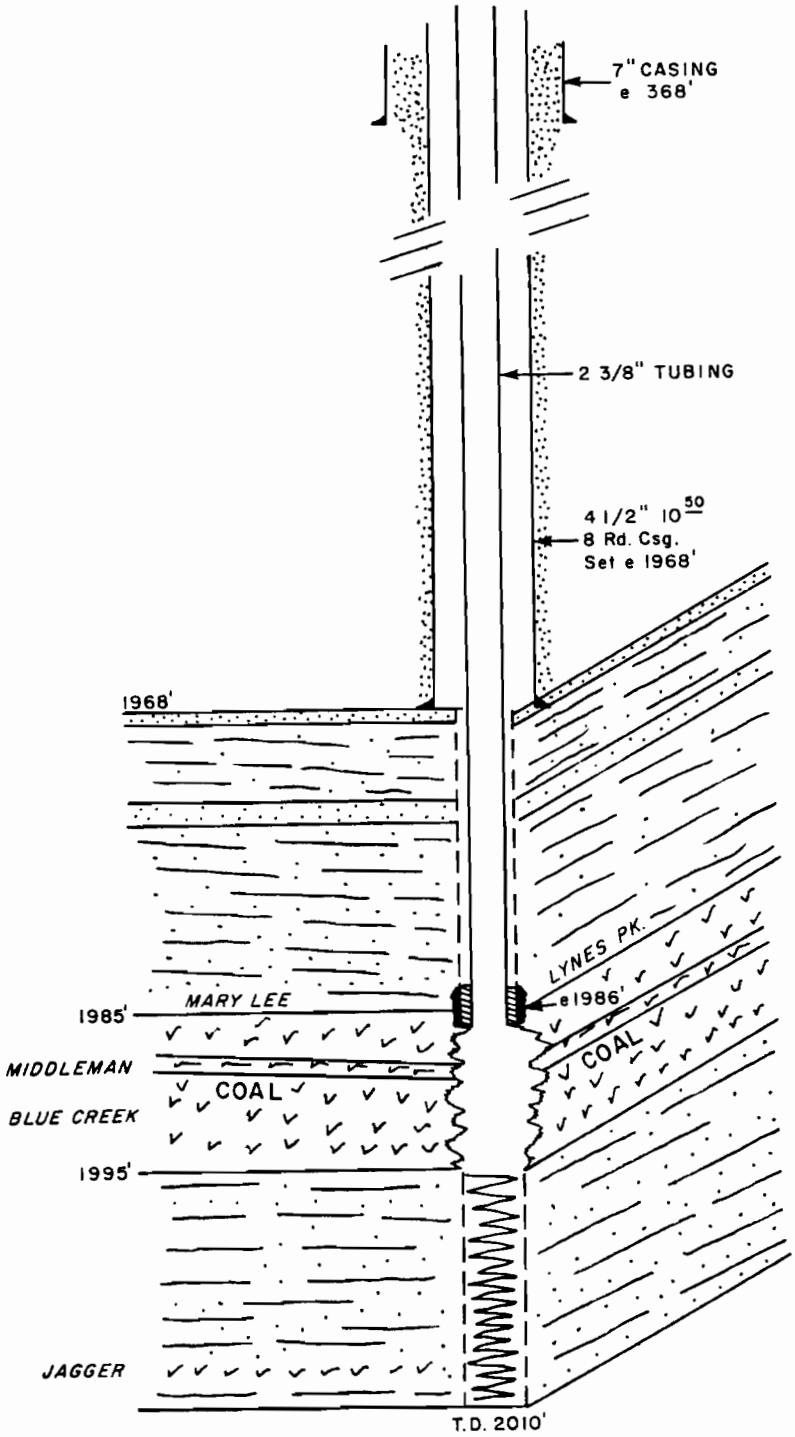
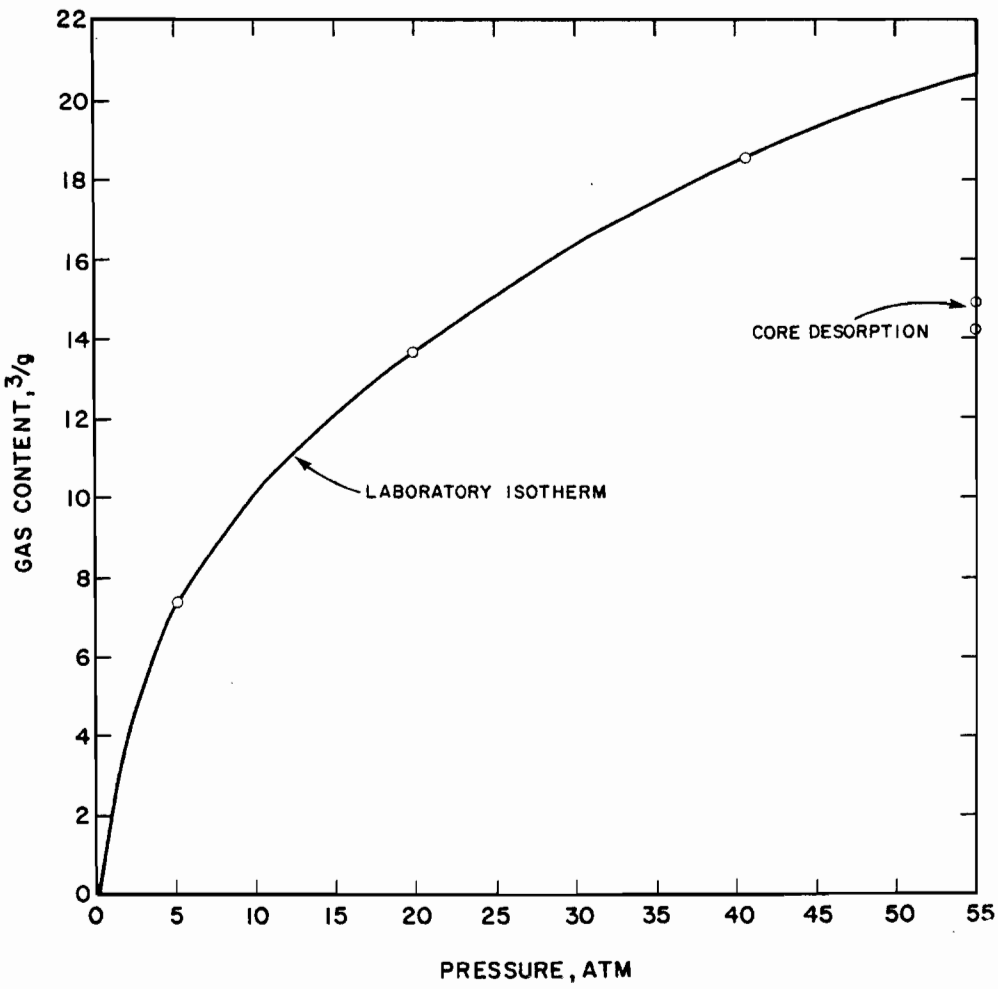


FIGURE 5
GAS CONTENT
BLUE CREEK COAL
TUSCALOOSA CO, ALABAMA



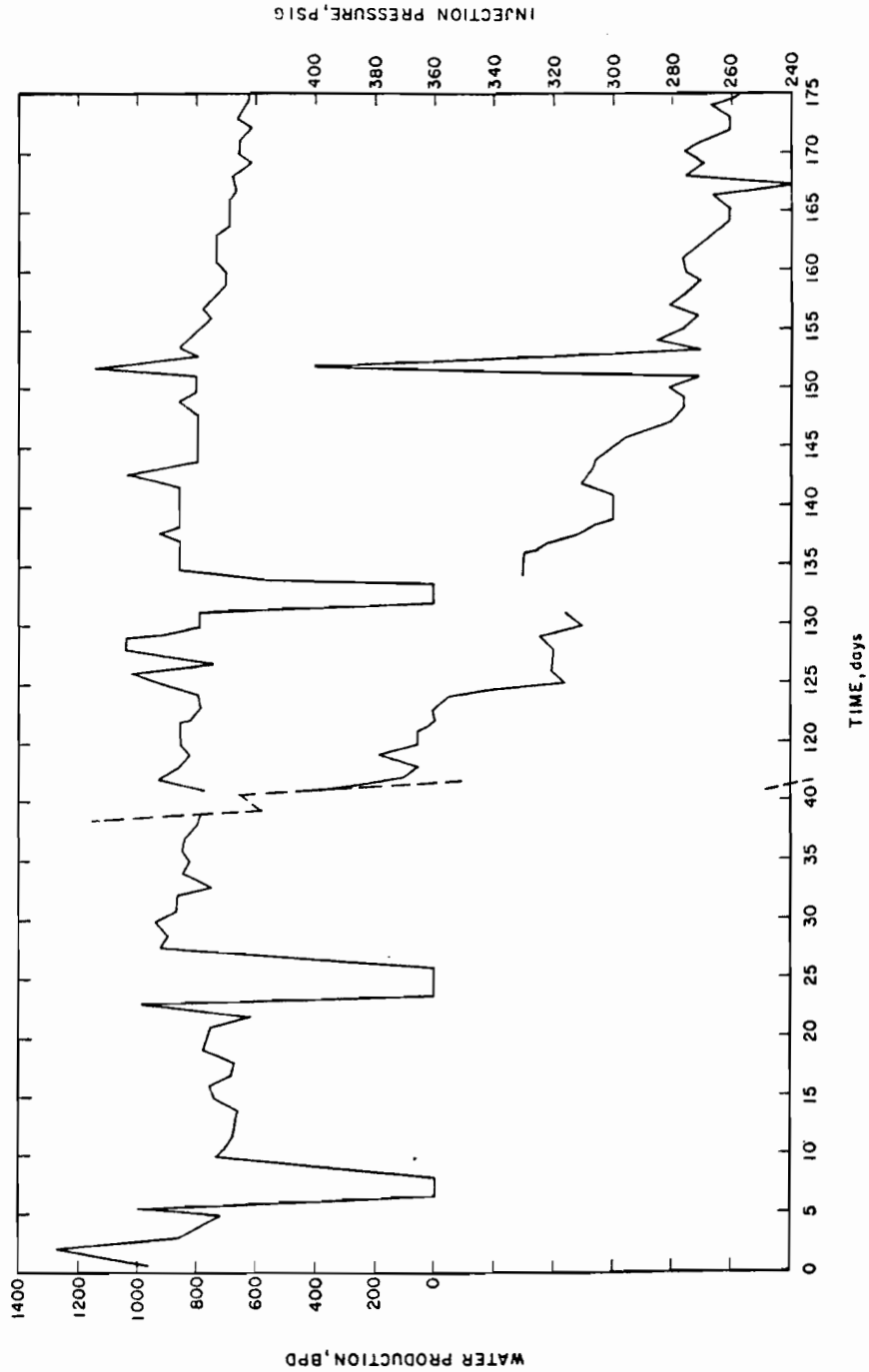


FIGURE 6
DEGAS NO1
WATER PRODUCTION

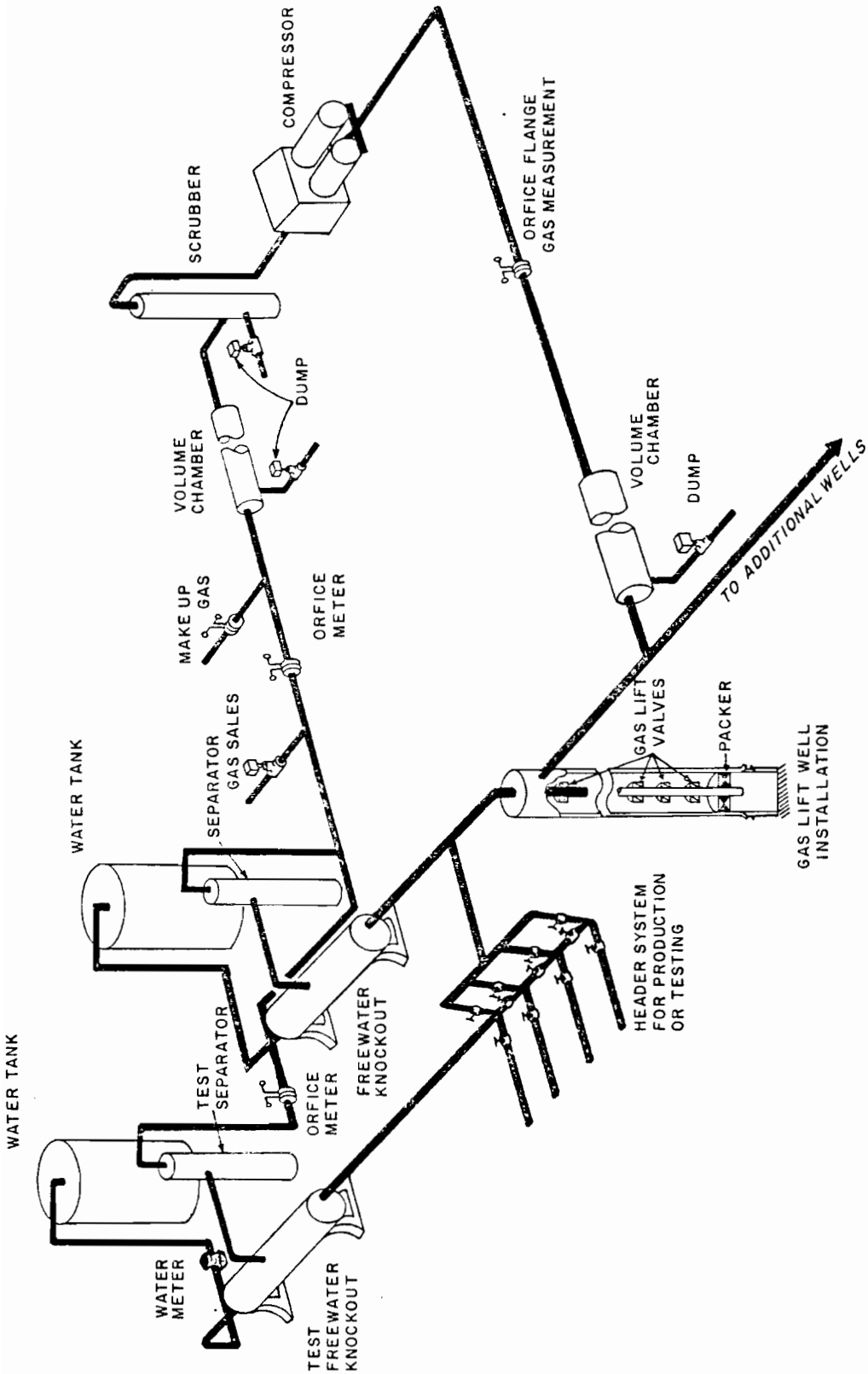


FIGURE 7

JIM WALTER RESOURCES
BASIC COMPONENTS FOR GAS LIFT SYSTEM

intercomp

FIGURE 8

EFFECT OF SPACING ON DEGASIFICATION

40 PERCENT DEPLETION

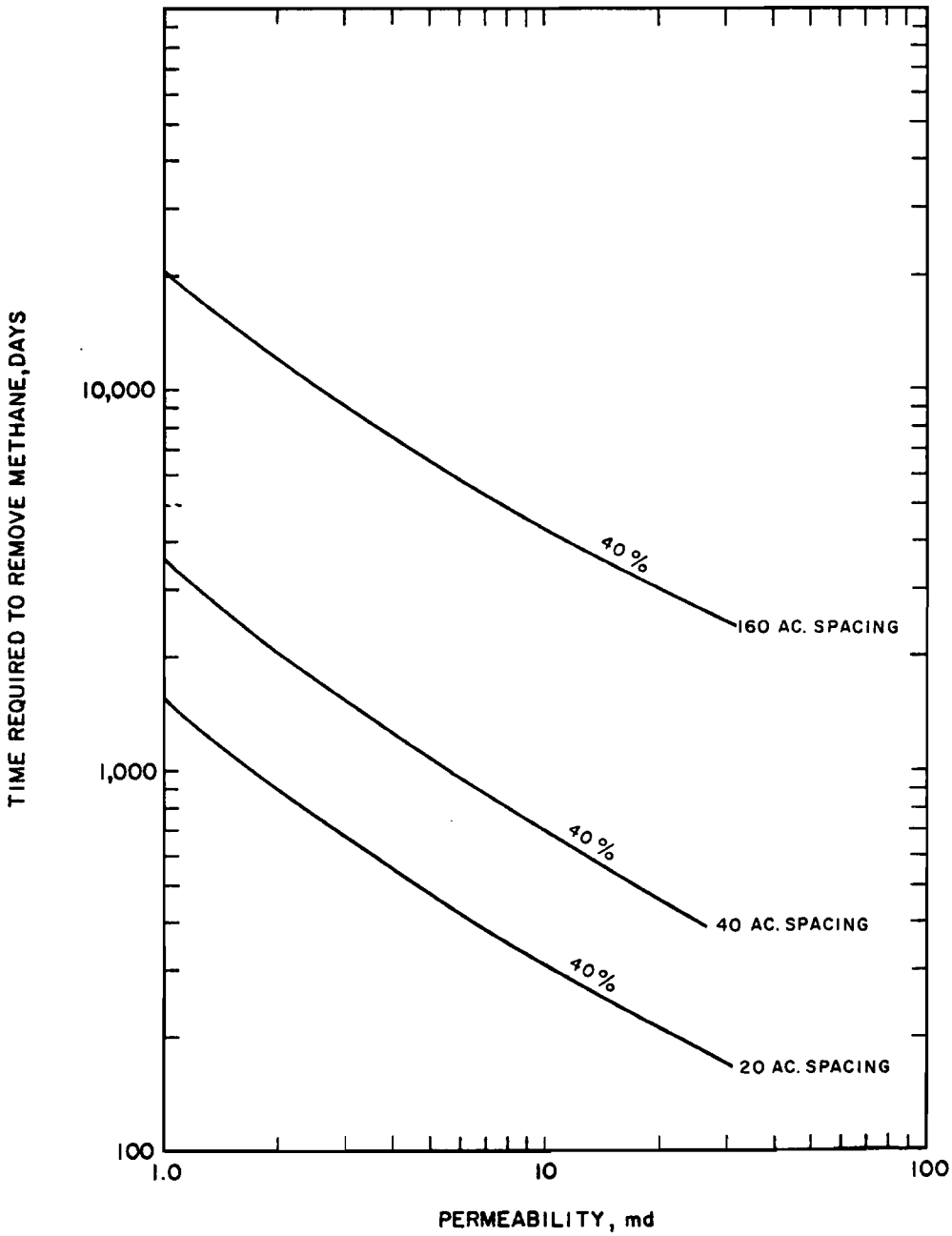
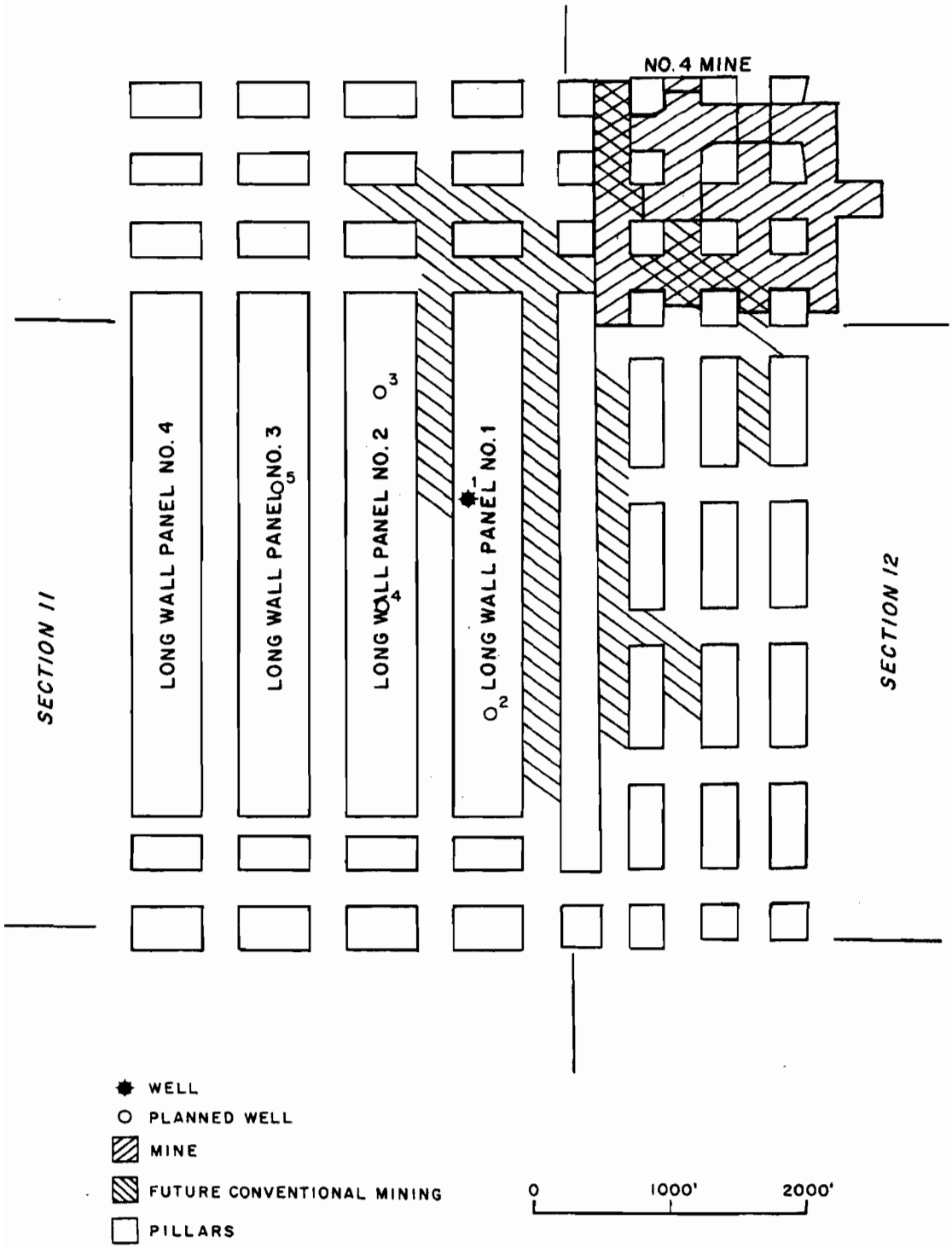


FIGURE 9

JIM WALTER RESOURCES
WELL PATTERN RELATIVE TO
MINING PLAN



THE EXTRACTION, COLLECTION, AND UTILIZATION OF COALBED METHANE

BY

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THE EXTRACTION, COLLECTION, AND UTILIZATION OF COALBED METHANE

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INTRODUCTION

The Advanced Energy Systems Division of Westinghouse currently has two contracts underway for the Department of Energy involving the extraction, collection and utilization of coalbed methane. Both programs are in Pennsylvania; one in Westmoreland County and the other in Cambria County. Both programs are based on a vertical well, multiple zone hydraulic stimulation technique for recovery of the methane. INTERCOMP Resources, of Houston, Texas, provided expertise in the areas of well design, core extraction and analysis, stimulation treatment design and reservoir performance.

WESTMORELAND COUNTY SITE

This program was started in 1978 at a Westinghouse owned site (850 acres) located south of Pittsburgh adjacent to Interstate Highway No. 70. Westinghouse activities on site include an industrial plant operation which uses approximately 100 x 10^6 cubic feet of natural gas annually. A commercial natural gas pipeline crosses the property near the Westinghouse plant operation. Coal reserves on the property are not considered profitable for coal mining, and the site is a good example of methane extraction from "unminable" coal seams.

The program underway is organized into three phases and work is presently underway in Phase II. The initial phase of work included core extraction and analysis at one site on the property. This same site was subsequently reamed, cased, cemented, perforated and hydraulically stimulated for methane gas production.

Eight of the twelve coal seam formations on site were stimulated (Kiel fracture process) sequentially in a single well, multiple zone fracture process. Figure 1 shows well detail, zone fracture treatment and coal seam formations. The well extends to a depth of 750 feet at this site. Table 1 summarizes site progress to date. Subsequent activity has included a pipeline hookup to the gas distribution system of the Westinghouse plant operation at this site, and gas flows are presently being used as commercial grade natural gas. Mass spectrometer analysis of the coalbed methane gas shows it to be free of any contaminants, very dry, and pure (99.2% CH_4) with a heating value exceeding 1000 Btu/SCF.

Tables 2 and 3 show additional detail in the areas of stimulation treatment and core analysis. The methane content of the coal (37 cubic feet/ton of in-place coal) is considerably less than expected and is also less than what would normally be predicted for the type of coal present at this site. An evaluation of methane migration, which has evidently been underway for many years, is still being conducted in conjunction with additional core sampling and analysis at other sites within the 850 acre tract.

Figure 2 shows additional technical data related to the gas desorbtion process from the coal. The data shown is based on fifteen individual core samples taken from a depth of from 187 feet to 630 feet at the well. Plotting all fifteen samples yielded a family of curves that were bounded by the two curves shown on Figure 2 as Data Maximum and Data Minimum. It is then possible to compute an effective D/a^2 for each of the curves from the early portion of the equation.

$$\text{Fraction} = \frac{M_t}{M_\infty} = 1 - \frac{6}{\pi^2} \sum_{n=1}^{\infty} \frac{1}{n^2} e^{-[(D/a^2)n^2\pi^2 t]}$$

where

$\frac{M_t}{M_\infty}$ = Fraction Desorbed

$\frac{D}{a^2}$ = Diffusion Parameter

D = Diffusion Coefficient

a = Sphere Radius

n = Number of Moles

This computation shows that the diffusion equation describes the desorbtion process very well over 85-95 percent of the volume. Further, the values derived from these curves are calculated to be in the order of 10^{-6} to 10^{-7}. These are really quite large with desorbtion values of 10^{-8} or 10^{-9} not uncommon from similar analyses.

Laboratory analysis of the cores also included adsorbed gas isotherm measurement, and subsequent comparison with desorbed gas from the same sample. The results of this "indirect method" show more adsorbed gas present than was measured in the desorbtion isotherm for that sample, with the differential being as high as four to one. This ratio is considered large and suggests migration of the methane, as previously noted.

Figure 3 summarizes the performance of the production well to date. Open well flow rate measurements increased to more than fifty thousand SCF/day at the time the well was shut in for interconnection to the Westinghouse gas distribution system in mid-January, 1979. Water flow measurements during the same period dropped to about 7 gpm. Water production by the well has been higher than projected. More water has already been recovered than was initially put in during the stimulation treatment. The quality of the water varies, but, in general, it is contaminated, and must be processed before it can be disposed of. Methods of disposal must of course comply with existing environmental regulations of Pennsylvania.

Economics

Long term projection of the economics at the Westmoreland County site necessarily involves some extrapolation of actual experiences and costs associated with the program to date into the future. Principal elements in this extrapolation include the number of wells required to fully develop the 850 acre site, drain radius per well, recovery factor, and long term average rate of flow per well. In developing numerical estimates for these parameters we have utilized a computerized two phase reservoir model developed by INTERCOMP Resources, of Houston, Texas. The resulting economic data base is as follows:

Site Lifetime - 12 years

Total Wells Required - 6 (for the 850 acre site)

Average Daily Flow per Well - 35,900 SCF

Recovered Methane - 60% of the reservoir content, or 1110 MCF per acre.

Using this data base and actual cost data from the program to date, the economic summary shown in Table 4 projects the overall economic viability of the system at this site. Costs shown include estimated costs for handling waste water from the six wells. This cost element is based on an on-site waste water well with associated plumbing and pumping facilities. The wellhead cost of the fuel, at $0.76/10^6$ Btu, is high considering that the reservoir contains only 37 cubic feet of methane per ton of in-place coal. At other sites, where the methane content of the coal could be much higher, the wellhead price of the fuel should be substantially less than the $0.76/10^6$ Btu shown.

Other economic data shown in Table 4 are developed from Table 5, which shows projected revenues, operation and maintenance costs, and cash flow for the projected twelve year system life cycle.

By definition the system present worth, S_{pw}, is given by:

$$(1) \qquad S_{pw} = \sum_{n=1}^{n=t} \frac{(\text{Cash Flow})}{(1+i)^t} + S_v - I$$

where

i = Rate of Earning Required by the Investor

S_v = System Salvage Value

I = Investment Cost

The first term on the right hand side of (1) can be rewritten[1] as a continuous rather than a discrete expression:

$$(2) \qquad \sum_{n=1}^{n=t} \frac{\text{Cash Flow}}{(1-i)^t} \xrightarrow[\text{Limit}]{} \int_0^T Q(t)e^{-it}dt$$

where

$Q(t)$ expresses cash flow as a function of time, and the discounting period, t, is made small

Multiplication by the factor (e^{-it}) instantaneously discounts the dollars given by $Q(t)$ to their present worth <u>at the time they are earned</u>.

The relation (1) above then becomes:

$$(3) \qquad S_{pw} = \int_0^T Q(t)e^{-t}dt + S_v - I$$

From Table 5, the data in the Cash Flow column are approximated by a simple linear time function:

$$(4) \qquad Q(t) = A + Bt$$

where A and B represent thousands of dollars

The result is:

$$(5) \qquad Q(t) = 141.37 + 21.69t$$

$$(6) \qquad S_{pw} = \int_0^{12} (141.37 + 21.69)\ e^{-.15t}dt + S_v - I$$

1. "Analysis for Production Management: - E. H. Bowman and R. B. Fetter, School of Industrial Management, Massachusetts Institute of Technology. Irwin Series in Industrial Engineering and Management, R. D. Irwin, Inc., Homewood, Ill., 1957.

where the assumptions are:

S_v = 0

i = 15 percent; the minimum acceptable rate to the investor

I = $991,000

It should be noted that the investment cost, $991,000, is based primarily on actual cost experience to date. The wells, wellhead equipment and pipeline system, which represent about 83 percent of the total cost of delivering methane to the burner, are known from cost experience to date.

Evaluation of the expression (6) under these conditions yields a S_{pw} value of $320,000, approximately. The exact value of the present worth, as computed from tables, is $359,518. The difference is due to the linear approximation used for cash flow.

In summary, this model indicates that over a twelve year period the system will:

- Pay for itself
- Earn 15 percent on the initial investment
- Yield a cash income whose present worth exceeds $350,000, or an average annual cash income of approximately $29,000.

Manipulation of the relation (6) shows that the present worth goes to zero at between 20 and 21 percent under the stated conditions for all other variables.

CAMBRIA COUNTY SITE

This program has been underway for a longer period than the Westmoreland County program discussed earlier, but on-site circumstances have delayed a more timely prosecution of initial program objectives. The application in this case is power generation through gas turbine-generator conversion of coalbed methane, with subsequent mixing of turbine power with a mine power grid. This system was discussed at the First Annual Coalbed Methane Symposium, which was held at the Ramada Inn in Pittsburgh in January of 1978. From that discussion, background information on this project is summarized below.

The principal sponsoring agency is the Department of Energy. Additional support is being provided by the United States Army, Bethlehem Mines Corporation, and the Commonwealth of Pennsylvania. The site is an operating coal mine near Ebensburg, Pennsylvania. This is one of several coal mining operations in this region of Pennsylvania by the Cambria Division of Bethlehem Mines Corporation.

Methane drainage practices at this mine include vertical wells drilled into gob areas created by the underground mining operation. This technique permits direct expulsion to the atmosphere of about 50 percent of the methane released underground as the mining operation progresses. Detailed examination of the quality and rate of flow of some of these gob gas wells indicate that they can easily support gas turbine-generator equipment up to about 800 kW from a single well for sustained periods of time. Larger generating capacities appear feasible with a manifolding of several wells. Safety constraints are the limiting factor in this type of application. Current regulations will not permit operation with Methane/Air volume mixture ratios of less than 50/50, i.e., with O_2 concentrations of no more than 10 percent. On this basis, the system has been designed to terminate operation on gas fuel when the mixture ratio falls below 60/40.

Initial objectives at the Cambria County site included on-site assembly of the hardware necessary to demonstrate a gob gas fueled system for power generation, with turbine supplied power to be fed back into the mining operation. These objectives have not been met at the present time, due primarily to an underground fire at this mine which required approximately one year to control. This has denied access of the system to a gob gas well. As an intermediate step, we have drilled to 950 feet in an area of virgin coal, and in the near future, will hydraulically stimulate the coal seam formations for gas flow. The principles involved are the same as those discussed earlier in connection with the Westmoreland County Site. There are some differences in the well design, however, and this is shown in Figure 4. The principal difference is in the lower casing, which is fiberglass. This type of casing minimizes problems for the mining operation which will pass through the area underground at a later date.

There is one other difference between the Westmoreland County well design and Figure 4 - the fracture treatment is larger in the case of Cambria County. Present plans call for injecting an 8000 barrel water/sand mix in the stimulation process.

Very briefly, the present status of the Cambria County site can be summarized as follows:

- The well has been drilled, cased and cemented.
- Perforation and hydraulic stimulation is scheduled for the week of June 11, 1979.
- All hardware components are available and most of these are already on site, awaiting the completion and cleanup of the well.

Economics

Internal Westinghouse evaluations of on-site development and use of coalbed methane have shown that power generation is generally more attractive economically than pipeline injection. This tentative conclusion is, however, very sensitive to actual site conditions. One of these conditions, for example, in pre-mining methane recovery, is the rate of flow which can be achieved. In marginal areas where flow rates are reduced, sufficient fuel may not be available for power generation. At the same time, these same flows may be quite acceptable (economically) for pipeline injection provided the pipeline is not too far away and right-of-way costs are not prohibitive. This type of situation exists at the Westmoreland County site discussed earlier, where the reservoir characteristics are extremely poor for a power generation application, but still useful for local recovery, transportation (short distances) by pipeline, and local conversion to industrial process heat.

In the case of power generation applications associated with coal mining activities, Westinghouse has focused on turbine-generator configurations of the Saturn and Centaur class. These systems are manufactured by SOLAR Turbines International, and are rated at 800 kW and 2500 kW, respectively. They appear to be the largest practical size for application in which the overall system is developed around the coal mining degasification program.

The cost of bus bar power from such installations can be estimated from the relation:

$$G_c = \frac{C_c \times F_{cr}}{8.76\ (1-R_o)} + \frac{H_r \times F_c}{10^5} + OM$$

where

G_c = Generation Cost, Mills/kWH

C_c = Installation Investment, $/kW

F_{cr} = Fixed Charge Rate, %

H_r = Turbine Incremental Fuel Rate, Btu/kWH

R_o = Turbine Outage Rate, %

F_c = Fuel Costs, Cents/10^6 Btu

OM = Operation and Maintenance Costs, Mills/kWH

A representative value of bus bar power cost, using what we consider realistic values for the other variables, yield G_c values as low as 20 mills/kWH. This assumes that the fuel cost factor, F_c, is charged to the mine degasification budget. If the system cost must include the cost of the wells, collection system, etc., then the factor G_c increases to about 27 mills.

In applications where the fuel costs are charged to the mine degasification budget, system payout can easily be three years or less. In one such case in western Pennsylvania, preliminary design calculations showed a methane flow rate capable of supporting three Centaur systems (7500 kW Capacity) and a system payout of less than three years. Current commercially supplied power at this site is about $0.04/kWH.

Westinghouse is hopeful that the Ebensburg site will provide some hard core experimental data which will confirm our present expectations that power generation is an economically attractive option now for the utilization of coalbed methane.

TABLE 1

SITE PROGRESS TO DATE

Coring	-	Fifteen core samples (2 inch) taken between September 27, 1978 and October 4, 1978. Depth ranged from 187 to 630 feet.
Drilling	-	Initiated October 2, 1978 and completed October 10, 1978, using an air-rotary Star drill rig. Uncased hole of 7-7/8 inch diameter penetrated to 760 feet below ground level.
Logging	-	Logging (Gamma Ray, Caliper, Compensated Density and Induction) completed on October 11, 1978 to 757 feet.
Casing	-	Well was cased and cemented down to a 5-1/2 inch OD. Used 150 sacks of Class A 75%; Pozmix 25% cement and 23 joints of 5-1/2 inch, K-55, 14 lb/ft ST&C casing.
Perforation and Stimulation	-	Completed on October 30 and October 31 (Kiel fracture process). Well sustained a small flare on October 31. Well was swabbed for several days with very little sand flowback. A 5 HP submersible pump was installed on November 17, 1978 with high/low water level sensors at 580/670 feet.

TABLE 2

STIMULATION TREATMENT DETAIL

Zone	Perforations Depth	Number of Holes	Number of Stages	Sand lb	Volume Pumped bbl	Rate bpm	Pressure psig
1	657-58	2	1	0	145	8	3800
	652-53	2					
	645-47	3					
	614-16	5					
2	570-72	4	5	26000	2105	26	2100
	530-32	4					
	490-92	4					
3	449-52	6	5	26000	2145	30	1200
	385-88	6					
4	333-35	4	5	24000	2080	32	1200
	256-58	4					
	193-95	4					
TOTAL				76000	6475		

TABLE 3

CORE DATA SUMMARY

Sample Number	Depth Feet	Seam Thickness Inches	Gas Content CC/G	Moisture Wt%	Ash Wt%	Volatiles Wt%	Fixed Carbon Wt%	Sulfur Wt%	Btu Btu/Lb
1	187-189.5	28	.376	4.01	10.74	33.52	51.72	4.10	12636
2	237-243	74	.458	4.13	24.56	29.44	41.86	4.49	10527
3			.648	2.95	7.47	36.52	53.06	2.51	13439
4			.821	2.53	14.82	33.15	49.50	5.61	12262
5	324-326	25	.807	4.02	27.61	25.84	42.53	1.90	10183
6	384-389	62	1.669	1.34	13.56	32.15	52.94	2.99	12801
7			1.628	2.42	10.11	32.41	55.06	4.49	13059
8	432-435.5	46	.723	5.24	14.29	32.04	48.43	2.13	11861
9	458-459.5	18	.878	1.91	12.92	34.55	50.61	4.53	13101
10	477.5-479	15	1.978	1.23	9.96	34.41	54.41	5.60	13266
11	517-518	14	.966	1.72	10.65	32.47	55.16	2.63	12903
12	552-554	24	1.482	1.54	6.96	32.36	59.14	1.80	13967
13	589	5	1.441	1.41	24.65	27.73	46.21	1.20	10810
14	618	4	1.846	3.33	31.26	23.94	41.47	3.92	9232
15	628.5	8	3.245	4.43	11.06	32.00	52.52	4.43	12680

TABLE 4

INITIAL ECONOMICS
(12 Year Life Cycle)

Cost Element	$/10^6$ Btu	Economic Projection
Wells	0.76	System Payout - 5 Years
Wellhead Equipment	0.06	Earnings - 15%
Collection System (3 miles of pipeline)	0.05	
Waste Water Handling System	0.18	Average Present Worth Cash Income - $29 K/Year
Sub-Total	1.05	
O&M Costs	0.20	
TOTAL	1.25	

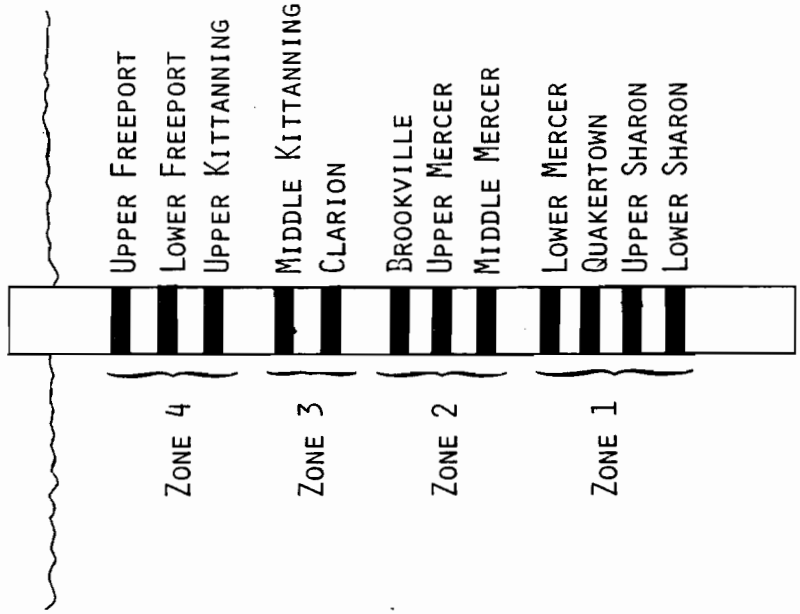
TABLE 5

PROJECTED REVENUES, O&M COSTS AND CASH FLOW

Year	Revenues*	O&M Costs**	Cash Flow
1 (1980)	$188,690	$10,229	$178,461
2 (1981)	$203,786	$11,047	$192,739
3 (1982)	$220,088	$11,930	$208,158
4 (1983)	$237,696	$12,886	$224,810
5 (1984)	$256,711	$13,915	$242,796
6 (1985)	$277,248	$15,031	$262,217
7 (1986)	$299,428	$16,231	$283,197
8 (1987)	$323,382	$17,530	$305,852
9 (1988)	$349,253	$18,318	$330,935
10 (1989)	$377,193	$19,310	$357,883
11 (1990)	$407,368	$20,856	$386,512
12 (1991)	$439,958	$22,524	$417,434

* Based on $\$2.40/10^3$ cubic feet in 1980 and escalated at eight percent annually.

** Includes labor and materials for operation of the system, and escalates at approximately 7.5 percent/year.



Each Zone to Receive:

- 5 stage fracture treatment
- Each stage includes:
  - 430 bbl water and 6720 lb of sand

Total Volumes Used for all Zones:

- 6475 bbl water
- 76,000 lb sand

Figure 1. Perforation/Stimulation Detail

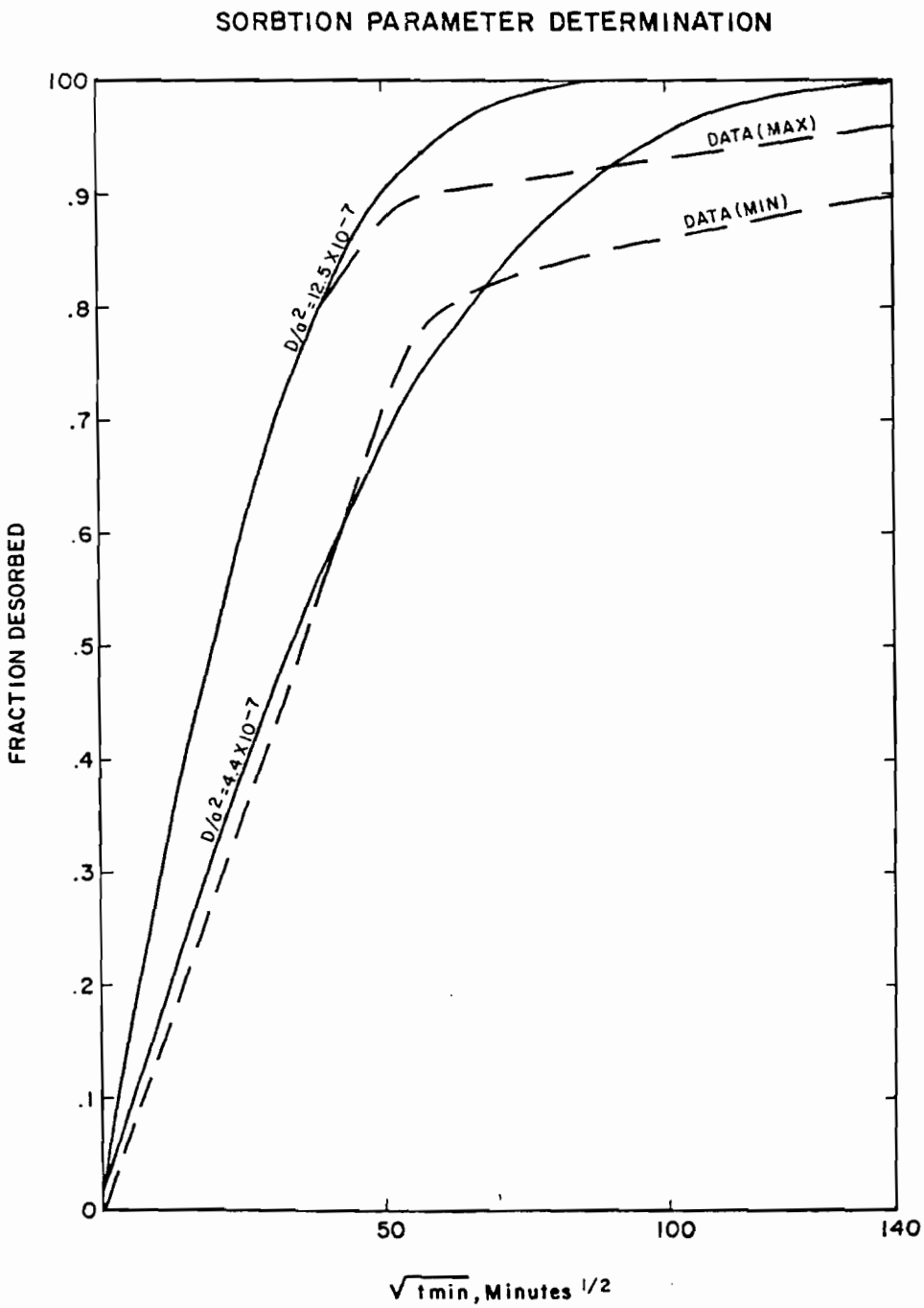


Figure 2. Gas Desorbtion Process

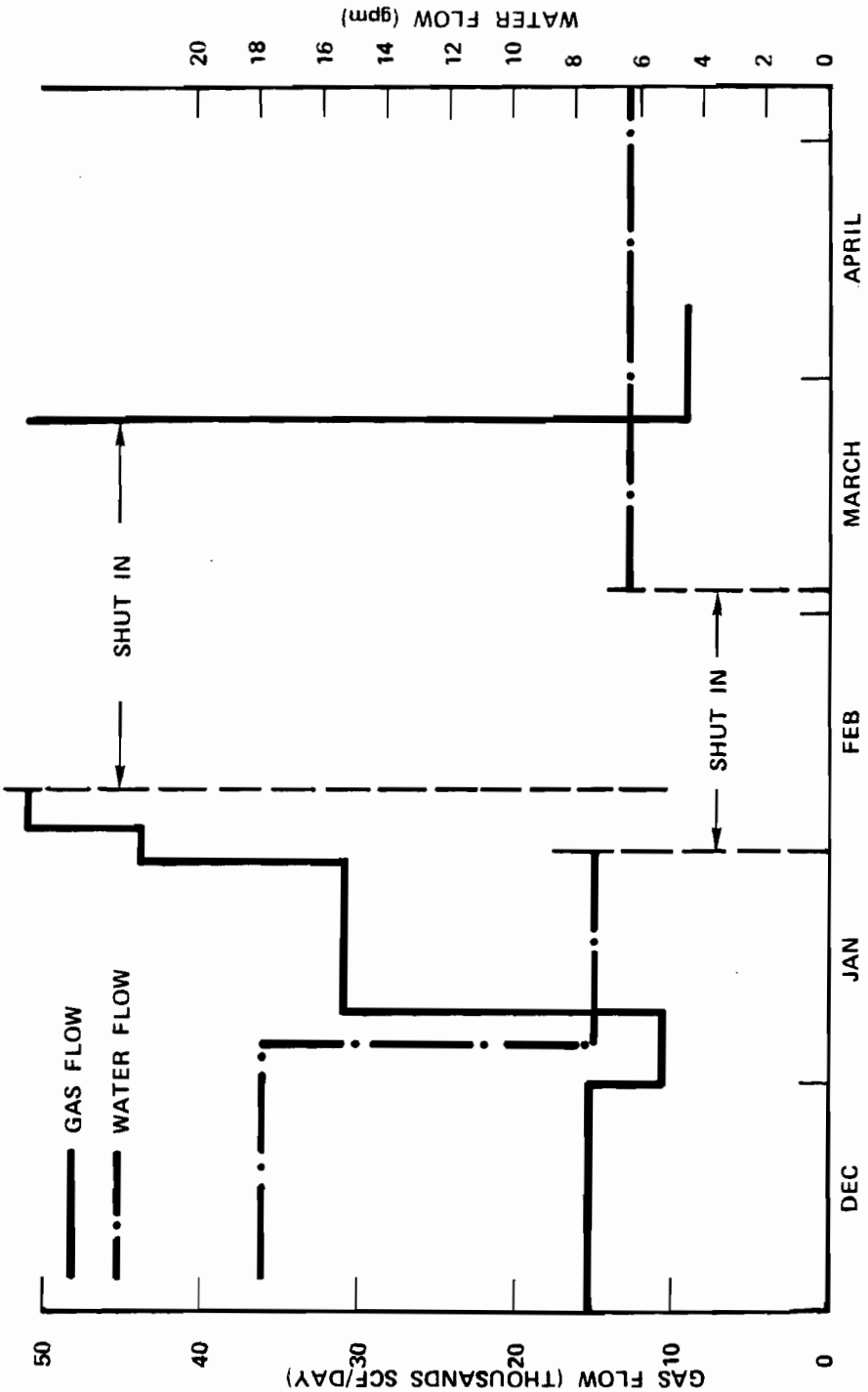


Figure 3. Well Performance

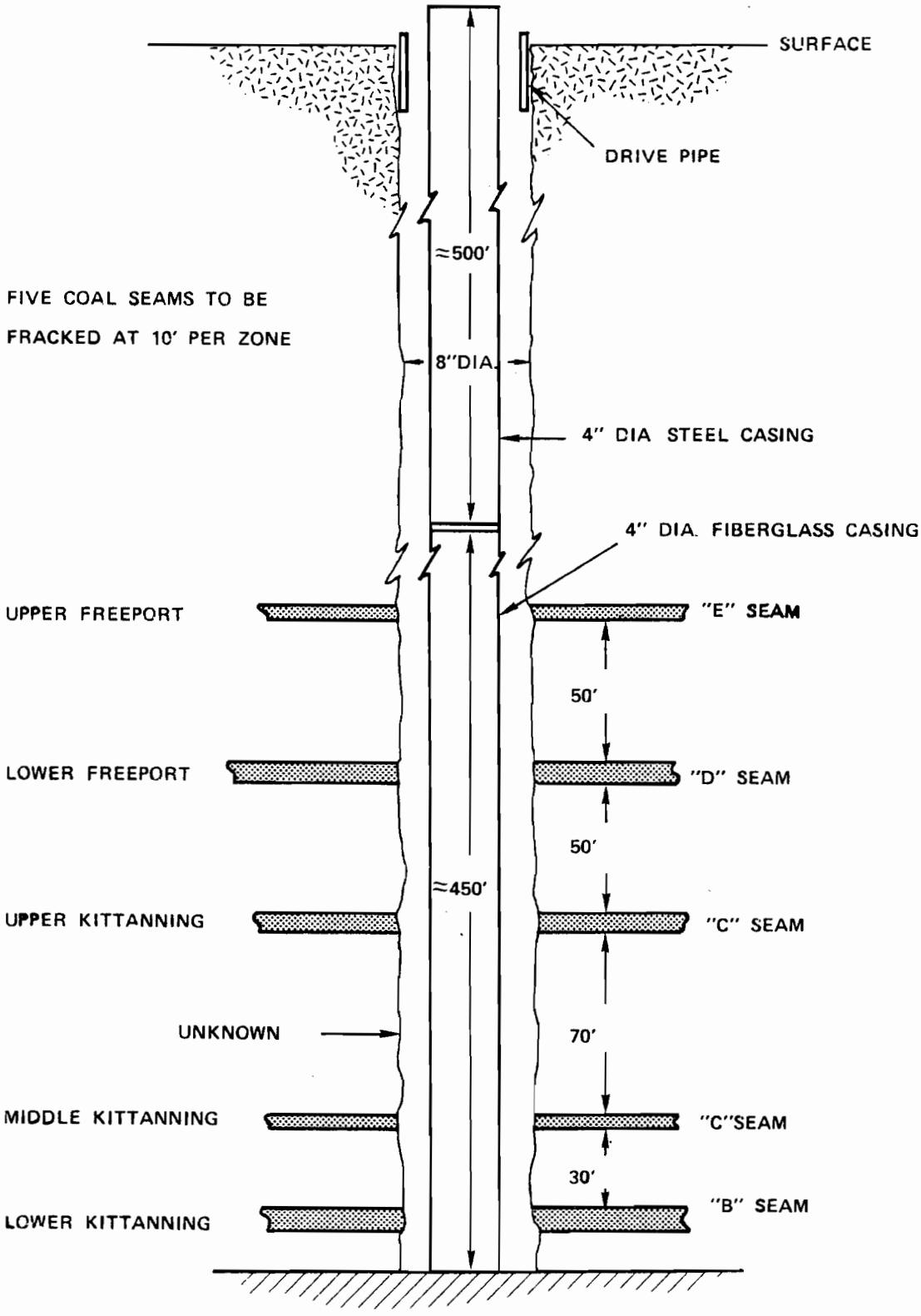


Figure 4. Design of Borehole for Hydrofracture

DEGASIFICATION OF THE BLUE CREEK COAL SEAM AT OAK GROVE MINE

BY

P. B. STUBBS, F. X. DOBSCHA AND J. V. MAHONEY
U. S. STEEL CORPORATION
MONROEVILLE, PENNSYLVANIA

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Mr. Stubbs received a BS degree in Chemical Engineering from the University of Pittsburgh and has been an author and coauthor of several publications on blast-furnace work. He is a member of the AIME.

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ABSTRACT

U. S. Steel's Oak Grove Mine near Birmingham, Alabama, is mining the Blue Creek Seam which contains an average methane content of 450 scf/ton of coal. Because these high gas concentrations could potentially interfere with mining, a program has been initiated to reduce the gas content of the coal seam prior to mining. With the assistance of DOE (Contract No. ET-75-C-01-9027), 21 vertical degasification boreholes have been installed on the Oak Grove property. Four of these were positioned in the vicinity of the active mine workings, were stimulated using various completion techniques, and were mined through after short gas production periods so that their effect on mining operations could be assessed. Although gas production from the first two boreholes was somewhat disappointing, encouraging results were obtained from the last two boreholes in that they removed more than 30 million cubic feet of gas over a total production period of 13 months.

The remaining 17, which will be the subject of this presentation, were planned to satisfy the dual objectives of determining the long-term production capabilities of vertical boreholes, and identifying those completion/stimulation techniques which maximize gas production. The basic arrangement of these boreholes was a 3-hole by 5-hole grid pattern of 21.5 acre spacings with two adjacent but outlying boreholes completing the 17. At the time of installation this grid pattern was at least five years in advance of mining. Except for two boreholes which were cased through the coal seam, an "open-hole" completion technique was employed. In an attempt to minimize structural damage to the overburden, our openhole completion specified casing and grouting the borehole to approximately the top of the Blue Creek coal seam leaving only the pay zone itself exposed to the stimulation fluids. Each borehole was then stimulated employing either a water gel, foam, or "Kiel-Process" treatment, the sizes of which were in the vicinity of 50,000 gallons, i.e., approximately two and one-half times larger than those of the two best producing near-mine boreholes. For all 17 treatments sand was used as the proppant material with the injection concentrations never exceeding 4 lbs/gallon and an average of 65,000 pounds of sand injected per hole.

In the main, gas production from these grid boreholes has been varied and inconsistent. Sustained peak production for an individual hole has ranged from 5 to 200 mcfd, while the total days the individual boreholes have produced varies from 0 to 305. Based upon the cumulative days of gas production and the total gas removed from the grid area, an average daily production rate per hole would be approximately 50 mcfd. This figure of course ignores the numerous days during which we have experienced absolutely no gas production. The major impediment to uninterrupted gas production has been the flow back of proppant sand into the well bore. This sand has interferred with the proper functioning of the downhole, mechanical dewatering equipment which in turn allows hydrostatic column to rise and inhibit or eliminate gas flows.

DEGASIFICATION OF THE BLUE CREEK COAL SEAM AT OAK GROVE MINE

In addition to discussing the details of the above synopsis, this presentation will explain some of the activities we have undertaken to optimize the operating conditions of the grid pattern.

INTRODUCTION

The Oak Grove area of the Warrior Coal Field in Jefferson County, Alabama is located about 20 miles west of Birmingham. This coal is present in two benches of the Mary Lee group. U. S. Steel nomenclature describes the lower bench as the Blue Creek seam and the upper bench, the Mary Lee seam. At Oak Grove, the two seams are separated by a parting 2 to 10 feet thick and only the lower (Blue Creek) seam is being mined. The Blue Creek seam is located about 1100 feet beneath the ground surface and averages about 5.5 feet in depth across the Oak Grove property.

Coal production from the mine was started in May 1974. Since initial development, methane-liberation rates have been much higher than expected. Mining operations are frequently interrupted by methane emissions, which automatically shut down the continuous miners and thereby materially restrict production.

Currently, more than 7 million cubic feet of methane per day is being removed from the mine by conventional ventilation techniques. As more sections are put into production, this figure could increase significantly and require large capital outlays for additional ventilation facilities. This indicated the need for developing alternate methods to control the methane.

Early in 1975, informal discussions with the U. S. Bureau of Mines (USBM) indicated that they were seeking a financial partner and site for a large-scale demonstration of hydraulically stimulated vertical boreholes. U. S. Steel and the USBM entered into a 50/50 cost-sharing contract to demonstrate methane drainage through vertical boreholes at Oak Grove mine. Twenty-one vertical degasification boreholes have been installed on the Oak Grove property. Four of these were positioned in the vicinity of active mine workings and the remaining 17 in a 3- by 5-hole grid pattern of 21.5-acre spacings, with two adjacent but outlying boreholes. At the time of the installation the location this grid pattern was at least 5 years in advance of mining.

NEAR MINE BOREHOLES

The first part of the program involved installing four boreholes near the mine workings. These holes were stimulated by using various completion techniques and were mined through after short gas-production periods so that their effect on mining operations could be assessed. Mining operations revealed that at several of the holes the hydraulic fractures did penetrate the mine roof. Supplementary roof support was required at the bottom of these holes, but no roof falls were experienced during development mining. Assessment of the long-term effect of such penetration requires the passage of time, and the effect of such penetration on pillar recovery must await that stage of mining operations.

The initial borehole was installed and stimulated using gelled water and the same practices employed by the USBM in about 10 other boreholes in various coal seams in the United States. Gas production from this hole was quite low, never exceeding 8500 cubic feet per day (cfd) (Figure 1). When mining reached this hole it was found that the fracture was in the rock below the coal seam. There was evidence that the coal seam had been fractured by the drilling mud and grouting cement prior to stimulation. On the basis of these observations, it was determined that if the Blue Creek was to be hydraulically stimulated, new drilling, grouting, and hydraulic-stimulation techniques would have to be developed.

The second hole was drilled without mud, casing was installed through the seam, and slots were cut in the casing at the coal seam to deliver the stimulation fluids. The hydrostatic pressure of the cement on the coal was reduced by grouting only the bottom 500 feet of casing. When this hole was stimulated there was no evidence of a breakdown occurring, although pressures up to a preset limit of 2500 psi were reached. The gas production from this hole was better, reaching levels of 25,000 cubic feet per day when the hole was dewatered (Figure 2). When this hole was mined through, it was determined that the slots in the casing were off target and located about a foot below the interface between the coal and floor rock. This position probably restricted the flow of gas.

In terms of gas-removal rate, the next two holes were the most successful of the four holes near the mine workings. Both of these holes were drilled without mud, cased to immediately above the coal seam, and treated by using nitrogen foam-stimulation techniques. The first of these two holes was stimulated using a treatment of about 21,000 gallons of nitrogen foam and placing 25,000 pounds of sand as proppant. At that time the closest mine workings were about 1000 feet from the borehole. Gas production from this hole was intentionally terminated after 10 months when it was necessary to shut down in anticipation of mining operations reaching the bottom of the hole. The borehole was shut down temporarily once during its production period to permit stimulation of the Mary Lee seam located only 7 feet above the Blue Creek seam. During its production life, nearly 16 million cubic feet of methane was released from the coal through this hole and had an average production rate of more than 62,000 cubic feet per day (Figure 3).

The fourth borehole near the mine workings was located about 600 feet from the third. This fourth hole had the highest gas-production rate to date, averaging 122,000 cfd for 3-1/2 months (Figure 4). There was evidence of communication between this borehole and the third borehole. When the third borehole was shut down, water production at the fourth hole increased and a steady decline in gas production followed. Simultaneously, mining was approaching the bottom of the hole and, when it was 200 feet away, gas production stopped entirely.

BOREHOLES AT TEST GRID

While the holes near the mine workings were being drilled and stimulated, a larger test program was being developed. The original scope of work called for installing and stimulating 25 boreholes in a 5- by 5-hole test grid using 1000- by 1000-foot centers (Figure 5). This plan was changed when the original hole near the mine workings produced only 8500 cfd. At the time, 14 holes had been drilled north of Valley Creek. No additional holes were drilled until gas-production rates from the second and third holes near the mine workings proved encouraging. Then three additional holes were drilled to complete a 3- by 5-hole rectangular pattern with two adjacent but outlying holes.

At the test grid, the holes were drilled to the parting rock between the upper and lower coal seams by using a rotary drill with a 6-1/4-inch bit. Four-and-one-half inch K-55 casing was installed and grouted with API Class A cement. The holes were then cored through the Blue Creek seam, and a 30-foot sump was provided for pump installation and water collection (Figure 6).

Coal obtained from the cores was used for desorption studies; the direct method developed by the USBM was used. Gas contents from 300 to 600 cubic feet per ton were obtained, from which it was estimated that the average gas content of the Blue Creek seam was about 450 cubic feet per ton.

Following drilling, casing, and stimulation of each vertical borehole, surface and downhole pumping equipment was installed. Four-inch pipe was used for the surface installation, and the horizontal section was run about 45 feet from the hole (Figure 7). In the horizontal section were drains, gas meter, shutoff valves, and pressure gages. Turbine-type positive-

displacement gas meters were found to be satisfactory for this service, provided that heating tape and fiberglass insulation were used to prevent freezing of moisture during the winter months. A vertical section about 25 feet high was run for the flare-stack arrangement.

The flare stack was topped with a flame arrestor and free vent. The initial vertical borehole near the mine workings was installed without lightning protection. During its early operation, it was struck by lightning and an ignition occurred. Following this occurrence, the Mine Safety and Health Administration (MSHA) required that lightning protection be installed on the surface installations of all other boreholes. Lightning protection was provided by 65-foot poles surrounding the flare stack, which were connected at the top with a grounded ridge wire.

The two outlying but adjoining boreholes at the test grid, No. 9 and No. 22, were used as test demonstration holes. Because these boreholes were located away from mine workings it was possible to use much larger stimulations, 50,000 gallons of fluid as opposed to 20,000 gallons or less near the mine. No. 9 borehole was fractured by using gelled water and CO_2 and No. 22 borehole was fractured by using a 75-percent-quality nitrogen foam. No. 9 borehole was a closed hole cased with 4-1/2-inch-diameter casing to the bottom of the hole. Five feet of the casing was perforated at the level of the Blue Creek seam with four 0.38-inch-diameter perforations per foot. The hole was stimulated by using gelled water with liquid CO_2 added to provide pressure to force out the water following the treatment. There was evidence of a formation break at 850 psi as measured on the surface, which was equivalent to 1315 psi at the coal seam. After the breakout occurred, treatment was continued at a rate of 10 bbl/min.

As delivered, the treatment included 5000 gallons of prepad, 50,000 gallons of gel, 15,000 pounds of 20- by 40-mesh sand, 7140 gallons of liquid CO_2, and 1130 gallons of water for flushing. The design for this well had specified an additional 10,000 gallons of gel and 35,000 pounds of sand, but it was impossible to complete the design treatment when the sand buildup in the formation restricted flow at the maximum injection pressure of 2500 psi. Following the stimulation, the hole was shut in for about 7 hours, then allowed to bleed off. This borehole bled off for about 84 hours before the flow stopped. One day after the pump was placed and dewatering of the hole began, a slight gas flow was observed from the borehole.

Figure 8 shows the gas and water production from this hole. Gas production has been a disappointment; the production rate has ranged from an initial high of about 10,000 cfd to about 2400 cfd when the gas flow stopped. In addition, this hole did not produce water at the rate of the other boreholes in the grid. Considering the combined lack of water and gas production, four reasons for the poor performance could be suggested: (1) poor fracture permeability, (2) failure of the biodegradable gel used in the fracturing fluids to break down, (3) plugging of the perforations in the casing, and (4) a combination of the above three.

Because gel, coal fines, and/or sand could be plugging the perforations and restricting gas flow, the borehole was shut down after three months of operation to prepare it for a backwash. Eight barrels of water were pumped down the annulus between the casing and water tubing at rates up to three barrels per minute. Water was allowed to return back up through the pump and 2-inch tubing. One barrel of water came back up the tubing and seven barrels went into the formation through the perforations. Following the backwash, the pump would not operate and it was necessary to remove the pump and tubing. Immediately after the pump was reinstalled and started, gas production was very encouraging, rising to a high of 19,700 cfd. Within a few days, however, the production rate continued its earlier decline, and 80 days later production had ceased.

Prior to stimulation of No. 22 borehole, the Blue Creek seam was notched by Abrasi-jetting at a rate of 2.5 bbl/min using a water/nitrogen mixture and 1 pound of 20- by 40-mesh sand per gallon. Two opposing slots 2 feet high were cut into the coal seam. The coal cuttings were left in the sump below the coal seam to inhibit fracture initiation below the desired coal interval. An inflatable packer was placed below the casing to protect the 5.33 feet of shale parting exposed below the casing.

A total of 49,140 gallons of foam, 25,000 pounds of 100-mesh sand, and 47,840 pounds of 20- by 40-mesh sand were placed. The treatment lasted 1 hour, 57 minutes and was stopped 3 minutes early when a leak occurred in the tubing delivering the fluid to the coal seam. Following the stimulation, a 34/64-inch choke was installed and the borehole blew back for about 34 hours. One month after pumping of the borehole was begun, gas flow was recorded and has continued until now. Initial production was around 54,000 cfd (Figure 9). Again a trend toward declining production has been observed, with recent values in the neighborhood of 11,000 cfd. Although more than 1.9 million gallons of water has been removed, water production is still quite high. This phenomenon possibly indicates the presence of a localized geologic anomaly which drastically increases the permeability of the coal seam or causes communication between the borehole and a regional aquifer.

Of the two holes, No. 22 borehole, which was stimulated by using the nitrogen foam, gave better early results by producing 952,000 cubic feet of methane in its first month of life compared with 223,000 cubic feet for No. 9 borehole in the same time period. On the basis of the early results from No. 22 borehole and the results from the third and fourth holes near the mine, a 50,000-gallon foam treatment was used for all but one of the remaining boreholes.

No. 7 borehole was used as a demonstration for a Kiel-type stimulation, which differs from a normal stimulation in that it employs an intermittent pressurization/depressurization process. This technique reportedly results in a number of fractures perpendicular to the main fractures. Eighty-four thousand gallons of water and 45,000 pounds of sand were used for this fracture, which was the largest stimulation used to date at the test grid. More than 500,000 gallons of water was removed from No. 7 borehole before gas production started. This was considerably more water than obtained on any other borehole before gas production.

For the remaining boreholes, the Blue Creek seam was notched prior to the stimulations by using a jet slotting tool. To help initiate the fracture, two opposing slots 2 to 3 feet high were cut into the coal seam. As already stated, the treatment design for all the remaining boreholes specified a foam treatment conducted through a 4-1/2-inch casing. In each case, open-hole conditions were maintained within the coal seam. The stimulation design was

Hydraulic Pad Volume, gal water	5000
Total Volume, gal foam	50,000
Foam Quality, % N_2	75
100-Mesh Sand, lb	25,000
20- by 40-Mesh Sand, lb	45,000
Pumping Rate, bbl/min	10

As with most reservoir endeavors, events occurring during some treatments required changes to be made in the anticipated treatment procedures.

Communication, that is, the linking of two or more boreholes with the high-permeability fracture, required abbreviated treatments to be conducted on four boreholes. There was direct visual evidence that five boreholes are intercommunicated. In these cases, injection of foam in one borehole resulted in the production of stimulation fluids out of another without the aid of dewatering equipment.

Several times problems were encountered with the nitrogen supply during the stimulations. On one occasion the nitrogen vaporizer broke down after 13,000 gallons of foam and 1500 pounds of sand had been pumped. Repair of the vaporizer required nearly 24 hours, during which time the borehole was kept shut in to maintain pressure on the coal seam. After this delay, it was possible to resume pumping and to complete the stimulation.

All stimulations were completed shortly before the start of the UMWA contract strike in December 1977. Although a concentrated effort was made, only a few of the boreholes could be fitted with production equipment prior to the start of the strike.

OPERATING PROBLEMS

One problem, which was to become a recurring one, was the accumulation of sand in the well bores. To remove these accumulations, tubing was inserted to the bottom and high-pressure nitrogen was used to blow out the sand. The pumping equipment was then installed and activated. Three boreholes, No. 5, 7, and 13, underwent this process, but again were in difficulty after several weeks. A fourth borehole, No. 22, did not require a cleanout process and was also made functional at this time. Because our contractor is a signator to the UMWA contract no installations or maintenance of production equipment could be made during the strike.

When the contractor returned to the site in mid-April, only No. 22 borehole was operating. The four holes were returned to service, and then efforts were concentrated in the northeastern part of the grid because we believed that the 609,000 gallons of water removed by No. 5, 7, and 9 boreholes made this area most favorable for early gas production. During the cleanout operations, accumulations of fracturing sand were found in most of the holes, with some of the holes being filled to levels of 75 feet above the coal seam. No. 5 borehole was put back into operation and produced for 37 days before sand in the effluent water caused the pump to sieze. Total methane produced from No. 5 borehole during this period was 1,007,000 cubic feet at an average of about 27,000 cfd. Water-level measurements made during this period indicated that these rates were being obtained while the water level was 500 or 600 feet above the coal seam.

During the period that No. 5 borehole was producing, sand-related problems were experienced on eight additional holes. Oak Grove appears unique in that we know of no other degasification endeavor experiencing this problem with such regularity. It appears that the horizontal closure stresses in the coal seam at Oak Grove are less than in other seams where degasification boreholes have been installed.

A second problem encountered was a phenomenon we describe as unloading. Unloading is an uncontrollable outrush of methane, liquid water, water vapor, and sand at rates in excess of 400 cfm. The unloading has had sufficient energy to carry sand to the surface and fill 45 feet of horizontal pipeline and 30 feet of vertical stack. We believe this results when the water level falls below the equilibrium head and bubbles of gas begin rising through the water. These bubbles expand as they rise toward the lower-pressure zone at the top of the water column. As the bubbles expand, their upward velocity increases and eventually the velocity is sufficient to lift the water and further reduce the hydrostatic pressure. Once this lifting begins, the effect becomes ever-accelerating and unloading occurs.

To minimize sand-related problems, we have raised the pumps 100 feet above the coal seam; to minimize unloadings, we have imposed a well-head back pressure of 100 psi during initial gas production. These high back pressures reduce bubble velocity through the water column and minimize lift. Once gas production has begun, the gas pressure can be lowered as the coal-seam gas pressure is lowered. However, positioning the pumps at the 100-foot level does present a problem in that the gas bubbles enter the pump and reduce the dewatering efficiency. In addition, some gas reaches the surface through the water line and must therefore undergo a separating step.

To reduce this bubble problem, we have employed a device known as a gas anchor (Figure 10). The gas anchor is a downhole gas/water separator made up of two concentric pipes with holes at the top of the outermost pipe and an inner pipe installed on the pump suction. This requires the fluid entering the pump suction to change directions several times, thereby permitting some preferential separation of gas and water.

Even with the pumps located 100 feet above the coal seam, some sand is still seen in the discharge water. Screens have been installed on the pump suction, but periodically have to be cleaned out. In addition, pump efficiency still declines more rapidly than would be expected (from product literature), indicating that wear is continuing on the valve cups.

With the pumps set 100 feet above the coal seam, a hydrostatic head is imposed upon the producing zone, thus reducing gas flow. In addition, the literature states that the permeability of a water-saturated coal seam is much lower than that of a dewatered coal seam. Therefore, it is imperative that we eventually have the pumps set at the coal seam. To accomplish this, we are experimenting with several types of plunger and tubing pumps and investigating alternate means of successfully dewatering the boreholes.

GAS PRODUCTION

Seventeen boreholes have been installed at Oak Grove, but the number operating each week varies because of sand flow-back and pump malfunctions (Figure 11). These interruptions cause water buildup that in turn inhibits gas flow. For the first 40 weeks of production a work over rig and crew was required on the site continuously. During the first half of this time sand flow back problems and unloadings made it difficult to have more than two or three pumps in operation at one time. As we became more experienced and developed corrective measures the number of boreholes in operation began to increase. Currently we find at least two boreholes per month can be expected to fail. Because of this experience we strongly feel that the operating cost of sand-propped vertical boreholes will be considerably higher than usually encountered in standard gas wells.

Even though the number of boreholes operating is usually less than 80 percent, the cumulative production of methane from the test grid for the past 8 months has exceeded 140 million cubic feet. This represents about 9 percent of the total methane in the area bounded by the test grid. The daily average methane production per borehole is about 50,000 cubic feet and would be significantly higher if the sand problems had not caused premature pump failures and necessitated periodic borehole cleanouts.

Of the boreholes that are producing gas, the individual production rates vary from 5000 to over 200,000 cfd. Gas production from No. 4, 7 and 14 boreholes has been very good, averaging 81,000, 81,000 and 88,000 cfd. It is interesting to note that during stimulation, communication was observed between these three high-producing boreholes. Production from No. 3 and No. 8 boreholes has also been very good, averaging about 155,000 and 94,000 cubic feet per day. On the other hand, production from No. 22 borehole has been disappointing. Although it has been in production longer than any other hole in the test grid, and more water has been pumped from it than from any other hole, the production averages about 10,000 cfd.

In this regard, it might be important to remember that No. 22 borehole is an unbounded perimeter hole. Comparing production from two similar perimeter holes in this region, an apparent anomaly exists. The adjacent hole, No. 23, averages 53,000 cfd, whereas No. 24, 1000 feet further to the north, is averaging 6000 cfd. Some of these variations are no doubt a result of varying hydrostatic heads resulting from malfunctioning pumps.

Without further information concerning the in situ reservoir conditions, however, the actual causes for these variations cannot be established. Future endeavors on these holes will certainly include reservoir analyses designed to explain these differences in production.

The gas obtained from these holes has had a high methane content and very little CO_2, sulfur, or higher hydrocarbons (Table I). The effect of the nitrogen used in the nitrogen/water-foam treatment can be seen in the nitrogen content of No. 5 borehole. After 24 days production

there was still 6.3 percent nitrogen in the gas discharging from the hole. Thirty-seven days later the nitrogen had dropped to 2.9 percent. The latest analyses indicate that the nitrogen content has dropped to 2.6 percent. On the basis of results obtained on the near-mine boreholes, the nitrogen will continue to drop to a level of about 1.2 percent or less. Similar analytical results indicate that the gas produced by the boreholes at Oak Grove has an average heating value in excess of 950 Btu/scf and, consequently, should be satisfactory for utilization as a high-Btu fuel.

In conclusion, during 8 months operation of vertical degasification boreholes at Oak Grove, more than 140 million cubic feet of gas was removed. Some holes were excellent producers while others were less than satisfactory. Flow-back of proppant sand and resulting pump malfunctions have been recurring major problems. Results are encouraging enough to expend further efforts toward improving production from these holes. To do this, the pumps will have to be lowered to the coal seam and more efficient methods found to dewater the coal seam. Future stimulation treatments will be designed to reduce the amount of propping sand used so as to decrease the flow-back of proppant into the borehole.

ACKNOWLEDGEMENTS

The authors are indebted to Stephen W. Lambert, Technical Project Officer, and Michael A. Trevits of the Department of Energy for their support, encouragement and technical advice. We also wish to thank Maurice Deul and the USBM who initially encouraged and obtained support for this program.

It is understood that the material in this paper is intended for general information only and should not be used in relation to any specific application without independent examination and verification of its applicability and suitability by professionally qualified personnel. Those making use thereof or relying thereon assume all risk and liability arising from such use or reliance.

TABLE I

Gas Composition Borehole No. 5, Oak Grove Mine

Days Produced	CH_4	N_2	CO_2	H_2	O_2	C_2H_6	S
24	93.5	6.3	<0.1	<0.1	0.1	ND	ND
27	94.7	4.9	<0.1	0.1	0.2	ND	ND
37	97.0	2.9	0.03	ND	<0.1	0.0046	ND
150	96.5	2.8	0.6	ND	<0.1	ND	ND
190	97.2	2.6	0.1	ND	0.1	ND	ND

ND - None Detected.

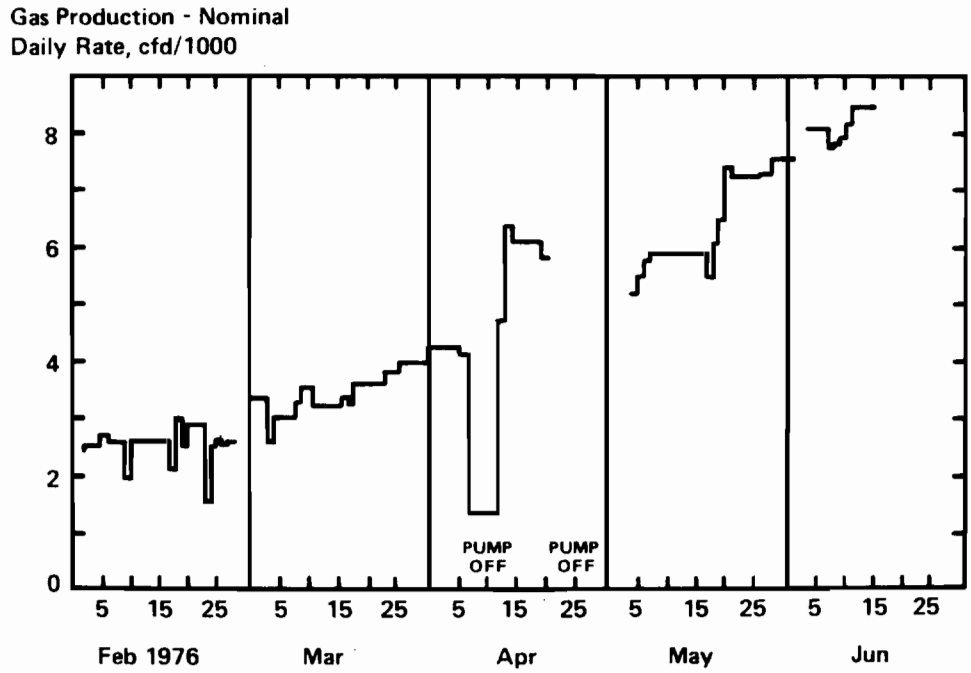

FIGURE 1
Gas Production - First Borehole Near Oakgrove Mine Workings

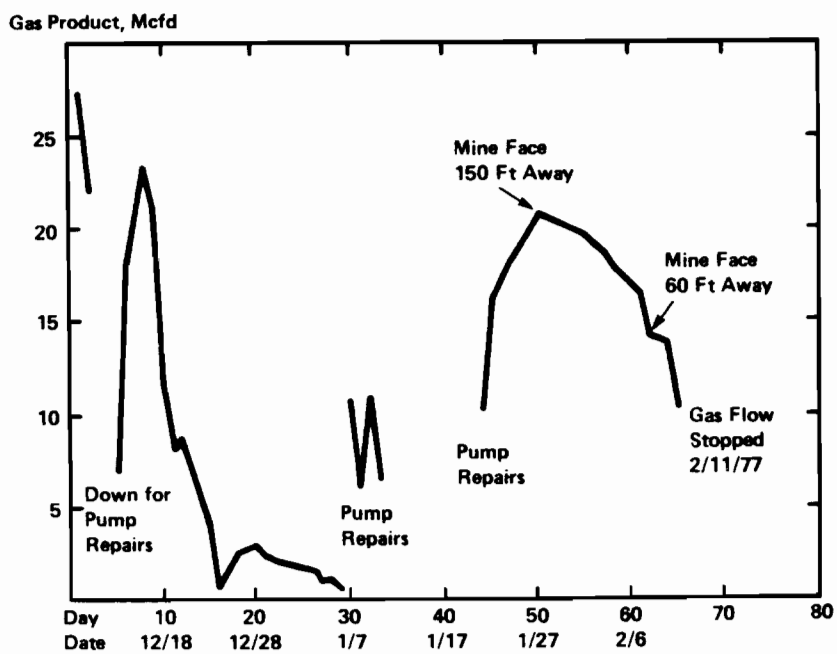

FIGURE 2
Gas Production - Second Borehole Near Oak Grove Mine Workings

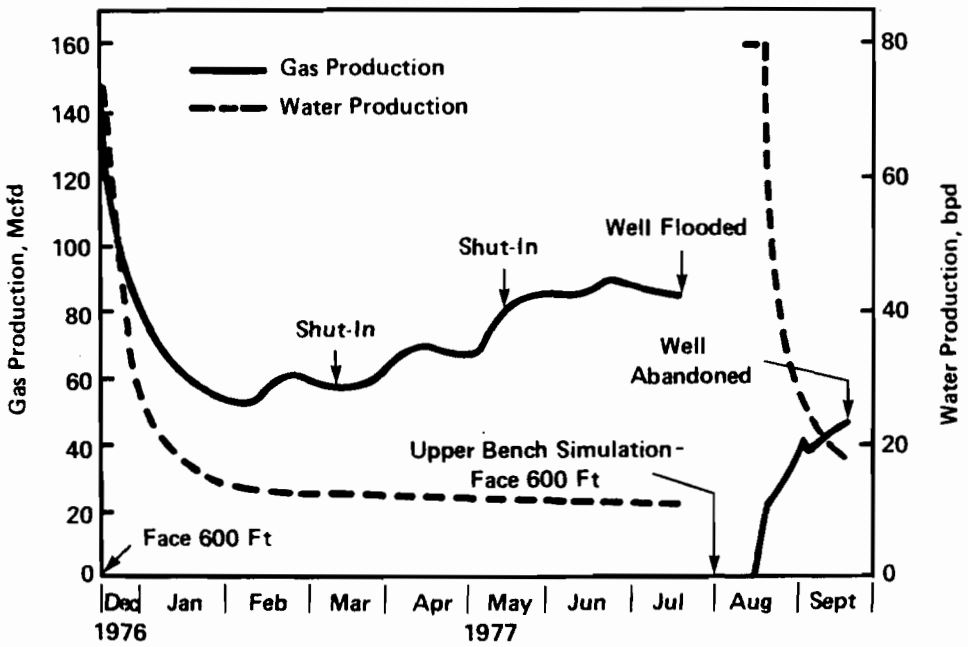

FIGURE 3
Gas Production - Third Borehole Near Oak Grove Mine Workings

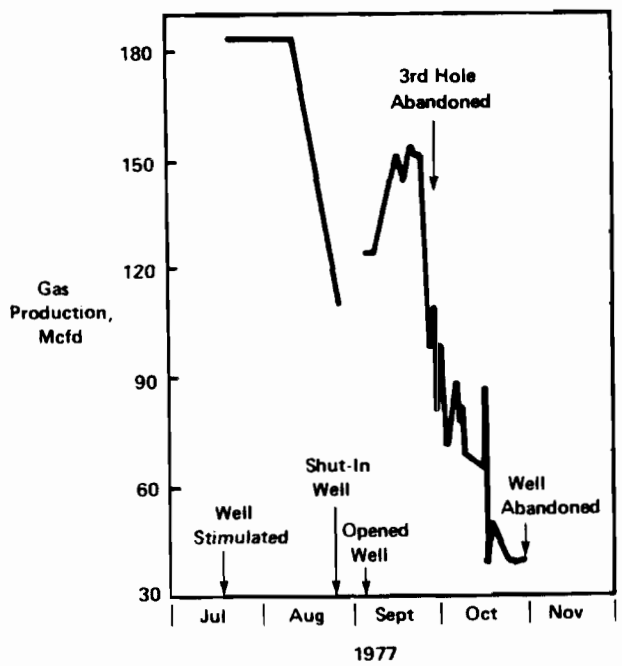

FIGURE 4
Gas Production - Fourth Borehole Near Oak Grove Mine Workings

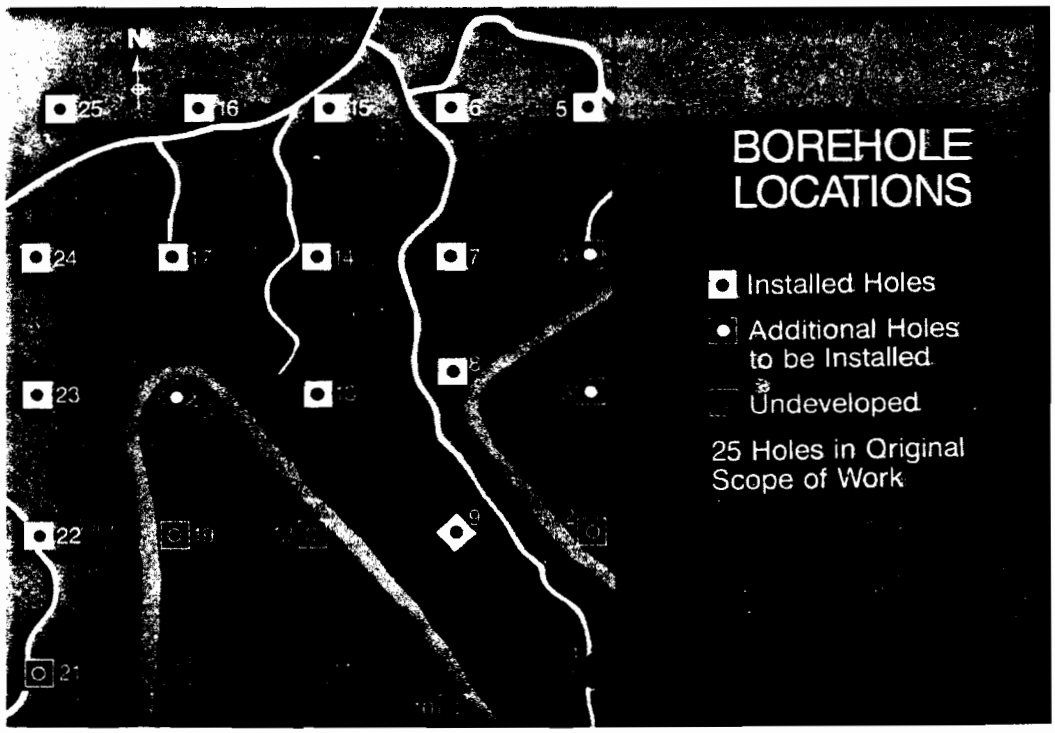

FIGURE 5
Test Grid - Oak Grove Mine, Alabama

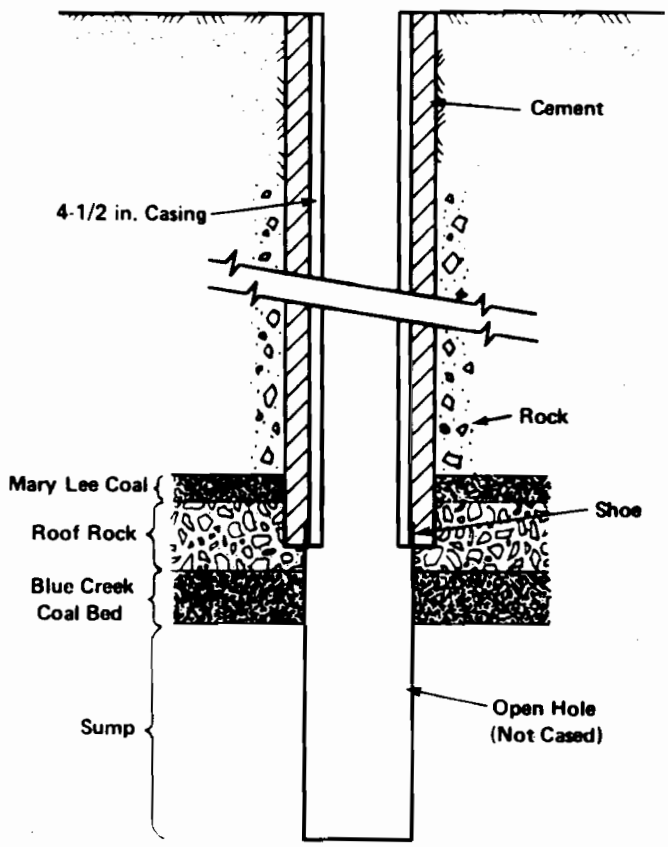

FIGURE 6
Degasification Borehole Installation at Oak Grove Test Grid

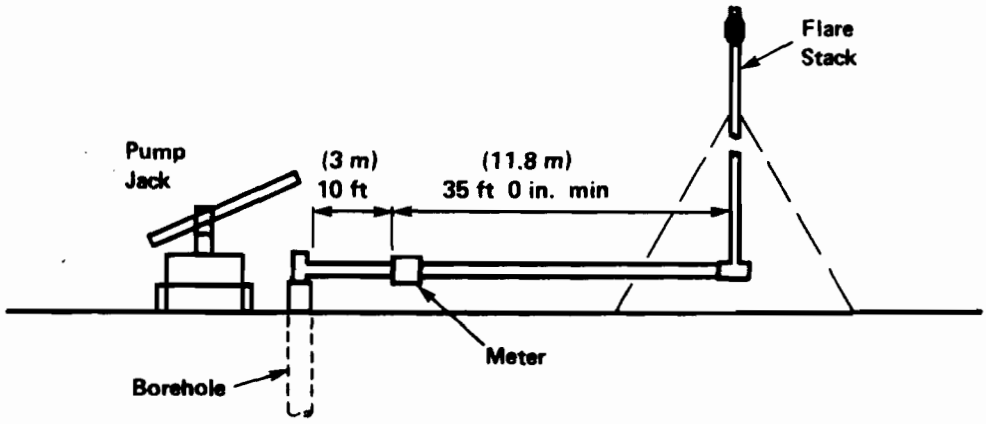

FIGURE 7
Degasification Borehole Surface Equipment at Oak Grove Test Grid

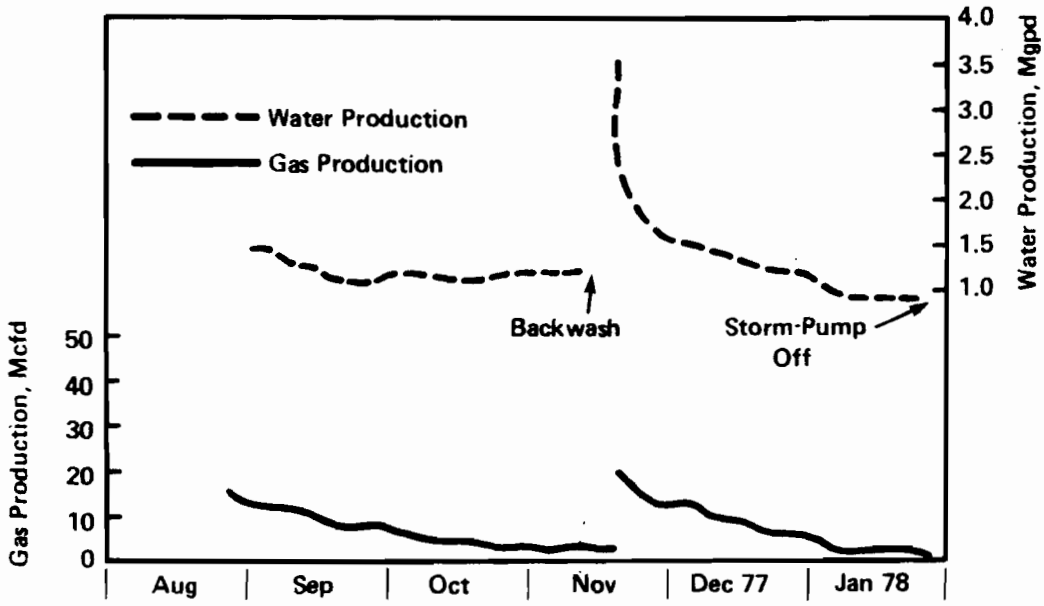

FIGURE 8
Gas and Water Production - No. 9 Borehole

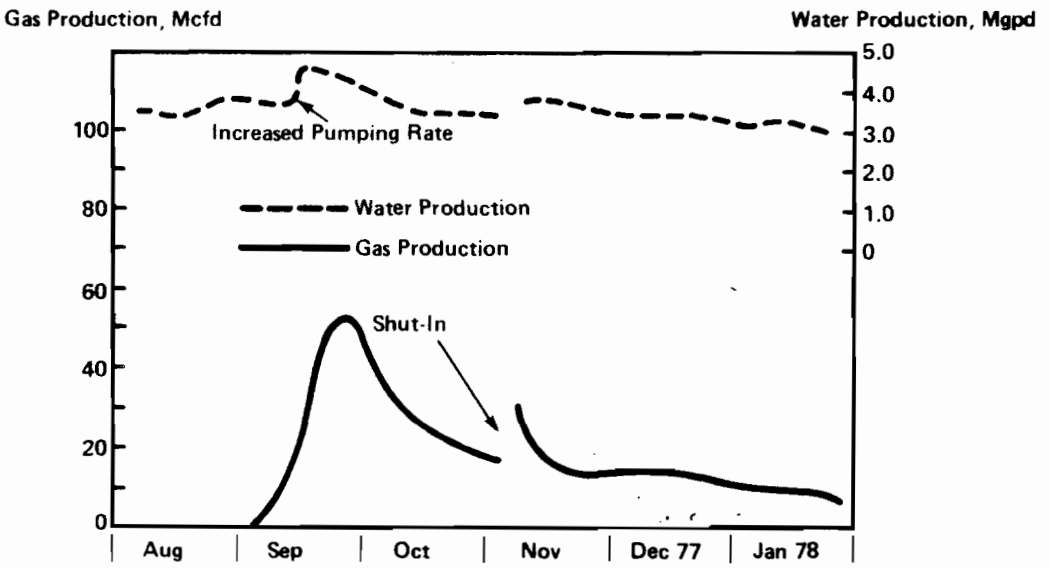

FIGURE 9
Gas and Water Production - No. 22 Borehole

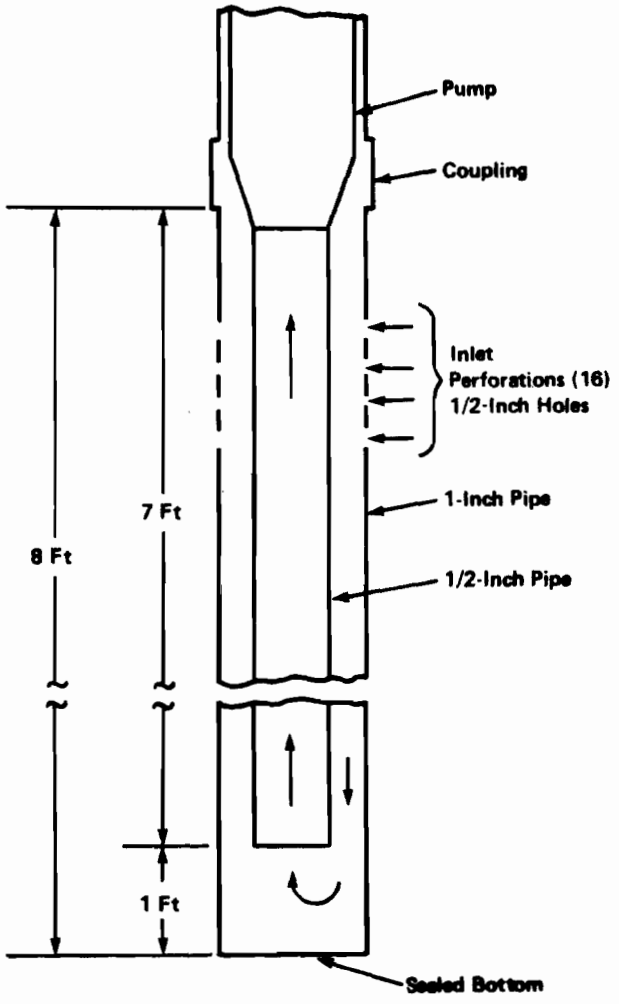

FIGURE 10
Down Hole Gas Water Separator (Gas Anchor)

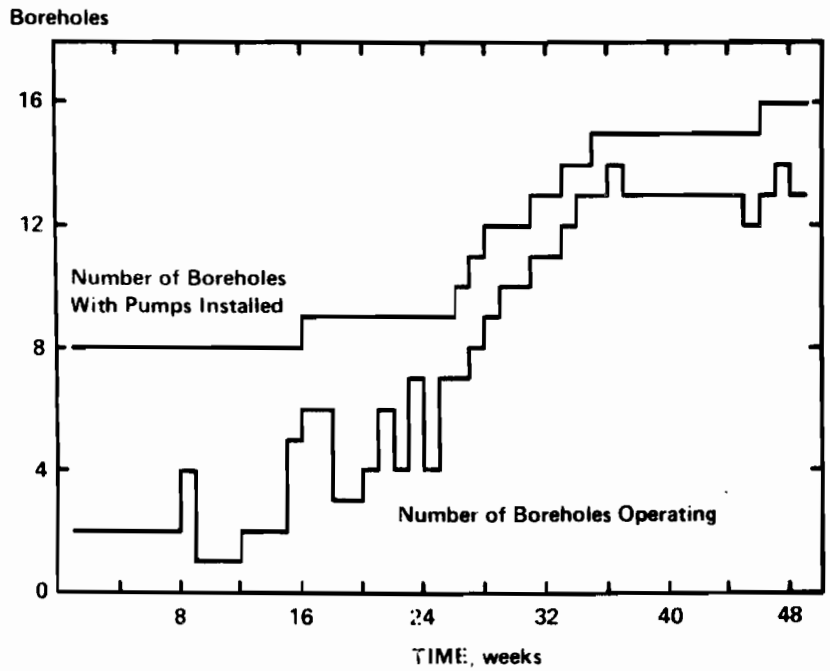

FIGURE 11
Operating Availability of Test Grid Boreholes

METHANE PRODUCTION FROM SNODGRASS NO. 2, PRICETOWN, WEST VIRGINIA

BY

H. B. SHOEMAKER, G. E. RENNICK, R. L. WISE
AND D. W. GILMORE

MORGANTOWN ENERGY TECHNOLOGY CENTER

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Dr. Shoemaker received BS and MS degrees in Agricultural Engineering and the PhD degree in Mechanical Engineering from West Virginia University. His doctoral research was performed at METC and involved determining the thermo-mechanical properties of coal. He is a member of Sigma Xi, Tau Beta Pi and Alpha Epsilon.

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ABSTRACT

The Snodgrass No. 2 well is completed within the Pittsburgh coal seam near the Pricetown I Underground Coal Gasification (UCG) Project at Pricetown, West Virginia. The well was originally drilled as a deep gas well, but was later plugged back and completed within the Pittsgurgh coalbed (860 feet deep). Attempts at gas production indicated there may have been severe wellbore damage and pressure tests indicate that the coal seam is of a tight, low permeability matrix, approximately 0.01 md. Desorption data from coal cores at Pricetown I indicate that the methane content of the Pittsburgh coal at Pricetown is 50 - 100 cf/ton.

A small water frac treatment was designed and conducted on the coal seam (3,700 gal water and 1,500 lb sand). The permeability of the coal seam was improved to 6.2 md; however, injection tests indicated only short fracture lengths (estimated fracture length of 12 ft). Following the pressure injection tests a pump was placed in the well and the water pumped off. The gas production rate stabilized at approximately 400 cfd methane and the water production at 1 bpd. Based on the production data obtained, a model was used to predict the well's performance if a large stimulation or multiple well program were implemented.

INTRODUCTION

The Morgantown Energy Technology Center (METC/DOE) is conducting an underground coal gasification (UCG) experiment in Wetzel County, near Pricetown, West Virginia. This site was selected on the basis of geographical, geological, environmental and other technical factors which were favorable to in situ gasification of the Pittsburgh coal seam, particularly for a proposed scheme involving directional wells drilled from the surface horizontally into the coal seam.

During the course of preparations for the UCG project, an old gas well (Snodgrass No. 2 well) was uncovered on the site (Figure 1). This well was initially proposed for use as a monitor well in the UCG program. However, during the implementation of the UCG project, the Snodgrass No. 2 well became available for testing in the DOE/METC methane drainage program.

The recovery of methane from coal seams dates back to 1894 and more actively to 1910-1920 when wells were drilled into coal seams for the purpose of producing natural gas. However, most of these wells were low producers and hence were subsequently drilled to deeper gas horizons or abandoned for economic reasons. It was not until the early 1950's that wells in coal seams were stimulated by hydraulic fracturing to increase the gas yields. Records are scarce on these early wells, particularly from those known to exist in Wetzel County, West Virginia.

The availability of Snodgrass No. 2 offered a low-cost opportunity to gain firsthand knowledge of Pittsburgh coal methane production properties. This paper reports the results of this modest well test and production program which was conducted.

METHANE PRODUCTION FROM SNODGRASS NO. 2, PRICETOWN, WEST VIRGINIA

BACKGROUND

The Pittsburgh coal is found at a depth of 850-900 feet at the Pricetown site. The coalbed dips to the southeast at about 1-1/4 feet per 100 feet (approximately 1°). The generalized geologic section at the site is illustrated in Figure 2. The subsurface lithology and accompanying geophysical logs from the HQ-1 well, which was drilled and cored on the Pricetown I site, are shown in Figure 3.

In order to determine the gas content of the Pittsburgh coal seam, three coal core samples were taken from the HQ-1 well. The gas content of the coal was estimated by the decline curve method (Chase, 1977) and the U. S. Bureau of Mines direct method (McCulloch, et al., 1975). The decline curve method indicates gas content between 100 and 150 cubic feet per ton, the direct method, between 50 and 65 cubic feet per ton (Table 1). The gas content of the Pittsburgh coal seam in this area was concluded to be conservatively between 50 and 100 cubic feet per ton.

The Snodgrass No. 2 well had been originally drilled to 3000 feet and cased to 2708 feet on February 6, 1919; the pipe was later cut and removed to 2034 feet. In early 1976, the well was cleaned out to 2034 feet and plugged to 2030 feet by incrementally inserting tubing and cementing to 862 feet. The 4-1/2 inch casing was set at 854.5 feet, just below the top of the Pittsburgh coal seam, and was cemented back to the surface. The plug was then drilled to 864 feet and the well was cleaned out, leaving the coal seam exposed. Figure 4 is a schematic drawing of the well completion.

TESTING PROGRAM

The test plan for the well was designed to obtain baseline data prior to any treatments, and to measure the same parameters after perforating and hydraulic fracturing. The test procedures included measurement of water and gas production rates, and water injection rates at 100 and 200 psig. The size of the stimulation treatments were limited because of the proximity of Snodgrass No. 2 to a directional well in the coal seam (approximately 600 feet), and to the Pricetown I UCG site (approximately 800 feet).

Pre-frac Testing

The well was shut-in in September 1977. Wellhead pressure was measured at 89.0 psig and the water level was at 644 feet. Water influx for a period of 476 days during well repairs was 0.37 gpd. In January 1978, the well was shut-in and the bottom hole pressure increased from an initial value of 109.1 to 131.8 psig in 813 hours (Figure 5). From these data the permeability of the Pittsburgh coal was calculated to be 0.0098 md.

In February 1978, a bailing machine was moved on the well and the water was removed. Water and gas flow rates were as follows:

Days Cumulative	Water Rate gpd	Gas Rate cfd
8	2.56	11.5
71	0.54	3.9

The well was then filled with water and injection tests were conducted at 100 and 200 psig (see Figure 6 for plot of 200 psig data).

In May 1978, the coal exposed in the open hole was perforated with 17 glass jet shots from 856 to 860 feet. Injection tests at 100 and 200 psig were repeated (see Figure 6 for plot of 200 psig test); after the perforation the water injection rate was less than both before perforating and after fracing.

Fracturing

In June 1978 the well was stimulated with a small water fracture (mini-fracture). The total volume of fluid used was 3700 gallons; 1500 pounds of 20/40 sand were used. The injection rate was 5 bpm. Breakdown was at a surface pressure of 1200 psi. Total pressure reached was 1450 psi. Recovery from the treatment was nearly 100% water with little sand return. Bailing tests indicated

post-fracture flow rates of approximately 3 bpd of water and 700 cu. ft. per day of gas - a marked improvement over the unfractured coal at approximately 1/2 gallon of water and 4 cubic feet of methane per day.

Post-Frac Testing

Water injection tests (Figure 6) also indicated that there was a marked improvement in the permeability of the coal after fracturing. After shut-in, a constant rate injection test was conducted for 8 hours at 1 gpm. The average injection rate was 0.997 gpm; the data from this test are shown in Figure 7. The calculated permeability from these data was 6.22 md; a value much higher than the well's initial permeability of approximately 0.01 md. An additional injection test was conducted at a constant pressure of 200 psi. Pressure fall-off was rapid and is demonstrated in Figure 8. The post-fracture coal permeability of 4.1 md was determined from these data.

A pumping jack and gas meter were placed on the well and production data were taken until the well was shut-in in December 1978. Gas and water production data are presented in Figure 9. The production stabilized at approximately 350 cubic feet of gas and 20 gallons of water per day. Table 2 summarizes the changes in permeability, gas production, and water production due to the mini-fracture of the Snodgrass No. 2 well.

The average gas analysis from nine samples taken over the period, January-September 1978, was as follows:

Constituent	Volume %
O_2	0.43
N_2	8.82
CH_4	88.87
C_2H_6	1.00
C_3H_8+	0.26
CO_2	0.62
	100.00

DISCUSSION OF RESULTS

The gas content and pressure in the Pittsburgh coal seam at the Snodgrass No. 2 well are anomalously low when compared to those which have been measured in other parts of the Appalachian basin. It may be that the connate marine brine (30,000 ppm NaCl) which overlies the Pittsburgh coal seam at this site seriously restricts methane adsorption by the coal and/or release into the wellbore.

Because of the low gas and water production from the subject well, it was initially suspected that there was severe wellbore damage (skin effect) in this well. However, three wells drilled into the Pittsburgh coal on the Pricetown I site with mud, water, and air, respectively, showed identical water influx rates after bailing each well. This behavior indicates that different drilling methods did not damage the well and hence that Snodgrass No. 2 well was probably not impaired by an apparent skin effect. The perforation of the coal seam in Snodgrass No. 2 well resulted in a decrease in the water injection rate. This may have been due to explosive pulverization of the coal and blocking of the coal matrix. The undistributed coal is extremely tight as noted by permeability values of 0.01 md or less.

The productivity of the Snodgrass No. 2 well was increased from 4 to 300 cfd methane gas, and 0.5 to 15 gpd water, by a small fracture treatment, estimated to develop a fracture length of 12 feet. These increases correspond to the calculated increase in permeability to approximately 5 md.

Based on the results of these tests, INTERCOMP predicted the performance of the well in its present condition, after a larger volume stimulation, and as part of a multiple well development pattern. The predicted production decline curves for three different cases are illustrated in Figure 10.

If the well were allowed to produce in its present condition, it would be expected to maintain current production of 300-400 cfd for an extended period and slowly decline in both gas and water

production. If the Snodgrass No. 2 well were given a large volume stimulation, creating, e.g., a 750-foot hydraulic fracture rather than the estimated 12-foot fracture, the well would be expected to produce as Case I in Figure 10, approximately 4 Mcfd declining to 2 Mcfd over a 10 year period. If a gas reservoir of this type were drilled on 160 acre spacings, with the same hydraulic fracture as Case I, the production rate would peak at approximately 6 Mcfd in 15 years and decline thereafter (see Case II, Figure 10). If this reservoir were drilled on 40-acre spacing, with the same fracture, the production rate would increase much more rapidly peaking at approximately 7 Mcfd and declining thereafter (Case III, Figure 10). Recovery in ten years is estimated at 10,400 Mcf for Case I, 12,200 Mcf for Case II, and 17,100 Mcf for Case III.

CONCLUSIONS

From these data it appears that vertical wells in the Pittsburgh coal seam at the Pricetown site are not likely to produce commercial gas in the near future. Even if the coal were given a large volume stimulation, creating a 750-foot hydraulic fracture, the resultant initial flows of around 4000 cfd would still not be considered commercially recoverable quantities of gas. The behavior of the Pittsburgh coal in this area is considered anomalous as the pressure and gas contents are very low considering the depth and character of the coal.

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3. T. L. Sole, C. W. Byrer, H. W. Rauch, W. K. Overbey, Jr., "Hydrogeologic Assessment of an Underground Coal Gasification Project Site, Grant District, Wetzel County, West Virginia", METC/TPR-76/5, 1976.

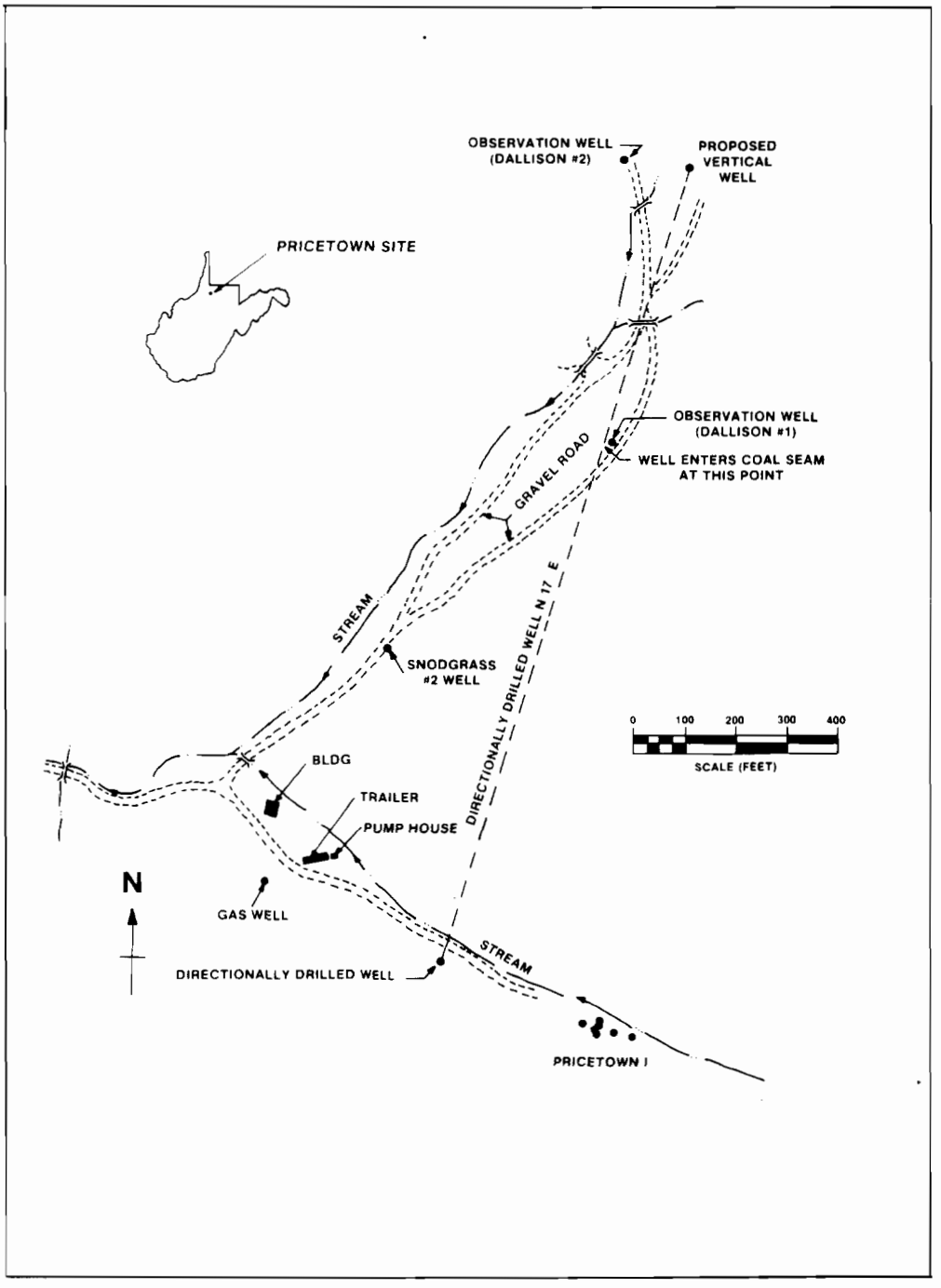

Figure 1. Location of the Snodgrass No. 2 Well

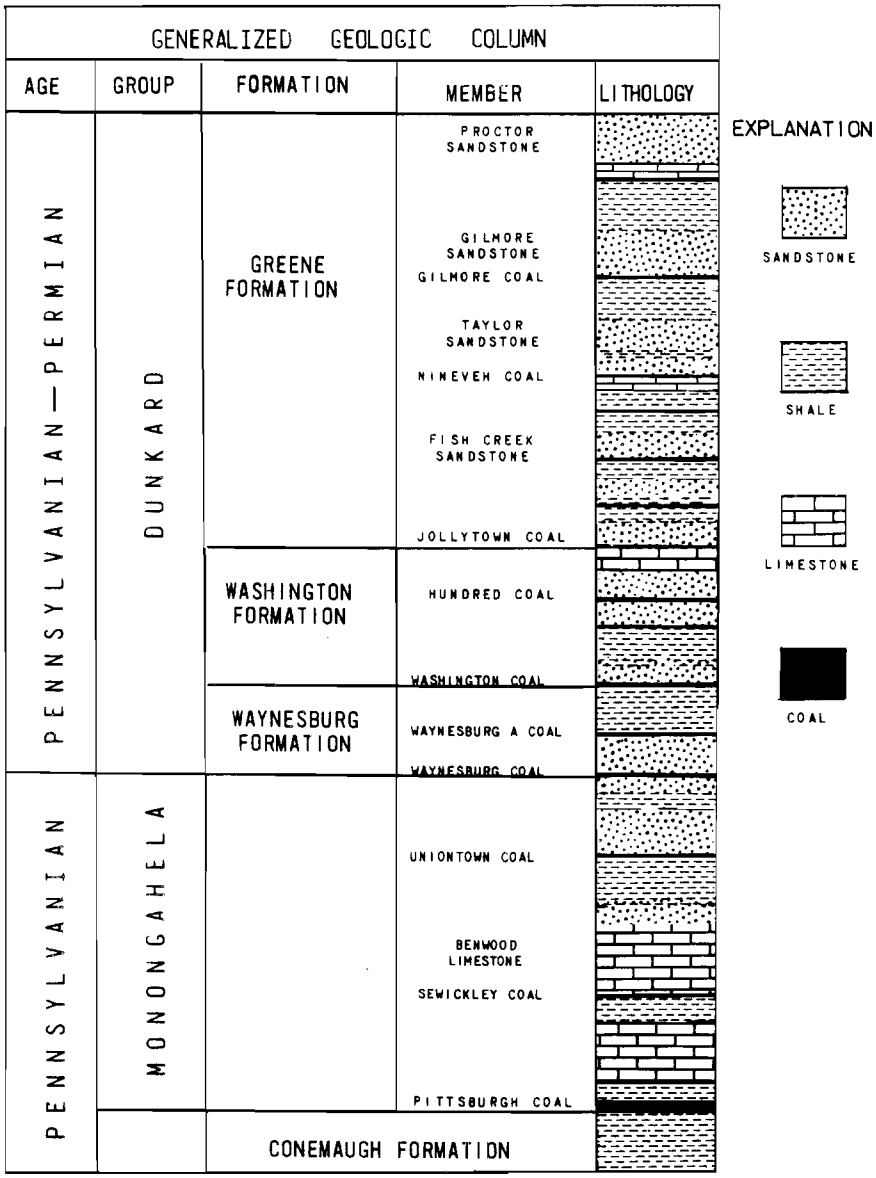

Figure 2. Generalized Geologic Column of Major Rock Units in Study Area (After Sole, 1976)

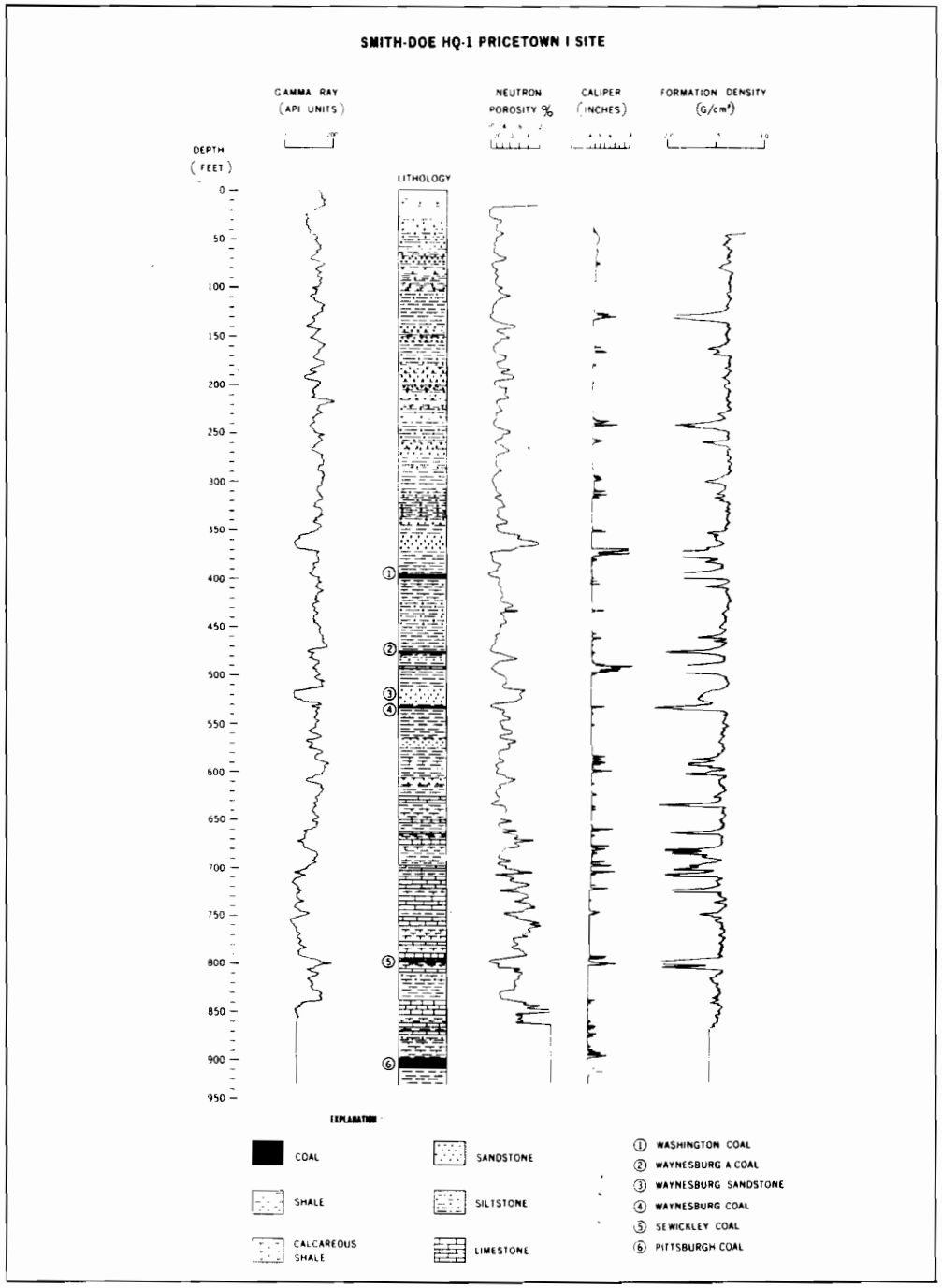

Figure 3. Subsurface Lithology at the Pricetown 1 Site with Accompanying Geophysical Logs

Table 1. Gas Content of the Pittsburgh Coal Seam, Pricetown, WV

SAMPLE NO.	DEPTH INTERVAL	GAS CONTENT			
		CHASE DECLINE CURVE METHOD		USBM DIRECT METHOD	
11	899.2-900.1	3.09	98.9	1.59	51.0
4	902.2-903.0	4.68	149.8	1.65	52.9
12	903.4-904.0	4.54	145.3	1.99	63.6

Table 2. Effect of Mini—Frac on Production, Snodgrass No. 2 Well

PARAMETER	BEFORE FRACTURE	AFTER FRACTURE
Permeability, md	0.01	6.2
Gas Production, cfd	4.00	350.0
Water Production, gpd	0.50	20.0

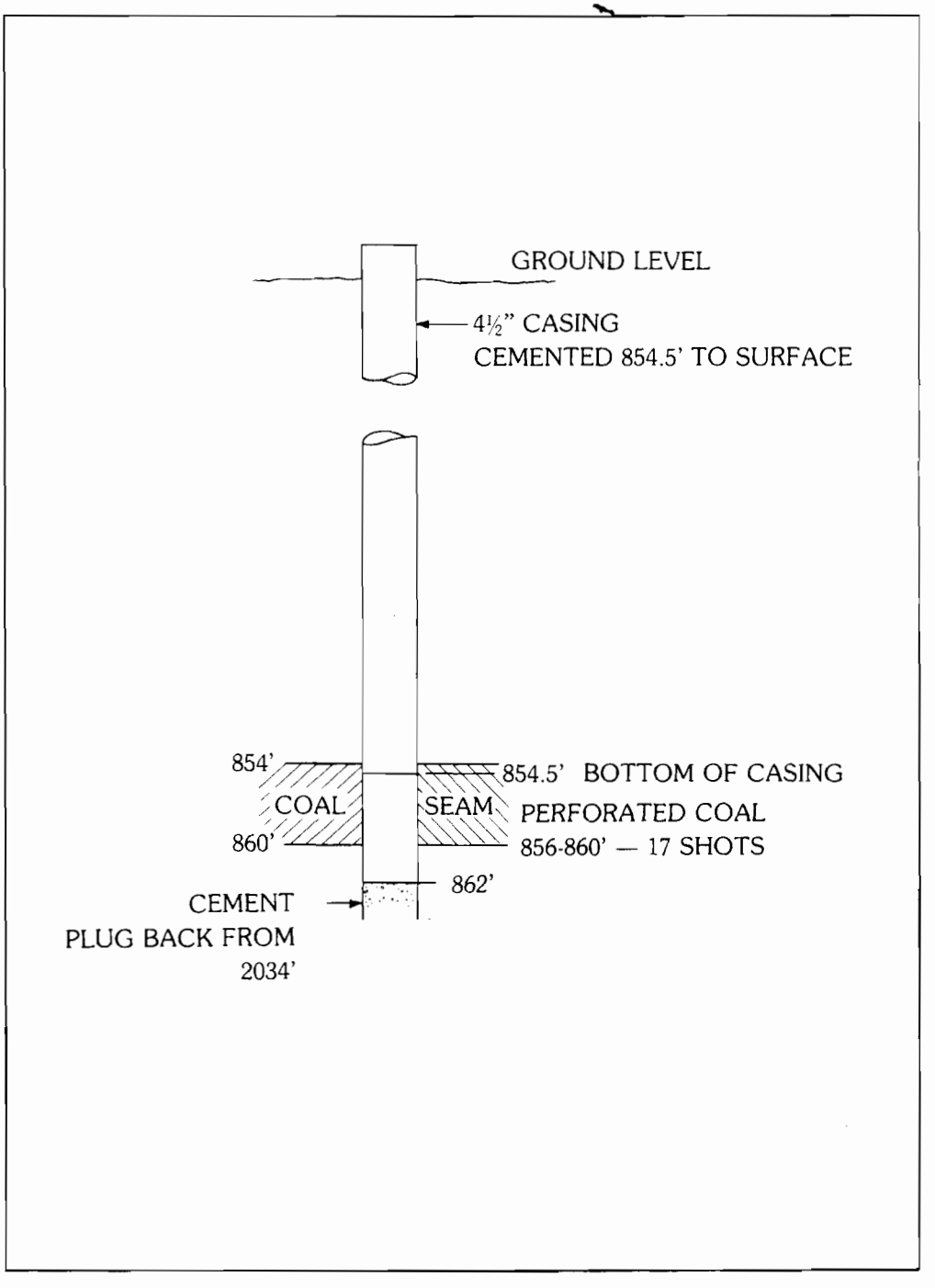

Figure 4. Schematic Drawing of the Snodgrass No. 2 Well Completion

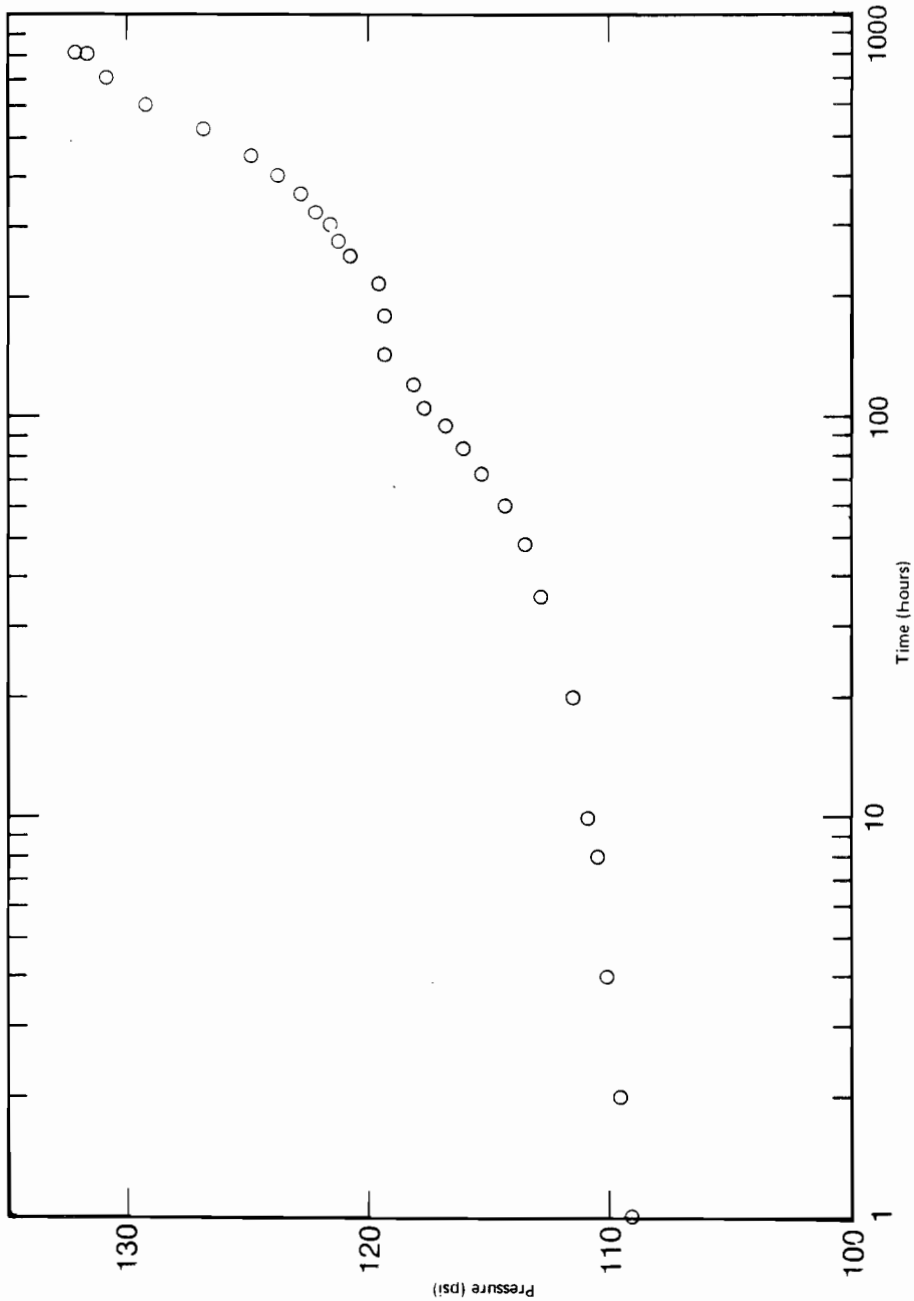

Figure 5. Pre-frac Bottom Hole Pressure Buildup, Snodgrass No. 2 Well

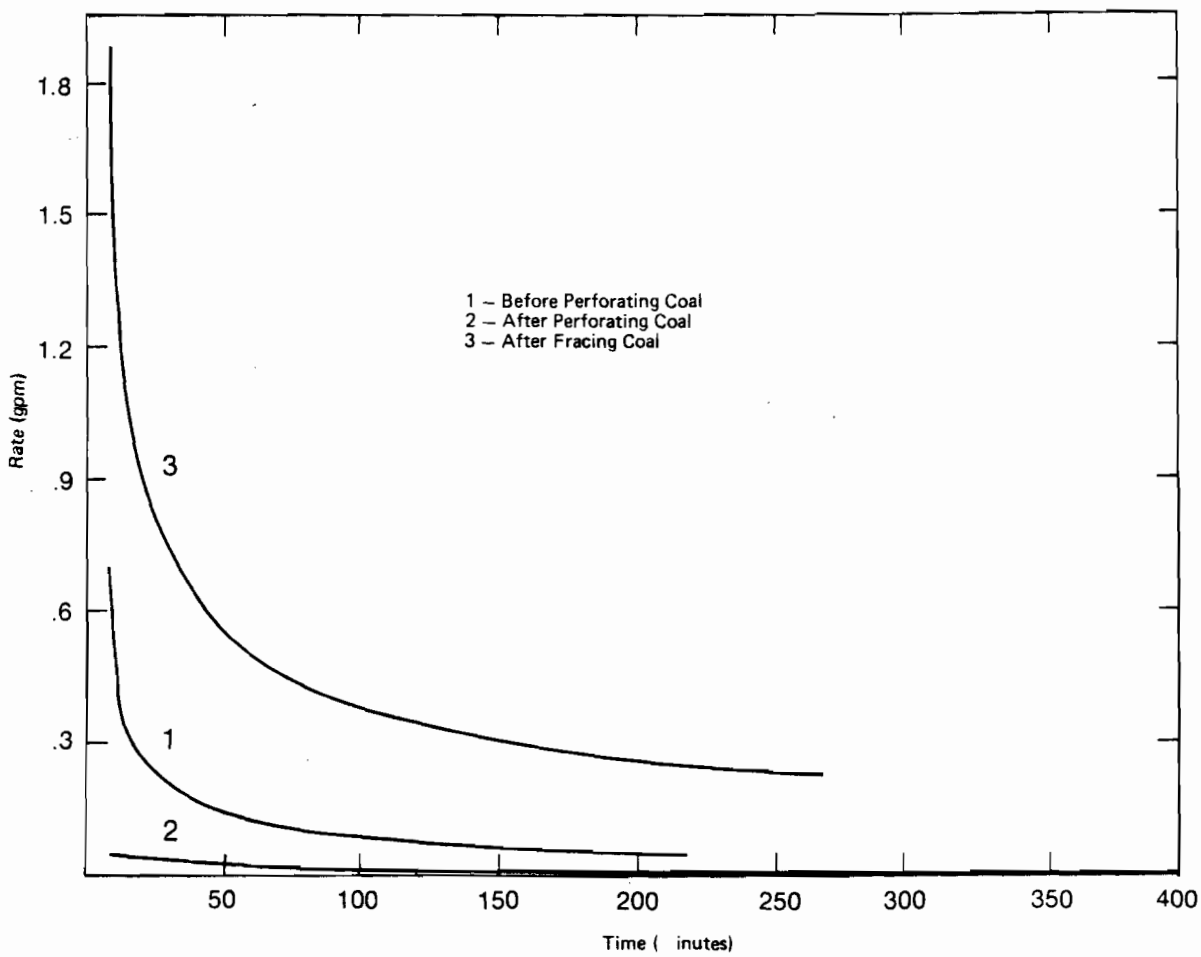

Figure 6. Water Injection Tests at 200 psi, Snodgrass No. 2 Well

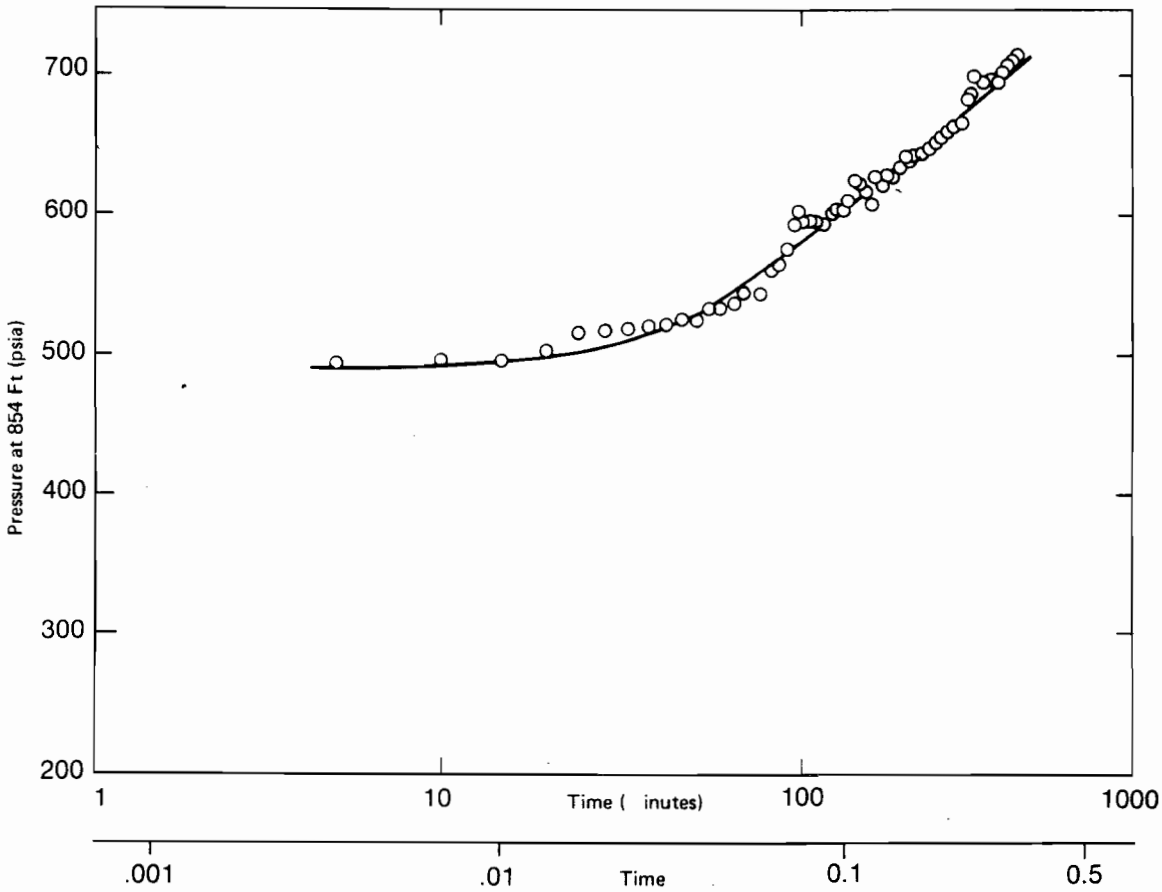

Figure 7. Injection Test at 1 , Snodgrass No. 2 Well

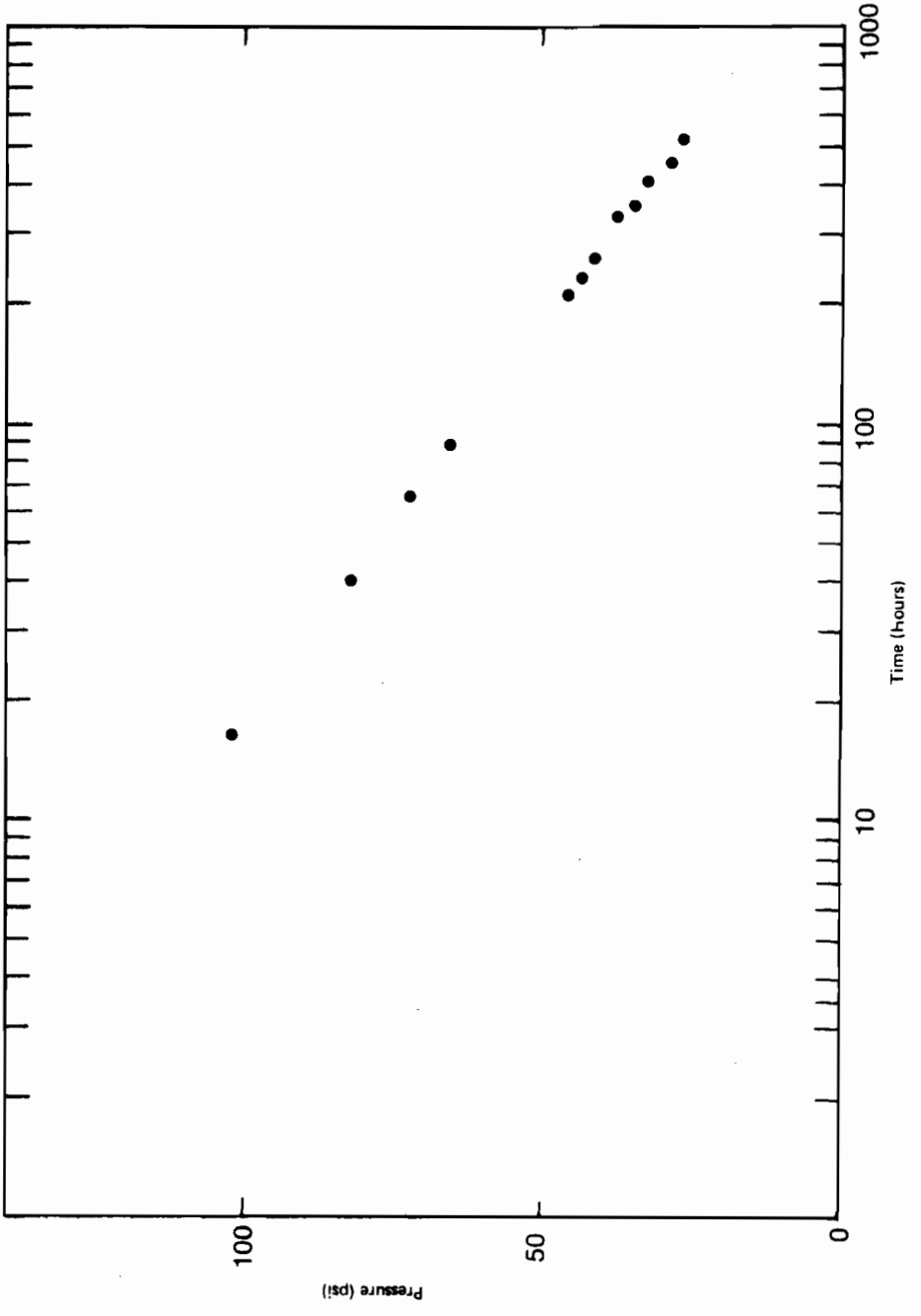

Figure 8. Pressure Fall–off After Water Injection at 200 si, Snodgrass No. 2 Well

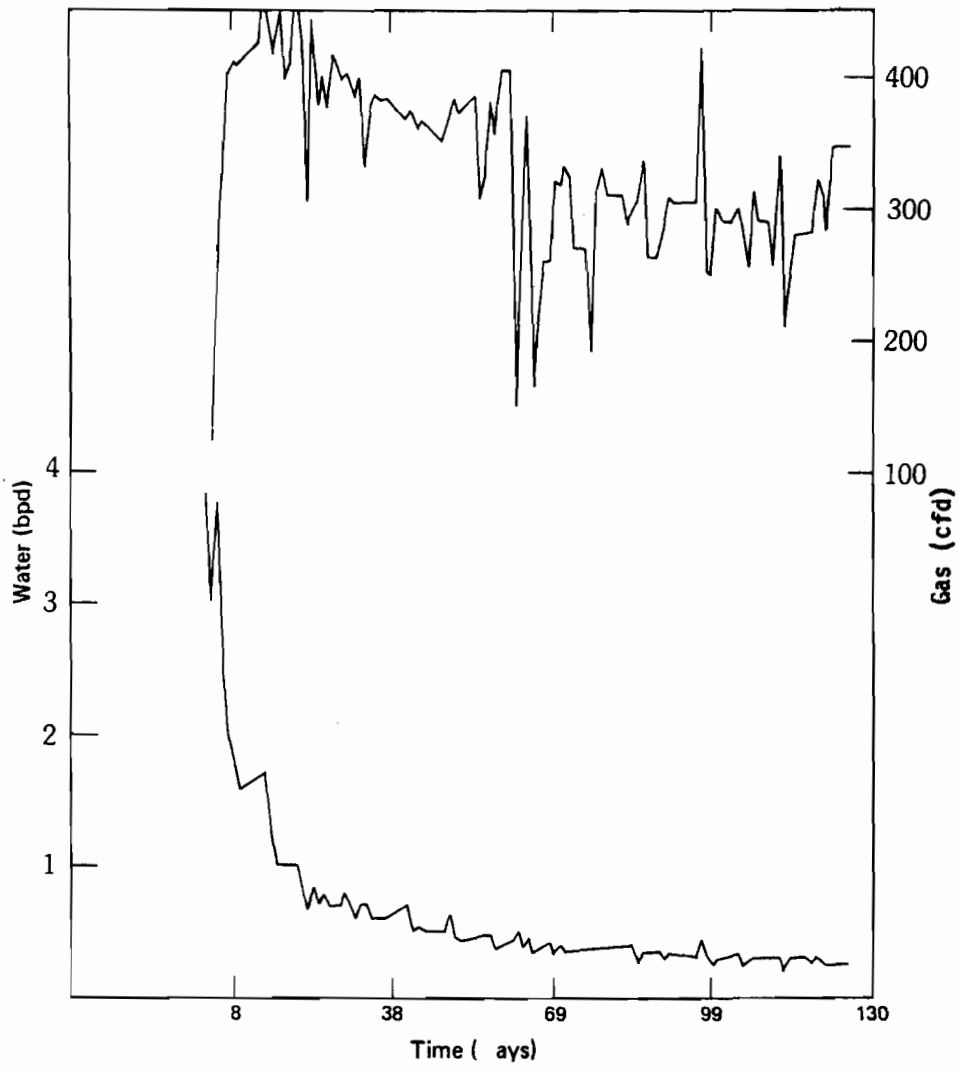

Figure 9. Production Data, Snodgrass No. 2 Well

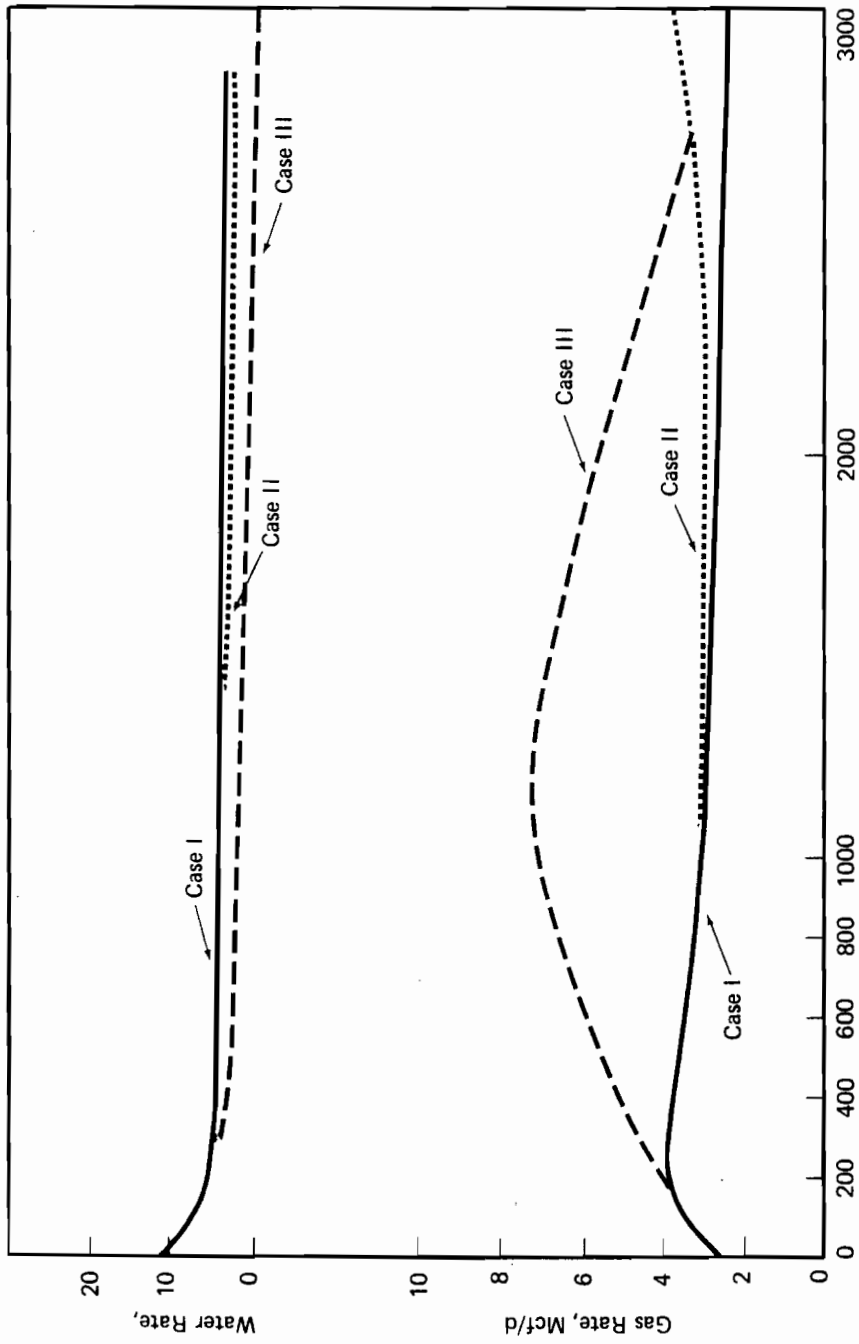

Figure 10. Predicted Performance, Snodgrass No. 2 Well

METHANE RECOVERY FROM DEEP MINES

BY

HILMAR VON SCHONFELDT

ABOUT THE AUTHOR

Hilmar von Schonfeldt received his academic training in Mining and Petroleum Engineering in his native Germany and in the United States. He holds a Mining Engineering degree from the University of Clausthal, Germany and a PhD degree from the University of Minnesota. He taught at the University of Texas, Department of Petroleum Engineering, as an Assistant Professor. His industrial experience includes underground mining in coal, iron ore and potash and in petroleum drilling and production operations. Dr. von Schonfeldt worked in the areas of in-situ stress measurements, design of longwall systems, surface subsidence, and methane control in coal mines. He is currently Manager of Mining Research for the Occidental Research Corporation. Current project areas include the productivity of longwall systems, ground control and methane control.

ABSTRACT

A system to recover methane from deep mineable coal seams is discussed. The method utilizes existing technology and involves drilling long horizontal holes into virgin coal from underground access points.

A series of tests was carried out to assess the potential for advance methane drainage in the Pocahontas #3 coal seam. The tests include pressure and flow tests for an extended period of time in long horizontal drainage holes. Apparent differences with data published in the literature are discussed. Although preliminary the results indicate that methane drainage through horizontal holes in the coal seam will provide an effective means of lowering the gas content of the seam in the test mine.

ACKNOWLEDGEMENT

The contributions of the entire methane control team under the leadership of Rao Pothini to the present study is gratefully acknowledged.

METHANE RECOVERY FROM DEEP MINES

BY

HILMAR VON SCHONFELDT

INTRODUCTION

It is well known that methane emissions in the deep mines of southwest Virginia represent a serious problem in mining operations. The gas content for the Pocahontas #3 coal bed in this area has been determined as 384 cubic feet per ton of coal in place [1]. Yet considerably more gas is vented to the atmosphere every day than can be accounted for by the produced coal. Sources other than the working face contribute to these high emission rates. These are roof, floor, gob areas and pillar ribs. In addition to the coal seam itself, gas is also stored in the overlying strata. This gas is generally mobilized by the caving process of the overburden as a result of the longwall mining operations [2].

ADVANCE METHANE RECOVERY TECHNIQUES IN THE U.S.

A number of different methane control techniques have been developed over the past 2 decades.

It will be instructive for the purpose of this paper to briefly review some of those techniques that aim at the recovery of gas in advance of mining. They may be divided into those that drain the gas through vertical holes drilled from the surface and those that drain methane from boreholes drilled from underground access points.

METHANE DRAINAGE THROUGH VERTICAL BOREHOLES.

In this technique vertical boreholes are drilled into the coal seam from the surface long before the coal is mined. The objective is to drain significant amounts of methane from the seam so that the mining operation can take place in an essentially degased coal. This technique is still in an experimental stage. It is being tried in several mining districts. Data available to date indicate, that the coal has to be hydraulically fractured before significant amounts of methane can be produced.

An advantage of this technique is that it can be carried out long before mining takes place with no interference with underground operations. The produced gas also does not get mixed into the ventilation air. It is however, not clear, yet, how effectively an entire coal seam can be degassed through these vertical holes. Many tests so far have shown disappointing results in the form of low methane production and difficulties arising from the influx of water into the boreholes [3]. The cost per hole can also be quite high especially in the inaccessible areas of the Appalachian mountains where building of access roads, site preparation and reclamation and acquisition of right of ways is frequently required.

HOLES DRILLED FROM UNDERGROUND ACCESS POINTS.

HORIZONTAL HOLES FROM SHAFTS.

The U.S. Bureau of Mines carried out an experimental program in which holes from the bottom of shafts or large diameter boreholes were drilled horizontally into a coal seam [4]. The holes were drilled on a radial pattern in order to degas a large circular area around the shaft. In this method of

methane control the work can be carried out long before mining takes place without interference of the mining operation. Also, because the holes are drilled within the coal seam they generally produce large amounts of gas. The costs, however, are relatively high because the sinking of a shaft or drilling of a large diameter borehole is required.

HORIZONTAL HOLES FROM OPERATING MINES.

In this method horizontal holes are drilled into the coal seam in the mine at or near the working face [5]. Horizontal hole drilling technology has been developed to the point where it becomes feasible to drill holes over a horizontal distance of 2,000 feet [6,4,7]. These holes are well suited for methane control especially in deep mines and mines with inaccessible surface area. They also offer almost immediate and effective relief from methane emission problems at the working face. By planning the drilling activity properly into the mine development plan large blocks of coal can be degassed in advance of mining. This method, as the others, offers the opportunity to recover the gas for further use if suitable piping systems are installed underground.

SLANT HOLES FROM THE SURFACE

It has been shown that it is technically feasible to drill a horizontal hole in a coal seam as an extension of an inclined hole from the surface [8]. It appears that directional control and dewatering techniques will have to be improved before this method will become an effective and economical alternative for advance methane drainage in mineable coal seams.

METHANE CONTROL IN EUROPE

A considerable effort is expended in methane control in the European mining industry. A total of 3,653 boreholes averaging 157 feet were drilled in Germany alone during 1976 [9]. This is equivalent to a total drilled length of 109 mi. All holes are drilled from underground and are mainly aimed into the roof and floor strata as well as into sealed gobs [10, 11]. A comparatively large portion of the produced gas is recovered for use as indicated in Figure 1. Until recently no significant success has been achieved with regard to utilization of the seam gas in the U.S.

METHANE CONTROL PROGRAM

THE RECOVERY PRINCIPLE

The system of methane control in advance of mining which is being developed for Island Creek Coal Company's deep Virginia mines is based on drilling long horizontal holes from underground access points into the Pocahontas #3 coal seam. The principle of the method is illustrated in Figure 2. The technology is similar to that developed by the U.S. Bureau or Mines and others [12]. Methane emissions are of greatest concern in entry development; the program concentrates on drilling holes parallel to future entries in the entry development sections therefore. In later stages holes will also be drilled into longwall panels.

The objective of the early program was to establish the feasibility of advance methane drainage in the Pocahontas #3 coal seam. Key parameters that needed to be determined included flow capacity of the holes, drilling characteristics of the coal seam, effect of degasification on the gas content in the coal, hole spacing and the effect of the degasification program on mining productivity. In order to determine these factors a limited number of horizontal holes were drilled into the coal seam.

DRILLING EXPERIENCE

Figure #3 shows the location of six such test holes. They vary in length from approximately 200 feet to 500 feet. All holes except hole #6 were drilled with semi-portable drilling equipment. The latter hole was drilled with a specially designed unit for degasification work in low coal seams. The equipment has been granted coal mine permissibility status by MSHA. The unit was designed to drill 3 inch to 3 1/2 inch diameter holes 2,000 foot long with the standard rotary drilling method. A more detailed description of the equipment is available elsewhere [13].

Drilling long horizontal holes within the confines of a coal seam requires a skillful operator. He has to be familiar with the drilling characteristics of his equipment and the particular coal seam he is working. The principles of directional control developed in the past [6] were found to be valid in a general sense for the Pocahontas #3 coal seam. Drilling horizontal holes, nevertheless, is still time consuming until the right combination of parameters like bit thrust, rotational speed and position of stabilizers for the particular coal seam has been found. Frequent surveys of borehole inclination and azimuth are required to steer the bit into the right direction. In spite of a

considerable difference in hardness between the coal and the floor rock the bit tends to penetrate the floor rock readily. Deflecting the hole upwards back into the coal seam on the other hand was considerably more difficult. Depending on the hardness of the rock, bit penetration rates were as low as a few inches per hour; wear on the equipment was high in this case. Past experience has shown that it is generally more efficient in such cases to retract the bit to a position within the coal seam and to deflect the drill from there into a new direction. It was also found that the bit had a tendency to drift laterally. The drift appeared to be gravity controlled in a way that resulted in a direction towards the down dip side of the seam. Recent experience indicated that drilling in the upper portion of the seam affords the most effective directional control.

THE METHANE PIPING SYSTEM

Considerable flow rates were expected from the holes because of the relatively high gas content of the coal seam. A methane piping system was installed, therefore, from the underground drill site to a vertical pipe in the return air shaft before drilling was started. Except for a short section near the coal face and except for the vertical steel pipe in the shaft the system uses polyethylene pipe (figure 4). Polyethylene was chosen for the piping material because it offered several advantages over steel: It is a lightweight material and therefore can be handled with greater ease in the underground environment; it also offers high resistance against corrosion and breakage due to impact from rock falls. The pipe may be easily cut and joined together with special fusion equipment. The fusion equipment, however, is not permissible and has to be operated in the fresh air stream. Major disadvantages of this pipe are its relatively low strength and its flamability. The combustion products on the other hand are carbon dioxide and water.

In choosing this particular material it was felt that the advantages greatly outweighed the disadvantages. The superior handling characteristics and its light weight were considered of particular value for underground work.

COAL SEAM DEGASIFICATION TESTS

In the following tests conducted on 2 groups of holes (figure 3) will be discussed.

Hole #1 and 2 were drilled from an outside entry into a barrier pillar at an angle of approximately 45° from the entry direction to a length of 206 feet and 140 feet, respectively. Mining of the entry was completed 35 days before hole #1 was drilled. It was allowed to flow freely; flow measurements were made at regular intervals with the help of an orifice meter. Hole #2 served to determine the gas pressure within the coal seam; it was shut in therefore for the entire monitoring period.

The production history over a 16 month period of hole #1 is given in figure 5. A total of approximately 18,600 MCF of gas were produced over this period. After an initially high production of approximately 87 MCF/D the flow began to decline to approximately 42% of peak production. The flow then steadily increased again to almost its original peak value. Such an increase in gas flow was explained elsewhere [14] with a changing gas-water relative permeability ratio. The water productior of the hole was quite stable at 8 to 10 gallons per day following an initial flash production of approximately 100 GPD (figure 5). A comparison with flow data of other holes in this mine which show no such rise and with no appreciable water production suggests that the flow increase might indeed have been caused by the relative permeability effect. When the mining face was extended past the borehole location the gas flow decreased noticeably as indicated in figure 5. Gas production curves of the 500 foot holes #3, 4 and 5 are presented in figure 6. The spacing between holes 3 and 4 was 50 ft., 100 ft. between 4 and 5 (cf. figure 3). It is interesting to note that the area around hole #5 seemingly has a higher gas content than the area around hole #3 indicated by a consistently higher gas flow. However, the closer spacing between holes #3 and 4 probably caused a strong interference effect reducing individual production.

The steady state production of about 180 CFT per day per foot of hole in #5 compared to about 240 CFT/D/ft. in hole #2 suggests that a certain amount of interference also took place between holes #4 and #5. It might also be speculated that the gas flow into hole #3 and 4 is somewhat shielded by the existence of entries to the west while hole #5 faces virgin coal to the east.

Whatever the reason may be for these relatively small differences in gas production it has been established that significant quantities of methane were produced through these test holes over sustained periods of time. The productivity during the stable production stage varied approximately between 180 CFD and 240 CFD per foot of hole.

A maximum pressure of approximately 215 psi was measured in hole #2 at a depth of 140 feet. A lower pressure existed in the group of the three 500 foot long holes as shown in figure 7. This difference is due to the fact that the entries were mined at different times. The coal face had been allowed to degas for about 700 days before the longer holes were drilled compared to only 35 days for hole #1 and #2. Qualitatively similar differences in gas pressure curves were observed in a mine in the same area [14].

A number of pressure buildup and draw down tests were conducted. This was done to determine (1) how the presence of the degasification holes would affect the gas pressure in the coal seam and (2) to establish whether a 50 foot spacing between holes would be sufficient to effectively lower the gas content of the coal in between. The pressure data presented in Figures 8 and 9 were taken in hole #3 before and after drilling the 4th hole. Figure 8 also contains a graph of the drilling progress for the duration of the pressure tests. It is indicated that good communication existed between holes on a 50 foot spacing. In fact, the pressure wave generated by shutting in hole #4 arrived at hole #3 in only about 7 hours. Figure 9 shows the gas pressure in the coal seam before and after hole #4 was drilled in the area. The latter was allowed to drain while the pressure was recorded in hole #3. It shows that the gas pressure in the seam was lowered by about 30% in only a few days of production.

The maximum pressure of 215 psi, reported above is considerably lower than previously published values for the Pocahontas #3 coal seam [15]. Some of the measurements, all made within a 10 mile to 15 mile radius, are summarized in Figure 10. Even at the very low reported permeabilities it is unlikely that such differences in gas pressure in the coal seam over such a relatively small area could have been sustained for the geological period of time. A more likely conclusion is that the coal seam permeability at the various mines in the area is different.

Once the mine is opened up this non uniform permeability distribution will allow the pressure to be drawn down at different rates. It is concluded, therefore, that the coal seam permeability in the present mine is higher than .32md reported for the area. This higher permeability will allow for a faster draw down of the coal seam pressure; one would expect very high methane emission rates especially in the early stages of mine development. This has indeed been verified by the fact that unusually high ventilation rates were required to dilute the methane during the first few years of mine development. This higher permeability in addition to a high defusion parameter [16] will increase the effectiveness of advance methane drainage. Additional work is required to verify these preliminary conclusions, however.

CONCLUSIONS

A number of preliminary tests were conducted in a deep mine in southwest Virginia to determine whether advance methane control through long horizontal holes is feasible.

All data generated in this study indicate that the potential for effective methane drainage is good. The expected flow from the horizontal boreholes is large enough as to warrant the installation of an underground piping system. Such a piping system offers the opportunity to recover the gas for a useful purpose. Additional work is required to determine optimum hole spacing for effective degasification in a given time period. Directional control of the horizontal holes and reliability of the drilling hardware are expected to remain the major problem areas in the near term.

The concept of advance methane drainage through horizontal holes in the coal seam rather than through vertical holes from the surface is currently seen as the most cost effective method for the deep southwest Virginia coal mines.

The characteristics governing the flow of methane in the Pocahontas #3 coal seam vary with location on a relatively small scale. This implies that a study similar to the present one might be required for each mine before committing major capital expenditures to a specific methane drainage program.

In order to determine the effect of the degasification program on mining productivity more work is required. Some information will become available shortly when the entries around holes 3, 4 and 5 will be developed.

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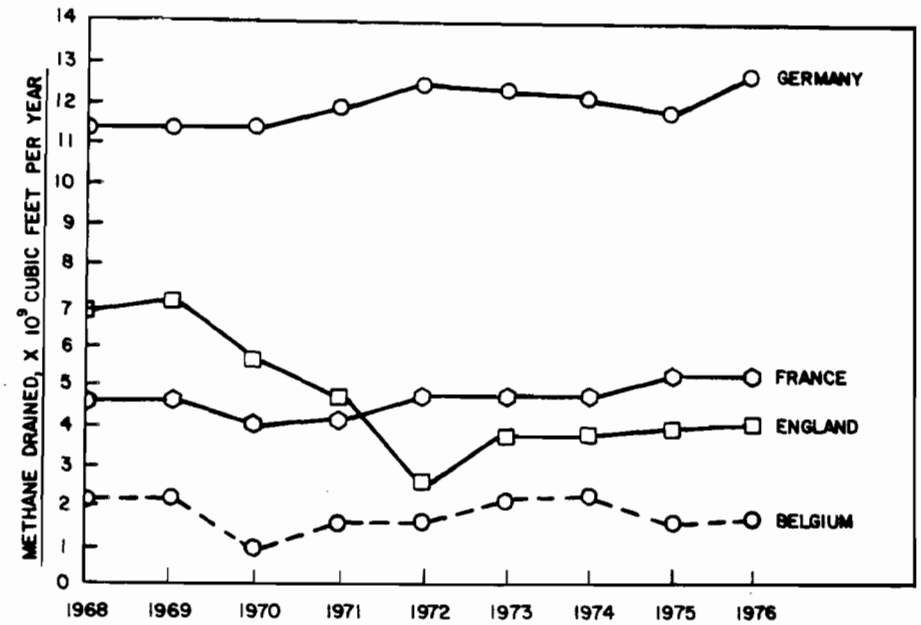
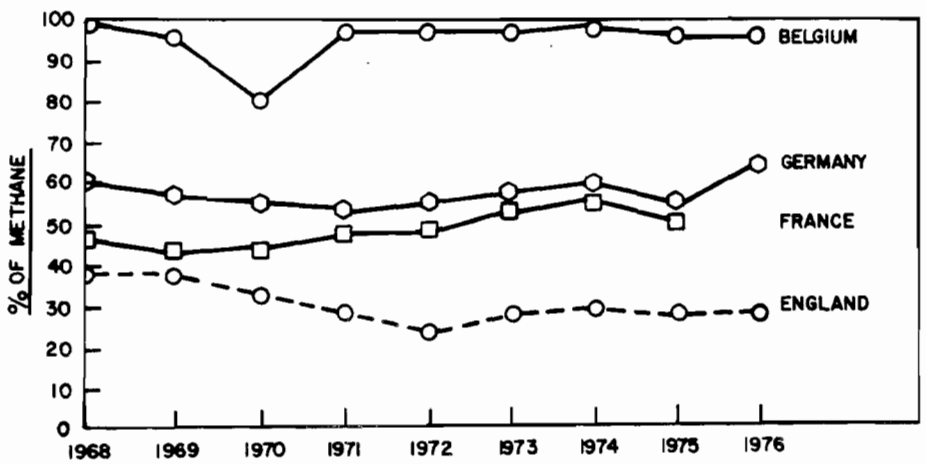
FIGURE 1

METHANE RECOVERY FROM COAL SEAMS IN EUROPE



TOTAL METHANE DRAINED IN GIVEN YEAR
(AFTER V. TRESKOW, 1977)



PERCENTAGE OF DRAINED METHANE RECOVERED FOR USE
(AFTER V. TRESKOW, 1977)

FIGURE 2
PRINCIPLE OF METHANE DRAINAGE AHEAD OF MINING

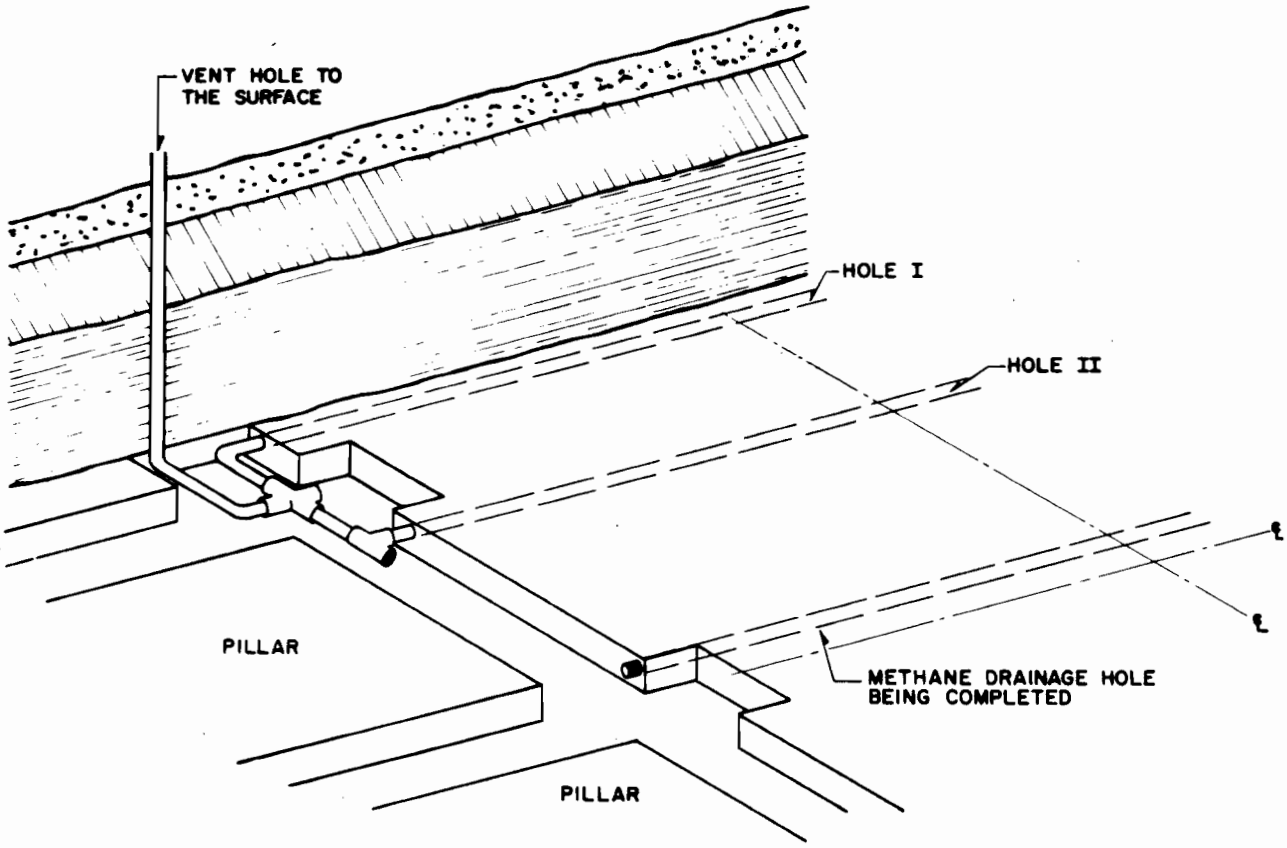


FIGURE 3

LOCATION OF TEST HOLES IN MINE PLAN (APPROXIMATE)

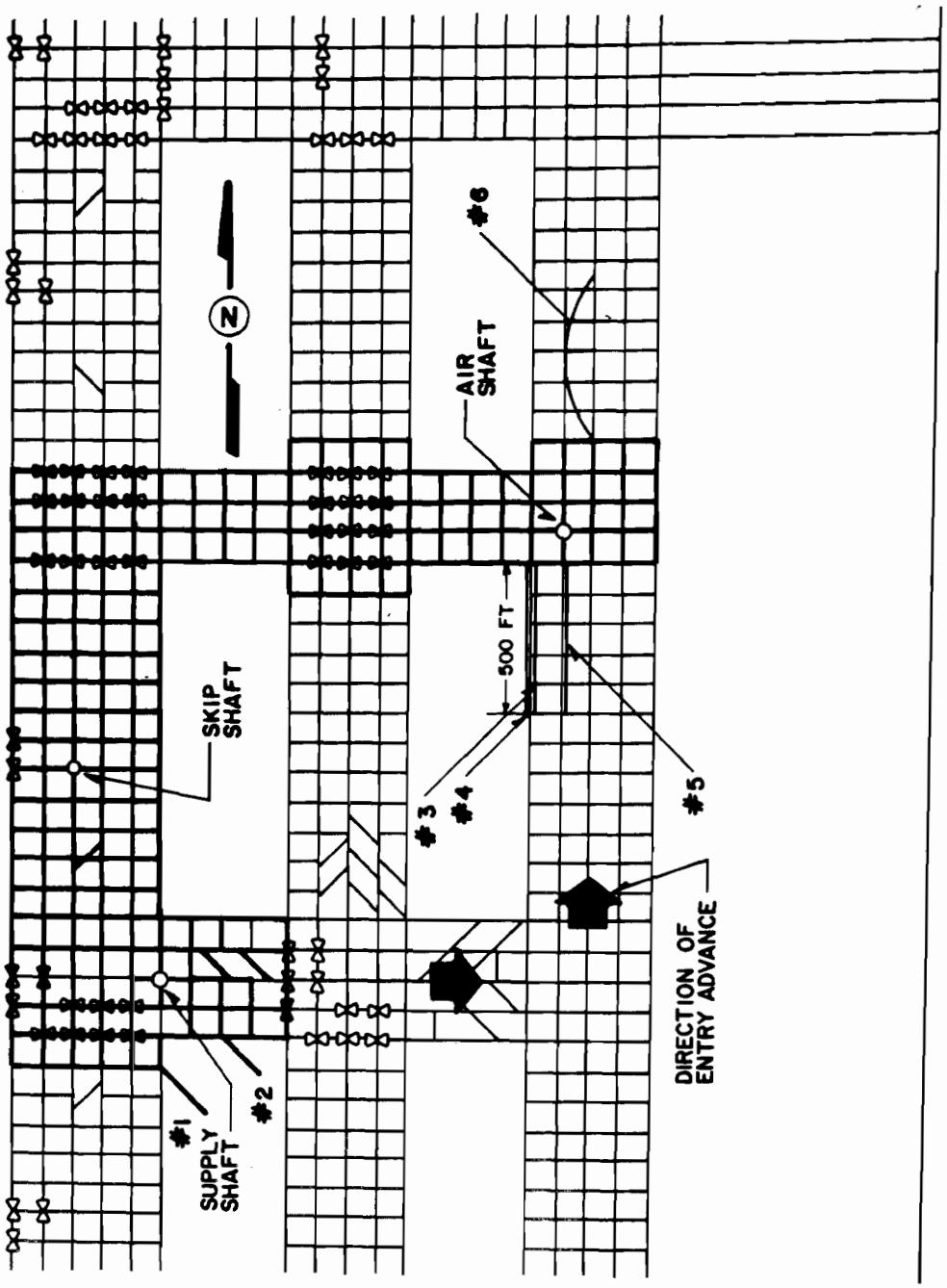


FIGURE 4

PIPING NETWORK (SCHEMATIC)

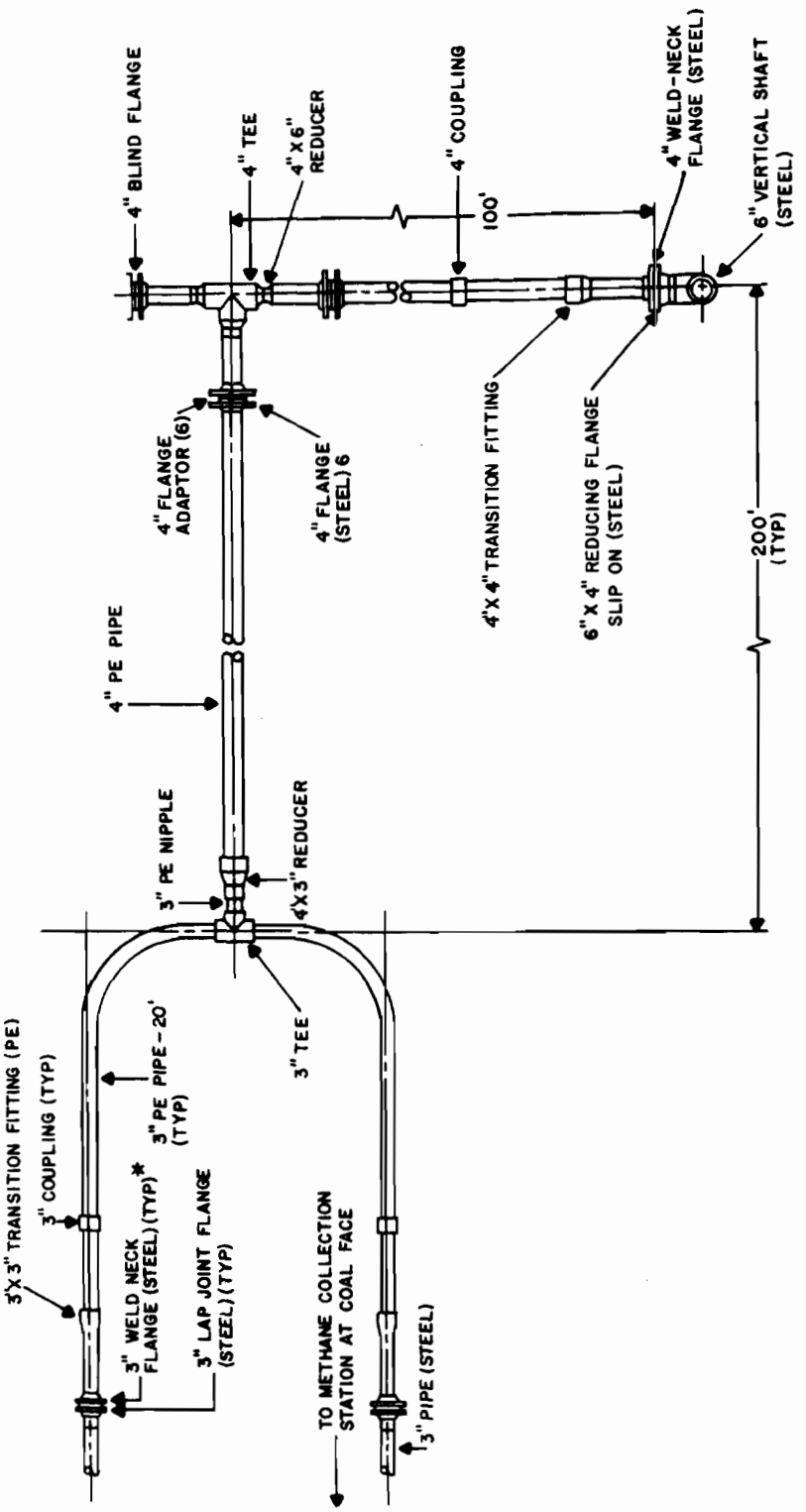


FIGURE 5

GAS AND WATER FLOW, HOLE # 1

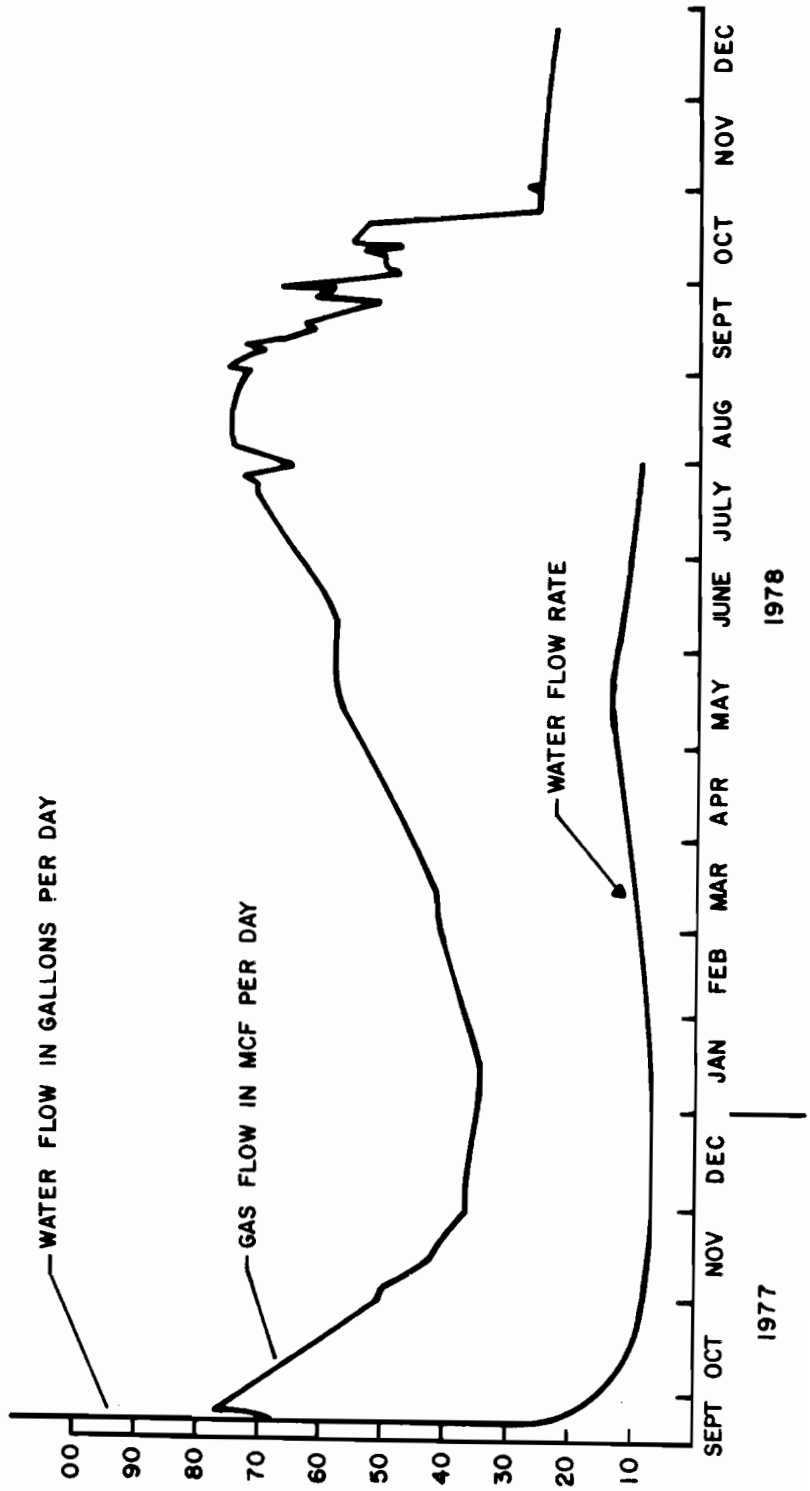
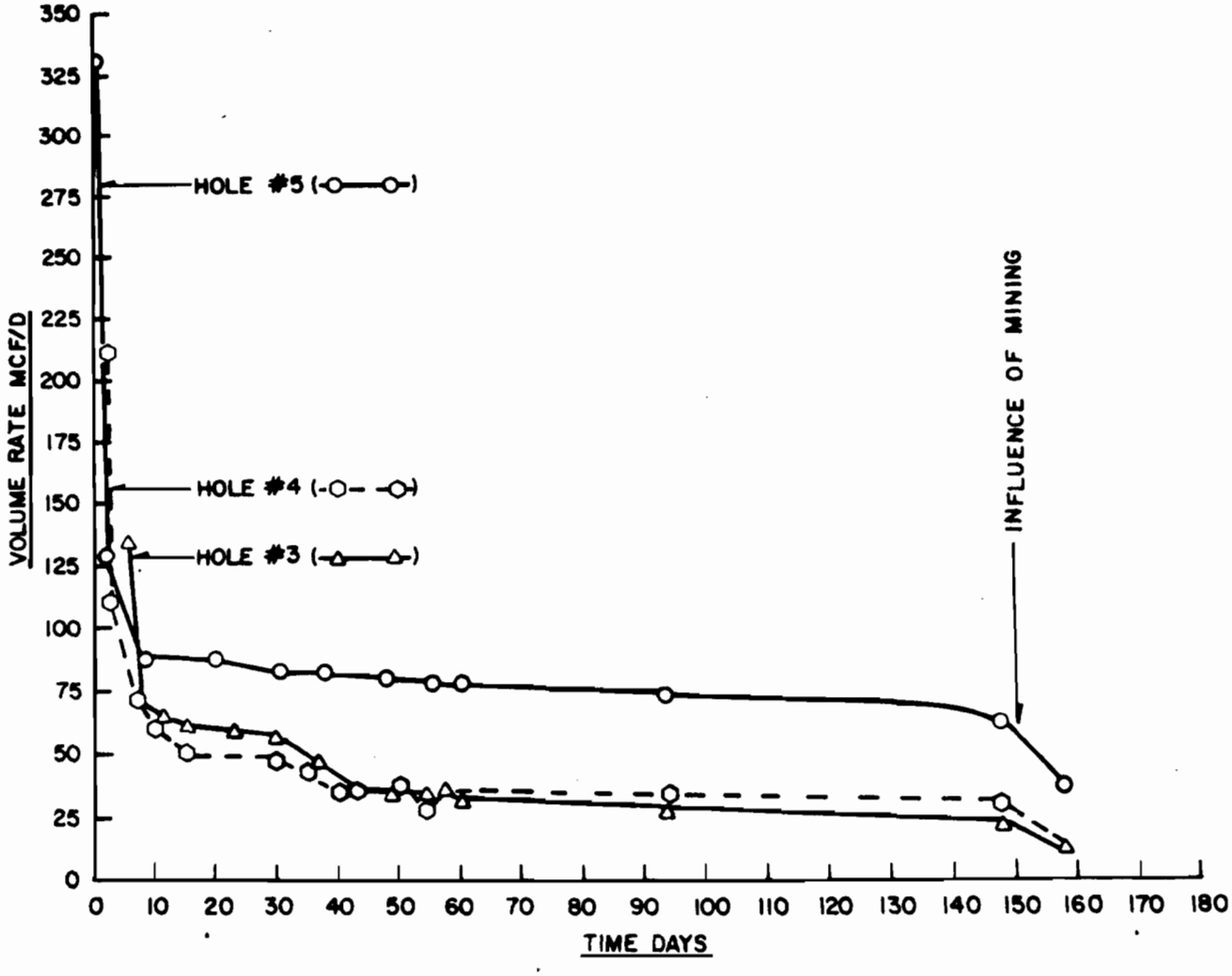


FIGURE 6

GAS FLOW FROM THREE HOLES



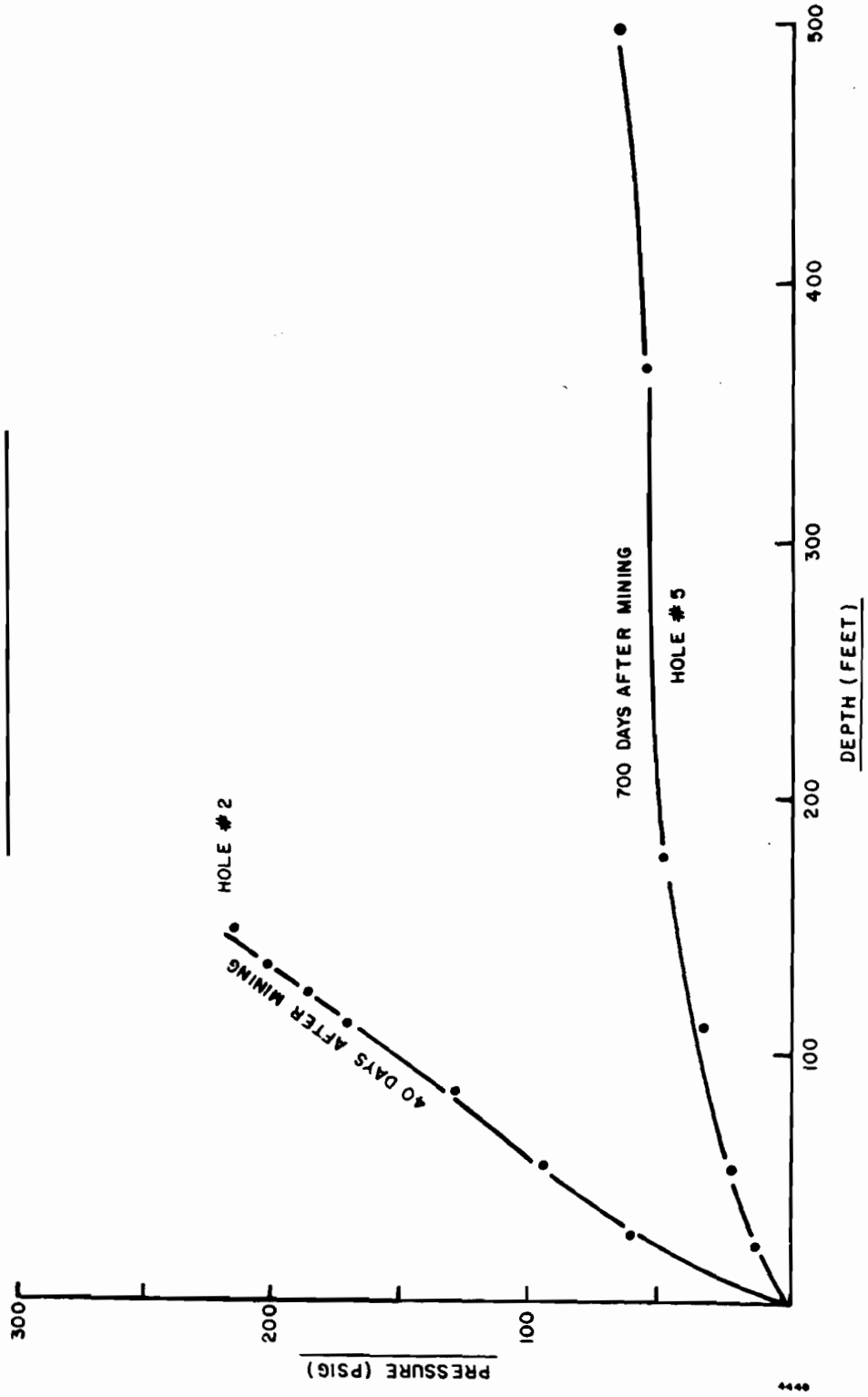


FIGURE 7.
METHANE PRESSURE IN COAL SEAM FROM HOLES #2 & 5

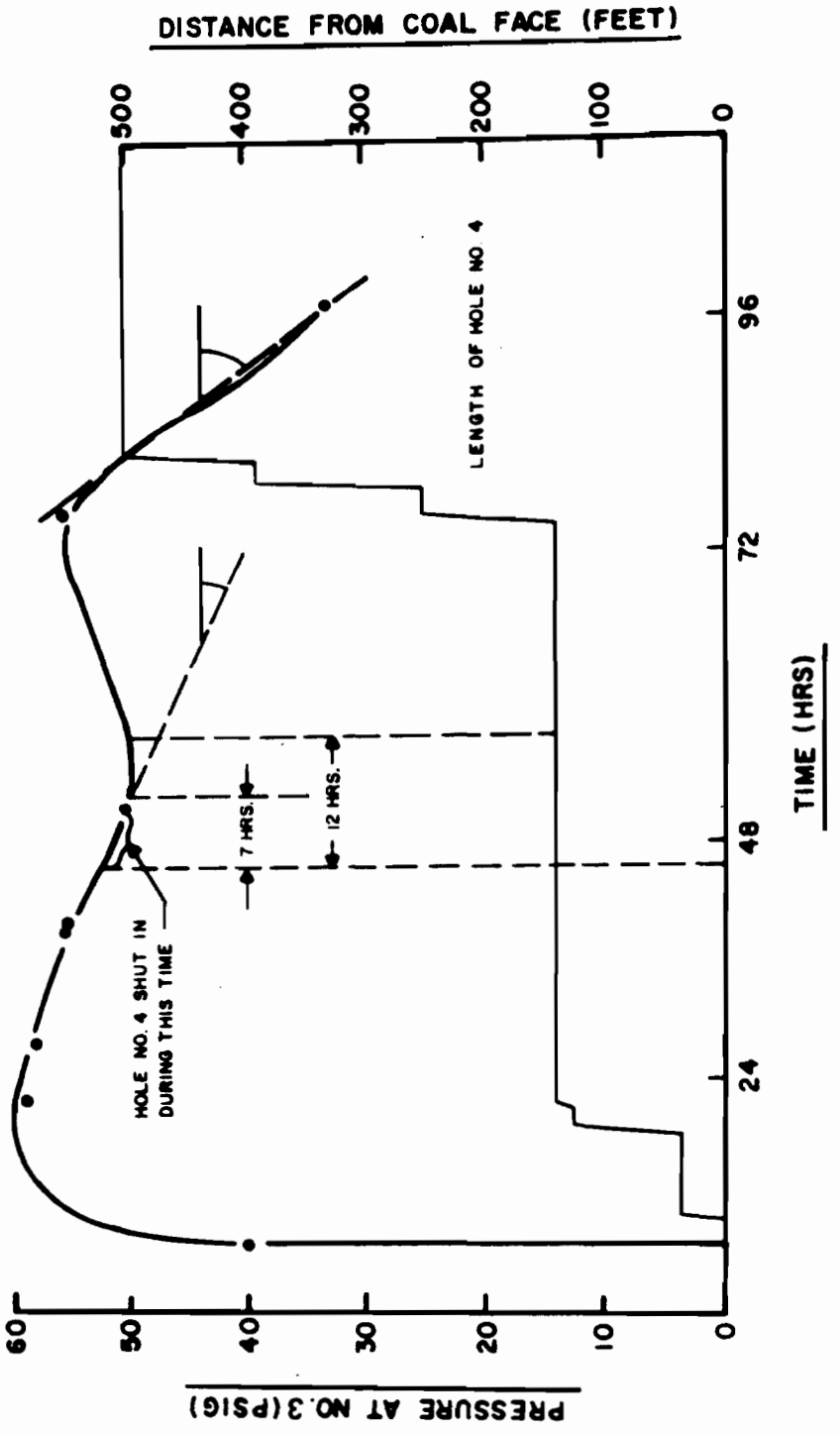


FIGURE 8

PRESSURE IN HOLE NO. 3 AND LENGTH OF HOLE NO. 4 VS. TIME

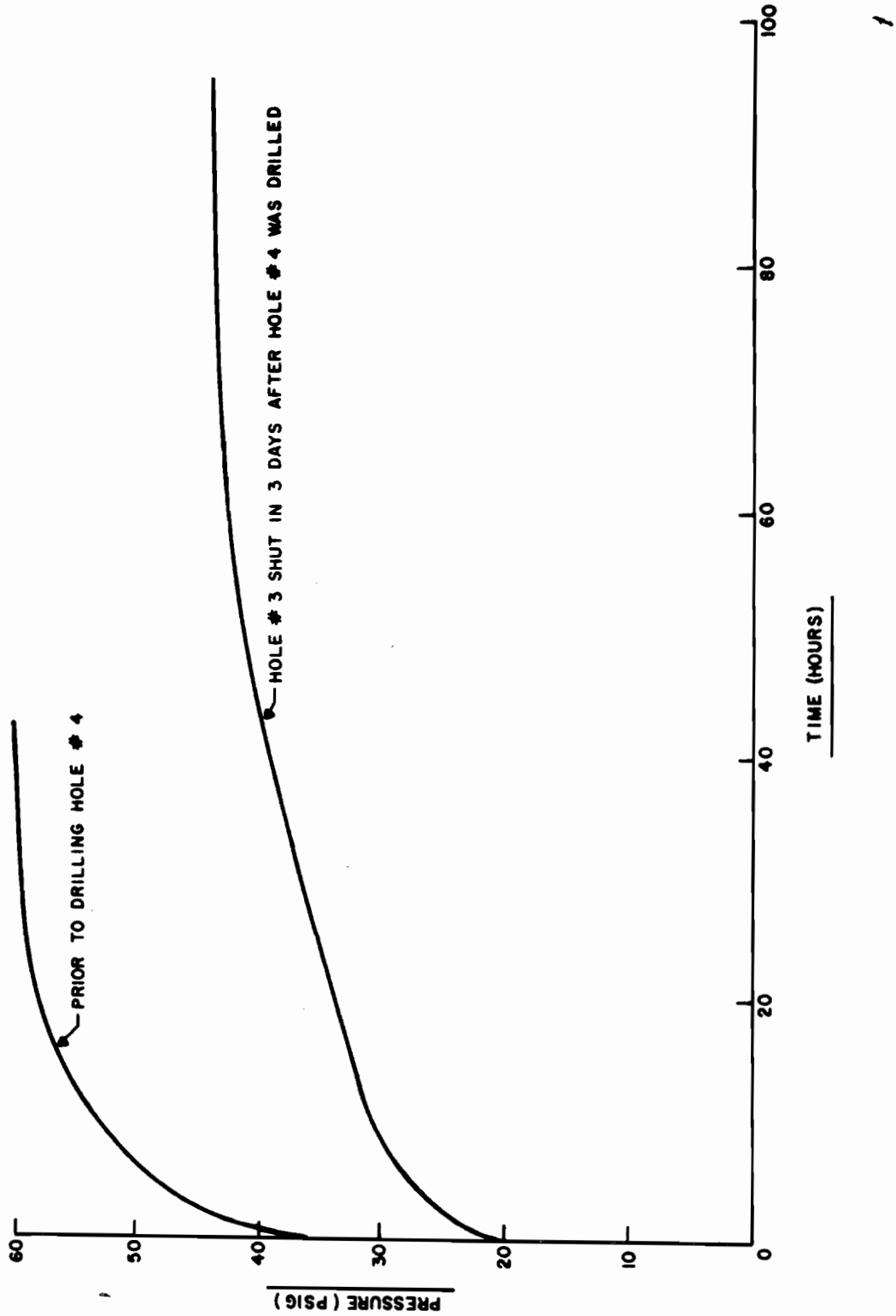
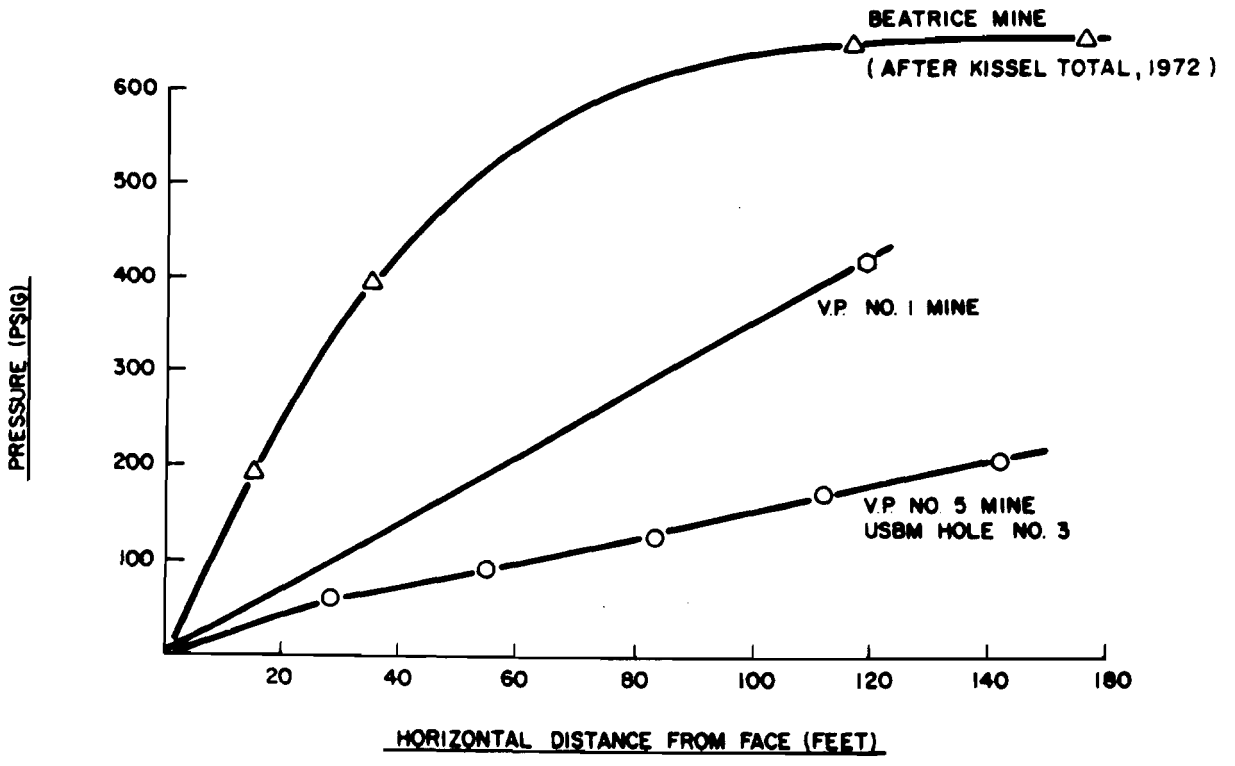


FIGURE 9

PRESSURE BUILD-UP, HOLE # 3

FIGURE 10

METHANE PRESSURE VS DISTANCE FROM COAL FACE, POCAHONTAS NO. 3 SEAM



HYDRAULIC STIMULATION OF THE PITTSBURGH COAL SEAM: A CASE STUDY

BY

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ABOUT THE AUTHOR

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HYDRAULIC STIMULATION OF THE PITTSBURGH COAL SEAM: A CASE STUDY

BY

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ABSTRACT

A vertical well was drilled through and completed in the Pittsburgh coal seam to evaluate gas inflow reductions into nearby development mining and to compare predicted and actual fracture behaviors in the Pittsburgh coal seam of northern Marion County, WV. The short-term project indicated that two closely spaced wells provided significant reductions of gas inflows into the mine. A hydraulically created fracture was mined through and visual inspections indicated that fracture length and width differed from predicted values by an order of magnitude. Fracture penetration of three strata overlying the seam was observed.

TEXT

A project was undertaken approximately three years ago to evaluate the impact on mining operations of a hydraulically stimulated degasification well drilled into the Pittsburgh coal seam. The primary areas of investigation were to determine the effectiveness of the well in reducing gas emissions into nearby development mining and to compare the physical aspects of a hydraulically induced fracture with those predicted a priori for height, width, and extension.

The presence of combustible gases in coal seams is well documented. The formation of hydrocarbon gases and carbon dioxide is a result of the coalification process. These gases will probably be encountered when mining coal in areas where pressures have not allowed them to escape.

The coal itself possesses practically no natural permeability, but is often found to have a fracture network. This fracture system, frequently referred to as cleats, is believed to be a result of tectonic forces and subsequent lateral movements. These cleats are often found to lie in sets of approximately perpendicular planes. The Pittsburgh coal seam in the study area is approximately horizontal with both cleat systems being vertical. The cleat system is generally accepted as comprising two categories. The predominant or "face" cleat is longer and more continuous than the shorter "butt" cleat. Varying degrees of gas conductivity depend upon the cleat lengths and widths. In the study area it has been generally observed that significantly larger rates of gas inflow are encountered when mining in a direction perpendicular to the face cleat.

Wells drilled through the Pittsburgh coal do not generally produce gas at commercial rates, with the majority having no measurable gas production naturally. There have been instances where significant long-term, gas production rates have been encountered when drilling through the Pittsburgh, but these instances have been generally accepted as being uncommon. Coalbed gas wells often produce small rates of water which must be removed to enable gas to flow to the wellbore through the cleats and other fractures.

The Bureau of Mines drilled five vertical wells to the Pittsburgh coal 1 1/4 miles to the west of the study area in 1974 (Figure 1). They selected the area partly because of its history of high gas emission into the nearby Loveridge Mine (Consolidation Coal Company). The wells were located in the coal reserves several years ahead of mining. Two of the wells were hydraulically stimulated.

The most prolific gas producer was making 30,000 SCF/d after 33 months of production. The gas content of the Pittsburgh coal at the Loveridge Mine has been measured on two occasions and reported by the Bureau of Mines to be 5.8 cm^3/g. (Ref. 1) The location where coal was extracted for these measurements is not specified, but this value is assumed to be representative for the Loveridge reserves.

Consol then decided to drill and hydraulically fracture four wells which were to be located in solid coal 250 feet to the east of the 7-North development projections. The purpose of the wells was to determine if the gas flowing through the seam could be "intercepted" before reaching the mine and also to determine if the actual behavior of a hydraulically induced fracture differed from that predicted (Figure 2). Two of the wells were drilled and completed (L-5 and L-6), one was mined through (L-5) to visually inspect the hydraulically created fracture, and the remaining two wells were dropped from the project when it was determined that the reductions in gas inflows did not warrant the well costs. The gas produced from the L-6 well is being marketed.

The drilling program decided upon was to drill through the seam and cement the casing back to the surface (Figure 3). Consideration was given to the possibility of inadvertently hydraulically fracturing and plugging the coal seam while cementing the casing. Existing data on coal seam injection rates and pressures near the test area from a previous underground gel-infusion project indicated that contamination of the coal with cement was unlikely. Later, when the well was mined through, a concentric, uniform cement sheath was found in the casing-hole annulus at the coal seam and no evidence of cement migration into the coal seam could be found. The "set through and perforate" technique was also considered to be the most positive method of assuring zonal isolation. There was concern that the hydraulic stimulation would migrate from the coal seam and break into the surrounding strata. These concerns were considered to be minimized by the "set through" technique because the fracture could be initiated in the seam with a higher level of confidence.

A considerable amount of attention was given to the design of the hydraulic stimulation treatment. The design of such a treatment can be tedious and is sensitive to a number of parameters relating to formation and fluid properties. Hydraulically created fractures generally can only be assessed through well productivity increases following the treatment. There have been only a small number of hydraulically created fractures seen at distances greater than a few inches from the wellbore. Fracture lengths and widths have been deduced from the necessary fluid conductivities required to result in the measured productivity increases. A large number of hydraulic stimulations and subsequent productivity increases have been measured for hydrocarbon bearing sandstones.

The structure of coal is recognized as differing considerably from that of a porous media such as sandstone, where the majority of field experience and expertise have been developed. The Pittsburgh coal has a very limited porosity and also has the well defined fracture system mentioned earlier. The ability of a fluid to perform work hydraulically on a formation is diminished if the fluid leaks into it. The cleat system in the Pittsburgh can unfortunately result in significant losses of fluid and thereby detract from the job efficiency. This cleat system is so extensive that even small fluid losses to individual cleats have a combined result of significant fluid losses.

It was suspected that an appreciable quantity of stimulation fluid leak-off could significantly reduce the effectiveness of the treatment in extending from the wellbore. It was also realized that the "down-fracture" proppant carrying ability of the fluid can also be significantly reduced as the fluid leaks off to the formation. The corresponding slurry density increases and velocity reductions can result in a "sandout" dictating job termination without further fracture extension.

Published values of Pittsburgh porosity and permeability, and the assumption that the shoulder beds were impermeable were used in the design. The seam pressure was obtained from one of the nearby coal wells mentioned earlier.

Theoretical studies of two-phase flow in coal suggested that the ability of gas to flow through the Pittsburgh could be quite sensitive to water saturations - much more so than is normally the case for porous media. Some existing data on coalbed gas well productions indicated that some wells did produce gas at larger rates after some months of "dewatering". Although this data was not conclusive, the general philosophy was that liquid volumes injected during stimulation should be kept minimal. This concern combined with the anticipated large fluid losses generated interest in a nitrogen based "foam" treatment. Since, at the time, no coal seams had been treated with nitrogen foam, it was decided to use a more conventional gelled-water treatment on L-5, and then to treat L-6 with foam. Both the foam and gelled-water treatments were kept as alike as possible so that

comparisons could be made.

Hydraulic stimulation plans submitted by two major oil field service companies specializing in these treatments were reviewed, one of which is presented as Figure 4, and compared with an in-house design. Primary concern was given to designing the treatment to stay in the seam and to avoid breaking the surrounding strata, particularly that overlying the coal. It has been postulated that upward vertical fracture extension increases with injection rate. The desire to maintain a hydraulically created fracture in the seam along with the anticipated reduced proppant transport ability of the treatment fluid resulted in the designed injection rate. The gelling agent was chosen primarily because of a higher degree of biodegradeability. It was felt that this "cleaner" fluid would be the better choice because of the anticipated high leak-off to the cleat system along with the small intrinsic permeabilities of the individual cleats. The design and actual treatment parameters are presented in Table I.

A 6 1/4-inch hole was air drilled to 60 feet below the Pittsburgh coal and electrically logged, and 4 1/2-inch casing was run and cemented back to the surface using conventional oil field procedures prior to mining (Figure 3). No measurable gas production was made from the 867 feet of empty, open hole. The well was perforated in the middle 2 1/2 feet of the 7-foot Pittsburgh coal seam with ten shaped charges after the cement had sufficient time to build adequate strength. The well was then hydraulically treated with the designed gelled-water treatment. The hydraulic stimulation treatment proceeded essentially as planned. Basically, 12,000 pounds of 20/40 Ottawa sand proppant were displaced at an average injection rate of 13 BBLS/min (Table I). The well was cleaned up during the four days following the hydraulic stimulation treatment with a considerable quantity of sand being "brought back" during well clean-up.

The L-5 well was completed when development mining was 350 feet away. It produced a total of 226,000 SCF of methane during the 51-day interval between the time it was completed and that of when it was mined through. The produced gas was composed primarily of methane and carbon dioxide prior to the time that the offset (L-6) was treated with a nitrogen based foam (Figure 5 and Table II). It is interesting to observe the higher nitrogen concentrations in the L-5 production five days following the foam stimulation of the offset well, L-6. It is difficult to estimate what the rate of gas production from L-5 would have been if there had been sufficient time for dewatering.

A significant reduction in methane into the mine did result, however. A summary of the methane production from L-5 and L-6, and in the mine air is presented (Figure 6 and Table III). The data indicates that L-5 and L-6 had a combined effect of reducing the methane inflows into the mine by approximately 40 percent. It must be pointed out that the long-term effects of these wells in reducing in-mine methane flow reductions was not established but that an immediate short-term relief did occur. The in-mine methane productions increased sharply just as L-6 was mined by. This suggests that the combined "intercepting" effect of L-5 and L-6 had greater than twice the impact of L-6. Another explanation offered is that the significant methane inflows encountered in the area are a result of gas inflows from the nearby abandoned wells (Figure 2). Well #3475 was an oil producer from a zone at 3,066 feet, was abandoned with two strings of tools in the hole in 1901, and has only 123 feet of 6 5/8-inch casing in it.

The hole (L-5) was mined through so that direct observations of the hydraulic stimulation treatment could be made. The hole was directionally surveyed in order that mining projections could be developed to intersect the well. The hole was found to intersect the coal 13.57 feet at S-28°51'-W from the surface location. The rate of mining advance was slowed as the well was approached with visual inspections of the face area being made once every foot or less. The ten perforations were found to be in the center of the seven-foot coal seam. They were found to penetrate the casing and the cement sheath in a N-0°-E and S-0°-W orientations, a direction approximately perpendicular to the face cleat. No effort had been made to orient the perforations. They were observed to be approximately 3/8 inch in diameter and to have penetrated the casing and the 5/8-inch cement sheath and at least nine inches of coal. The casing was well cemented and was concentrically oriented in the hole.

The fracture was vertical and extended diametrically from the well bore. It appeared to have initiated from the five southerly perforations (Figure 7). The fracture direction turned abruptly (within one inch) to follow the face cleats (approximately N-80°-W). The fracture was 1 1/4 to 1 1/2 inches in width, tapering to one inch at the bottom, which was located one foot from the bottom of the coal seam. There was some slight fracture separation on the west side of the hole. There were two small coal stringers within the well propped fracture, resulting in a maximum overall

fracture width of at least two inches. These observations are confined to the 13 1/2 feet of entry width. The calculated overall length of propped fracture on the basis of observed width and sand volume is approximately 80 feet, that is 40 feet on either side of the well bore (assuming the fracture continued to propogate symmetrically from the well bore). The length of fracture extension is known to be less than 61 feet from the well bore in the westerly direction, providing it remained in the face cleats as it probably did.

The fracture did penetrate the immediate roof. It was observed to extend through 12 inches of head coal, 12 inches of shale, 16 inches of a rider coal seam, and appears to terminate several inches into another shale member above the rider seam. The measured fracture height is 8.7 feet, 2.7 feet of which extends into the immediate roof above the top of the Pittsburgh coal seam (Figure 8).

There is one circumstance regarding the well casing that should also be mentioned. The casing was found to be parted in the coal seam. The casing had two material separations; one longitudinal and the other circumferential. The reason is unclear as the pressure rating was greater than the bottom hole treating pressure. Each joint had been hydrostatically tested to 3,000 psi. A sufficient safety factor was used and pipe tension was considered. There has been an opinion expressed that the roof breakage is a result of these casing separations. This is unlikely. Both casing separations were in the coal seam, therefore, any fracture initiation would have to commence in the seam. The perforations were found to be well propped with sand and the fracture probably initiated at the perforations with the casing separations occurring later.

The hydraulic stimulation program was designed with emphasis being directed towards keeping it in the coal seam while at the same time creating a reasonable length of fracture extension for the job size. The cause of the treatment to extending through and breaking the strata immediately overlying the coal seam is unknown; nor is it understood why the created fracture is more than ten times wider and shorter than predicted (Figure 4). Suspicions are that the heterogeneous nature of the coal seam is at least partially the cause of the considerable deviations between the predicted and observed fracture behaviors. The fact that the fracture did not propagate to the bottom of the seam but did penetrate three distinct, separate strata (two of which have drastically different rock properties) overlying it suggests that the confining stresses were more prominent than anticipated and had a greater effect on fracture propagation than did the rock properties.

CONCLUSIONS

1. A significant (40 percent), short-term reduction of in-mine methane inflows resulted from two wells drilled into and completed in the coal 250 feet from development mining in the Pittsburgh coal seam. The combined gas capturing effect of the two wells having a 500-foot spacing appears to be greater than twice that of a single well.

2. The hydraulically created fracture penetrated three distinctly separate strata overlying the coal seam, yet, did not propagate to the bottom of the seam. This behavior suggests that the confining stresses had more of an effect on fracture behavior than did the rock properties of the overlying coal and shale members.

3. The hydraulically induced fracture turned abruptly upon exiting the well bore to follow the major cleat system.

4. The "set through and perforate" completion technique permitted fracture initiation in a seven-foot coal seam.

NOMENCLATURE

BBLS	=	barrels (42 gallons)
cm^3/g	=	cubic centimeters per gram
d	=	days
gal	=	gallons
lb	=	pounds
md	=	millidarcies
min	=	minutes
pct	=	percent
psi	=	pounds per square inch
s	=	seconds
SCF	=	standard cubic feet

REFERENCES

1. Kissell, F. N., C. M. McCulloch, and C. H. Elder, "The Direct Method of Determining Methane Content of Coalbeds for Ventilation Design", Bu. Mines RI 7767, 1973, pp. 14-15.

2. Personal Communication, C. H. Elder, USBM.

Figure 1

Location of Study Area

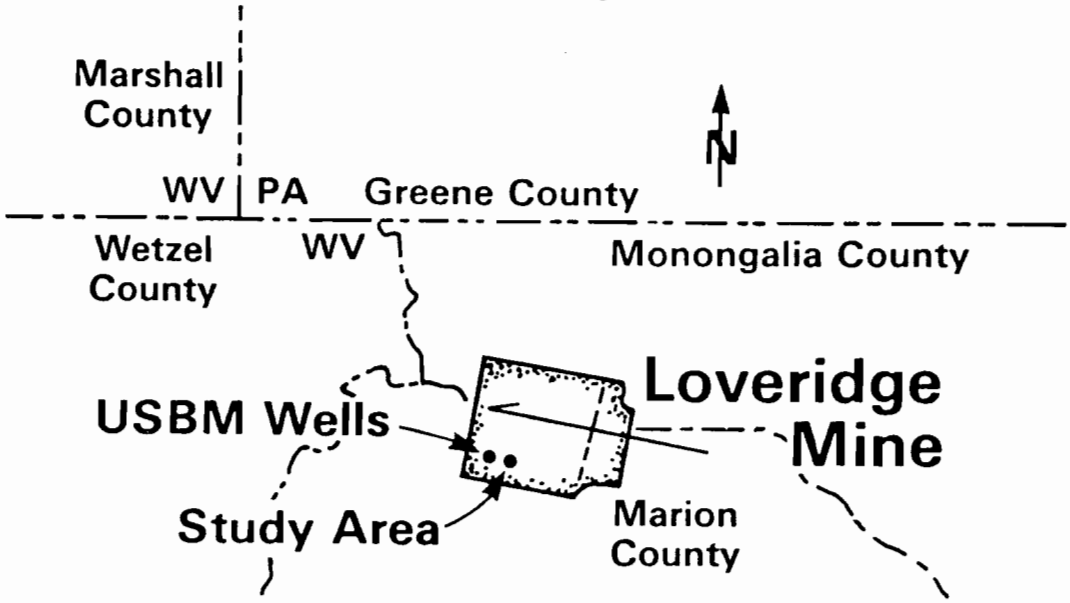


Figure 2

L-5 Coalbed Gas Well
Loveridge Mine, Consolidation Coal Company
Marion County, WV

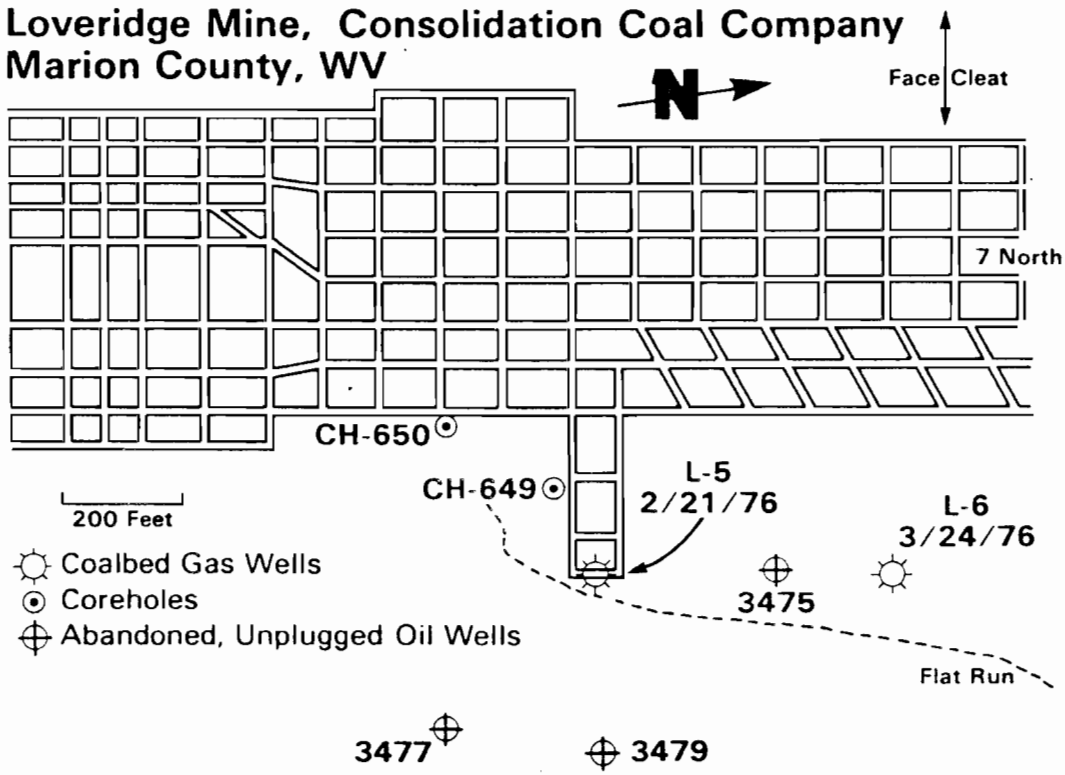


Figure 3

Well #L-5, Loveridge Mine, Marion County, WV (Completed 2/21/76)

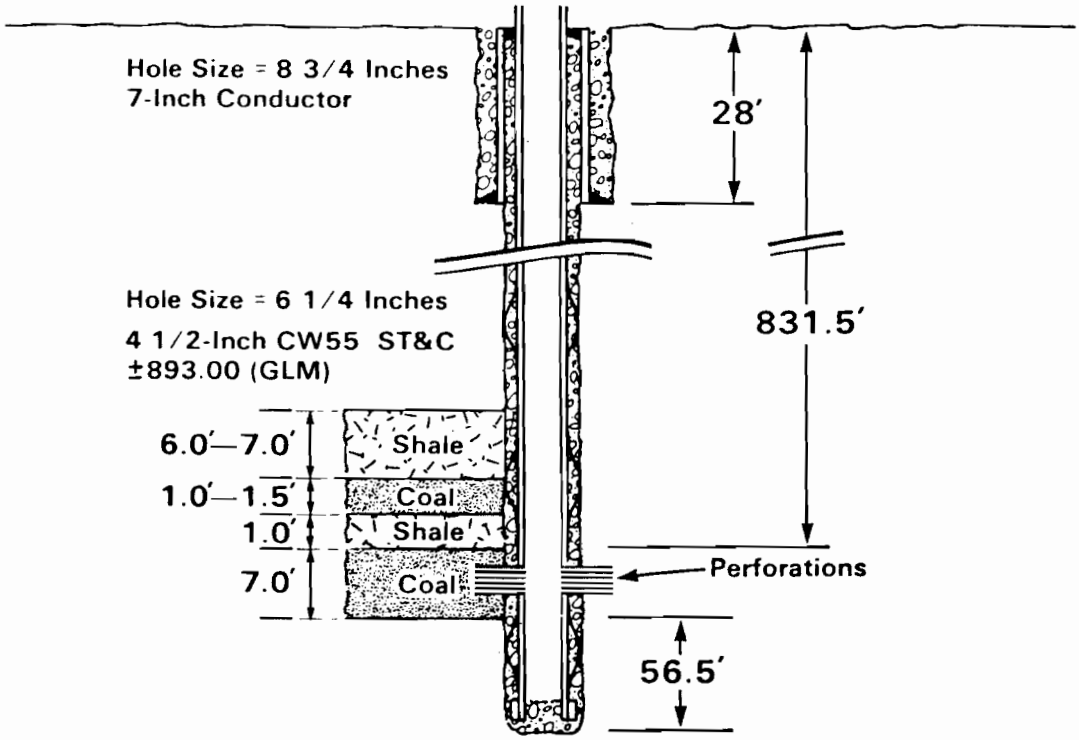


Figure 4

MODIFIED FRACPLAN II

JOB TYPE — WATERFRAC FRACTURING SERVICE

CONTINENTAL OIL CO

WATERFRAC PROCESS

INJECTION RATE — BBL/MIN	10.0
ASSUMED FRACTURE HEIGHT — FT	5.0
INTERVAL HEIGHT PERMEABLE — FT	5.0
FRACTURE HEIGHT PERMEABLE — FT	4.0
NUMBER OF LAYERS DEFINED	3
LAYER THICKNESS, STARTING AT BOTTOM, FT	
1.00 5.00 1.00	
LAYER PERM. STARTING AT BOTTOM, MD	
0. 5.00 0.	
ELASTIC MODULUS — PSI	0.30E+06
FORMATION PERMEABILITY — MD	5.00
FORMATION POROSITY	0.04
BHTP — PSI	1000.
RESERVOIR PRESSURE — PSI	600.
RESERVOIR FLUID VIS — CP	0.02
SPECIFIC GRAVITY TREATING FLUID	1.0150
CV — FLUID LOSS COEF. — FT/SQRT(MIN)	0.00220
SPURT LOSS — GAL/SQFT	0.03300
TYPE OF GEL	WG-11
GEL CONCENTRATION	10#/MGAL
N-PRIME	0.7300
K-PRIME(SLOT) — LBF-SEC**N/SQFT	0.000900
TYPE & CONC NO 1 PROP 20-40 SAND	0.60 LB/GAL AV

DESIGN NO	PROD INCREASE (TINSLEY)	TOTAL VOL GAL/1000	PAD VOL GAL/1000	PROPPED FRAC LN FT	PROPPED FRAC HT FT	VIS CPS	FRAC WIDTH IN	PROP 1ST SX	PROP 2ND SX
1	0.	10.5	5.2	178.	3.1	7.	0.342	32.	0.
2	0.	21.0	5.2	431.	3.3	8.	0.396	95.	0.
3	0.	31.5	5.2	637.	3.4	8.	0.431	158.	0.

NOTE: PRODUCTION INCREASE VALUES NOT CALCULATED

DESIGN NO	CREATED LENGTH	HHEC	C-EFF	FLOW CAP 1ST PROP	FLOW CAP 2ND PROP
1	2650.	3.09	0.001008	0.	0.
2	4377.	3.32	0.000997	0.	0.
3	5671.	3.44	0.000991	0.	0.

Table I—L-5 Hydraulic Stimulation Program

I. Design Parameters

A. Porosity (pct)	3
B. Permeability (md)	5
C. Elastic Modulus (psi)	$0.30\ (10)^6$
D. Formation Pressure (psi)	600*

II. Materials

Gel:hydroxyethylcellulose

Fluid Loss Additive: silica flour

Proppant: Ottawa sand, 20-40 mesh

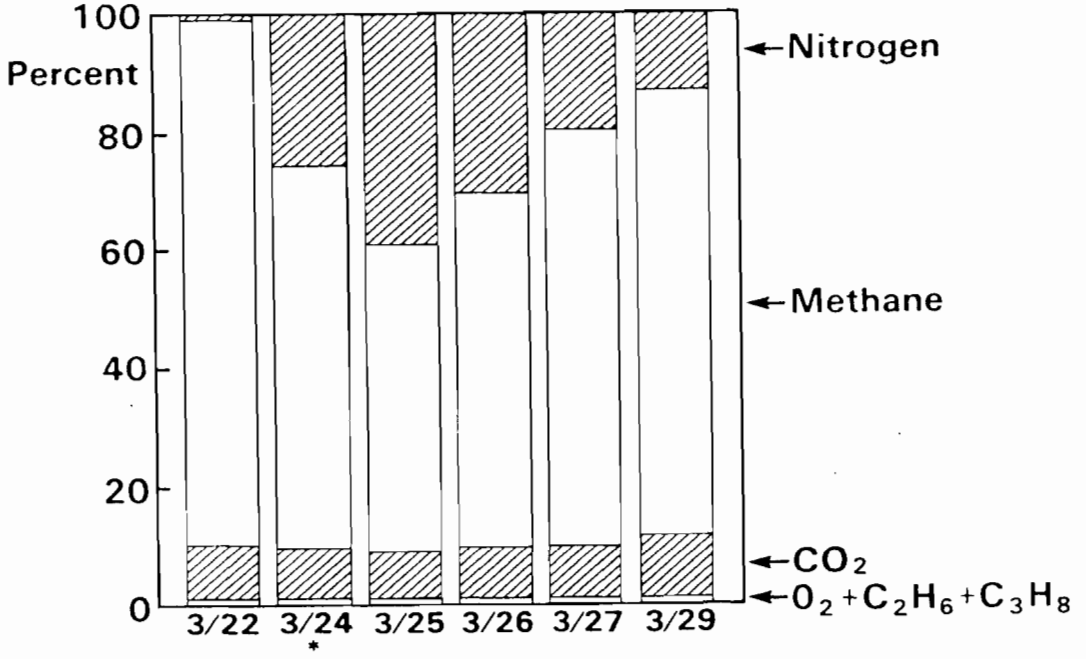
III. Treatment	Design	Actual
A. Volume		
1. Total (BBLS)	500	494
2. Pad (BBLS)	105	104
3. Flush (BBLS)	15	17
B. Concentrations		
1. Gel (lb/1000 gal)	10	10
2. Fluid loss additive (lb/1000 gal)	30	30
3. Proppant (lb/gal)	0.75	0.76
C. Rate		
1. Pad (BBLS/min)	**	15
2. Treatment (BBLS/min)	13	13
3. Flush (BBLS/min)	15	14
D. Maximum Surface Pressure (psi)	2,500	1,903

*It was later learned that a seam pressure of 168 PSIG had been extrapolated from drill stem test data on one of the Bureau wells (Ref. 2)

**Rate required to yield surface pressure of 1500 psi.

Figure 5

L-5 Gas Composition



*Offset Well (L-6) Hydraulically Stimulated

Table II L-5 Gas Composition

Date	3/22	3/24*	3/25	3/26	3/27	3/29
Methane	89.62	65.06	52.00	60.41	70.35	75.88
Ethane	0.10	0.09	0.05	0.08	0.10	0.10
Propane	0.01	0.01	—	0.01	0.01	0.01
Carbon Dioxide	9.96	9.55	9.00	9.40	9.55	10.80
Nitrogen	0.28	25.07	38.93	30.07	19.94	13.11
Oxygen	0.03	0.22	0.02	0.03	0.05	0.10
Total	100.00	100.00	100.00	100.00	100.00	100.00

*Hydraulic stimulation performed on offset well (L-6) located 475 feet to North.

Figure 6

Methane Production Summary
7-North Loveridge Mine January—June 1976

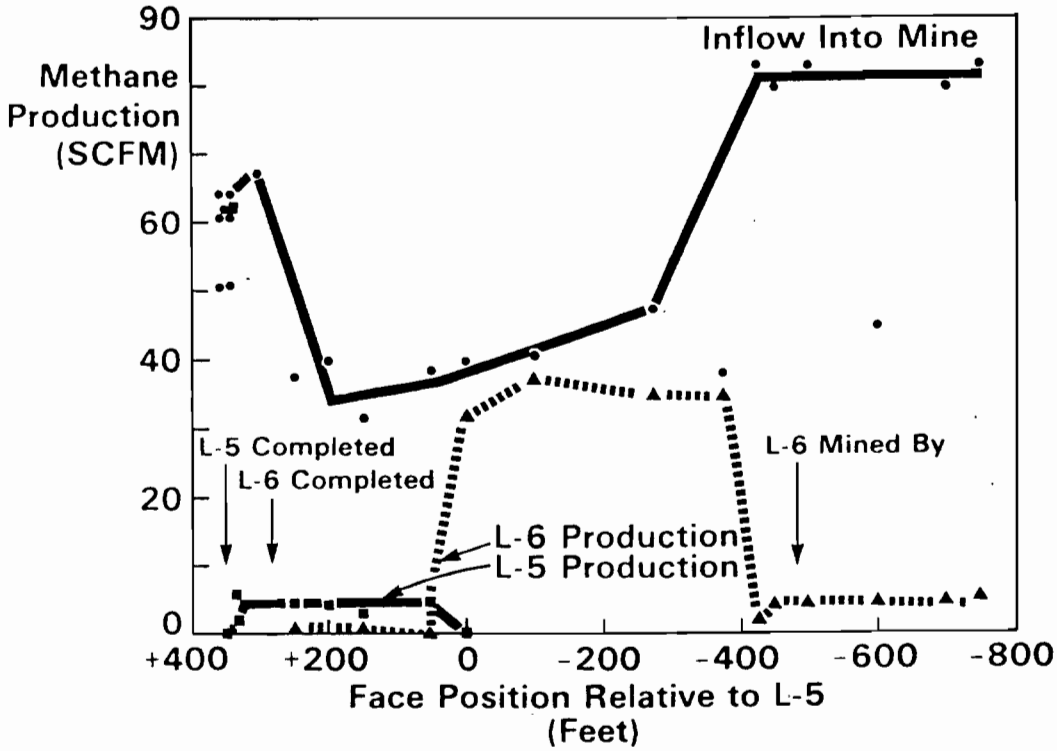


Table III Methane Production Summary 7-North Loveridge Mine

Date	Face Position* (Feet)	Right Regulator (SCFM)	L-5 (SCFM)	L-6 (SCFM)
1/30	+350	61	0	0
2/6	+350	51	0	0
2/13	+350	51	0	0
2/20	+350	64	0	0
2/25		L-5 Completed		
2/27	+350	61	0	0
3/5	+350	62	2	0
3/12	+325	64	6	0
3/19	+300	37	0	0
3/24		L-6 Completed		
3/26	+250	38	4	1
3/31	+200	40	4	2
4/9	+150	31	3	1
4/16	+50	39	5	0
4/23	0	40	0	32
4/30	-100	39	0	37
5/7	-275	48	0	35
5/14	-375	38	0	35
5/21	-425	83	0	1
5/28	-450	80	0	2
6/4	-500	83	0	2
6/11	-600	45	0	2
6/18	-700	80	0	2
6/25	-750	83	0	2

L-5, L-6 spacing = 475 feet
(L-6 mined by when face position = -475)

*Referenced to L-5

Figure 8

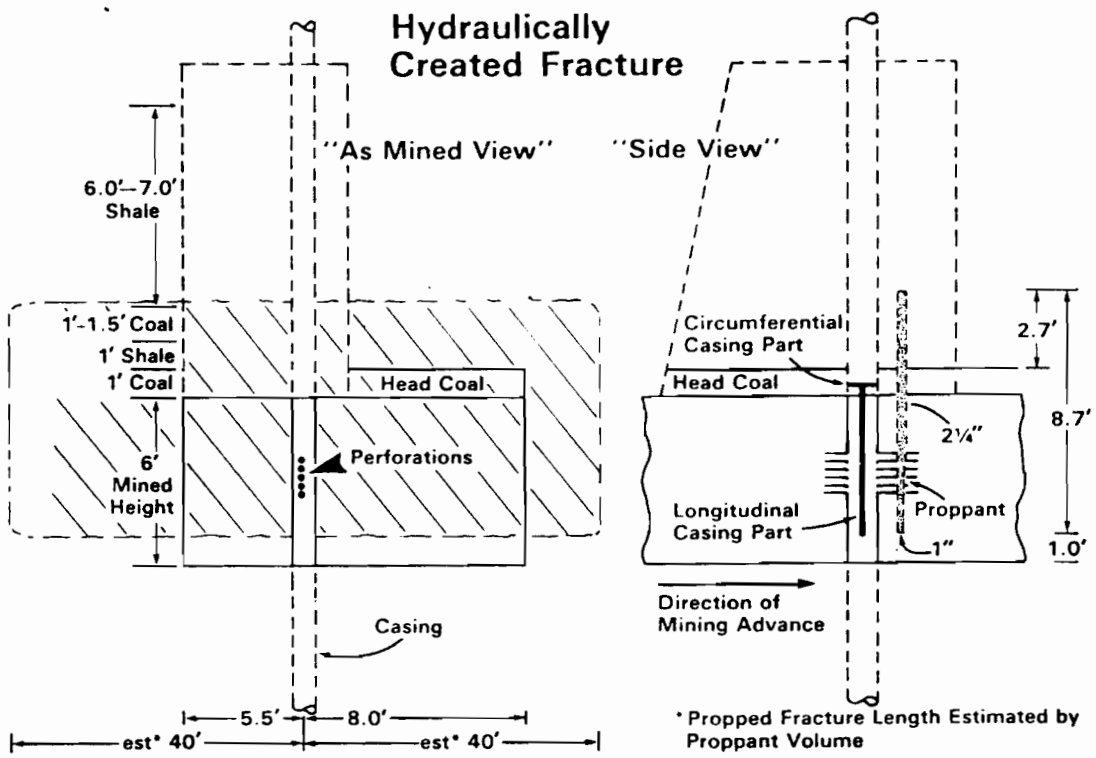
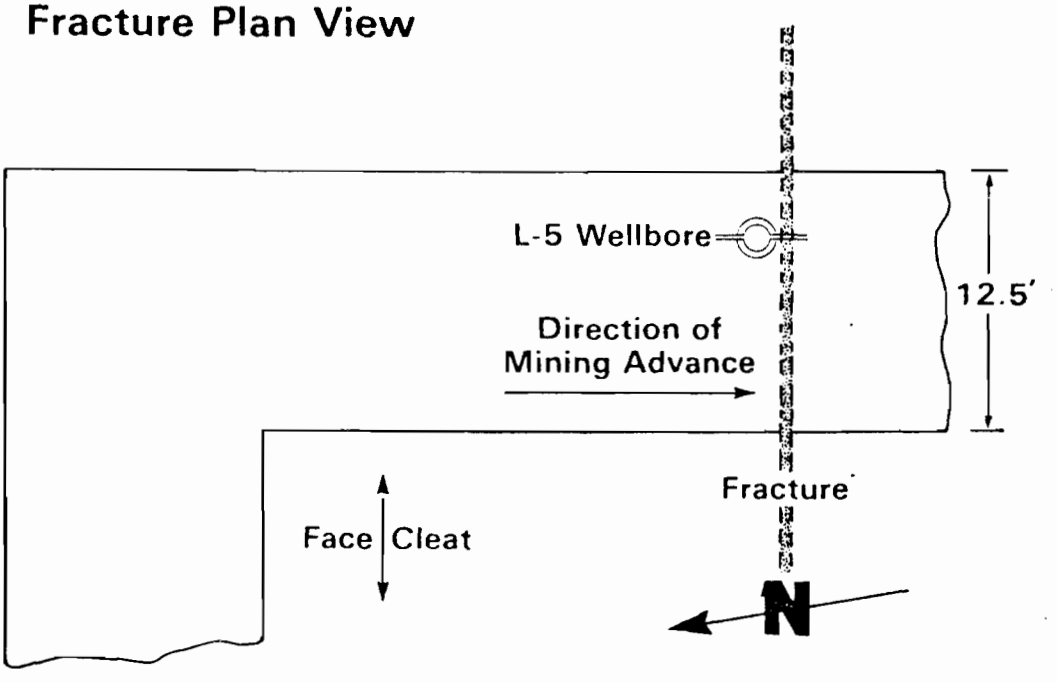

Hydraulically
Created Fracture
"As Mined View"
"Side View"
6.0'–7.0'
Shale
1'-1.5' Coal
1' Shale
1' Coal
Head Coal
6'
Mined
Height
Perforations
Casing
5.5'
8.0'
est* 40'
est* 40'
Circumferential
Casing Part
Head Coal
2.7'
8.7'
2¼"
Longitudinal
Casing Part
Proppant
1"
1.0'
Direction of
Mining Advance
* Propped Fracture Length Estimated by
Proppant Volume

Figure 7

Hydraulically Created Fracture Plan View



DIRECTIONAL DRILLING FOR COALBED DEGASIFICATION IN ADVANCE OF MINING

by

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ABOUT THE AUTHORS

William P. Diamond received his Bachelors Degree in Geology from the University of Kentucky in 1968. Prior to entering graduate school, he worked for the Kentucky Geological Survey, Water Resources Section. A Masters Degree in Geology was earned at the University of Kentucky in 1974, and he went to work for the Chevron Oil Company, New Orleans, Louisiana as a production geologist. In 1973, he joined the U.S. Bureau of Mines as a geologist in the Pittsburgh Mining and Safety Research Center, Pittsburgh, Pennsylvania. His present position is that of Supervisory Geologist in the Methane and Mining Environmental Control Group. Areas of research responsibility include the investigation of geologic factors which influence the migration and storage of gas in coal measures, and managing directional and vertical drilling programs to degasify coalbeds in advance of mining.

David C. Oyler graduated from the University of Pittsburgh in 1972 with a BS Degree in Physics. From 1972 through 1974, he was employed by Schlumberger Well Services in south Texas as a Cased Hole Service Engineer. In 1975, he began working at the U.S. Bureau of Mines, Bruceton Research Center, as a General Engineer. He has worked primarily on directional drilling for coalbed degasification. Since 1977, he has also been Project Leader on the Multipurpose Borehole Degasification Project.

DIRECTIONAL DRILLING FOR COALBED DEGASIFICATION IN ADVANCE OF MINING

ABSTRACT

The U.S. Bureau of Mines has conducted research in directional drilling for degasification in advance of mining since 1973. This technique is designed to combine the highly successful underground horizontal degasification drilling technology with surface drilling methods. The use of directional drilling techniques will be particularly useful in areas where access to gassy coalbeds is not possible underground, and where topography makes multiple sites for vertical degasification holes impractical or prohibitively expensive.

Previous research in this program has been conducted by the Bureau of Mines at sites near Jollytown and Mather, Pa. Currently a directional degasification project funded by the Department of Energy, with the U.S. Bureau of Mines providing research planning and technical management, is underway at the Emerald Mine, near Waynesburg, Pa. The Emerald Mine directional hole is designed to start from the vertical and enter the Pittsburgh coalbed horizontally at a vertical depth of approximately 1,000 feet.

The drilling program includes a 3-inch diameter pilot hole to be drilled to the coalbed with a downhole motor and later reamed to 8-3/4 inches for 5-1/2-inch OD casing. Three individual 3-inch diameter 3,000-foot horizontal gas collection holes will be drilled into the coalbed in a "bird foot" pattern. Previous experience has shown the need for determining the thickness and coalbed elevation at the anticipated coalbed intercept, and the general attitude of the coalbed in the area to be drilled. It has also been determined that dewatering of the coalbed, which is essential for degasification, cannot be effectively accomplished using currently available pumping equipment operated in a horizontal position. To obtain the required specific geological data, a corehole has been drilled at the anticipated coalbed intercept. A vertical hole has been drilled at the same location for dewatering the coalbed. Seven vertical holes for monitoring the progress and effectiveness of coalbed degasification have been drilled within the horizontal drilling area.

INTRODUCTION

For many years the Bureau of Mines has conducted a program of research in coalbed degasification. This program has evolved to include degasification through the use of horizontal holes drilled underground either in mines or from shaft bottoms (3,4,5), and surface vertical boreholes using modified oilfield technology (8,9,11). Horizontal holes were found to have the advantages of relatively low drilling costs and the ability to interconnect the coalbed cleat or fracture system thus increasing permeability to gas flow. However, this drilling required underground access and facilities which often interfered with the mining cycle. The requirement of access to the coal occasionally limited the value of the horizontal degasification holes due to the limited time and/or distance they could be drilled ahead of mining. Hydraulically stimulated vertical holes eliminated the latter problems, but had the disadvantages of requiring large numbers of surface sites, higher costs, and production and maintenance problems.

The concept of directionally drilled degasification holes was originally considered by the Bureau of Mines as a means of combining the above techniques to best advantage. From a single surface site, a vertical or near vertical well could be progressively deviated to intersect a coalbed horizontally (fig. 1). Several horizontal gas collection holes could then be sidetracked from the original well path in the coalbed. It would also be possible to orient the drill rig in several other directions on the same surface site, and drill a succession of directional degasification holes (fig. 2). The cost of site preparation and production facilities would be significantly reduced by having the entire gas flow from a large degasification area centralized at one location.

HISTORICAL DEVELOPMENT

The Bureau of Mines drilled the first directional hole into a coalbed in 1973 on the property of Consolidation Coal Company's Blacksville No. 2 Mine near Jollytown, Pa. The 3-inch hole was started at a 20° angle at the surface and intercepted the Pittsburgh coalbed at a vertical depth of 776 feet. The actual drilled distance along the circular arc to the coalbed intercept was approximately 1,310 feet.

The original hole was drilled using a Joy[1/] drill rig, BQ wire line rod, and a 1-3/4-inch Dyna-Drill[1/] tool for the directional control. The Dyna-Drill tool (fig. 3) is essentially a positive displacement mud motor encased in a housing and attached to a drill bit. The drill bit is driven by the down-hole motor without drill pipe rotation. Because the drill pipe does not turn it is possible to orient the drill pipe and the attached Dyna-Drill tool to control the direction of penetration. The amount of deviation achieved by the Dyna-Drill can be varied by using either interchangeable bent sub or housings of various angles. Bent housings of 30 and 45 minutes have been used on the directional holes drilled by the Bureau of Mines. The higher the sub or housing angle, the greater the amount of deviation. A standoff ring also can be incorporated as part of the tool above the bent assemblies to hold the tool slightly off bottom on the low side and thereby increase the penetration angle. Control of azimuth is obtained by turning the bend in the bent housing to the left or right.

Horizontal drilling in the coalbed at Jollytown reached 414 feet. At this depth it became impossible to pull the drill string and a decision was made to establish production by "perforating" the 414 feet of pipe in the coalbed. The efficient production of gas from coalbeds is dependent upon several factors, including dewatering of the coal. Gas flow rates as high as 25 to 30 Mcfd were reported immediately after swabbing the hole to remove water. A rapid influx of formation water killed the gas flow within 15 to 20 minutes. A down-hole sucker rod pump was installed at a depth of 1,310 feet for continuous production of water. The waterflow rate began at 14 barrels per day and declined to 7 barrels per day after several weeks. Gas production during this testing phase ranged from 1,200 to 3,800 cfd.

The BQ rod in the Jollytown hole was overreamed to a depth of approximately 1,000 feet and the old pipe removed. A string of 4-1/2-inch casing was then installed to allow the use of larger down-hole pumps and provide a less restricted gas flow. Two additional holes were also drilled into the coalbed from the bottom of the casing. The maximum horizontal penetration of the coalbed by these holes was approximately 400 feet due to the low pulling capacity of the rig. Shortly after this phase of drilling, the coal company began construction of a holding pond adjacent to the drill site, necessitating a shutdown of further research activities for approximately 2 years.

The Jollytown hole was cleaned out in early 1976 and a down-hole sucker rod pump was installed at a depth of 1,410 feet. Initial water production was 3-1/2 barrels per day declining to less than 1/2 barrel per day in approximately 2 months. The "water" produced was in many instances a black muddy sludge. Gas production varied from less than 1,000 cfd up to 3,100 cfd. Various remedies, including moving the pump progressively up the hole to position it in less horizontal attitudes, failed to improve the production of water and gas. The hole was abandoned in late 1976.

The Jollytown hole proved that a directional well path could be started near vertical at the surface and controlled to intercept a specific small target in a comparatively short vertical distance. The experience in attempting to establish production through the slant hole indicated that conventional sucker rod water pumping equipment would not function properly in a horizontal attitude and that other methods of dewatering would be needed. The problem of keeping the hole and pump free from particulate matter was thought to be a result of the casing being set too high, leaving approximately 300 feet of open hole exposed between the bottom of casing and the top of the coalbed.

In the fall of 1975, the Bureau of Mines began a second directional drilling project (1). This hole, at Mather, Pa., was to degasify the Upper Freeport coalbed in advance of mining. Due to the problem of pulling pipe at the Jollytown site, a larger drill rig with greater pulling capacity was used. The rig was completely hydraulic to aid in providing a smooth feed of drill pipe while using the Dyna-Drill. A newly developed 2-3/8-inch Dyna-Drill was used in place of the 1-3/4-inch tool used at Jollytown.

The general drilling plan included a 3-inch diameter pilot hole drilled on a 1,500-foot well path to intersect the coalbed at a vertical depth of 930 feet (fig. 1). After the intercept of the coalbed, the hole was to be reamed to 8-3/4-inches and 5-1/2-inch casing installed. Three horizontal gas collection holes up to 3,500 feet in length were then to be drilled into the coalbed.

1/ Reference to specific equipment or manufacturers does not imply endorsement by the Bureau of Mines.

DIRECTIONAL DRILLING FOR COALBED DEGASIFICATION IN ADVANCE OF MINING

The pilot hole was completed to the coalbed intercept point, but not without many difficulties. Most of the problems encountered could be placed in two categories, mechanical and directional control. Mechanical problems included rig, Dyna-Drill and mud pump breakdowns. Problems in maintaining the proper well path required 3 plug backs and redrilling prior to the first intercept of the coalbed.

The first penetration of the Upper Freeport horizon at Mather encountered only 0.5 feet of coal. Approximately 1,500 feet of exploratory horizontal drilling after the initial coalbed intercept and 5 additional penetrations of the coalbed horizon could not locate sufficient continuous thickness of coal to continue the project. Seven coreholes within the near vicinity of the drill site indicated 5.9 to 8.5 feet of Upper Freeport coal. The first penetration of the coalbed was only 750 feet from a corehole which indicated 6.75 feet of coal.

The Mather project confirmed the feasibility of drilling a directional hole to a predetermined target. The 2-3/8-inch Dyna-Drill was developed into a useable tool, and considerable experience was gained in directional control of the hole, especially in the horizontal phase of the drilling. The project also suggested the need for more complete geologic evaluation of drill sites, to include the drilling of a corehole at the proposed initial coalbed intercept. The corehole would confirm the thickness and exact evaluation of the coal for accurate drill path projections.

CURRENT DIRECTIONAL DRILLING RESEARCH

Immediately after termination of the Mather project in 1976, a search began for a new site. In the fall of 1978, a directional degasification drilling project into the Pittsburgh coalbed began at the Emerald Mine near Waynesburg, Pa. The site was chosen based on several factors including an indication of sufficient coalbed gas to warrant degasification, adequate overburden to utilize the directional drilling technique, and the relatively consistent Pittsburgh coalbed as a target. The Emerald Mine had also been the site of a vertical degasification project which will provide an excellent comparison for the directional degasification drilling concept.

The major objective of the Bureau of Mines in conducting the Emerald Mine project was to demonstrate that directional drilling can be used as a technique for degasification of coalbeds in advance of mining to increase coal mine safety. When the project was transferred to the Department of Energy's Division of Fossil Fuel Extraction, increased emphasis was placed on the analysis of the mechanics under which a coalbed behaves as a gas reservoir. Seven vertical monitoring holes (EM 21-27, fig. 4) were added to the drilling program to investigate the coalbed reservoir mechanics.

Specific objectives of the project are to improve the techniques (and hence lower the cost) of directional drilling, and to determine the actual limit of horizontal drilling with the system presently in use. The economics of the system will largely depend upon the total horizontal footage that can be drilled into the coalbed and the associated area of coal that can be degasified. Experience from U.S. Bureau of Mines horizontal drilling in the Pittsburgh coalbed (2,3,4,5) indicates that a production rate of approximately 125 cubic feet of methane/day/linear foot of hole can be achieved and maintained for a period of several years. If the total 9,000 feet of horizontal drilling is achieved, there is a potential of removing approximately 1 MMcf of methane per day prior to the mining of the coal. The removal of gas from the Pittsburgh coalbed at the previously observed rates has been shown to provide significant relief from the influx of gas into a working section (2,3).

DRILLING PROGRAM AT EMERALD MINE

Directional Hole

A 3-inch diameter pilot hole has been drilled on a circular arc starting vertically at the surface and intercepting the Pittsburgh coalbed at a vertical depth of 993 feet (fig. 5). The hole was drilled using a 2-3/8-inch Dyna-Drill, with a 3-inch diameter Christensen[1/] drill bit constructed of whole stone drill bortz (diamonds) and General Electric Strata Pax.[1/] This relatively new bit design provided excellent service and penetration rates.

The mud system used was a low solids, polymer mud. Two types of polymer are used, one to prevent fluid loss and the other type to provide gel strength and aid in removal of drill cuttings. This system, used throughout all drilling on the Mather hole, kept the hole open without problem for 4 months.

Directional surveying of the pilot hole and Dyna-Drill orienting was performed using Eastman Whipstock[1/] magnetic singleshot equipment and a muleshoe orienting sub. Non-magnetic stainless steel Dyna-Drills and 80 feet of stainless steel drill rod were used to minimize the effects of the drill string on azimuth readings. Surveying was normally done every 10 feet (each joint). Survey calculations were made using both angle averaging and radius of curvature methods. Frequent well projections were made to insure that the actual well path did not deviate too far from that required to intercept the coalbed horizontally.

Major problems encountered in the pilot hole drilling phase of the project included mud pump mechanical malfunctions and lost circulation zones in the upper 200 feet of drilling. Even with these delays, the well path to the coalbed was completed on schedule in 31 working days.

Prior to starting the horizontal portion of the drilling, the pilot hole was reamed to a diameter of 8-3/4 inches. The reaming operation was accomplished using 8-3/4-inch diameter Strata Pax and conventional diamond reaming shoes run over the BQ wire line rod which was left in the hole as a guide. The slant hole was cased with 5-1/2-inch OD casing to a point approximately 1,585 feet into the coalbed. The bottom of casing is approximately 90 feet horizontally from the dewatering hole.

The horizontal portion of the drilling is to include three 3-inch diameter holes (H1-H3, fig. 4), each planned to reach a horizontal extent of 3,000 feet. These holes will be drilled with the same Dyna-Drill and bit design used on the pilot hole. The only significant change in the drilling system will be the use of clean water for drilling in the coal. The use of the same drilling mud that was used in the pilot hole would perhaps cause formation damage by infiltrating the coal cleat (fracture) system, thereby plugging the permeability.

The surface facility of the completed hole will include a wellhead for servicing the well, gas flow measuring equipment, water separator, flare stack, flame arrestor, and gasline shut-off valves. All of the equipment will be installed in a protective wellhouse.

Core and Dewater Holes

Prior to beginning drilling on the directional hole, a core hole (EM-78-1, fig. 4) was drilled near the anticipated coalbed intercept. The core hole was used to confirm the presence, thickness, and elevation of the coalbed, and to provide stratigraphic information for correlation to the directional hole. Samples of the Washington, Waynesburg, Sewickley, and Pittsburgh coalbeds were obtained for gas content evaluation by the direct method (7,10). A stratigraphic column of this core hole is shown in figure 5.

Experience at the Jollytown site indicated that conventional water pumping equipment will not function properly in a horizontal position. The efficient production of gas from coalbeds is dependent upon the dewatering of the coal. In light of the problems experienced in pumping water from the Jollytown directional hole, a vertical dewatering hole (EM-20, fig. 4) has been drilled near the anticipated intercept of the coalbed and adjacent to the core hole (EM-78-1). The dewatering hole was to be a "straight" hole, however a multishot directional survey of the hole revealed that the well path deviated approximately 60 feet to the northwest. The deviation probably occurred because the drill pipe was not adequately stabilized; it is not considered to be severe enough to cause any problems.

The dewatering hole was cased with 7-inch OD casing to a depth of 114 feet below the bottom of the Pittsburgh coalbed. Communication between the cased hole and the coalbed was accomplished by "slotting" with a Dowell Abrasijet[1/] tool. This procedure uses a high pressure jet of water and sand to abrade the casing, cement and formation to a potential depth of about 12 inches. A 4-port tool and a treatment of 36,000 gallons of water and 30,000 pounds of sand at pressures ranging from 2,400 to 3,000 psi was used on this hole. Total slotting time was 2.8 hours, during which a 5.2-foot zone in the Pittsburgh coalbed was treated. Theoretically, four slots, 90° apart and perhaps 0.25 to 0.75 inches wide were cut through the casing and into the coalbed.

After the directional hole was cased, the dewatering hole was stimulated using foam and sand. This procedure is designed to increase the permeability around the dewatering hole, and hopefully provide a direct link between it and the directional hole. The dewatering process is not scheduled to actually begin until the horizontal drilling portion of the project is completed. The dewatering process is to begin late in the project because of the increased potential for plugging the coalbed's permeability by the drilling fluid and cuttings, if the coalbed has been dewatered prior to the horizontal drilling.

DIRECTIONAL DRILLING FOR COALBED DEGASIFICATION IN ADVANCE OF MINING

Since the dewatering hole should behave as a conventional vertical degasification well and produce gas as dewatering proceeds, it has been engineered to both produce and monitor gas as well as water. The surface facility (fig. 6) will include a flare stack with a flame arrestor to safely vent gas and a protective enclosure for the wellhead equipment. A 40- by 15- by 4-foot deep holding pond will be located near the hole for disposal and required treatment of the produced water.

Vertical Monitoring Holes

Seven vertical boreholes have been drilled to the Pittsburgh coalbed in the area to be degasified by the directional hole. These holes (EM-21 through 27, fig. 4) will be used primarily to monitor the coalbed formation pressures by observing changes in water level in each hole. A lowering of the water column height in a hole will indicate the loss of formation pressure caused by removal of water and gas from the dewatering and directional holes. Having a number of holes equipped with continuous recording water level devices spaced throughout the horizontal drilling pattern will allow both the degree and areal extent of degasification to be monitored. The holes will also be completed for the production and measurement of gas and waterflows. This will allow short periods of production to conduct formation evaluation tests. The holes can also be used for general coalbed dewatering should the prime dewatering hole prove inadequate. Since any long term production from these holes would make it difficult to determine the effectiveness of the directional hole and fluid levels cannot be used to determine formation pressures in producing holes, it will not be desirable to use these holes for production.

Each monitoring hole will be completed open-hole and "jetted" using the same equipment that was used to "slot" the casing in the dewatering hole. This technique performed in the open hole will remove the coal exposed to drilling fluids helping to minimize loss of permeability caused by plugging of the fracture system (cleat) near the well bore. Each monitor hole will be completed with surface equipment similar to that in the dewatering hole (fig. 6), and in addition, a water level sensing device with a continuous data recorder will be installed on each hole. The holes will probably not be hydraulically stimulated unless they are eventually used for sustained gas and/or water production.

FUTURE DIRECTIONAL DRILLING RESEARCH

Bureau of Mines directional drilling research for degasification of coalbeds in advance of mining will primarily be concerned in the immediate future with the feasibility of drilling "hard" formations and deeper coalbeds. These studies will focus on matching drilling equipment to the specific geologic conditions expected. The possibility of using the directional drilling technique for draining gas from roof strata over coalbeds to be longwall-mined is also under consideration.

Since directional drilling techniques were first adapted for degasification of coalbeds, numerous suggestions have been offered on the "best" way to accomplish the desired result. The most frequent suggestion has been to use larger drilling equipment, thereby eliminating the need to ream the directional hole to a larger size. In theory, this suggestion is attractive, especially when coupled to the lure of increased drilling rates, which it is claimed, would offset the increased cost of the larger equipment.

Consideration was given to drilling larger holes. Several factors made them unattractive for the Emerald Mine project specifically, and future projects in general. These factors include (1) previous encouraging results at Mather and Jollytown with the smaller equipment, (2) a large investment in Government-owned equipment for drilling and reaming a 3-inch pilot hole, (3) the general experience that drilling is very unpredictable and that any delays with the more expensive equipment would quickly reduce the cost effectiveness, and (4) the fact that an economical method using smaller equipment would be more attractive to coal companies and the small drilling contractors likely to do the work.

Another frequent suggestion is to begin the deviated hole at an angle less than vertical at the surface, perhaps as much as 45° or 60° off vertical (fig. 7). The primary benefit inferred with this drilling program is that a significant portion of the drill path could be drilled with traditional rotary straight-hole techniques. The downhole motor would only be used on the lower portion of the hole to control the drill path into the coalbed horizontally. It is assumed that the rotary straight-hole drilling would be faster and cheaper, since a downhole motor would not be used. This perhaps would be true if no significant problems were encountered in the rotary drilling phase. But, as mentioned earlier, problem-free drilling is seldom a reality, especially on "unconventional" holes.

Several problems with drill paths starting at an angle substantially less than vertical immediately present themselves. A rig capable of drilling and handling pipe at the chosen initial penetration angle is required. Maintaining the proper inclined straight well path during the rotary drilling phase is critical and perhaps more difficult than when using a downhole motor on the circular arc drilling phase. Gravity would be continually acting on the drill string during rotary drilling, tending to pull the bit down and off the proper well path. To counteract the effects of gravity, drill string stabilizers and perhaps even various bit designs and variable thrust would be required. If the proper combinations of the above factors are not determined early in the drilling, plug backs and even course corrections using a downhole motor may be necessary. The need to maintain the proper well path, even during the rotary drilling phase, will require frequent directional surveys, just as when building angle with a downhole motor. Thus there will be no significant time and equipment savings for surveying.

Rotary drilling requires the use of force on the bit, supplied by the weight of the drill string and the "pull down" capacity of the rig. The pressure on the rotary drill string can force the pipe against the wall of the hole, abrading a slot (keyseat), especially where the hole is "dog legged." When the drill string is pulled, the bit will tend to hangup in the keyseat, since it is larger in diameter than the drill pipe and the abraded slot. Damage to the hole and the drill string, extra expenditures for corrective action, as well as the potential for the eventual abandonment of the hole are all possible results of keyseating. The possibility of this problem will increase with the increasing sinuosity of the hole, again pointing out the need for maintaining the proper well path.

The potential problems of a directional hole with an inclined initial well path do not end with the successful completion of the drilling phase. All servicing of the hole will have to be through an inclined wellhead, probably requiring a specially built or modified service rig.

It has been supposed that by having an inclined initial well path, that the total drilled distance to a specific target would be less. In fact, as table 1 indicates, the greater the divergence from vertical of the initial well path, the longer the total drilled distance. At a 45° surface angle, the total distance drilled is 14 percent greater than for a circular arc, and at 60° the length is 44 percent greater.

TABLE 1. - Drilling distances of various surface penetration angles

Surface angle, θs	Vertical distance to target, TVD	Drilled distance, feet		Total distance to be drilled, feet	Additional drilled distance, percent
		Straight hole	Circular arc		
0	1,000	0	1,571	1,571	-
20	do	364	1,222	1,586	1.0
30	do	577	1,048	1,625	3.5
45	do	1,000	785	1,785	14.0
60	do	1,732	524	2,256	44.0

Table 1 also indicates that as the surface angle increases, the proportion of straight hole to circular arc increases. This relationship would indicate a potential advantage, if the inclined straight hole could be drilled problem free, by reducing the use and cost of downhole motors.

Short radius drilling systems have been suggested as being applicable to the general concept of directional drilling for coalbed degasification. A short radius drilling plan would include a vertical hole rotary drilled to a point approximately 50 feet above the coalbed. A special short radius drill string, usually consisting of some type of jointed, flexible pipe, would then be used to make a tight curve from vertical to horizontal. The advantage of this system is the use of cheaper rotary drilling equipment for most of the drill path to the coalbed.

A major drawback to this idea is that most proposals include the use of drilling equipment which essentially does not exist outside of a patent application. A large investment in development cost and time would be required before a system would be ready for field testing. Most systems brought to the attention of the authors fall short of the requirement to drill at least 3,000 feet of controlled horizontal drilling. The systems are usually rated at significantly less than 3,000 feet of drilling. The general high cost of the flexible pipes makes a 3,000-foot drill string essentially unaffordable.

Other problems exist with short radius systems, primarily related to the extremely tight curve produced in going from vertical to horizontal in 50 vertical feet. Conventional drill pipe and casing will not bend around a curve of the suggested magnitude. Leaving an uncased hole above the coalbed would perhaps lead to similar problems, as experienced at the Bureau of Mines' Jollytown hole. The purveyors of most short-radius equipment cannot guarantee or sufficiently document that the drill string can be controlled adequately to follow a well path of limited deviation in the coalbed. The tightness of the curve will not allow the passage of currently available directional surveying equipment, which means that either the hole attitude and location could not be determined, or new surveying equipment would have to be developed. Very few coal companies would allow the drilling of unsurveyed holes in their coalbeds.

CONCLUSION

Directional drilling techniques have been shown by the Bureau of Mines to be capable of intersecting a predetermined target horizontally at depths of approximately 1,000 feet below the surface. These techniques have also been capable of drilling up to approximately 450 feet horizontally after intercepting the target horizon. Present and future Bureau of Mines research will be concerned with extending the horizontal drilled distance in the target horizon and obtaining the maximum methane drainage capability from the system under varying geologic and engineering conditions.

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FIGURE 1

SECTION VIEW OF MATHER SLANT HOLE WELL PATH

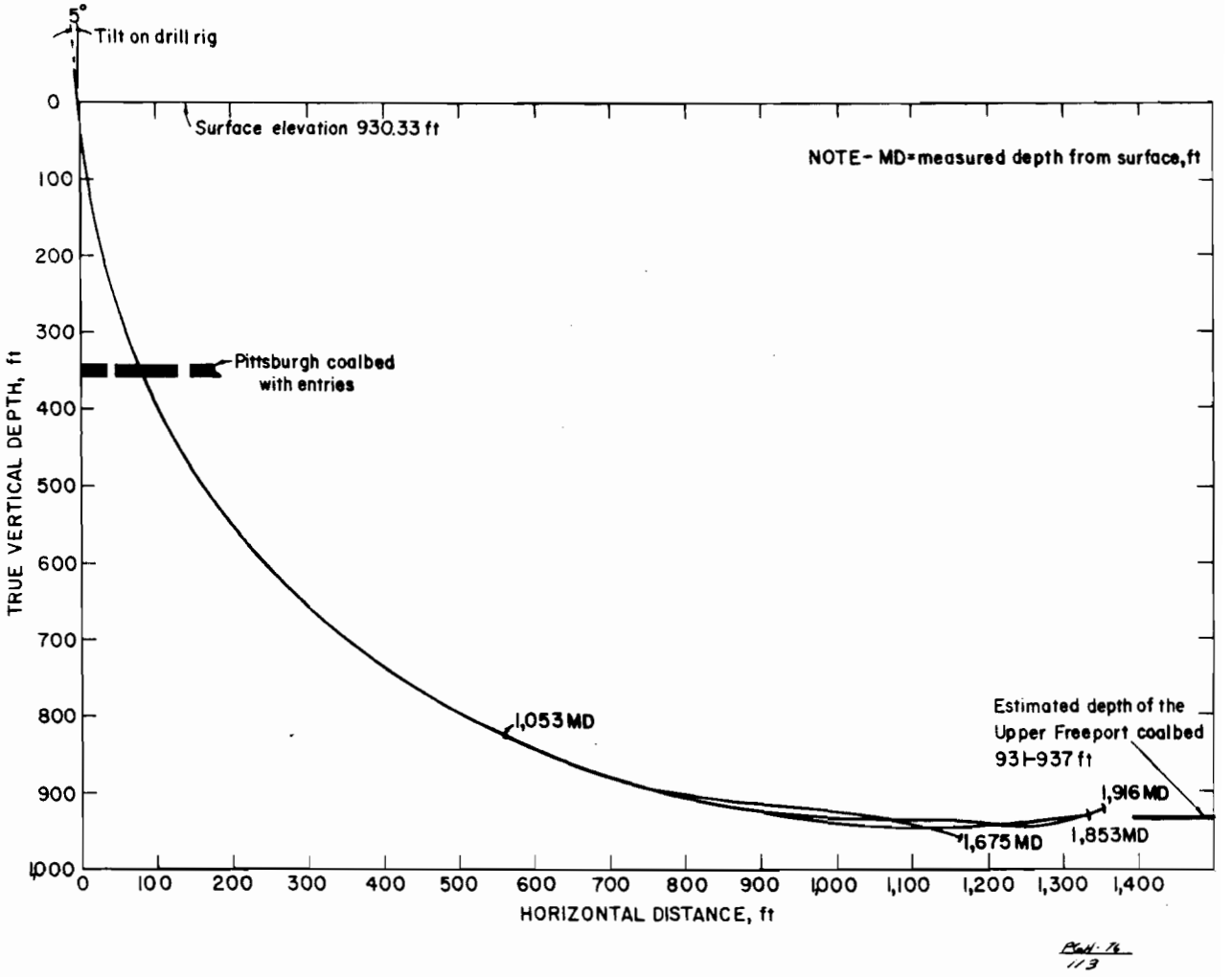
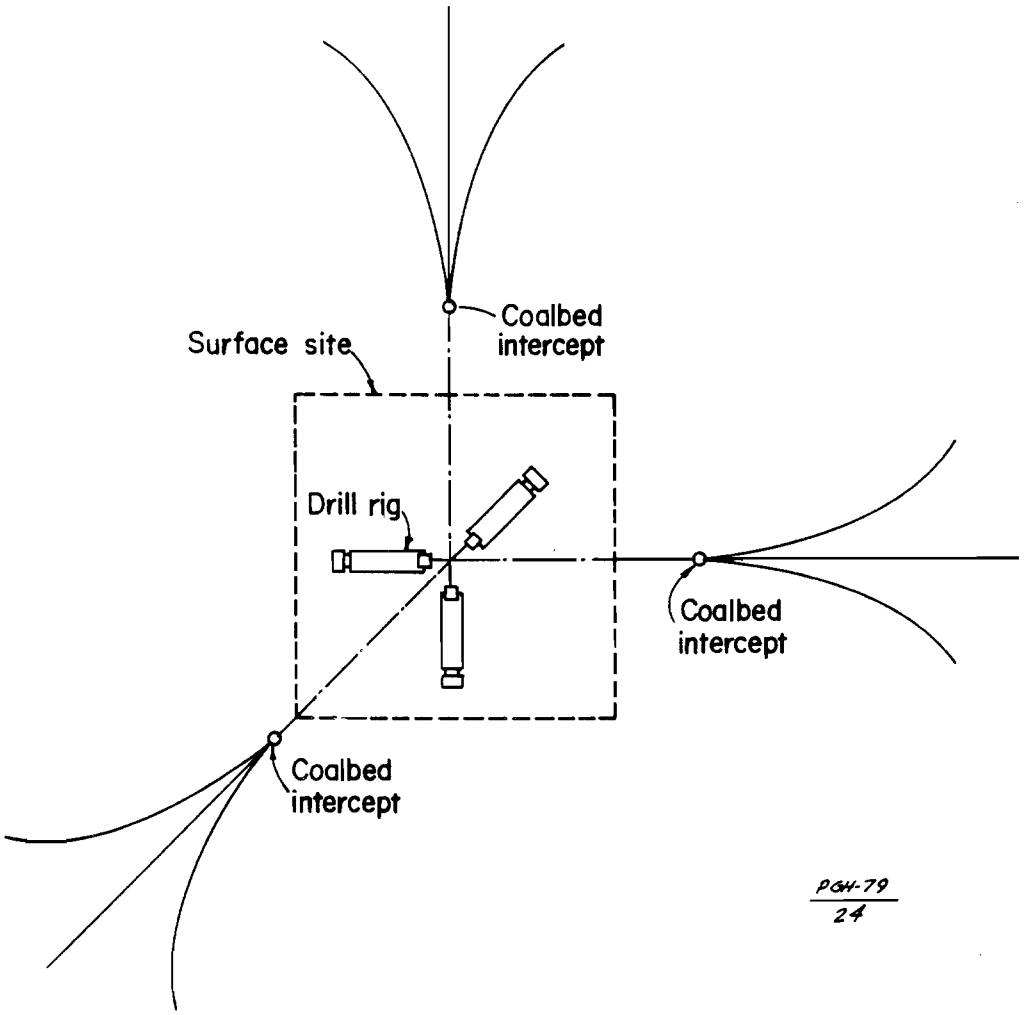


FIGURE 2

SCHEMATIC PLAN VIEW OF THEORETICAL MULTIPLE-WELL DIRECTIONAL DEGASIFICATION SYSTEM.



(not to scale)

FIGURE 3

DYNA-DRILL TOOL ASSEMBLY

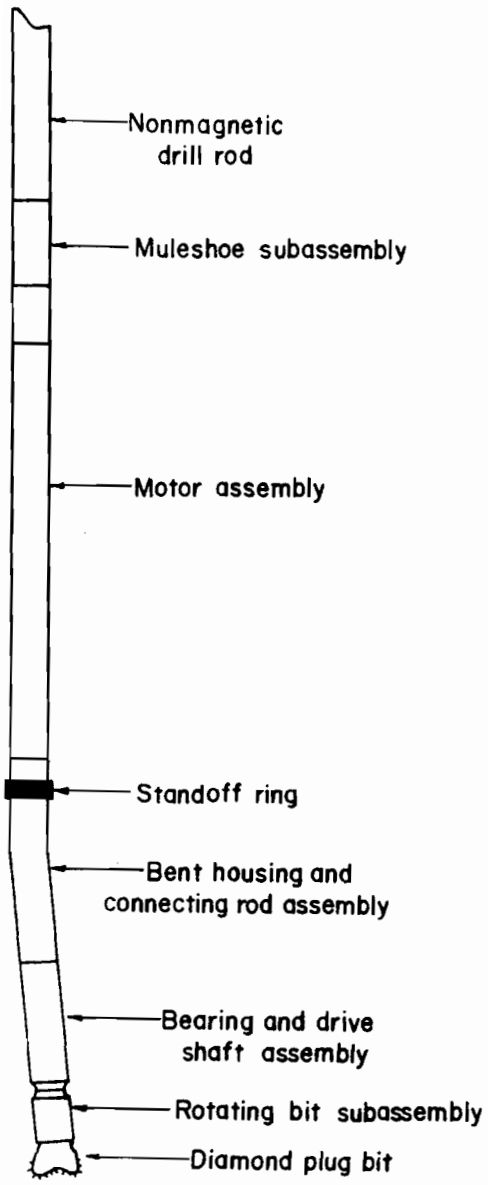


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FIGURE 4

PLAN VIEW OF DRILL SITES AND PROPOSED SLANT AND HORIZONTAL HOLE WELL PATHS

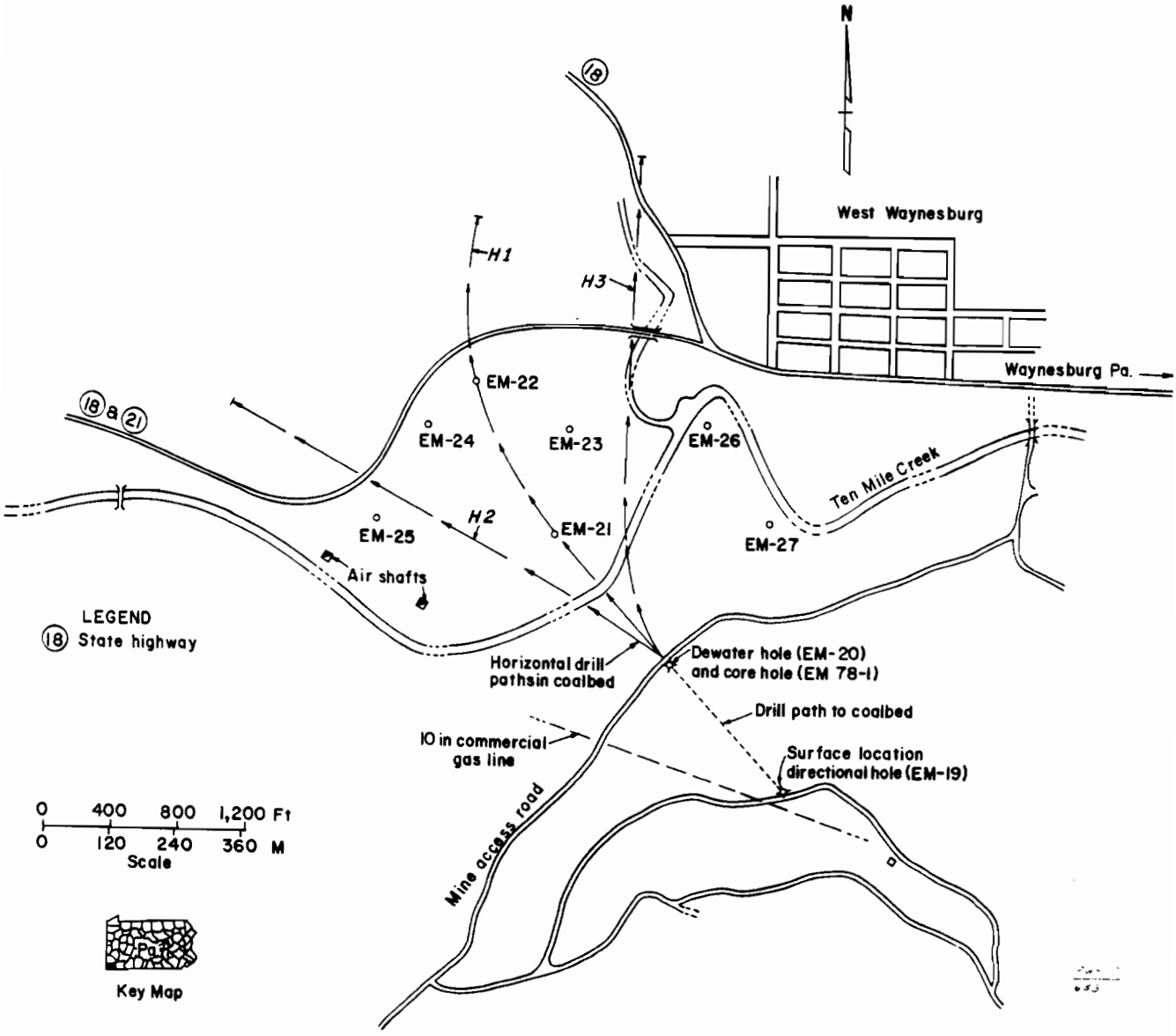


FIGURE 5

SECTION VIEW OF PROPOSED EMERALD MINE SLANT HOLE WELL PATH WITH GEOLOGIC COLUMN

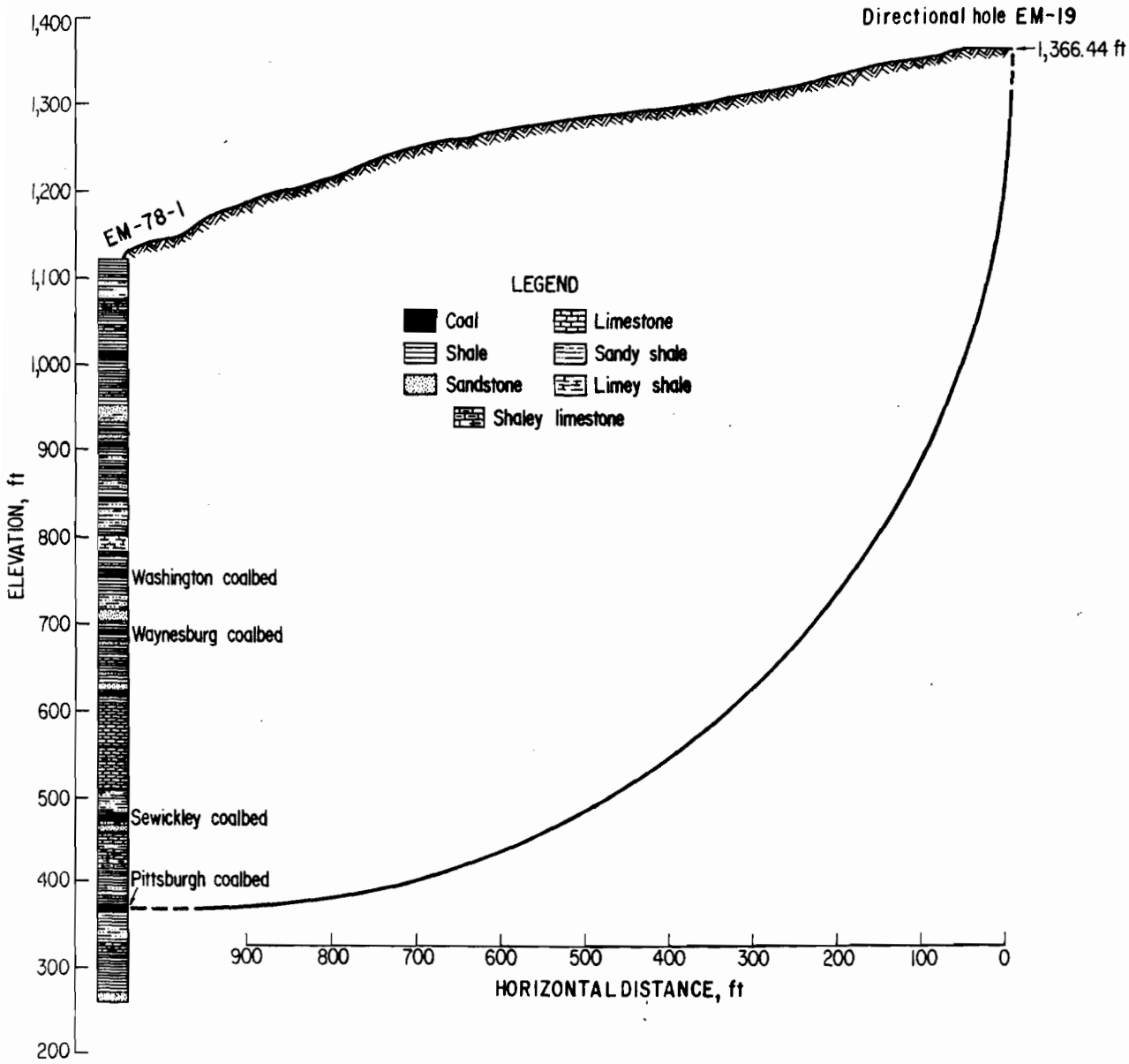
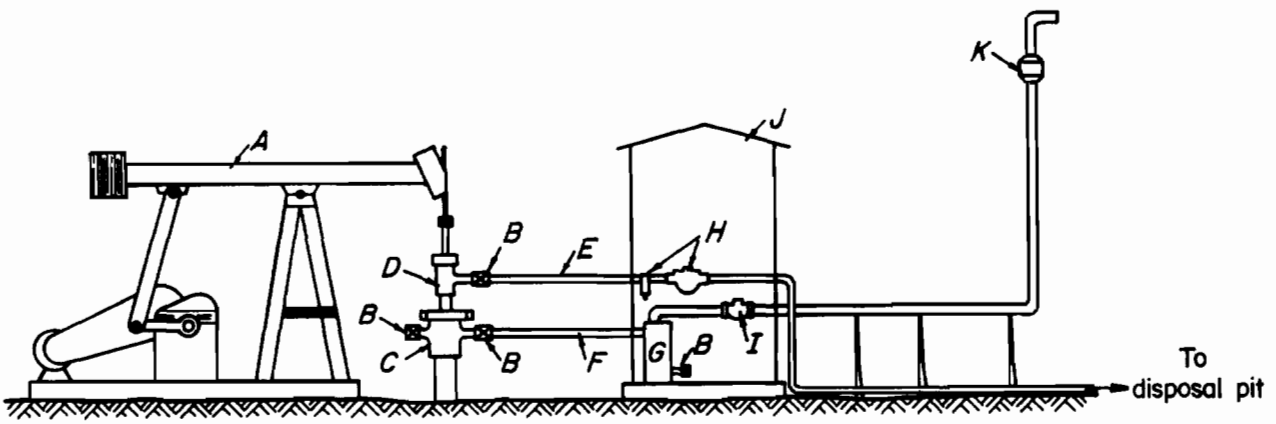


FIGURE 6

SCHEMATIC DIAGRAM OF PROPOSED SURFACE FACILITY AT DEWATERING HOLE



KEY

A Pumping unit	*G* Water separator tank
B Valves	*H* Filter and water meter
C Tubing head	*I* Gas meter
D Stuffing box	*J* Meter house
E Water line	*K* Flame arrestor and flare stack
F Gas line	

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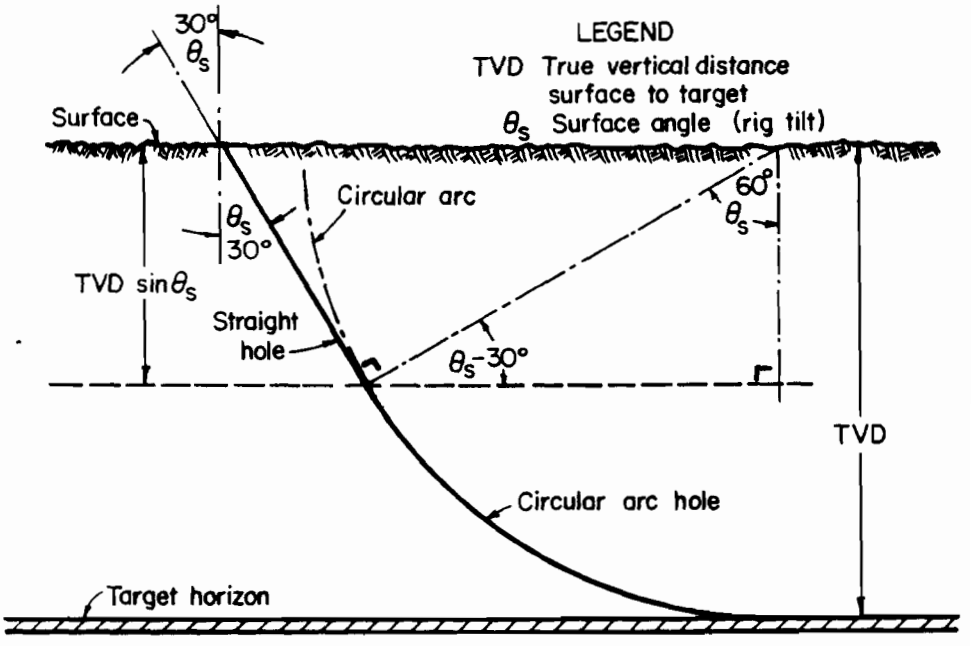
FIGURE 7

SECTION VIEW OF THEORETICAL INCLINED DIRECTIONAL WELL PATH



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METHANE DRAINAGE TURBODRILLS

BY

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METHANE DRAINAGE TURBODRILLS

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ABSTRACT

Maurer Engineering has developed high power turbodrills specifically designed for drilling methane drainage boreholes. These turbodrills utilize high torque blades which deliver 2 to 3 times more power than the turbine blades used in competitive motors. These improved blades allow the motors to be much shorter and more powerful than competitive motors. Large roller thrust bearings allow the application of the high bit weights needed for fast drilling. Because of the higher power output and the high capacity bearings, these turbodrills drill 3 to 4 times faster than conventional rotary drills, resulting in significantly reduced drilling costs. Both 5-3/8 inch and 7-3/4 inch turbodrills are currently being marketed. A new 3-1/4 inch turbodrill specifically designed for drilling horizontal methane drainage boreholes in coal seams is currently being developed and will be commercially available soon.

INTRODUCTION

The objective of this research program was to develop a short, high power turbodrill specifically designed for drilling methane drainage boreholes as shown in Figure 1. The borehole is curved from the surface into the coal seam and then drilled horizontally for 1000 to 3000 feet in the coal seam. Problems have been encountered in drilling these boreholes with existing motors due to universal joint failures, low power outputs, and other limitations.

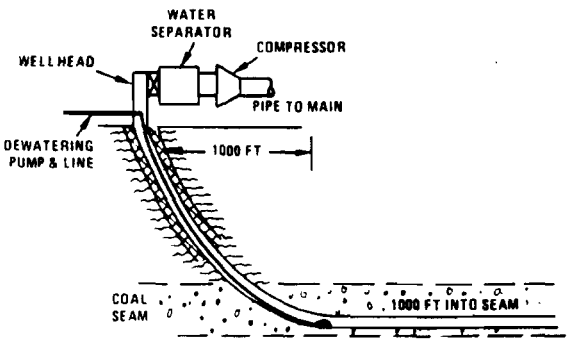

Figure 1 Methane Drainage Borehole

Drill motors were first tested in the 1920's, but did not find widespread use until the 1950's, when turbodrill use began in the Soviet Union. [1,2] By the

early 1960's, about 85% of the Soviet's oil and gas wells were being drilled with turbodrills.

Turbodrills currently being used in the petroleum industry (Figure 2) have several limitations including:

1. Low Power Output
2. Excessive Tool Length
3. Thrust Bearing Failures
4. Limited Bit Pressure Drops

The excessive length and low power output preclude their use for drilling methane drainage holes.

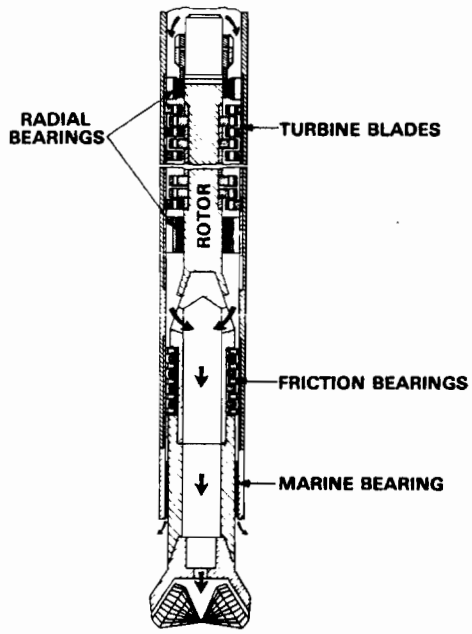

Figure 2 Typical Turbodrill

Positive displacement mud motors were introduced into the petroleum industry in the 1960's (Figure 3). These motors consist of an eccentric steel shaft rotating in a rubber stator. The rotor turns as fluid is pumped down through cavities contained between the rotor and stator.

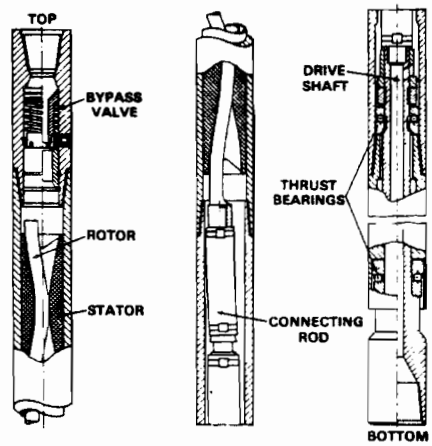

Figure 3 Moineau Motor Concept [3]
(Dyna-Drill)

These Moineau motors have limitations including:

1. Excessive Stator Wear
2. Bit Weight Limitations
3. Flow Rate Restraints
4. Universal Joint Failures
5. Short Bearing Life

TURBODRILL OPERATION

Turbodrills typically contain from 50 to 100 sets of axial flow turbine blades. Output torque and power are produced as drilling fluid is circulated through these turbine blades as shown in Figure 4. The fluid which is deflected by the stationary stator blades imparts torque to the rotating rotor blades.

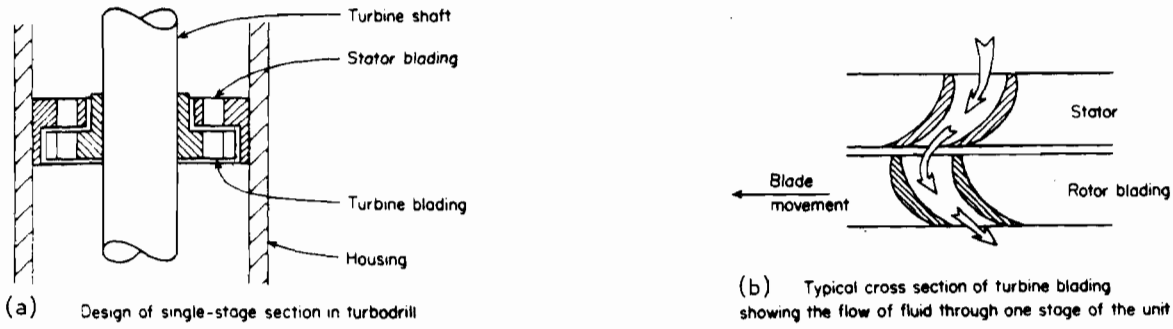

Figure 4 Turbodrill Blading [4]

TURBODRILL DESIGN

A computer program was developed which accurately predicts the operating characteristics of turbodrills. This program was used to develop a 20 foot long turbodrill which is more powerful than the 40 to 60 foot turbodrills currently used in the petroleum industry. This turbodrill drills 3 to 4 times faster than conventional rotary drills. These turbodrills have potential for significantly reducing the cost of drilling methane drainage holes.

Turbodrills operate most effectively at speeds of 300 to 1000 rpm which is the ideal operating speed for diamond bits and for the new STRATAPAX (man-made diamond) bits currently being developed. These high rotary speeds produce high drilling rates which could significantly reduce methane drainage well costs

The new turbodrill developed for drilling methane drainage boreholes is shown in Figure 5.

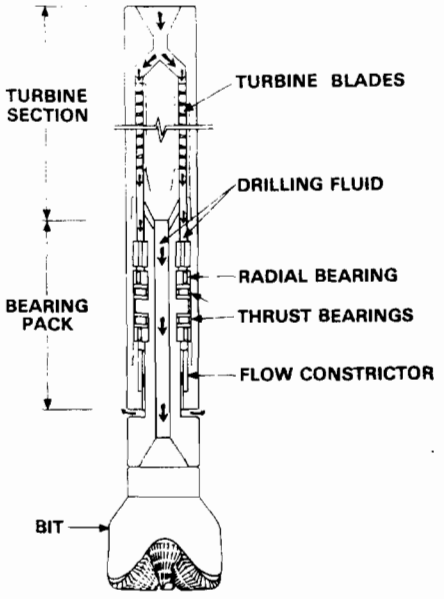

Figure 5 New Methane Drainage Turbodrill

This turbodrill utilizes new high torque turbine blades which deliver 2 to 4 times more power than the turbine blades used in other turbodrills. The turbodrill contains large roller thrust bearings (Figure 6) which allow the application of the high bit weights needed for fast drilling. A flow constrictor diverts 2 to 5 percent of the drilling fluid through the bearings to cool and lubricate them. The combination of increased torque and high bit weight results in 3 to 4 fold increases in drilling rate in granite and other hard rocks.

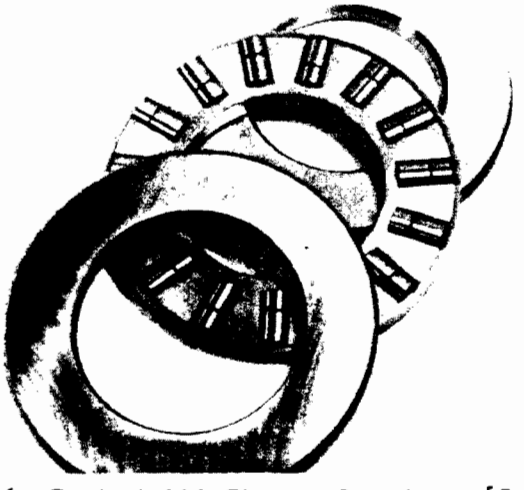

Figure 6 Turbodrill Thrust Bearings [5,6]

The turbodrill also contains three large roller radial bearings to provide radial support (Figure 7). These roller bearings are utilized to accommodate lateral loads on the drive shaft produced by tool deflections in crooked holes, by asymmetrical bit loads, and by other factors. Good radial support is important when drilling highly deviated methane drainage boreholes because of tool deflection which occurs when the hole angle is changed rapidly.

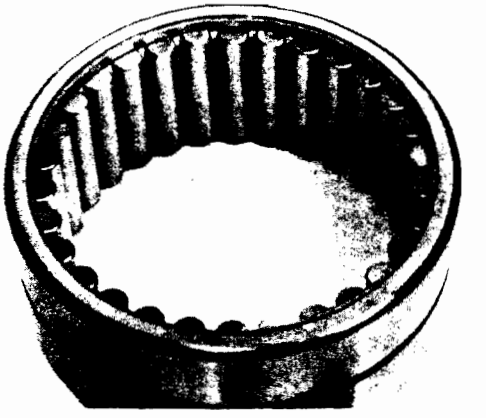

Figure 7 Turbodrill Radial Bearing [5,6]

DYNAMOMETER TESTS

The operating characteristics of the turbodrills are measured on the turbodrill dynamometer test stand shown in Figure 8. The dynamometer applies variable torque to the turbodrill, thereby allowing measurement of the torque-speed-flow characteristics of the turbodrills. Halliburton and Dowell pump trucks are used to circulate fluid through the turbodrills during these tests.

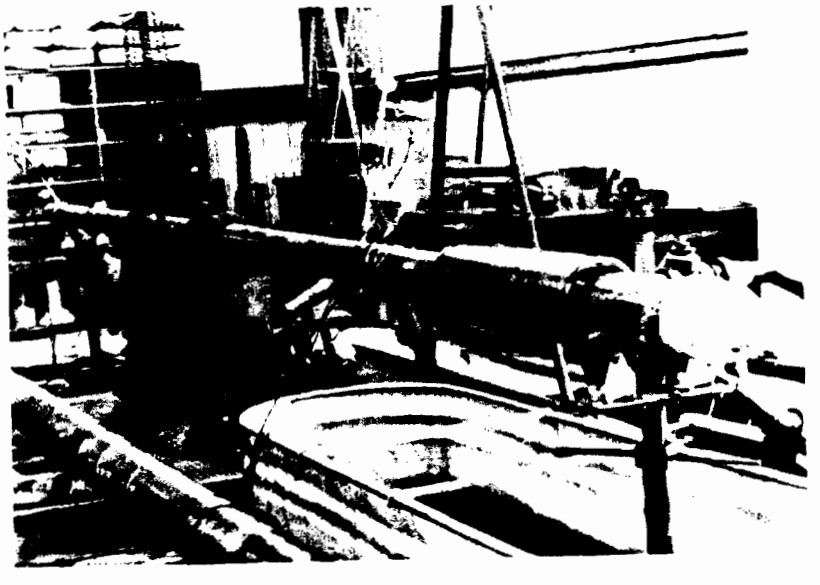

Figure 8 Turbodrill in Dynamometer Test Stand

METHANE DRAINAGE TURBODRILLS

These tests showed that the 5-3/8 inch turbodrill can deliver in excess of 130 horsepower at the higher speeds.

LABORATORY DRILLING TESTS

The 5-3/8" methane drainage turbodrill was tested in the Terra Tek Drilling Research Laboratory (DRL) in Salt Lake City on April 8 and 9, 1979. Figure 9 shows a photograph of the 7-3/4 inch turbodrill in the DRL full-scale drilling test stand.

Figure 9 Turbodrill in Drilling Rig

The 5-3/8 inch methane drainage turbodrill (300 to 500 RPM) drilled Texas Pink granite at rates in excess of 50 feet per hour with a 7-7/8 inch insert roller bit. This compares to 10 feet per hour for a conventional drilling rig (60 RPM). The 7-3/4 inch turbodrill also drilled granite at 50 ft/hr using a 12-1/4 inch diameter insert bit. This 5-fold increase in drilling rate would significantly reduce the cost of drilling methane drainage holes.

FIELD TEST PLANS

These turbodrills will be extensively field tested during the summer of 1979 and then they will be used to drill methane drainage holes on various DOE programs.

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DESIGN OF A MOBILE HORIZONTAL DRILL

BY

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ABSTRACT

This paper describes design problems and the working procedure for mobile horizontal drills in underground mines. Considerable experience was gained by drilling 15,000 feet of horizontal holes using prototype drills. Mobile drills were designed in the light of this experience and used to drill nearly 3,000 feet of horizontal holes. Several improvements were made in subsequent designs. Such drills have been successfully used for advance degasification, location of sand channels, and production of oil and gas from shallow deposits.

INTRODUCTION

Coal resources of the United States are estimated at 3.968 trillion tons to a depth of 6000 feet.[1] It is generally agreed that the gas content of coal seams increases with the depth and the rank of coal.[2, 3] However, a definitive assessment of total gas reserve cannot be made at present for lack of sufficient data. Preliminary estimates indicate that the total reserve of methane in coal could be as high as 766 trillion cubic feet.[4]

A fact, generally not realized, is that in spite of concerted efforts only a fraction of this total estimated resource can be recovered. The recovery percentage may vary depending on the reservoir properties, such as gas content, diffusivity, and gas pressure, and the method of methane drainage, but is not likely to far exceed 30 percent. The recoverable reserve of gas from coal is therefore likely to be less than 230 trillion cubic feet. This is equivalent to only eleven years of current national consumption of natural gas.

Currently all U. S. coal mines are venting an estimated total of 250 million cubic feet of methane per day. Extensive methane drainage without a large capital investment can be done only from underground mine workings. Even if all coal mines practiced methane drainage on a large scale, only 25 percent of the total gas emissions, on the average, can be recovered. Thus, the average daily production from all coal mines can be 62.5 million cubic feet per day, which is only one tenth of one percent of our daily consumption. Higher production rates can be achieved with considerably larger capital investments, but methane from coal seams is not likely to solve our energy problem. It does, however, create a safety hazard in our mines.

There has been continued interest in methane drainage from coal seams for the last 30 years in many coal mining countries including the United States. Primary reasons for methane drainage are, and possibly will remain, safety and productivity. As shallow reserves of coal are depleted, more new coal mines will be opened in deeper parts of the coal fields. In all probability, these mines will be gassier than the present ones. Depending on ventilation alone to control methane emissions may be prohibitively expensive.

Because of the shallow depth and blocky structure, advance degasification techniques for U. S. coal fields are somewhat unique. These can be classified in four categories, namely, vertical wells with hydraulic stimulation, slant holes from the surface, horizontal boreholes from shaft bottoms, and

horizontal boreholes drilled from entries near mining faces.

In our experience, unstimulated vertical wells produce very little gas. Even hydraulically stimulated wells do not produce enough gas for efficient advance degasification. Besides, the damage to roof or floor owing to hydraulic fracturing makes future mining of the coal difficult. In view of these drawbacks, we would not recommend this technique of advance degasification for mineable coal seams. Slant holes from the surface with sufficient horizontal extension in the coal seam are promising, but the cost of drilling and completing such holes at present is prohibitive. Horizontal holes drilled from shaft bottoms will produce well but require large shafts, ventilation and hoisting equipment, and periodic inspection of shaft bottom installations. These prerequisites make this option economically less attractive than horizontal holes drilled from underground workings. Advance degasification with horizontal holes drilled from underground workings is not only the cheapest but also the most effective method. Almost all horizontal boreholes drilled from a shaft bottom or slant holes with horizontal extensions will have to be plugged before that area can be mined. Horizontal holes drilled from mine workings can be so located that plugging of boreholes will be minimized if not altogether avoided.

In view of the above, the Mining Research Division of Continental Oil Company (CONOCO) has put in considerable effort in developing the hardware and technology for drilling horizontal holes from mine workings.(5) Consolidation Coal Company, the coal subsidiary of CONOCO, did pioneering work in this area in the 1950's.(6) The borehole size varies from two inches to six inches in diameter but an optimum appears to be found around four inches. The length of the horizontal hole drilled for advance degasification in the United States has varied from 100 feet to 2500 feet. The most useful length appears to be about 1000 feet since development sections usually advance 100 feet per week or less.

The purpose of this paper is to describe the design of a mobile horizontal drill capable of drilling three to four-inch diameter holes up to 1000 feet in coal seams, higher than five feet, such as the Pittsburgh seam. For convenience, the drilling rig can be divided into a number of sub-systems which are largely independent of each other. These are the mobile chassis, drill bits, the thrust and feed assembly, the hydraulic power pack, the water circulation system and the gas and water separation system.

THE MOBILE CHASSIS

Most prototype horizontal drilling assemblies had consisted of a skidded or tire-mounted feed carriage, an electrohydraulic power pack, a separate drilling console, a water pump with electric drive, a fresh water reservoir, drill rods, a gas and water separation system, hand tools, and surveying instruments. Considerable time was lost in moving the equipment from one site to another. The equipment was also subject to mishandling causing damage, delays and high maintenance costs. Besides, moving heavy equipment by hand posed a safety hazard. In order to improve safety and efficiency, it was decided to mount all drilling equipment on two mobile units.

For the Pittsburgh seam in northern West Virginia, the height of underground equipment is generally limited to about 50 inches, and the width seldom exceeds eight feet. There is no strict restriction on the length of the unit, however, it must be able to negotiate turns in the mine entry and also leave enough room for a person to walk past when set up in drilling position, often at an angle, in an entry.

After careful scrutiny, a mobile chassis built by J. H. Fletcher and Co. of Huntington, WV, was selected. It is 48 inches high, 84 inches wide, around 15 feet long and similar to a chassis for Fletcher dual-boom bolters. It is driven by two Staffa hydraulic motors using a four-wheel-drive, squirm-steer system.

The "drill unit" is shown in Figure 1. It houses the feed carriage, the drilling console, 1000 feet of 10-foot long drill rods, and the electric cable reel for surveying instruments. Four floor jacks are used to level the machine and raise the drill head to the desired level. Two five-ton telescopic hydraulic props, one on each side, anchor the drill unit to the roof.

The "auxiliary unit" is shown in Figure 2. It contains the electrohydraulic power pack, the water circulating pump, control boxes for electric motors, a trailing cable spool, and a steel tank which serves for water storage and closed-loop separation of drill cuttings and gas.

The advantage of this distribution of components is that the drill unit can be used even in return airways with only intrintrinsically safe power on it while the auxiliary unit is set up in fresh air. Hydraulic power from the auxiliary unit is provided to the drill unit through umbilical hoses. Each of these units weighs around 12 tons and can travel at 110 feet per minute.

DRILL BITS AND RODS

The most commonly used drill bits are the drag type, three-cone roller and Stratapax bits as shown in Figure 3. Each of these bits is capable of drilling at rates in excess of 3 feet per minute when adequate thrust and torque are applied. Drag bits are the cheapest and the easiest to guide but cannot drill through some hard rock inclusions in coal. Three-cone roller bits are a little more difficult to guide but will cut through most materials. The life of a roller bit is generally less than 1000 feet, especially in the small sizes. Even if the teeth remain sharp, the bearings develop some play and guidance of the bit becomes very poor. Stratapax bits need higher torque but appear to be most suitable for drilling holes deeper than 1000 feet since the diamonds maintain their side cutting capacity well. Drilling footages up to 5000 feet have been claimed for these bits.

Drill rods are made of steel and are 2 3/4 inches in outside diameter with an internal diameter of 2 3/8 inches. It is important that the rods do not have any internal or external dimensional upset. Changes in internal diameter create problems in pumping surveying tools and upsets in outside diameter tear up the packing in the wellhead stuffing box.

THRUST & FEED ASSEMBLY

The thrust and feed assembly is mounted centrally on the drill unit. It has a feed of 11 feet and can swing $\pm 17^{o}$ laterally to allow drilling multiple holes from one location. It can also sump forward four feet. The drill head has a "through" chuck such that drill pipes can be fed from the side or the back end.

For a given size borehole, the thrust required is a function of several variables, such as the length of the borehole, the torque being applied, the rate of penetration, etc. Data obtained while drilling 5 1/8-inch diameter holes in a coal seam using three-cone roller bits were analyzed using regression analysis. Equations are given below for different situations. For a non-rotary system, i.e., when a down-hole motor is used and drill rods do not rotate,

$$Y = -2764 + 8.36X_1 + 46.5X_2 + 437.6X_3 \quad (1)$$

And for rotary borehole assemblies,

$$Y = -236.5 + 418.4X_3 + 1.73X_4 \quad (2)$$

$$X_4 = 224.2 + 0.22X_1 + 0.3Y \quad (3)$$

where Y = thrust, pounds

X_1 = length of borehole, feet

X_2 = pressure differential across the down-hole motor, psi

X_3 = rate of penetration, ft/min

X_4 = torque, lb-inch

In deriving these equations, variables which did not make a significant contribution were dropped. It is to be noted that in the case of rotary borehole assemblies, the thrust is not dependent on the length of borehole. In general, rotary borehole assemblies require less thrust than non-rotary borehole assemblies.

DESIGN OF A MOBILE HORIZONTAL DRILL

General specifications of the thrust and feed assembly are as follows:

High speed:	Torque = 5000 lb-inch
	RPM = 1000
Low speed:	Torque = 11,000 lb-inch
	RPM = 470
Thrust:	20,000 pounds
Maximum Feed Rate:	20 ft/min

HYDRAULIC SYSTEM

The main hydraulic power pack is located on the auxiliary unit. It consists of two gear pumps with a total of five sections. These pumps can deliver a total 86 gpm at 2500 psi. Each is powered by a 40-HP electric motor. The power pack drives the equipment on the drill unit, the water pump and the separation systems. The drill unit has only one pump with two sections. It is powered by a 40-HP electric motor. This part of the hydraulic system is used only for tramming the drill unit. Both units use conventional oil in their hydraulic systems.

WATER (MUD) CIRCULATION SYSTEM

For advance degasification of coal seams, the turbulent flow of coal cuttings, water and gas through the annulus in a horizontal borehole largely determines the size of the borehole and the pump size. While the gas does provide a "lift", the flow can still be considered a two-phase (solid-liquid) flow for design purposes. A typical size distribution for drill cuttings is shown in Figure 4. The median size is typically 0.05 inch. Some variations depending on the size of annulus, bit type, and rotational speed of the drill column can be expected. The concentration of solids in the slurry seldom exceeds 30 percent by volume. Minimum transfer velocity (V_L) is calculated using Durand's formula:

$$V_L = F_L \sqrt{2\, g\, d\, \frac{S - S_L}{S_L}} \qquad (4)$$

where F_L is a factor dependent on the particle size and concentration

g is the acceleration due to gravity

d is the hydraulic diameter of the annulus

S is the specific gravity of solid particles

S_L is the specific gravity of the liquid

Estimates of F_L for graded solids based on median diameter, d_{50}, are given by McElvain and Cave.[7] For a d_{50} of 0.05 inch and volumetric concentration of 30%, the minimum transport velocity for coal particles (S = 1.3) works out to be 5 ft/sec. For shale (S = 2.2), the minimum transport velocity is 8 ft/sec. The capacity of the pump is determined simply by multiplying the minimum transport velocity by the cross-sectional area of the annulus. The head required of the pump is computed from the sum of pressure losses in the circulation system, i.e., the drill pipe, the bit, the annulus and the hoses connecting the drill unit with the gas water separation system.

For drilling a 4-inch diameter, 1000-foot long, horizontal hole, a triplex, reciprocating pump was selected. It has a capacity of 75 gpm at 900 psi. It is driven by a hydraulic motor so that the capacity of the pump can be varied according to needs.

GAS WATER SEPARATION SYSTEM

The gas and water separation tank is of a unique design which is being patented. It prevents any spillage of water or gas for increased safety. The main tank is 10 ft x 3.6 ft x 3.3 ft in overall size and has two compartments. An inner compartment has sufficient capacity to hold drill cuttings from a 200-foot long hole of 4-inch diameter. Drill cuttings, gas and water enter the inner compartment at one end. Baffles in the tank collect large cuttings while fines are collected by a plate separator. In future designs, the plate separator may be replaced by a cyclone to further improve the separation of solid particles.

Coal fines have a tendency to froth but this is cured with suitable surfactants. The clean water flows to an outer compartment which stores fresh water. Float controls, for both high and low levels provided in this part of the tank, ensure that the correct level of water is always maintained. The low-level control opens up a make-up water valve. The gas is drawn from the tank via an outlet connected to the accompanying underground methane pipeline system. The tank works under slight positive pressure and is designed to withstand 14 psig. A relief valve is provided, however, to keep the gas pressure slightly lower than the designed pressure. At the end of a shift, the vehicle is trammed to an appropriate unloading point and cuttings are discharged by means of a built-in screw feeder.

SUMMARY AND CONCLUSIONS

Horizontal boreholes drilled from mine workings are the cheapest and the most effective means of methane drainage in U. S. coal mines. The design of mobile horizontal drills capable of drilling a 1000-foot long, 4-inch diameter borehole is presented in this study. A mobile rig not only saves time in moving from one site to another but also improves safety and reduces maintenance problems. The mobile horizontal drill described here has been used to drill nearly 3000 feet of horizontal hole on one project. An average drilling rate of 200 feet in an eight hour shift was achieved.

Although the design is for relatively thick seams, such as the Pittsburgh seam, many design principles are also applicable to low seams, shaft bottoms, or other places where horizontal drilling may be applicable.

Negotiations are currently underway to make this CONOCO development available to the industry as a whole through established equipment manufacturing and marketing organizations.

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FIGURE 1

THE DRILL UNIT

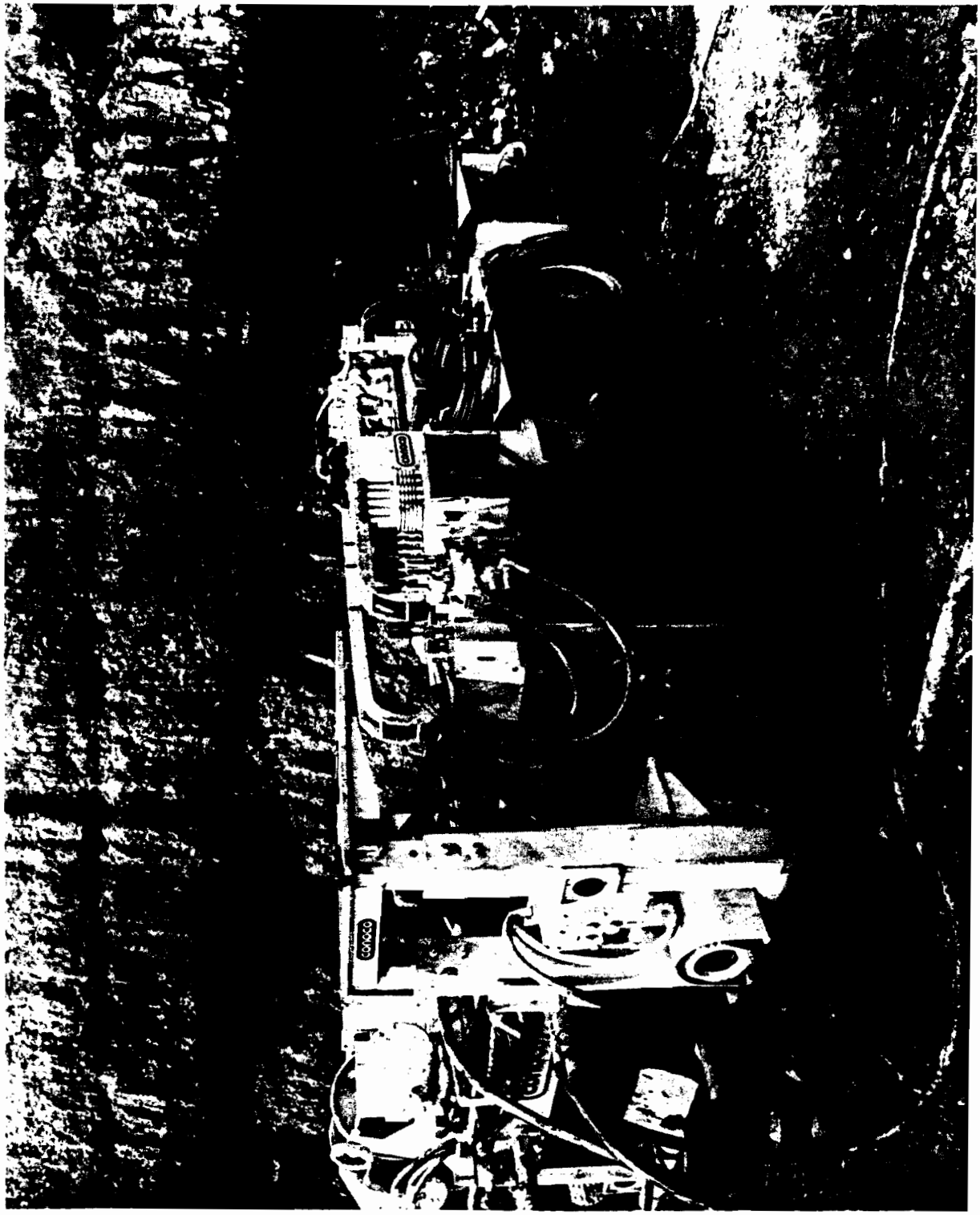


FIGURE 2

THE AUXILIARY UNIT

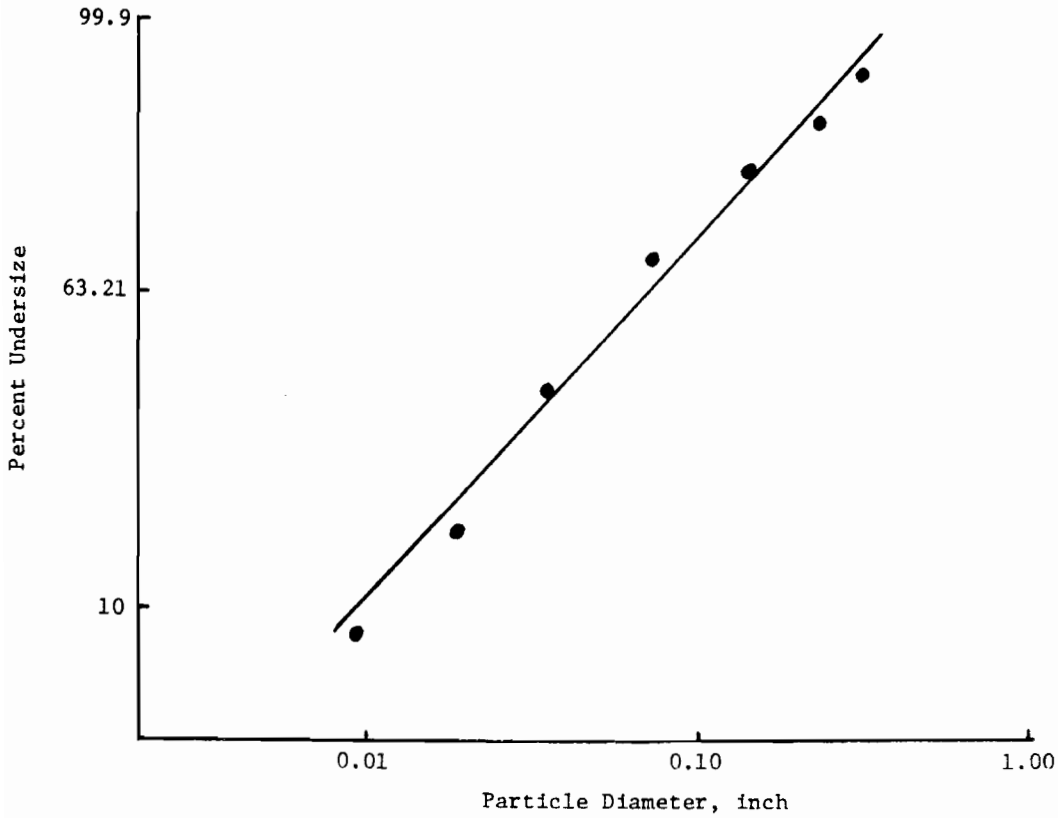
FIGURE 3

DRILL BITS

A - Three Cone Roller Bit, B - Stratapax Bit, C - Drag Bit

FIGURE 4

TYPICAL SIZE DISTRIBUTION OF DRILL CUTTINGS



EVALUATION OF THE METHANE CONTENT AND RESOURCES OF COLORADO COALS

by

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Mr. Murray has authored several papers on the energy resources of the Nevada-Colorado region with specific topics on coal and methane gas in the Piceance Creek Basin.

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THE METHANE CONTENT OF COLORADO COALS

ABSTRACT

Since 1975, the Colorado Geological Survey, through cooperative arrangements with the U.S. Bureau of Mines and Department of Energy, and, more recently, with the Colorado Oil and Gas Conservation Commission, has been conducting an evaluation of the content and potential resources of methane in Colorado coal beds. Compilation of available data revealed that "gassy" conditions, explosions, and fires, costing hundreds of lives, have occurred in more than 130 coal mines throughout the State from the 1880's to the present. The gassy coal mines of record are located primarily in the southern part of the Raton Mesa coal region, Las Animas County, and in the southeastern part of the Uinta region, Gunnison and Pitkin Counties. These mines are in structural basins of Laramide age that exhibit moderate to intense tectonic deformation. These same areas contain the gassiest currently producing coal mines in Colorado, which, in total, vent (i.e., waste) over 11 million cu ft (0.3 million m^3)of methane per day, an amount sufficient to heat 25,000 homes. Coals from these gassy regions (1) are Late Cretaceous to early Tertiary in age; (2) include the highest grade coking coals in the western U.S.; (3) often are high-volatile A to medium-volatile bituminous in rank and generally less than 31 percent in volatile-matter content; (4) occur in areas exhibiting relatively high geothermal gradients; (5) typically are associated with late Tertiary igneous activity, both intrusive and extrusive; (6) may exist from the surface to depths in excess of 10,000 ft; (7) range in dip from nearly horizontal to vertical; and (8) vary in thickness from a few ft to in excess of 20 ft per bed, and from approximately 10-20 ft to over 100 ft in aggregate. The main objectives of these methane-from-coal bed studies are to (1) improve mine safety, (2) increase coal mine productivity, (3) assist in the development of new sources of pipeline-quality methane, (4) conserve a valuable resource currently being wasted, and (5) utilize in mine-related operations the methane produced from coal. Previous cooperative studies with the Bureau of Mines (and our current study sponsored by the Colorado Oil and Gas Conservation Commission) stressed "minable" coal beds, whereas our present efforts with the DOE emphasize unmined/"unminable" coal. Since early 1976, the Colorado Geological Survey, using standard desorption methods, has measured the gas content of more than 120 fresh coal samples cored by evaluation drilling programs conducted by both the U.S. Geological Survey and industry at approximately 20 sites in four of the State's eight coal-bearing regions. Total gas content of these cores ranged from almost zero to 492 cu ft/ton (15.4 cc/g); and depths sampled varied from 100-4,709 ft. Selected samples of the desorbed coal gas have been analyzed and found to have methane contents of from 46-99 percent and heating values of from 465-997 Btu/cu ft. Total gas content of desorbed cores taken from depths above 1,000 ft has not exceeded 160 cu ft/ton (5cc/g). Desorption measurements are continuing as additional coal cores become available. These gas content data will be correlated with coal rank and other properties as soon as the coal analyses have been completed and made available. The deeper parts of several of the coal "basins" in Colorado are believed to contain trillions of cubic feet of in-place methane in multiple, thick (± 10-40 ft) beds of relatively high-rank coal.

INTRODUCTION

Project History

Since October 1975, the Colorado Geological Survey has been investigating the methane content of the coal beds and coal mines of Colorado. The project began with a two-year cooperative agreement between the Colorado Geological Survey and the U.S. Bureau of Mines (Pittsburgh, Pa.) to compile and evaluate data on the methane potential of the coal beds of Colorado; the emphasis of this project was on mined or "minable" coals (see Fender and Murray, ref. 2).

This overall project is continuing through a cooperative agreement which commenced on April 1, 1978, between the Colorado Geological Survey and the U.S. Department of Energy (Morgantown Energy Technology Center). The objective of this phase of the project is to evaluate the methane potential of the unmined/"unminable" coal beds in Colorado. To achieve this goal, the Colorado Geological Survey is engaged in the following activities: (1) selection of favorable sites for test drilling; (2) compilation and synthesis of pertinent geologic information (e.g., regional tectonics, stratigraphy, geothermal factors, etc.); (3) monitoring industry activity and determining the potential for cooperative agreements for core sampling, methane desorption, flow testing, etc.; (4) supervision of well-site geologic activities; and (5) performance of methane desorption measurements and reduction and interpretation of the resulting data.

In addition, on February 1, 1979, the Colorado Geological Survey entered into an agreement

with the Colorado Oil and Gas Conservation Commission to conduct a study of the conservation of methane from mined/"minable" gaseous coal beds in Colorado. For the first project year, the Commission has authorized the expenditure of $45,000 (obtained from mill-levy funds that the Commission collects from Colorado oil and gas producers). The chief goals of this project are to conserve a valuable energy resource and to promote its utilization in mine-site operations related to coal mining and coal preparation, and/or in communities located near such operations. The work plan of this project includes the following: (1) evaluating the geologic factors related to the generation, concentration, and emission of methane within and around certain active coal mines in Colorado; (2) constructing the maps (structure, overburden, coal isopachs, etc.) and cross sections necessary to conduct this geologic evaluation; (3) evaluating and synthesizing studies conducted by the U.S. Bureau of Mines and Department of Energy (and by their contractors) concerning the occurrence of methane in coal mines, coal bed degasification, methane recovery and utilization, etc.; (4) securing the cooperation of selected mine operators in the "gassy" coal fields in order to apply the pertinent geologic and engineering technology to coal mines; and (5) evaluating the economics of methane recovery, compression, transmission, and utilization in mines or nearby communities.

In summary, the various methane-from-coal beds studies conducted by the Colorado Geological Survey have the following goals: (1) improvement in coal mine safety; (2) increase in coal mine productivity; (3) development of new sources of pipeline-quality natural gas; (4) conservation of a valuable resource heretofore wasted; and (5) utilization of methane produced by coal mining in mining-related operations and/or in nearby communities.

Statement of the Problem

Since the late 1800's, many hundreds of lives have been lost in Colorado coal mines as a result of explosions, fires, and suffocation attributable to the presence of methane. If the gas content of a coal bed were determined prior to mining, a ventilation and/or coal-bed degasification program could be designed that might prevent dangerous concentrations of methane in the mine workings and costly resultant mine shut-downs.

Approximately 11 million cu ft (0.3 million m^3) of methane per day (diluted to about one percent concentration, as required by Federal law) presently is being vented (i.e., wasted) into the atmosphere from 10 to 12 coal mines in Colorado. This amount equals more than 4 billion cu ft (120 million m^3) per year, or approximately two percent of all of the hydrocarbon gas produced from the State's oil and gas fields during 1977 (some 191.8 billion cu ft, or 5.75 billion m^3). Because coal bed gas typically contains more than 90 percent methane, it usually is of pipeline quality. Therefore, this wasted gas could be used to heat about 25,000 homes.

EVALUATION OF COAL-BED METHANE

Colorado Geological Survey Procedure

During the first phase of the Colorado Geological Survey--U.S. Bureau of Mines cooperative study (before coal cores were made available for methane desorption measurements), the literature was searched in order to locate coal mines that had reported "gassy" conditions, explosions, fires, suffocations, etc. More than 130 closed and open mines in the State had reported significant concentrations of methane, and many of these concentrations had proved disastrous (Fig. 1; and ref. 1).

In addition, methane emission data from active coal mines in Colorado were obtained from the Mining Enforcement and Safety Administration (or M.E.S.A., now Mine Safety and Health Administration, M.S.H.A.) and are listed on Table 1. However, M.S.H.A. measures methane emissions from a mine's ventilation system in cu ft/day. This daily emission rate includes methane emitted from gob areas, ribs, roofs, floors, and pillars in both old and active workings, as well as emissions from the working face(s). Therefore, the emission rate for a given day cannot simply be divided by the tons of coal mined that day to arrive at the *in situ* methane content of the coal in cu ft/ton.

In order to obtain *in situ* gas-content measurements of Colorado coal beds, the Colorado Geological Survey, in collaboration with the U.S. Bureau of Mines and TRW, Inc. (a Department of Energy contractor), has collected more than 120 samples of coal cores since 1976. These cores came from some 20 drill holes, located in four of the eight coal-bearing regions in Colorado (Fig. 2). These holes were drilled as part of coal evaluation programs conducted by

the U.S. Geological Survey and by industry, or for oil and gas exploration.

The Colorado Geological Survey determined the gas content of each sample using the Bureau of Mines' "direct" desorption method. For this method, a sample of coal approximately 1,000 g in weight is obtained from a conventional core and is sealed in a desorption cannister (usually made of plastic or aluminum) immediately after the core has been removed from the core barrel. The gas emitted by the coal is measured daily (by water displacement in a graduated cylinder) until emission (desorption) ceases. The gas lost from the coal between the time it was first penetrated by the coring head and the time it was encapsulated in the cannister is estimated using a "back calculation" method. After desorption, the residual gas in the coal is measured as the coal is crushed in a sealed ball mill at the U.S. Bureau of Mines' Pittsburgh (Bruceton) facility. The estimated lost gas, plus the measured desorbed and residual gas, are added to give the total in-place gas content (in cc/g or cu ft/ton) of the coal bed. (Refer to McCulloch and others, ref. 16, for a more complete description of this method.)

After completion of the desorption measurements, the samples were sent to the Department of Energy's Pittsburgh laboratory for proximate, ultimate, and related analyses and to the U.S. Geological Survey in Denver for geochemical (including trace-element) analyses. In the future, petrographic work may be done on selected samples made into thin sections and/or polished pellets. The coal gas-content data then will be correlated with the results of these analytical studies.

Additional Methane Measurement Procedures

Other methods to determine the gas content of coal samples include the desorption of sidewall core samples and the "indirect" adsorption isotherm method.

Sidewall core guns have been used successfully to obtain coal samples from several drill holes in various coal regions in the U.S., including Colorado. The gas content of these samples is being determined by a variation of the "direct" method. Research comparing the gas content measurements of coal beds cored both conventionally and using a sidewall coring tool is being conducted by contractors of the Department of Energy.

The "indirect" adsorption isotherm method presently has been used on four coal samples from Colorado. Adsorption isotherms graphically display the quantity of gas that a powdered sample of coal is able to adsorb at various pressures while the temperature is held constant. If the reservoir pressure and temperature are known, the adsorption isotherms can provide an estimate of the total gas content of the tested coal. However, the calculated gas content of a coal using this "indirect" method represents only its potential gas content, inasmuch as the sampled coal may have lost much of its desorbable methane through faults, permeable roof and floor rock, or outcrops of the coal bed. A more detailed comparison of the "direct" and "indirect" methods is given in Kissell and others (13). Figure 3 graphically depicts this comparison for four Colorado coal core samples taken from the Raton Mesa region.

Qualitative Methane Detection

During the coring operations that provided the coal samples for desorption measurements, several methods of detecting methane (while coring) and determining reservoir parameters were used. These methods are described below.

The presence of methane occasionally was determined by visual inspection. Indications of methane encountered while drilling or coring coal beds range from gas breaking out of the drilling medium to an uncontrolled blowout. Gas bubbling out of drilling fluid at the discharge line was observed at several of the drill sites that the Colorado Geological Survey sampled in both the Uinta and Raton Mesa coal regions. More dramatically, a blowout occurred in December 1978, in an underground coking coal mine in Gunnison County (southeast Uinta region) as a coal below the bed currently being mined was cored.

Hand-held methanometers and gas detection devices on mud-logging units also have given qualitative indications that a gassy coal bed was being penetrated. A portable methanometer which measures up to 5 percent methane in the air (the lower explosive limit) was used last year on several coal coring operations in the Raton Mesa and Uinta coal regions. In one case, when the methanometer registered more than 5 percent methane in the air near the end of the drilling medium discharge line, the operation was temporarily halted for safety reasons.

Portable mud-logging units have been installed (and connected to a drilling-rate recorder mounted on the rig) on several of the coal coring operations in which we participated during 1978 in the Raton Mesa and Green River regions. While coring and drilling coal in one of the Raton Mesa tests, the mud-logging unit frequently registered more than 10 percent methane (the upper limit of the unit) in the drilling fluid. This recording device was useful in correlating the various coal beds with the drilling-rate chart and, upon completion of the hole, with the wire-line geophysical logs that were run (see Danilchik and others, ref. 5).

After a drill hole has been completed, geophysical logs and drill-stem tests have provided valuable information regarding gassy coal-bed reservoirs. Wire-line gamma ray, resistivity, neutron, density, sonic, and hole-caliper logs, for example, have indicated depth, thickness, and other parameters of penetrated coal beds, particularly when tied to cores. Drill-stem tests provided useful reservoir pressure and permeability data, as well as measured actual flow rates of methane from a coal bed (see Table 2).

PRODUCTION OF METHANE FROM COAL BEDS

At least two coal mines in the Uinta region of Colorado are, or soon may be, producing methane from coal beds. One coking coal mine in Pitkin County presently is utilizing methane from vertical degasification holes drilled into mine gob areas. At another mine, in Gunnison County (the mine in which the blowout occurred), the operator is drilling several vertical core holes from within its underground mine into coal beds located below the one now being mined. The Colorado Geological Survey has sampled several of the coal beds cored in the latter mine and presently is conducting desorption measurements. If methane flow rates of sufficient quantity are obtained from gassy coals thus far cored, and if the legal questions regarding ownership of the coal-bed gas within the leased area can be resolved, the operator may utilize this gas in some of its contemplated surface operations (e.g., coal preparation).

At least two petroleum companies in Colorado currently are involved in projects designed to produce methane from gaseous coal beds. In one 5,000-ft (1,524-m) drill hole, multiple coal beds totalling more than 150 ft (46 m) in thickness may soon undergo selective stimulation and production testing (once the desorption measurements of the cored coals have been completed). In another well, a coal bed approximately 25 ft (7.6 m) in thickness, at a depth of 8,000 ft (2,440 m), has flowed methane at rates between 300 and 500 MCFD following a hydraulic fracture treatment. Additional information on these two wells is being held confidential.

However, details can now be released on the Twin Arrow Drilling Co. C & K No. 1-13 well, located in western Rio Blanco County. Five coal intervals in the Upper Cretaceous Mesaverde Group (see Fig. 4) between 573 and 810 ft (175 and 247 m) were tested through perforations in casing run in this well; no flow was recorded through a 1/8-in. (0.32 cm) orifice, and shut-in pressures were zero. However, because the coal beds in this hole had not been cored, no gas content measurements were available. To our knowledge, no significant gas content measurements have yet been noted in coals cored above 1,000 ft (350 m) in depth anywhere in Colorado. Moreover, the coal beds tested in the Twin Arrow test probably crop out within a mile or two of the well because of the dissected topography of the surrounding area. Consequently, any movable gas that the coal beds once might have contained probably has leaked to the surface.

GASEOUS COAL-BEARING REGIONS

Our studies to date reveal that the Uinta and Raton Mesa coal regions have a high potential for significant resources of coal-bed methane. These two regions contain some of the largest resources of coal in the western U.S.--resources that probably exceed 100 billion short tons (90 billion tonnes) to depths exceeding 10,000 ft (3,048 m). Both the Uinta and Raton Mesa coal regions are essentially coincident with structural basins of Laramide age, the Colorado portion of the former with the Piceance Creek basin, and the latter with the Raton basin, of southern Colorado and northern New Mexico.

Approximately 10.5 of the 11 million cu ft (0.3 million m3) of methane vented daily from active coal mines in Colorado comes from mines in the southeast part of the Uinta region. Individual mines in the Coal Basin/Redstone area, Carbondale field (in Pitkin County) emit 2-3 million cu ft (0.06-0.09 million m3) of methane per day (Table 1). The highest grade coking coal in the western U.S. is mined in this area. Papers by Collins (4) and by Murray, Fender, and Jones (19) treat in some detail the geology, gas, and coal resources of this region.

The Raton Mesa coal region is the second most important "gassy" region in Colorado (see

Fig. 1 and Table 1). Las Animas County, an especially "gassy" portion of this region, is the most important county in the State from the standpoint of historic coal production. The Trinidad coal field, which is coincident with the limits of Las Animas County, has produced more than 174 million short tons (158 million tonnes) of coal to date; this represents about 27 percent of the total for Colorado. This county also is an important coking coal producer and accounted for approximately one-fifth of the total coking coal output of Colorado in 1978. Detailed information regarding the geology and the coal and methane resources of the Raton Mesa region can be found in articles by Danilchik and others (5), Dawson and Murray (6), Dolly and Meissner (7), and Murray (18).

DESCRIPTION OF GASEOUS COAL BEDS

Coal core samples desorbed by the Colorado Geological Survey from the two regions noted above have exhibited total gas contents ranging from near zero to 492 cu ft/ton (15.4 cc/g). The coals with the highest gas contents are found in the Upper Cretaceous Mesaverde Group in the Uinta region (Fig. 5) and in the Upper Cretaceous Vermejo Formation in the Raton Mesa region (Fig. 6; see also Fig. 2).

Individual coal beds in the Uinta region vary from approximately 1-40 ft (0.3-12 m) in thickness; aggregate thicknesses commonly are between 50 and 150 ft (15-46 m). Mesaverde coals in the deeper parts of this region occur at depths exceeding 10,000 ft (3,048 m). In the Raton Mesa region, coal beds in the Vermejo and Raton Formations (Fig. 6) range from about 1-15 ft (0.3-4.6 m) in thickness and total approximately 10-70 ft (3-21 m) in thickness in a given locality. In the northwest part of the region, coals are found to depths exceeding 3,000 ft (914 m) (see map by Jones and others, ref. 12).

The Colorado coals with the highest gas contents measured to date are from high-volatile A to medium-volatile bituminous in rank and generally less than 31 percent in volatile matter content. These coals often are of metallurgical quality and include the highest grade (premium) coking coal produced in the western U.S. In both the Uinta and Raton Mesa regions, the gassy coal beds typically are associated with Late Cretaceous and Tertiary igneous activity and with areas of abnormally high geothermal gradients (Fig. 2).

The gas content of a coal bed also appears to be related to its present depth of occurrence. In the coal cores obtained to date from depths above 1,000 ft (305 m), total gas content has not exceeded 160 cu ft/ton (5 cc/g). Furthermore, in the two core holes containing the "gassiest" coals yet desorbed, the deeper the coal in a particular hole, the higher its gas content. See Figure 7 for the most notable example of this observation.

COMPOSITION OF COAL-BED GAS

We have collected samples of coal-bed gas at atmospheric pressure from the "gassier" coals using the "direct" desorption technique. So far, 14 gas samples from coal cores collected from the Green River, Raton Mesa, and Uinta regions have been analyzed for their contents of hydrogen, oxygen, hydrogen sulfide, carbon dioxide, nitrogen, methane, ethane, and propane-plus. Table 3 displays a typical analysis of gas desorbed from a Vermejo Formation coal bed in the southern Raton Mesa region.

For the coal-bed gases thus far analyzed, contents of hydrogen have ranged from zero to 61.99%; carbon dioxide, from zero to 26.47%; nitrogen, from 0.10-53.8%; methane, from 34.24-98.98%; propane from zero to 0.35%; isobutane from zero to 0.02%; and n-butane from zero to 0.02%. Isopentanes-plus, hydrogen sulfide, and oxygen contents have been nil. All of the above percentages were calculated on an air-free mol percent basis.

Calculated gross heating values of these coal-bed gas samples varied from 465-997 Btu/cu ft. Figure 8 compares the composition of coal-bed gas from a Vermejo Formation coal in Las Animas County (Table 3) with that of a sample of gas from a conventional gas well located in the Denver basin (Adams County).

ESTIMATED RESOURCES OF COAL-BED METHANE

According to Averitt (1), the estimated remaining identified coal resources of Colorado between 0-3,000 ft (0-914 m) in depth total nearly 129 billion tons (117 billion tonnes). If only 50 percent of these resources contains an average of 200 cu ft/ton (6.3 cc/g) of desorbable (i.e., potentially producible) methane, the resources of coal-bed gas in the State

would total nearly 26 trillion cu ft (approximately 73 x 10^{10} m^3).

The Uinta region alone contains at least 60 billion tons (54 billion tonnes) of in-place coal resources (Murray, ref. 18). If one-half of this coal contains an average of 200 cu ft/ton (6.3 cc/g) of producible methane, the coal-bed gas resources of this region could be on the order of 6 trillion cu ft (17 x 1010 m3). Using coal reserve data from Dolly and Meissner (ref. 7, p. 264), and again assuming an average gas content of 200 cu ft/ton (6.3 cc/g), the Colorado part of the Raton Mesa region could contain in excess of 4 trillion cu ft (11 x 1010 m3) of coal-bed methane resources.

As can be seen from the above estimates, if the unique and poorly understood problems connected with the production of gas from "unminable" (i.e., relatively deep) coal beds can be solved, the recoverable natural gas reserves of Colorado will be substantially increased.

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Table 1.--Methane gas emissions from active Colorado coal mines (data from Mine Safety and Health Administration).

Coal Region	Coal Mine Name, Coal Company	Coal Bearing Rock Unit	Depth of Overburden (ft.)	Range of Methane Emissions 1974-1976 (MCFD)	Average Methane Emissions (MCFD)
Canon City	Twin Pines, Twin Pines Coal Co.	Vermejo Fm.	75 - 200	0 - 0	0
Denver	Eagle, Imperial Coal Co.	Laramie Fm.	385 max	0 - 7	5
	Lincoln, Imperial Coal Co.	Laramie Fm.	270	0 - 0	0
Green River	Apex No. 2, Sunland Mining Corp.	Iles Fm.	400 max	0 - 9	7
	Wise Hill No. 5, Empire Energy Corp.	Williams Fork Fm.	300 - 600	0 - 44	24
Raton Mesa	Allen, CF & I Steel Corp.	Raton Fm.	400 - 1,000	330 - 452	410
San Juan River	King Coal, Henrietta Coal Co.	Menefee Fm.	284 max	0 (?)	0 (?)
Uinta	Bear, Bear Coal Co., Inc.	Mesaverde Group	1200	172 - 194	183
	Bear Creek No. 4, Midcontinent Coal and Coke Co.	Mesaverde Group	-	537 - 660	605
	CMC, Cambridge Mining Corp.	Mesaverde Group	1800	0 - 24	19
	Coal Basin No. 5, Mid-Continent Coal and Coke Co.	Mesaverde Group	3000 max	820 - 1168	966
	Dutch Creek No. 1, Mid-Continent Coal and Coke Co.	"	2500 max	1100 - 1489	1338
	Dutch Creek No. 2, Mid-Continent Coal and Coke Co.	"	3000 max	911 - 2194	1426
	Eastside, Louis J. Bendetti	"	60 +	0	0

Table 1 - Continued

Coal Region	Coal Mine Name, Coal Company	Coal Bearing Rock Unit	Depth of Overburden (ft.)	Range of Methane Emissions 1974-1976 (MCFD)	Average Methane Emissions (MCFD)
Uinta	Hawk's Nest East, Western Slope Carbon, Inc.	Mesaverde Group	1600 max	0 (?)	0 (?)
	Hawk's Nest West, Western Slope Carbon, Inc.	"	1600 - 2000	154 - 414	301
	L. S. Wood, Mid-Continent Coal and Coke Co.	"	3000	1512 - 2432	2170
	Nu-Gap No. 3, Henry Bendetti Coal Co.	"	400 - 800	0	0
	O. C. No. 2, O. C. Mining Co.	"	1800 - 2000	0 (?)	0 (?)
	Rienau No. 2, Sewanee Mining Co., Inc.	"	150	0	0
	Somerset, U.S. Steel Corp.	"	200 - 2000	832 - 896	874
	Sunlight, Carbon King. Ltd.	"	370 - 1500	0	0
	Thompson Creek No. 1, Anschutz Coal Corp.	"	400 - 1300	0 - 20*	11
	Thompson Creek No. 3, Anschutz Coal Corp.	"	400 - 1300	0 (?)	0 (?)

*Under construction

Table 2.--Summary of results obtained from 3 drill-stem tests run in coal beds in 2 drill holes located in Green River and Raton Mesa coal regions, Colorado (exact locations confidential).

Test No.	Total Coal Thickness (ft)	Test Interval (ft)	Drill Pipe Recovery (ft)	Sample Chamber Recovery	Final Shut in Pressure (psi)	Gas to Surface
1.	18	3700-3800	256' mud-cut water	0.08 cu ft gas at 70 psi	1591	no
2.	17	4634-4714	1478' water-cut mud, gas-cut +	2400 cc water at 100 psi	2020	yes
			1478' mud-cut water, gas-cut +			
			1477' fresh water, gas-cut			
3.	17	849-920	500' water	not applicable	222	no

Table 3.--Composition of coal-bed gas from a desorbed coal core sample, U.S.G.S. DH 78-1A, Las Animas County, Colorado.

U.S.G.S. DH 78-1A

Component	Mol Per Cent	
	With Air*	Air Free**
Hydrogen	0.09	0.14
Oxygen	8.04	Nil
Hydrogen Sulfide	Nil	Nil
Carbon Dioxide	0.70	1.11
Nitrogen	28.67	0.10
Methane	62.46	98.59
Ethane	0.04	0.06
Propane plus	Nil	Nil
	100.0	100.00

*Calculated gas gravity (Air = 1.000) = 0.723

**Calculated gas gravity (Air = 1.000) = 0.564

***Calculated gross heating value = 994 BTU per cubic foot of dry gas at 14.65 psia at 60°F.

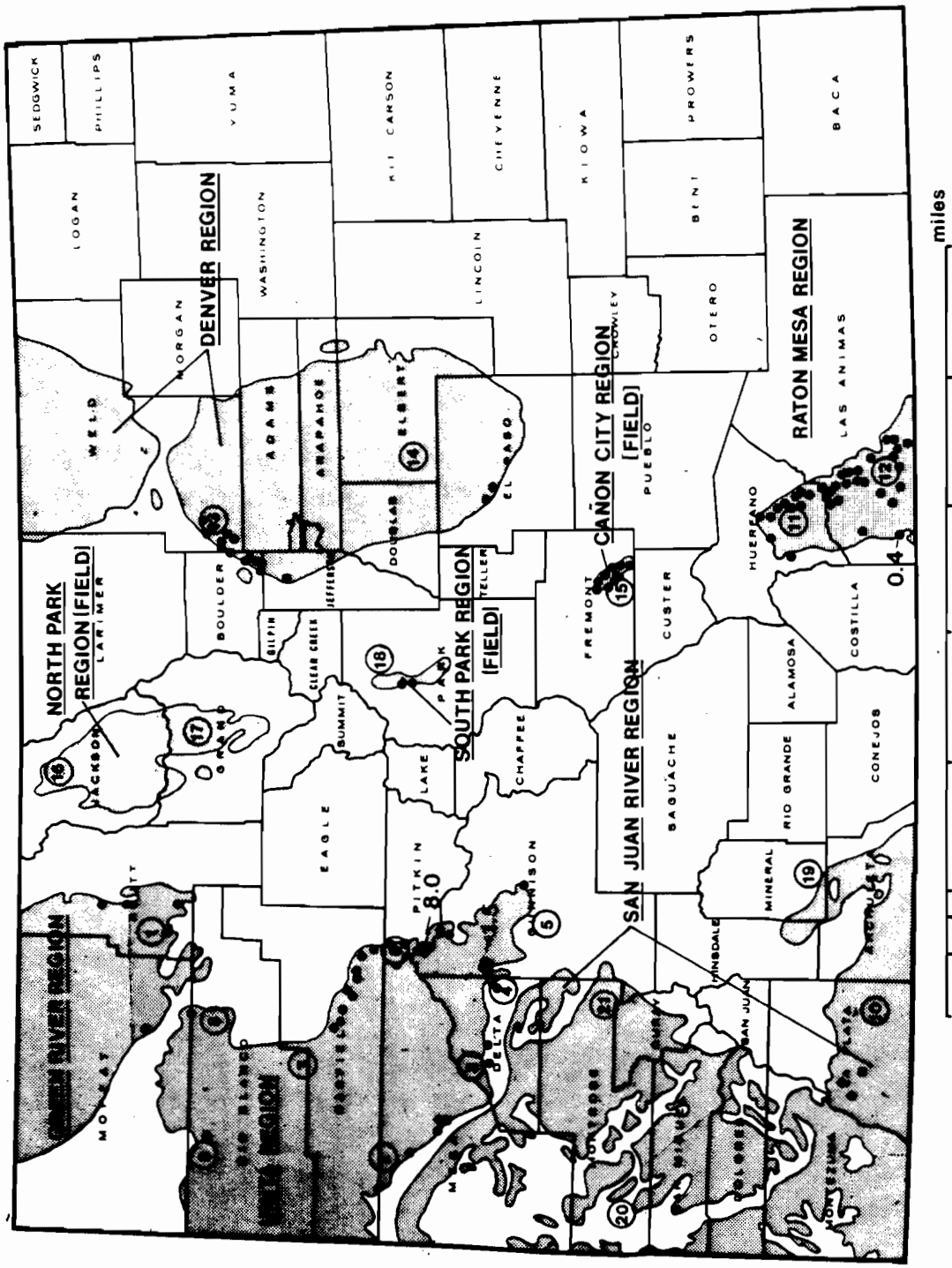
Collected at 0 psig and 75°F., on 7-3-78

COAL FIELDS

1. Yampa
2. Book Cliffs
3. Grand Mesa
4. Somerset
5. Crested Butte
6. Carbondale
7. Grand Hogback
8. Danforth Hills
9. Lower White River
10. Durango
11. Walsenburg
12. Trinidad
13. Boulder-Weld
14. Colorado Springs
15. Canon City
16. North Park
17. Middle Park
18. South Park
19. Pagosa Springs
20. Nucla-Naturita
21. Tongue Mesa

Fig. 1.--Index map, coal regions and fields in Colorado. Black circles indicate known gassy coal mines, both closed and active; large uncircled numbers (e.g., 8.0) indicate average methane emission rates in MMCFGD of gassiest active mines. Circled numbers refer to coal fields.

FIGURE 1



COAL REGIONS AND FIELDS IN COLORADO
[ROCKY MOUNTAIN COAL PROVINCE]

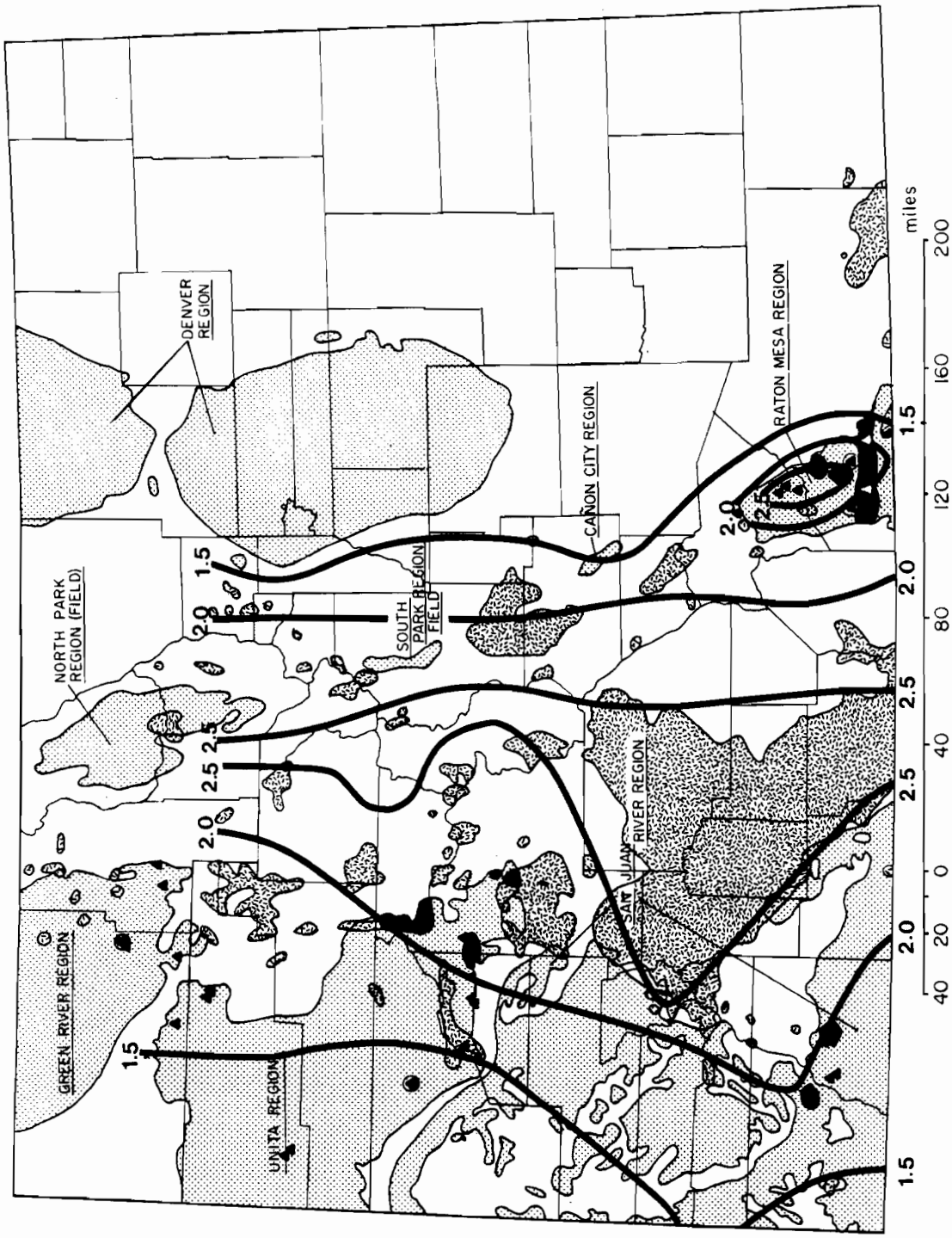


Fig. 2.--Map of coal regions in Colorado, showing locations of desorbed coal cores (triangles), extent of Upper Cretaceous to Cenozoic extrusive rocks (random dashed pattern), areas of historic and present coking coal production (black), and heat-flow isotherms. Circled triangles represent coal cores containing more than 200 cu ft/ton (6.3 cc/g) of total desorbed gas.

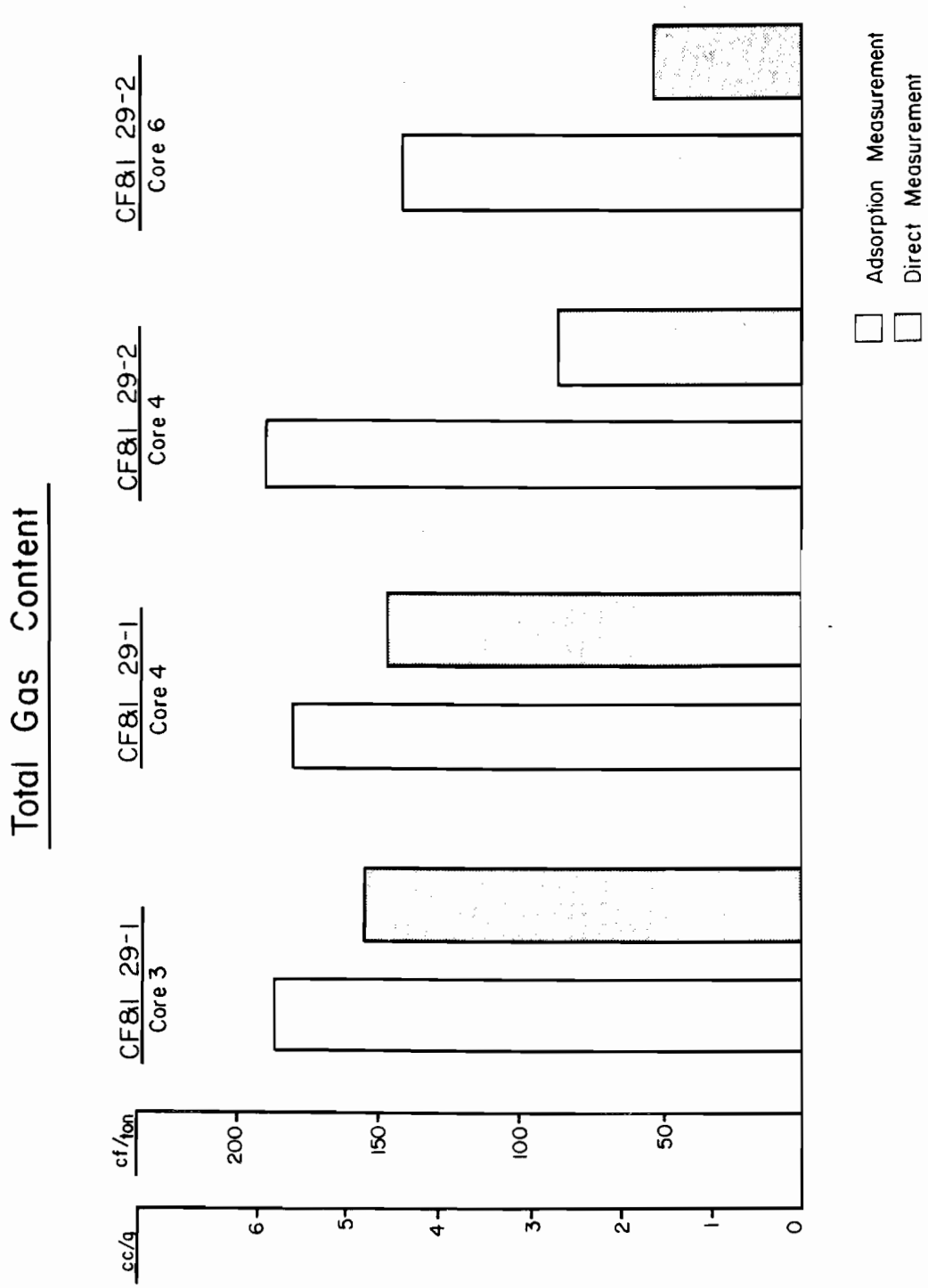


Fig. 3.--Comparison of total gas contents of 4 cored coal samples from Raton Mesa region, Colorado, as determined by adsorption isotherm ("indirect") and U.S. Bureau of Mines "direct" measurement methods.

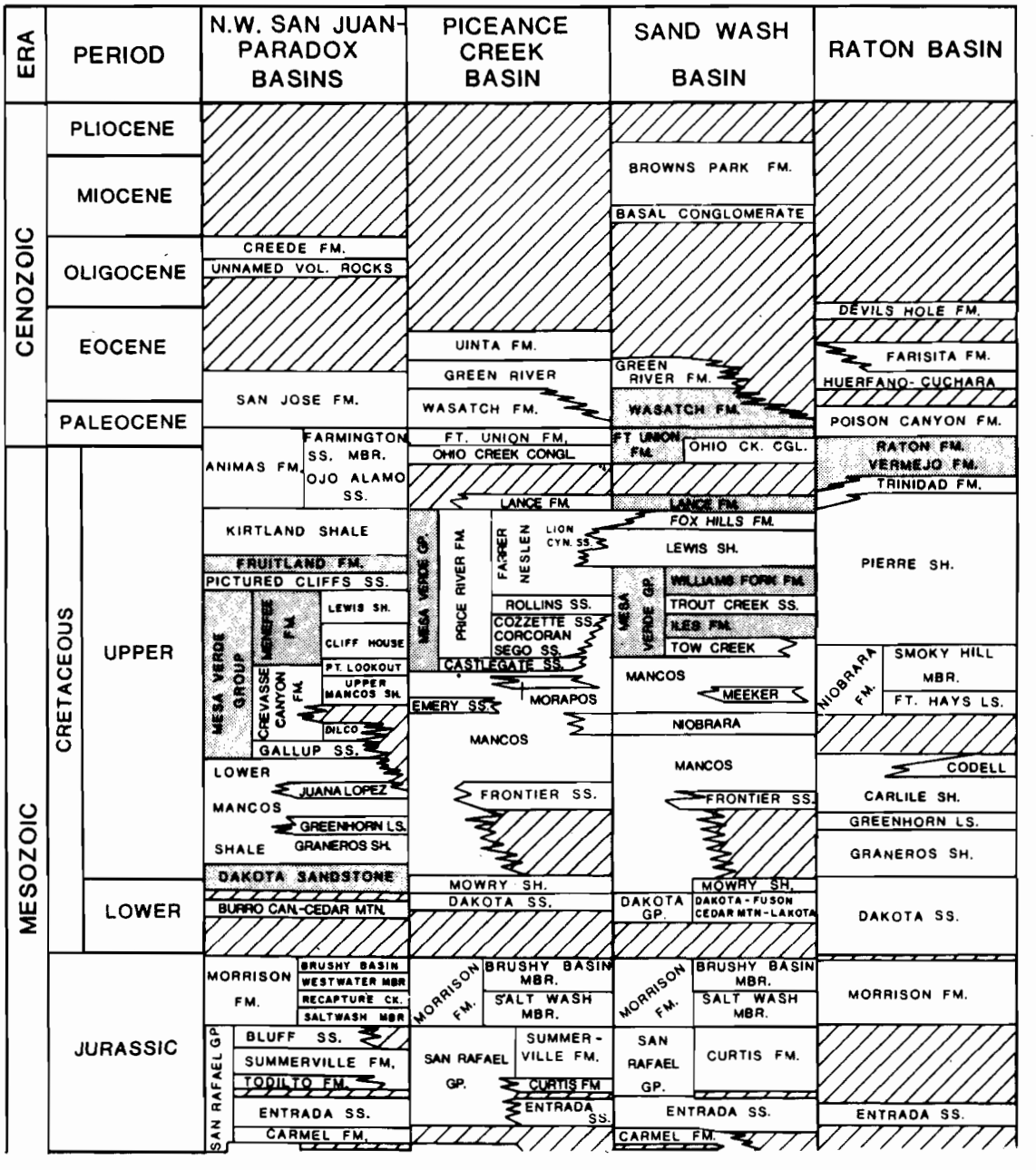


Fig. 4.--Colorado stratigraphic correlation chart (abbreviated); coal-bearing units are shaded.

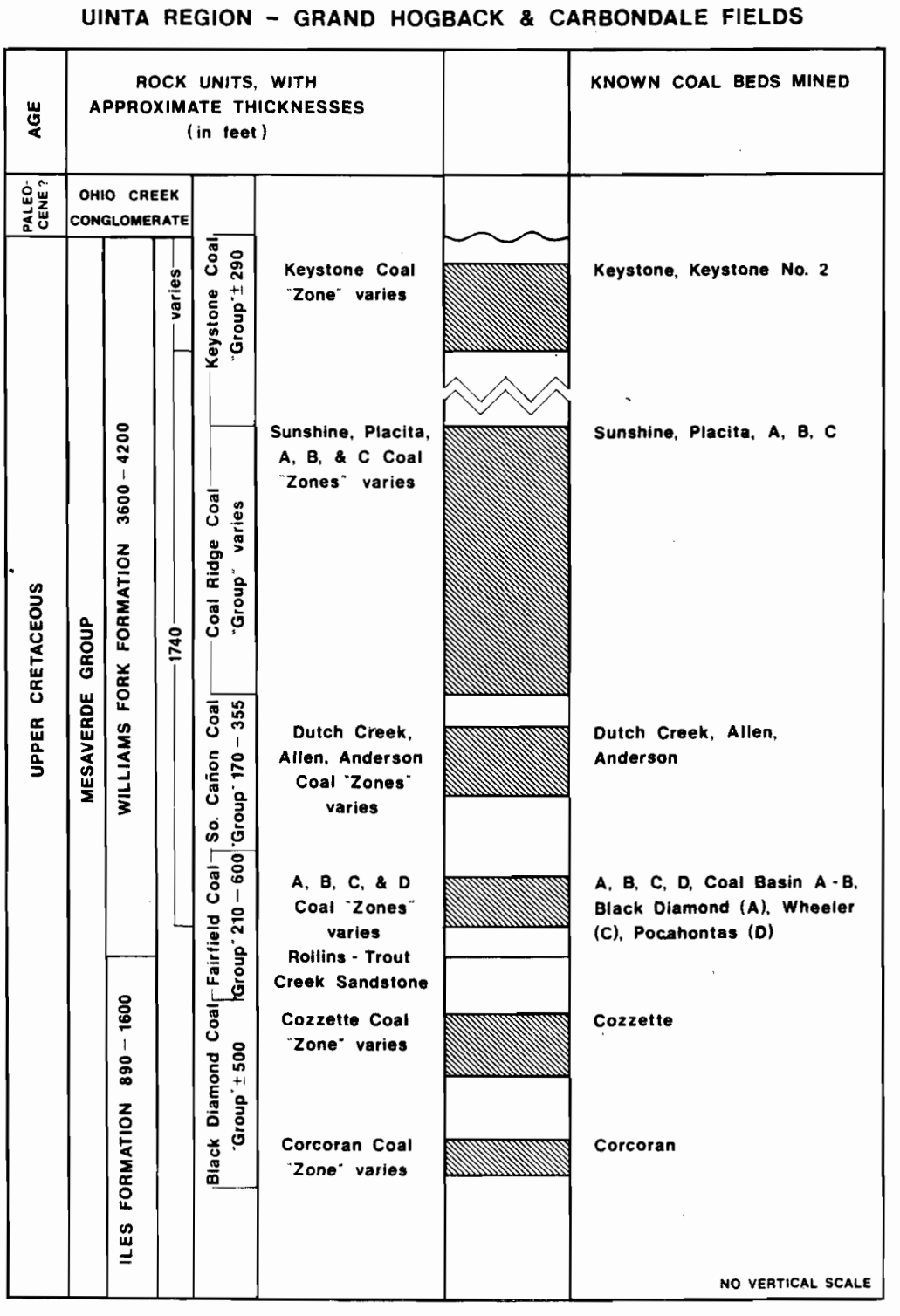


Fig. 5.--Generalized columnar section of Mesaverde Group, Grand Hogback and Carbondale coal fields, Uinta region, Colorado (from Boreck and Murray, ref. 3).

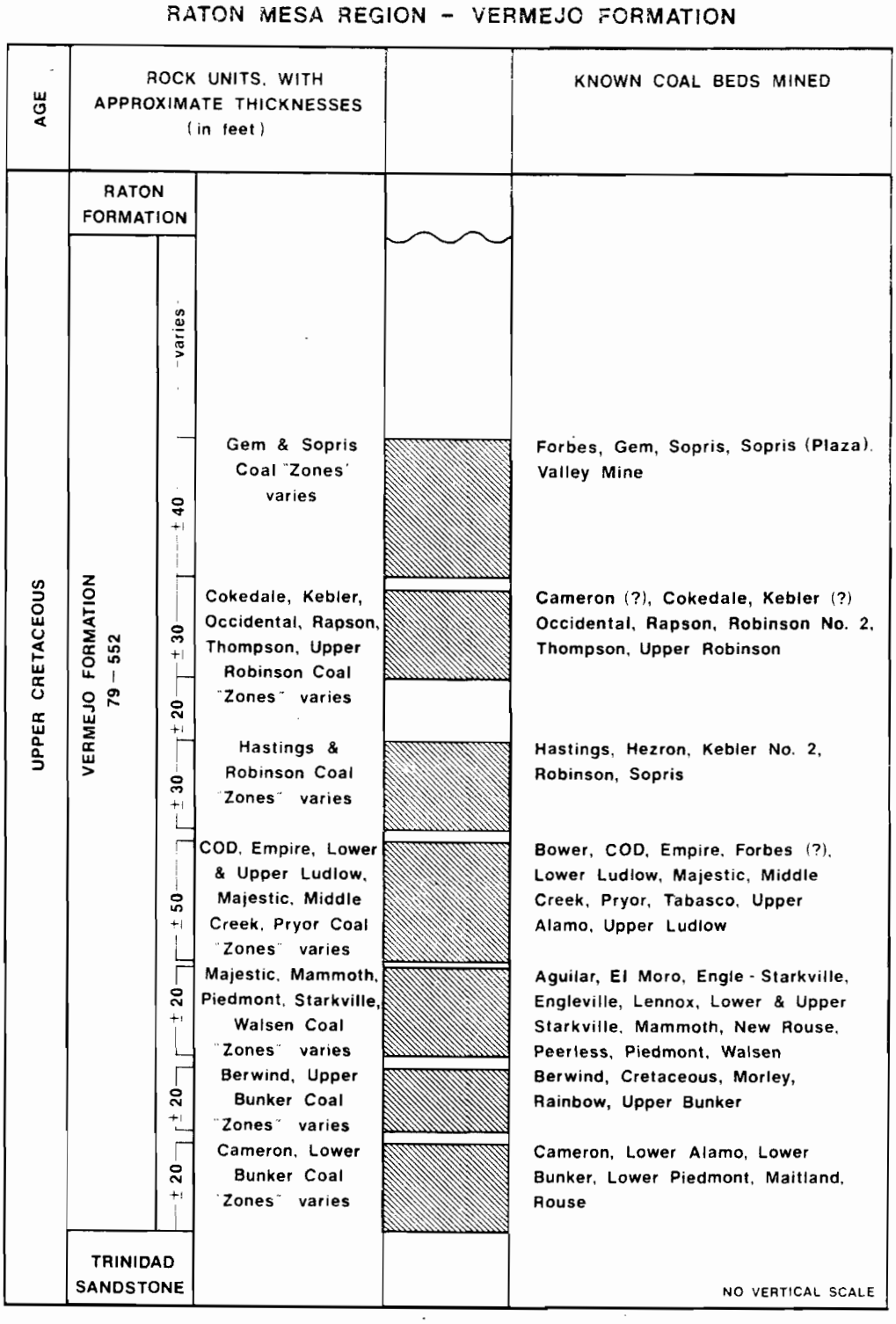


Fig. 6.--Generalized columnar section of Vermejo Formation, Raton Mesa coal region, Colorado (from Boreck and Murray, ref. 3).

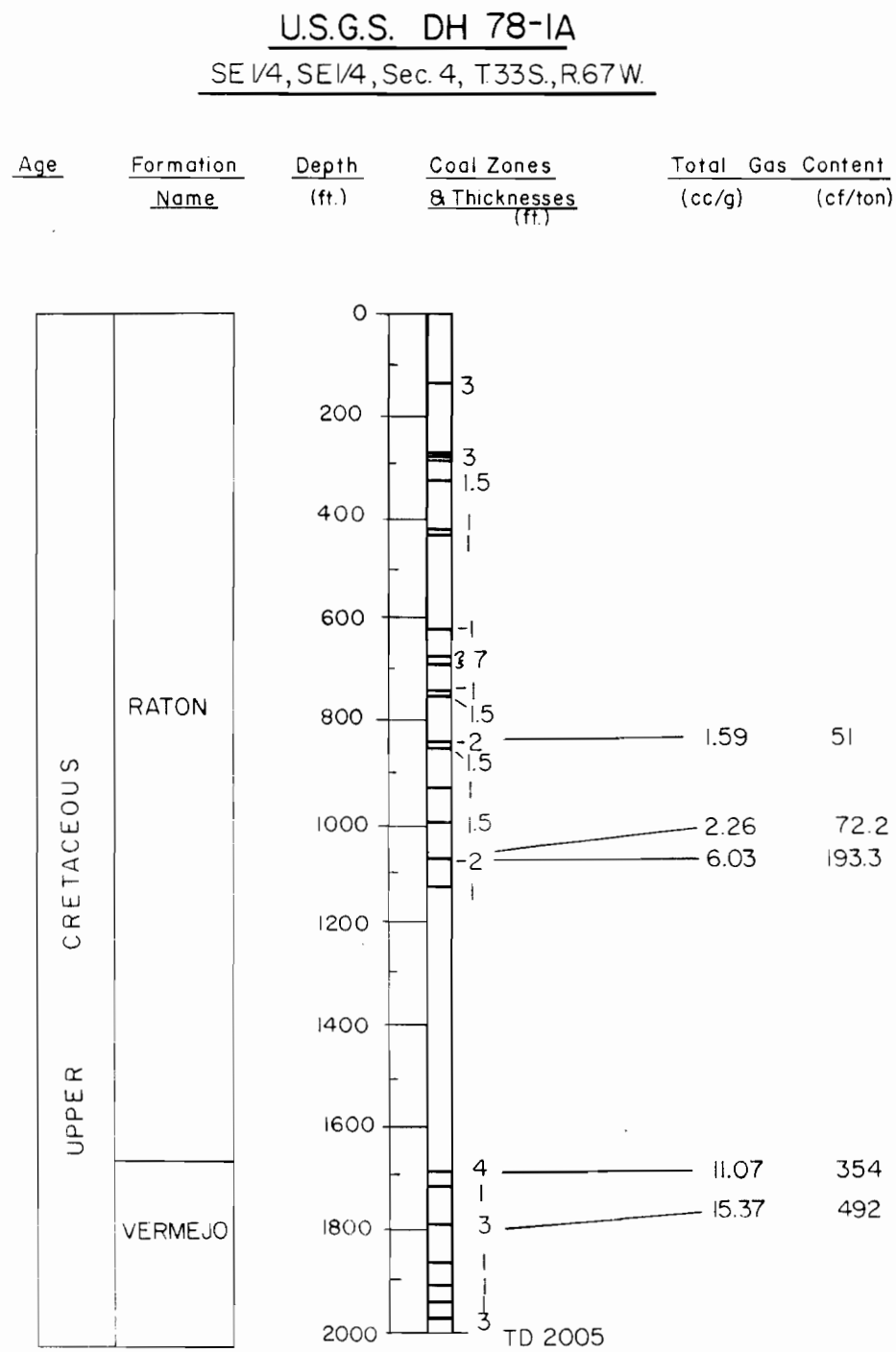


Fig. 7.--Stratigraphic column, U.S. Geological Survey drill hole DH 78-1A, Raton Mesa region, Colorado, showing coal beds and total gas content of cored coals (modified from Danilchik and others, ref. 5, Plate 2).

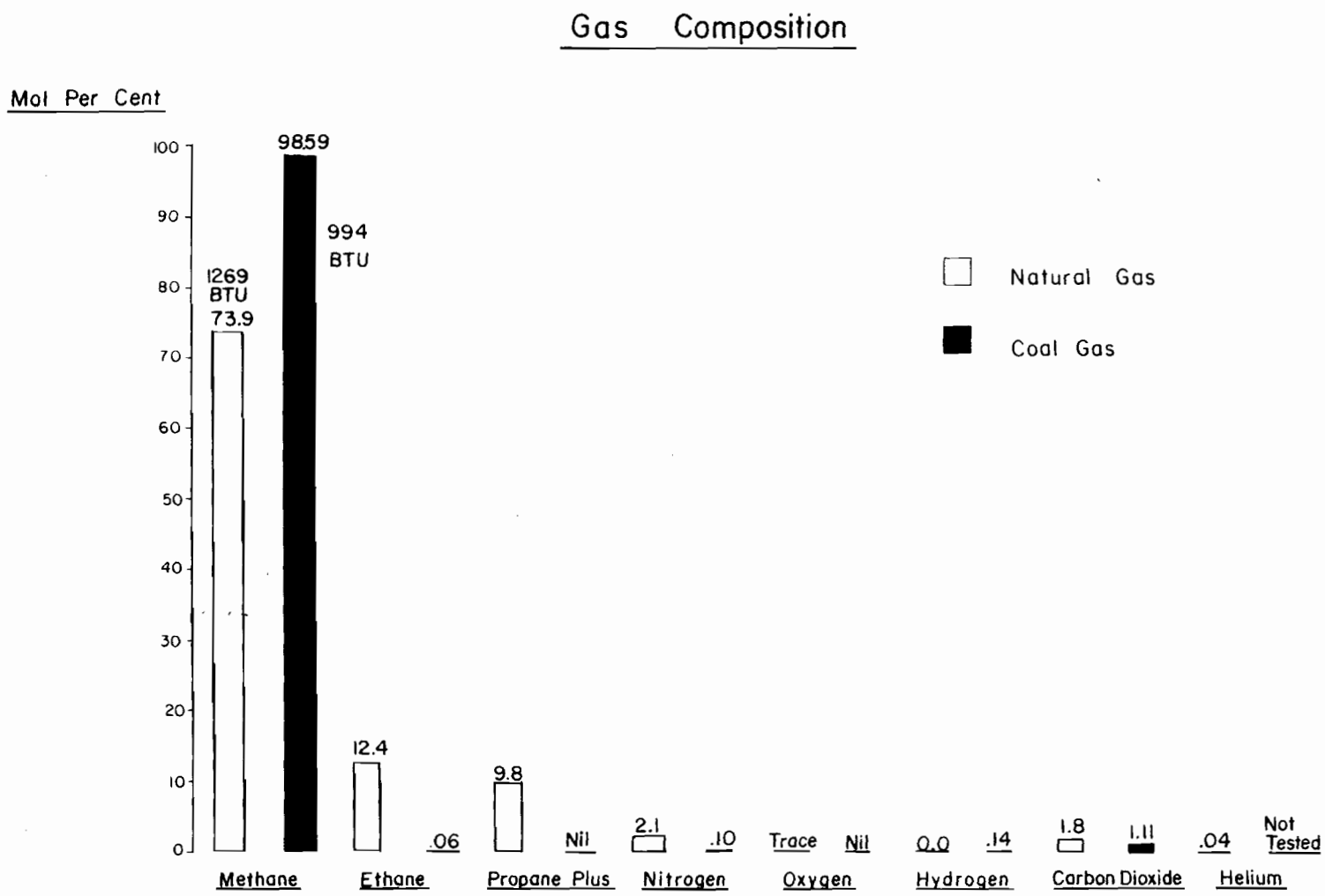


Fig. 8.--Comparison of composition of coal-bed gas with that of natural gas. Coal-bed gas composition from Table 3, this report; natural gas composition (of gas from well in Adams Co., Colo.) from Moore, ref. 17, p. 13.

THE DELINEATION OF METHANE RESOURCES IN UNMINABLE AND MINABLE COALBEDS

BY

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ABSTRACT

As a major part of its activities as the Integrating Contractor for the Methane Recovery from Coalbeds Project, TRW is assisting the DOE in its delineation of the methane resource.

The principal field activity in this resource engineering work is the testing of wells which are in target areas selected on the basis of the underlying coalbeds. TRW enters into cooperative agreements with the drilling company and provides the funding for the testing period.

This paper summarizes current and future activities and describes how cooperative projects are developed. The target areas, types of testing, the companies involved and the protection afforded the cooperative companies are also covered in this paper.

INTRODUCTION

Delineation of the methane content of the nation's coalbeds has been done on a very limited basis, mostly in conjunction with active mining. Previous work includes only a very small percentage of the coal resource and does not provide the knowledge needed to locate recovery and utilization projects in coalbeds with the greatest potential for methane production.

The objectives of the MRCP resource delineation effort are threefold:

- To estimate more reliably the amount of methane in coalbeds of the United States
- To determine the producibility of the resource
- To determine the characteristics which allow exploration data and production technologies to be extrapolated from test sites to larger resource areas.

To accomplish these objectives, a resource delineation plan was developed which defines an approach to providing a data base for determining the national resource and the reserve, and guiding management of the overall effort. The plan encompasses examination of 380,000 square miles of coal bearing rocks in the conterminous United States, to determine the quantity, distribution and production characteristics of some 789 trillion cubic feet of methane estimated to be contained in those rocks. Early efforts will concentrate on some 20 percent of this area (80,000 square miles) where the probabilities of finding, producing, and utilizing the methane are higher. Attempts will be made within this area of 80,000 square miles to supply one data point every 1,000 square miles (see Figure 1.)

THE DELINEATION OF METHANE RESOURCES IN UNMINABLE AND MINABLE COALBEDS

The basic approach utilized in the development of this plan was:

- To operate in a reconnaissance mode and use a basic 1,000 square mile sampling pattern within the areas of interest, and
- To operate first in those areas which are geologically best known and have the highest probability of early commercialization.

Basin selections were guided by the following general criteria:

- Physical and chemical characteristics of coal (i.e., fixed carbon, percent volatiles, percent sulfur, etc.) -- Higher rank coals generally contain more methane.
- Seam depth (East: 400 ft; West: 700 to 800 ft) -- Deeper coals are more likely to have retained the methane.
- Total effective coal thickness (East: 20 ft for high rank; West: 30 ft. Both related to individual thickness and depth) -- Higher total production per well possible on basis of multiseam completion.
- Individual seam thickness (minimum of 5 to 10 ft for shallow beds; multiple coalbeds considered as one if separated by permeable rock units) -- Minimize need for multiple fracturing.
- Extent (contiguous basin) -- Allow extrapolation of results to a wider area.

Based upon these criteria, portions of major basins were selected as the targets for initial resource delineation activities (Figure 2).

Wells are categorized on the basis of the kind of testing permitted as Type I, Type II, or Type III. Type I wells are conventional oil or gas wells being drilled to potential reservoirs beneath the coal and are available only for short-term (one or two day) tests. They are generally cored (conventional and sidewall, where possible) and drill stem tested in order to determine methane content and bed pressure. Type II wells are those drilled for any other purpose and scheduled for abandonment. All activities with Type II wells assume that the coal is cased with good cement over the coal zone. These wells are generally perforated in the coal zone and utilized for injection testing in order to better determine the bulk permeability of the coal bed(s). Type III wells are those expressively for completion as production wells for recovering methane from coalbeds. They can be used for the entire suite of tests.

SUMMARY OF 1978 ACTIVITIES

During 1978, the following wells were tested (see Figures 3 and 4):

San Juan Basin - Western Coal Company

Testing in the San Juan Basin in 1978 was confined to one core from a Western Coal Company corehole in San Juan County, New Mexico. The objective of this test was to provide coalbed methane content information on coal seams within the Fruitland Formation in the northwest portion of the San Juan Basin. Forty-three and a half (43.5) feet of core were cut between 370 and 413.5 feet, encountering accumulative coal thickness of 12.2 feet. Coals were cored between 387.3 and 387.8 feet, 395.5 and 403.7 feet, and 404.0 and 407.5 feet.

Two samples were selected for desorption, 398.2 to 398.8 feet and 398.8 to 399.4 feet. The gas content of these two very closely spaced samples range from 16.3 to 73.0 ft^3/ton of coal. The following table provides desorption and laboratory analyses of the sampled coals:

Depth (feet)	Gas Content (ft^3/ton)	Rank	Heating Valve (Btu/lb)	Moisture %	Volatile Matter %	Fixed C %	Ash %
398.2-398.8	73.0	Hvaa	12293	4.7	38.2	49.3	7.7
398.8-399.4	16.3	Hvab	12543	4.2	37.1	52.6	6.1

Piceance Basin - FUELCO

The first test, in conjunction with Fuel Resources Development Company (FUELCO), involved the cutting of 142 feet of core with coal samples collected for desorption from coal intervals at 1584 to 1586 feet and 1603 to 1604 feet. This coal was desorbed and yielded total gas in place of 17.9 and 80.9 ft^3/ton of coal, respectively. The coal unit which was the principal objective in this test was not cored because of an unanticipated fault shortening the section.

Piceance Basin - Twin Arrow #1

A Type II test to determine gas permeability flow rate and producibility of several coal seams was conducted in a well up for abandonment by Twin Arrow Drilling, the C&K #1-13 well. Coal was observed on borehole geophysical logs at the following intervals: 573 to 581, 627 to 633, 661 to 665, 726 to 736, 801 to 810, 1278 to 1282, 1494 to 1496, 1864 to 1870, 2116 to 2119, and 2148 to 2154 feet. It was determined that a retrievable bridge plug should be set at 1050 feet and the units above that point tested. The hole was swabbed dry following the insertion of the bridge plug. Water continued to enter the hole through existing perforations at 927 and 1025 feet at a rate of 2.5 barrels/hr. The pressure and flow were negligible. The hole was then squeeze cemented from 1050 to 320 feet and the well perforated in five (5) zones at one shot per foot. The zones perforated were 573 to 581 feet, 627 to 633 feet, 661 to 665 feet, 726 to 736 feet, and 801 to 810 feet. All zones were treated with 7.5% HF totalling 500 gallons, swabbed dry and pressure tested. Shut-in pressure was 0.0 psig, no flow was observed through a 1/8 inch orifice, and testing was terminated.

Illinois Basin - Hagen Oil Company

Testing of the Hagen Oil Company, #2 Henderson well, in Clay County, Illinois (Type I), provided gas content and reservoir parameter data for the Illinois Basin coals of Pennsylvanian age. One hundred and ninety four feet of core was cut between 990 feet and 1510 feet. Coal was encountered at the following depth intervals: 992 to 995 feet, Danville No. 7; 1034 to 1036 feet, Herrin No. 6; 1074 to 1075.5 feet, Briar Hill No. 5A; 1089 to 1090.5 feet, Harrisburg No. 5; and 1352 to 1352.5 feet, the Seelyville.

Desorption of eight conventional core coal samples yielded gas contents ranging from 8.3 to 40.0 ft^3/ton of coal. While the sample from the deepest coal, the Seelyville, had the highest gas content, the next highest was from the shallowest coal sampled. There appears to be minimal correlation of gas content with depth in these samples. Proximate/ultimate analysis has not yet been completed, so we are not yet able to attempt any coal rank vs gas content correlations. Sidewall core desorption analyses were conducted on one coal sample (992.5 to 993.0 ft, coal and gray shale) and on two shale samples (993.5 to 994.5 ft, gray shale; and 1077.5 to 1078.5 ft, carbonaceous shale to dark gray shale). The coal contained 27.7 ft^3/ton gas in place while the shales contained 55.2 ft^3/ton and 19.0 ft^3/ton, respectively.

Three DST's were attempted to attempt to ascertain reservoir parameters for the respective coal bearing intervals. In this well, it was possible to set packers to test a 12 foot interval so only relatively small portions of the non-coal section were tested. The intervals tested were 1342 to 1354 feet, the Seelyville interval; 1071 to 1083 feet, the Briar Hill No. 5A interval; and 1026 to 1038 feet, the Herrin No. 6 interval. The last test was misrun when the tool plugged. The other two showed the reservoirs to be at normal hydrostatic pressure and with limited permeability (< 2 md). No gas was observed in either successful test.

An estimate of gas-in-place based on eight feet of coal thickness is only 200 MMcf/640 acres. With the extremely low permeability of the two seams tested, the deliverability must be less than 10 Mcf/day. A realistic value for discounted gas deliverability, Ø, is in the range of 1000 to 2000 Mcf.

Arkoma Basin - Arkla Exploration

Sidewall coring and drill stem testing were conducted on a well drilled and logged by Arkla Exploration, the Brown #1-2, in Pittsburg County, Oklahoma. This well was drilled in the Arkoma Basin and the cooperative work led to the sidewall core desorption and drill stem testing of the Hartshorne coal of Pennsylvania age at about 2700 feet. On the basis of depth and coalbed description, it is likely that the coalbed encountered at 2726 feet is the Upper Hartshorne coal. The shallower seams are likely thin coals in the McAlester Shale. No conventional coring was planned or conducted.

Forty-eight sidewall core shots were taken in the intervals 1833.0 to 1834.0 feet, 1903.0 to 1906.0 feet, 2124.0 to 2131.0 feet, and 2703.0 to 2732.0 feet, identified on borehole geophysical logs as being coal-bearing intervals. Two sidewall cores were recovered in the first interval, three in the second, seventeen in the third interval, and eighteen in the deepest interval. Gas contents observed ranged from 72 ft^3/ton to 131 ft^3/ton of coal.

Two DST's were planned, one in the Upper Hartshorne coal and one in the coal at about 2120 feet. The DST of the Hartshorne, conducted over the interval 2700 to 2740 feet showed flow of 9.0 barrels of water per day at a shutin pressure of 716 psig. The average permeability calculated over the interval was 4.5 md. The second DST was cancelled at Arkla's request because of risk of sticking tail pipe below the packers during the test.

Using weighted average values for gas content, the gas-in-place is estimated at 1.4 Bcf/640 acres. Using maximum permeability of 1.0 md and maximum relative permeability curve and maximum permeability of 0.1 md and minimum relative permeability curve, a range of discounted gas deliverability, Ø, of 40,000 Mcf and 3500 Mcf, was calculated.

Confidential - Colorado

Tests on a Confidential (Type I) well in Colorado yielded data on coals from the Upper Cretaceous Mesaverde Group between depths of about 3650 and 4985 feet. Conventional coring was planned to provide coal samples for desorption from three coal rich zones in the Mesaverde Group. A total of 16.2 feet of coal in eight different intervals was encountered in 139 feet of core. Two feet were cored in the upper coal zone (3652.0 to 3652.6 ft and 3674.7 and 3676.1 ft), 1.6 feet in the middle zone (3923.0 to 3924.1 ft, 3937.0 to 3937.2 ft and 3947.9 to 3948.2 ft), and 12.6 feet in the lower zone (4649.0 to 4659.8 ft, 4660.8 to 4661.0 ft, and 4704.4 to 4706.0 ft). Mesaverde coals are discontinuous, lenticular bodies which are difficult to correlate under good conditions. The nearest well control which was logged through the coal zone was six miles from this test, making any attempt at correlation questionable at best. Borehole geophysical logs on this hole indicate the presence of approximately 150 feet of coal in the well.

Methane desorption of the 14 conventional core samples is still in progress but the preliminary data indicate methane contents of most samples well in excess of 200 cubic feet per ton of coal. Some of these samples have been desorbing significant volumes of methane for more than six months.

Twenty-six sidewall cores were obtained from this well. Eleven coal samples and one very carbonaceous shale were selected for complete desorption by GeoChem Research to provide additional gas content data on seams observed on logs. These samples yield gas contents ranging from less than 100 ft^3/ton for carbonaceous shale to about 210 ft^3/ton for coal at 4864 ft. Attempts were made to collect sidewall cores from each interval cored by conventional methods. However, the high percentage of misfires and sidewall core bullets lost in the hole stymied this effort. While these gas contents are lower than those being determined for conventional core samples, it must be noted that they are within the same range.

Two drill stem tests were conducted in an attempt to gain additional information on the reservoir parameters of coalbeds. The tests were over intervals significantly thicker than the coalbeds of interest and as such cannot be considered to be representative of the coalbeds alone. The tests were conducted over depth intervals of 3700 to 3800 feet and 4634 to 4714 feet. DST testing of the upper interval (3600-3700 feet) flowed gas to the surface at about 4 oz pressure. Two hundred and fifty six feet of mud cut water was recovered. Pressure extrapolates to 1642 psia with a pressure gradient of 0.44 psi/ft. Testing of the lower interval (4634-4714 feet) also flowed trace of gas to surface. Recovery totalled 4433 ft of fluid including 1478 ft of gas and mud cut water, and 1477 ft of gas cut water. The formation fluid was fresh with a chloride content of 700 ppm. Extrapolation

of initial shutin pressure build up indicates a maximum reservoir pressure of 2028 psig with a pressure gradient of 0.44 psi/ft. This test indicates a permeability of about 1450 md for the 15 foot interval reported by Johnston and of about 1000 md for the 22 foot interval reported by Intercomp on their analysis of Johnston's test data.

Estimates of gas-in-place for the upper zone range from 1.8 to 4.0 Bcf/640 acres. These parameters give ranges of discounted gas deliverability, Ø, of 16,000 Mcf to 65,000 Mcf. These calculations are based on the assumption that only the twelve feet of coal in the 100 ft interval tested contribute to the parameters utilized in the calculation of deliverability.

Estimates of gas-in-place from the lower zone yield 6.6 Bcf/640 acres. The high permeability determined from the DST is outside the ranges investigated for the model, so no effort was made to calculate discounted gas deliverability, Ø, for this interval.

In light of the relatively high gas contents and the thickness of the coal, additional testing is anticipated in this well in 1979. Plans have been made to complete one coal interval, 4863 to 4873 feet, utilizing artificial stimulation (fracturing) if necessary, to equip the well for a long term production test, and to conduct a long term production test if water and gas flow conditions justify such.

Piceance Basin - Twin Arrow #2

A second Type I test was conducted in a well being drilled by Twin Arrow Drilling, the C&K #4-14 well, on the Douglas Creek Arch. Of the series of tests planned for this well, only the coring and desorption of the shallow coal seams could be completed as the hole was lost before reaching the deeper coal seams at about 2100 feet. One hundred and fifty feet of core were cut from which five coal samples, two carbonaceous shales with coal samples, and two carbonaceous shale and/or siltstone were collected for desorption analysis.

Gas-in-place estimates utilizing gas content data from Fuelco and Twin Arrow #1 and an average thickness of 6.2 ft yield approximately 750 MMcf/640 acres. This low gas content coupled with no flow from the tests of Twin Arrow #1 indicates minimal deliverability.

Green River Basin - Belco Petroleum Corporation

Testing of a Belco Petroleum Corporation well (S-29-27) in Sublette County, Wyoming (Type I), in the northwest corner of the Green River Basin yielded thin coals with very high gas contents. Three coal seams were anticipated, on the basis of nearby well control, in a 100 foot interval. Unfortunately, the upper seam was penetrated in drilling at 3436 feet and was not sampled by conventional core. These coal seams are in the upper part of the Mesaverde group in this area. Ninety feet of core was cut starting at a depth of 3450 feet. Coal was cored and sampled at depths of 3479.1 to 3481.4 feet, 3494.8 to 3496.5 feet and 3526.6 to 3528.2 feet. Nine conventional core samples of coal are still desorbing but to date have indicated between 384 and 480 ft^3/ton of coal. Two carbonaceous shale samples from these intervals yielded 28 and 172 ft^3/ton.

Eighteen sidewall cores were collected and combined into 7 samples. The depth intervals and lithologies sampled were 3438.5 feet, coal (1 spl); 3440 to 3485.5 feet, carbonaceous shale (3 spls); and 3498 to 3499.5 feet, coal (3 spls). Methane contents for the coal samples range from 214 to 315 ft^3/ton of coal while those for carbonaceous shale range from 98 to 212 ft^3/ton of rock.

Gas chromatographic analysis of gases desorbed from conventional cores normalized for air contamination indicates that the gas is 94% light hydrocarbons, 6% CO_2, trace amounts of H_2.

An anticipated DST was not run at the request of the cooperator because of inclement weather (-50°F) and potential for hole problems caused by well bore sloughing.

Estimates of gas-in-place using average gas content values and an average thickness of 14 feet yield 6.1 Bcf/640 acres. Estimating permeability at between 1.0 and 10.0 md and maximum and minimum relative permeabilities, fracture length and conductivity at 1000 ft and 50,000 md/in respectively, and reservoir pressure at hydrostatic, the estimated value for Ø is between 25,000 and 90,000 Mcf.

Northern Appalachians - Kinloch Development

Testing was conducted in the Kinlock Development, Murdock Farm #1 well (referred to as Murdock #1) in Whiteley Township, Greene County, Pennsylvania by Kinlock Development and their subcontractor Intercomp. The well was drilled to a total depth of 1608 feet and penetrated 11 seams totalling 60 feet of coal. Twelve and a half feet of coal are from the Pittsburgh coal zone and 17.5 feet are in the Kittanning Formation. The well was logged (Neutron, Compensated Density, Induction, and Lithological), sidewall cored, perforated, flow tested, stimulated (hydraulic fracturing, using the Kiel process), and post fracture injection tested. Water and gas production testing were recommended but not carried out.

Two coal samples were collected by sidewall coring and analyzed for methane content. One sample from the Pittsburgh seam at a depth 658 to 664 feet yielded gas-in-place determination 62.4 ft^3/ton of coal. Another from the Waynesburg coal, 329 to 333 feet yielded 33.3 ft^3/ton.

Coal seams at 1340, 1398, 1424, and 1485 were perforated and injection tested. Pre-stimulation permeability was determined to be between 0.5 and 1.0 md. An eight stage Kiel frac stimulation process was designed for 5000 barrels of water containing 32,000 pounds of 80/100 mesh sand. The design injection rate was 40 bbl/minute at 1800-2000 psi. The design injection rate was never attained because of higher than anticipated injection pressures. The first stage was achieved at a rate of 26 barrels/min at pressure of 3800-3900 psi, the maximum pressure allowed on the casing. Succeeding stages were shortened due to high pressures. The total volume pumped was 1533 bbl, containing 18,480 pounds of 80/100 mesh sand and 15,750 pounds of 20/40 mesh sand. Following a few days of flow back, the well produced about 80 bbl of water per day with a show of gas.

A series of short-term injection tests were run prior to pumping the well. These tests produced little quantitative information but indicated significant improvement in flow in three of the four zones stimulated.

A sucker rod pump was placed on the well, but no gas or water meters were installed so it was impossible to accurately monitor production or changes in production.

A second well, the #1 Stoner, was drilled, logged, and sidwall cored but not tested. Sidewall core gas content data follows:

Coal Seam	Depth (ft)	Gas Content (ft^3/ton)
Pittsburgh	422-426.5	105.6
Bakerstown	825.5-826.5	243.2
U. Freeport	1003-1005	265.6
M. Kittanning	1155-1155.5	214.4
L. Kittanning-Brookville-Clarion	1181-1244	425.6

The expected increase in gas content with depth of coal is observed.

The five samples from the #1 Stoner well represent a total of 34 feet of coal with a combined gas content of 14,430 Mcf/acre. This represents gas-in-place of 9.2 Bcf/640 acres.

1979 PLANNED ACTIVITIES

The 1979 Resource Delineation efforts revolve around:

- 24 Individual Well Tests
- 6 Basin Geologic Reports
- 1 detailed site investigation including landsat review, surface geophysical testing and site surface geologic mapping.

We expect to reasonably accomplish this many well tests during 1979 because of a fairly simplified contracting mode for operating with cooperating drillers/operators. This allows rapid contract placement while meeting government requirements and the ability to provide valid assurances of the acceptance of responsibility for wells while they are being tested for MRCP purposes. To date, TRW has preliminary agreements for nine well tests in 1979. The basin reports scheduled for 1979 preparation are the Illinois Basin, Powder River Basin, San Juan Basin, Arkoma Basin, Green River Basin and Bellingham, Cokedale-Hamilton.

The site selected for the detailed geological investigation is on the Colorado/New Mexico border near Durango, Colorado. Well tests are also scheduled for the area so correlation of test results will be possible.

METHANE RECOVERY FROM COALBEDS

RESOURCE DELINEATION

AREAS OF INTEREST:

NORTHERN APPALACHIANS	ILLINOIS BASIN
MIDDLE APPALACHIANS	POWDER RIVER BASIN
SOUTHERN APPALACHIANS	RATON MESA BASIN
ARKOMA BASIN	SAN JUAN BASIN
BELLINGHAM, WASHINGTON	UINTA-PICEANCE BASIN
GREEN RIVER BASIN	WIND RIVER BASIN

Figure 1. MRCP Resource Delineation Areas of Interest

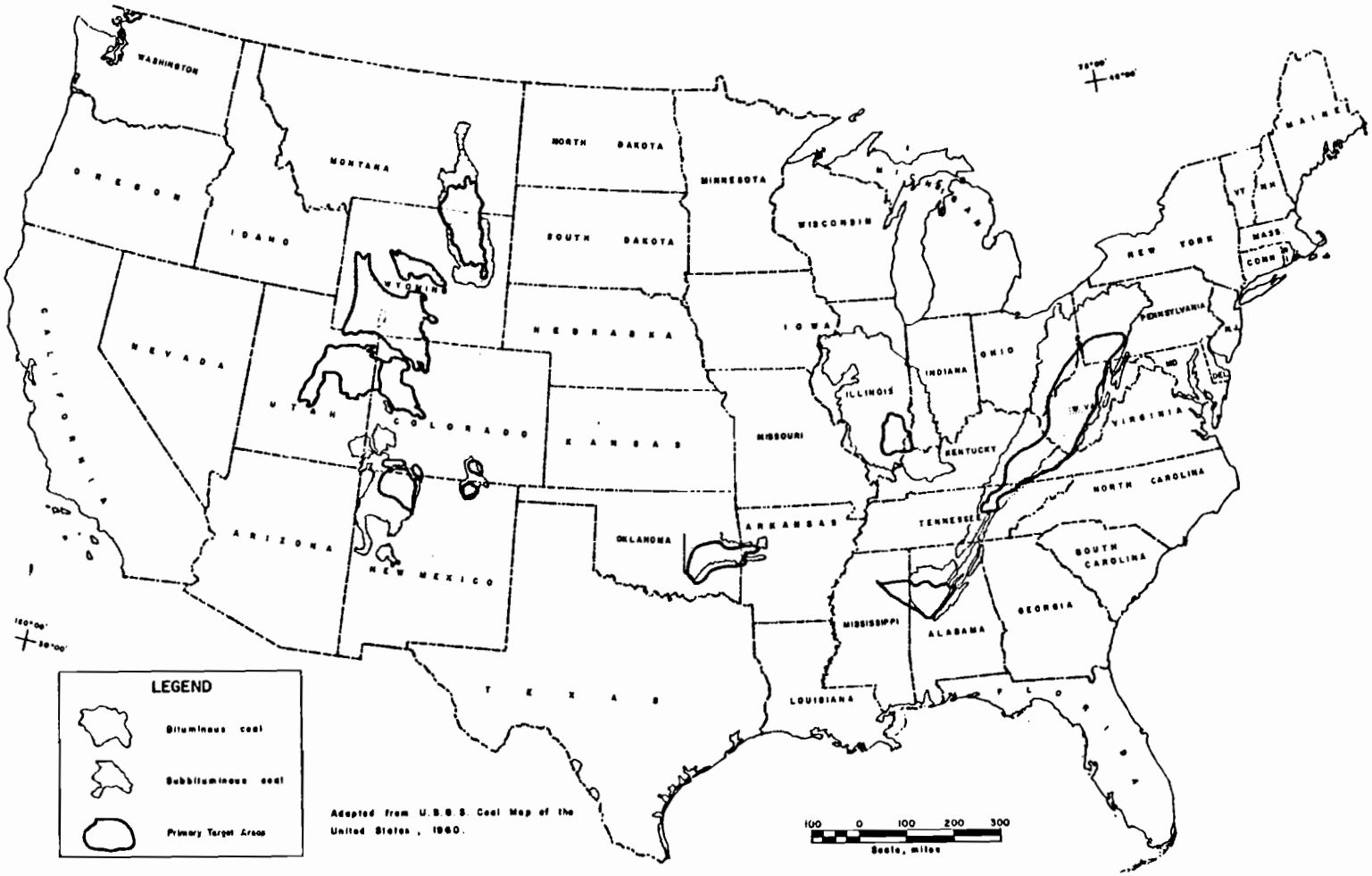

Figure 2. Target Areas for Initial Resource Delineation Activities

COOPERATING COMPANY	LOCATION	GEOLOGIC BASIN	TYPE OF TEST	COAL CORED (FT)	GAS CONTENT FT^3/TON
WESTERN COAL	SAN JUAN COUNTY, NM	SAN JUAN	CONVENTIONAL CORE DESORPTION	12.2	16.3-73.0
FUELCO	RIO BLANCO COUNTY, CO	PICEANCE	CONVENTIONAL CORE DESORPTION	4.5	17.9-80.9
TWIN ARROW #1	RIO BLANCO COUNTY, CO	PICEANCE	PRESSURE AND FLOW TEST	--	--
HAGEN OIL	CLAY COUNTY, ILLINOIS	ILLINOIS	CONVENTIONAL CORE SIDEWALL CORE SAMPLE DESORPTION DRILL STEM TEST LOGGING	8.1	8.3-40.0
ARKLA EXPLORATION	PITTSBURG COUNTY, OK	ARKOMA	SIDEWALL CORE DRILL STEM TEST		72-131
CONFIDENTIAL	COLORADO	--	CONVENTIONAL CORE SIDEWALL CORE SAMPLE DESORPTION DRILL STEM TEST LOGGING	16.3	170.5-259.0

Figure 3. 1978 Wells Tested

COOPERATING COMPANY	LOCATION	GEOLOGIC BASIN	TYPE OF TEST	COAL CORED (FT)	GAS CONTENT FT^3/TON
TWIN ARROW #2	RIO BLANCO COUNTY,CO	PICEANCE	CONVENTIONAL CORE SAMPLE DESORPTION	7.9	33.1-146.9
BELCO	SUBLETTE COUNTY, WY	GREEN RIVER	CONVENTIONAL CORE SIDEWALL CORE SAMPLE DESORPTION LOGGING	5.6	23.5-392.0*
KINLOCH	GREENE COUNTY, PA	N. APPALACHIAN	WELL TEST		55-65

Figure 4. 1978 Wells Tested (Contd.)

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METHANE RECOVERY FROM COALBEDS SYMPOSIUM

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