18A

PNL-3413
UC-11

An Assessment of Environmental Health and Safety Issues Associated with the Commercialization of Unconventional Gas Recovery: Methane from Coal Seams

Project Manager
E. F. Riedel

July 1980

Prepared for the U.S. Department of Energy
Assistant Secretary for Environment
Office of Environmental Assessments
Technology Assessments Division
under Contract DE-AC06-76RLO 1830

Pacific Northwest Laboratory
Operated for the U.S. Department of Energy
by Battelle Memorial Institute

Battelle

PNL-3413

NOTICE

This report was prepared as an account of work sponsored by the United States Government. Neither the United States nor the Department of Energy, nor any of their employees, nor any of their contractors, subcontractors, or their employees, makes any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness or usefulness of any information, apparatus, product or process disclosed, or represents that its use would not infringe privately owned rights.

The views, opinions and conclusions contained in this report are those of the contractor and do not necessarily represent those of the United States Government or the United States Department of Energy.

PACIFIC NORTHWEST LABORATORY
operated by
BATTELLE
for the
UNITED STATES DEPARTMENT OF ENERGY
Under Contract DE-AC06-76RLO 1830

Printed in the United States of America
Available from
National Technical Information Service
United States Department of Commerce
5285 Port Royal Road
Springfield, Virginia 22151

Price: Printed Copy $_____*; Microfiche $3.00

*Pages	NTIS Selling Price
001-025	$4.00
026-050	$4.50
051-075	$5.25
076-100	$6.00
101-125	$6.50
126-150	$7.25
151-175	$8.00
176-200	$9.00
201-225	$9.25
226-250	$9.50
251-275	$10.75
276-300	$11.00

PNL-3413
UC-11

3 3679 00055 2309

AN ASSESSMENT OF ENVIRONMENTAL HEALTH AND SAFETY ISSUES ASSOCIATED WITH THE COMMERCIALIZATION OF UNCONVENTIONAL GAS RECOVERY: METHANE FROM COAL SEAMS

Authors

L. J. Ethridge
C. E. Cowan
E. F. Riedel

PNL Project Manager

E. F. Riedel

DOE Project Manager

G. J. Rotariu
Office of Environmental Assessments
Technology Assessments Division

July 1980

Prepared for
the U.S. Department of Energy
under Contract DE-AC06-76RLO 1830

Pacific Northwest Laboratory
Richland, Washington 99352

CONTENTS

1.0 INTRODUCTION 1-1

2.0 RESOURCE DESCRIPTION 2-1

2.1 ORIGIN OF COALBED METHANE 2-1

2.2 COALBED GAS COMPOSITION 2-2

2.3 LOCATION OF COALBEDS 2-3

3.0 METHANE RECOVERY TECHNOLOGY 3-1

3.1 EXPLORATION AND SAMPLING 3-1

3.2 SITE PREPARATION 3-2

3.3 DRILLING TECHNIQUES 3-2

3.3.1 Vertical Surface Boreholes 3-3

3.3.2 Horizontal Boreholes from Shaft Bottoms . . . 3-4

3.3.3 Directional Drilling 3-7

3.3.4 Horizontal Boreholes in Active Mines 3-8

3.3.5 Vertical Boreholes into Gob Areas 3-8

3.4 STIMULATION TECHNIQUES 3-9

3.4.1 Hydraulic Fluids 3-10

3.4.2 Conventional Hydraulic Stimulation 3-11

3.4.3 Foam Stimulation 3-13

3.5 PRODUCTION AND UTILIZATION 3-15

3.5.1 Pipeline Injection 3-15

3.5.2 Power Generation 3-16

3.5.3 Heating Applications 3-17

3.5.4 Liquefied Natural Gas (LNG) Production . . . 3-17

3.5.5 Chemical Production 3-18

3.6 SITE RESTORATION 3-18

4.0 BARRIERS TO COMMERCIAL PRODUCTION 4-1

4.1 OWNERSHIP OF THE COALBED METHANE 4-1

4.2 CLASSIFICATION OF COALBED GAS 4-2

4.3 APPLICABILITY OF REGULATIONS 4-4

4.4 JURISDICTION OF THE FEDERAL ENERGY REGULATORY COMMISSION . 4-5

4.5 PERCEPTION OF MINING HAZARDS 4-6

5.0 ASSESSMENT ENVIRONMENTAL, HEALTH AND SAFETY IMPACTS . . . 5-1

5.1 ENVIRONMENTAL ASSESSMENT 5-1

5.1.1 Exploration 5-1

5.1.2 Field Development 5-4

5.1.3 Production 5-9

5.1.4 Abandonment 5-10

5.2 HEALTH AND SAFETY ASSESSMENT 5-11

5.2.1 Noise 5-11

5.2.2 Air Pollution 5-13

5.2.3 Mining Hazards 5-14

6.0 CONCLUSIONS AND RECOMMENDATIONS 6-1

LITERATURE CITED Ref-1

BIBLIOGRAPHY Bibl-1

FIGURES

1. Areal Distribution of Coals in the Contiguous U.S. . . . 2-4
2. Process Development Sequence 3-1
3. Typical Surface Plant Layout 3-3
4. Cross Section of a Borehole Used for Degasification . . . 3-5
5. Flow of Processes in Degasification 3-6
6. Schematic for Power Generation 3-17
7. Decibel Levels and Verbal Loudness Descriptions of Various Sounds 5-12
8. Relationship Between CO Exposure (Hours and Concentration) Versus Health Effects 5-14

TABLES

1. Average Composition of Coalbed Gas from Different Mines as Compared with Natural Gas 2-3
2. Representative Production Data for Degasification of Coalbeds . 3-4
3. Comparison of Three Hydraulic Fracturing Procedures . . . 3-13
4. Foam Stimulation Treatments 3-14
5. Applicable Environmental, Health, and Safety Regulations . . 5-2
6. Potential Environmental Impacts from Coalbed Methane Production . 5-3
7. Emissions from One 1100 hp Diesel Engine 5-7
8. Emissions from a Typical Stimulation Job 5-9
9. Composition of Water from Three Coalbeds 5-10

1.0 INTRODUCTION

The United States is in the midst of an energy crisis which is becoming increasingly more serious. The problems, which became readily apparent with the Arabian Oil Embargo of 1973, have worsened with the loss of production of oil in Iran coupled with large price increases by the Organization of Petroleum Exporting Countries (OPEC). These problems have emphasized the need for the United States to develop and implement new techniques for the identification and increased recoverability of our fossil energy resources.

Recovering natural gas from unconventional sources is of major importance in the overall energy program. There are currently four identified sources of unconventional natural gas. The Department of Energy (DOE) has initiated four projects, directed at each of these resource areas:

Sources	Projects
Tight gas sands	Western gas sands
Methane associated with coal seams	Methane from coal
Devonian age shales	Eastern gas shales
Methane contained in geopressured aquifers	Geopressured aquifers

On July 16, 1979, President Carter proposed a program which would have a major impact on the recovery of gas from unconventional sources. The President asked Congress to create an independent Energy Security Corporation which will make investments in the production of synthetic fuels from coal, biomass, peat and oil shale, and in the development of reserves of unconventional natural gas. Before these unconventional natural gas sources can add significantly to our nation's supply, the public health and safety, environmental, social, economic, and legal/political consequences and constraints that may be associated with these technologies must be identified and examined. The assessment discussed in this paper is limited to the identification and examination of potential public health and safety programs and the potential environmental impacts from recovery of gas from coalbeds. The gas associated with coalbeds is frequently referred to as methane gas, even though methane is only one of a number of gases

present. The terms methane and coalbed gas are used interchangeably in this report. This assessment is being conducted for the Technology Assessments Division, Office of Environmental Assessments, under the Assistant Secretary of the Environment in the U.S. Department of Energy. This division is responsible for assessing all potential consequences and constraints of any new technology for producing energy. These assessments provide information for a number of different uses: Environmental Readiness Documents (ERD's), Environmental Assessments (EA's), Environmental Impact Statements (EIS's), Environmental Development Plans (EDP's), and Project Environmental Plans (PEP's). In addition the results may be used in the development of policy and the formulation and implementation of Research and Development (R&D) plans.

The interest in coalbed methane as a gas resource grew out of research to reduce the safety hazard of methane in the atmosphere of coal mines. The presence of methane in coal seams is a major safety problem in coal mining operations. Mine safety laws forbid the operation of equipment in an atmosphere that contains more than 1% methane. Therefore, the methane content within the mine is constantly monitored. To make the mine atmosphere safe, tremendous quantities of air must be circulated through the mine to dilute and expel the methane. In the average coal mine, approximately 4 to 6 tons of air are circulated per ton of coal produced.

To make coal mining safer and to reduce costs caused by delays, due to excessive methane concentrations in the mine atmosphere, extensive research has been conducted on methane-related problems. One technique employed to reduce the concentration of methane was to drain it from the coalbeds prior to mining, especially in gassy mines. During the development of these drainage techniques, it was discovered that gas drained from coalbeds was of sufficient quality and quantity to be used as a supplement to natural gas supplies. Such gas has been recovered from European mines for a number of years and used as natural gas.

Coal mines in the United States emit more than 200 thousand standard cubic feet per day (Mscfd) of methane into the atmosphere from ventilation shafts. If the average gas content is estimated at 220 ft^3/ton, the minable coal in the coterminous U.S. contains more than 300 trillion cubic feet (Tcf) of gas

(Kim 1978b). This is a conservative estimate that may be extended as additional information becomes available on the thickness and continuity of other deeper formations. Coalbeds considered too thin to be mineable can still contain significant volumes of methane gas that may be recoverable.

This report describes the resource in Section 2; and, then, in Section 3, sample production data, operational experiences, and utilization techniques. Section 4 presents background information on the legal barriers associated with the development of coalbed methane utilization. Section 5 presents assessments of potential environmental impacts resulting from methane recovery techniques. Effects on air quality, surface water and ground water quality, land use, and ecology are discussed. Section 5 also discusses occupational safety problems that may be encountered during methane recovery. A listing of the cited literature is provided along with a bibliography of related information to provide a greater overview of the technology.

The technology of methane recovery from coalbeds is still in the developmental stage; some of the process descriptions and constraints described in this report may not apply to future developments and the final application of commerial-scale recovery projects. The situation described herein is representative of the state-of-the-art as reflected by governmental and industrial publications and contacts as of early 1979.

2.0 RESOURCE DESCRIPTION

This section describes the orgin and composition of coalbed gas and the location of coalbeds from which methane can be recovered.

2.1 ORGIN OF COALBED METHANE

Methane is the predominant component of natural gas. It is also a byproduct of the coalification (coal formation) process, and is found, along with other hydrocarbons and gases, in bedded coal deposits.

Coalification is the metamorphosis of plant and the animal material into the combustible, carbonaceous solid, coal, through a series of biochemical and geochemical reactions. The rank designations peat, lignite, bituminous, and anthracite are equivalent to different stages in a sequential transformation. There is an increase in the carbon content and in the aromatic character of the coal caused by a loss of alkyl side-chains during this process. During this metamorphosis there is a transition from simple randomly arranged molecules to complex clusters of ring compounds oriented parallel to the the bedding plane.

There are several mechanisms by which methane and other gases are formed during the coalification process. Methane, other hydrocarbons, and hydrogen can be produced by the removal of alkyl side-chains from aromatic molecules, by fragmentation of longer straign-chain molecules, or by condensation of straight chain molecules to ring compounds. Methane can be formed by the reduction of CO_2, the reduction of unsaturates, or the secondary decomposition of paraffins to lower-molecular weight gases. Methane is also produced during anerobic decomposition of organic matter.

The term "coalbed methane" refers not only to the methane contained in the coal but also other gases that have been detected. These gases include higher-molecular-weight hydrocarbons, carbon dioxide, oxygen, nitrogen, and helium. Carbon dioxide is produced by oxidation of organic material, primarily during the early stages of coalification. Oxygen and nitrogen are absorbed during the deposition of the organic sediment. They may also be introduced into the coalbed by percolating ground water. Most of the oxygen is consumed during the formation of carbon dioxide. Helium, which is also present, is a product of radioactive decay.

Water is normally entrapped in the coalbed during the coalification process. The exact quantity and quality of this water depends on the climate and ecology of the coalbeds. This water is normally saline.

The postdepositional history also affects the gas contained in the coal. Coal is a highly porous solid with two distinct pore systems. The macropore system consists of cracks and fractures; the micropores have an average diameter of 5 to 20 Å. Gases can exist as free gases in the macropores or can be absorbed on the surface within the micropores. The amount of gas in the coalbed depends on temperature, pressure, degree of fracturing, permeability of coal, and the geology of the adjacent strata (Kim 1973, pp. 1-2).

2.2 COALBED GAS COMPOSITION

Chromatographic analysis of gas flowing from coalbeds shows that coalbed gas contains methane and other higher-molecular-weight hydrocarbons. Table 1 lists the average composition of gas from seven different coalbeds and an average composition of natural gas (Kim 1978a, p. 12, Moore 1966).

Gas from these seven coalbed is well within the variability range of gas obtained from the more conventional petroleum reservoirs. The alkanes; ethane, propane, butane, and pentane are the only higher-molecular-weight hydrocarbons found in gas samples obtained directly from a coalbed. When coal is heated, unsaturated hydrocarbons are emitted; but these are absent in samples of gas that are obtained at ambient temperatures. Carbon monoxide, sulfur compounds and nitrogen oxides are not found in gas obtained from coalbeds.

Since coal is formed in a reducing environment, the absence of sulfur dioxide and oxides of nitrogen is not unusual. Hydrogen sulfide has not been detected in coalbed gas, even though coal contains sulfides, organically combined sulfer and sulfates. Carbon monoxide is frequently detected in coal mine air, where it occurs as a product of low-temperature oxidation; but it is not found in gas drain from coal that has not been exposed to air. The heating value of gas drained from coalbeds is approximately 1,000 Btu/scf, which is comparable to the heating value of natural gas. Due to its high caloric value and absence of undesirable components (carbon monoxide, sulfur oxides, nitrogen oxides), coalbed gas may be used as a substitute for natural gas.

TABLE 1. Average Composition of Coalbed Gas from Different Mines as Compared with Natural Gas

	Pocahontas No. 3 (VA)	Pittsburgh (PA and WV)	Upper Kittanning (PA)	B-Seam (CO)	Lower Hartshorne (OK)	Mary Lee (AL)	Anthracite (PA)	Natural Gas
	percent							
Ch_4	94.9	91.1	97.4	87.8	99.2	96.0	96.0	94.4
C_2H_6	1.3	0.3	0.01	0.05	0.01	0.01	0.01	3.8
C_3H_8	0.004	--	--	0.005	--	--	Trace	0.6
C_4H_{10}	0.002	--	--	0.001	--	--	--	0.3
C_5H_{12}	Trace	--	--	--	--	--	--	0.2
CO_2	0.3	8.2	0.1	12.0	0.1	0.1	0.1	--
O_2	0.2	0.2	0.2	--	0.1	0.1	--	--
N_2	3.2	0.5	2.3	0.1	0.6	3.5	1.0	0.4
H_2	0.02	--	--	--	--	Trace	--	--
He	0.04	--	--	--	--	0.3	Trace	--
BTU/SCF.	1030	975	1037	935	1056	1022	1053	1068

2.3 LOCATION OF COALBEDS

The location of the coal reserves in the United States is shown in Figure 1. It is estimated that there is 300 Tcf of methane gas associated with coals classified as "remaining identified sources." These reserves have less than 3000 ft of overburden. Additionally, there are coal deposits in unmapped and unexplored areas as well as deeper (those beds that are deeper than 3000 ft) coal deposits. These reserves could contribute as much as 550 Tcf of additional methane (U.S. DOE 1978, p. 8), although not all this gas may be considered recoverable.

This total estimated quantity of methane from coal was approximately the same the U.S. Geological Survey's estimate of the total undiscovered reserves of recoverable natural gas for the coterminous United States.

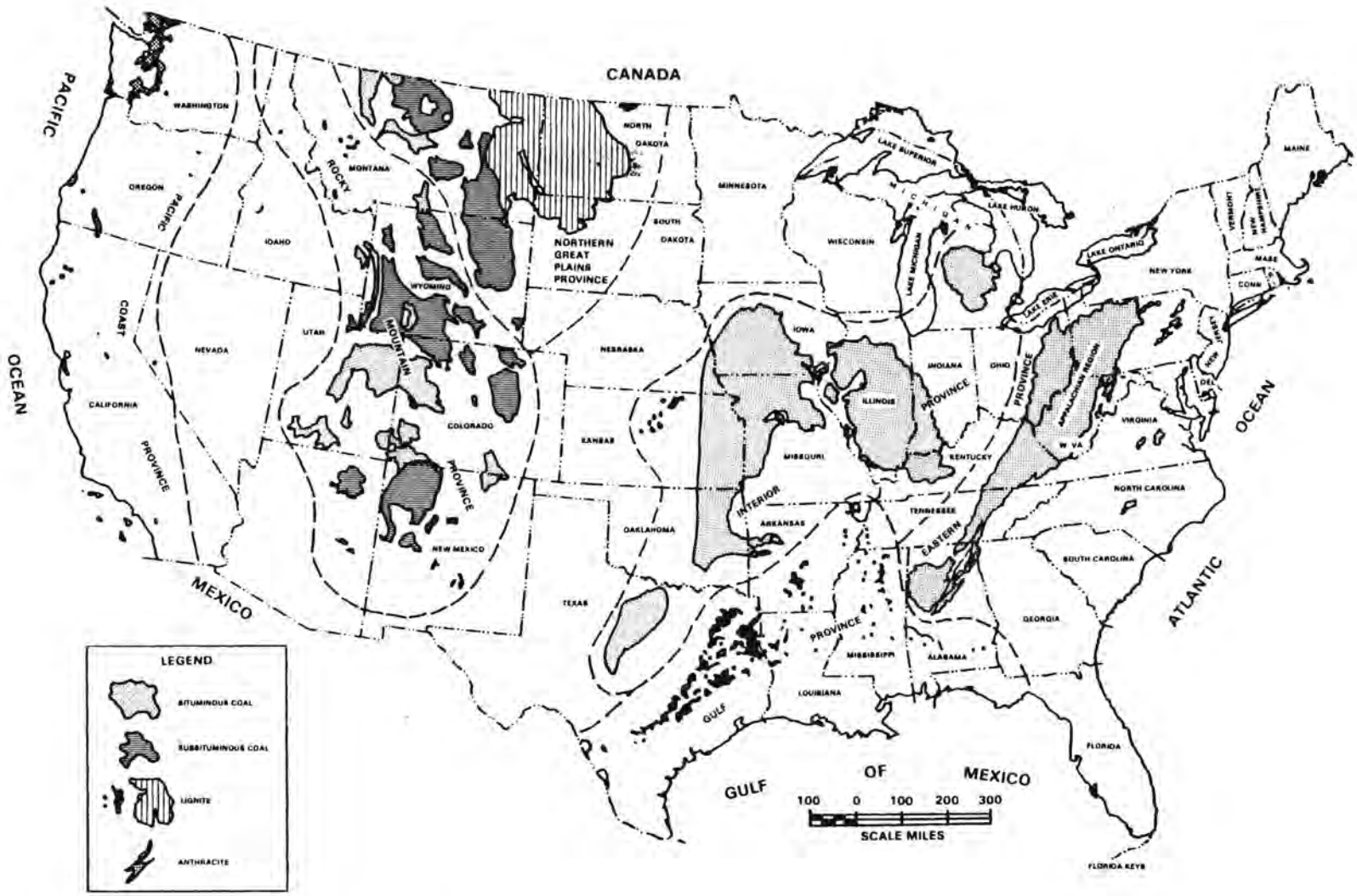

FIGURE 1. Areal Distribution of Coals in the Contiguous U.S. (adapted from Irani et al. 1973, p. 3)

3.0 METHANE RECOVERY TECHNOLOGY

Vast quantities of high British thermal unit (Btu) gas are contained in United States coalbeds. This gas can be recovered and added to the existing reserves to complement our more conventional natural gas supplies. Current methods of coalbed methane recovery fall into two main categories: recovery from coal before mining (virgin coal) and recovery from active mines. Figure 2 shows the overall process development sequence used to recover gas from coalbeds. Each of the steps will be discussed in this chapter.

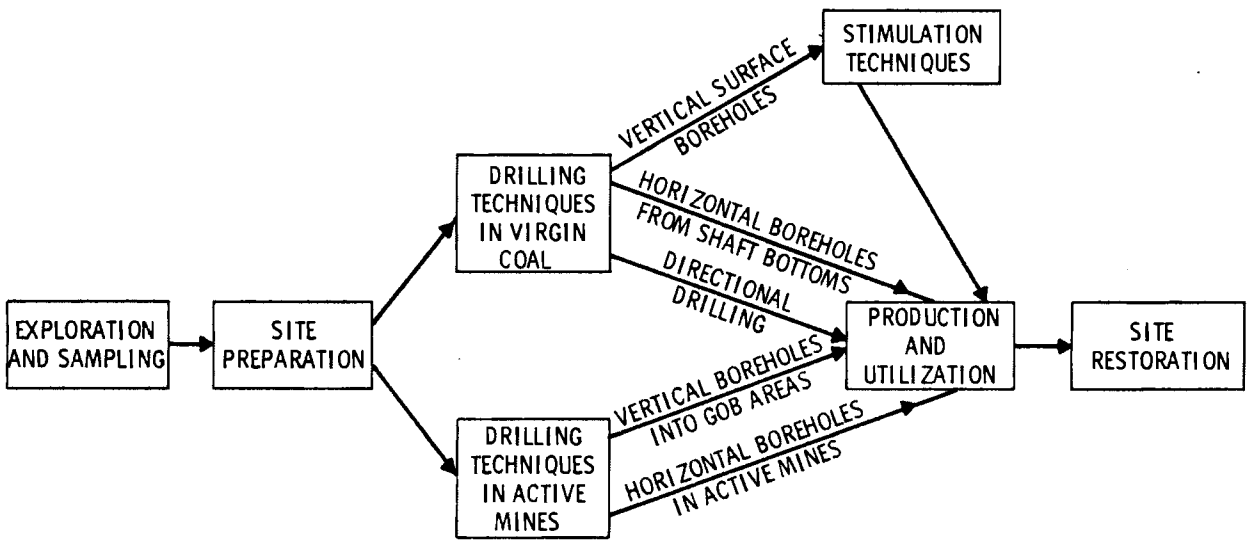

FIGURE 2. Process Development Sequence

3.1 EXPLORATION AND SAMPLING

The first step in the production of coalbed methane is exploration. Since the locations of coalbeds are well established, exploration to locate the resource is not needed. Instead, exploration involves determining the composition and quantity of coalbed gas. Several methods can be used to estimate the gas content of the coals in the United States. The most accurate method is the direct method. In this procedure, holes are drilled into the virgin coalbed and a core sample is removed and placed in an airtight container to minimize gas loss. The core sample is allowed to desorb for several weeks. The gas content in the virgin coal is calculated by summing the gas desorbed from

the sample, the estimated gas lost while taking the core sample, and that gas estimated by empirical methods. The residual gas can also be estimated empirically or the coal can be pulverized after desorption and the gas content can be measured. In general, friable coals (those easily crumbed or pulverized) emit nearly 96 percent of the total gas during desorption while blocky coals emit only about 60 percent of their total gas. (Deul et al. 1975, p. 1).

If data from direct measurements are not available, the gas content may be estimated by the methane emission rate (MER) from active coal mines in the area.

3.2 SITE PREPARATION

After determining that the quantity and quality of the coalbed gas is adequate for production, the site is prepared for drilling. The site preparation for each new location depends on the drilling technique that will be used and the potential for the application of stimulation techniques. However, the generic steps for each site are very similar. First, the access road must be constructed. Two different drilling rigs are used, a small rig for the taking of a core and a much larger rig for the actural borehole. After clearing a small location, a small diameter hole is drilled in order to obtain a sample core. This core is used to determine the character of the strata above the coalbed. Upon completion of the coring operation, a one-half acre site is prepared by grading it for drainage, excavating a small settlement pond and providing 480 volt a.c. power. The drilling rig is then transported to the site and erected. After drilling is completed, a surface plant, including the ventilation, hoisting, and degasification facilities, is constructed. This equipment is used to prevent dangerous accumulations of methane during periods of non-production, to move equipment in the borehole during maintenance, and to prepare the gas for commerical use, respectively. Figure 3 shows a typical surface plant layout. (Fields et al. 1973, p. 12).

3.3 DRILLING TECHNIQUES

The next step in the production of the coalbed methane is drilling. The drilling technique used depends on whether the methane is recovered from virgin

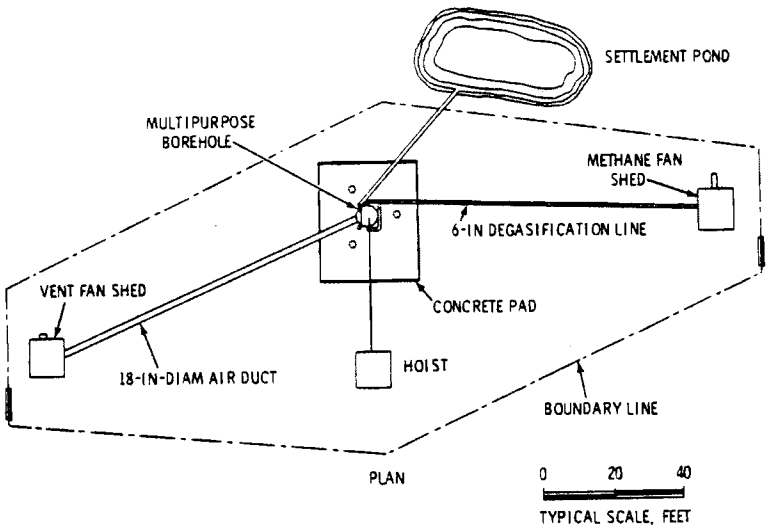

FIGURE 3. Typical Surface Plant Layout

coal or from an active mine. Methane may be removed from coal before mining (virgin coal) by vertical boreholes drilled from the surface, horizontal boreholes drilled from shaft bottoms, and directional slant holes drilled from the surface. Methane may be removed from active mines through horizontal holes drilled into the working face of the mine or through holes drilled from the surface into waste material (gob) areas. Representative production data on these recovery methods are given in Table 2 (Deul and Kim 1975, p. 5).

3.3.1 Vertical Surface Boreholes

Vertical boreholes from the surface provide a means of draining methane from coalbeds before they are opened for mining. To be effective, this technique must be employed at least 3 to 5 years before mining begins (Elder and Deul 1974, p. 2). In this technique, small-diameter, vertical boreholes are drilled from the surface to the coalbed. After drilling is completed, the well is cased and cemented to the surface. As the water that accumulates in the well is pumped off, methane flows from the coalbed. Since coal has a relatively low permeability, flowrates from coal into small vertical boreholes is quite low, usually between 0.5 and 10 thousand standard cubic feet per day (Mscfd). Stimulation increases gas production substantially, 5 to 20 times the original flowrate (Elder and Deul 1975, p.1). A description of stimulation techniques can be found in Section 3.4.

TABLE 2. Representative Production Data for Degasification of Coalbeds

Degasification Method	Coalbed	Location	Av flow rate, Mscfd	Av pct, recovered Mscf	Total gas removed, MMscf	Time period, months
Horizontal Boreholes from Shaft Bottoms	Pittsburgh	Monongalia County W. Va.	650	87	620	33
	Pittsburgh	Monongalia County W. Va.	892	85	560	21
Gob Degasification	Pittsburgh	Monogalia County W. Va.	126	89	45	12
	Lower Kittanning	Cambria County Pa.	421	79	8	1
	Pocahontas No. 3	Buchanan County Va.	388	65	179	15
Vertical Borehole/Hydraulic Stimulation	Mary Lee	Jefferson County Ala.	60	92	32	22
	Pittsburgh	Washington County Pa.	33	85	16	16
Horizontal Boreholes in Active Mines	Pittsburgh	Monongalia County W. Va.	100	NA[a]	NA	NA
	Pocahontas No. 4	Buchanan County Va.	200	NA	NA	NA
Directional Drilling	----------NO GAS PRODUCED----------					

(a) NA = not available

3.3.2 Horizontal Boreholes from Shaft Bottoms

Horizontal holes in coalbeds produce gas at rates substantially higher than from vertical boreholes. In this technique, a shaft or group of shafts is sunk to the coalbed a minimum of three years before mining is to be started. In the coalbed, the base of the shaft is enlarged to provide space for men and equipment to drill a series of horizontal holes 500 to 2000 feet long into the coalbed. These holes intersect the fracture system of the coalbed. It is this fracture system that comprises the effective permeability of the coalbed. Figure 4 shows a cross sectional view of a borehole used for degasification.

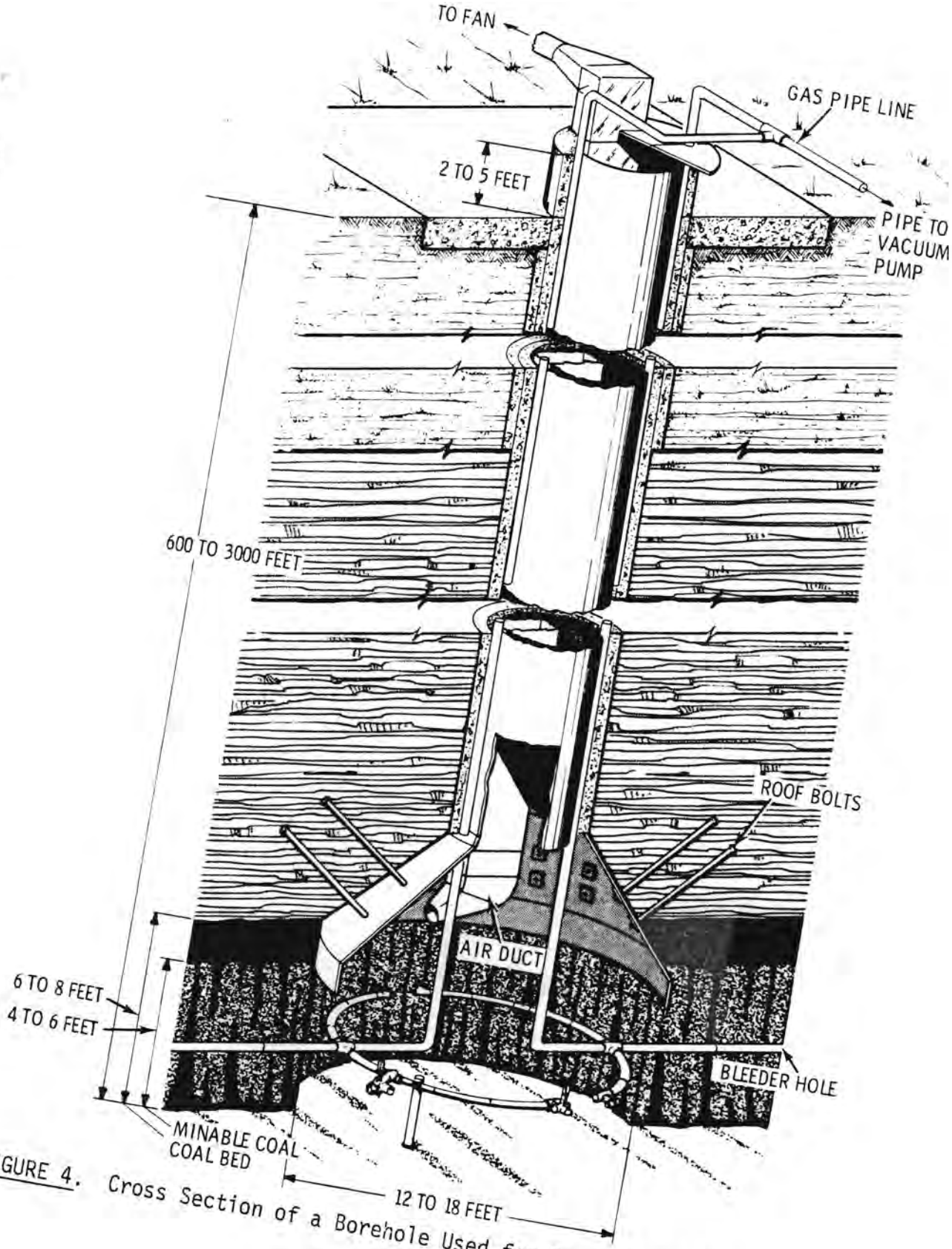

FIGURE 4. Cross Section of a Borehole Used for Degasification

Each of the horizontal holes is connected through a mechanical packer and water trap to a common receiver tank, as shown in Figure 5. The gas is then piped to the surface.

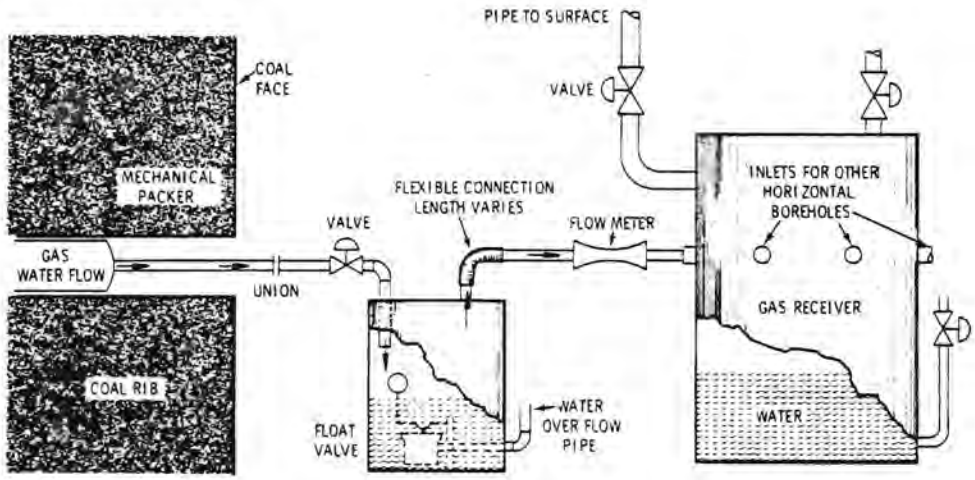

FIGURE 5. Flow of Processes in Degasification

This technique has been used twice: at the Honey Run shaft (18 ft diameter) of Federal No. 2 mine and the multipurpose borehole (8 ft diameter), both in the Pittsburgh coalbed. In both of these trials, the methane drained from the coal was compressed on the surface and added directly to commerial natural gas pipelines. These shafts were drilled for degasification but could be used as ventilation shafts for mining operations in the future.

The Honey Run shaft produced methane between August 1973 and May 1977 (3.7 years). Gas production total daily production from the horizontal boreholes average 650 Mscfd or approximately 110 scfd per foot of drainage hole.

Between September 1972 and January 1977, 907 MMscf of methane was drained from the coal through the multipurpose borehole at an average daily production of 567 Mscfd. Between January 1974 and January 1977, 463 MMscf of gas was sold as pipeline gas. No gas was produced between January 1977 and October 1977 due to a plant malfunction which caused excessive flooding. After repairs were completed in October, the gas sales resumed. As of December 1977, a total of 967 MMscf of gas had been drained from the coalbed at this site.

Over 1.8 billion cubic feet of methane has been drained from the Pittsburgh coalbed at these two sites. The area subtended by the horizontal drainage holes contained only an estimated 0.3 billion cubic feet of methane. The area of effective drainage is much larger than the are penetrated by horizontal boreholes. When the demonstration at the Honey Run shaft was terminated after 3.7 years, it was producing gas at the rate of 390 Mscfd. After 5 years, gas production at the multipurpose borehole remains at 424 Mscfd. Reducing the gas pressure near the shaft and dewatering the coalbed causes methane to migrate more fully through the natural fractures in the coalbed toward the boreholes.

3.3.3 Directional Drilling

Directional drilling techniques for removing gas from coalbeds combine the efficient drainage of horizontal boreholes with the lower cost of small-diameter vertical boreholes. In directional drilling, a small diameter borehole is drilled from the surface and intentionally deviated in order to intercept the coalbed horizontally. The major difficulty with this technique is the narrow target zone. The coalbed must be penetrated at a very acute angle since the average coalbed thickness is between 3.9 and 5.9, feet which is considered a very small target for normal drilling (Deul and Cervik 1977, p. 11).

Mechanical difficulties have slowed further development of this procedure. All boreholes produce water, which must be removed by pumps to maintain gas production. Generally, down hole pumps are designed to operate in a vertical position and will manfunction when used in the horizontal portion of the slant hole. The problem of dewatering a slant hole must be solved before this technique can be effectively used to drain gas from coalbeds.

The use of directional drilling has been successfully demonstrated in the Pittsburgh coalbed. A 3-inch borehole was drilled from the surface to the coalbed 787 feet below the surface. The borehole penetrated the coalbed 900 feet along a slanted trajectory, and was drilled horizontally in the coalbed for 420 feet.

The potential advantages of this technique make its development worthwhile. Rapid degasification can be achieved with slant holes if the technical difficulty of dewatering can be overcome. This method may be important in

areas where mining will be advancing within five years. Sites can be used for slant hole drilling that are unsatisfactory for other types of gas recovery form coalbeds. Another advantage of directional drilling is that several deviated holes may be drilled from a single surface site. Using a single surface site has economic benefits because of reduced transport of equipment and drill site preparation (Deul and Cervik 1977, p. 12).

3.3.4 Horizontal Boreholes in Active Mines

Gas can be produced from the active working sections of a developing mine that has not been advanced to the property boundaries. This technique consists of drilling small diameter horizontal boreholes into the virgin coal as the working face is advanced. The methane drained from these boreholes is conducted by pipeline to the surface.

In-mine drainage has been successfully tried in the Pittsburgh and Sunnyside coalbeds where flow rates of 100 Mscfd were typical. Production rates from horizontal holes in the Pocahontas No. 3 coal were low because of low permeability. However, this technique was used to drain gas from the underlying Pocahontas No. 4 coal through a mine in the Pocahontas No. 3 at a flowrate of 200 Mscfd.

Before this technique can be utilized, several probems relating to the operations of underground pipelines must be solved. One of these problems is leakage caused by improper installation or alignment of the pipeline. Leakage can be prevented or minimized by hydraulic or pneumatic pressure testing of the pipeline before it is placed in service. Currently safety regulations require that the pipeline be intrinsically safe and incorporate fail-safe leak detectors and shut-off controls. Another major prolem preventing the utilization of this technique is the resistence of coal producers to having a gas pipeline in the hazardous environment of a coal mine.

3.3.5 Vertical Boreholes into Gob Areas

Vertical boreholes are also used to drain methane from strata above the coalbed. A hole is drilled to the strata just above coalbed and ahead of mining operations. When it is intersected by mining, the overburden fractures and the methane that would normally be released into the gob (waste material)

is drawn to the surface. Such holes can remove as much as one MMscfd of methane from a mine and reduce underground emission by more than 50% (Kim 1978b, p. 15). Holes drilled over solid coal prior to gobbing reduce methane levels underground more effectively than holes drilled after the gob is formed. When intersected by mining, initial flows range from 0.13 to 0.22 Mscfd and decline to 0.025 Mscfd in a period of 600 to 1000 day (Deul and Cervik 1977, p. 11).

The concentration of the methane in the produced gas stream will decrease with time. Within several months the methane content may drop by 50 percent or more. The use of an exhauster increases flow rates, but by entraining air from the mine, the methane concentration will decrease. The amount of air in gas can be reduced in the use of a short "hole," a hole that terminates in the strata slightly above the coalbed. Since it is not directly connected with mine workings, the amount of air in the gas is reduced.

3.4 STIMULATION TECHNIQUES

If vertical drilling is used, stimulation techniques may be employed to increase gas flowrates. Coalbeds have very low flowrates due to very low permeability and porosity. The major technical problem associated with production of gas from coalbeds is the development of methods to increase flow rates. There are many different stimulation methods that have been used, but currently the most successful is hydraulic stimulation.

Hydraulic stimulation increases flow by inducing and extending vertical fractures in a selected section of a formation or coalbed. This fracture is a zone of very high permeability and porosity that will allow high flow rates. (Therefore, the end result is the same as that for a horizontal borehole.) For coalbeds, the large surface area that is produced, promotes gas desorption.

The fracturing is accomplished by applying hydraulic pressure with controlled injection of a fluid. Water based and foam based fluids are the types of fluids currently in use. The continued pumping of a large volume of treatment fluid extends the induced factures several hundred feet into the coalbed. The factors that determine the length of the induced fractures are injection

rate, formation strength characteristics, volume of treatment fluid and the flow characteristics of the fluid. Sized particles, such as sieved sand, are added to the gelled fluid and carried into the induced fractures. The sand serves as a propping agent to hold the fractures open after the applied hydraulic pressure is released. The propped fractures provide a highly permeable path to the borehole.

3.4.1 Hydraulic Fluids

There are two types of fluids currently used in hydraulic stimulation. One type of hydraulic fluid is water that has been gelled by the addition of natural gum (guar gum). Prop sand is added to the fluid to keep the fractures open once they have been formed. Another type of hydraulic fluid is formed water. The foam is formed by pumping nitrogen into water that contains a forming agent (a surfactant). Prop sand is added to the foam to keep the fractures open after the pressure is released. A variety of other chemicals may also be added to the fracturing fluids, usually in small quantities. Some of these chemicals prevent fluid loss, others provide fluid stability, and others increase the sand carrying capacity. Another group of chemicals is added to cause the fluids to break down a few hours later and lose their high viscosity and sand carrying capabilities.

After fracturing a well, it is shut-in to allow the fluids to break down. The well is then cleaned to remove the water and any excess sand. When this has occurred the degasification process is begun.

The equipment for hydraulic stimulation consists of truck-mounted, high-pressure, positive-displacement pumps; gelled water; a storage tank; and a truck-mounted blender and sand proportioner. A typical pump unit is capable of delivering 1000 hydraulic hp, with injection rates up to 42 bbl/min. The blending equipment consists of booster pumps, semiautomatic proportioners and a jet blender used to mix the gelled fluid, chemical additives, and the propping agent. A storage tank for water and fracture fluid is placed onsite at a location convenient to the pumps, blending units and the borehole. Flow and pressure recorders are used to monitor the mixing of chemicals and sand, the injection rate, and the wellhead pressures to provide control during the fracture stimulation treatment (Elder and Deul 1975, pp. 2-3).

The "Fracbook Design/Data Manual" of Halliburton Services, Oklahoma, contains details of the procedures used to select a hydraulic treatment design.

3.4.2 Conventional Hydraulic Stimulation

Three hydraulic stimulation treatments have been successfully completed in the Pocahontas No. 3 coalbed, Buchanan County, Va., the Mary Lee coalbed, Jefferson County, Cla., and the Pittsburgh coalbed, Washington County, Pa.

3.4.2.1 Pocahontas No. 3 Coalbed, Buchanan County, Va.

A test hole was drilled into a projected barrier pillar in an area not to be mined for several years. (A barrier pillar is the block of unmined coal that forms the boundary between two separate mining operations.) The hole penetrated a series of Pennsylvania sandstones and coals to test the gassy Pocahontas No. 3 coalbed. The 8-inch-diameter hole was cased with 4.5-inch steel casing from the surface to the top of the coalbed, and the casing was pressure cemented. The initial waterflow was measured at 1.3 gal/hr. The inflowing water inhibited the flow of gas and required frequent swabbing (cleaning) to maintain a gas flow. With continued swabbing to remove the water, the gas flowed from the borehole at 600 scfd.

In July 1970, a hydraulic stimulation procedure design by the Bureau of Mines was attempted. The coalbed was successfully stimulated with a thickened water base fracturing fluid containing 10- to 20-mesh sand as a propping agent. The initial fracture in the coalbed occurred at 3,200 psig. The fractures were propagated with pump pressures from 2400 to 3450 psig at an average injection rate of 10 bbl/min of fluid. Fourteen thousand eight hundred gallons of fracturing fluid and 4000 lb of propping sand were injected into the coalbed. After stimulation treatment, the hole was swabbed to remove the water and the gas flow was monitored. On the first day, the water flow decreased from 120 to 20 gal/hr while the gas flow increased from 2500 to 3500 scfd. By the fifth day, gas flow had stabilized at an average of 12,000 scfd and the water flow had declined to 2.9 gal/hr (Elder and Deul 1975, pp.4-7). The twentyfold increase in gas flow was encouraging but it was evident that a pumping or swabbing system must be provided to maintain gas production.

3.4.2.2 Mary Lee Coalbed, Jefferson County, Ala.

A test site was chosen near Oak Grove, Alabama for experimental degasification of the Mary Lee coalbed in advance of mining. The five holes drilled penetrated Pennsylvania sandstones, shales, and coalbeds. One hole was cased with 7-inch steel casing and put on production. The gas production was low initially, but increased as the coalbed was dewatered. After 16 months of production, the gas flow averaged 5000 scfd, with a water flow of 6 bbl/day. A stimulation treatment was planned to test the effectiveness of stimulation on this coalbed.

The initial fracture of the coal occurred at 800 psig. The fracture was propagated into the coalbed with pumping pressure of 1100 to 1200 psig and a steady injection rate of 10 bbl/min. Ten thousand gallons of gelled water and 6000 lb of 10- to 20-mesh propping sand were pumped into the coalbed. After stimulation, the water and excess treatment sand were removed from the borehole. After a water pump was installed, production of the gas resumed. The gas flow increased from 5000 scfd to a maximum of 90,000 scfd after stimulation. The flowrate stabilized at 50,000 scfd after 7 months. This stimulation increased gas production tenfold (Elder and Deul 1977, pp. 7-10).

3.4.2.3 Pittsburgh Coalbed, Washington County, Pa.

A test site near Lone Pine, Pa., was chosen for experimental degasification of the Pittsburgh coalbed in advance of mining. Four holes were drilled, penetrating Pennsylvanian sandstones, shales, limestones, and coalbeds. The holes were cased and put on production. The low initial gas production increased as the coalbed was dewatered. After 18 months the gas production from one borehole averaged 7000 scfd. This borehole was stimulated to improve the degasification rate and to test the effectiveness of stimulation on the Pittsburgh coalbed.

The initial fracture of the coal was achieved at 500 psig. The fracture was extended into the coalbed at 1200 to 1400 psig pumping pressure and a steady injection rate of 11.4 bbl/min. Ten thousand two hundred and thirty gallons of gelled water and 6000 lb of 10- to 20-mesh propping sand were pumped into the coalbed. With the reinstallation of the water pump, the borehole was returned to production. The gas flow increased after treatment from

7000 scfd to 35,750 scfd in 3.5 months. Gas production had not yet stabilized after 10 months (Elder and Deul 1977, pp. 11-14). A comparison of flow rates for these three fracturing procedures is presented in Table 3.

TABLE 3. Comparison of Three Hydraulic Fracturing Procedures

	Pocahontas No. 3 Buchanan County, VA	Mary Lee Coalbed Jefferson County, AL	Pittsburgh Coalbed Washington County, PA
Initial water flowrate (gal/hr)	1.3	10.5	7.4
Initial gas flowrate (scfd)	600	5,000	7,000
Sand size	10- to 20-mesh	10- to 20-mesh	10- to 20-mesh
Initial fracture (psig)	3,200	800	500
Pumping pressure (psig)	2,400 to 3,450	1,100 to 1,200	1,200 to 1,400
Injection rate (gal/min)	420	420	480
Total amount injected (gal)	14,800	10,000	10,230
Total amount of sand (lb)	4.000	6,000	600
Final stabilized gas (scfd) flowrate	12,000	50,000	35,750 (not stabilized)
Final stabilized water flowrate (gal/hr)	2.9	not available	26.25

3.4.3 Foam Stimulation

Foam stimulation was tested on several wells drilled into the Pittsburgh coalbed. The 6.25-inch diameter wells were cased with 4.25-inch OD casing that was set in the shale above the coalbed and cemented to the surface. Each of the seven foam treatments used an average of 8200 gallons of water, 5 gallons

of foaming agent per 1000 gallons of water, 10,900 pounds of 10/20- or 20/40-mesh prop sand and 300,000 scf of nitrogen. Details of each treatment are presented in Table 4.

TABLE 4. Foam Stimulation Treatments

Well Number	1	3	4	5	6	7	8
Depth to Base of Coal (ft)	641	908	849	770	588	734	652
Treatment Date (1976)	06-01	08-18	08-25	09-01	04-15	09-08	09-15
Treatment Pressure (psig)	1,400	1,600	1,300	1,375	1,500	1,400	1,050
Injection Rate (bbl/min)	11.2	11.2	10.8	11.6	17.7	10.8	10.8
Foam Volume (gal)	33,000	25,260	39,000	31,500	29,200	29,000	42,600
Sand Weight (lb)	12,500	11,000	10,000	10,000	14,000	7,400	12,800
Gas Flow ∿1 Year after Stimulation (scfd)	3,060	15,200	3,510	72,300	61,100	25,900	3,140
Percent Methane ∿1 Year after Stimulation	91.7	91.7	87.7	90.9	92.5	93.5	91.4

In October 1977, approximately one year after stimulation, the flow rates from the seven wells totaled over 184,000 scfd. Gas production from some of the treated wells having low production was expected to rise substantially after the coalbed around them was dewatered. This did not occur because mining in the vicinity of the wells has slowed gas production. However, continued

production rates of 200,000 scfd or above from the seven wells show that degasification before mining is feasible and economical in the Pittsburgh coalbed. In addition, degasification increases mining safety and allows increased coal production rates by reducing methane emissions in the mine, (Steidl 1978, pp. 3-7).

3.5 PRODUCTION AND UTILIZATION

After the wells have been drilled and stimulated, production of gas can occur. It is technically feasible to utilize coalbed gas in systems in which natural gas is normally used (Bastress 1978, pp. 109-115): These systems include:

- pipline injection
- power generation
- heating application
- LNG production
- chemical production.

Steady production rates and gas content fluctuations over time are important considerations in choosing the most appropriate method for utilizing the gas. The potential uses of coalbed methane in each of these systems are discussed below.

3.5.1 Pipeline Injection

Gas produced from coalbeds may be utilized by direct injection into a commercial pipeline. To be suitable for this purpose, the gas must meet certain requirements set by the pipeline companies. A typical specification for the quality of purchased gas set by a pipeline company is summarized as follows: The gas quality shall:

(a) be in its natural state as produced;

(b) be commercially free from dusts, gums, gum-forming constituents or other liquid or solid matter that might become separated from the gas in the course of transportation through pipelines;

(c) not contain more than three-tenths (0.3) of a grain of hydrogen sulfide (H_2S) per one hundred standard cubic feet;

(d) not contain more than thirty (30) grains of total sulfur per one hundred standard cubic feet;

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

(f) not contain more than one percent (1%) of oxygen by volume;

(g) have at least nine hundred and fifty British Thermal Units per standard cubic foot calculated as the gross saturated value at 14.73 psia and 60°F;

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

Gas obtained by predrainage of coalbeds approaches these specifications for pipeline quality gas. In cases where CO_2 content is higher than the specifications allow, direct injection may be allowed since sufficient dilution may occur in the pipeline to bring the Co_2 down to acceptable levels. Moisture removal may be required although wellhead water separation combined with pipeline dilution may be sufficient. Direct pipeline injection is thus possible. Gob gas, on the other hand, because of its low methane content and high inert gas content, is unacceptable for direct pipeline injection unless it is upgraded.

3.5.2 Power Generation

Coalbed gas can also be utilized for onsite power generation. The fuel requirements of a gas turbine/generator unit can be net by both predrainage and gob gases. The use of gob gas is extremely attractive since no upgrading is necessary. The combustor section of the gas turbine/generator can easily burn gas that has as low as 50% methane; and it can handle reasonable fluctuations in methane concentration. Besides wellhead water removal and possible filtration, no pretreatment of the gas is necessary. A general process schematic for power generation can be seen on Figure 6.

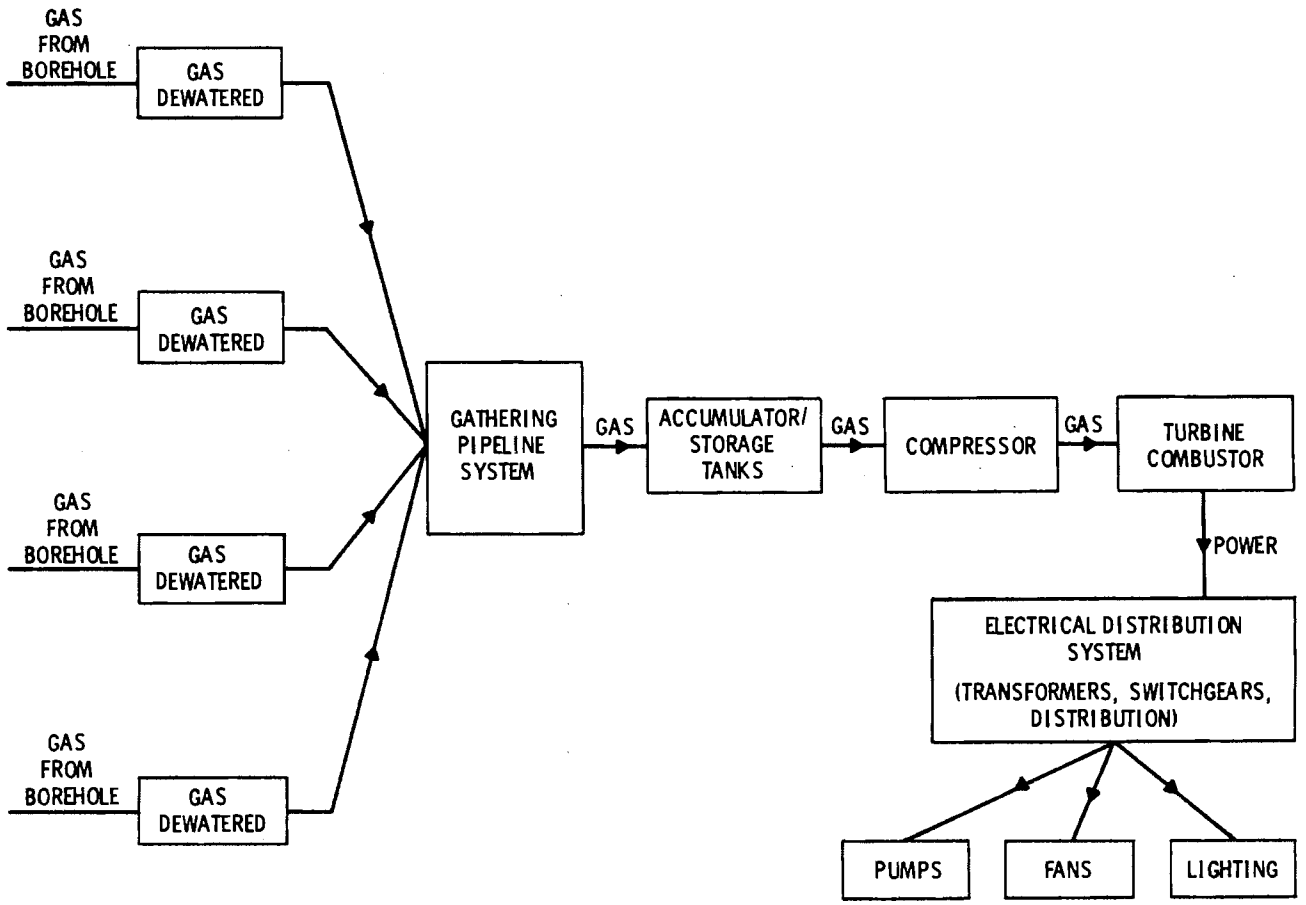

FIGURE 6. Schematic for Power Generation

3.5.3 Heating Applications

Several applications are possible for using gas as a fuel to supply heat. They include coal drying, thawing of railway cars, space heating, and ventilation air heating. The fuel requirements of burners used for these applications can be met by both predrainage and gob gases. Removal of water from the gas at the wellhead is necessary but further upgrading is not required.

3.5.4 Liquefied Natural Gas (LNG) Production

If a well is not located near a pipeline and if local use is not anticipated, the gas could be converted to LNG for more convenient transportation to distant markets. Both gob and predrainage gases are suitable for LNG production. Predrainage gas can be used readily in existing LNG process technology but some

modification of the air separation technology is necessary for gob gases. Both gases must be treated to provide a stream that is dry and free of CO_2 and dust.

3.5.5 Chemical Production

Two of the most promising chemical production usages of coalbed methane are ammonia and methanol production.

Ammonia production requires a methane concentration above 80% as a feed stream. Although a methane concentration as low as 50% can be handled, the heat requirements for processing increase, causing the plant to become uneconomical. Commercial plants currently are sized down to about 50 tons ammonia production per day, although plants having a capacity of 15 tons per day have been built in special instances. Assuming 2 MMscfd gas feed, the ammonia production rate would be approximately 53 tons/day for pre-drainage gas and 45 tons/day for gob feedstock. These quantities are definitely within proximity of current commercial practice. Even at the rate of 1 MMscfd, considered the lower limit for demonstration gas production, the lowest plant capacity would still be within existing technology. A typical ammonia plant would receive dewatered gas from the gathering pipeline network into accumulator plant feed will be fairly uniform in supply and composition. The supply and composition may also be contolled by the phasing and blending of gas production. Gas from the accumulator is subsequently compressed and fed into the gas treatment module.

The minimum size for a conventional methanol plant is 100-150 tons of methanol per day which requires 315,000 to 470,000 scfd of methane feed. Below this capacity centrifugal compressors are uneconomic and capital costs rise so sharply that even "free" methane may not make the plant profitable. The viability for using methane from degasification as feed for methanol production depends on gas cost, gas production rate, long-term gas supply and methane concentration. In certain cases methanol production may be an attractive option but no general statement can be made.

3.6 SITE RESTORATION

When the methane production from a minable coal seam is completed, the boreholes drilled from the surface may be used by the mining companies as vent

holes, for powerline entry, as rock dust supply holes, etc. In this case, site restoration would not take place until coal mining is completed.

If methane has been produced from an unminable coal seam, site restoration would be done after production ceases. Complete restoration would involve grading, to approximately the original topography, and planting of native vegetation to help recover the area more quickly. However, since most of the sites are on private property, there are no regulations for site restoration. Usually, the site involved is small; therefore restoration should be fairly easy.

4.0 BARRIERS TO COMMERCIAL PRODUCTION

As discussed in Chapter 3, several drilling techniques exist which are technically feasible for the recovery and utilization of coalbed gas. However, several institutional and other barriers exist that hinder development of the coalbed methane resource. The main issues that are constraining development of the coalbed methane resource are ownership of the gas, classification of coalbed gas, applicability of regulations, the jurisdictional control of the Federal Energy Regulatory Commission, and perception of mining hazard.

4.1 OWNERSHIP OF THE COALBED METHANE

Ownership claims for the coalbed methane arise from both the oil and gas industry and the coal industry. Before the energy crisis forced the country to determine new methods for enhancing domestic energy supplies, coalbed methane was considered a nuisance by coal mine operators. Now coalbed methane is considered a viable energy resource for certain uses, and the controversy over ownership has increased.

When oil and gas rights and coal rights are held in common for a particular coalbed, the problem of ownership of the methane is not an impediment to production. In many cases, however, ownership of the gas and oil rights and the coal rights are held by different groups. In these cases, the issue of ownership and the right to remove and market the methane becomes a major problem and a deterrent to development.

Some coal companies view the ownership of coalbed methane as concomitant with ownership of the coal. However, the petroleum industry feels that an oil and gas lease gives the holder the right to drill and produce oil and gas from <u>any</u> formation. Several court opinions have expressed the same view as the petroleum industry. Some of the legal issues that arise when the courts decide the gas owner has rights to the coalbed gas are (McGinely 1978, pp. 86):

1. May the coal owner ventilate gas during mining operations without having to pay the gas owner for waste?

2. If the coal owner may ventilate for safety reasons, without compensating the gas owner, may he also capture the gas by degasification prior to mining and sell it or use it himself?

3. May the gas owner enjoin mining of coal to deter waste of his coalbed gas?

4. To what extent can the gas owner use recovery techniques that may decrease the minability of the coalbed? (For example, it has been suggested that hydraulic stimulation of the coal seam might damage the "roof" strata and, thus, make mining unsafe?)

5. If the gas owner must compensate the coal owner for damage to mining rights, how would the damage be proved? Would there be a duty to mitigate damages?

Maurice Deul of the U.S. Bureau of Mines suggests some solutions to the ownership problem (Deul 1975):

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

In a recent court case in Greene County, Pennsylvania (U.S. Steel vs M. J. Hoge et al. 1980), the judge ruled that the methane belonged to the owner of the mineral rights and not to the owner of the coal rights. The judge further ruled that the coalbed methane owner could not fracture the coal bed. If the ruling is accepted in the other legal jurisdictions, then the issue of ownership would be resolved and no longer act as a barrier to commerical coalbed methane production.

4.2 CLASSIFICATION OF COALBED GAS

In addition to the issue of ownership, the classification of the coalbed gas is a major issue which could affect the production and sale of this gas.

Lack of classification is a barrier to coalbed gas production because if coalbed gas is classified as natural gas then production will be regulated by natural gas rules and regulations; however, if coalbed gas is not classified as natural gas then a new set of regulations will be required before production can proceed. Clarification of this issue would also impact the issue of ownership. If coalbed gas is not defined as natural gas then ownership could become even more uncertain.

The main constituent of both natural gas and coalbed gas is methane. Both gases have a similar heat of combustion range and are compatible when mixed in a pipeline. From the chemical and end use points of view, the differences are insignificant. However, the legal point of view raises some questions. The Natural Gas Act defines natural gas in this way: "'Natural gas' means either natural gas unmixed or any mixture of natural and artificial gas." Because this definition is fairly general, questions have arisen that require a more specific interpretation. Notes of Decision appearing in the United States Code Annotated clarify some points of the meaning of the Natural Gas Act:

> Liquefied natural gas is "natural gas" within the meaning of this chapter. Distrigas of Massachusetts Corp. v. Federal Power Commission, C.A.1. 1975, 514 F.2d 761.
>
> Jurisdiction of the Commission under this chapter does not extend to production, transportation, and sale of unmixed synthetic gas produced from coal; such gas is "artificial" within meaning of this chapter. Henry v. Federal Power Commission, 1975, 513 F.2d 395, 168 U.S. App. D.C. 137.
>
> "Casinghead gas" produced from a well, was "natural gas" within meaning of this section defining natural gas as either natural gas unmixed, or a mixture of natural and artificial gas. Deep South Oil Co. of Tex. v. Federal Power Commission, C.A.5, 1957, 247 F.2d 882.
>
> "Natural gas" is a mixture of gaseous hydrocarbons found in nature in many places connected with deposits of petroleum, to which the gaseous compounds are closely related.

In many states the definition of "gas" is dependent on the definition of oil which precedes it. For example, the Oklahoma Statutes state the following definitions:

> The word "oil" shall mean crude petroleum oil and any other hydrocarbons, regardless of gravity, which are produced at the well in liquid form by ordinary production methods;

> The word "gas" shall mean all natural gas, including casinghead gas, and all other hydrocarbons not defined as oil in the subsection above.

The Attorney General of Pennsylvania addressed the question in his Official Opinion No. 53 (1974), which is only advisory and not binding:

> It is our conclusion that methane (coalbed) gas must be classified as a natural gas. Under the Gas Operations, Well-Drilling, Petroleum and Coal Mining Act, 52 P.S. §2102 (10), gas is defined as "any natural, manufactured or byproduct gas or any mixture thereof," this necessarily includes methane. Furthermore, in Emerson v. Commonwealth, 108 Pa. 111, 125 (1884), the court defined natural gas as a gaseous fuel "which may be converted into heat by combustion with atmospheric air." As such the conclusion is inescapable that methane is a natural gas. This is an attempt to interpret statutory language and is not directly comparable to a situation where there is no statute.

Under some state laws and court decisions and under some federal laws, it is possible to interpret definitions of "gas" or "natural gas" to include coalbed methane. However, a statute or regulation that specifically defines coalbed methane would minimize the probability of litigation.

4.3 APPLICABILITY OF REGULATIONS

A related issue to that of classification is the applicability and appropriateness of existing natural gas regulations to coalbed methane production. Some individuals interested in the coalbed methane resource feel that methane production is different from conventional natural gas production and should be regulated under different criteria. Also, because the methane is produced from coal, the issue of the applicability of coal mining regulations is raised. Until this issue is resolved, commericalization of coalbed methane production will be impeded.

Coalbed methane can be removed under two different sets of circumstances with different objectives. One is removal of methane from coalbed which will be mined in the future. The other is removal of methane from coal seams that are too thin (less than 20 inches), too deep, or otherwise not suited for conventional coal mining techniques. When mining is a factor, the objectives are to conserve the methane that would be wasted during mining operations and to remove the potentially dangerous gas from the mining area in a short period of time, usually three to five years. The objective, when mining is not

planned, is to develop a production field with a reasonable economic life, (at least twenty years). The differences in timing, spacing and operation in these two situations may call for differences in the application of existing or new regulations.

The regulations that apply to natural gas from conventional sources could be appropriately applied to methane production from non-mining areas. However, the state or federal agencies must recognize that the production from these wells is usually much lower in volume than from wells in conventional sources. This difference may call for some specific standards with regard to spacing, collection systems and pricing.

Methane removal from minable coalbeds presents unusual problems that may require specific management and regulation development. Federal agencies, such as the Mining Enforcement and Safety Administration (MESA), and state oil and gas and mining agencies will be concerned and involved with regulation development.

State agencies have regulations that apply to oil and gas activities and others that apply to coal mining activities. Questions continue to arise about the applicability of current oil and gas regulations to methane production or the necessity for new, methane-specific regulations. For example, in West Virginia, no permits are required for air shaft or ventilation holes during mining operations but permits are required for holes or shafts that are made for gas production. Coal mine operators are encouraged to vent gas to the atmosphere by the safety requirement for air quality in the mine while the oil and gas regulations read, "waste of oil or gas is hereby prohibited."

Some regulations dealing with spacing, completion, abandonment, etc. may not be appropriate to either vertical or horizontal boreholes in coal seams. Fracturing to increase gas production must be controlled in some manner if mining is planned for the future. Fracturing could damage the roof structure.

4.4 JURISDICTION OF THE FEDERAL ENERGY REGULATORY COMMISSION

The jurisdictional position of the Federal Energy Regulatory Commission (FERC) is another potential barrier to coalbed methane production. Because of

the definition of gas in the Natural Gas Policy Act, the FERC could consider coalbed methane to be "natural gas." As a "natural gas," the FERC would have jurisdiction over the methane when it was stored, transported, or sold for resale in interstate commerce. However, this agency must recognize the peculiarities of recovering this unconventional resource, when applying regulations such as those for abandonment, collection systems and pricing. If these peculiarities are not recognized coalbed methane could be regulated by inappropriate regulations which would impede commerical production.

4.5 PERCEPTION OF MINING HAZARDS

Because of perceived hazards to coal miners due to fracturing activities, in mine pipelines and borehole degasification techniques, most mine operators do not endorse degasification projects. Mine operators fear that massive hydraulic fracturing may weaken the overlying strata thus increasing the possibility of cave-ins. There is also wide spread resistance to having methane pipelines in the hazardous environment of a coal mine because of the potential for leaks and explosions. In addition, mine operators are concerned that borehole degasification techniques may result in gas pockets which when intersected during mining, could cause in mine explosions. These potential hazards are discussed in section 5.2.3. The opposition of mine operators will continue to impede commercial production until these health and safety impacts are addressed and mitigated.

5.0 ASSESSMENT OF ENVIRONMENTAL, HEALTH AND SAFETY IMPACTS

The purpose of this chapter is to present an assessment of the environmental health and safety impacts for normal operations during development of coalbed methane gas field. The chapter identifies research needs required to generate data not currently available, but needed to improve the assessment of impacts. The impacts are examined for each of the development steps discussed in the technology description. Environmental, health and safety impacts from coalbed gas recovery are controlled by a number of existing federal and state regulations. Federal regulations applicable to these activities are summarized in Table 5. State regulations are specific to each drill site, and will not be discussed in detail.

5.1 ENVIRONMENTAL ASSESSMENT

This section examines the potential impact of coalbed methane production on air quality, water quality and on the ecology. Table 5 shows the potential environmental impacts from coalbed methane production. These impacts are summarized in Table 6. In most cases, as has been found in previous DOE studies (DOE/ERD-0011, DOE/EDP-0049, and DOE/ERD-0022), the impacts are minor or temporary. These effects are discussed in greater detail below for each phase in the development of a well to produce coalbed gas.

5.1.1 Exploration

Coalbed methane exploration is done by drilling holes into the coal formation and removing samples for analysis of gas content. The drilling is similar to, though not as extensive as, drilling for production. Therefore the impacts will be discussed under well drilling.

In order to transport drilling equipment into the site where the core is to be taken, temporary roads or off road vehicular travel may be necessary. The amount of temporary roads constructed or land impacted by off road vehicular travel will be minimal because of the large number of roads already available in the area (Adamson 1978). Also the impacts will be less on the meadow vegetation than on other ecological environments (CEQ 1979).

TABLE 5. Applicable Federal Environmental, Health, and Safety Regulations

Legislation	Pollutant/Concern	Current/Proposed Standards	Possible New Standards
Clean Air Act NSPS PSD Nonattainment Visibility	Fugitive emissions Particulates SO_x NO_x Hydrocarbons Polycyclic aromatics Hydrogen sulfide Ammonia Accidental releases of noxious gases (CO, H_2S)	Environmental Assessment and Environmental Impact Statement needed. Ambient standards have been set for: SO_2, NO_x, particulates, CO, hydrocarbons, and oxydants. NSPS have not yet been set.	NSPS will be developed for criteria pollutants. States may classify areas as nonattainment.
Federal Water Pollution Control Act	Disposal of drilling wastes and produced waters Subsidence	A NPDES permit is required unless waste water is reinjected. Subject to the Act of discharging into a navigable water. If toxics are released or treated in effluent stream they will be regulated under Sec. 307.	
Toxic Substances Control Act	Injection fluids and products of production		
Resource Conservation and Recovery Act	Sludges from drilling mud cleanup and recovered brine.	Waste streams will require testing for hazardous waste. If waste is classified as hazardous, the facilities will have to meet RCRA requirements. Hazardous waste disposal must comply with air and water standards. Potential impacts on siting.	Facilities engaged in treatment, storage, or handling of hazardous waste will require permits.
Safe Water and Drinking Act	Injection fluids surface wastewaters	Underground injection permit will be required--although the stringency is uncertain. Public hearings on each permit application.	State regulations could restrict siting and injection practices.
Occupational Safety and Health Act	Explosives Fires Exposure to toxics	Maintain employee health and exposure records. New benzene standards.	Revised toluene standard.

TABLE 6. Potential Environmental Impacts from Coalbed Methane Production

	Air Pollution	Surface Water	Ground Water	Land Use	Flora	Fauna	Noise	Geological
Exploration	Very little	--	--	Very little	Very little	Very little	Very little	--
Site Preparation	Increased Dust Diesel Combustion (short term)	Increased Siltation	None	~1/2 acre	Destruction of flora from land clearing (renewable)	Disturbance due to destruction of homes and noise	High levels of noise for short time	Little (topography changes)
Vertical Drilling	Increased Dust Diesel Combustion (short term)	Drilling mud pits, small impact	Drilled holes cased	--	--	Noise and human activity and flora damage	High levels (short term)	--
Horizontal Drilling	Increased Dust Diesel Combustion (short term)	Drilling mud pits, small impact	Drilled holes cased	--	--	Noise and human activity and flora damage	High levels (short term)	--
Directional Drilling	Increased Dust Diesel Combustion (short term)	Drilling mud pits, small impact	Holes cased	--	--	Noise and human activity and flora damage	High levels (short term)	--
Drilling into Gob Areas	Increased Dust Diesel Combustion (short term)	Drilling mud pits, small impact	--	--	--	Noise and human activity and flora damage	High levels (short term)	--
Drilling in Active Mine Face	All Extra Air Pollution is Underground	--	--	--	--	--	Not able to hear drilling noises on surface	Little
Stimulation	Diesel Combustion (SO_x, No_x etc)	--	Little chance of groundwater contamination	--	--	Driven off by noise	Excessive noise (short term)	Possible damage to rock formulations overlying coal bed
Production	Very Little from Pumps	Disposal of "acid" mine water during production	--	--	--	Small amount of noise, human activity	Small amount	--
Site Restoration	Dust from Regrading (small)	--	--	Return to original use	--	Disturbed by noise but very short term	Some noise	--
Road Construction	Dust Diesel Combustion Traveling on Roads	Extra Silitation	--	Largest land area used Erosion	Largest amount of flora distruction	Disturbed by noise, habitat destroyed, road kills	Large amount of noise - intermittent	--

Any disturbance of flora and fauna by exploration drilling will be temporary and of limited magnitude as described above. The flora and fauna should quickly recover from any disturbance.

5.1.2 Field Development

The activities associated with development of a coalbed methane field that could potentially result in environmental impacts are:

1) Construction of roads and electrical transmission
2) Construction of pipeline
3) Drilling of production wells
4) Construction of treatment and distribution facilities
5) Stimulation of production wells

5.1.2.1 Roads

The construction of permanent roads has probably the largest areal impact. For example, a 20-ft road bed would result in a minimum of 2.42 acres cleared for every mile of road. Removal of flora and fauna will occur along all road beds. The amount of flora and faurna removed will have animal impact on the total ecosystem because of the small amount of land involved.

Since there will be increased road traffic in the area, the probability for road kills of animals will increase. The net road usage is still low, (a few trips per week) however, and the net probability for road kills will be slight.

During construction of the road, the principal pollutant will be air pollution, mostly diesel engine emissions and dust. The impact of diesel emission on air quality is anticipated to be minimal except in the immediate vicinity of the road equipment because of the good atmosphere dispersion charateristics and the lack of sensitive environments in the immediate vicinity (Copenhaven et al. 1978, Clusen 1979). Dust will be a severe local problem at the construction site and during high wind conditions. However, the small amount of road constructed is anticipated to add very little to the total suspended particulate (TSP) level.

In addition to air pollutants, diesel engines create approximately 85-95db of noise at 50 feet (Adamson 1978). This level of noise will disturb neighboring fauna. It may cause them to flee from the immediate area and could also disturb breeding and brooding activities (Jansen 1978). Road construction will last only a few days at one site so that permanent impacts should not occur.

Erosion and runoff from the road bed may result in some surface water pollution.

5.1.2.2 Pipeline

In addition to construction of roads for transporting well field equipment, development of a gas field may require construction of pipelines between wells and to the nearest commercial transmission pipeline if the gas is to be sold to a pipeline company. Distance to the nearest commercial transmission pipeline is highly variable and may only be determined in a field-by-field case. If the pipelines are buried, and they need not be buried, a backhoe digs a trench about 10 inches wide that, after burial of the pipe, is recontoured and reseeded. Disturbance to flora and fauna would be minimal. Noise and atmospheric emissions will result in minor impacts because of their short duration and low levels.

5.1.2.3 Production Wells

The major activity associated with development of the gas field is drilling of the wells. The major impact from the drilling is clearing of the drill pad which covers about 1/2 acre. Included in this acreage is a mud pit for disposal of drilling mud and waste production water. The mud pit is about 1250 ft^2 in area.

All vegetation on the well pad sets is totally destroyed. If the wells are located in a cleared area or an old field, the animal habitat and plant cover destruction will be minimal. If it is necessary to site the well on a slope or hilltop, the topography of the area will be altered and part of the hillside leveled. The blasting associated with clearing a drill pad on a hillside would have considerably more impact on the surrounding communities than

merely locating the well on level ground at the bottom of one of the area's natural hollows.

The disturbed vegetation and surface topography may lead to excessive erosion. The excess siltation in the streams from erosion may have adverse effects on the aquatic life.

The construction equipment noise of about 85-95db at 50 ft (Adamson 1978) will cause many animals to flee from the surrounding area and depending on the season of the year could interfer with breeding. This noise level is not expected to cause any permanent damage to the wildlife because the noise level is not excessive (Jansen 1978) and should last for a maximum of about one month at each drilling site (Fields et al. 1973).

Air pollution resulting from construction of the drill pad will result from diesel engines and wind blown dust. The diesel engines emit carbon monoxide (CO), sulfur osides (SO_x), nitrogen oxides (NO_x), hydrocarbons (HC) and particulates. Dust will also be a problem during construction and for the life of the pad site. These should have an impact only in the immediate vicinity of the construction and be well below air quality standards a short distance from the site. During high wind conditions, dust from the construction area would add to the local TSP levels although the addition will be very small.

During drilling, the major potential sources of pollution are the air emissions from the 1000 to 1500 hp diesel engines and ground water pollution from the drilling mud pit.

The diesel engines will run continuously, 24 hours a day for between 2 days and 54 days, depending on whether the well is a small diameter water well or a large 72-in. borehole (Fields et al. 1973). Primary emission will be CO, SO_x, NO_x, hydrocarbons and particulates. The quantities emitted by a diesel engine are given in Table 7 . These values are very small and will be below air quality standards in a few hundred feet. Normally, only one or two drilling rigs will be operational, at a given time in a field. These emissions, averaged over the entire gas field, will be quite small and well within ambient air quality standards.

TABLE 7. Emissions from One 1100 hp Diesel Engine

Pollutant	Quantity (g/sec)
SO_x	2.08
HC	1.63
NO_x	2.84
CO	2.50
Particulate	0.80
Aldehydes	0.13

The noise generated by the diesel engines will be approximately 90db at 50 feet. There are homes scattered about the woods and some maybe close enough to the project to be disturbed by the noise. Based on EPA prescribed maximum safe levels from 10 pm to 7 am of 45 decibels. This maximum could be exceeded within a 2 mile radius if hills do not block or deflect the noise (Adamson 1978). Wild animals that are sensitive to high noise levels will flee from this zone; however, most of the fauna consists of domesticated or semi-domesticated animals who should be able to tolerate these noise levels.

If mud is used during drilling, a small mud pit will be dug to hold the mud. In most cases air or gas is used in drilling because it speeds up the drill rate. This would eliminate any environmental impacts associated with the mud pit. Gas or air drilling does result in localized increase in particulates. If drilling mud is used, constituents of the drill mud water are normally non-toxic and have been deemed so by the EPA in conjunction with the Resource Conservation and Recovery Act of 1976 (RCRA) (PL-94-580). The only "toxic" element which could be present in mud or naturally contaminated waste water is barium. The concentration of the element is expected to be less than the 10 mgl level set by EPA as the concentration which is potentially toxic to public health. (National Interim Drinking Water Regulations 1976, Development of Environmental Guidelines for EOR and EGR Process 1978, Vol II). Under normal conditions, drilling mud fluids will be isolated from public exposure pathways by high dikes. If a spill into neighboring water should occur this

could seriously impact the water quality and in turn affect wildlife using the stream and organisms which live in the stream.

5.1.2.4 Treatment and Distribution Facilities

At each well site in the gas field, distribution and gas treatment facilities are constructed to collect the gas, remove liquid gas elements and pump the gas into the local pipeline. Construction of these facilities will be on the 1/2-acre pad cleared at the drill site and requires only hauling in and hooking up the machinery. These impacts will be minimal.

5.1.2.5 Stimulation

To get reasonable flow rates from the well, the wells are stimulated using some type of advanced hydraulic fracturing. The principal potential pollution sources are air pollution from diesel engines during the fracturing job and minor spills of the chemicals used in the fracturing fluid. Contamination of freshwater aquifers with fracturing fluids components will only occur if the cementing of the casing has not been properly done. However, this should not occur because a cement bond log is run previously to insure a good bond. Fracturing should not result in seismic effects in the basin because the Appalachean Basin is not a seismically active area and other fracturing activities using chemical explosives have not resulted in any abnormal subsurface movement (Tonnessen 1977).

During the fracturing job several large diesel engines will be used to pump the fluid under high pressure into the well. For example, for a hydraulic fracturing job of 20,000 to 50,000 gallons, there will be one pump truck and one blender or mixer truck each with two large diesel engines. If a foam fracturing method is used then there will be one additional nitrogen pump truck. These large diesel engines will result in locally high levels of air pollutants and noise. The air pollution levels expected during the 1/2 to 2 hour operation are given in Table 8.

Local air quality standards will not be exceeded within a short distance of the well site.

TABLE 8. Emissions from a Typical Stimulation Job Using Ten 1100 hp Diesel Engines

Pollutant	Release Rate (g/sec)	Release During Typical Sized Job (kg/hr)
SO_x	21.23	76
HC	16.6	60
NO_x	28.93	104
CO	25.46	92
Particulate	8.2	30
Aldehyde	1.32	4

Noise levels will also be very high on the order of 100db at the center of the pad or 58db at 400 ft from the engine (Adamson 1978). This latter level of noise is about the level of normal conversation and may cause dispersal of fauna.

Fracturing jobs usually last three to eight hours and, therefore, the impacts over the long term will probably not be measurable. The constituents of fracturing fluid are non-toxic, so provided spills are cleaned up, no impact from chemical spills will result.

5.1.3 Production

After production begins, the noise levels, the human activity, and the air pollution decrease. The only noise that may occur from the site is when the gas needs to be compressed before entering the pipeline (Adamson 1978). Compressors can be extremely noisy pieces of equipment but may be housed in a building to bring the noise down to acceptable levels. There may also be intermittent high noise levels during routine maintenance checks. This should be minimal compared to drilling or fracturing.

The subsidence of land due to gas production is of no consequence when compared to coal mining.

The major problem during production is disposal of the water that is produced from the coal seam. Table 9 lists the composition of water from

TABLE 9. Composition of Water from Three Coalbeds

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

ND - Not detected.
* - Reported as percent.

three coalbeds (U.S. DOE 1978, p. 29). The composition varies widely, from slightly acidic to slightly alkaline, and from potable to saline. The waste water is temporarily stored in a lined waste water pit until treated for release to nearby surface water. The water must meet state or federal standards before being released into the natural water system. The planning of pollution control and water disposal systems must be determined on the basis of the water at each site. Water from some coalbeds, especially in the western part of the United States, may be of higher quality than the alkaline surface waters.

5.1.4 Abandonment

Site restoration is important, especially if the gas has been produced from an unminable coalbed. In this case, the original topography should be restored to reduce erosion. To make any great changes in the topography, large equipment will be needed. This would cause a short-term increase in noise levels, human activity, air pollution from diesel powered equipment and air pollution from blowing chemicals if fertilizer is used. The plant life would slowly recover the damaged area and the local fauna population would return to normal.

In the case that the gas was produced from a minable coal seam, the boreholes drilled from the surface may be used by the mining companies as vent holes, for powerline entry, or rock dust supply holes, etc. Restoration would probably not be done until after mining was completed.

The amount of site restoration depends on the requirements of the local land owner. In some cases, the waste water pit, may be left for the use of the local land owner after being cleaned and decontaminated. Other equipment including roads may also be left for the use of the land owner.

5.2 HEALTH AND SAFETY ASSESSMENT

This section will examine the human health and safety impacts that could potentially result from development of a gas field. The primary areas of concern are the effects of noise, air pollution and mining hazards.

5.2.1 Noise

Ambient noise levels will be increased in the vicinity of the well site during the development period, especially during the drilling and fracturing phases of the operation. Sources of particularly large increases in noise levels include: operation of service vehicles and construction equipment, the operation of generators and diesel motors during drilling and stimulation and pumping operations, and the noise resulting from the general increase in the level of activity at the site. Typical noise levels at 50 feet are (Adamson 1978, pp. 40-41):

scraper	88-95 decibels (dBa)
grader	77-87 dBa
truck	66-91 dBa
drilling rig	∿90 dBa
fracturing	90-100 dBa

Figure 7 (Turk, Turk and Wittes 1972) shows the decibel levels and verbal loudness description of various sounds. In general, noise levels of about 80 decibels or higher can produce permanent hearing loss; however, the effect is faster for louder noises. For example, exposure to a 95 decibel

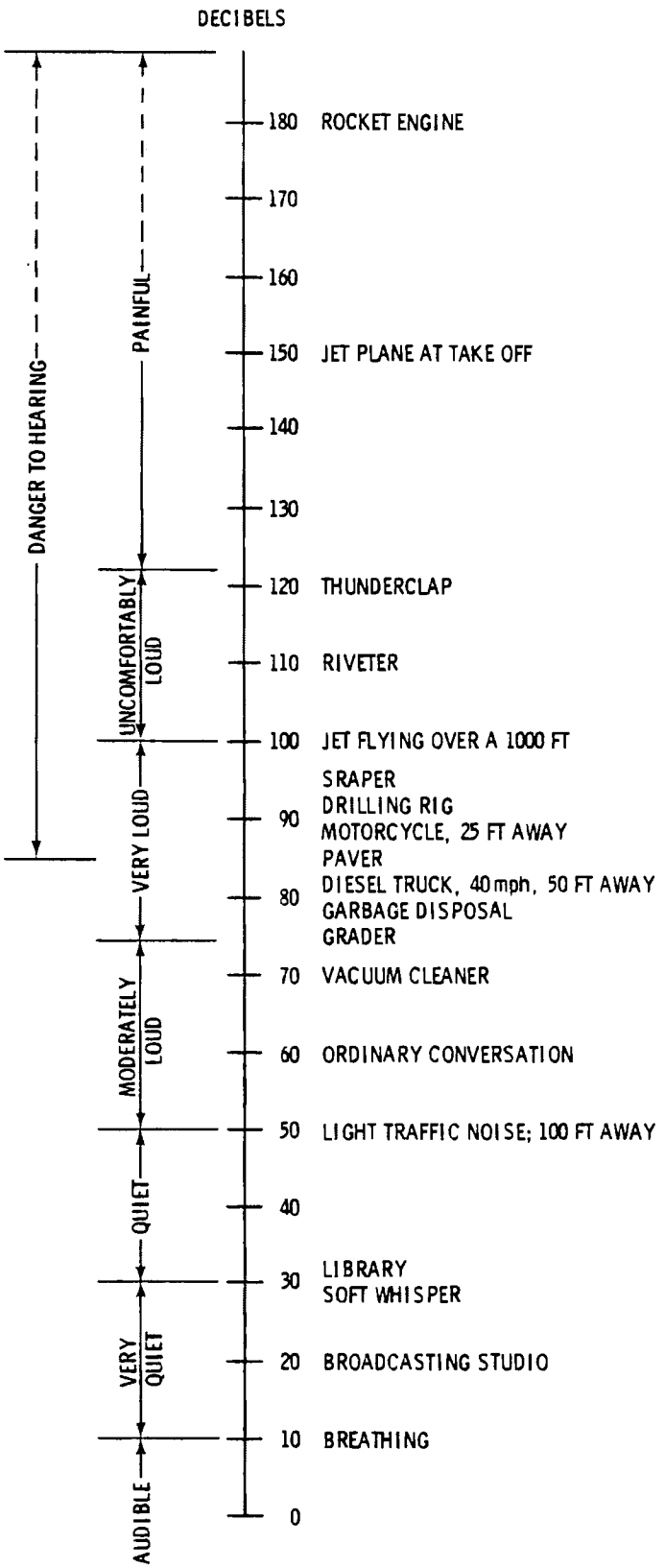

FIGURE 7. Decibel Levels and Verbal Loudness Descriptions of Various Sounds

noise in an occupation will depress one's hearing ability by 15 decibels in 10 years. To prevent this hearing loss, the onsite workers need hearing protection according to OSHA (Occupational Safety and Health Administration) occupational health requirements. Although hearing protection is usually provided, it is often not used.

5.2.2 Air Pollution

During many parts of the well field exploration, development, production and abandonment, diesel trucks and engines will be operating, releasing into the air CO, SO_x, NO_x, hydrocarbons and particulates. The concentrations of these constituents at any time depend on the number of engines operating and atmospheric conditions. The highest concentration of these air pollutants is most likely to occur during a fracturing job. At this time, diesel engines will be operating at full capacity. The amounts of each of the air pollutants produced are given in Table 8.

CO produced from these operations is expected to reach 15-50 ppm near the source under calm wind conditions. These levels will not exceed the threshold limit value for workroom environments but could cause somatic worker effects. Myers et al. (1970) estimates that 50 ppm would be the level at which one might expect some reduced mental acuity and headaches over a 10-hour period (see Figure 8). Since noise is believed to lower susceptibility levels, one would also suspect that CO combined with elevated noise levels may have a synergistic effect, thereby intensifying the potential acuity problem.

Other effects of slightly elevated carabon monoxide concentrations include cardiac function effects ($\sim$30 ppm CO) and work performance impairment ($\sim$120 ppm). Poisoning, however, is rarely reported at levels below 60 ppm because it is asymptomatic (Sax 1957).

Based on the calculated concentrations of the diesel exhaust constituents, these constituents such as sulfur dioxide (SO_2), photo chemical oxidants, nitrogen dioxide, and particulates are not expected to exceed the "alert levels" as specified in the Clean Air Act (PL 91-604). More research is needed to determine the health effects of diesel exhaust since diesel particulates are bonded to organic compounds which have been shown to be at least mutagenic and may be carcinogenic (Environmental Reporter 1979).

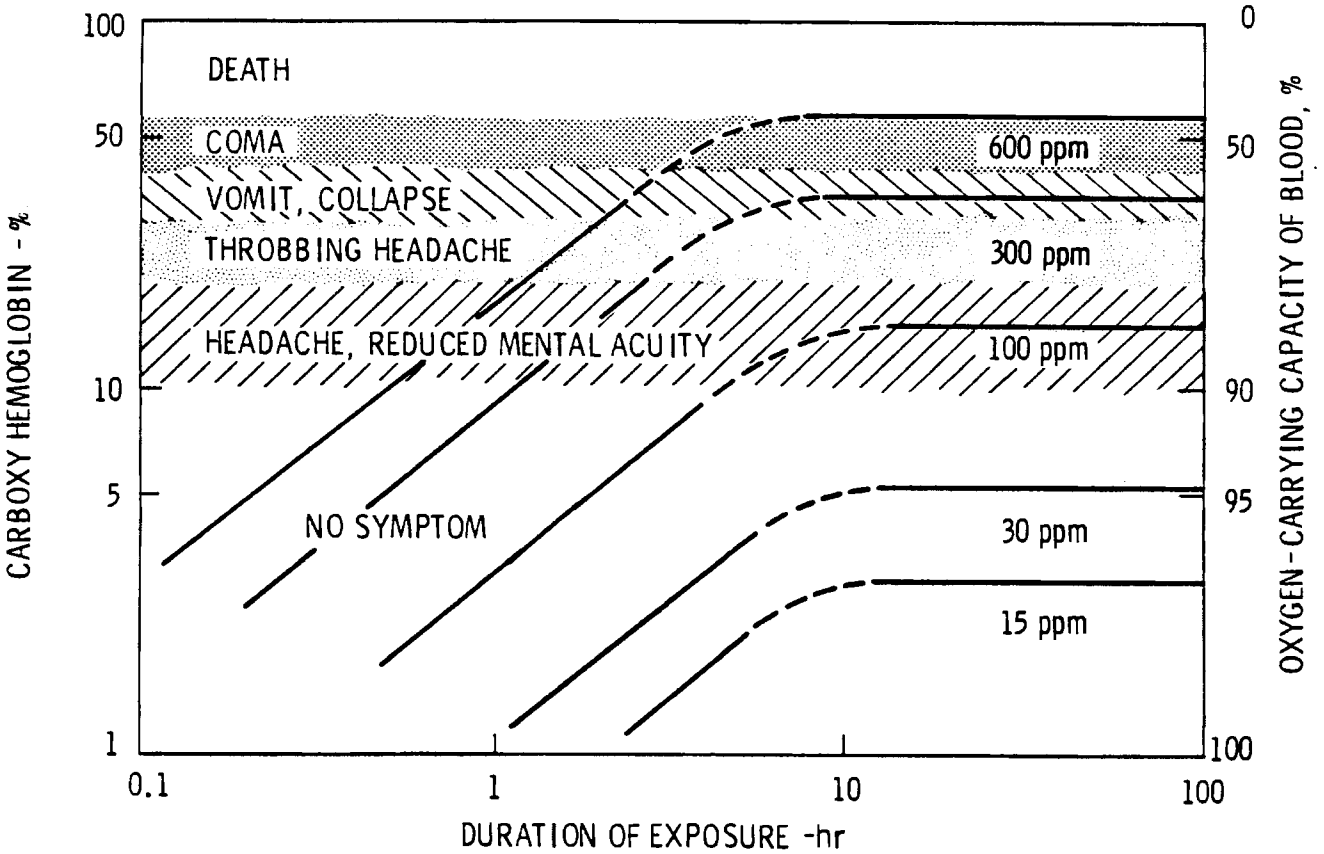

FIGURE 8. Relationship Between CO Exposure (Hours and Concentration) Versus Health Effects

When using the technique of horizontal boreholes from shaft bottoms, men must be sent to the bottom of the shaft drill the horizontal boreholes. The ventilation must be excellent to remove the methane accumulating in the shaft and the gases produced by the drilling rigs and these reduce the potential exposure to high levels of methane.

Another source of airborne pollutants is windborne fracturing fluid chemicals during the fracturing process. Proper handling procedures will eliminate this source of pollutant.

5.2.3 Mining Hazards

Techniques associated with degasification of coal seams may result in increased hazards to miners. For example fracturing of coal has proved effective in increasing the gas flowrates however, most mine operators are concerned that fracturing may damage the overlying rock, which makes up the roof of the

mine, creating unsafe mine conditions. Although a number of stimulated boreholes have been mined through and show that the fracturing was contained within the coal seam, more research is needed to guarantee that the overlying rock is not damaged by fracturing.

Also there is a potential safety hazard associated with a pipeline in the mine. Concentrations for explosive mixtures of methane air range from 5% to 15% by volume. In the case of an accident or detector malfunction, a leak in the pipeline could fill the mine area with an explosive mixture very quickly. Mining safety regulations require that the pipeline be intrinsically safe and incorporate fail-safe leak detectors and shut-off valves. There has been limited operational experience with these fail-safe systems. The overall effectiveness of these systems is not known.

Another problem is the danger of mining through a degasification borehole. This empty space is essentially a "gas pocket" and can almost instantly create an explosive mixture. Extreme care must be taken with horizontal boreholes so that their exact location is known when mining operations approach the area. Extra precautions may be taken by totally plugging the borehole before the mining operation comes close. This would decrease the chances of explosive mixtures entering the mine. More research is needed to determine the potential hazard and methods for reducing the chances of explosive mixtures entering the mine.

6.0 CONCLUSIONS AND RECOMMENDATIONS

No significant environmental barriers to the development of coalbed methane have been identified. The most important environmental impacts identified were from health and safety impacts during fracturing and from potential health and safety impacts to miners during coal mining. The impacts during fracturing result from the emissions released by the diesel engines and from high levels of noise. The potential impacts to miners result from the potential for cave-ins due to fracturing of overlying strata during stimulation and from the potential for explosions due to in-mine pipeline leaks and intersection with gas pockets caused by boreholes used in degasification. Environmental impacts can also result from road construction, well pad clearing and well drilling; however it appears that most of these effects would be localized and/or temporary. There are limitations in current abilities to predict and assess environmental effects. It is therefore recommended that further work be done to improve knowledge in the areas of health and safety impacts of diesel emissions and high levels of noise and in the areas of the potential health and safety impacts on miners due to fracturing in mine pipelines and borehole degasification techniques.

The principal barriers to commercial utilization of this resource are based on institutional issues and the perception of mining hazards. The institutional barriers include ownership of the methane, classification of coalbed methane, applicability of regulations and jurisdictional control of the Federal Energy Regulatory Commission. The perception of potential hazards to miners from cave-ins and explosions resulting from coalbed degasification activities have caused many mine operators to oppose coalbed degasification activities. Recent court decisions and the results of research into the potential coal mining hazards should help to overcome these barriers.

LITERATURE CITED

Adamson, M. A. 1978. Environmental Report: Enhanced-Gas Recovery Project, Gallier County, Ohio. UCID-17945, Lawrence Livermore Laboratory, Livermore, CA.

Bastress, E. K. 1978. Utilization options for coalbed methane. In: Proceedings from Conference on Methane Gas from Coalbeds, Development, Production and Utilization. January 18, 1978.

Copenhaven, E. D., R. J. Olson and P. L. Rioe. 1978. Regional Energy-Enviornmental Data Book: Southern Region. ORNL-5443.

Clusen, R. 1979. Regional Issue Identification and Assessment First Annual Report. Department of Energy, Washington, DC.

Council of Environmental Quality. 1979. Off-Road Vehicles on Public Lands. CEQ-772, Jackson Place N.W., Washington, DC.

Deul, M. 1975. Recover Coalbed Gas. Hydrocarbon Processing, July 1975.

Deul, M. and J. Cervick. 1977. Methane Drainage in the Pittsburgh Coalbed. Presented in Varna, Bulgaria. October 3-7, 1977.

Deul, M. and A. G. Kim. 1975. Safety and economic implications of the degasification of coalbeds. In: Proc. First Symposium on Underground Mining, NCA/BCR Coal Conf. and Expo. II., October 21-23, 1975, Louisville, Ky.

Deul, M., F. N. Kissell, J. R. Levine and C. M. McCulloch. 1975. Measuring the Methane Content of Bituminous Coalbeds. RI 8043, U.S. Bureau of Mines.

Elder, C. H. and M. Deul. 1974. Degasification of the Mary Lee Coalbed Near Oak Grove, Jefferson County, Ala., by Vertical Borehole in Advance of Mining. RI 7968, U.S. Bureau of Mines.

Elder, C. H., and M. Deul. 1975. Hydraulic Stimulation Increases Degasification Rate of Coalbeds. RI 8047, U.S. Bureau of Mines.

Fields, H. H., S. Krickovic, A. Sainato, and M. G. Zabetakis. 1973. Degasification of Virgin Pittsburgh Coalbed through a Large Borehole. RI 7800, U.S. Bureau of Mines.

Janssen, R. 1978. Noise and Animals: Perspectives of Government and Public Policy in Effects of Noise on Wildlife. J. L. Flethcher and R. G. Bumel, ed., Academic Press Inc., New York, NY.

Kim, A. G. 1973. The Composition of Coalbed Gas. RI 7762, U.S. Bureau of Mines.

Kim, A. G. 1978a. Experimental Studies on the Origin and Accumulation of Coalbed Gas. RI 8317, U.S. Bureau of Mines.

Kim, A. G. 1978b. Methane drainage from coalbeds: research and utilization. In: Proc. from Symposium on Methane Gas from Coalbeds--Development, Production and Utilization. January 18, 1978.

Halliburton Services. 1971. The Fracbook Design/Ratio Manual for Hydraulic Fracturing. Halliburton Services, Duncan, OK.

Irani, M. C., E. D. Thimons, T. G. Bobick, M. Deul, and M. G. Zabetakis. 1972. Methane Emission from U.S. Coal Mines. A Survey. IC 8558, U.S. Bureau of Mines.

Myers, P. S. et al. 1970. "Nation's Cost/Benefit Ratio Weighs Heavily on Auto Emissions." SAE Journal.

McGinley, P. C. 1978. Legal problems relating to ownership of methane gas in coal deposits. Presented at ALI - ABA Course of Study Legal Issues in the Coal Industry, June 1-3, 1978, Washington, D.C.

Moore, B. J., R. D. Miller and R. D. Shrewsbury. 1966. Analyses of Natural Gases of the United States. IC 8302, U.S. Bureau of Mines.

Olson, M. L. 1978. Institutional constraints to the development of coalbed methane. In: Proc. of Conference on Methane Gas from Coalbeds Development, Production and Utilization, Jan. 18, 1978.

Sax, N. I. 1957. Dangerous Properties of Industrial Materials. Reinhold Publishing Corp., New York, NY.

Steidl, P. F. 1978. Foam Stimulation to Enhance Production from Degasification Wells in the Pittsburgh Coalbed. RI 8286, U.S. Bureau of Mines.

Tonnessen, K. A. 1977. Environmental Impact Assessment: Chemical Explosive Fracturing Project, Petroleum Technology Corporation. Leslie, Letchen and Perry Counties, KY. UCID-17475, Lawrence Livermore Laboratory, Livermore, CA.

Turk, A., J. Turk and J. T. Wittes. 1972. Ecology, Pollution, Environment. W. B. Saunders Company, Philadelphia, PA.

U.S. Department of Energy. 1978. Nonconventional Natural Gas Resources. DOE/FERC-0010, GPO.

U.S. Department of Energy. 1978. Environmental Readiness Document, Enhanced Gas Recovery. DOE/ERD-0011.

U.S. Department of Energy. 1979. Unconventional Gas Recovery (Enhanced Gas Recovery). DOE/EDP-0049.

U.S. Department of Energy. Environmental Readiness of Emerging Energy Technologies, Summary Report. DOE/ERD-0022.

BIBLIOGRAPHY

Deul, M. 1978. The methane content of coalbeds in Region III. Pres. at Symposium: Methane Gas from Coalbeds: Development, Production, and Utilization, Jan. 18, 1978, Corapolis, PA.

Deul, M. and A. G. Kim. 1975. Coal beds: a source of natural gas. Oil and Gas Journal 73(24):47-49.

Deul, M., M. L. Skow, and A. G. Kim. 1977. Helping finance new mines with revenues from coalbed degasification. Presented at NCA/BCR Coal Conference an Expo. IV, Oct. 18-20, 1977, Louisville, KY.

Diamond, W. P., D. C. Oyler, and H. H. Fields. 1977. Directionally Controlled Drilling to Horizontally Intercept Selected Strata, Upper Freeport Coalbed, Green County, PA. RI 8231, U.S. Bureau of Mines.

Elder, C. H. 1977. Effects of Hydraulic Stimulation on Coalbeds and Associated Strata. RI 8260, U.S. Bureau of Mines.

Fields, H. H., J. Cervik and T. W. Goodman, 1976. Degasification and Production of Natural Gas from an Air Shaft in the Pittsburgh Coalbed. RI 8173, U.S. Bureau of Mines.

Tilton, J. G. 1976. Gas from coal deposits. In: Natural Gas from Unconventional Geologic Sources. National Academy of Science-National Research Council.

DISTRIBUTION

No. of Copies

OFFSITE

A. A. Churm
DOE Chicago Patent Group
9800 South Cass Avenue
Argonne, IL 60439

27 DOE Technical Information Center

Col. H. L. Arnold, Jr.
District Engineer, Portland District
Corps of Engineers
P.O. Box 2946
Portland, OR 97208

S. Ballou
Argonne National Laboratory
9700 South Cass Avenue
Argonne, IL 60439

J. Binanado
Bureau of Land Management
P.O. Box 30157
Billings, MT 59107

W. W. Burr
DOE Office of Health and Environmental Research
Washington, DC 20545

E. S. Burton
DOE Resource Applications and Evaluations
Washington, DC 20545

R. L. Butenhoff
DOE Office of Environmental Research
Washington, DC 20545

No. of Copies

R. C. Clusen
DOE Assistant Secretary for Environment (Mail Stop E-201)
Washington, DC 20545

L. E. Coate
U.S. Environmental Protection Agency
1200 Sixth Avenue
Seattle, WA 98101

J. A. Coleman
DOE Office of Technology Impacts
Mail Stop E-201
Washington, DC 20545

H. G. Curtis
Public Power Council
P.O. Box 1307
Vancouver, WA 98660

L. A. D'Andrea
Resource Applications
Department of Energy
Washington, DC 20545

R. M. Davis
Oak Ridge National Laboratory
P.O. Box X
Oak Ridge, TN 37830

R. Doell
U.S. Geological Survey
354 Middlefield Road
Menlo Park, CA 94025

M. Duel, Research Supervisor
Methane & Mining Environmental Control
Pittsburg Mining and Safety Research Center
Bureau of Mines
Pittsburg, PA 15213

No. of
Copies

R. A. Duncan
Northwest Power Pool, Room 1210
920 S. W. Sixth Avenue
Portland, OR 97204

C. W. Edington
DOE Office of Health and Environmental Research (Mail Stop E-201)
Washington, DC 20545

H. C. Elmore
Pacific Northwest Utilities Conference Committee
P.O. Box 1231
Wenatchee, WA 98801

W. Esselman
Electric Power Research Institute
P.O. Box 10412
Palo Alto, CA 94304

W. O. Forster
DOE Office of Environmental Research (Mail Stop E-201)
Washington, DC 20545

W. Fulkerson
Oak Ridge National Laboratory
P.O. Box X
Oak Ridge, TN 37830

A. J. Goldberg
DOE Office of Technology Impacts
Mail Stop E-201
Washington, DC 20545

W. Gwillian
Morgantown Energy Technology Center
Collins Ferry Road
Morgantown, WV 26505

Mr. Ted Harris
DOE Office of Technology Impacts
Mail Stop E-201
Washington, DC 20545

No. of
Copies

J. A. Hebert
Human Affairs Research Centers
4000 N. E. 41st Street
Seattle, Washington 98105

L. Henning
Electric Power Research Institute
P.O. Box 10412
Palo Alto, CA 94304

L. J. Hoover
Argonne National Laboratory
9700 South Cass Avenue
Argonne, IL 60439

J. Hoozen
Bonneville Power Administration
P.O. Box 3621
Portland, OR 97208

P. W. House
DOE Office of Technology Impacts
Mail Stop E-201
Washington, DC 20545

J. Jaksch
University of California
Los Alamos Scientific Laboratory
P.O. Box 1663
Los Alamos, NM 87545

A. B. Joseph
DOE Office of Nuclear Regulatory Research
Washington, DC 20555

M. Katz
Bonneville Power Administration
P.O. Box 3621
Portland, OR 97208

J. E. Kiley
Bonneville Power Administration
P.O. Box 3621
Portland, OR 97208

No. of
Copies

D. Layton
University of California
Lawrence Livermore Laboratory
P.O. Box 808
Livermore, CA 94550

D. J. Lewis
Pacific Northwest Utilities
Conference Committee
920 S. W. Sixth Avenue
Portland, OR 97204

R. K. Lohrding
University of California
Los Alamos Scientific Laboratory
P.O. Box 1663
Los Alamos, NM 87545

F. G. Lowman
DOE Office of Nuclear Regulatory
Research
Washington, DC 20555

J. Maher
DOE Office of Technology Impacts
Mail Stop E-201
Washington, DC 20545

H. McCammon
DOE Office of Health and
Environmental Research
Washington, DC 20545

W. J. McCool
DOE Office of Environmental
Compliance and Overview
Washington, DC 29545

P. M. Meier
Brookhaven National Laboratory
Building 475
Associated Universities, Inc.
Upton, NY 11973

D. M. Monti
DOE Office of Technology Impacts
Mail Stop E-201
Washington, DC 20545

No. of
Copies

W. D. Moore III, Drilling Editor
Oil & Gas Journal
1200 S. Post Oak Road
P.O. Box 1941
Houston, TX 77001

P. Moskowitz
Brookhaven National Laboratory
Associated Universities, Inc.
Upton, NY 11973

W. E. Mott
DOE Office of Environmental
Compliance and Overview
Washington, DC 20545

S. M. Nealey
Human Affairs Research Centers
4000 N. E. 41st Street
Seattle, WA 98105

E. Neblet
DOE Federal Energy Regulatory
Commission
U.S. Custom House
San Francisco, CA 94111

Maj. Gen. W. E. Peel
Division Engineer
North Pacific Division
P.O. Box 2870
Portland, OR 97208

Col. J. A. Poteat, Jr.
District Engineer, Seattle
District
Corps of Engineers
1519 Alaskan Way South
Seattle, WA 98134

M. Reilly
DOE Division of Fossil Energy
Washington, DC 20545

Col. G. R. Robertson
District Engineer, Alaska District
Corps of Engineers
P.O. Box 7002
Anchorage, AK 99510

No. of
Copies

J. B. Robertson
DOE, Federal Region X
Federal Building, Room 1992
915 Second Avenue
Seattle, WA 98174

G. J. Rotariu
DOE Office of Technology Impacts
Mail Stop E-201
Washington, DC 20545

A. Rudolph
Battelle Memorial Institute
505 King Avenue
Columbus, OH 43201

M. Savitz
DOE Office of Conservation
and Solar Energy
Washington, DC 20545

R. D. Shull
DOE Office of Technology Impacts
Mail Stop E-201
Washington, DC 20545

W. E. Siri
University of California
Lawrence Berkeley Laboratory
No. 1 Cyclotron Road
Berkeley, CA 94720

D. H. Slade
DOE Office of Environmental Research
Mail Stop E-201
Washington, DC 20545

E. Swenson
Resource Applications
Department of Energy
Washington, DC 20545

J. Swinebroad
DOE Office of Environmental Research
Mail Stop E-201
Washington, DC 20545

No. of
Copies

R. Uhler
Electric Power Research Institute
P.O. Box 10412
Palo Alto, CA 94304

R. J. Vissia
Bureau of Reclamation
Federal Building
550 West Fort Street
Boise, ID 83724

B. W. Wachholz
DOE Office of Technology Impacts
Mail Stop E-201
Washington, DC 20545

C. H. Walkins
Bonneville Power Administration
P.O. Box 3621
Portland, OR 97208

Henry F. Walter
DOE/ESED
M/S EV-132-E-201
Washington, DC 20545

E. R. Williams
DOE Office of Technology Impacts
Mail Stop E-201
Washington, DC 20545

B. Wise
Morgantown Energy Technology
Center
Collins Ferry Road
Morgantown, WV 26505

R. W. Wood
DOE Office of Environmental
Research
Mail Stop E-201
Washington, DC 20545

T. York
Resource Applications
Department of Energy
Washington, DC 20545

No. of
Copies

ONSITE

DOE Richland Operations Office

H. E. Ranson

Pacific Northwest Laboratory

W. J. Bair
N. M. Burleigh
C. E. Cowan (3)
L. J. Ethridge (3)
D. L. Hessel (10)
R. C. Liikala
J. W. Litchfield
I. S. Levy
S. Marks
E. F. Riedel (15)
W. H. Swift
E. C. Watson
L. D. Williams
Publishing Coordination Ma (2)
Technical Information Files (5)