Open-File Report 80-5

Conservation of Methane from Colorado's Mined/Minable Coal Beds: A Feasibility Study

By
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Colorado Geological Survey
Department of Natural Resources
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COLORADO GEOLOGICAL SURVEY
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ABSTRACT

Coal bed methane, a well documented hazard in coal mines, is also a potential energy source. In Colorado, an estimated resource of 38.8 TCF may exist in the Green River, Raton Mesa, San Juan River, and Uinta coal regions. Methane content for minable coalbeds ranges from 0 to near 500 cubic feet of gas per ton of coal. The presence of coal bed methane depends on geologic factors, while development of coal bed methane depends on geologic, mining, economic, and legal factors which must be considered in determining the feasibility of a coal degasification project. Vertical, horizontal, and directional hole degasification methods are summarized,and a case study of the Hawk's Nest Mine area, Somerset, Colorado, is included.

INTRODUCTION

In 1978, approximately 11 million cubic ft per day of methane was emitted from Colorado's coal mines. The gas, which occurs in concentrations of less than 1 percent in the mine's return air, was released into the atmosphere by the mine's exhaust system. In an effort to conserve this gas, the Colorado Oil & Gas Conservation Commission funded a joint project with the Colorado Geological Survey to study the feasibility of degasifying Colorado's coalbeds ahead of mining. This paper gives a summary of the results of the first year's work.

ACKNOWLEDGMENTS

A project of this nature could not have been completed without the active support of individuals from both the private and the public sector.

First, we wish to thank Douglas V. Rogers, the Board of Commissioners, and the staff of the Colorado Oil and Gas Conservation Commission, Denver, for their financial support and assistance. Andrew Deborski, State Coal Mine Inspector, retired, and Norm Blake, Director, retired, of the Colorado Division of Mines are acknowledged for their moral support and valuable input on coal mining practices in Colorado. We also wish to express our appreciation to Peter E. Matthies, Vice President, Al Amundson, Chief Engineer, and staff of Western Slope Carbon, Inc. for their cooperation and assistance on the Hawk's Nest Mine study.

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Disclaimer

Mention of any specific product in this paper does not necessarily imply endorsement of that product.

METHANE--HAZARD AND RESOURCE

Firedamp is an explosive mixture of gases well known to coal miners throughout history. Its main constituent, methane (CH_4), is an odorless, colorless gas of the paraffinic subgroup of hydrocarbons. Methane along with carbon dioxide, water, and small amounts of heavier hydrocarbons, is a byproduct of the coalification process.

Methane is highly combustible in the presence of oxygen. Figure 1 gives the explosive limits of the oxygen-methane mixture. As can be seen from the graph, the concentration of methane in air must be kept well below 5% to avoid the explosions that over the years have caused the deaths of thousands of U.S. miners. Federal law requires that methane concentrations be kept below 1% in all mine workings.

In the past, high methane concentrations have been controlled predominantly by proper ventilation of the mine workings. The main coal-producing European countries and the United States have directed their research toward developing alternate methods of controlling methane emission into the mine's atmosphere. One of the most promising methods is draining methane from the coalbed prior to mining by using vertical, horizontal, or directionally drilled degasification holes. The methane becomes a useable resource, as the gas can be collected and utilized on mine site; in nearby communities; or (if of sufficient quality and quantity), injected into a public gas pipeline. Most of the gas is of pipeline quality, with Btu values ranging from 500 to greater than 1000 Btu's per cubic foot. The gas may contain CO_2, but H_2S has not been found in samples to date. Figure 2 compares coalbed gas with a sample of commercial grade natural gas.

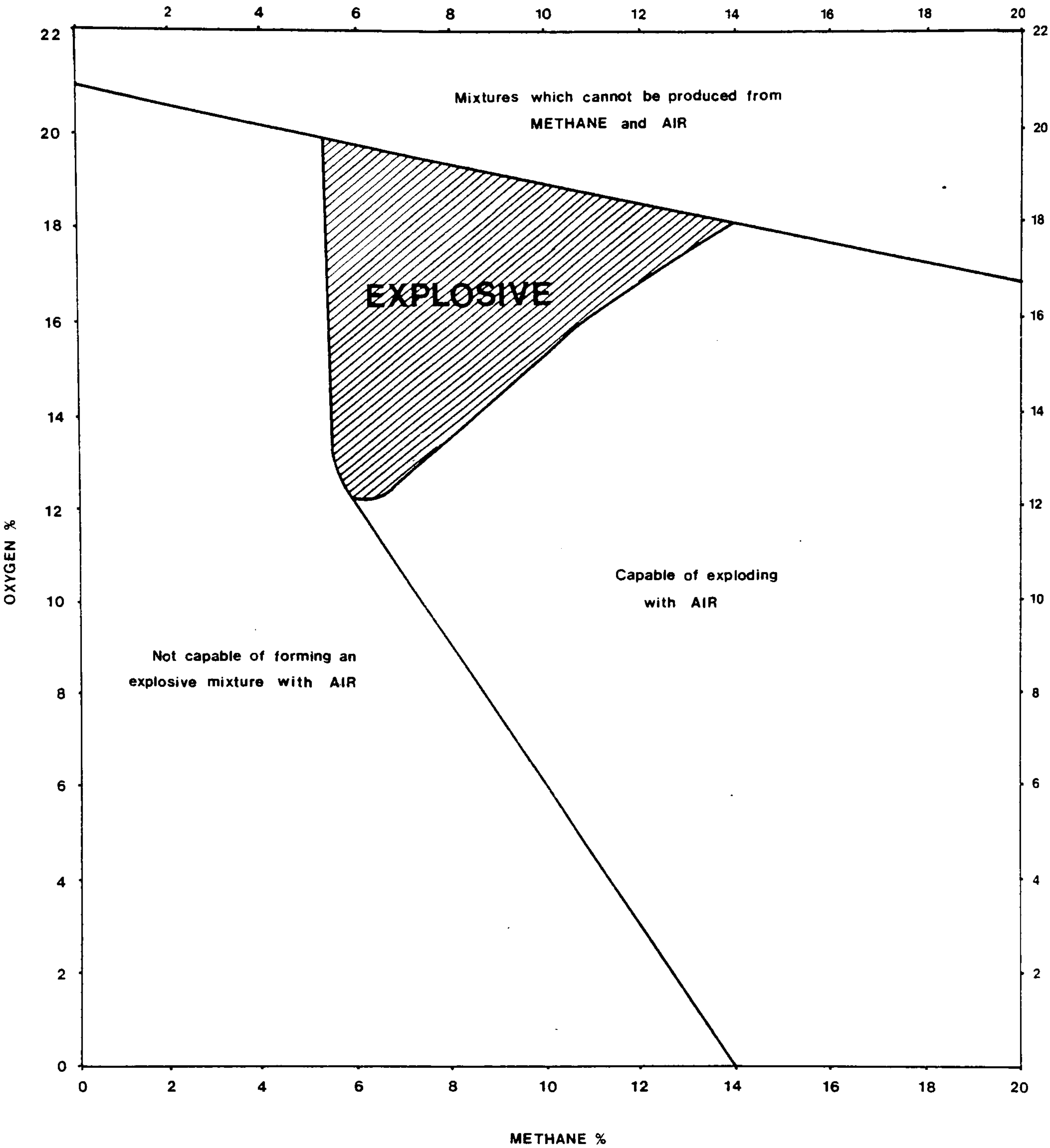


Figure 1. Flammability of methane/air mixtures (Modified from Linton, 1977).

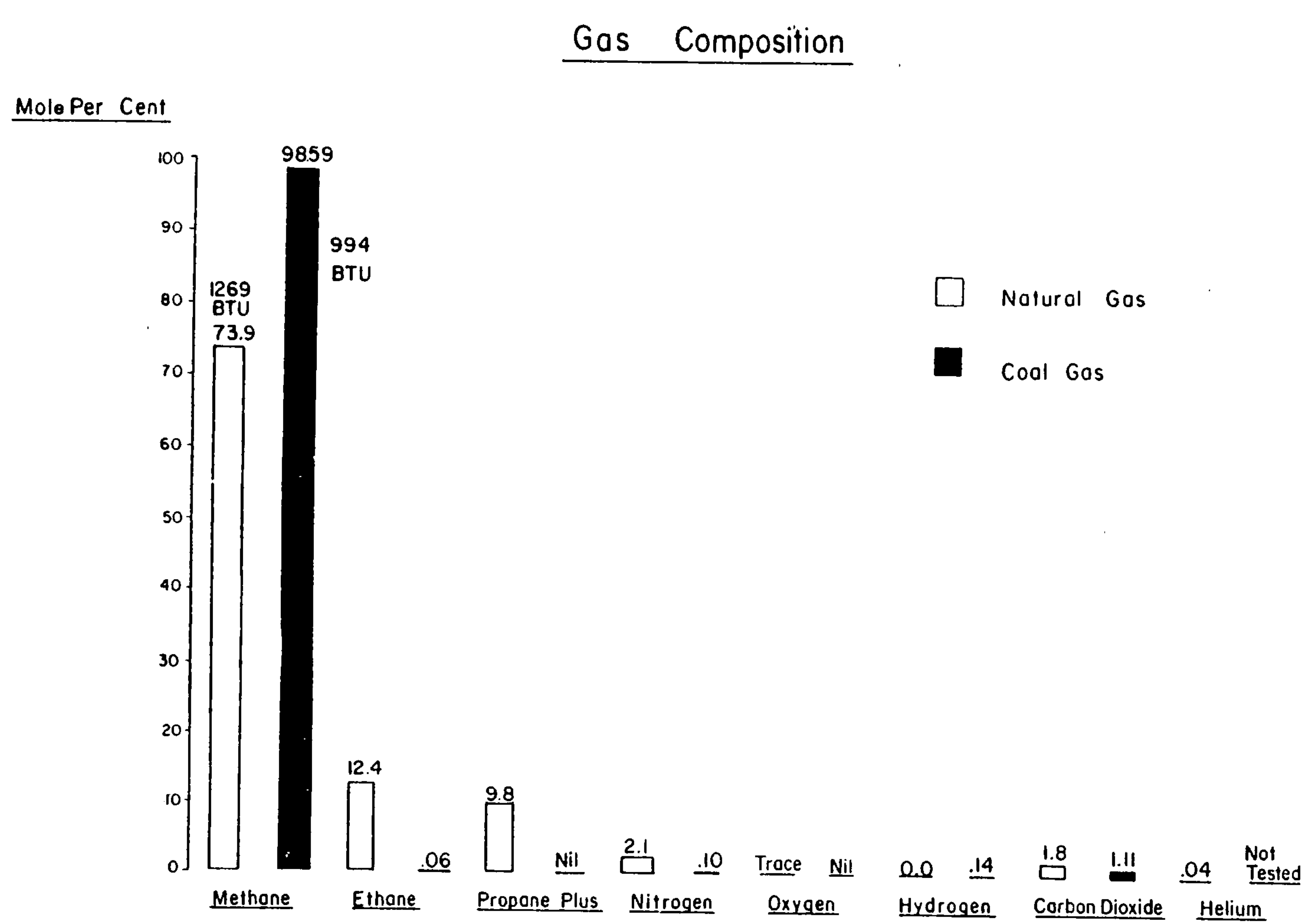


Figure 2. Comparison of the composition of a sample of coal bed gas with that of a sample of natural gas from a well in Adams County, Colorado (from Murray and Tremain, 1979).

METHANE RESOURCES IN COLORADO

The Colorado Geological Survey's study of methane over the past four years has delineated areas in the Green River, Raton Mesa, San Juan River, and Uinta regions that may be suitable for gas recovery (Figure 3). Preliminary figures (based on incomplete coal resource totals) show that an estimated methane resource of 38.8 TCF may exist in these regions (Table 1).

Many of the gassiest coals are at unminable depths. Yet, large resources are known to exist in four actively mined coal fields in Colorado: the lower Trinidad field in the Raton Mesa region and the Book Cliffs, Carbondale, and Somerset fields in the Uinta region. Table 2 lists the average and ranges of methane contents for these fields. Table 3 gives the average and range of methane concentration figures for each coal region where mining has or is occurring.

PROCEDURES USED FOR DETERMINING METHANE CONTENT IN COAL BEDS

Methane content in the coal was determined using the "direct method" as developed by the U.S. Bureau of Mines (McCulloch and others, 1973).

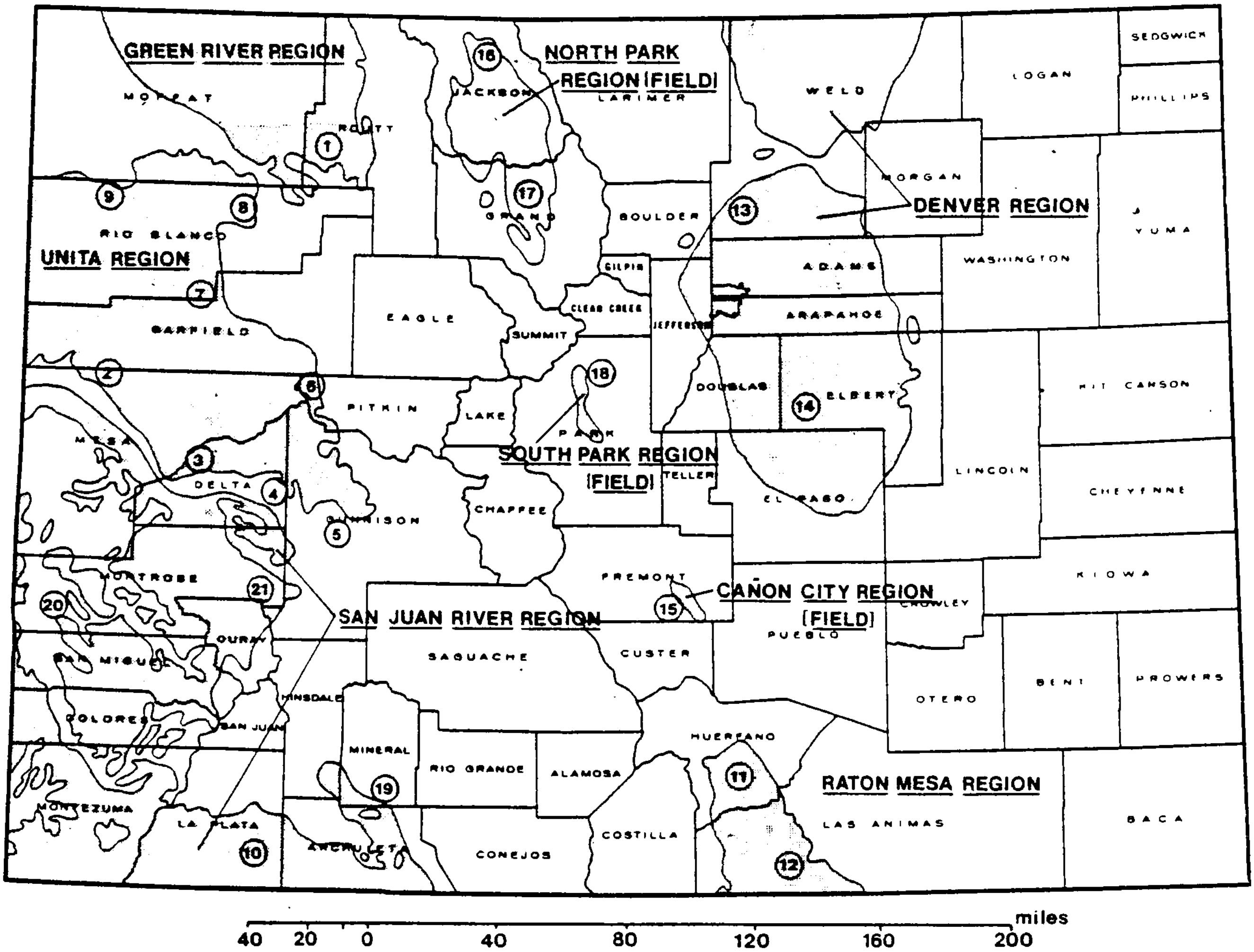
The "direct method" was first developed in France by Bertar, Bruyet, and Gunther (CERCHAR) in 1970. Since then, several variations on this method have been designed for specific mines throughout Europe and the United States. In 1973, Kissell, McCulloch, and Elder put together the method most commonly used in the United States. In the Kissell method, a coal core sample obtained from a vertical borehole is sealed in an air-tight canister (Figure 4). Pressure builds up in the canister as the gas is released from the coal. Tubing is attached to the valve on the canister and is run into a water-filled inverted graduated cylinder. When the valve is opened, the excess gas flows through the tubing and displaces the water within the cylinder until atmospheric pressure is again reached in the canister. Total gas emitted from the canister equals the total volume of water displaced during the desorption process. The total desorption of a sample may take from a week to months, depending on the gassiness of the coal and the condition of the sample.

The in-situ methane content of the coal can be estimated by adding three different quantities. The first quantity is Q_1, the volume of gas lost from initial sampling of the coal to the time the coal is sealed in the container (Curl, 1978). Q_1 is related to the elapsed time by the following equation:

$Q_1 = kt^n$

K = constant

n varies from 0.3-0.5



COAL REGIONS AND FIELDS IN COLORADO
(ROCKY MOUNTAIN COAL PROVINCE)

COAL FIELDS

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

Figure 3. Coal-bearing regions in Colorado.

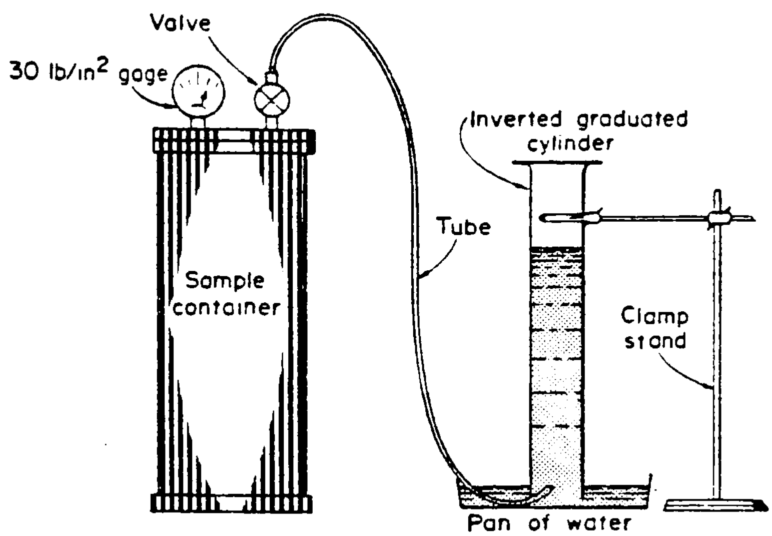


Figure 4. Diagram of methane desorption equipment.

Table 1. Preliminary Methane Resource Estimates for Four Regions in Colorado.

Coal Region	Area	Methane Resource Billion Cubic Feet
Green River	Part	32
Raton Mesa	Trinidad Field	200
San Juan River	?	7,220
Uinta	Piceance Basin	31,335
	TOTAL	38,787

TABLE 2. Methane Content of Coals in Four Actively Mined Coal Fields in Colorado

		METHANE CONTENT OF COALS (cubic feet per ton)			
		Less Than 1000 ft overburden		Greater Than 1000 ft overburden	
Coal Region	Coal Field	Average	Range	Average	Range
Raton Mesa	Trinidad	79	2-254	159	38-492
Uinta	Book Cliffs	79	--	224	--
	Carbondale	--	--	458*	--
	Somerset	150	80-217	162	9-245

*Estimated using U.S. Bureau of Mines formula based on rank and depth of coal (Kim, 1977).

Coal Region	Coal Field	Formation	Less than 1000'		Greater than 1000'	
			Avg. Methane Content (CF/T)	Gas Content Range (CF/T)	Avg. Methane Content (CF/T)	Gas Content Range (CF/T)
Denver	Unnamed	Denver	7.3	4.0-10.6	--	--
Green River	Yampa	Williams Fork	7.2	2.9-16.1	236.88	15.3-376
Uinta	Danforth Hills	Williams Fork	8.06	3.7-12.5	23.2	3.2-41.6
Uinta	Grand Mesa	Williams Fork	10.4	6.4-179.2	--	--
Uinta	Grand Mesa	Mesa Verde	7.3	0-14.6	--	--
Uinta	Carbondale	Williams Fork			22.7	6.9-54.2
Uinta	Book Cliffs	Mesa Verde	79.6	?	223.3	?
Uinta	Rangely	Mesa Verde	188.0	111-355	18.5	16-21
Uinta	Somerset	Mesa Verde	173.08	9-245	--	--
San Juan	Durango	Menefee	7.75	5.3-10.2	--	--
Raton	Trindad	Vermejo	83.77	2.3-154.7	166.77	38-492
Raton	Walsenburg	Vermejo	32.1	29.7-34.5	28.96	4.6-65.5
Raton	Trinidad	Raton	81.68	26-160	132.5	72-143
Raton	Walsenburg	Raton		47.9-52.5	--	--

Figure 3. **Methane content of coals in historically mined coal fields in Colorado.**

In the Kissell method, an "n" value of .5 is used. Q_2 is the quantity of methane emitted from the canister as described above. Q_3 is the residual gas emitted when the coal sample is crushed to a fine powder. The total in-situ gas content is $Q = Q_1 + Q_2 + Q_3$ (cc/g). Figure 5 shows the data forms utilized by the Colorado Geological Survey for methane desorption analyses. The times listed and the drilling media are important in determining constant k and the lost gas, Q_1.

GOB GAS

Gob gas is a mixture of air and methane occurring in the mine. Methane in the gob gas is released from either coalbeds above or below the mined bed or from permeable beds in the roof when the roof is caved during mining. The gob gas, which contains from 35 percent to 90 percent methane, can be treated either by separation or adsorption methods to increase its methane content. This, at present, is not economical. Gob gas is also usable for turbine power generation, and Liquid Natural Gas (LNG) production (TRW, 1977).

FACTORS AFFECTING METHANE DEVELOPMENT

Harnessing methane as an energy source involves determining the geologic, mining, and economic controls of a potential degasification site. Each is summarized below.

GEOLOGIC FACTORS

Geologic parameters influencing methane content and migration in coal beds and the subsequent emission into the coal mine are:

1) Rank of the coal.

2) Lithology of the roof and floor rock.

3) Degree of cleat development in the coal bed and structure of the general area.

4) Depth of the overburden.

5) Thickness and extent of the coal bed.

6) Degree of water saturation.

Rank and Composition of Coal

Coal bed gas occurs 1) as free gas in the cleats of the coal, and 2) more importantly, as gas adsorbed onto the inner surface area. One kilogram of coal has an estimated surface area of between 20,000 m^2 and 200,000 m^2 (Curl, 1978). The gas in the free state is in equilibrium with the gas in the adsorbed state. The

DESORPTION FORM

State:		County:		Location			Hole No:	P.
Time 0 Date	Time	Elapsed Min.	$\sqrt{T}$ [1]	Cylinder Reading 1 ml 2	cc Gas Released	cc Total Gas	DER cc/g [2]	Cylinder No. Sample Wt.
								Comments

[1] $\sqrt{T}$ = $\sqrt{\text{"Lost" gas time + desorption time in minutes}}$, Plot on Figure 4 graph

[2] Sample Weight/ Daily Emission = DER

$\sqrt{\text{"Lost" Gas Time}}$ =

R = Reverse Flow

CORE SAMPLE DATA SHEET

WELL IDENTIFICATION

Company Drill Hole No. (Sample No.) ____________ Date ____________

(tape Company Name and Drill Hole No. on cylinder)

Company ____________ Person Collecting Core ____________

Drilling Company ____________

Hole Location ____________

County ____________ State ____________

Air Temperature ________ Surface Elevation ________ Total Depth of Hole ________

Formation Name ____________

Coal Bed Name ____________

Condition of Sample ____________

CORING TIMES

Time Coring Started ____________

(A)Time Coalbed Encountered ____________

Time Coring Completed ____________

(B)Time Core Started Out of Hole ____________

(C)Time Core Reached Surface ____________

(D)Time Core Sealed in Canister ____________

CORING METHOD

Type of Core Retrieval ____________

____

Drilling Media ____________

Barrel Length ____________

Core Size ____________

Cored Interval ____________

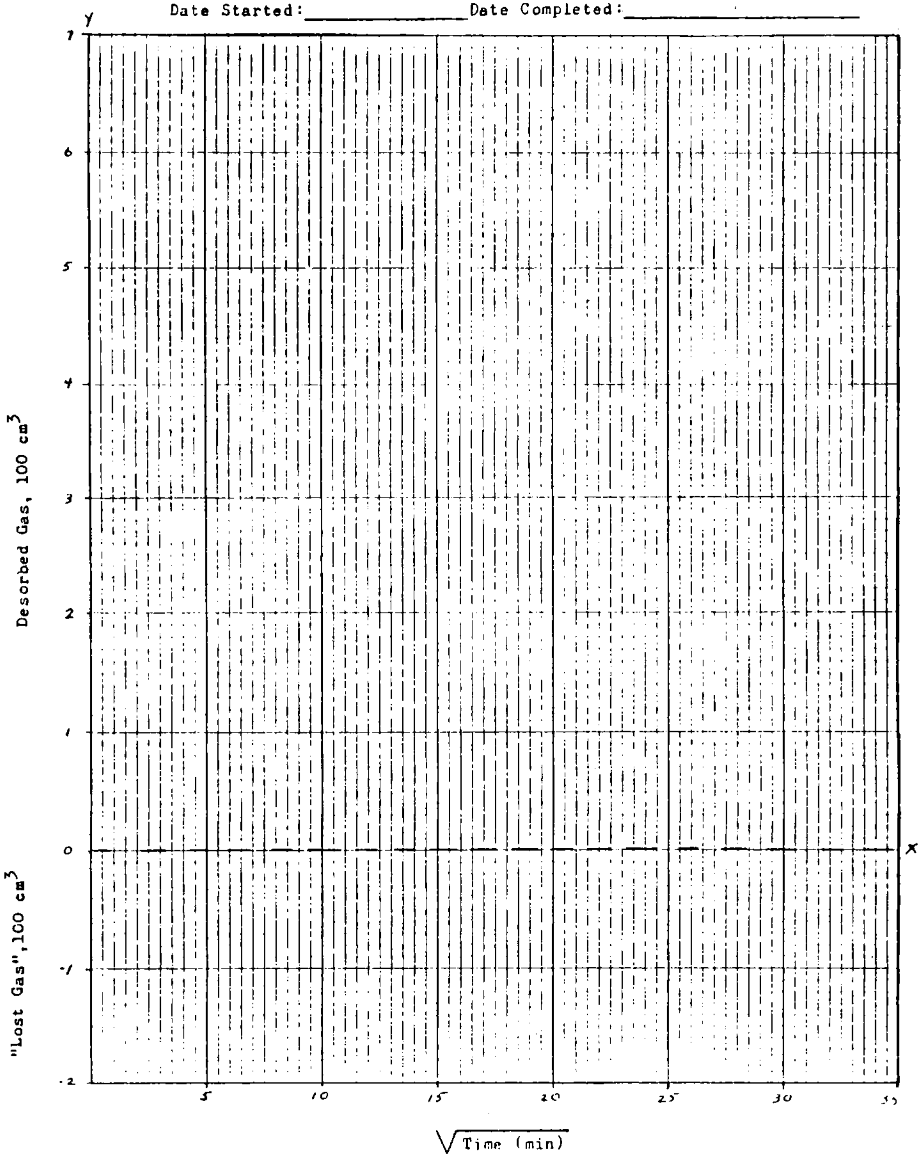
CORE DESCRIPTION (include roof, floor, & coal)

Figure 5. Data-form used by the Colorado Geological Survey in direct method methane content determinations.

State:________ County:________ Loc.:________

Co.:________ Hole No.:________ Cyl. No.:________

Date Started:________ Date Completed:________



CALCULATION SHEET

Cylinder no.________

Weights

Cylinder Wt. + Coal________gm.

Cylinder Wt.________gm.

Coal Sample Wt.________gm.

Lost Gas Time: if air or mist is used (D-A) ________

if water or mud is used (D-C) $+\left(\frac{C-B}{2}\right)$ ________

$\sqrt{\text{Lost Gas Time}}$ ________min.

Lost Gas ________cc

Gas from Canister ________cc

Residual Gas from Crushing ________cc/g

Gas Content = $\frac{\text{Lost Gas (cc) + Gas from Canister (cc)}}{\text{Sample Weight (g)}}$ + Residual Gas from Crushing $\frac{cc}{g}$

________cc/g x 32 = ________cf/ton

Figure 5. (continued).

maximum amount of gas that can be adsorbed on the coal's surface, or the adsorptive capacity of the coal, depends on many parameters. The most important are pressure and temperature both in historic and present conditions (i.e., a lowering in temperature or an increase in pressure increases the adsorptive capacity of the coal). As rank of coal is dependent on the temperature and pressure, it has been shown that the adsorptive capacity increases with an increasing rank of coal (Kim, 1977). This fact is important in that most of the known gassy coals in Colorado occur in areas of high geothermal gradient and where the coals have been upgraded by igneous activity. These coals tend to be high volatile A to medium volatile bituminous in rank. The composition of the coal and the concentrations of various constituents in the coal also affect the adsorptive capacity of the sample. The USBM (Kim, 1977) found in U.S. coals, the ratio of fixed carbon to volatile matter correlates with the maximum amount of gas adsorbed by the coal. Moisture content is also important as an increase in moisture can decrease the coal's adsorptive capacity as shown in Figure 6. According to Joubert (Curl, 1978), the methane sorption decreases with increasing moisture to a critical value above which further increase in the moisture will not retard the sorption of methane. Joubert has also shown that this critical value is dependent on the oxygen content of the coal (Figure 7). Another parameter which may also affect the gassiness of the coal is the maceral composition of the coal. At present, research has not been done in this area.

Data on the adsorptive capacity of Colorado's coals is presently scarce. The bulk of available data is the result of direct method analyses done by the Colorado Geological Survey in conjunction with the USBM and the U.S. Department of Energy (U.S. DOE). Plotting the direct method gas content against the Dry Mineral Matter Free (DMMF) fixed carbon, and the "as received" fixed carbon/volatile matter (FC/VM) ratio, shows that the coal analyses values are in a narrow band between 1.2 and 1.5 (gas content vs FC/VM) and 55 to 60 (fixed carbon DMMF vs gas content) (Figures 8-9). These erratic results, based on 56 representative samples from Colorado, may reflect the small sample size, or they may show the wide discrepancy between Direct Method values and adsorptive capacity values for coals below the medium volatile bituminous rank (Figure 10).

The moisture content has a definite relation to gas content as is shown in Figure 11. The graph, based on 89 data points, shows that the gas content decreases with increasing moisture in the coal.

Figures 8, 9, and 11 all show the effect of depth on the gassiness of the coal. This will be covered in a following section.

Lithology of the roof and floor rock

The amount of methane present in the coal bed and its emission into the mine may also be influenced by the lithology of the strata

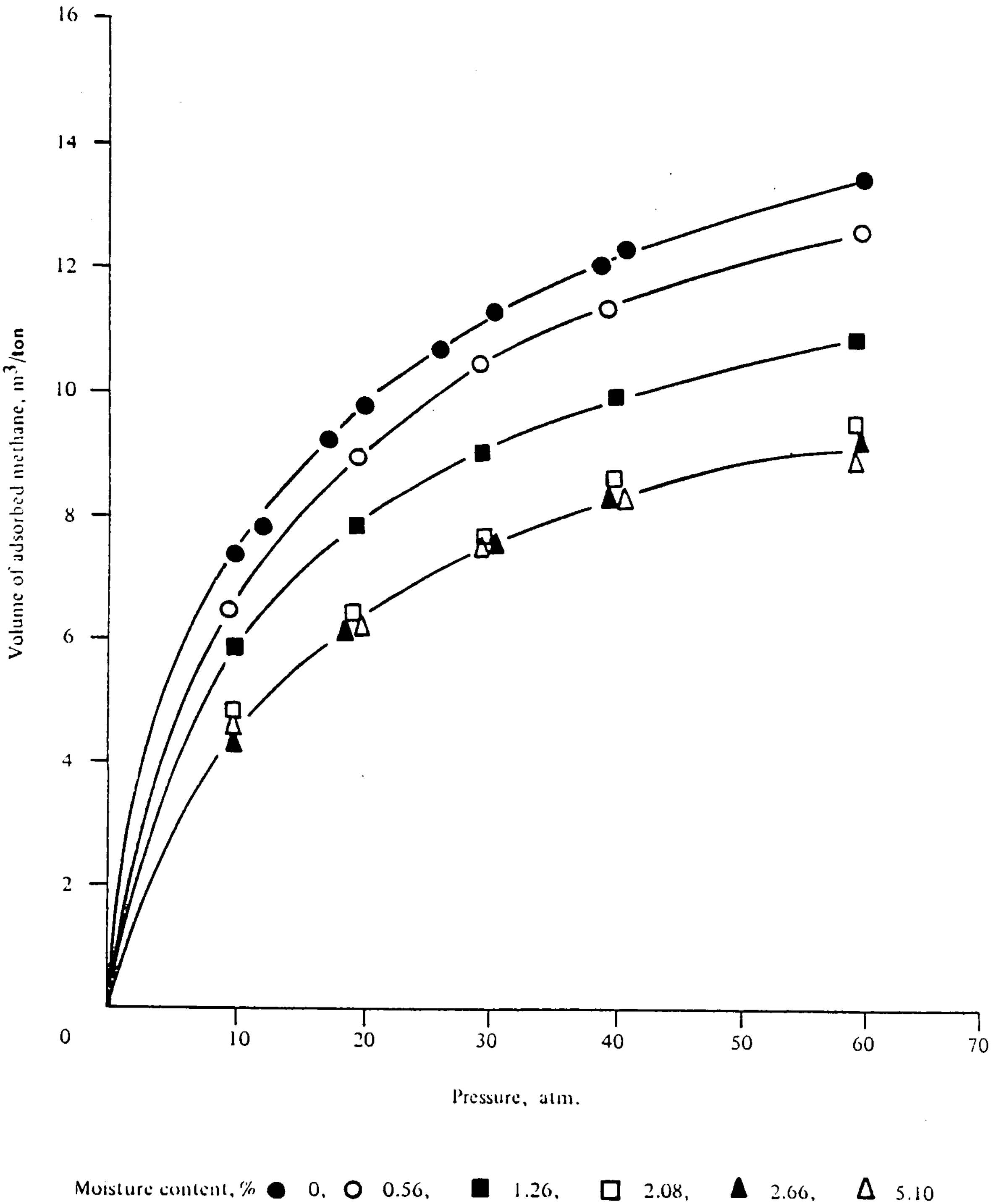


Figure 6. Methane adsorption isotherms for Pittsburg II coal at 30°C at various moisture contents (From Curl,1978)

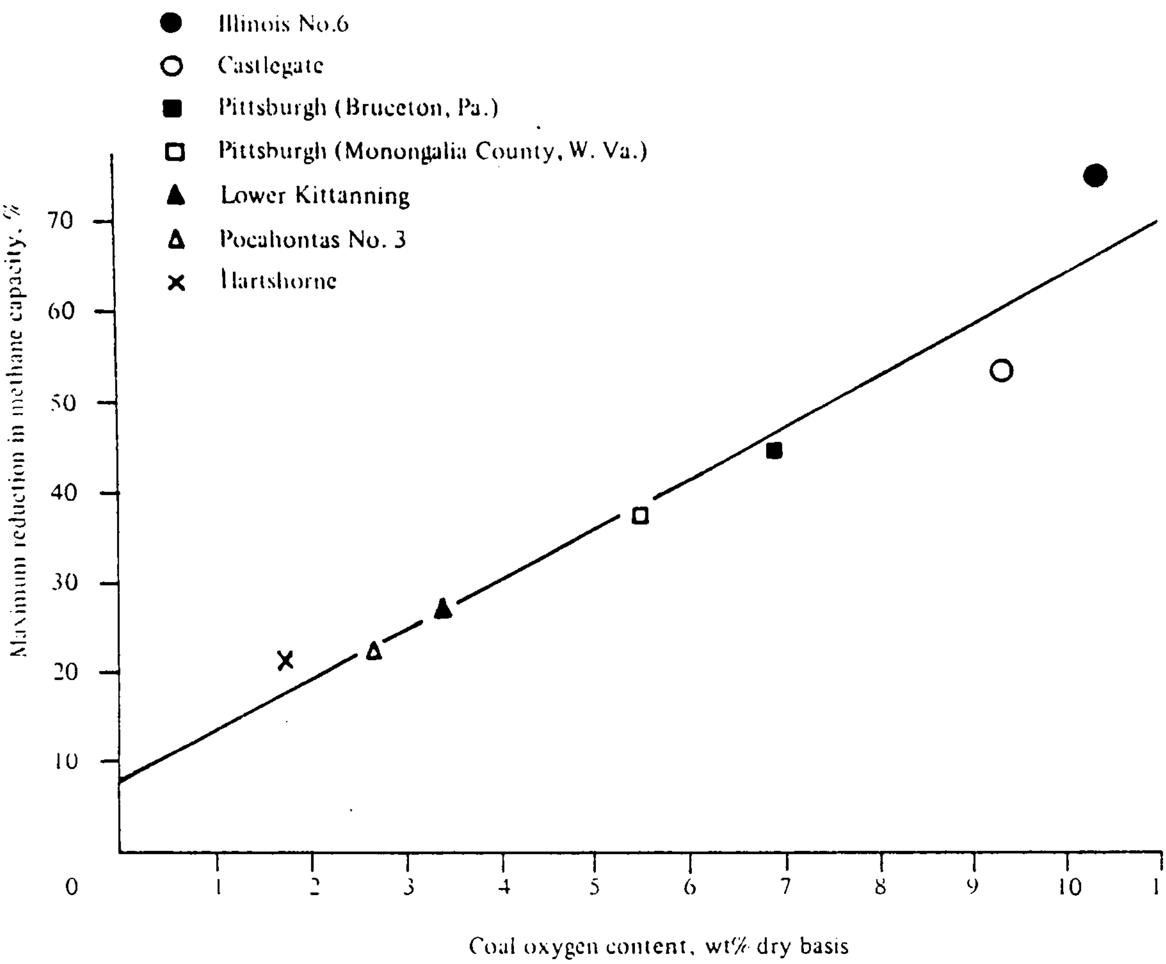


Figure 7. Maximum reduction in methane sorption versus coal oxygen content at values of moisture content above the critical values, 10 atm., 30°C (From Curl, 1978).

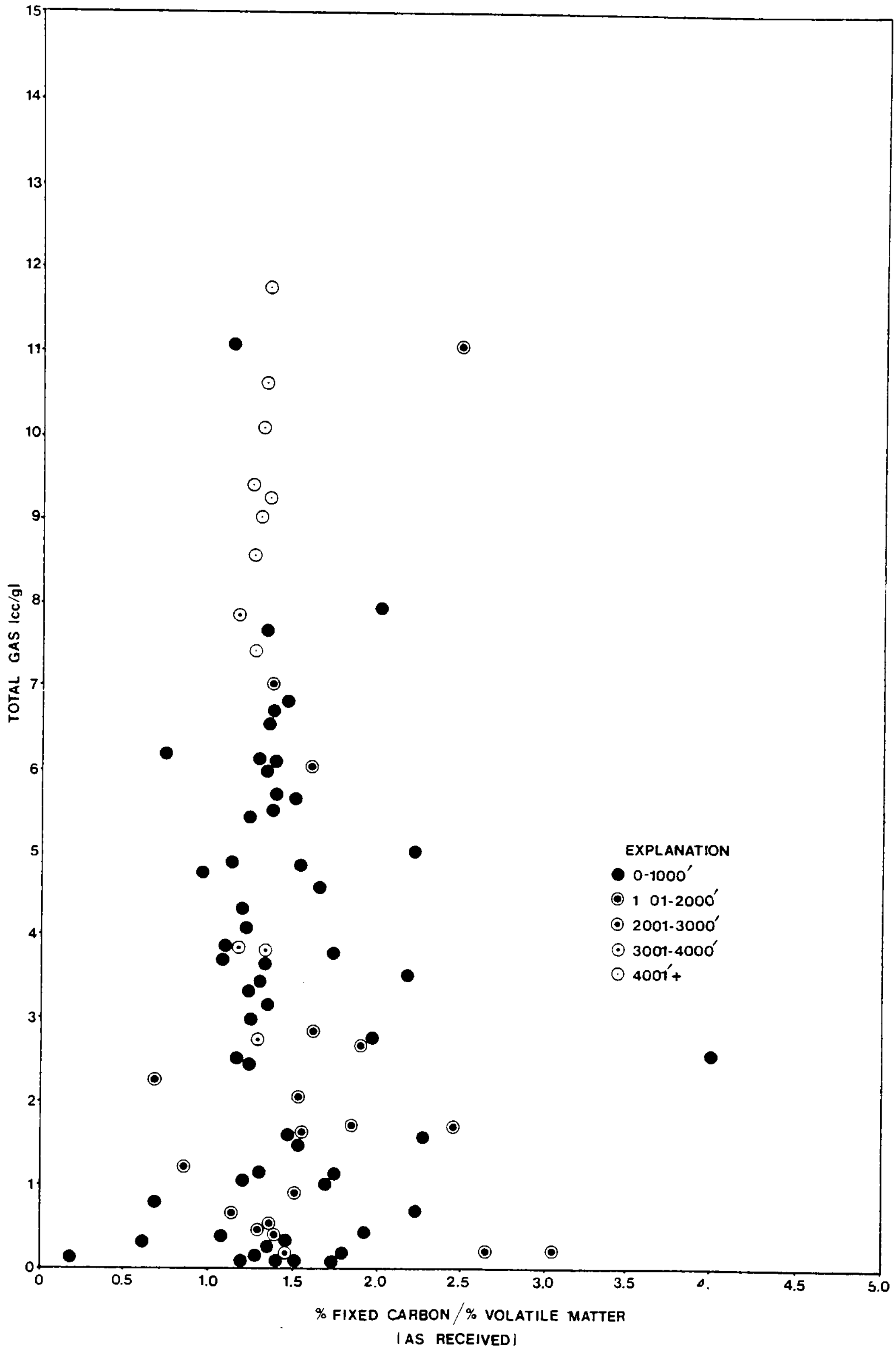


Figure 8. Plot of % fixed carbon / % volatile matter ratio vs total gas content (Direct Method Detremination) for 56 Colorado samples. Dot patterns vary with increasing overburden.

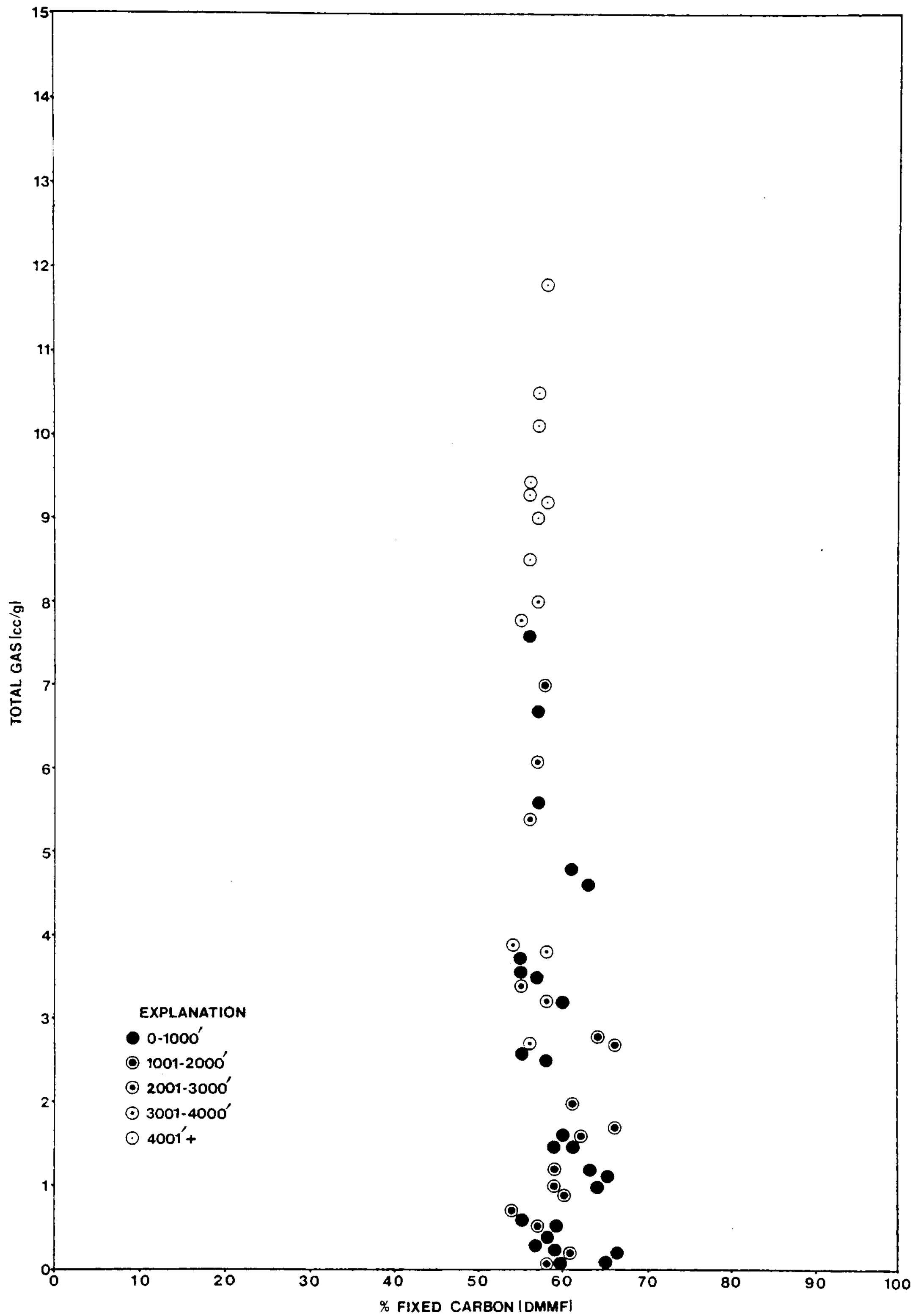


Figure 9. Plot of % fixed carbon (DMMF) vs total gas content (Direct Method Determination) for 56 Colorado samples. Dot patterns vary with increasing overburden.

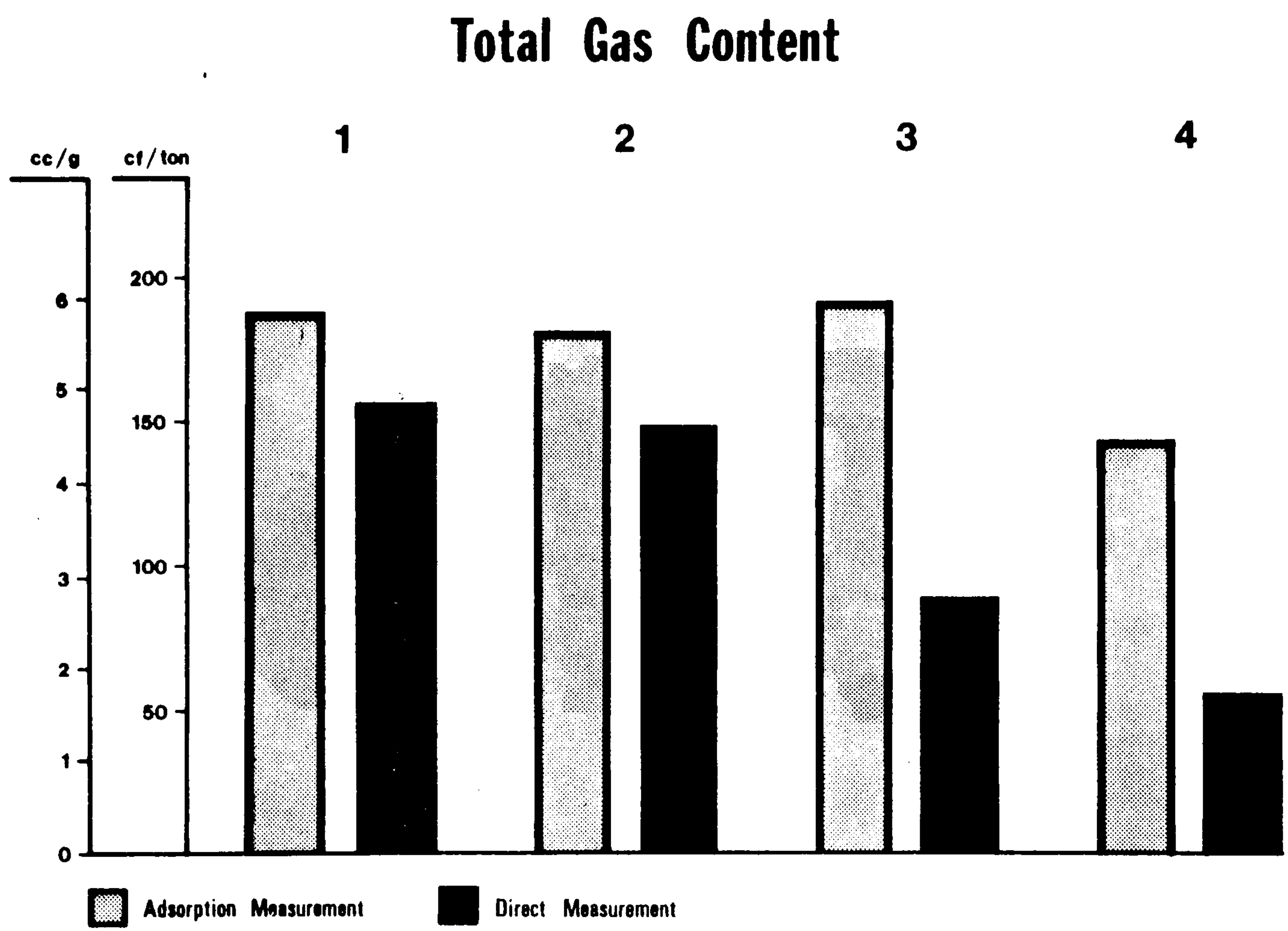


Figure 10. Comparison of total gas contents of 4 cored coal samples from the Raton Mesa region, Colorado, as determined by adsorption isotherms ("indirect") and U.S. Bureau of Mines "direct" measurement methods, (From Murray and Tremain, 1979). All samples are hvA Bituminous in rank.

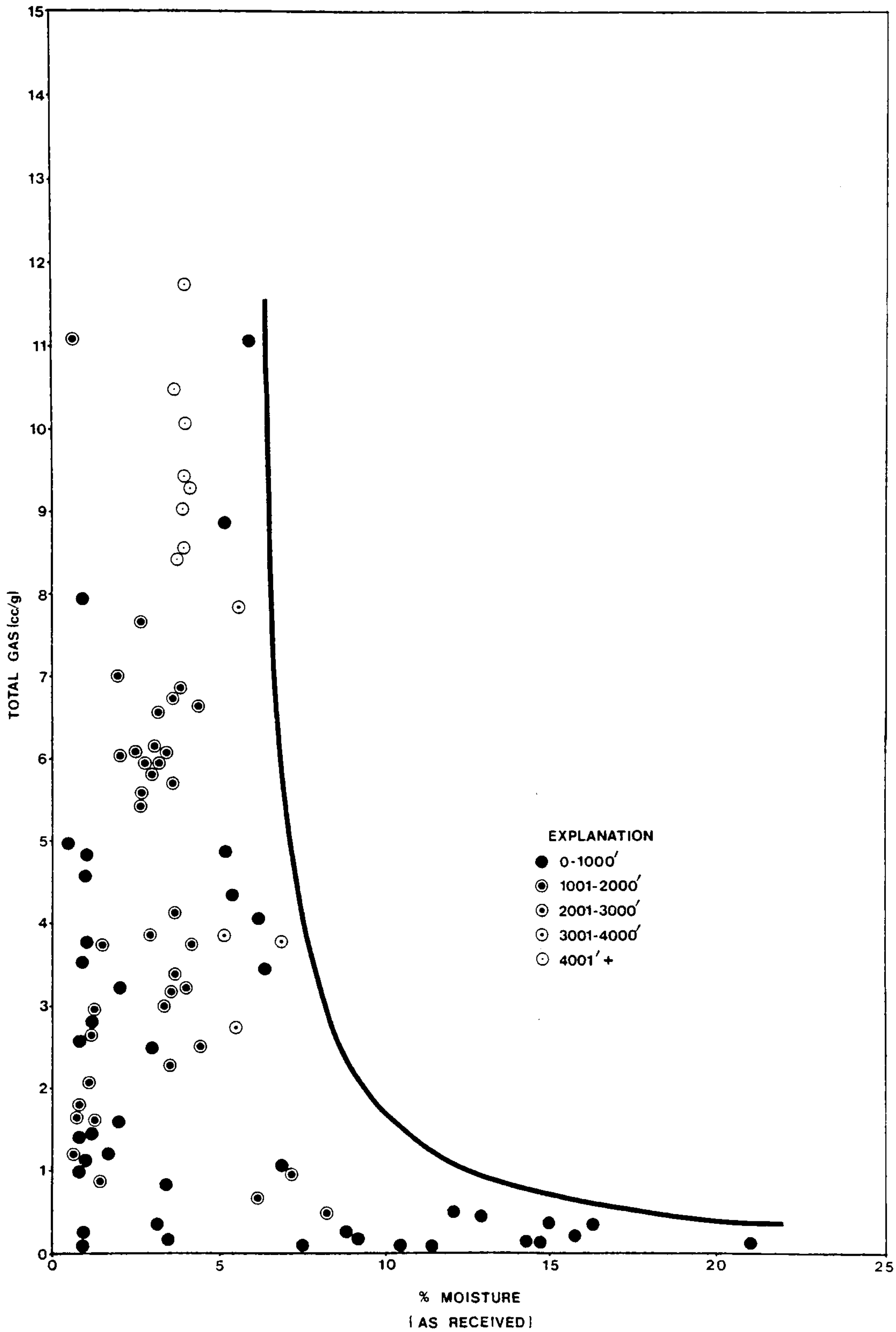


Figure 11. Plot of % moisture (as received) vs total gas content (Direct Method Determination) for 89 Colorado samples. Dot patterns vary with increasing overburden.

above and below the coal. These factors may determine the migration of gas into and out of the coal bed. In the roof, an unfractured shale lying directly above the coal may act as an impermeable layer restricting the flow of methane; while a sand or other material exhibiting a higher permeability might allow for the migration of methane out of the coal. Collapse of the roof strata during retreat and longwall mining may recirculate the methane into the mine workings.

The lithology of the floor rock is important where the mined coal is underlain by coal stringers or carbonaceous shale. With fracturing of this interburden between the stringer and the main bed, methane migrates upward into the mine workings.

Degree of cleat development in the coal bed

In coal, the flow of methane is determined by a two step process. First, diffusion of methane through the micropore structure of the coal; and second, flow of the gas along natural fractures in the coal bed. These fractures, called cleats, occur in coal in two sets; the face or primary cleat, and the butt or secondary cleat. The face cleat, the more continuous and well developed of the two, is the main migration path for fluids in the coal bed. The butt cleat tends not to be as well developed and extensive as the face cleat. The control on migration in the butt cleat direction is dependent on the degree of development of the butt cleat. Previous work has classified the origin of cleat as endogenetic, or related to compaction; and exogenetic, or related to tectonic forces (McCulloch and others, 1974). Evidence exists to justify both theories, and research done in Europe and the United States show that either or both of the processes may be involved in the origin of cleats in different coals. These controls also vary from region to region.

Studies done by McCulloch and Duel (1973); McCulloch and others (1974, 1975); Diamond and others (1975, 1976); MuCulloch and others (1976); and Henkle and others (1978) showed that in many areas:

1) The directions of cleating and jointing are in many cases similar.

2) The cleat orientations are similar through a vertical section with multiple coalbeds. The largest variation in cleat directions between the two coal beds occurred horizontally and not vertically.

3) The direction of cleating and jointing are either perpendicular to the fold axis, i.e., the face cleat, or are parallel to the axis, i.e., the butt cleat. Research done by Billings, Hough, Secor, Hodgson, and Griggs (McCulloch, and others, 1974) suggested that face cleats are extension fractures that form parallel to the

direction of the compressive force. They are formed in a water-saturated state, under high confining compressive pressures, early in the folding of the strata. The butt cleats are thought to be release fractures developed after load removal due to erosion and uplift.

In areas where an exogenetic or tectonic control is evident, the surface joint direction, the trends of cleats in upper or lower beds, and the main structural trends may be used to determine main migration controls on the subject coal bed.

Depth and nature of overburden

The presence and extent of fracturing and faulting in the overburden controls the concentration of methane in the coal and its subsequent migration out of the coal.

Research done by the U.S. Bureau of Mines in the 1970s (McCulloch and others, 1975, Popp and McCulloch, 1976) noted that, for a given location, the amount of gas in a coal bed increased with increasing depth. In Colorado, several areas show increases in gas content with increased overburden (Figures 8, 9, and 11). In other areas this pattern was not present possibly due to migration of methane out of the coal bed or local upgrading in rank due to thermal influences.

Thickness and extent of the coal bed

The reserve base of methane in an area depends not only on the gas content of the coal but also on the coal's thickness and areal extent (Diamond, 1978). Since coal acts as the source and/or reservoir rock of the gas, the three dimensional area of the coal bed along with other factors determines the in-place resources.

Degree of water saturation of the coal bed

As has been noted in this discussion, coal composition affects methane storage, and the amount of moisture in the coal controls the adsorption capacity of the coal. Inversely, water in the coal bed restricts the flow of methane. Kissell (1972) noted that regions of a coal bed adjacent to older areas of a mine were considerably more permeable than freshly mined areas. Shrinkage of the coal due to loss of methane is one possible factor causing the increased permeability. Also, according to work done by Kissell and others, "the increased permeability was due to a relative permeability effect in which the flow of methane is controlled in part by the degree of coal bed water saturation; the permeability to methane increases as the water in the coal bed decreases and makes more pore space available to the gas phase" (Kissell and Edwards, 1975). Graphs of water and gas production vs. time illustrate this effect (Figure 12).

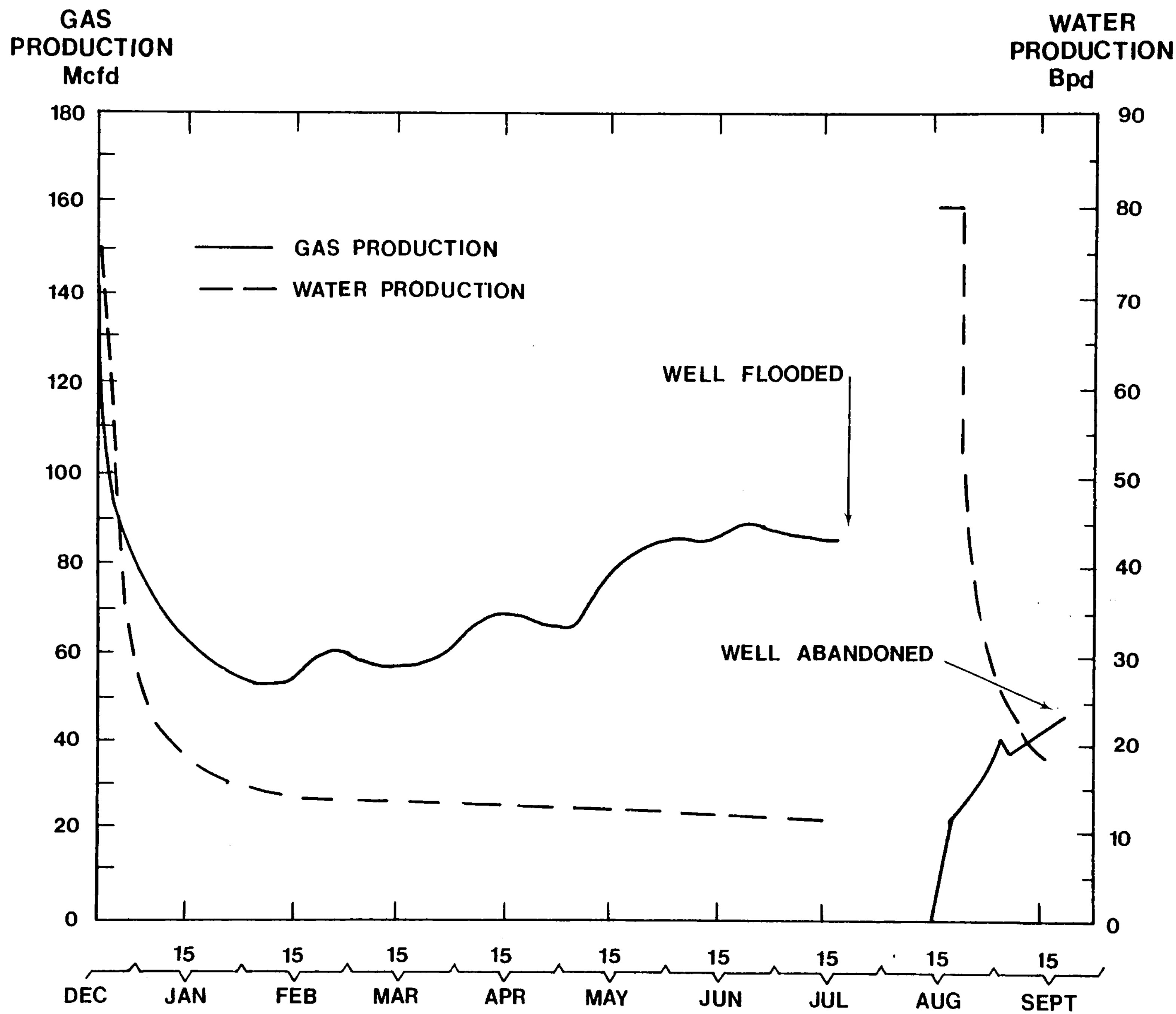


Figure 12. Gas and water production in the Mary Lee coalbed, Alabama (From Lambert and Trevits, 1979).

MINING PARAMETERS INFLUENCING METHANE DEGASIFICATION

In mining, various parameters affect the need for degasification prior to mining. The first of these is the mining method used or planned on the property. The method is important because 1) the number of entries, 2) the amount of caving, and 3) the area of the working face all determine the amount of methane released. In longwall mining, methane degasification using the horizontal method has been used successfully due to its flexibility. The vertical and directional hole method is also compatible with most mining methods. One main problem with the vertical method is that the hole, if cased with steel throughout the mined coal bed, can cause a safety hazard and damage equipment when it is mined through.

The amount of coal production is a major factor in the amount of methane emitted into the air. Noack of the Free Republic of Germany (Curl, 1978) describes the amount of gas emitted at the face (make) as having inert and energized components. The inert component is the gas make at zero coal output. The energized component is the increase in make per unit of production.

It has been found in research done in Poland and the United Kingdom that the methane emission increased with increased production, and the rate of increase tended to lessen at higher outputs (Curl, 1978) (Figure 13). The characteristics of the coal seam must be considered, as the gas make varies in different seams. Taking the above into account, the amount of production may determine either the need for degasification in a new mining operation or the inclusion of degasification techniques into an expanding operation.

The amount of time available for degasification before the coal is mined from the property is important. Depending on both the mining method and the characteristics of the coalbed, a sufficient amount of time must be set aside to allow for dewatering of the coalbed and methane drainage.

Another factor involved in coal bed degasification is the presence of workings, both active and abandoned. It was previously noted that the presence of active or abandoned workings helps decrease the water saturation in a coalbed and, as a result, increases the gas flow by increasing the permeability and decreasing reservoir pressure.

ECONOMIC FACTORS

The economics of pre-mining degasification is important in determining the feasibility of any drainage program on a given mining property. The cost of drilling, completion, production, and maintenance on the wells should be balanced by the value of the recovered gas. This can be accomplished in various ways:

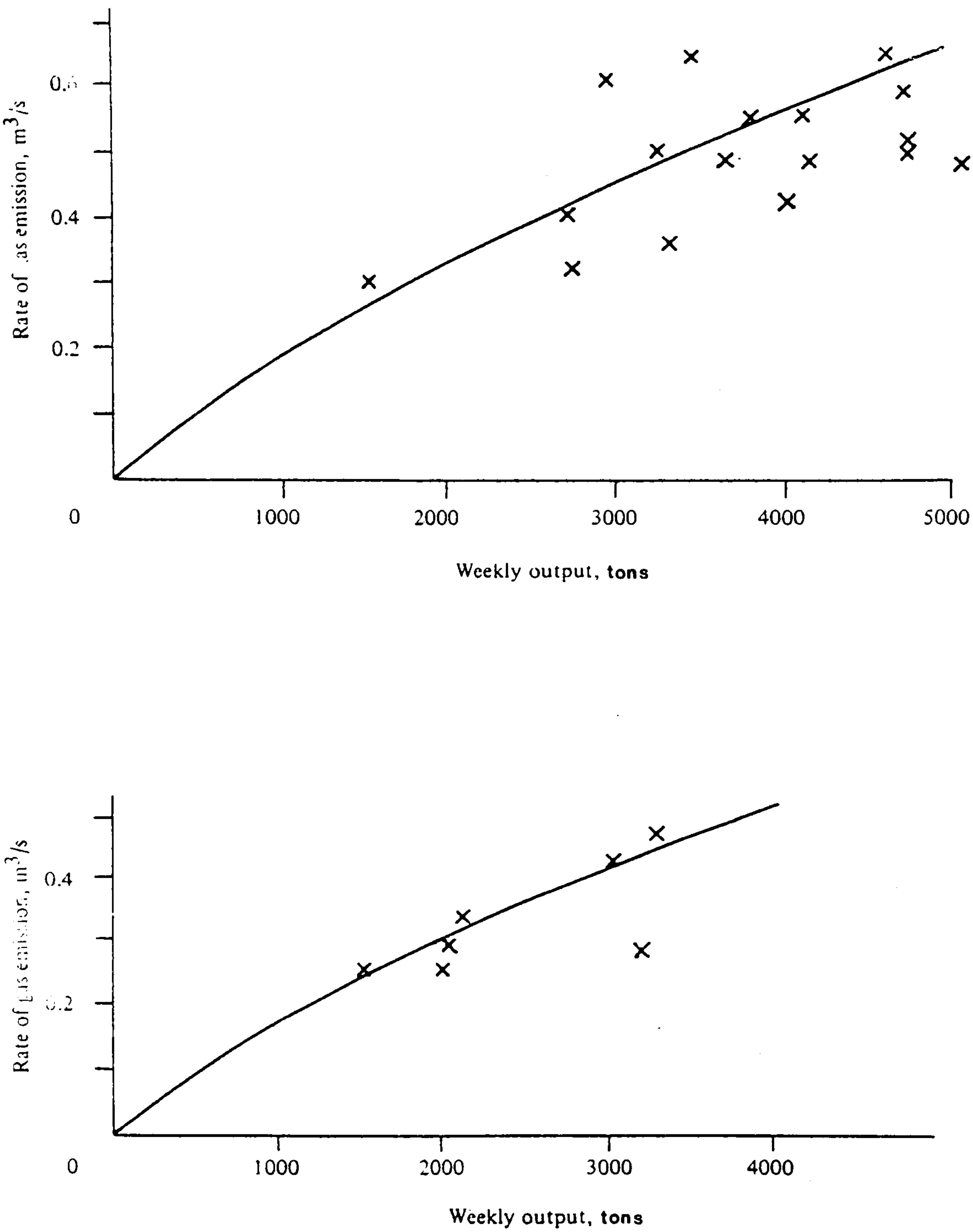


Figure 13. Gas emission from two United Kingdom longwall faces compared with curves of the form:
Methane emission = constant x (advance rate)$^{0.8}$
(From Curl,1978).

1. By decreasing the downtime and ventilation costs associated with high methane concentrations in the mine workings.

2. By using the gas on-site for heating or power generation.

3. By selling the gas for use either in nearby communities or as a pipeline product.

It should be noted that it may be possible to put a price on the amount of gas conserved and used by incorporating a methane degasification program. It may also be possible, when looking back, to determine the savings due to lower ventilation costs and decreased downtime. Yet it is not possible to totally determine the savings due to increased mine safety brought about by a well-engineered degasification program.

LEGAL ASPECTS

At present, the ownership of coal gas has not been firmly established on the federal level. On the state level, the Colorado Board of Land Commissioners addressed the problem in Sec. 23 of the Coal Mining Lease. At the federal level, ownership and rights of the surface, oil and gas, and mineral lease holders have yet to be defined. Research into the legal consequences must be a part of each degasification project.

DRILLING AND COMPLETION METHODS FOR DEGASIFYING COALBEDS PRIOR TO MINING

Vertical, horizontal, and directional drilling techniques can all be used to degasify the coalbed ahead of mining. Each degasification method has its strengths and weaknesses; and each can be used both alone or in combination. It should also be noted that, in degasifying mined/minable coal beds, <u>the drilling and completion plan must incorporate present mine health and safety regulations, so as not to endanger the present or future mining operation</u>.

VERTICAL DEGASIFICATION METHOD

Drilling and completion

The vertical degasification method is a modified oil and gas production method. Holes are drilled from the surface through the coal zone or zones from which gas is to be produced. These holes are then extended below the lowest producing zone to provide sump areas for the collection of water and solids. A truck-mounted rig is usually of sufficient size to drill holes down to 3000 feet. The holes can be drilled using either air, water, or mud. Drilling with mud is discouraged because the mud will often decrease the permeability of the producing zone. A minimum of four inch diameter holes are usually drilled so as to accommodate most standard down-hole tools. The most common drilling bit is a standard Tri-cone bit. A tungsten carbide bit is preferable when drilling with air flushing due to the longer life of the bit.

The holes may be completed in several ways. The USBM has found the most successful form of completion is open-hole, where the hole is drilled and cased to the top of the producing zone. The hole is then extended through the producing zone. Although in the past this method was used for single horizon completions, technology is available that allows for selectively cementing intervals between producing horizons (see Figure 26).

An alternate method is to drill to total depth, case, cement, and selectively perforate or slot at the zones of gas production (Figure 14). This method has been used mainly for multiple zone completions with limited success. The two main problems with completion through casing are (1) less efficient gas production due to the lack of surface area of coal exposed, and (2) possible coalbed damage (fracture plugging) during cementing.

It should be noted that the use of steel casing can be a hazard if the coal beds drained by the well are to be mined through.

Gas and Water Production

The well shown in Figure 14 is designed for production of both gas and water. In this case, 2" production tubing is run down into the sump below the lowest producing zone. A standard downhole pump is used to produce water through the 2" tubing. Gas is produced through the annulus between the 4" well casing and the water production tubing. The gas is piped from the well-head to a gas-water separation unit and then put into the gas pipeline.

Stimulation of a Coal

Coal beds in general tend to be low permeability reservoirs. Although there have been exceptions, it is necessary in many cases to stimulate the producing zones to increase well yield. In stimulation, a reservoir is fractured using a viscous fluid (such as a gel-water, or foam) and propping agent. These are mixed together and injected into the formation at high pressures. The fluids and propping agents vary depending on the method used, the rock to be fractured, and the desired result.

The U.S. Bureau of Mines, in conjunction with coal and gas producers, has conducted 63 hydraulic stimulation treatments in coal in eastern and midcontinent states (Trevits, 1980 personal communication). They have utilized gel, foam, and the Kiel frac methods for fracturing the coal. Foam fracs are preferred because of reduction of water in the coal and easy breakdown of the foam in the

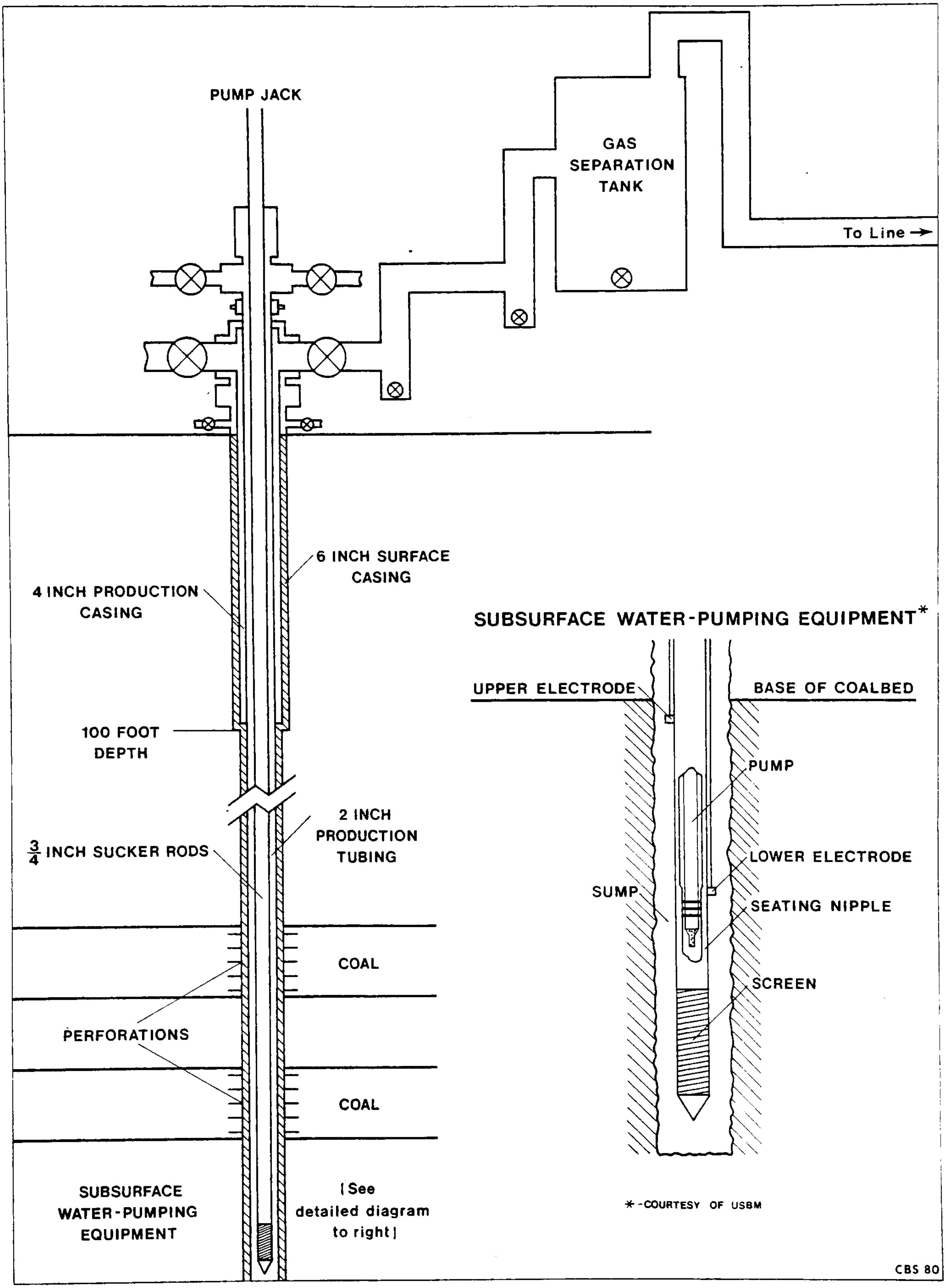


Figure 14. Multiple coal zone completion in a cased and cemented hole.

formation. The most common proppant used has been from 10 to 40 mesh sand. These treatments have resulted in a zero to greater than sixty-fold increase in production. However, hydraulic stimulation of minable coalbeds remains controversial due to possible weakening of the strata by propogation of fractures into the roof and floor rock. Using geologic and rock mechanics data run on exploration cores and down hole, a stimulation treatment can be designed to help minimize the possibility of roof damage.

Of the 63 hydraulic treatments done by the U.S. Bureau of Mines, 12 have been mined through and observed underground. Most of the induced fractures have been localized in the coalbed, although a few have extended into the roof rock. In several cases, increased roof support has been needed in these areas of fracturing. Although the immediate effect of the fracturing has not been, in itself, severe; the long term effect of fracturing on the mine roof and mining is not known.

In the end, the company must weigh the risk of weakening the roof strata against the increase in safety and productivity offered by a decrease of methane in the coal bed being mined.

HORIZONTAL DEGASIFICATION HOLES

Where coals are at considerable depth and under rough terrain, as in many western areas, horizontal boreholes from the mine workings may be an advantageous method of degasification. Horizontal holes are drilled into virgin coal parallel to the bedding planes and away from the mine workings. The hole is drilled entirely in coal and every foot (except the first 20 to 30 feet, which are cased) produces methane. The direction in which the holes are drilled is important due to the cleat controlled directional permeability of coalbeds. Drilling perpendicular to the face cleats intersects the largest number of extensive fractures which results in a larger gas flow from the hole.

The gas collected from horizontal holes in eastern coal mines and in Utah have proved to have a methane content suitable for on-site utilization or sales.

Drilling Horizontal Holes

In drilling the horizontal holes, a hydraulically powered rotary drill capable of drilling horizontal or inclined holes is used. The drill must be permissible for drilling underground. There are many such units on the market. The drill is made up of two parts, the drilling unit and the power unit. Valves, gauges and levers controlling rotational speed, thrust, and movement of the carriage are located on the drilling unit. When drilling, the drill pipe water pressure is monitored constantly to insure adequate water circulation to prevent the bit from getting stuck.

During drilling, the power unit is kept in the intake air and hydraulic lines connect the drill and the power unit. These hydraulic lines can be up to 500 ft. in length. Drilling rates average about 100 ft/shift for a 2,000 ft hole (Cervick, 1979, personal communication). This advance can vary significantly if unusual conditions are encountered. The drilling crew consists of a driller and driller's helper.

The main problem encountered in drilling horizontal holes is keeping them in the coalbed. The bit tends to go down into the floor or up into the roof because of gravity or deflection by hard inclusions. Because deviations from the "horizontal" will occur, precise surveying and methods of correcting the deviations are needed. The Bureau of Mines has found a drill string configuration that works well (Cervick and others, 1975). It consists of replacing the first rod in the string of BQ rods with a heavy NW drill rod. The 20 ft NW rod weights 205 lb and the BQ rod weighs 80 lb. The NW rod adds weight to the bottom side of the bit and stiffens the drilling assembly. A centralizer is placed behind the bit and another on the end of the NW rod (see Strever, 1980).

Two other factors affect the trajectory of the hole: the bit thrust and rotational speed. Cervick and others (1975) noted that in the Pittsburg coalbed, a thrust of 1200 lbs and a rotational speed of 400-600 rpm using a 3 1/2" bit will hold the hole trajectory. These rates are subject to many factors and could be quite different in various coalbeds. If the bit starts to turn up, a reduction in thrust and an increase in rotational speed will wear away the bottom of the hole and turn the bit downward. It can also be brought down quickly by removing the front stabilizer. When the bit drops towards the floor, it can be angled upward by increasing thrust and reducing rotational speed. The back stabilizer is also removed to bring the bit up quickly.

The correct bit type is a very important part of the entire drilling assembly. When drilling coal, a three-blade drag bit is preferred as it has three to four times the penetration rate of a tri-cone roller bit and costs less. The only disadvantage of the drag bit is that it will not penetrate a hard inclusion, or discontinuity.

Finally, there is no substitute for a driller who has experience in drilling long horizontal holes. He must be familiar with the equipment and its responses to drilling conditions. He must also be able to react quickly to hard spots which deflect the bit in an unpredictable manner, and soft spots where the bit arcs rapidly downward.

Surveying the Hole

During the drilling, hole surveys must be made every 30 ft initially until the drilling parameters are determined. Once these parameters are determined, surveys every 50 ft are usually sufficient unless severe (greater than 1 degree) deviations occur. A single-shot survey instrument will determine the inclination of the hole. It contains electrical components, and, therefore, must be approved for use in coal mines.

During the drilling operation, a plot should be maintained of the trajectory of the hole so that the location of the bit with respect to the floor or roof is known at all times. Changes in thickness or slope of the coal bed are other variables which can affect the operation.

Methane Control During Drilling

Methane gas encountered during the drilling operation needs to be considered and controlled. One two thousand ft hole in the Sunnyside mine (Perry and others, 1978) produced methane gas at the rate of 200 cfm during drilling. To keep the methane concentration at the site below 1%, 20,000 cfm of methane-free air was required. Since this amount of air is not available everywhere within a mine, other methods of handling the methane are needed. Cervick and others (1975), designed a stuffing box that removes the methane before it escapes into the air. The drilling is conducted through a box which is attached to a 20 ft length of 6" pipe (see Strever, 1980). This pipe, called the anchor pipe, is grouted into the coalbed. Water and drill cuttings coming out of the pipe drop to the bottom of the box and the methane is drawn off the top by a slight vacuum. The vacuum is maintained in the box by means of flexible tubing connected to an exhauster or similar apparatus in a return airway.

Difficulties also arise as drill pipe is pulled or during drill hole surveys when methane can escape into the mine atmosphere. A one-way check valve placed in the drill string eliminates this problem.

Piping System

The methane gas can be piped to the surface in several ways. The first would be to pipe the gas to the surface through a vertical borehole. The second, described below, would be to pipe the gas to the surface through the mines' entries.

Finding the correct pipe sizes for the methane drainage system is an extremely complex problem. There are several factors which must be taken in account such as head losses in the pipe, and economics of pipe sizing.

The type of pipe used will depend on the special conditions at the drill site (Table 4). The easiest and safest way to install the pipe is by hangers from the roof. They are spaced according to the weight of the pipe, and material flowing in it. Automatic shut-down valves are used in the system to stop the flow of gas if there is a break in the pipe.

	Aluminum	Copper	Carbon Steel	Stainless Steel	Fiber-glass	Polyethy-lene	Polybuty-lene	Poly-vinyl Chloride
1.a)Resistance to Internal Corrosion caused by Coalbed Gas & Liquids	Good	Good	Good	Good	Good	Good	Good	Good
b)Resistance to External Corrosion caused by Mine Environment	Good	Fair	Poor	Good	Good	Good	Good	Good
c)Resistance to External Corrosion caused by Electrolysis	Poor	Fair	Fair	Good	Good	Good	Good	Good
2.a)Resistance to Impact Forces	Good	Fair	Good	Good	Poor	Good	Poor	Fair
b)Resistance to Failure as a Result of Bending or Tensile Stresses**	Poor	Poor	Fair	Fair	Poor	Fair	Poor	Poor
3.Fire Resistance:a)Safety with respect to Causing a Fire	Poor	Good	Fair	Fair	Good	Good	Good	Good
b)Ability to Resist Heat or Fire	Fair	Fair	Good	Good	Poor	Fair	Fair	Fair
4.Ability to Withstand Design Pressures	Good	Good	Good	Good	Good	Good	Good	Good
5.a)Weight (Per 21' Joint of 8.625" O.D. Pipe)*	205 lbs	665 lbs	470 lbs	470 lbs	75 lbs	168 lbs	166 lbs	247 lbs
b)Ability to be Easily and Safely Connected	Poor	Poor	Fair	Fair	Poor	Good	Good	Fair
6.a)Approximate Cost per Ft.of Pipe (8.625" O.D. Pipe)*	$9.00	$60.00	$6.00	$40.00	$5.00	$5.25	$7.00	$5.00
b)Availability of Pipe in Various Diameters and Wall Thicknesses	Good	Poor	Good	Fair	Fair	Good	Fair	Good

*The comparisons shown are based upon the wall thicknesses of 8" pipe that would most likely be used if that particular material were selected. Copper-.3125; Fiberglass-.162; Aluminum-.322; Carbon Steel-.250; Stainless Steel-.250; Polyethylene-.750; Polybutylene-.750; Polyvinyl Chloride-.750

**Includes consideration of the joining method

Table 4. Comparison of pipe materials,(From Energy Applications, Inc., 1976).

The piping network is kept in the return airways as an additional safety precaution. If an accident occurs to the pipe, the escaping methane will be quickly purged from the mine. This prevents dangerous methane gas buildups in the mine workings.

Safety Regulations

There are no MSHA regulations specifically referring to the methane recovery piping systems in coal mines. However, if a mine is seriously considering horizontal drilling, it should draft a set of working guidelines for methane drainage. Once approved, these guidelines become law for the mine and the mine can be cited for failure to comply with them.

Production

Before the effluent out of the horizontal holes can flow into the pipeline laterals, it must go through a liquid separation system. The system must be capable of removing entrained as well as surges of water. Since no system is 100% effective, it is common practice to place manual valves at several low spots in the piping system to drain off the water that accumulates there.

Metering of the flow rates from the horizontal holes should be done to provide data to the operator that allows him to evaluate the effectiveness of each borehole, and to detect malfunctions or line blockages in the system.

For the surface measurement station, an orifice meter could be used. Natural gas utilities rely on orifice measurement for most of their large volume flow metering applications. The gas buyer may wish to provide the metering facility or may have specific recommendations for his measurement needs.

If the gas is to be injected into a pipeline, it must be compressed to pipeline pressure levels. The compressor could have a natural gas-fired engine. Generally, a compressor like this will consume approximately 5% of its inlet gas as engine fuel. Once started, these units run unattended but require daily maintenance.

DIRECTIONAL DRILLING METHOD

The directional drilling method is a hybrid of the horizontal and vertical methods. A hole is progressively deviated from the vertical at the surface until the hole enters into the target coalbed horizontally (Figure 15). The hole is then extended horizontally into the coalbed for a distance of 1,000 to 3,000 ft (Figure 16). Two to three more horizontal "branches" are also drilled from the same vertical hole in different directions in the

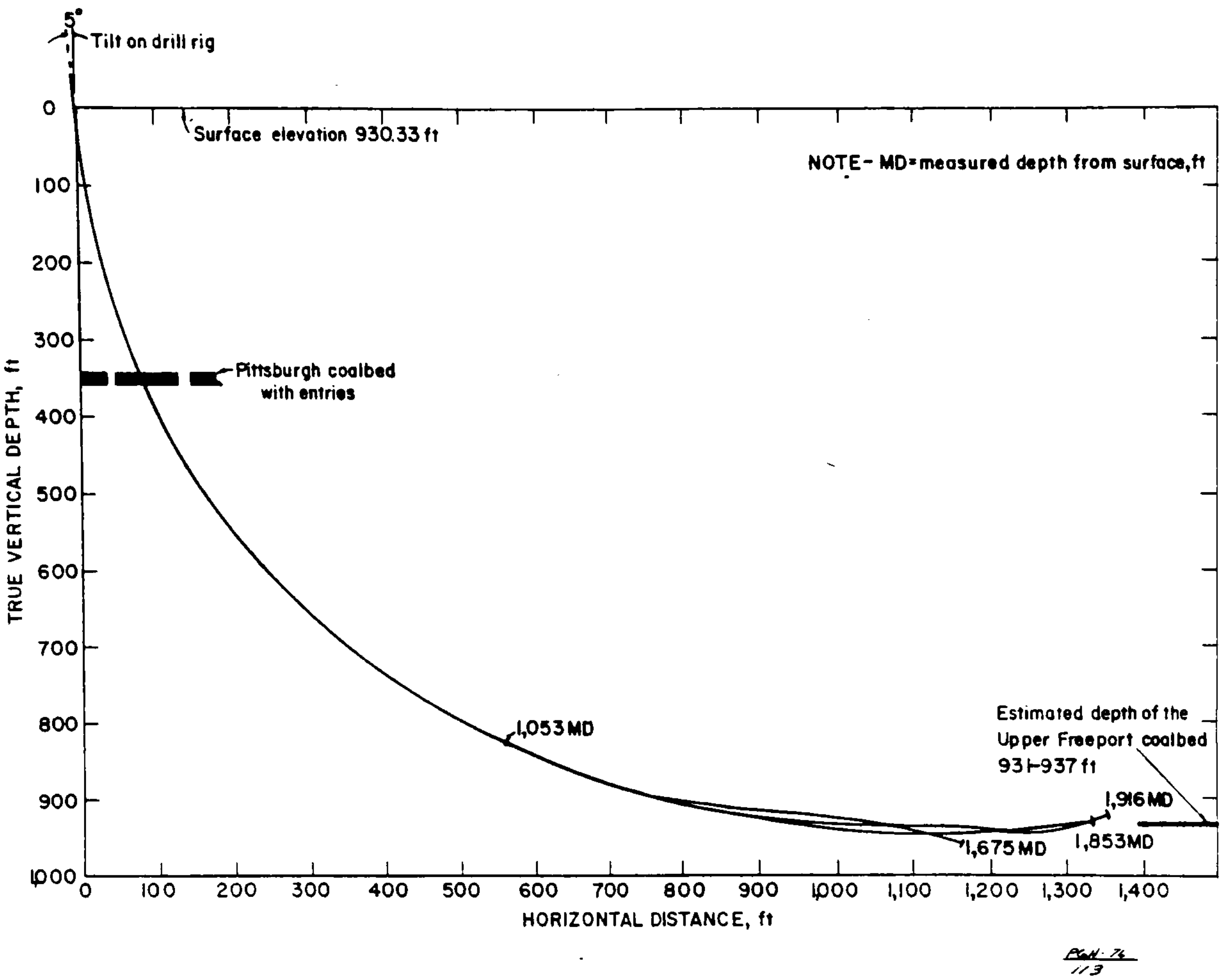
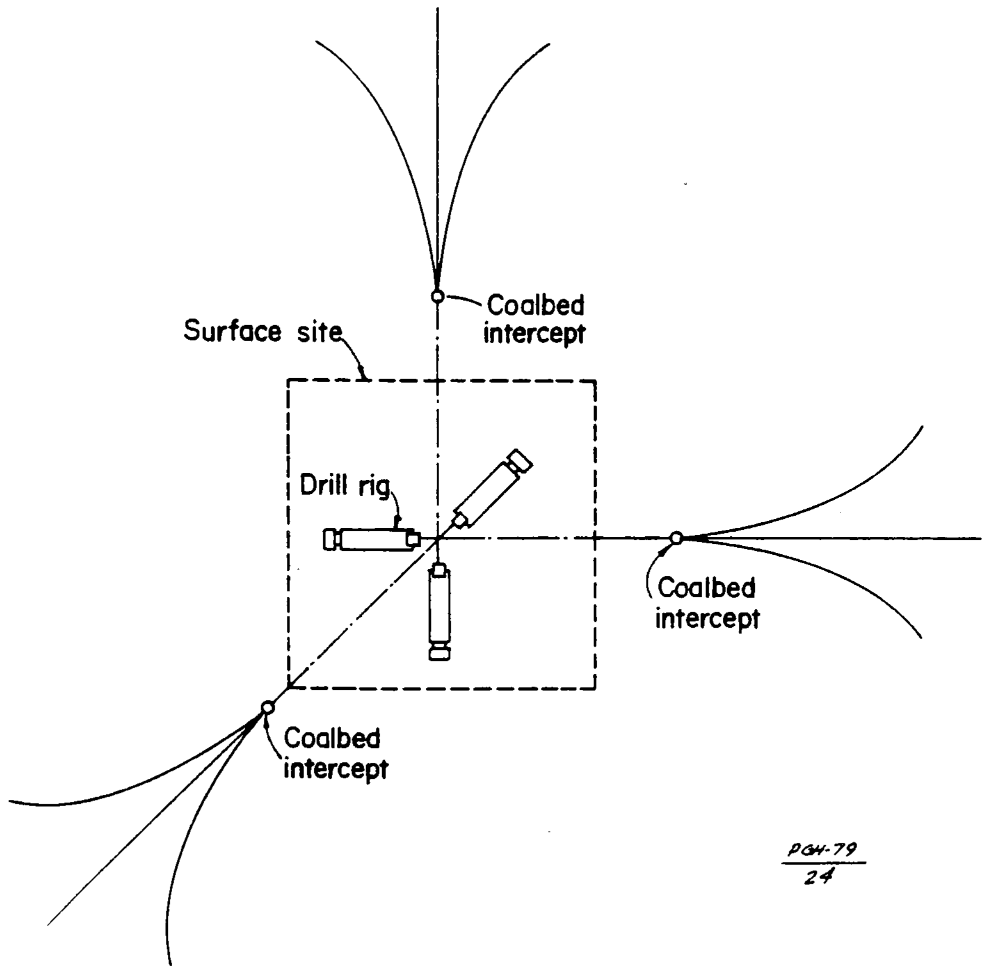


Figure 15. Section view of slant hole well path (From Diamond and Oyler, 1979).



(not to scale)

Figure 16. Schematic plan view of theoretical multiple-well directional degasification system (from Diamond and Oyler, 1979).

coalbed. The directional method has definite advantages over both the vertical and horizontal methods. The directional method does not require access underground as does the horizontal method. Also, since only one directional hole is drilled into the coalbed for each set of branches, the method works well in areas where severe topography would make a vertical multiple hole degasification program infeasible. At present, the directional drilling method is still experimental, and is too costly for a standard degasification program. For more information see Diamond 1977; and Diamond and Oyler, 1979.

HAWK'S NEST MINE CASE STUDY

The Hawk's Nest Mine property is 11 miles northeast of Paonia in Gunnison County, west central Colorado (Figure 17). The property covers approximately 2.5 sq mi (6.5 sq kilometers) in Secs. 1, 2, 3, 10, 11, and 12, T13S, R90W (Figure 18).

GEOLOGIC SETTING

The main coal-bearing rock units in the Somerset Field are in the Upper Cretaceous Mesaverde Group. The Mesaverde Group was deposited in a marginal marine transitional environment during Montanan time (RMAG, 1972). Johnson (1948) defined the Mesaverde Formation as consisting of four members: the basal Rollins Sandstone, the Lower coal member, the Upper coal member, and the Barren member. The Lower coal member contains the A, B, and C coal zones. The Upper coal member includes the D, Wild, E, and F coal zones. Figure 19 shows thickness variations for the minable beds in each zone.

The Somerset Field lies on the southeast edge of the Laramide age Piceance Creek Basin. The study area is structurally uncomplicated with beds striking approximately E-W and dipping at 2° to 3° to the north. The main structural control in the area is the Gunnison Uplift to the south-southeast of the Hawk's Nest property in the Somerset Field.

Mining began on the Hawk's Nest site in 1931 and continues to the present. From 1931-1979, the complex of mines produced a total of 3,043,793 short tons from the "E" or "Hawksnest E" seam. All past mining was done using room and pillar methods. In the future, the mine will incorporate longwall mining into the mine plan. Overburden ranges in thickness from 800 ft to greater than 2,000 ft.

WORK ACCOMPLISHED

In 1979, Western Slope Carbon, Inc. permitted staff of the Colorado Geological Survey access to their mine workings. The following was accomplished:

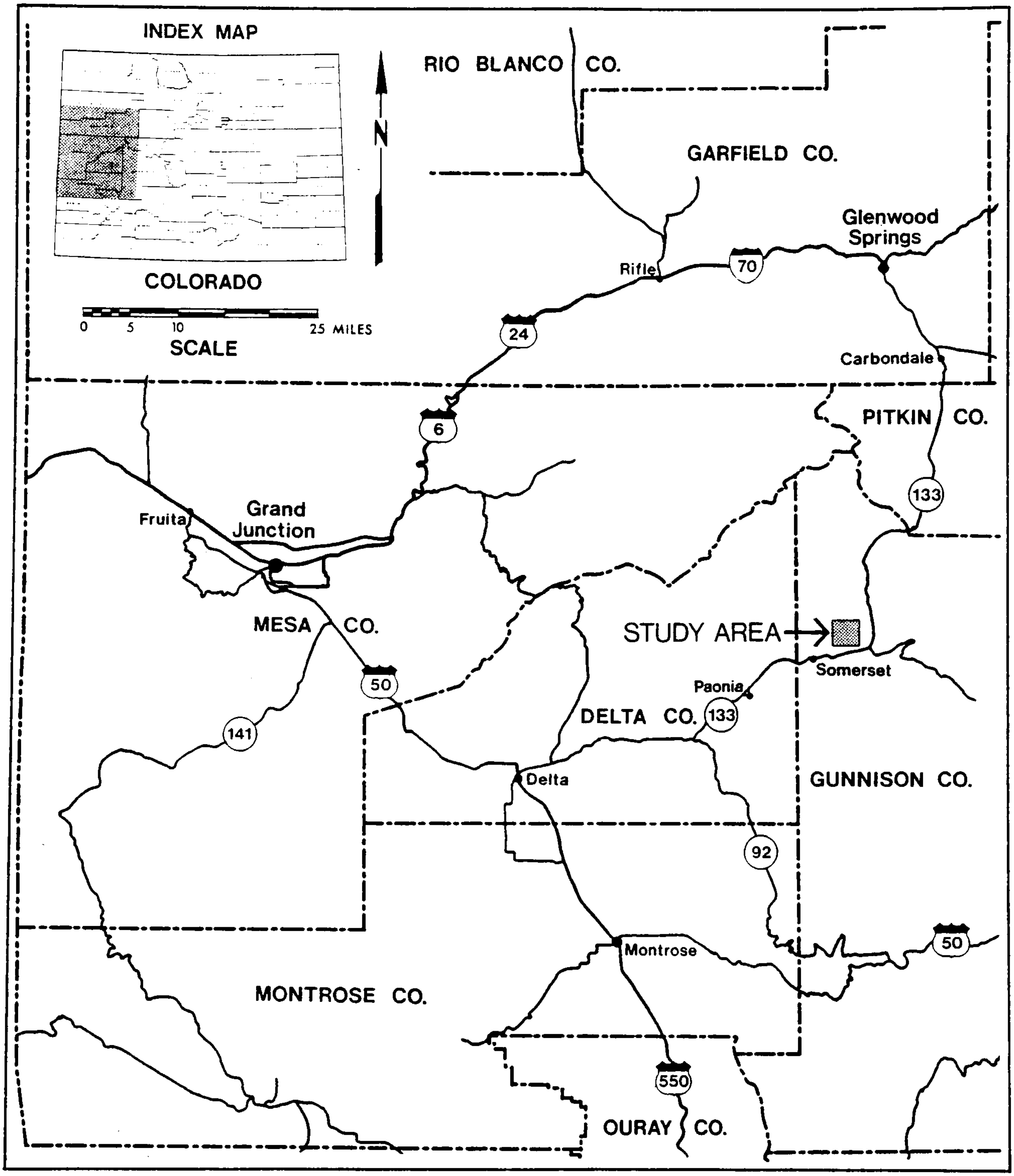


Figure 17. Index map of part of western Colorado and the Hawk's Nest mine study area.

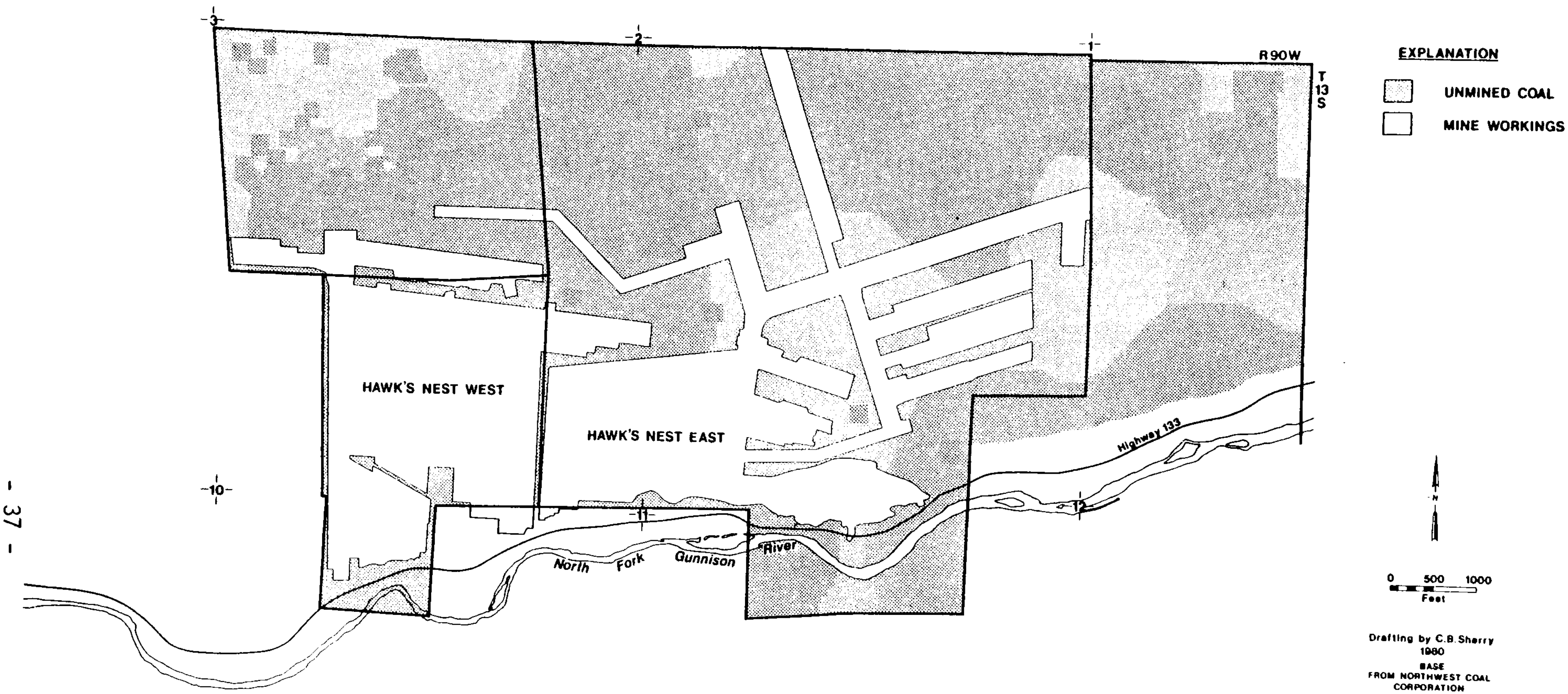


Figure 18. Map of mine workings at the Hawk's Nest East and West mines, Somerset, Colorado.

UINTA REGION - SOMERSET FIELD

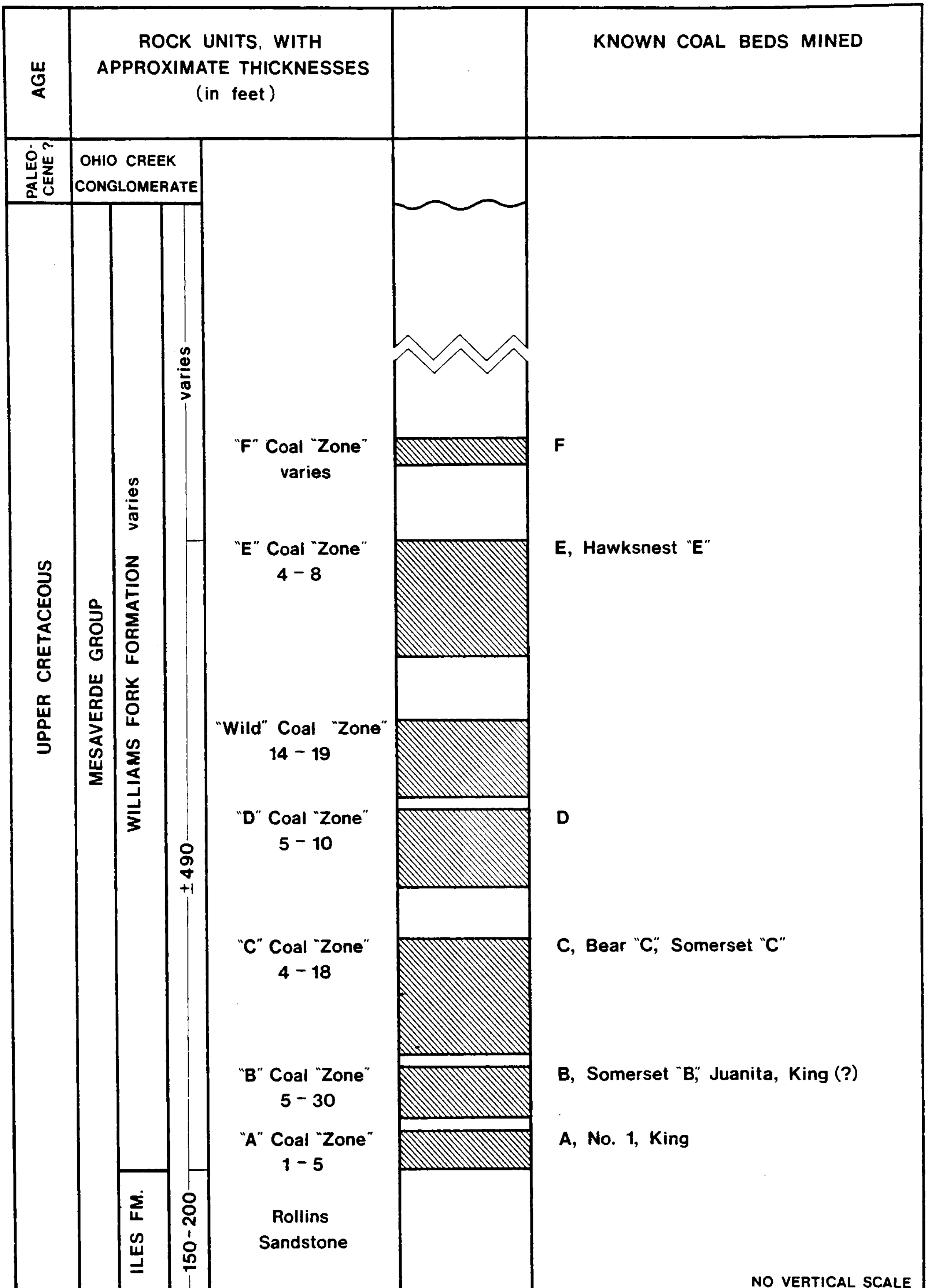


Figure 19. Generalized columnar section of coal-bearing rock units in the Upper Cretaceous Mesaverde Group (Revised from Boreck and Murray,1979)

1. Desorption samples were taken from 4 in-mine exploration core holes.

2. 404 cleat directions were measured in the mine workings.

3. 63 joint directions were measured on the surface.

4. Coal thicknesses were measured and complete descriptions of the coal were taken at 43 sites throughout the mine.

5. Lineation directions were taken in the study area using 1:38,000 areal photographs.

This data, along with drill hole data and maps supplied by Western Slope Carbon, Inc., constitutes the data base for the following report.

COAL BED STRATIGRAPHY

The enclosed plate shows the stratigraphy of the coalbeds in the Hawk's Nest mine area. The stratigraphic sequence consists of interbedded sandstone, shale, and coal. The E coal zone is laterally continuous but is eroded in the southern quarter of the area. The A coal zone, which varies from 0-2.1 ft, was omitted from the panel diagram due to its uneconomic thickness in the study area. The F coal zone was also omitted due to lack of data.

The B, C, D, Wild, and E coal zones are present and continuous over the mine property. As can be seen on the panel diagram, the coal beds in the B, D, and Wild coal zones tend to thicken, thin, and split. The C and E zones are continuous and retain their thickness with minimal splitting over most of the map area. The sandstone in the sections are, for the most part, lenticular. Two exceptions are the basal Rollins Sandstone and a continuous sandstone below the D coal zone. Thicknesses between the coal zones do not vary significantly over the study area. One exception is in the northwest part of the area where a wedge of sandy sediment increases the amount of interburden between the D and the Wild coal zones.

Total coal thickness

Figure 20 is a total coal thickness isopach map for the Hawk's Nest mine property. As can be seen from the map, the total coal thickness increases to the east, southeast, south, and southwest of the area, with a local thickening in the central part of the area. Figure 21 is a structure map on the top of the Rollins Sandstone. Comparing the two maps shows that the total coal thickness is not directly controlled by the site-specific structure of the area. It is more likely controlled by the depositional history of the area.

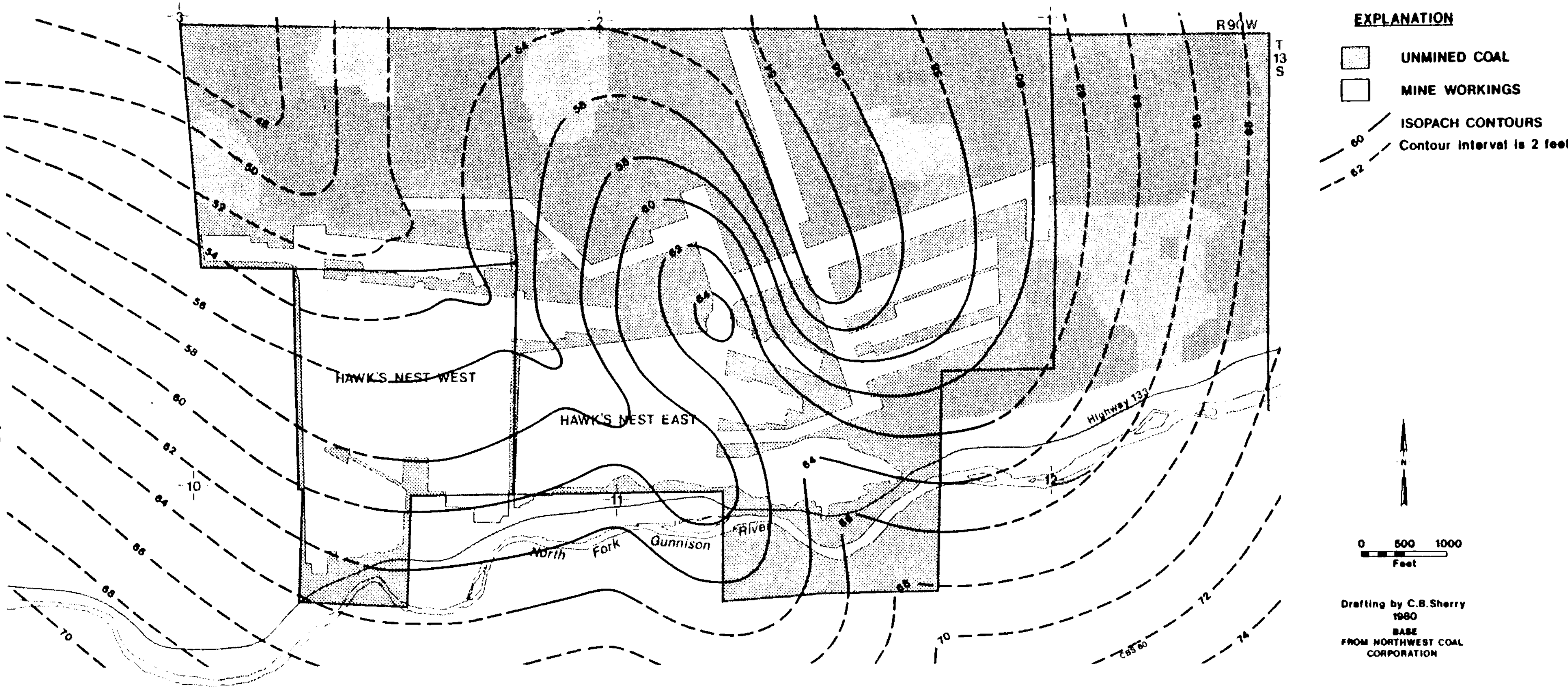


Figure 20. Total coal thickness isopach map of the Hawk's Nest property.

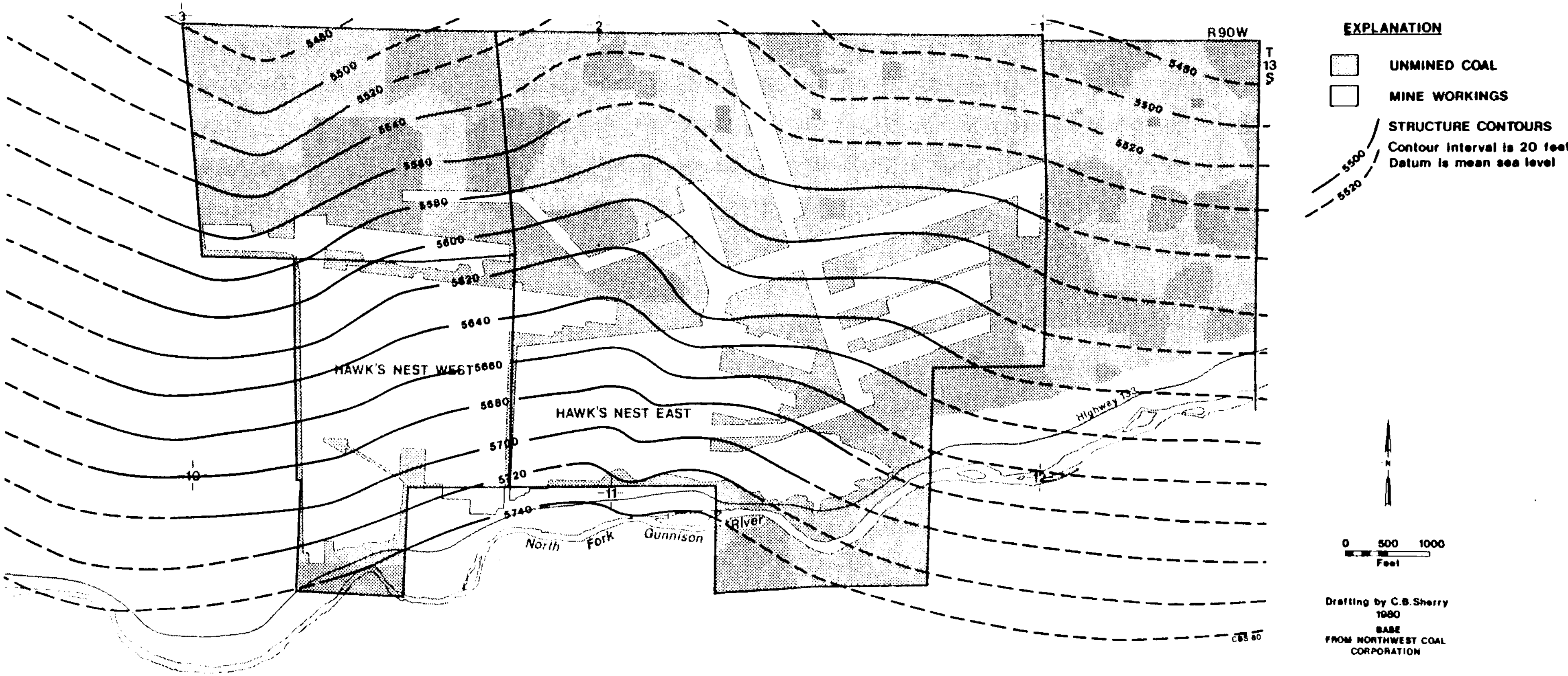


Figure 21. Structure map on top of Upper Cretaceous Rollins Sandstone, Mesaverde Group, Hawk's Nest property.

Thickness of "E" coal seam

The E coal seam is the only seam that has been worked at the Hawk's Nest Mine. It ranges in thickness from less than five feet to greater than nine feet in the study area. Figure 22 is an isopach map of the "E" coal seam. In general, the coal thickens to the west-southwest. Local thickening and thinning in the mine area is due to the presence of rolls in the coalbed.

The structure on the base of the E seam is locally complex as is shown in Figure 23. The map only partially shows the effect of rolls on the structure. Very little correlation exists between the thickness of the coal and the structure on the base of the coalbed. It is believed that the structural trends shown in the map represent deformation after deposition of the coal.

CLEAT AND JOINT DIRECTIONS ON THE HAWK'S NEST PROPERTY

Rose diagrams of 404 cleat directions measured show different sections of the mine (Figure 24) and the face and butt cleat directions within the E seam.

The average face cleat trends from N70°E to East; the butt cleat trends from N10°W to N20°W.

The face cleat is well developed throughout the mine. The butt cleat is poorly to well developed. In most areas, the face cleat will act as the main control on methane migration with the butt cleat acting as a secondary control depending on its degree of development.

The 63 surface joint readings show an average trend of N80°E to due E and N20°W - N30°W.

Inspection of the mine roof in the Hawk's Nest East mine showed that joints were common in the sandstone roof. Where present, they provide a migration path for gas and water to enter the workings. Where the immediate roof consisted of mudstone or shale, fractures similar in orientation to the coal cleats were also common.

Surface lineation analysis revealed that lineations in the area averaged due north.

GAS CONTENT OF THE COAL

The gas content of the coal was measured using the USBM "direct method" previously described. All samples were collected during an underground exploration drilling program carried out at Hawk's Nest mine property from November 1978 through February 1979. The samples were completely desorbed and then sent to U.S. Bureau of Mines in Bruceton, Pennsylvania, for residual gas measurement. The lost gas

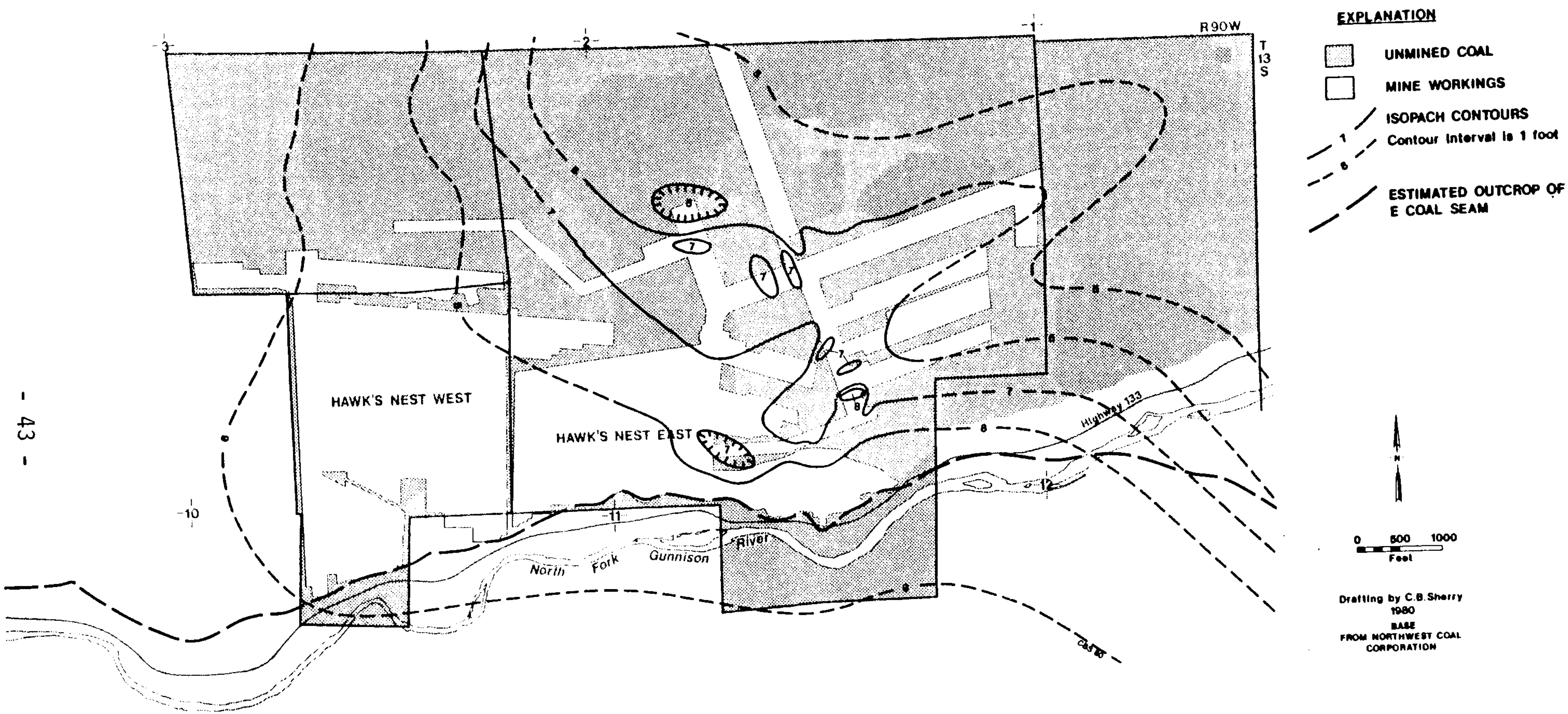


Figure 22. Coal thickness isopach map for the E coal seam, Hawk's Nest property.

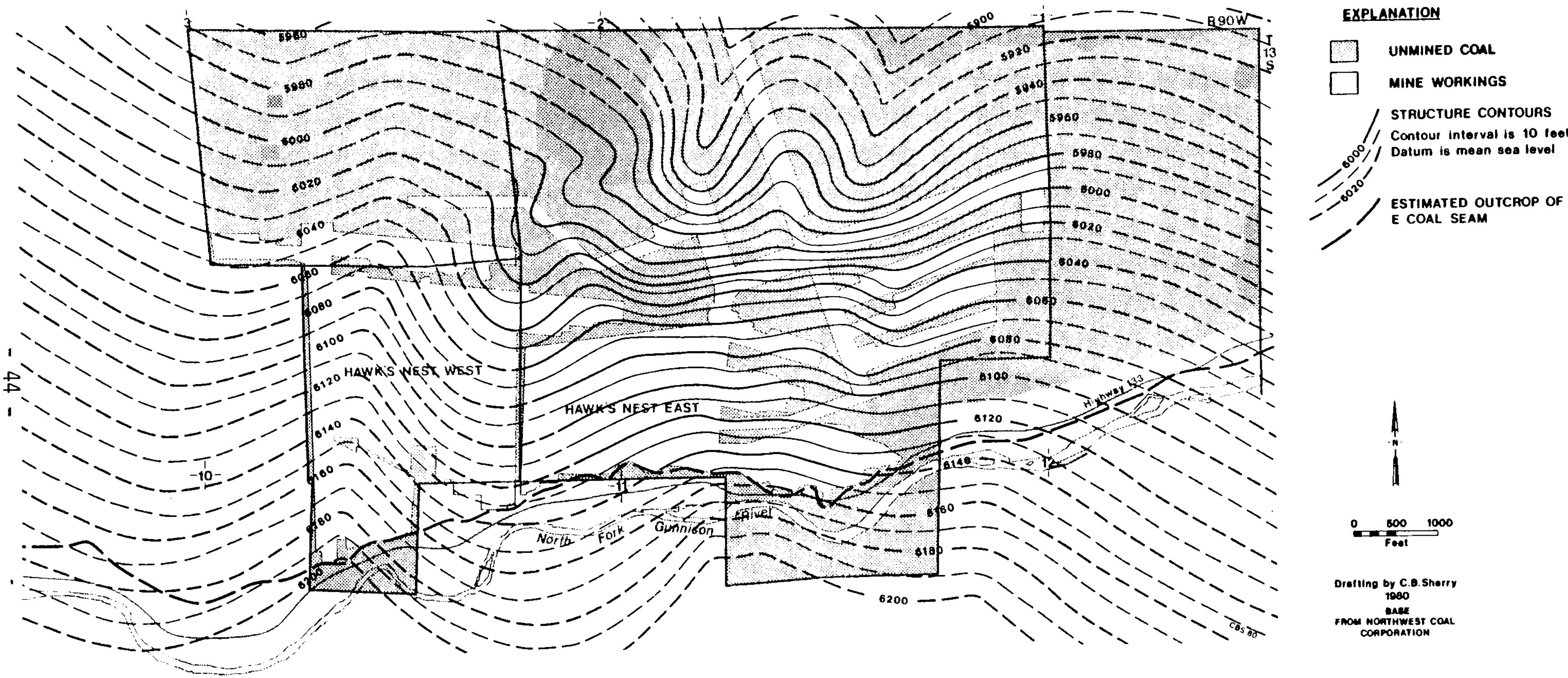


Figure 23. Structure map on the base of the E coal seam, Hawk's Nest property.

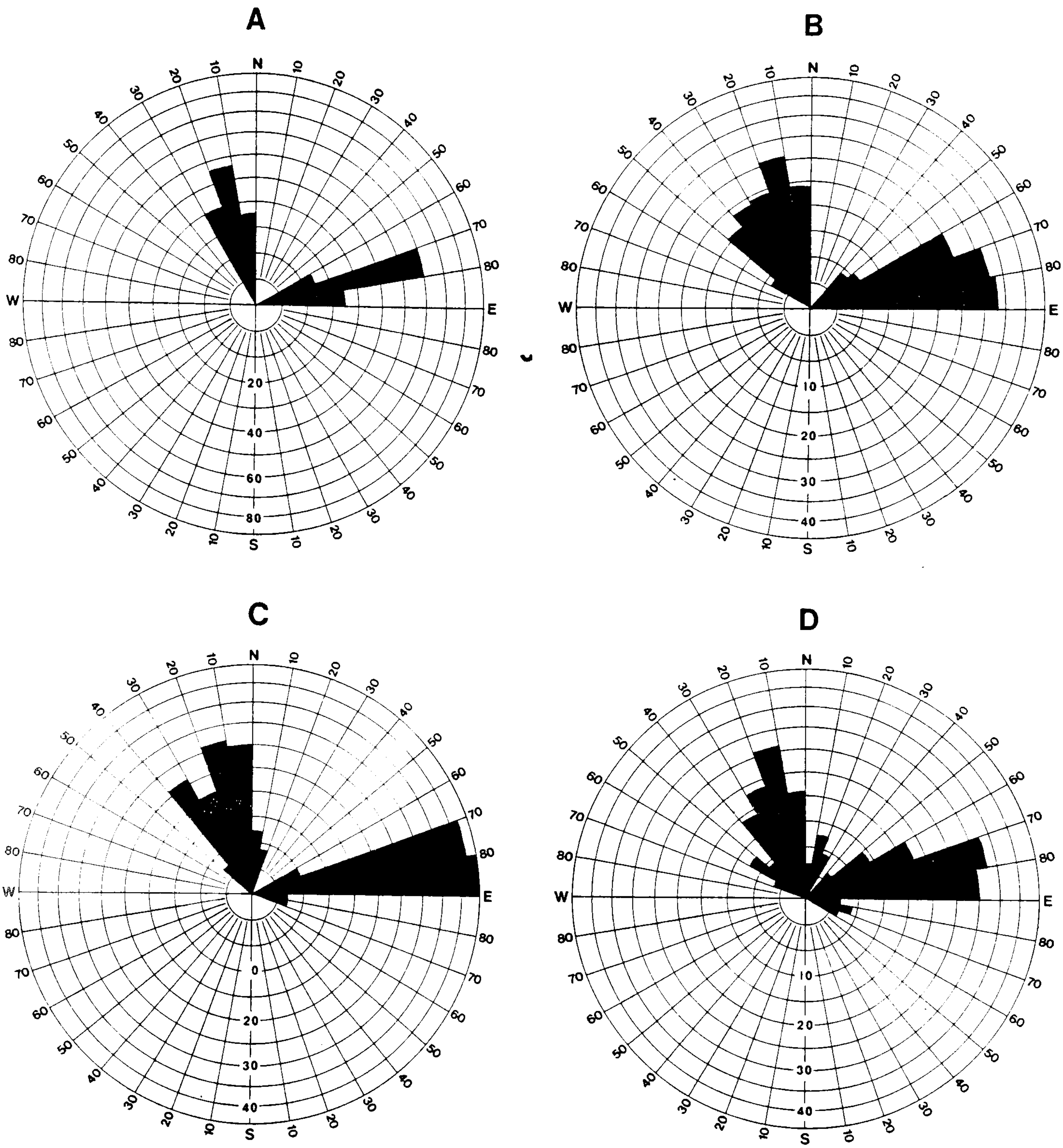


Figure 24a. Diagram showing cleat directions from 404 in-mine readings, Hawk's Nest East mine.

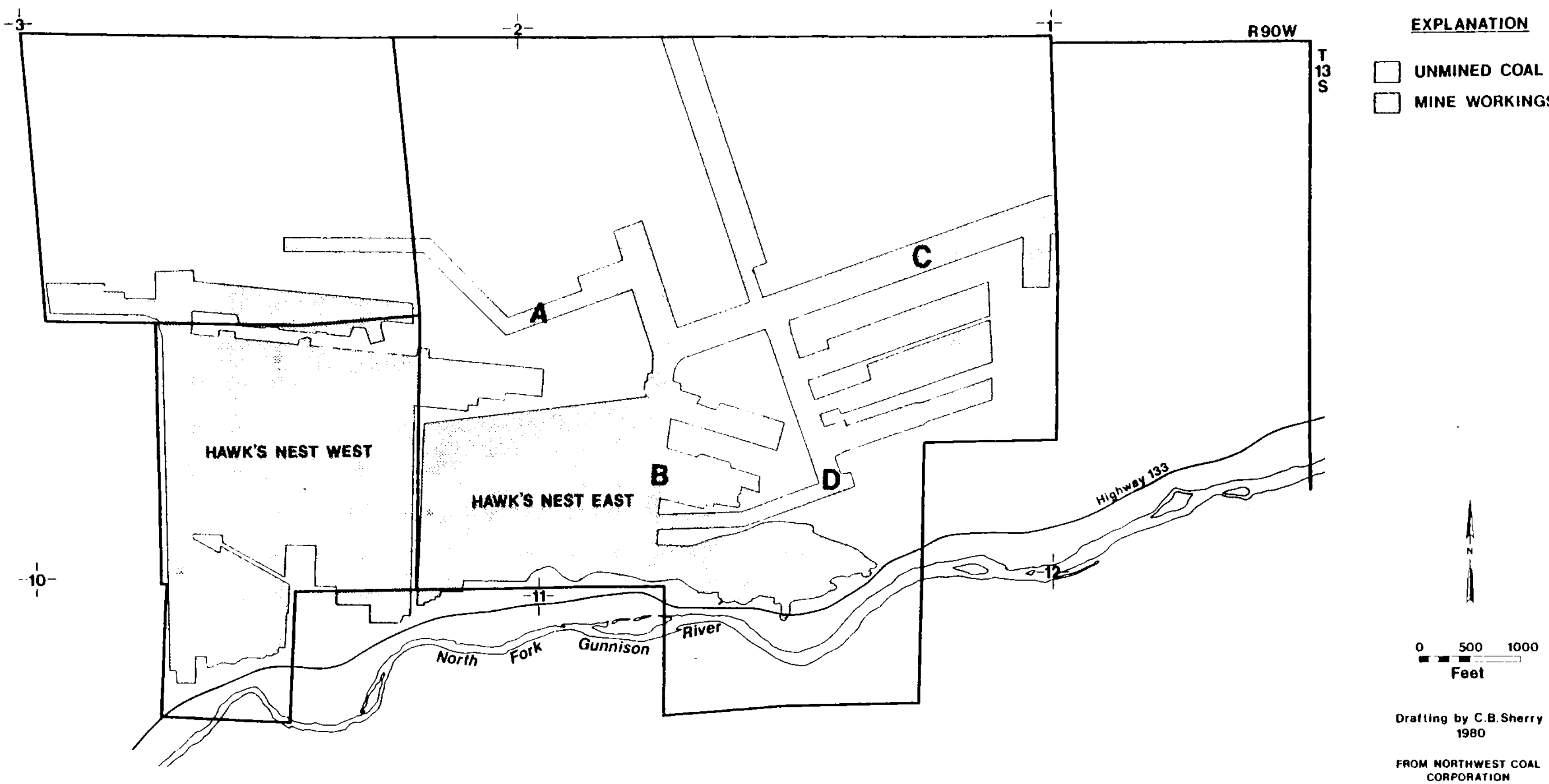
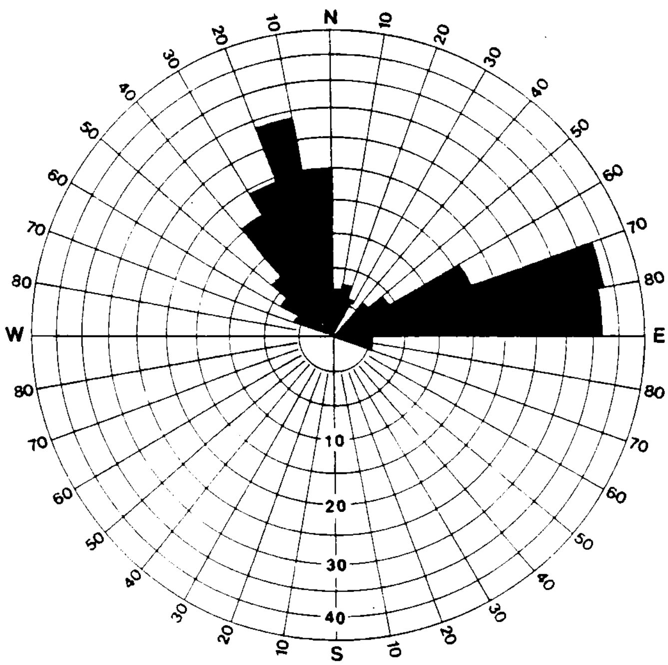
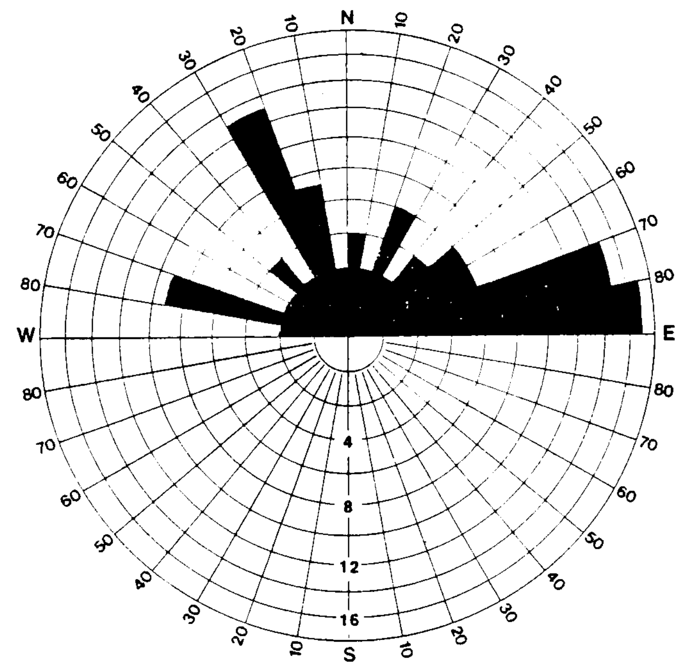


Figure 24b. Index map of the Hawk's Nest property showing areas represented by orientation diagrams A,B,C,and D.

COMPOSITE OF A,B,C,&D



JOINT DIAGRAM



LINEATION DIAGRAM

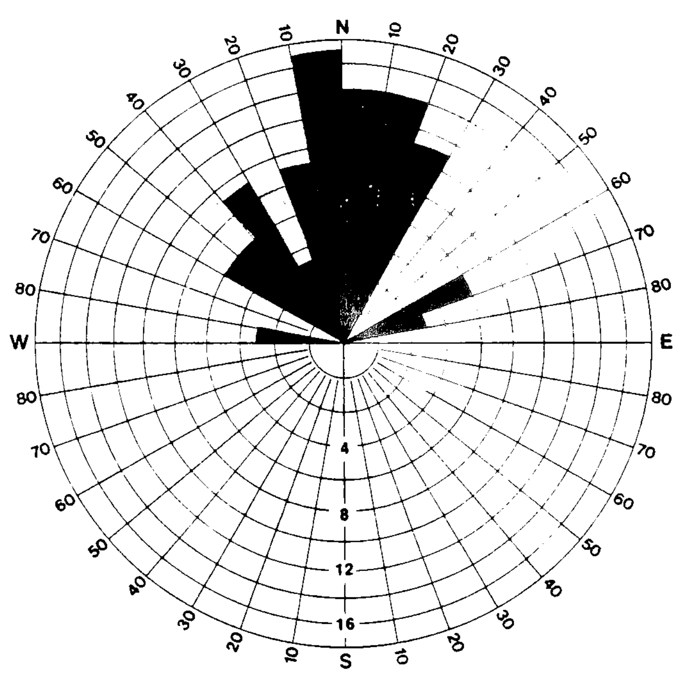


Figure 24c. Diagrams comparing composite in-mine cleat, surface joint, and lineation directions for the Hawk's Nest property.

content was determined using graphical methods. Proximate and ultimate analyses were run on each coal sample by the U.S. Department of Energy. Table 5 gives sample data and results. Two gas samples were also taken from the desorbing coal samples and analyzed by Core Laboratories. These results are given in Table 6. It is believed that the samples may not be representative of the quality of the gas recoverable from the coal due to air contamination of the samples. An analysis done by Western Slope Carbon is also included for comparison.

METHANE RESERVES FOR THE HAWK'S NEST MINE PROPERTY

Coal on the Hawk's Nest property occurs in six main coal zones; five of these are planned for production using the vertical hole method and one is planned for production using the horizontal hole study. Table 7 gives coal zones, average coal bed thickness, average methane content of the coal, and methane resources for the vertical degasification method on a per well basis. Each well was estimated to produce from an 18 acre area. At 20% recovery, the reserves are approximately 51.3 million cubic feet per well. At 40% recovery, which may be possible with the following vertical hole setup, the reserve base contains approximately 102.6 million cubic feet per well.

It is difficult to determine the methane reserves recoverable using the horizontal method, as gas may come from strata both above and below the coal as well as from the subject seam. From the plate, it is evident that coal occurs both above and below the seam to be mined. An average thickness of the mined "E" seam is 9 feet; while a rough average of the coal occuring above and below the E seam in stringers and beds of uneconomical thickness is approximately 7 feet. The total in-place gas resource was calculated for a panel with the dimensions (in feet) 5500 length x 1700 width x 16 thickness. The total in-place resource is estimated to be 593.45 MMCF. At 50% recovery rate, reserves were estimated at 296.7 MMCF.

Test No.	Sample Number	Geologic Age & Formation	Coal Bed Name	Date Sampled	Bed Thickness (ft.)	Test Period (days)	Gas Desorbed (CC)	Lost Gas (CC)	Residual Gas (CC)	Total Gas (cc/g)	Total Gas (cf/t)
96	WSC #5 1-A	Upper Cretaceous Mesaverde Fm, Bowie Member	Wild Seam	11-27-78	4.8	30	458	15	1.6	2.49	80.
97	WSC #5 1-B	" " " " " "	Wild Seam	11-29-78	6.1		2220	45	0.4	3.2	102.
98	WSC #5 1-C	" " " " " "	Wild Seam	11-29-78	1.6	217	1800	35	0.9	3.74	120.
99	WSC #5 1-D	" " " " " "	D Seam	11-29-78	2.9	238	2261	140	0.8	3.88	124.
100	WSC #5 1-E	" " " " " "	C Seam	12-04-78	6.7	23	159	10	1.4	.28	9.
101	WSC #5 1-F	" " " " " "	C Seam	12-04-78	6.7	261	3775	25	0.8	6.81	217.9
102	WSC #5 1-G	" " " " " "	Upper B Seam	12-06-78	14.0	259	5955	150	1.5	5.82	186.2
103	WSC #5 1-H	" " " " " "	Upper B Seam	12-06-78	14.0	233	5147	190	1.5	5.94	190.0
104	WSC #5 I	" " " " " "	Lower B Seam	12-06-78	6.8	259	3345	35	2.0	6.15	197.
105	WSC #5 J	" " " " " "	A Seam	12-07-78	1.2		1256	75	.97cc/g	3.72	119.
106	WSC #6 B1	" " " " " "	Upper B Seam	1-12-79	13.0		2581	110	2.2	6.06	194.
107	WSC #6 B11	" " " " " "	Upper B Seam	1-12-79	13.0	194	4250	300	1.9	6.77	217.
108	WSC #6 C	" " " " " "	C Seam	1-10-79	6.0	175	4495	?	1.2	6.62	212.
109	WSC #7 C	" " " " " "	C Seam	2-07-79	6.9	196	5510	120	1.3	5.70	182.4
110	WSC #7 UB	" " " " " "	Upper B Seam	2-12-79	12.7	191	5701	75	1.8	5.93	189.7
111	WSC #7 LB	" " " " " "	Lower B Seam	2-12-79	5.3	191	4131	40	2.1	6.53	208.9
112	WSC #8 Wild	" " " " Paonia Member	Wild Seam	2-21-79	12.0	133	1390	Not calc.*	1.1	3.16	101.
113	WSC #8 DU	" " " " " "	D Seam	2-21-79	8.0	154	2510	35	1.0	3.36	108.
114	WSC #8 DL	" ": " " " ":	D Seam	2-21-79	8.0	154	2364	Not calc.*	1.5	4.12	132.
115	WSC #8 CU	" " " " Bowie Member	C Seam	2-23-79	12.0	180	3936	55	1.2	5.42	173.4
116	WSC #8 CL	" " " " " "	C Seam	2-23-79	12.0	100	480	70	2.3cc/g	2.99	96.
117	WSC #8 UBU	" " " " " "	Upper B Seam	2-23-79	14.6	180	3973	80	1.8	6.10	195.2
118	WSC #8 UBL	" " " " " "	Upper B Seam	2-23-79	14.6	152	3274	50	2.1	5.53	177.
119	WSC #8 LBU	" " " " " "	Lower B Seam	2-23-79	6.75	308	4840	90	1.4	5.98	191.3
120	WSC #8 LBL	" " " " " "	Lower B Seam	2-23-79	6.75	280	2237	Not calc.*	2.2	7.66	245.

Table 5. Sample data and desorption results for 25 core samples from the Hawk's Nest property.

Table 6. Hydrocarbon analysis of three gas samples from Hawk's Nest East Mine core holes (air free basis).

	1	2	3	
Oxygen	--	--	--	
Hydrogen Sulfide	--	--	--	
Carbon Dioxide	16.15	11.62	2.37	
Nitrogen	18.83	31.50	--	
Methane	60.34	56.57	96.9	
Ethane	.98	.31	.64	
Propane	--	--	.06	
iso-Butane	--	--	.04	all rem gases
n - Butane	--	--	--	
iso - Pentane	--	--	--	
n - Pentane	--	--		
Hexanes - plus	3.69	--		
Btu/cubic ft	799	575	998	

*Western Slope Carbon analysis. Gas sample was taken from the B & C coals during testing of an exploration drill hole.

TABLE 7. Methane Content and In-Place Gas Resources of the Coal Zones on a Per-Well Basis

Coal zone	Average thickness (ft)	Average Methane Content (cubic feet per ton)	Total in-place methane per well (cubic feet)
E	6.9	96*	21,498,048
Wild	11.5	101	37,696,230
D	8.5	122	33,655,896
C	7.8	192	48,605,184
Upper B	12.4	191	76,866,804
Lower B	5.6	210	38,166,660
TOTAL			256,488,822

*Estimated from table in Kissel, F. N. (1973), p. 9.

DRILLING PLANS FOR THE HAWK'S NEST PROPERTY

Two drilling plans were drawn up for the Hawk's Nest property. It should be noted that the following are plans used only for cost comparison. Neither of the proposals were carried to completion. The plans and estimates are preliminary and further, more detailed engineering studies will be necessary before implementation. They also were designed specifically for the Hawk's Nest property. Other properties would require alternate proposals.

Vertical hole drilling plan

As was previously noted, gas production increases with the reduction of reservoir pressure and decrease of water saturation in the coalbed. For this reason and for compliance to state well placement laws (Rule 318: Location of Wells. Oil and Gas Conservation Commission, 1977):

1. The wells are placed in areas of maximum total coal thickness.
2. The wells are spaced taking into account the face cleat direction.
3. The wells are spaced close to but no less than 500 ft from present mine workings.
4. Wells are spaced on no greater than a 1,000-ft grid.
5. Wells were placed within no less than 600 ft of the mine's property line (Rule 318: Location of wells).
6. The wells were spaced taking into account the timing of coal removal from the property, i.e., how soon the area was to be mined.

A total of 11 holes are to be drilled in the north and northeast section of the project area (Figure 25). The holes will range in depth from 1500 to 2700 feet. The holes should be air drilled in 4 sets, 2 to 3 holes in each set to allow for maximum drainage in each area. Each hole is drilled to 100' with a 9 7/8" surface bit. The remaining footage is drilled using a 6 3/4" jet sealed journal bearing bit. The five coal zones are then abrasijetted using a Dowell Abrasijet tool. As 1) the coal is to be mined, and 2) initial

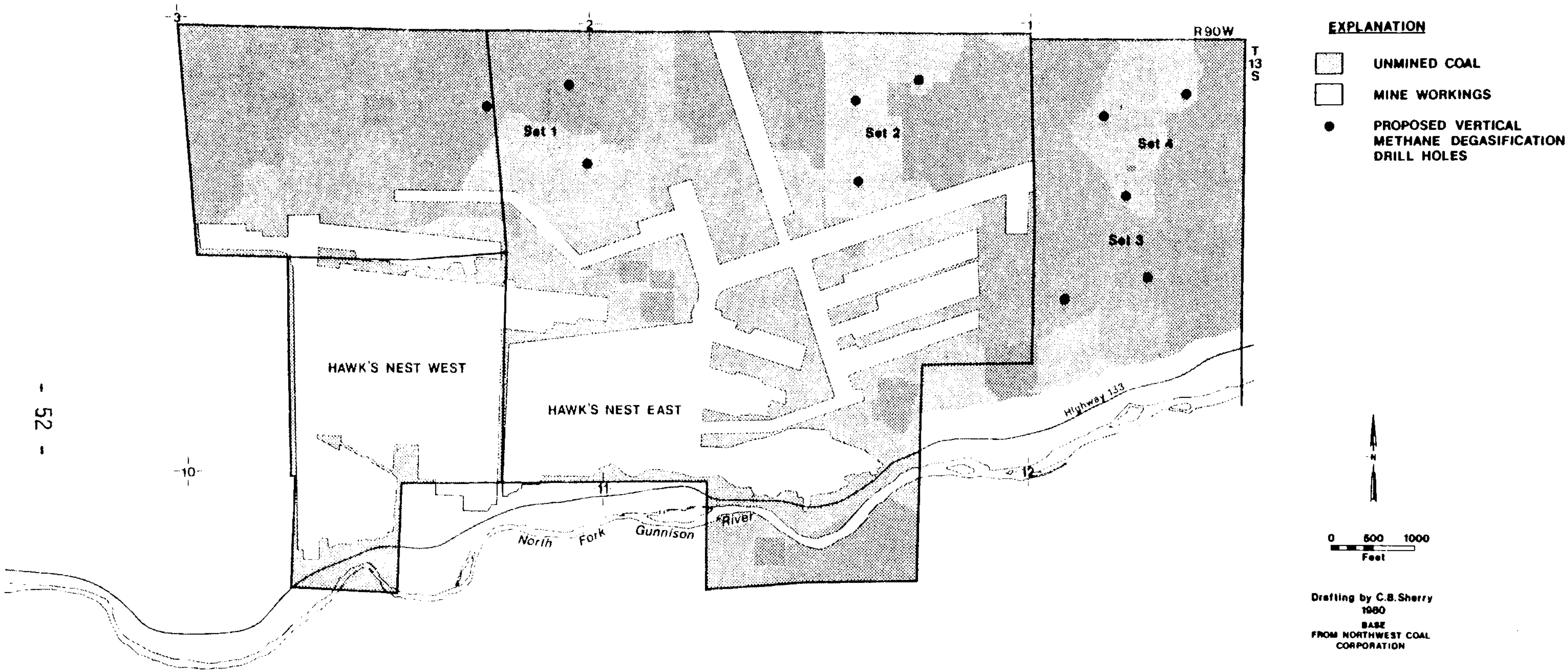


Figure 25. Proposed location of eleven drill holes, Hawk's Nest property.

gas flow tests from exploration holes (confidential) were favorable, stimulation of the coal zone was not included in the initial plan. A secondary case will be considered later.

The holes are completed as follows (Figure 26): Each hole is cased from 0-100' depth with 8 5/8" surface casing and cemented. The remaining footage is drilled and cased with 5 1/2" well casing to above the E coal zone. From the E coal zone to the Rollins sandstone, a PENGO selective Completion tool is used to block off the five coal zones to be produced. The section from the base of the surface casing to above the E coal zone and the units between the coal zones are cemented using a selective cementing tool. The selective cementing technique was designed to:

1. protect the coal zone from damage during the cementing process and allow for an open-hole completion,

2. reduce the water coming in from sand units between the producing zones and protect aquifers from possible contamination, and

3. insure an unconventional gas price for the gas produced.

After the coal zones are abrasijetted, a string of 2" production tubing is run down the hole and the well is set up for production as shown in Figure 14.

Figure 27 shows the collection system for the gas. In this plan, water is pumped to the surface through the 2 inch tubing using a conventional downhole pump as shown is Figure 14. The gas is brought up in the annulus. The produced gas is then piped to a gas-water separation unit which is set up at four stations (Figure 27) and is shipped to the main pipeline through three collector lines, one east line and two west lines. The gas is piped by the mains to both the Hawk's Nest East Mine and the Hawk's Nest West mine for on-site use or sale.

Total cost for the project, which includes drilling, completion, production, and maintenance is 2.3 million dollars (1980 dollars). Table 8 gives an itemized list of all expenditures.

Horizontal Hole Drilling Plan

In order to degasify a 5500' x 1700' coal panel at the Hawk's Nest East mine, 13 horizontal holes are to be drilled 1800 ft into the coal bed in a direction perpendicular to the face cleat (Figure 28). These holes are approximately 3 1/2" in diameter and spaced 400 ft apart. The estimated flow rate from the panel is 150 cfd/foot of hole.

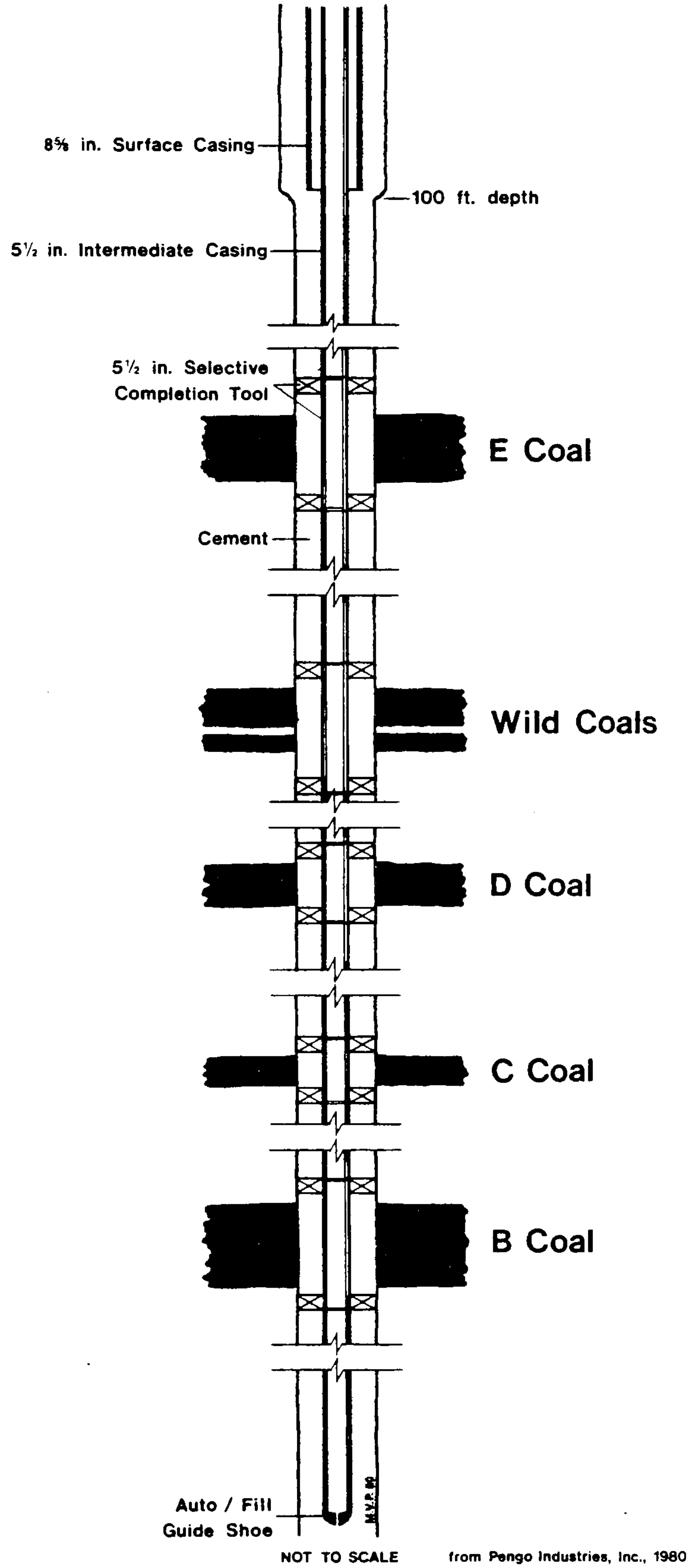


Figure 26. Proposed well completion of vertical degasification holes, Hawk's Nest property.

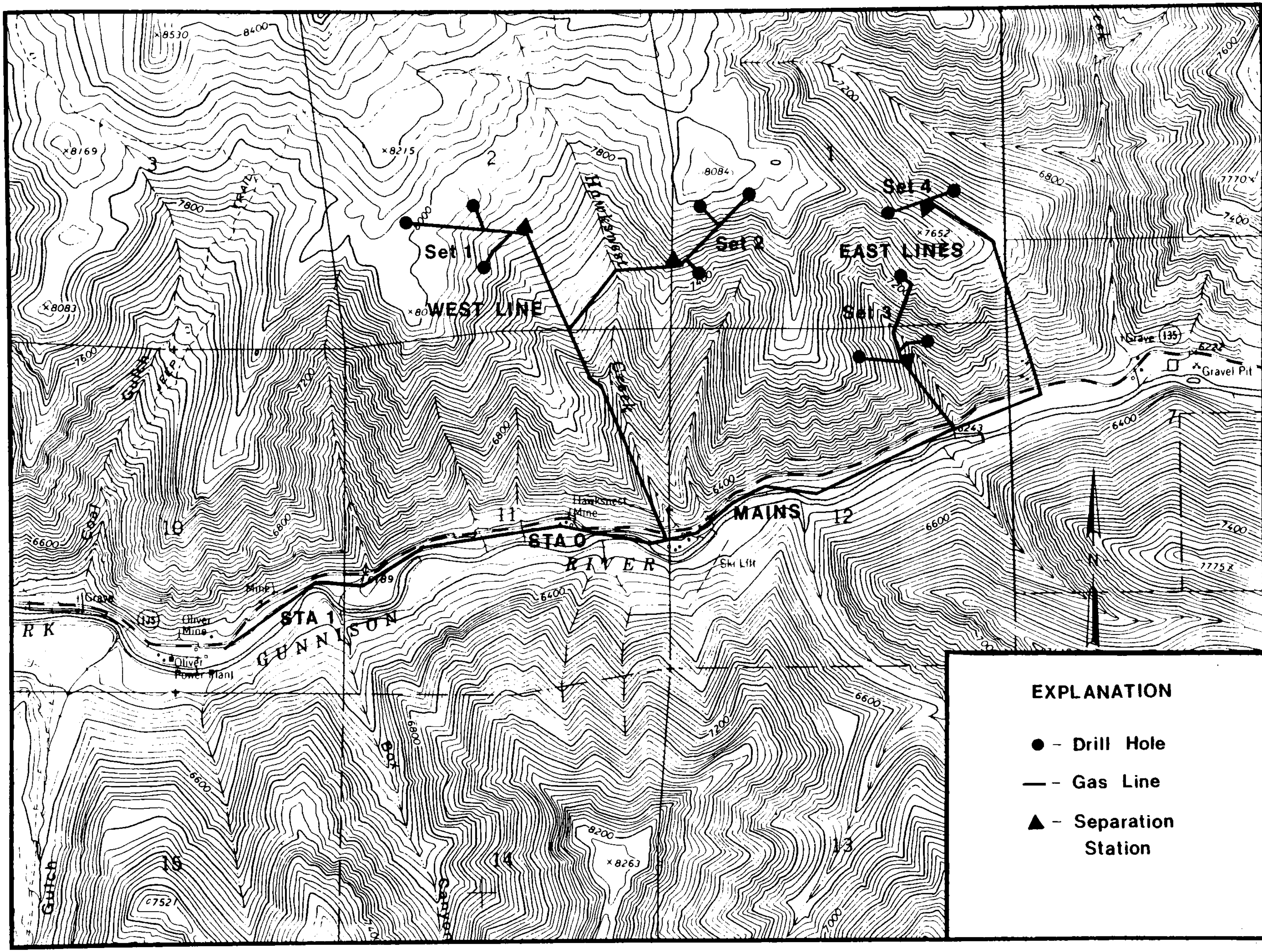


Figure 27. Proposed gas collection system, Hawk's Nest property.

TABLE 8. Itemized expenditure list for vertical degasification plan.

SITE PREPARATION

Road Preparation:	estimated 2.44 miles @ 2 days/1/2 mile @ $480/day	$ 4,685
Site Preparation:	11 sites, 1 site/day @ $480/day	$ 5,280
Surveying and Staking		600
	Subtotal	$ 10,565

DRILLING

Drilling:	23,500 ft @ $15/foot	$352,500
Bits:	6 3/4" jet sealed journal bearing bit. Est. 15 @ $790/bit	$ 11,850
	9 7/8" surface bit @ $1090/bit Est. 2	$ 2,180
	Subtotal	$366,530

LOGGING

Logging:	monthly @ $5,000 month @ 4.3 months	$ 21,500
	23,500 ft @ $0.25/foot	$ 5,875
	Man per diem @ $30/day @ 7 days/month x 4.3 month	$ 903
	Subtotal	$ 28,278

COMPLETION

Completion:	Rig @ $2,000/day @ 11 days	$ 22,000
Cement:	Surface cementing @ $4.60/bag @ 12'/bag	$ 422
	Downhole cementing @ $4.60/bag @ 11'/bag	$ 10,304
Casing:	Surface - 8 5/8" 24 pound K55 short thread 1,100' @ 1,029.23/100 feet (includes transport charges).	$ 11,321
Well -	5 1/2" 14 pound K55 short thread 22,703 ft @ 599.65/100 ft (includes transport charges)	$136,138

TABLE 8 (Cont.)

Production Tubing: 2 3/8" OD steel tubing 23,500 ft @ $3.90/foot	$ 91,650
Abrasijetting: For 11 wells, 5 coal zones in each well at $6276.50/well	$ 69,040
Completion using Dowell packers (Figure 28) 11 holes @ 17,467.50/hole	$192,142
Downhole pump: 11 pumps @ $500/pump	$ 5,500
Rods: 23,500 ft of 3/4" rods @ $1.50/ft	$ 35,250
Well head: 11 holes @ $1,200/hole	$ 13,200
Pump Jack: 11 holes @ $6000/hole	$ 66,000
Pump Installation: 11 wells @ $805/well	$ 8,855
Subtotal	$661,823
SEPARATION	
Separation tank: Pitkin gas separation tank-- 4 @ $8,000/tank	$ 32,000
Subtotal	$ 32,000
SURFACE PIPING SYSTEM	
Surface pipe: 40,680 ft of 2 3/8" OD seamless pipe @ $129/100 feet	$ 52,477
Couplings: Est. 2441 couplings @ $5.18/coupling	$ 12,644
Labor: 1 x cost of materials	$ 65,121
Subtotal	$130,242
MAINTENANCE	
Completion unit: 6 visits/yr @ $2,000/visit and 5 yr life of 11 wells	$660,000
Labor: First month, 31 days x $64/day. Remaining five years--$64/day @ 1 day/week x 256 weeks	$ 18,368
Subtotal	$678,368

TABLE 8 (Cont.)

MISCELLANEOUS

Labor: 1.0 geologic and engineering personnel on site. 94 days @ $300/day	$ 28,200
Analyses: Lab analyses	$ 3,000
Gas meters: 14 meters @ $1,000/meter	$ 14,000
Gas gauge: 11 gauges @ $50/gauge	$ 550
Subtotal	$ 45,750
TOTAL	$1,953,556
Total (1.2 contingency factor);	$2,344,267

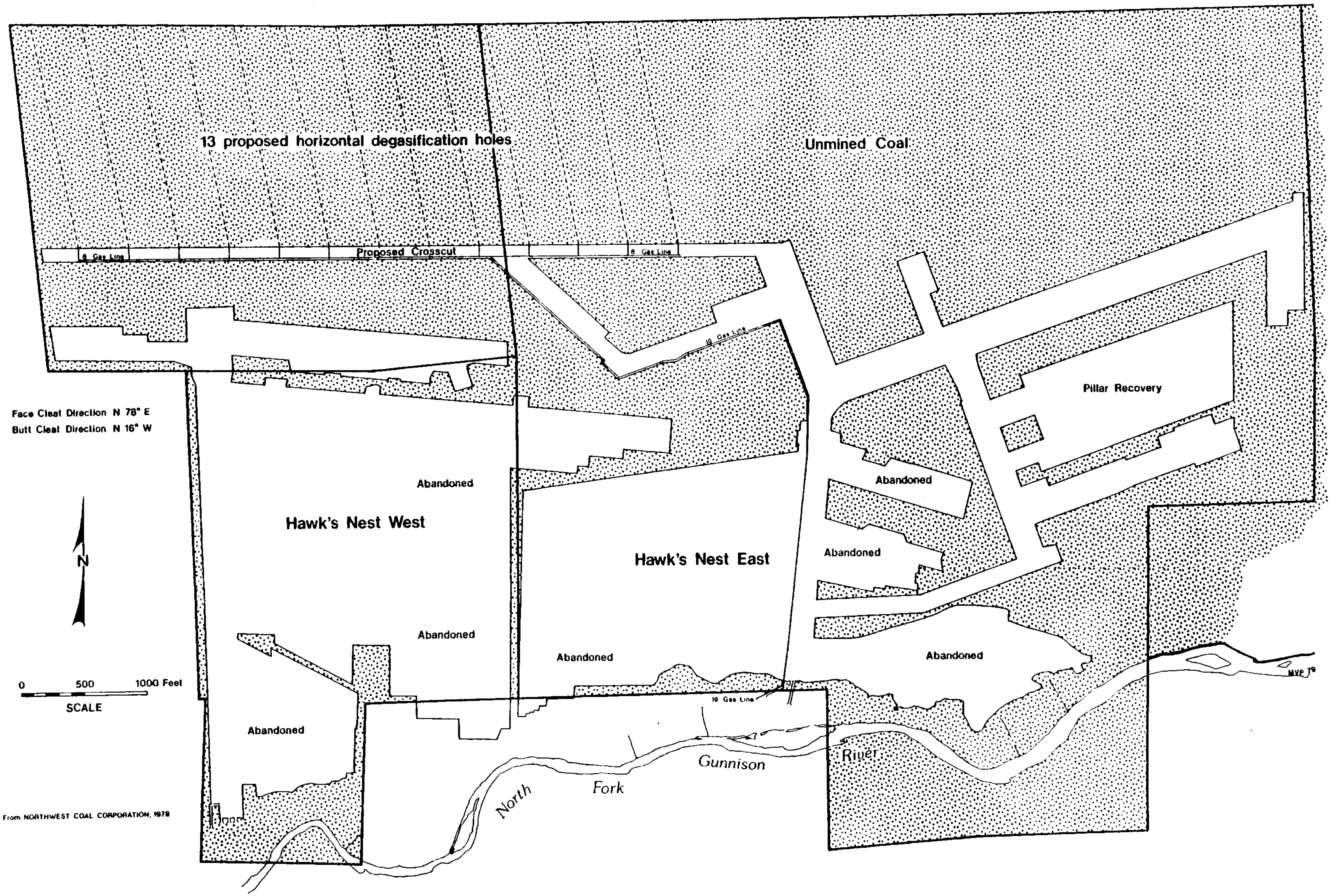


Figure 28. Proposed horizontal degasification plan for the Hawk's Nest property.

The drilling is to be accomplished using an Acker "Big John" Degasification Drill. A method of keeping the bit in the coal bed during drilling, a system for de-watering the effluent out of the horizontal holes and metering the gas flow are included in the plan. The piping system is composed of 10" mains, 8" sub-mains, and 3" laterals suspended by hangers from the roof in the return airway. For a more complete breakdown of the project, see Strever, 1980.

Total cost for the project was estimated to be $417,600 on November, 1979, using a contingency factor of 1.2 to take into account overlooked costs. To bring costs up to January 1980, total cost of the project was multiplied by 1.15 to give 480,200. Table 9 lists individual costs for the project.

ECONOMICS OF DEGASIFICATION

As was pointed out in the section on economic factors, the cost of degasification can be recovered in various ways. One is the amount of money saved by decreasing down time when excessive methane levels are encountered and a reduction in ventilation costs due to the lowering of the methane concentration in the mine workings. In the case of the Hawk's Nest mine, this would not be a cost factor large enough to warrant a degasification program in itself. Two other possibilities are using the gas on site and/or selling the gas. Utilization of coal bed methane on-site as an energy source or sales of the gas are covered in the following sections.

Projected power needs for the Hawk's Nest mine are 640,000 KWh/month with no increases over the next five years. This amounts to a cost of approximately $24,000 per month or $288,000 per year. At an annual rate increase of 5% and a discounted value of 10%, the mine will pay an estimated $1,255,104.00 for energy during the next five years. This figure and the annual breakdown given in Table 10 were calculated using the following compound amount - present value per annum formula.

$$\text{Value} = R \times [(1 + i)^{1}(1 + t)^{-1} + (1 + i)^{2}(1 + t)^{-2} + \ldots + (1 + i)^{n}(1 + t)^{-n}]$$

Where:

R = annual payment

i = inflation rate: 5% for this problem

t = discount rate: 10% for this problem

n = year

TABLE 9. Itemized expenditure list for the horizontal degasification plan (estimate as of November, 1979).

Drill	
Acker "Big John" Degasification Drill	$135,000
Piping System	
7000' of 10 3/4" x .109 wall thickness steel with victaulic ends @ $4.12/ft	$ 28,900
4900' of 8 3/8" steel pipe with victaulic rolled groove ends @ $3.44/ft	$ 16,900
300' of 3 1/2" steel pipe with victualic rolled groove ends @ $1.45/ft	$ 500
350 10" victaulic #75 light weight couplings @ $30.60	$ 10,700
245 8" victaulic light weight couplings @ $16.63 ea.	$ 4,100
15 3" victaulic light weight couplings @ $4.23 ea.	$ 100
610 pipe hangers on 20' centers @ $5 ea.	$ 3,100
13 3" vic flange adaptors @ $30.40 ea.	$ 400
Total Pipe Cost	$ 64,700
Valves, elbows, etc. @ 10% of total pipe cost	$ 6,500
Total pipe cost including valves, etc.	$ 71,200
Miscellaneous	
13 separators and float traps @ combined cost of $900 for both	$ 11,700
13 Rockwell 3" Mode DPS - H Security Valves @ $1230	$ 16,000
Lease on Sperry-Sun single shot surveying instrument for 6 months	$ 5,000
Total Miscellaneous Cost	$ 32,700
Labor*	
Drilling labor cost is 2 men (8 hrs/day/man) (234 days) ($14/hr)	$ 52,400
Installing 10" pipe .36 hr/ft (7000') ($14/hr)	$ 35,300
Installing 8" pipe .30 hr/ft (4900') ($14/hr)	$ 20,600
Installing 3" pipe .18 hr/ft (300') ($14/hr)	$ 800
Total Labor Cost	$109,100
TOTAL COST	$348,000
TOTAL COST X 1.2 ENGINEERING CONTINGENCY FACTOR	$417,600
January 1980 prices, total cost x 1.15	$480,200

*Labor rate includes benefits

TABLE 10. Annual cost of power for the period from 12/80 to 12/84.

YEAR	COST	CA-PV FACTOR	PRESENT VALUE COST	CUMULATIVE COST
12/80	288,000	.955	275,040	275,040
12/81	"	.911	262,368	537,408
12/82	"	.870	250,560	787,968
12/83	"	.830	239,040	1,027,008
12/84	"	.792	228,096	1,255,104

Vertical Hole Degasification - On-Site Utilization

Direct use of the gas for heating and processing is preferable because the overall conversion efficiency is higher than for the generation of electricity. Yet, in a mine, only a fraction of the gas can be used for heating and processing. The remainder of the gas must be converted to electricity to operate mining equipment, the ventilation system, lights, etc. It should also be noted that the ventilation system by law must be on a separate noninterruptible power source. For ease in analysis, only total mine power requirements will be considered.

Since the major part of power is in the form of electricity, the main utilization of the produced gas will be to run a gas turbine generator. At peak production, a total of 550 MCFD or 14.85 billion Btu/month is available for use (Table 11). In this study, a Saturn 800 KW gas turbine generator from Solar Turbines, International will be used. Fuel consumption of this generator is rated at 13 million Btu's/hour. The generator starts on diesel and switches to methane when it is at full load. The availability of the generator is assumed to be 99%. Utilization time is estimated at 90%. The efficiency factor for the Saturn at standard conditions is 22%. A compressor would be needed to raise the methane to approximately 150 psig. The system, including a compressor, costs $477,802 at October 1979 prices or $549,472 (a 1.15 inflation factor) to bring the cost up to 1980 prices. As has been previously noted, utilization of gas to generate electricity is less efficient than direct use. This, as well as a 0.8 performance correction for altitude factor and a 3% transmission loss was taken into account to determine energy utilized on-site (Table 12).

TABLE 11. COMPARISON OF ENERGY RECOVERY AT DIFFERENT PRODUCTION RATES (BASED ON 900 BTU/CF GAS).

PRODUCTION BREAKDOWN BY WELL			TOTAL PRODUCTION BREAKDOWN		
MCFD	BTU/day $x10^6$	BTU/month $x10^6$	MCFD	BTU/day $x10^6$	BTU/month $x10^6$
50	45	1350	550	495	14850
30	27	810	330	297	8910
20	18	540	220	198	5940
10	9	270	110	99	2970
5	4	135	55	49	1485

TABLE 12. ENERGY INPUT, AND OUTPUT AT HAWK'S NEST PROPERTY ON A PER MONTH BASIS

Energy available	14.85×10^9 Btu	15.67×10^9 KJ
Fuel consumption	8.42×10^9 Btu	8.89×10^9 KJ
Energy output	640 KW month(800 KW x 0.8)	1.49×10^9 KJ
Energy output - Transmission Loss	1.49×10^9 KJ (1.00-.03)	1.44×10^9KJ
On-site energy needs	640,000 KWH	2.30×10^9 KJ

Note from Table 12 that the maximum energy from the 800 KW turbine generator working at 100% power is 63% of the projected minimum needs of the mine operation. The remainder of the energy, a minimum of 37%, must be brought in from elsewhere or generated on site using alternate methods.

The energy savings will be .63 x $288,000, or $181,440/year. Table 13 shows the cost breakdown for a 5-year period beginning 12/80 and ending 12/84. Given the above parameters, the break-even point is not reached. Note that depreciation and salvage value of equipment is not taken into account.

Table 13. Energy Savings in Dollars for Years from 12/80 - 12/84 for On-Site Vertical Hole Degasification Program

YEAR	SAVINGS ($)	CA-PV FACTOR	PRESENT VALUE SAVINGS ($)	CUMULATIVE SAVINGS ($)
12/80	181,440	.955	173,275	173,275
12/81	"	.911	165,292	338,567
12/82	"	.870	157,853	496,420
12/83	"	.830	150,595	647,015
12/84	"	.792	143,700	790,715

The above data shows that a project life of five years is not sufficient to recover funds spent for drilling, completing and maintaining the wells along with the cost of compressors and generators. The outlook could be improved in several ways:

1. An increase in production from the wells by stimulation of the coal zones could supply more gas for use or sales.
2. More detailed engineering may refine the drilling and completion plan and decrease the cost.
3. A 5%/year increase in power cost was used. If the increase rose above the 5% mark, the economics would improve.
4. A longer project life and substantial savings in related areas, such as ventilation or sales, would also help recover the original funds invested in the project.
5. Drilling holes from the mine through the lower coal zones would result in substantial savings due to lower drilling footage, and a more simplified piping system (see piping system, horizontal degasification, p. 30).

Vertical hole, stimulation of the coal zones - on site utilization

As was previously mentioned, a coal bed generally has low permeability. With low production, the company may elect to stimulate the coals to increase the wells production. For this example, a Dowell nitrogen foam frac, using 20/40 mesh sand as a proppant, was designed. The cost estimates based on a 7 BPM fracing rate and a one day job, were $53,486 per hole. For 11 holes, the cost would be $588,346; bringing the total cost of the project to $2,541,902 x 1.2 (contingency factor) or $3,050,282. The costs listed do not include tests run either on cores of the roof, coal, and floor rock or down-hole to determine the potential formation damage due to fracing. These costs vary significantly depending on the testing methods used and the extent of the testing program. A stimulation treatment may increase production over the projected 50 MCFD maximum for the unstimulated hole. Yet, even when the gas is in sufficient quantity to supply 100% of the mine's energy needs, the cost of power alone would not pay for the project in the five years projected (Table 10). As in the unstimulated case, the initial costs of the project would need to be lowered and substantial saving made in other areas to brighten the feasibility of the project.

Horizontal Hole Degasification - On-Site Utilization

The horizontal hole degasification plan for the Hawk's Nest mine has been discussed previously.

Since the main thrust of the plan is quick degasification of a panel to be longwall mined within the year, the drainage setup would drain the panel in too short a period to allow for full utilization and development of the gas resource.

Because of this, the flow will be regulated using the 3" globe valves in each of the 3" lateral lines coming from the borehole. A daily flow was estimated by presuming a 0 decline rate and dividing the reserve base given as 296.7 MMCF by 365 days. The resulting number of 813 MCF/day was used as an average daily gas flow. The gas is estimated at 1000 BTU/CF. Due to this proposed increase in gas flow per day over the vertical hole degasification plan, the Solar Turbines International Centaur 2600 KW turbine was considered. The turbine at 88.5% power, utilizes all projected gas production, a total of 33.87 million BTU's/hour. Percent utilization of the generator is again assumed to be 90%. The gas turbine unit averages around 99% availability and has a thermal efficiency of 26.5% under standard conditions.

The turbine will supply a total of 1840 KW (2600 KW x 0.885 power x 0.80 performance correction factor for elevation). Table 14 shows the energy available and utilized, the energy output, and energy needed per month on-site.

TABLE 14. ENERGY INPUT AND OUTPUT AT HAWK'S NEST PROPERTY ON A PER MONTH BASIS

Energy available	24.39×10^9 Btu	25.73×10^9 KJ
Fuel consumption	24.39×10^9 Btu	25.73×10^9 KJ
Energy output	1840 KW month	4.29×10^9 KJ
Energy output - Transmission Loss	4.29×10^9 (1.00-.03) KJ	4.16×10^9 KJ
On-Site energy needs	640,000 KW hr.	2.30×10^9 KJ

From the above data, it can be concluded that utilization of a 2600 KW turbine generator working at 88.5% of its rated capacity supplies greater than 100% of the projected minimum energy needs of the mine.

The economic analysis of the horizontal method presumes the following (Figure 29):

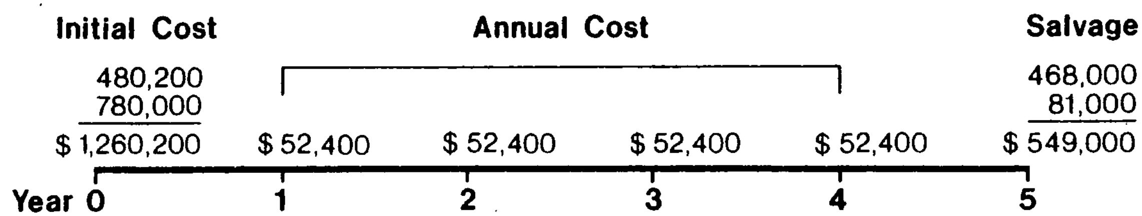
1) The initial cost of the project will be \$480,200 plus \$780,000 for a 2600 KW Centaur turbine generator and a compressor, or \$1,260,200.

2) New horizontal holes will be drilled in an unmined panel each year for the remaining four years at a labor cost of \$52,400 per year escalated at a rate of 15% and discounted at 10%, or a total of \$234,490 after five years.

3) The Centaur generating unit and compressor have a salvage value of 60% of the initial cost or \$468,000 after five years. The Big John drill will also be salvageable at 60% of the initial cost or \$81,000. Using a 10% discount, total present value salvage over 5 years will be \$340,874 in todays dollars.

4) The costs do not reflect replacement of parts and labor cost.

Utilizing the same calculation as was used in the previous determinations, a total cost (using i = 15% price increase and t = 10% discount factor) of \$234,490 + the initial project cost of \$1,260,200, \$1,494,690 is obtained. Subtracting the salvage value of \$340,874 gives a total project cost of \$1,153,816. Comparing this figure with the power costs in Table 10, the project breaks even between the fourth and fifth year.



$ 234,490 p.v. annual cost at i = 15%, t = 10%

$ 340,874 p.v. salvage at a 10% discount

Initial cost.............	1,260,200
Annual cost...........	+ 234,490
Salvage.................	- 340,874
Total project cost	$1,153,816

Figure 29. Cost breakdown diagram for the horizontal degasification - on site utilization model.

On-Site utilization - other available options

The above studies analyze only two of many options available for on site utilization of coal bed methane.

One of these is cogeneration. In cogeneration systems, the exhaust heat from the gas turbine generator is used as a heat source. The exhaust flow can be 1) used either as a direct heating or drying medium, 2) passed through a heat exchanger to transfer its heat to a process fluid, or 3) used as highly preheated combustion air in boilers, heaters and hot gas generators.

Another option is to run the generators in parallel. For example, on the horizontal hole method, two 800 KW Saturn generators could be run on the projected gas production. The generators would supply approximately 1280 KW. The energy output would be enough to supply the energy needs of the mines. The units are more expensive than the 2600 KW generator, yet offer the option of having one unit working if the other unit is down.

Sale of Coal Bed Methane

The sale of coal bed gas is another option available to the operator. In the study, it is presumed the operator owns the gas rights on the property. Five after tax cash flow analyses were run.

Two runs, the Hawk's Nest Coal Degasification Plan Vertical (HNCDPV) 001 and 002, analyzed the economics of degasification for the vertical hole plan--no stimulation, at a 0 and 2.5 decline rate, respectively, and a $3.50/MCF price. Runs HNCDPV 003 and 004 treated the case of vertical hole degasification with stimulation using the same decline rate and cost. The decline rates were obtained by comparing past production data from U.S. Bureau of Mines and private sources. It should be noted that, in several cases, the curve showed a negative decline (i.e. increased production with time).

The horizontal plan for the Hawk's Nest property (HNCDPH 005) was run using the same price as the vertical. The decline rate was presumed to be 0 due to the addition of new panels.

Table 15 lists the parameters run for each test. The six after tax cash flow analyses are included in the appendix. Profitability Indices, both before and after tax, are calculated for each case.

As can be seen from the appendix, tests HNCDPV 001 and 002 proved uneconomic at the $3.50/MCF price with an after tax Profitability Index (P.I.) of 0.5 for both projects. This would improve with 1) possible decrease in completion and maintenance costs; 2) increase in the gas price; and 3) savings due to decreased ventilation costs when the degasified coal seam is mined.

Table 15. Economic parameters for the proposed Hawk's Nest Coal Degasification Project.

	PROJECT IDENTITY NUMBER				
	HNCDPV 001	HNCDPV 002	HNCDPV 003	HNCDPV 004	HNCDPH 005
Initial Production Rate MCF/day	550	550	1,100	1,100	813
Decline Rate (%)	0	2.5	0	2.5	0
Price ($)	3.50	3.50	3.50	3.50	3.50
Initial Expenses ($)	2,344,267	2,334,267	3,050,282	3,050,282	480,200
Operating Expenses $/yr	Yr 1 137,056 Yr 2 155,627 Yr 3 178,971 Yr 4 205,817 Yr 5 236,690	same as 001	same as 001	same as 001	Yr 1 ----- Yr 2 60,260 Yr 3 69,299 Yr 4 79,694 Yr 5 91,648

Tests HNCDPV 003 and 004 proved economic with after tax P.I's. of 1.3 and 1.2, respectively. The horizontal hole test HNCDPV 005 proved highly economical with an after tax P.I. of 2.8.

It should be emphasized that both the horizontal and vertical projects are proposals and their success depends on the gas production rates listed for each plan.

Conclusions

Colorado is a state with abundant energy resources. One such resource, overlooked in the past, is coal bed methane. To produce and utilize the gas from minable coal beds, the geologic, technologic (both in mining and production), economic, and legal controls must be analyzed.

In Colorado, the coal gas is present in sufficient quality and quantity to warrant attention. Yet in minable coalbeds, large amounts of potentially producible gas are known only in areas within the Raton Mesa and Uinta coal regions. Using the Hawk's Nest mine as a case study, the report presented shows that the gas is present; the technology is available (although more research needs to be done on completion in coal beds); and the present economics vary, depending on degasification method and final use of the gas.

Unfortunately, what is not available and is needed is more gas content and production data in Colorado's minable areas; a quantitative picture of the benefits and hazards of degasification on coal mining; and a decision on the legal ownership of coal bed methane. Despite these insufficiencies, coal bed methane is and will prove to be a viable energy source in Colorado's future.

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APPENDIX

FIVE YEAR PRODUCTION CASH FLOW - HNCDPV 001

YEAR	0	1	2	3	4	5
Gross Revenue	0	702,600	702,600	702,600	702,600	702,600
Royalty Expense (12.5%)	0	87,800	87,800	87,800	87,800	87,800
Operating Expense	1,565,600	137,100	155,600	179,000	205,800	236,700
Depreciation	0	77,600	77,600	77,600	77,600	77,600
Severance Tax	0	30,900	30,900	30,900	30,900	30,900
Gross profit	(1,565,600)	369,200	350,700	327,300	300,500	269,600
State tax (5%)	0	0	0	0	15,000	13,500
Federal tax (46%)	0	0	0	0	131,300	117,800
Net profit	(1,565,600)	369,200	350,700	327,300	154,200	138,300
Depreciation	0	77,600	77,600	77,600	77,600	77,600
Net cash flow	(1,565,600)	446,800	428,300	404,900	231,800	215,900

P.I. Based on gross profit = 0.6
P.I. Based on net profit = 0.5

STATE AND FEDERAL TAX CALCULATION - HNCDPV001

Year	0	1	2	3
Operating Loss	0	-1,565,600	-1,196,400	-845,700
Net after Severance	-1,565,600	369,200	350,700	327,300
Loss Carry Forward Taken	0	369,200	350,700	327,300
State & Federal Taxable	-1,565,600	0	0	0
State Tax (5%)	0	0	0	0
Federal Tax (46%)	0	0	0	0

FIVE YEAR PRODUCTION CASH FLOW - HNCDPV 002

YEAR	0	1	2	3	4	5
Gross Revenue	0	702,600	685,000	667,900	651,200	634,900
Royalty Expense (12.5%)	0	87,800	85,600	83,500	81,400	79,400
Operating Expense	1,565,600	137,100	155,600	179,000	205,800	236,700
Depreciation	0	77,600	77,600	77,600	77,600	77,600
Severance Tax	0	30,900	30,000	29,100	28,300	27,500
Gross profit	(1,565,600)	369,200	336,200	298,700	258,100	213,700
State tax (5%)	0	0	0	0	12,900	10,700
Federal tax (46%)	0	0	0	0	112,800	93,400
Net profit	(1,565,600)	369,200	336,200	298,700	132,400	109,600
Depreciation	0	77,600	77,600	77,600	77,600	77,600
Net cash flow	(1,565,600)	446,800	413,800	376,300	210,000	187,200

P.I. based on gross profit = 0.6
P.I. based on net profit = 0.5

STATE AND FEDERAL TAX CALCULATION - HNCDPV002

Year	0	1	2	3
Operating Loss	0	-1,565,600	-1,196,400	-860,200
Net after Severance	-1,565,600	369,200	336,200	298,700
Loss Carry Forward Taken	0	369,200	336,200	298,700
State & Federal Taxable	-1,565,600	0	0	0
State Tax (5%)	0	0	0	0
Federal Tax (46%)	0	0	0	0

FIVE YEAR PRODUCTION CASH FLOW - HNCDPV 003

YEAR	0	1	2	3	4	5
Gross Revenue		1,405,300	1,405,300	1,405,300	1,405,300	1,405,300
Royalty Expense (12.5%)	0	175,700	175,700	175,700	175,700	175,700
Operating Expense	2,154,000	137,100	155,600	179,000	205,800	236,700
Deprecia-tion	0	77,600	77,600	77,600	77,600	77,600
Severance Tax	0	66,000	66,000	66,000	66,000	66,000
Gross profit	(2,154,000)	948,900	930,400	907,000	880,200	849,300
State tax (5%)	0	0	0	31,600	44,000	42,500
Federal tax (46%)	0	0	0	276,300	384,700	371,100
Net profit	(2,154,000)	948,900	930,400	599,100	451,500	435,700
Deprecia-tion	0	77,600	77,600	77,600	77,600	77,600
Net cash flow	(2,154,000)	1,026,500	1,008,000	676,700	529,100	513,300

P.I. based on gross profit = 1.7
P.I. based on net profit = 1.3

STATE AND FEDERAL TAX CALCULATION - HNCDPV003

Year	0	1	2	3
Operating Loss	0	-2,154,000	-1,205,100	-274,700
Net after Severance	-2,154,000	948,900	930,400	907,000
Loss Carry Forward Taken	0	948,900	930,400	274,700
State & Federal Taxable	-2,154,000	0	0	632,300
State Tax (5%)	0	0	0	31,600
Federal Tax (46%)	0	0	0	276,300

FIVE YEAR PRODUCTION CASH FLOW - HNCDPV 004

YEAR	0	1	2	3	4	5
Gross Revenue	0	1,405,300	1,370,200	1,335,900	1,302,500	1,270,000
Royalty Expense (12.5%)	0	175,700	171,300	167,000	162,800	158,800
Operating Expense	2,154,000	137,100	155,600	179,000	205,800	236,700
Deprecia-tion	0	77,600	77,600	77,600	77,600	77,600
Severance Tax	0	66,000	64,300	62,500	60,900	59,300
Gross profit	(2,154,000)	948,900	901,400	849,800	795,400	737,600
State tax (5%)	0	0	0	27,300	39,800	36,900
Federal tax (46%)	0	0	0	238,600	347,600	322,300
Net profit	(2,154,000)	948,900	901,400	583,900	408,000	378,400
Deprecia-tion	0	77,600	77,600	77,600	77,600	77,600
Net cash flow	(2,154,000)	1,026,500	979,000	661,500	485,600	456,000

P.I. based on gross profit = 1.6
P.I. based on net profit = 1.2

STATE AND FEDERAL TAX CALCULATION - HNCDPV004

Year	0	1	2	3
Operating Loss	0	-2,154,000	-1,205,100	-303,700
Net after Severance	-2,154,000	948,900	901,400	849,800
Loss Carry Forward Taken	0	948,900	901,400	303,700
State & Federal Taxable	-2,154,000	0	0	546,100
State Tax (5%)	0	0	0	27,300
Federal Tax (46%)	0	0	0	238,600

FIVE YEAR PRODUCTION CASH FLOW - HNCDPH 005

YEAR	0	1	2	3	4	5
Gross Revenue	0	1,038,600	1,038,600	1,038,600	1,038,600	1,038,600
Royalty Expense (12.5%)	0	129,800	129,800	129,800	129,800	129,800
Operating Expense	345,200	52,400	60,300	69,300	79,700	91,700
Deprecia-tion	0	10,800	10,800	10,800	10,800	10,800
Severance Tax	0	47,700	47,700	47,700	47,700	47,700
Gross profit	(345,200)	797,900	790,000	781,000	770,600	758,600
State tax (5%)	0	0	22,600	39,500	38,500	37,900
Federal tax (46%)	0	0	197,800	345,200	336,800	331,500
Net profit	(345,200)	797,900	569,600	396,300	395,300	389,200
Deprecia-tion	0	10,800	10,800	10,800	10,800	10,800
Net cash flow	(345,200)	808,700	580,400	407,100	406,100	400,000

P.I. based on gross profit = 4.1
P.I. based on net profit = 2.8

STATE AND FEDERAL TAX CALCULATION - HNCDPH005

Year	0	1	2	3
Operating Loss	0	-345,200	0	
Net after Severance	-345,200	797,900	790,000	
Loss Carry Forward Taken	0	345,200	0	
State & Federal Taxable	-345,200	452,700	790,000	
State Tax (5%)	0	22,600	39,500	
Federal Tax (46%)	0	197,800	345,200	

THE PANEL DIAGRAM HAS BEEN OMITTED FROM OPEN FILE 80-5 DUE TO THE CONFIDENTIAL NATURE OF THE MATERIAL.