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VERTICAL BOREHOLE DESIGN AND COMPLETION PRACTICES TO REMOVE METHANE GAS FROM MINEABLE COALBEDS

By
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REPORT OF INVESTIGATION

Stephen W. Lambert, Michael A. Trevits, and Peter F. Steidl

Report Date - June, 1980

U.S. Department of Energy

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VERTICAL BOREHOLE DESIGN AND COMPLETION PRACTICES USED TO REMOVE METHANE GAS FROM MINEABLE COALBEDS

by

Stephen W. Lambert[1], Michael A. Trevits[2], and Peter F. Steidl[1]

INTRODUCTION

Coalbed gas drainage from the surface in advance of mining has long been the goal of researchers in mine safety. Bureau of Mines efforts to achieve this goal started about 1965 with the initiation of an applied research program designed to test drilling, completion, and production techniques for vertical boreholes. Under this program, over 100 boreholes were completed in 16 different coalbeds. The field methods derived from these tests, together with a basic understanding of the coalbed reservoir, represent an available technology applicable to any gas drainage program whether designed primarily for mine safety or for gas recovery, or both.

Much of the subject matter contained in this report is derived from past work sponsored by the Bureau of Mines. The most recent work presented was later completed under the Department of Energy, which, after October, 1977, assumed responsibility for many of the vertical borehole programs previously initiated by the Bureau of Mines.

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SUMMARY

Borehole Specifications

1. The minimum casing size that accommodates most standard down-hole tools is four inches inside diameter.

2. Degasification boreholes, after mine-through, can be used for mine development by providing convenient avenues to the surface. The diameter and completion of these wells should be specified during planning phases to meet the intended usage.

Some Principles of Coalbed Gas Storage, Release and Migration

1. For practical application, the maximum amount of gas stored in coalbeds is generally assumed to be the amount at equilibrium with the measured pressure/temperature conditions of the coalbed. This is best illustrated by an equilibrium sorption isotherm curve for methane gas.

2. Coalbed gas travels by diffusion to natural fractures and then by Darcy flow to a point of lowest pressure. By lowering coalbed water saturation, the coalbed's permeability to gas increases, enhancing flow rate.

Effective Well Placement

1. Single wells placed alone in very large coalbed areas do not produce high sustained gas flows because they do not effectively lower coalbed hydrostatic pressure or water saturation.

2. An efficient method for reducing pressure and decreasing coalbed water saturation within a practical time interval (essential to high gas flow rate) is to place wells in closely spaced patterns or position wells close to mine workings.

Drilling

1. Portable drilling rigs, capable of drilling degasification boreholes to depths of 2,500 feet, are available in the water well and petroleum drilling industries.

2. In general, drilling muds should be avoided since they almost certainly cause coalbed permeability damage.

3. Percussion type drill bits enable boreholes to be drilled quickly. Tri-cone type bits, however, cause less coalbed permeability damage.

Logging

Geophysical logs which measure rock density provide an excellent means of identifying coalbed stratigraphic horizons in an openhole. Caliper logs offer the precise quantitative information required to select casing equipment and cementing parameters. Neutron type logs are reasonably good indicators of coal after the borehole is cased.

Completion

Coalbed gas drainage has been most successful when "openhole" type completions are used for degasification boreholes. Production from perforated wells has been significantly lower. Abrasive-jet slotted completions have been most effective through casing.

Method of Removing and Measuring Water

1. A proven method of removing water from degasification boreholes is by means of a sucker-rod pump. This method is effective when production is less than 200 bpd but requires routine maintenance.

2. Positive-displacement meters are used to measure water but this method usually requires an inappropriate amount of routine maintenance.

3. The timing mechanisms installed within the electric power circuit to borehole pump motors automatically control pumping intervals but require constant attention in order to maintain a "dry hole" condition.

Problems of Monitoring Water Production

1. Solids and gas in waterlines cause significant meter inaccuracies and/or pump malfunctions.

2. Improper pump intervals allow water to rise in boreholes above coalbeds, reducing gas production; or allow water to fall below pump horizons, resulting in excessive wear of equipment.

Improved Methods for Monitoring Water Production

1. Gas contained in waterlines can be removed before the water is metered by incorporating a vented separation tank in the surface water flow system.

2. Most large pieces of solid debris carried through waterlines settle in the separation tank (Item 1, above). The remaining solids, suspended in the flow system, can be removed with a dirt-and-rust water filter installed downstream from the separation tank.

3. Downhole pump stoppage due to lodging of large pieces of coal or other rock material can sometimes be averted by installation of a screen at the lower end of the water production tubing.

4. Automatically controlled pump cycles must be checked frequently and reset with every significant change in water production. An alternative method to cycled pumping is the use of a variable-speed control on the pump.

5. To prevent freezing, surface waterlines can be wrapped with heat tape and then covered with insulation.

Method of Removing and Measuring Gas

1. Gas is produced through the annular space between the water production tubing and borehole casing.

2. Wells should be produced under minimal back-pressure.

3. Diaphram, rotary, and turbine type gas meters are used to monitor degasification borehole gas flows.

Gas Production Monitoring Problems

1. Water build-up in gas lines decreases meter accuracy and can permanently damage working components when freezing occurs.

2. Sudden pressure release after wells have been shut-in, or when unloading occurs can damage gas monitoring equipment.

Improved Methods for Monitoring Gas Production

1. Commercially available filters are designed to remove fine solid particles from gas lines with very little pressure drop.

2. The moisture content of coalbed gas is removed by cooling, absorption, and impingement.

3. Meter inaccuracy and possible meter damage caused by sudden pressure release is avoided by allowing gas pressure to bleed-off gradually while maintaining flow pressures within the given meter range.

4. Ice formation in gas lines near the wellhead is prevented by properly insulating and heating the meters and other points favorable to water accumulation. The number of routine field inspections should be increased during cold weather periods to assure minimum condensate build-up.

Analyses Of Gas Produced From Vertical Boreholes

1. Methane content of gas sampled from 34 vertical boreholes average approximately 96 percent. The percent of higher hydrocarbons average 0.08 percent.

2. Hydrogen, helium, carbon monoxide, sulfur dioxide, and other such gases present in conventional natural gas are only rarely found in coalbeds.

3. The heat of combustion of coalbed gas is comparable to that of natural gas, ranging from 900 to 1,100 BTU/ft^3.

Introduction To Well Stimulation

1. The basic mechanics of the stimulation procedure include:

   a. Generation of a hydraulic fluid force at the surface by pumping.
   b. Application of this hydraulic force to a selected rock unit through a borehole which causes a fracture, or widening of a preexisting fracture.
   c. Extension of this break by continued injection (pumping) of fluid.
   d. Addition of propping agent which serves to hold the fracture open after the applied hydraulic force is released.

2. The intent of stimulation is to propagate conductive fractures from the wellbore to a point up to several hundred feet away within the coalbed and thus expand the area being drained by the wellbore.

Physical Rock Properties Affecting Stimulation

1. Natural fracture systems can account for fluid "leak off" during stimulation treatments. Induced fracture direction(s) also parallel natural fracture trends and can be predicted within 10 degrees azimuth.

2. Mechanical properties of rocks can be used to predict breakdown parameters for stimulation if the rocks exposed to treatment are "flawless." This is a tenuous viewpoint considering the natural fractured condition of most rock strata.

3. It is relatively easy to propagate fractures into future mine roof or floor if the rock is already fractured.

Characteristics of Induced Coalbed Fractures

1. Induced coalbed fractures may be oriented vertically, horizontally, or inclined.

2. The direction of vertically induced fractures is usually parallel to existing natural fracture trends.

3. Fracture length is usually less than the length predicted in frac design. One reason for this is excessive fluid "leak-off". More viscous treating fluids produce short fractures.

4. Given similar treatment pressures, fracture width is controlled mainly by fluid viscosity. Highly viscous fluids produced wide fractures.

5. The size and arrangement of proppant material within induced fractures controls the ease of fluid flow through these fractures and effects the amount of coalbed pressure reduction attainable within a given time period.

6. Continued accumulation of sand proppant in boreholes suggest closure stresses are less than originally anticipated.

Stimulation Using Gelled Fluids

1. Twenty-two stimulation treatments using gelled fluids have been conducted since 1970. This type of hydraulic fluid is water based, and contains natural gum to thicken the mixture allowing it to carry sand proppant and retard fluid leak-off.

2. Six case studies illustrate the Government's past experience using gelled fluids.

Stimulation Using Foam

1. Thirty-nine Government sponsored coalbed stimulation tests have been conducted using foam. This type of hydraulic fluid is a mixture of liquid (usually fresh water), gas, and foaming surfactant.

2. Four case studies illustrate the Government's past experience using foam.

Miscellaneous Stimulation Techniques

1. An explosive type fracture treatment yielded no increase in gas production. The same poor production results were obtained after pumping nitrogen gas into a coalbed.

2. One experimental coalbed stimulation design incorporates the use of gelling agents, water and liquid CO_2. Several months of pumping after the treatment produced only small amounts of gas and water.

3. The patented "Kiel Frac" has been applied twice to mineable coalbeds. This type of stimulation incorporates the use of sand and water and is applied in pressurization/depressurization cycles or stages. A preliminary underground study showed this technique to produce horizontal fracturing.

4. A stimulation design recently tested uses foam and a very low injection rates but does not include a solid propping agent. The possible benefits of this design include: better fracture height control, and the elimination of pumping problems resulting from inflow of frac sand in operating boreholes. This design has been tested one time in the Mary Lee Coalbed and the production results were encouraging.

Production Problems Related to Coalbed Stimulation

1. The presence of gel or gel residue is believed to greatly retard fluid flow to wellbores, especially when this gel material is used in perforation type completions.

2. Sand proppant, carried back to the wellbore, results in mechanical pump failures or severe losses in pump efficiency.

3. Well unloading, similar to well "blowouts" in petroleum industry terminology but much smaller in scale, refers to occasions when much or all of the water contained in a well is carried to the surface by volumes of expanding gas. During unloading, fluid velocities are very high and fluids become exceptionally effective carriers of solid debris to wellbores.

Effects of Hydraulic Stimulation on Mining

1. Of 64 Government sponsored stimulation treatments, the results of 12 have been observed directly underground.

2. The results of stimulation have varied greatly within the same coalbed and even within the same mine.

3. Potentially, the worst mine roof condition attributable to hydraulic stimulation is the extension of horizontally-oriented fractures, positioned above the coal unit(s) being mined.

4. To date, there has been no observed or reported affects on roof stability to indicate the Government's degasification program adversely affected mining operations.

The Effects of Removing Coalbed Fluids Before Mining

1. If not sufficiently depleted, producing boreholes creates favorable conditions for gas release and migration into mines.

2. There are two ways which mining can avoid potentially excessive gas flows: (a) allow the well to deplete, or (b) pump water back into the coalbed through the wellbore or simply turn off the dewatering pumps and allow the boreholes drainage area to "flood" itself naturally.

Cost of Vertical Borehole Degasification

Current total costs for drilling and completing (including adequate stimulation) a vertical degasification borehole range from $54 to $63 per foot of borehole depth.

BOREHOLE SPECIFICATIONS

Early degasification efforts included attempts to utilize exploration core holes placed by coal mining companies for formation testing in the Pittsburgh coalbed. These efforts were unsuccessful because of the small diameter casing (less than two inches) and the limited size of stimulation equipment that could be used (5). 3/ Today, the minimum size diameter borehole drilled is six inches. After casing, the inside diameter of the well is usually four inches which is large enough to accommodate most standard downhole oil field tools, pipe tubing, and water pumps.

The borehole used to drain gas ahead of mining can be used for mine development after the well has been intercepted underground. The diameter of these wells can thus be specified to meet the intended use in the mine plan. Such wells provide ventilation, convenient power, dust, or water transport avenues from the surface to mine workings. Vertical wells have also been used to manifold gas drained from holes drilled horizontally from within the mine to the surface.

3/ Underlined number in parentheses refers to item in the list of references.

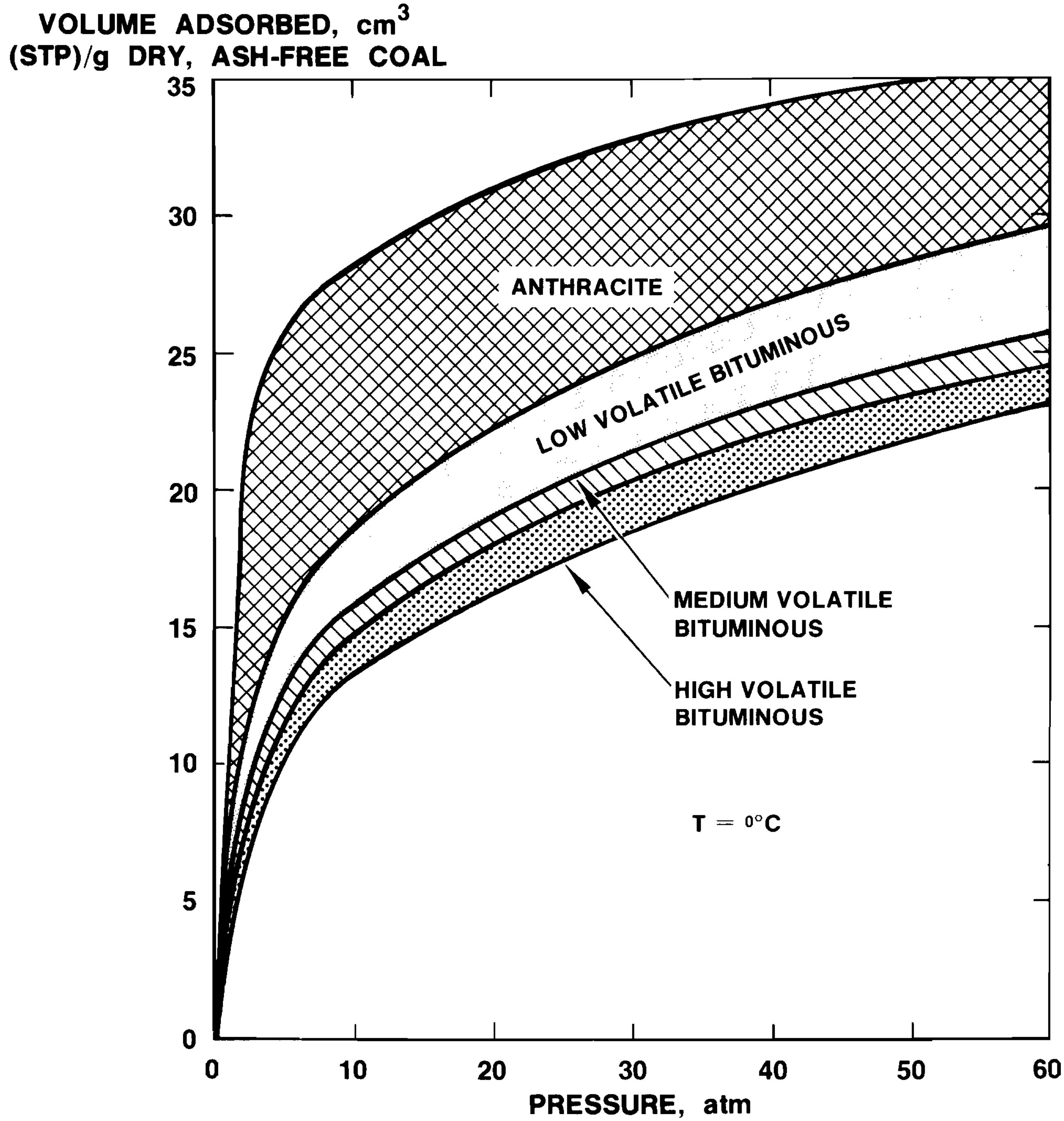
SOME PRINCIPLES OF COALBED GAS STORAGE, RELEASE, AND MIGRATION

Coalbed gas is adsorbed onto the internal surfaces of coal matrix material (31). The amount of gas contained in this manner within any given area of a coalbed depends primarily on the coals' inherent storage capacity and on the physical conditions of the coalbed. Kim (20) indicates that the amount of gas that coal can contain is limited by coal rank. Within a given rank, however, the amount of gas actually adsorbed on the coal depends on the pressure/temperature history of the coalbed. For practical application, the quantity of gas is assumed to be that which is at equilibrium with the measured pressure/temperature conditions of the coalbed. This relationship is best illustrated by equilibrium isotherms as shown on Figure 1.

Adsorption isotherms demonstrate how coals capacity decreases when external pressures are reduced. Induced pressure reductions, intentional or otherwise, figure heavily into the bases of all the gas control or drainage efforts presently being tested. Any opening in a coalbed from which fluids are removed, lowers pressure and changes equilibrium conditions in the area surrounding that opening. The coal affected by this pressure reduction releases a portion of its gas in order to achieve equilibrium with the new reservoir condition. A working mine, a shaft draining water, or a producing borehole each disrupts a coalbed's previous pressure/gas storage equilibrium in a way which causes gas to be released (desorbed) from the coal matrix. This is why degasification efforts are designed, in essence, to cause coalbed pressure reductions ahead of mining.

Once released from the coal's inner surfce areas, coalbed gas travels by diffusion to natural fractures in the coalbed referred to as "cleat". Once gas enters these fractures, migration is similar to conventional fluid flow (Darcy flow) to a point of lowest pressure; i.e., a borehole, a mine, a shaft, and so forth.

FIGURE 1. - VARIATION OF ADSORPTION ISOTHERMS WITH COAL RANK, AT 0°C (20).



EFFECTIVE WELL PLACEMENT

The two most important reservoir changes brought about by the removal of coalbed fluids are: (1) pressure reduction, and (2) a lowering of water saturation (25). The equilibrium sorption isotherm, Figure 2, demonstrates the critical importance of the coalbed pressure condition. The isotherm shows that as pressure is lowered, sufficient gas will be released to reestablish equilibrium at the new pressure condition. In addition, the gas which is released into the coalbed's fracture system is made more readily available for flow to the wellbore as reservoir water saturation is reduced. This is because the coalbed's permeability to gas flow increases as demonstrated on Figure 3 (22).

Production From Single Wells

Experience has shown that single wells in virgin coalbeds do not produce high sustained gas flow rates. This indicates that they cannot reduce coalbed pressure and decrease water saturation rapidly enough and/or to a great enough degree to maintain high flow rates. Given a water-saturated condition and an infinitely large reservoir, fluid drainage can only be effective in an area where permeability to the well is greater than the coalbed's natural permeability. At stimulated wells, this effective drainage area is directly related to the length and conductivity of the induced fractures. Outside these zones of induced permeability, significant pressure and saturation reductions occur slowly because water is supplied by the coalbed at nearly the same rate it is removed.

Water production from a single well is typically high during early phases of pumping since water originates primarily from the area of induced permeability around the well. Water flow, however, decreases sharply and drainage expands beyond this highly permeable zone. This lower level of water production then very slowly decreases throughout the remaining life of the well.

Figure 4 shows a gas production curve from a well placed in a coalbed far from other drainage points. Even though coalbed fluid pressure was reduced several hundred feet away from this well (Figure 5), the reduction was small and only a small percentage of the total amount of gas stored in the coal was released (refer to Figure 2). Since there was relatively little gas available for flow, gas production rates declined quickly. The production curve shown on Figure 6 also demonstrates the relatively rapid decline and low gas flows measured from single wells isolated from other drainage points.

FIGURE 2. - EQUILIBRIUM SORPTION ISOTHERM CURVE (25).

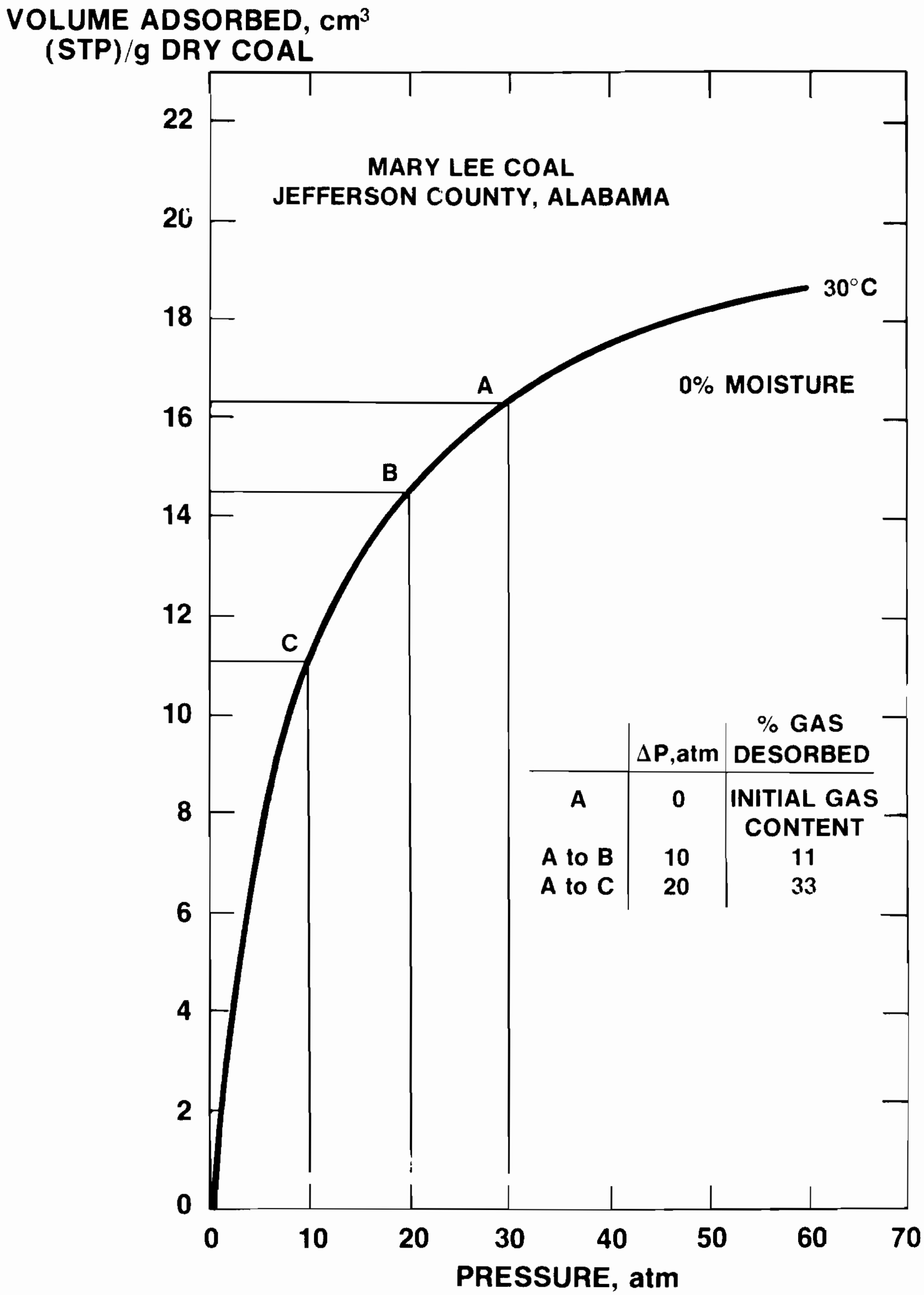


FIGURE 3. - GAS PERMEABILITY RELATIVE TO WATER SATURATION (22).

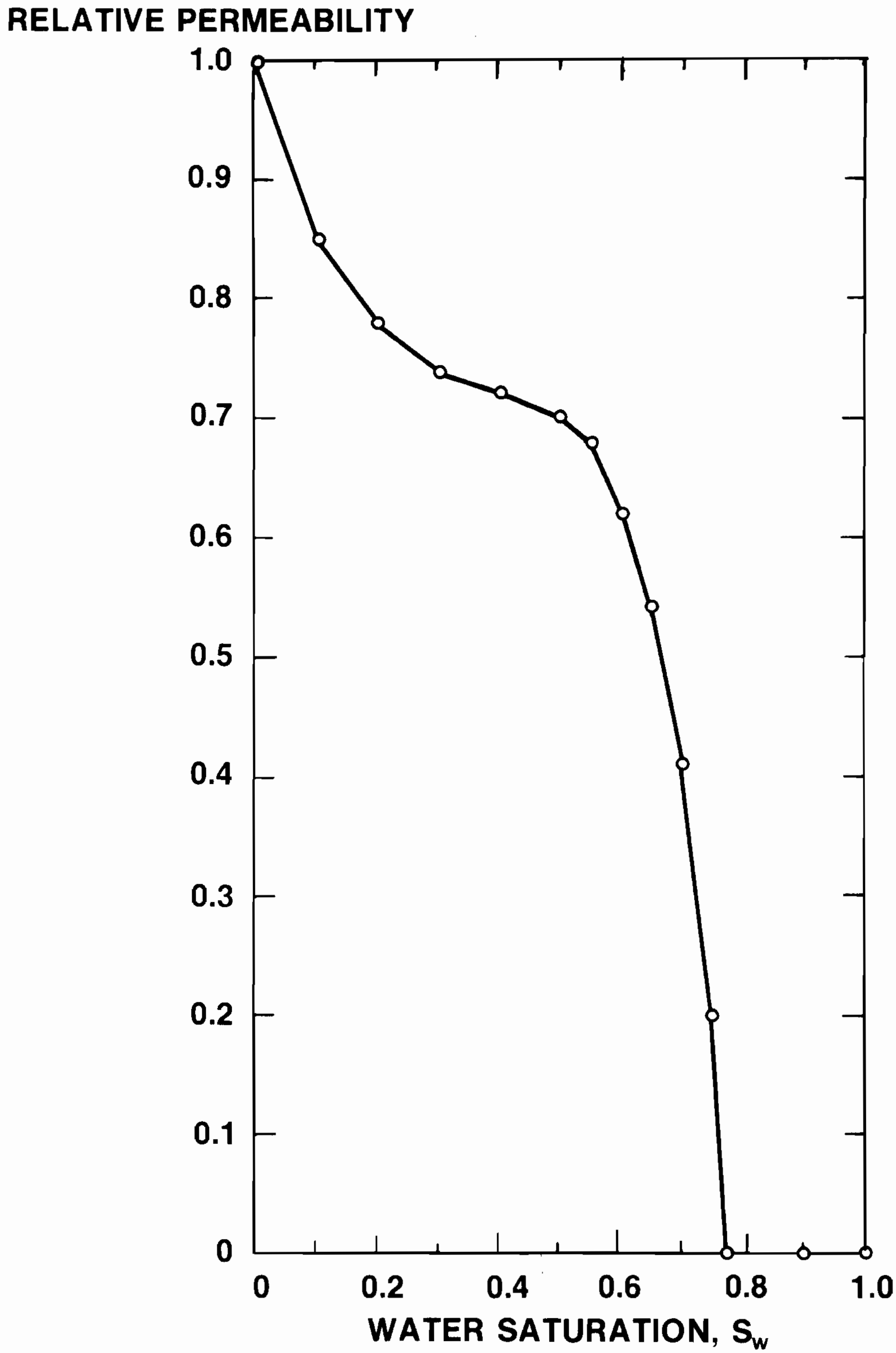


FIGURE 4. - PRODUCTION CURVES FROM A DRAINAGE WELL PLACED MORE THAN 3000 FEET FROM ANOTHER DRAINAGE POINT IN THE MARY LEE COALBED.

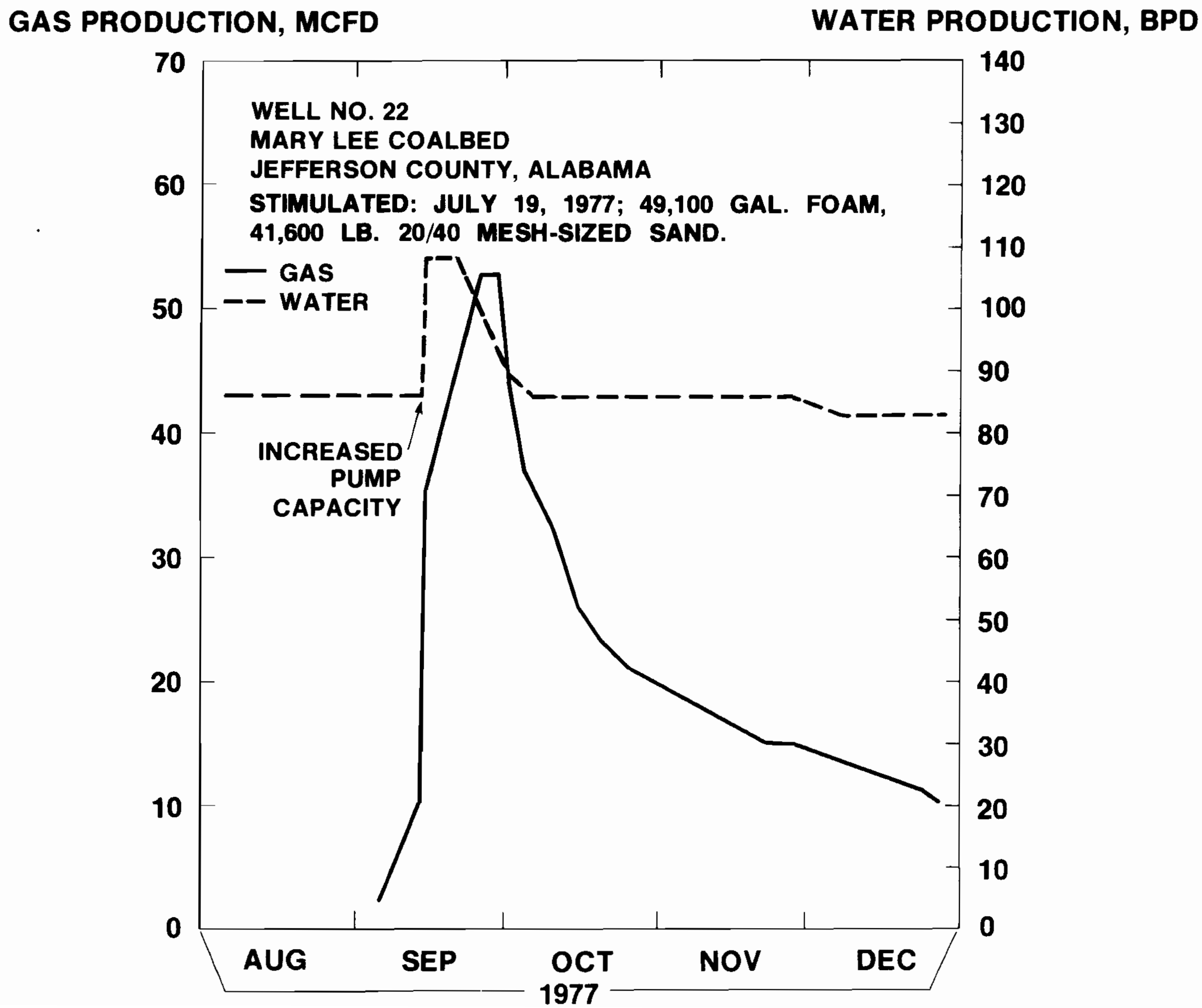


FIGURE 5. - COALBED WATER PRESSURE DECLINE MEASURED AT OBSERVATION WELLS PLACED ALONG A NORTH-SOUTH LINE AND UP TO 2,945 FEET FROM PRODUCTION WELL.

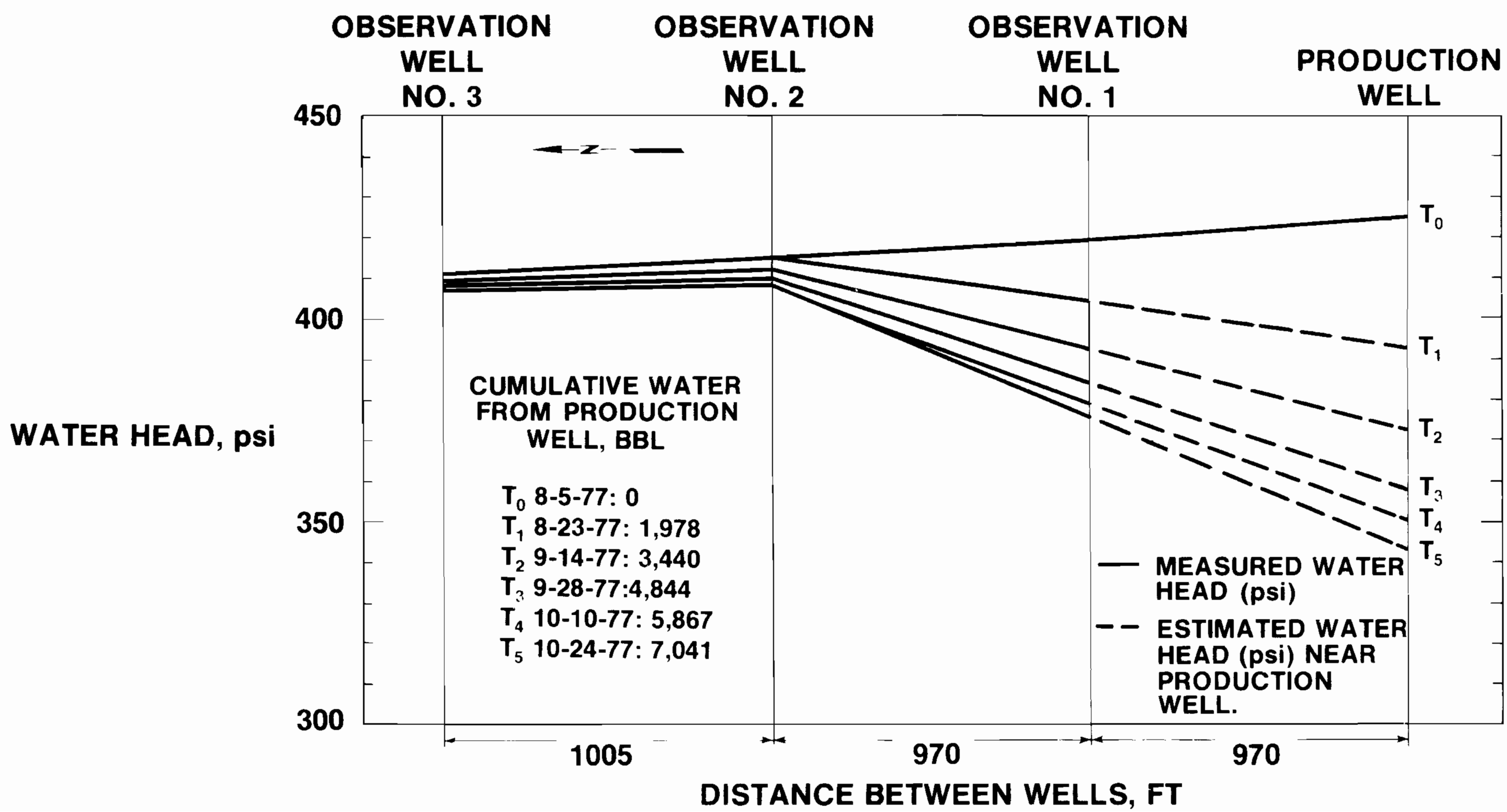
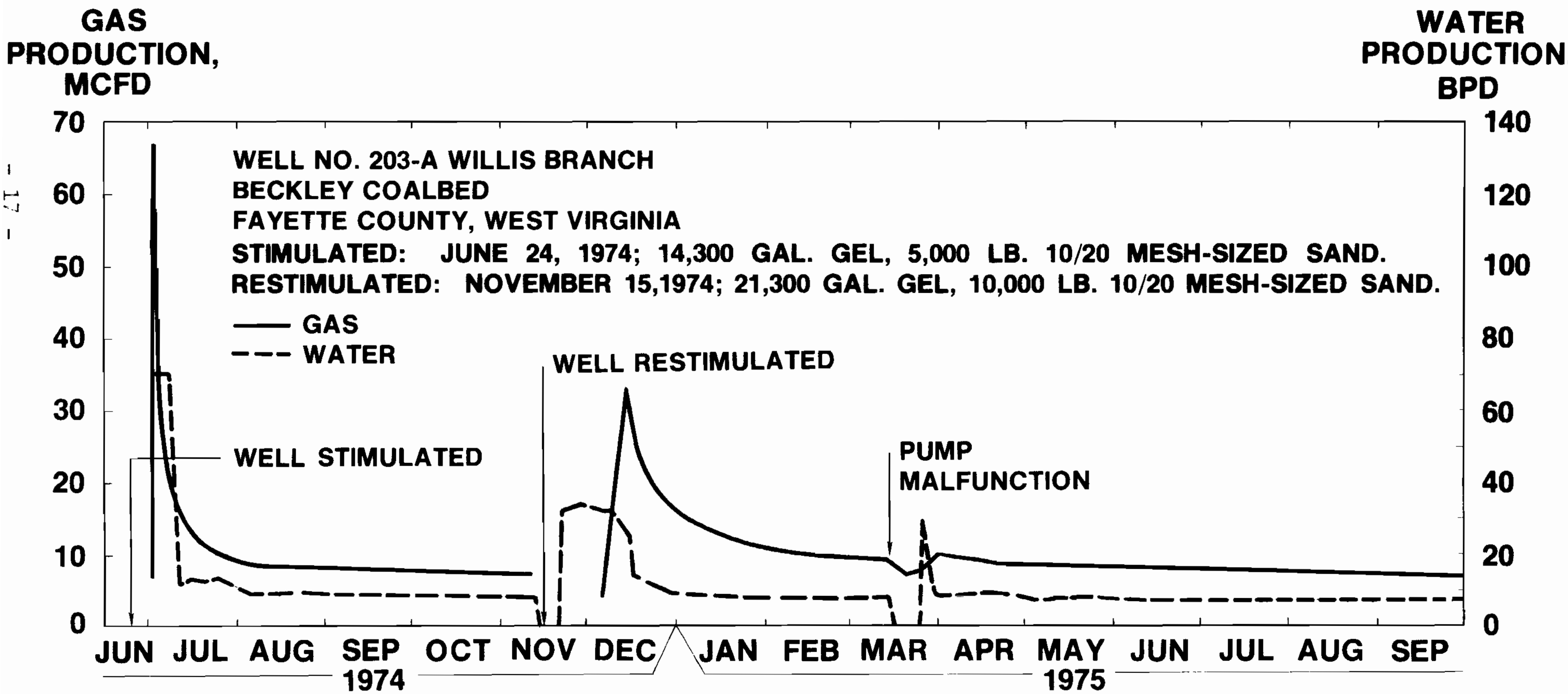


FIGURE 6. - PRODUCTION CURVES FROM A COALBED GAS DRAINAGE WELL PLACED MORE THAN 3000 FEET FROM ANOTHER DRAINAGE POINT IN THE BECKLEY COALBED.

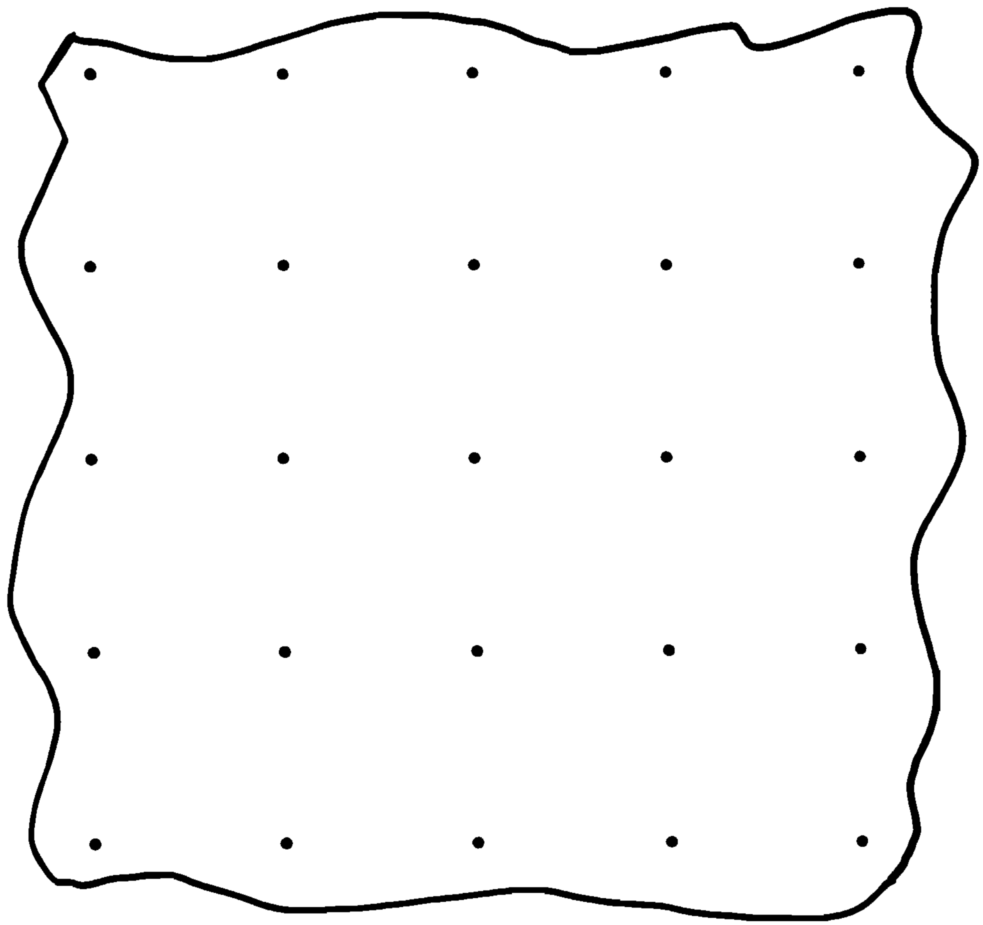


Production From Well Patterns or Near Mine Operations

A more efficient method used to reduce pressure and decrease water saturation is to draw fluids from a more "limited reservoir area" of a coalbed. This can be accomplished by completing multiple-well patterns or by positioning wells close to mine workings. As coalbed fluids are removed from two or more wells, the drainage areas overlap, and allow the wells to remove fluids from specific reservoir areas. By doing this, coalbed pressure is reduced to a greater degree within a shorter period of time, allowing much more gas to be released. Water saturation is also lowered to a greater degree increasing gas permeability and enhancing gas flow to the wells.

Figure 7 demonstrates a square grid or "experimental" arrangement of wells used when little is known about the specific flow and/or structural properties of the coalbed. Another pattern, shown on Figure 8, is an arrangement which could be used to take advantage of certain directional permeability characteristics, as would be determined from geologic studies (28) (29) (30) (6) or from prior experimental drilling work in the area (23).

Figure 9 demonstrates one type of well arrangement which can be used near mine workings. Here the mine workings and the surrounding wells create overlapping drainage areas. Production has been encouraging from the few boreholes completed successfully near mine workings (26). Figure 10 shows production measured from one such well placed about 600 feet from a mine opening. Gas production from this well began to increase about 60 days after pumping was initiated because an overlapping drainage area was established between the well and the mine opening. The same type of production (shape of curve, Figure 10) is expected from wells placed in grid patterns since overlapping drainage areas must occur. Current research on spacing is being conducted so that the distance and time required for overlapping drainage to occur can be forecasted.



• COALBED GAS DRAINAGE BOREHOLE.

FIGURE 7.
EXPERIMENTAL
GRID PATTERN.

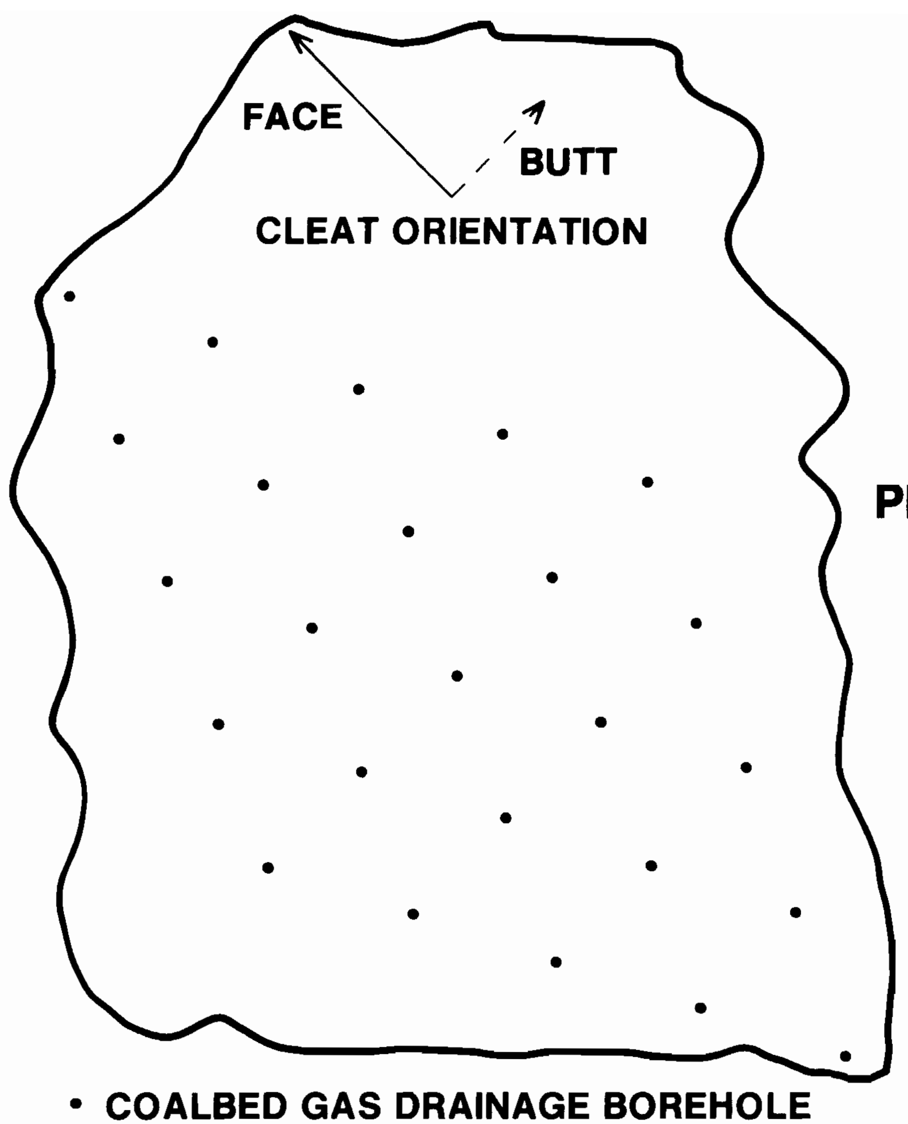


FIGURE 8.
PRODUCTION GRID PATTERN.

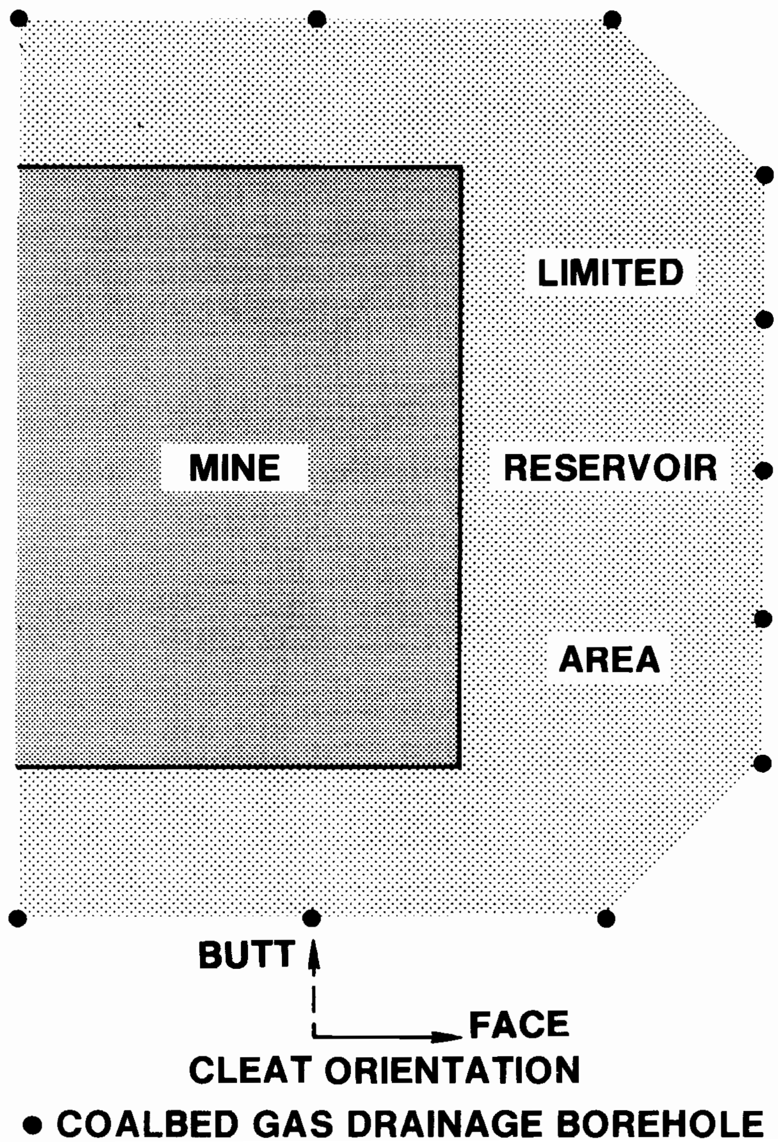
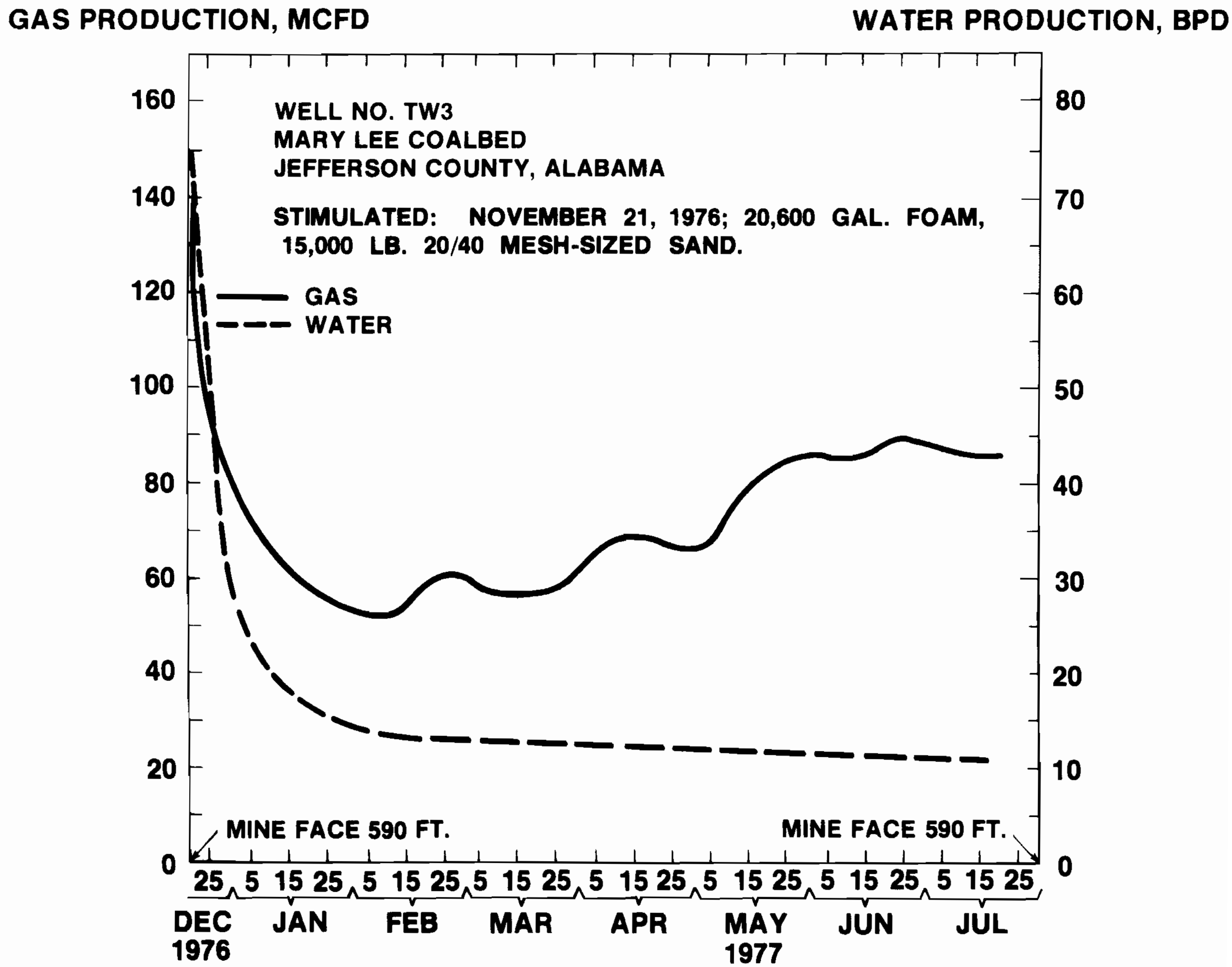


FIGURE 9.
BOREHOLE ARRANGEMENT NEAR MINE WORKINGS.

FIGURE 10. - PRODUCTION CURVES FROM A COALBED GAS DRAINAGE WELL PLACED NEAR MINE WORKINGS IN THE MARY LEE COALBED.



DRILLING

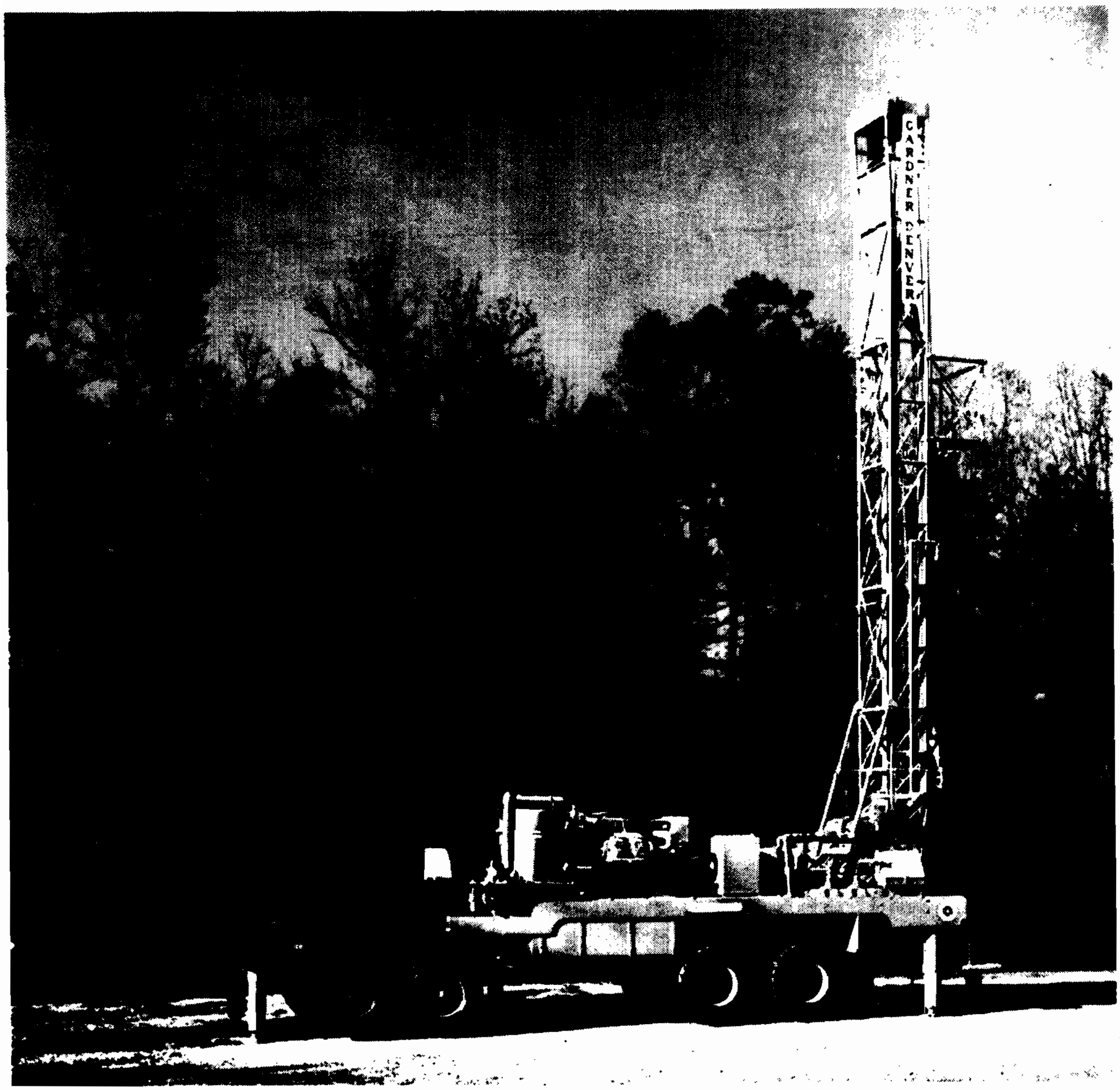
Degasification boreholes are normally rotary drilled using portable drilling rigs similar to that shown on Figure 11. Rigs capable of drilling with 4-1/2 inch diameter drill pipe to depths up to 2,500 feet have been used most extensively. These rigs are usually equipped with an air compressor and a water or mud pump.

Drilling operations have utilized air, mist, water, foam, or mud as a medium to carry rock cuttings to the surface. In order to minimize the possibility of coalbed permeability damage by infiltration of drilling fluid, more recent operations have strictly avoided the use of drilling muds except where they were considered absolutely essential. Air, or light foam, are the most desirable drilling mediums used today since they guard against permeability damage and increase drilling speed by reducing pore pressure at the bit/rock interface (17).

The type of bit used to penetrate coal strata is an important consideration in drilling coalbed drainage holes. Coal, because it has a low mechanical strength, readily suffers formation damage and this reduces the permeability at the well periphery.

Tri-cone drilling bits were used almost exclusively during the early phases of experimental work. More recent work using air drilling techniques has enabled operators to use percussion type bits which easily penetrate the rock types encountered. Care must be taken, however, when using such high compression bits when drilling soft coal horizons because mechanically induced formation damage may occur. One practice has been to switch from a percussion bit to a tri-cone bit several feet above the expected coal-bearing horizon (23).

FIGURE 11. - TYPICAL SIZE AND TYPE OF DRILLING RIG USED TO ROTARY DRILL COALBED GAS DRAINAGE BOREHOLES.



LOGGING

There are two general methods used to obtain records or "logs" of the various rock strata penetrated by coalbed gas drainage boreholes. The first method is applied during drilling operations and involves the sampling of rock or formation fluid(s) and the measurement of penetration rates. The second method of logging boreholes is applied during any non-drilling phase of well development and includes the use of wire-line electrical logging equipment.

Depth and thickness of the coal units penetrated in boreholes are of primary concern to successful drilling projects. This information is vital for stratigraphic correlation purposes, well completion plans, and stimulation design. Rock cuttings and drilling timelogs, though helpful to the operator, are generally a poor substitute for the type of precise information usually required. Best results have been obtained from cores but these are quite expensive, especially when obtained from larger diameter boreholes. Geophysical logging is much less expensive and can be used to delineate coal zones less than a foot thick (34).

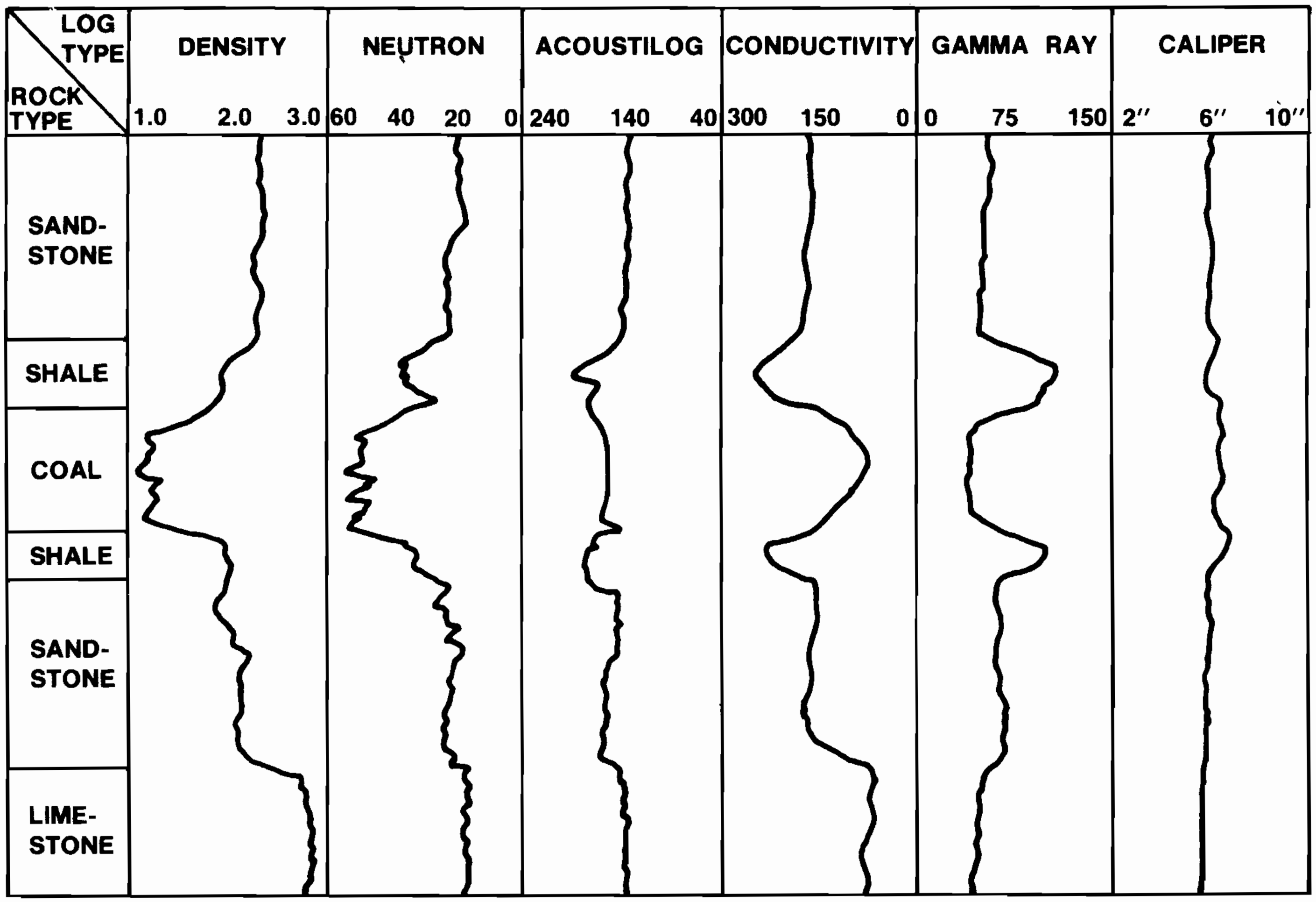
Geophysical logs which measure rock density are excellent for use in coal identification and are used most often in drilling projects (7), (14), (23). The relatively low bulk densities of coal cause distinctive log responses which are easily recognized. Such density logs are obtained for boreholes before they are cased.

Logging devices which measure levels of natural radioactivity are also used to record the presence of coal in a borehole. One such log uses a Gamma-Ray counting device usually run in an openhole along with a density tool. The Neutron log, a reasonably good indicator of coal, is a valuable tool used to locate coal zones after the borehole is cased. This becomes of major importance if several zones are to be exposed to the wellbore for gas drainage.

Determination of hole conditions is necessary to many well completion procedures including selection of casing equipment (packers, centralizers, baskets, etc.), and cementing operations parameters (slurry volume, type of cement required, necessary additivies). This is especially true when hole cavings and lost circulation problems are experienced during previous drilling operations. Although most geophysical logging tools respond to variations in borehole diameter, they do not give the precise quantitive information normally required. Therefore, a caliper device is usually run in an openhole hole along with the other logging tools. The caliper tool consists of spring loaded arms which ride along the walls of the hole. These springs are compressed, or extended by the variations in the hole size as the tool is raised and recorded on graphs at the surface.

There are several other types of logging devices available which, although not included in past work, may prove to be helpful in future projects. Figure 12 shows some of these logs along with the more traditional logs and each tool's response to coal and associated rock types.

FIGURE 12. - SEVERAL TYPES OF GEOPHYSICAL LOG RESPONSES TO COAL AND ASSOCIATED ROCK STRATA.



COMPLETION

Coalbed gas drainage boreholes are drilled or cored through one or several coalbed horizons. An additional length of borehole is drilled below the lowest coalbed to allow water and debris to collect in a sump below the coalbed.

Boreholes that drain gas from a single horizon are typically cased and cemented from immediately above the coalbed to the surface, as shown on Figure 13. This "openhole" type completion is accomplished using one of two methods. The first method is to drill the entire length of borehole; locate the coalbed using logging tools; and then set casing equipped with an expandable packer shoe, to just above the coalbed. The advantage of this type of openhole completion is that it allows the coal zone and the sump interval to be logged as well as the rest of the hole. A drawback to this method is that the packer used to seal-off the coal zone often fails, exposing the coal to cement. The second method is to drill to the top of the coalbed, set casing, and then cement. The remaining portion of the hole (the coalbed and sump) is then cored or drilled out. Since it is not possible to log the coalbed interval, this method should be used where stratigraphic control is suitable to locate casing within a few feet of the top of the coalbed, as would be the case for a well pattern or wells placed near mining. This method is simple in that it does not rely on a packer; and it effectively prevents damage caused by cementing. An added benefit is that coal samples can be retrieved for "direct method" gas content testing (21) and/or determination of various physical and chemical properties of the coalbed.

Casing may be set through several coalbeds along the full depth of the borehole. Production is then accomplished through openings which are either cut or shot through the casing at each coalbed horizon. This manner of completion allows any number of selected horizons to be produced simultaneously (Figure 14). One disadvantage of this method is that coals are directly exposed to cement and require the use of light weight, low fluid-loss cementing materials which are relatively expensive. Costs also increase as extra well services may be necessary to remove the cement damage.

Experience has shown that coalbeds drain gas most successfully when exposed to the wellbore using an openhole method of completion. This type of completion provides the maximum exposure to production of water and gas with minimal chance of formation plugging by invasion of well cement. Openhole completion also provides the least interference with underground mining operations since there is no steel casing present in the coalbed to be intercepted. At wells where more than one zone is produced, however, several coal horizons may have to be completed through the casing. The practicality of openhole completion also becomes limited if the coal zone to be produced is exceptionally thick and/or if it is prone to caving.

FIGURE 13. - SINGLE-HORIZON (OPENHOLE) COMPLETION

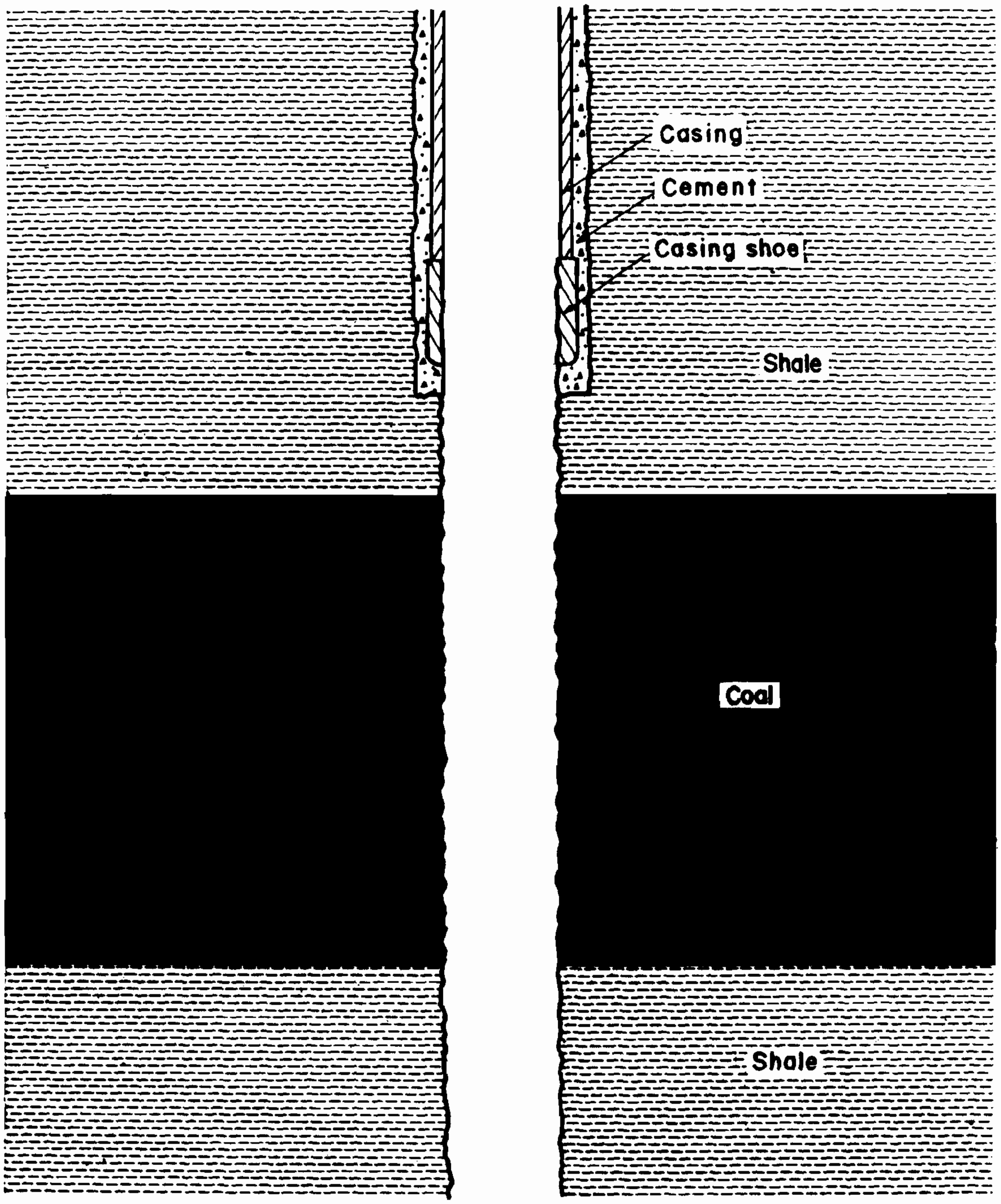
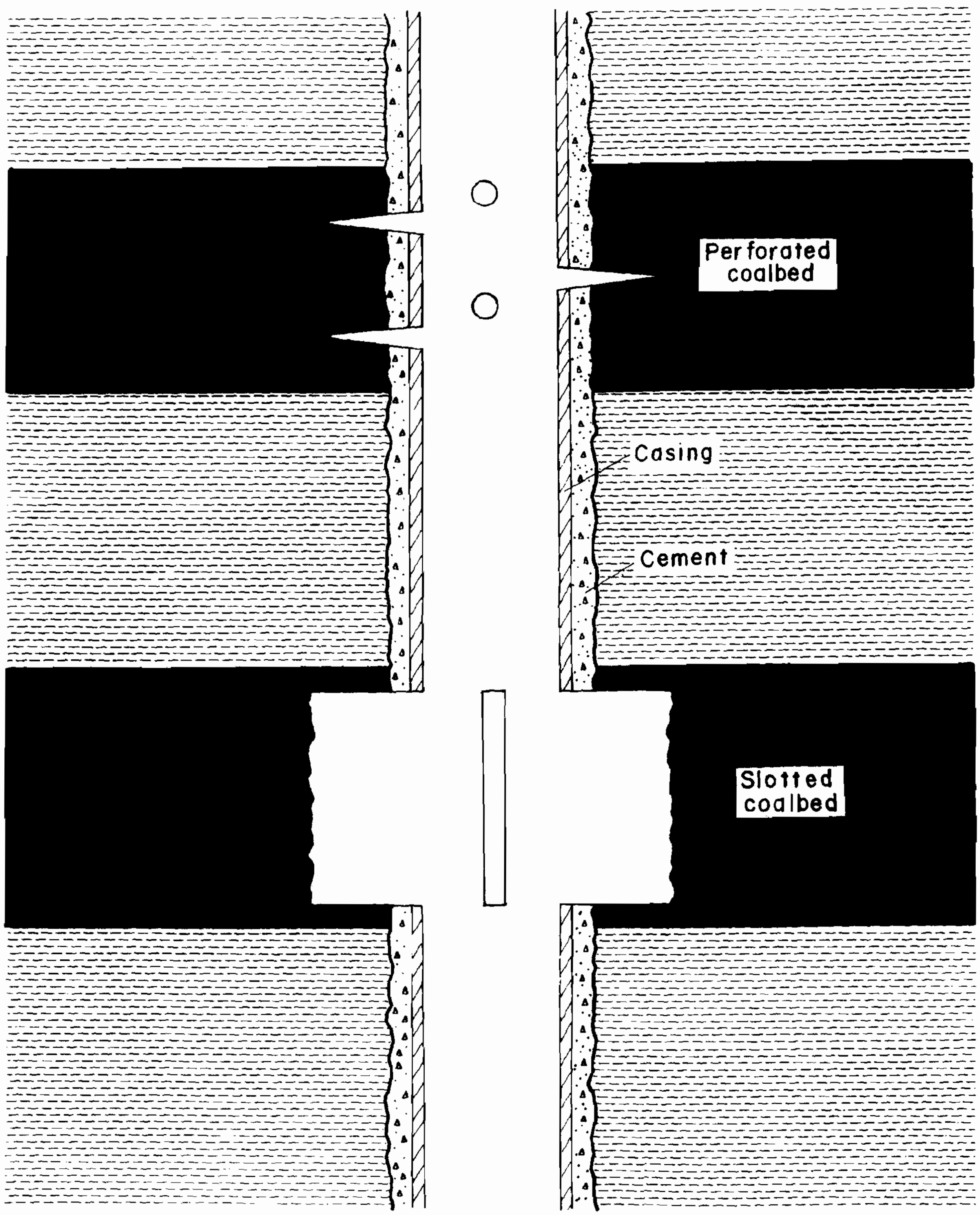


FIGURE 14. - MULTIPLE-HORIZON (THROUGH CASING) COMPLETION.



Government research has tested two completion techniques used to expose coalbeds through casing: perforating using shaped charges; and cutting vertical slots using jetting equipment.

The perforating technique has been used to produce gas from 15 different coalbeds. At least a dozen of these coalbeds have been hydraulically stimulated with treatment volumes ranging from 5,000 gallons to over 55,000 gallons. Nevertheless, in all cases tested, production from perforated wells has been significantly lower than the production measured from wells which were openhole completions.

Partial plugging of perforations is thought to be a major cause for the comparatively low flows measured at wells completed through casing in this manner. The materials responsible for such flow restrictions may be solid rock particles contained in most wells (24), or heavily gelled frac fluids which have failed to "breakdown" after stimulation (23, 15).

Another reason for poor production from perforated wells is that even though several openings are created, only a few may have a direct connection with the fracture induced as a result of well stimulation. In one particular case studied, a test wellbore's connection with the induced fracture was limited to the extreme lower portion of the coalbed (23). Since water drained to lower horizons of the coalbed and desorbed gas (free gas) accumulated in the upper horizons against overlying impervious shale rock, the test well could only produce gas when gas pressures temporarily exceeded water pressures, or when the coalbed became totally "dewatered". Similarly, a wellbore with direct communication to only the upper portion of the coalbed could not be expected to provide much gas because the dewatering process would be hindered.

Jet slotting is thought to be a viable alternative method to gun perforating wells through casing. This technique incorporates a two to four jet nozzle slotting tool which is lowered down the well on small diameter high-pressure tubing. Slots are then cut by pumping sand-laden foam or water down the tubing and through the jetting device. As the abrasive mixture is pumped, the tubing string is moved up and down cutting a number of vertically oriented openings through the casing.

Since slots are cut vertically to expose the entire coalbed thickness, it is very likely that all the induced vertical fractures will have a direct and continuous connection to the wellbore. The coalbed, therefore, can be drained more efficiently than could be expected using perforations. In addition, although the possibility of partial plugging of slots exists, it is much less likely than with perforations, because slotting creates a much larger opening. The area exposed by four slots 1/4 inch wide along a five foot interval, for example, is equal to about 300 1/2 inch diameter gun or shot perforations or approximately 60 perforations per foot. An added benefit to slotting is that the technique removes any cement adjacent to the production opening and leaves a clean, notched (penetration measured to be 12 to 15 inches) zone that is highly suitable for stimulation.

GENERAL METHOD OF REMOVING AND MEASURING WATER

The removal of water from coalbed strata is crucial to any successful borehole degasification field operation, yet little has been accomplished in the area since 1970 when Elder recognized a need for continuous long-term pumping (13). The pump equipment prescribed at that time and the standard equipment used at the present has not changed noticeably. This should not suggest that the borehole water removal system used in the last 10 years is either recommended or even adequate, especially for today's higher rate, multizone completed wells. The basic downhole plunger pump/surface rocker arm system has, however, proven to be a relatively effective, inexpensive, and durable off-the-shelf item that is highly suited for most shallow, single zone well completions.

Water drained from exposed formations collects in the borehole sump and is removed using a sucker-rod pump. Water is then brought up through the holes via production tubing, normally 1½ to 2-3/8 inches in diameter. On the surface, the water is then piped through a positive-displacement meter and measured. The mechanical configuration used to drain water from coalbed gas drainage boreholes was adapted from oil field applications and has proven to be effective when water drainage is less than 200 bpd.

A timing mechanism is sometimes installed within the electric power circuit to the pump motor which automatically controls pumping intervals. In this manner, a pump may be preset to operate during designated intervals of each 24 hour period.

WATER PRODUCTION MONITORING PROBLEMS

Solids in waterlines have caused significant meter inaccuracies and pump malfunctions. Freezing temperatures have resulted in loss of water production data and permanent damage to wellhead equipment, pipes, and meters. Improper pumping intervals have allowed water to rise in boreholes to levels above the coalbed, and reduce gas production; or have allowed water to fall to the pump horizon, and resulted in excessive wear of equipment. Such water-related problems result in higher maintenance costs in terms of meter repair, rig time, and number of manhours prescribed to insure proper well operation.

Solids in Waterlines

Water produced from boreholes, especially during early stages of production, normally contains some coal or other rock fines. Scale resulting from oxidation of casing and tubing is another common solid in the water produced. If formation water contains large percentages of salts, precipitates may form in surface flow lines and increase the total solids in the water.

Except for very large particles, most solids pass through the water production and monitoring system without difficulty. The solids remaining in the system usually accumulate in the housing chamber of the water meter, impairing and eventually stopping the measuring mechanism. At some wells, however, meters repeatedly malfunction within several days after meter installation.

Rock material sometimes becomes lodged in valve openings in the downhole pumping mechanism. Usually this material is coal or shale that has sloughed-off formations exposed in the wellbore. Pump stoppage due to lodging of this material is most likely to occur during the first few days of production and especially after the well has been stimulated.

Freezing

Wellbore water sometimes freezes inside surface lines, restricting flow and causing leakage. Extended freezing weather conditions result in permanent damage to wellhead equipment, pipes, and meters.

Gas-producing coals are normally several hundred feet deep, and the water drained is usually warm compared with winter surface temperatures. If pumping is controlled by a timing mechanism, there are periods when no water moves through surface lines. Water remaining in the lines during these periods cools rapidly and may freeze.

Improper Pumping Time Interval

To achieve maximum gas production from coalbed gas wells, borehole water levels must be kept below the lowest producing coalbed. This is accomplished by either operating the pumps continuously, or time-cycling pumps to operate for certain intervals each day.

Continuous pump operation over extended periods (months) may result in excessive wear of moving parts within the motor and the pump jack. Downhole pump components may also be worn quickly, especially when borehole water has been lowered to the pump horizon causing a dry or semidry condition.

Wells equipped with a timing mechanism to control pumping time intervals should be adjusted as changes occur in water flow to the wellbore. At many well sites, pumping times are improperly set. In some cases the time is too long, causing excessive pump wear. Where the time is too short, the fluid level is constantly above the coalbed, thus limiting production.

Gas in Waterlines

Gas passing through positive-displacement water meters is measured as water and may account for significant errors in production records. Such errors are found to be very common. At some wells, gas accounted for up to 75 percent of the metered water volume. Gas enters water flow lines in the dissolved state (as minute bubbles of gas coming out of solution) or as free gas drawn directly into lines by the downhole pump.

The solubility of coalbed gas increases directly as pressure increases, and diminishes as temperature increases. As much as four cubic feet of gas can be dissolved in one barrel of water (42 gallons) at a depth of 1,000 feet, based on a hydrostatic pressure of 443 psig and a formation temperature of 100° F (40). As the pressure gradient is reduced around a wellbore, some of the dissolved gas comes out of solution and is produced through gas flow lines; however, a percentage of the dissolved gas remains in the water as it is pumped. This gas comes out of solution while being brought to the surface and is measured through the water meter. Field tests to determine the degree of meter error resulting from such dissolved gases have been conducted at several wells. At the start of the tests, borehole water levels were known to be at a static level well above the downhole pump horizon, preventing large quantities of undissolved gas from entering waterlines. The meters were checked for accuracy before and after these tests. Results indicate that dissolved gases account for 10 to 23 percent errors in measurements of water production.

Improper cycle settings or continuous pump operations which lower water level in a borehole to the downhole pump horizon cause gas to be drawn directly into waterlines, pumped to the surface and result in large errors in metered water measurements. Tests conducted at wells where fluid levels were known to be at or near the base of the downhole pump show meter readings from 20 to 75 percent greater than the actual volume of water removed.

IMPROVED METHODS FOR MONITORING WATER PRODUCTION

Gas contained in waterlines can be removed before water is metered by incorporating a 30 to 50 gallon capacity, vented separation tank in the surface water flow system. Such tanks have been tested at several producing wells where gas in waterlines had severely decreased meter accuracy. After the tanks were installed, meter accuracies increased to over 98 percent in all cases. The suggested position and installation design suitable for use at coalbed gas wells is shown on Figure 15.

Most large pieces of solid debris carried through waterlines settle in the separation tank. The remaining solids, suspended in the flow system can be taken out of the water with a dirt-and-rust water filter installed downstream from the separation tank (Figure 15). The type of filter used at testwell sites is a small plastic unit with a 3/4 inch diameter connection and a replaceable filter cartridge.

Downhole pump stoppage from lodging of large pieces of coal or other rock material can be avoided by installation of screens at the lower end of the water production tubing (Figure 16). Stainless steel screens identical to those used in the water-well industry have been used successfully in many of the wells completed.

Cycled pumping, if properly maintained, is effective in controlling borehole water levels without causing unnecessary wear of equipment. Pump cycles must, however, be checked frequently and reset with every significant change in water production if optimum benefits are to be realized.

One system that automatically controls pumping intervals to maintain water level below the coalbed is being tested at several well sites. Two electrode wires are fastened to the water tubing; one near the bottom of the hole in the sump and the other just below the base of the coalbed. When the borehole water level rises to the top electrode, a circuit is completed that activates the pump jack motor (Figure 16). Water continues to be pumped from the well until the fluid level drops below the lower electrode. This system eliminates the frequent need to monitor fill-up rates and the possibility of drawing large volumes of gas through waterlines because the downhole pump is always submerged in fluid.

An alternative method to cycled pumping involves the use of a variable speed control on the pump. After the borehole water has been lowered to the pump horizon, pump speed is reduced so the fluid level is held constant. Periodic checks for changes in the well's gas productivity would then indicate a need to change the pumping speed. After shut-in periods or maintenance, the pump is adjusted to full capacity to dewater the wellbore more rapidly.

FIGURE 15. - SURFACE WATER-PUMPING AND MONITORING EQUIPMENT.

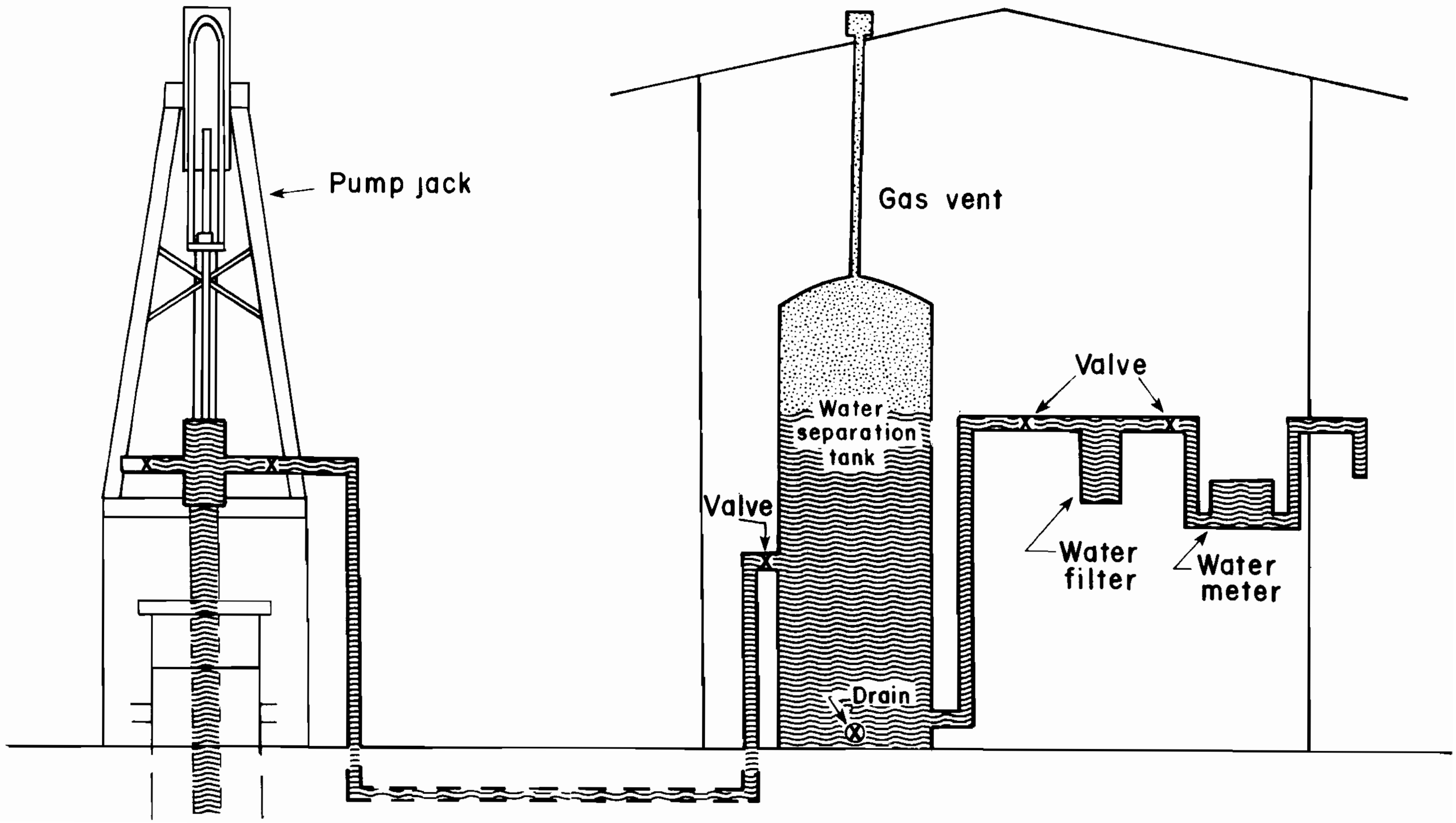
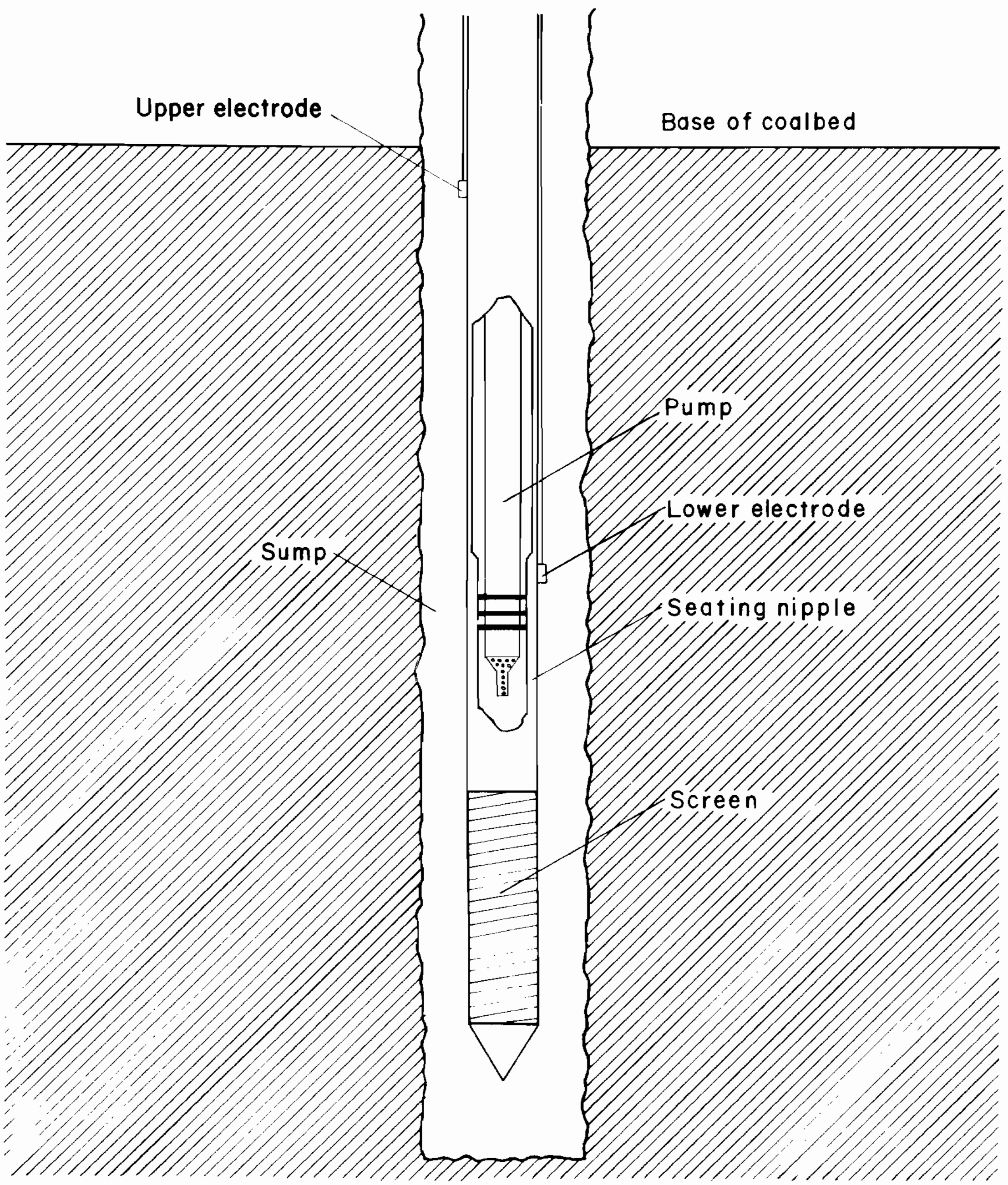


FIGURE 16. - SUBSURFACE WATER-PUMPING EQUIPMENT



To prevent freezing, surface waterlines are wrapped with heat tape and then covered with insulation. In areas where severe and prolonged low temperatures are common, waterlines are buried below the frostline. In addition, meters, water filters, and separator tanks should be contained in small, insulated meter houses. Heat lamps, installed in these houses, have proven to be a simple, effective, and inexpensive preventative against freezing. (All houses should be ventilated to some degree, especially those which use heat lamps.)

GENERAL METHOD OF REMOVING AND MEASURING GAS

Gas from coalbeds is produced through the annular space between the water production tubing and borehole casing. Wells are normally produced under minimum back-pressure in order to optimize coalbed gas desorption and water drainage. Once gas reaches the surface, it is piped through a positive-displacement meter where it is measured. Three types of meters have been used to measure coalbed gas production, depending on the volumes of gas produced. Diaphragm meters are normally used on nonstimulated wells that produce less than 10,000 cfd at STP. A common kind of meter used to monitor gas flow from stimulated wells is the rotary meter with a measuring capacity of about 84,000 cfd at STP. Four inch turbine meters are used to monitor flows of over 84,000 cfd at STP.

GAS PRODUCTION MONITORING PROBLEMS

Gas produced from coalbeds contains water vapor that condenses and collects along various points in the gas line, including the meter. Field studies indicate that water build-up decreases meter accuracy and, in many cases, permanently damages working components. The effects of even small quantities of water in gas lines are most pronounced during periods of freezing weather. Sudden pressure release after wells have been shut-in results in temporary, large-volume gas flows usually greater than can be accurately measured by the gas meter. Rock fines accumulate within the gas meter over time, but solids build-up accelerates if excessively high gas volumes are allowed to flow through lines.

Water in Gas Lines

As warm coalbed gas is cooled at the surface, some of its ability to carry moisture is lost; therefore, condensation occurs. The water condensate accumulates at low points along the pipeline and in metering devices. The problem occurs frequently during winter months when differences between gas temperature and surface temperature are the greatest.

Reduction of gas flow velocity also causes water to separate from gas; this occurs in areas where pipe diameter increases, providing favorable sites for liquid accumulation.

Finally, water is stripped from the gas stream at angled sections along flow lines and at meter locations where there is turbulent flow resulting from the collision or impingement of gas against pipe walls or meter chambers, causing moisture to be condensed from the gas.

Freezing

The problem of water in gas lines is greater during periods of low temperature because conditions for condensation are intensified. The problem becomes acute when temperatures drop below freezing. Even small amounts of ice in gas flow lines cause back-pressure, and result in apparent low coalbed gas production. Formation of ice in gas meters has damaged many of these instruments since the Government first began its coalbed gas-drainage program several years ago.

Sudden Pressure Release

Sudden, uncontrolled release of gas pressure has been a major cause of meter inaccuracies and has resulted in severe meter damage on many occasions.

Gas flows from wells are shut-off routinely for pipe or meter maintenance, or to test for pressure buildup. During these periods, gas continues to flow from the coalbed, building pressure in the wellbore. When the pressure is released quickly, a sudden surge of gas, or pressure wave, strikes the meter. Diaphragm meters are especially vulnerable to this surge and are almost always damaged. Rotary and turbine meters, although not damaged as easily, have been rendered inoperable by sudden surges of pressure.

Although damage to the meter may not occur, significant errors have resulted from recording measured gas volumes during a period of gas pressure release. When gas is moving under pressure, more volume (at standard temperature and pressure) passes through the meter than is actually indicated on the meter index. If the necessary correction multipliers for gas flow under pressure are not applied, incorrect volume measurements result.

Sudden pressure release has occurred at several wells simply because water was allowed to buildup in the wellbore. Normal pumping operations may be temporarily interrupted for a number of reasons, such as electric power failure, mechanical malfunction, or general maintenance. As the liquid level rises, gas production to the surface decreases in proportion to the increasing hydraulic pressure exerted on the coalbed. Field studies suggest, however, that gas continues to accumulate close to the wellbore, building pressures similar to those exerted by the increasing hydraulic head. Once pumping is resumed and the borehole water level is lowered, a disequilibrium is created in which gas pressure in the coalbed exceeds hydraulic head. As a result, sometimes violent eruptions of water and gas occur at the surface as large volumes of expanding gas travel up the wellbore to reestablish a pressure equilibrium. Sudden gas pressure release of this nature is referred to as "unloading."

Solids in Gas Lines

Particles of rock or other solid material accumulate in most gas meters over extended periods of time under normal flowing conditions. If left unchecked, solids cause malfunctions in all types of meters. Field experience indicates that rotary meters are the most susceptible to malfunction caused by solids because of the close tolerance between components of the rotating cartridge. Diaphragm meters usually do not stop functioning with small amounts of solids buildup, but meter accuracy diminishes as portions of the meter's measuring reservoir is filled with solids. Turbine meters will normally allow very small (less than one millimeter in diameter) material to pass through inner mechanisms.

Larger solids are normally carried through gas lines when well pressure is suddenly released, especially when unloading occurs. Such solids almost invariably clog and usually damage inner meter components.

Commercially available filters have been designed to remove fine solid particles with very little pressure drop (0.5 psig or less), which makes them suitable for use on coalbed gas wells. Fiberglass is normally the filtering element used. At one test well equipped with such a filter, the gas meter operated for over one year without malfunctioning or losing accuracy. Suggested in-line placement of gas filters is indicated in Figure 17.

The moisture content of coalbed gas has to be sufficiently low to assure accurate measurement of gas flow. In addition, coalbed gas sold commercially must meet requirements specifically noted in purchase agreements which normally limit the water content to approximately seven pounds of water per million cubic feet of gas measured at standard temperature and pressure. During cold weather periods, test wells (ranging from 1,053 to 1,076 feet deep) have been found to contain from 31 to 103 pounds of water per million cubic feet of gas produced. 4/

Although gas line water condensate buildup has been a chronic problem at many vertical test wells, experimentation with water-gas separation devices has been limited because the gas produced has not been sold.

The basic means used to remove moisture from coalbed gas lines are cooling, absorption, and impingement (33). Devices used to remove liquid impurities are drips and separators.

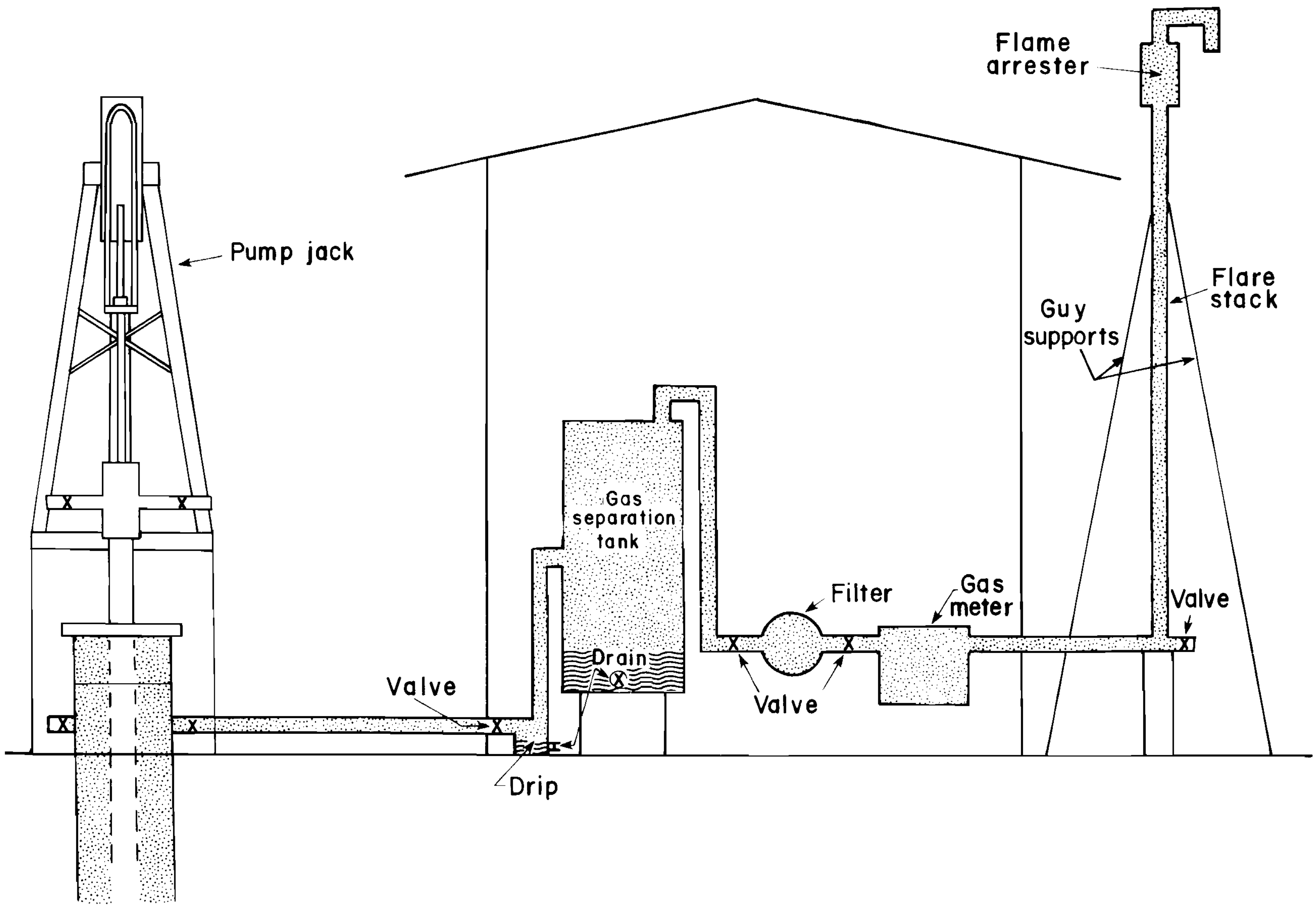
The basic function of a drip is to remove liquid from the gas stream or liquid that has accumulated within the pipeline. A drip catches liquid in a gas stream by reducing the velocity of the gas stream which causes the liquid to drop out. Liquid that has accumulated at low points within the pipeline is removed by use of a drip equipped with a drain which operates automatically or manually.

The primary function of a separator is to remove entrained fluids from the gas stream. Baffles, deflectors, tubes, rare elements, and gravity separation chambers are some of the mechanisms used within a separator device to remove moisture. There are several commercially designed separators that meet requirements for a single well for several wells in the same pipeline system.

Meter inaccuracy and possible meter damage caused by sudden pressure release can be avoided by allowing gas pressure to bleed off gradually while maintaining flow pressures within the given meter range. To do this, a pressure gage is installed in the gas flow line near the meter. Flow pressures are periodically recorded and are then put into a standard equation to calculate actual flow.

4/ Based on volumes of condensate accumulated in a flare stack similar to that shown on Figure 17.

FIGURE 17. - GAS PRODUCTION AND MONITORING EQUIPMENT



Sudden pressure releases that result in unloading can be avoided if a few precautionary steps are taken. These include restricting gas flow in order to build up pressure in the wellbore and then operating the pump under back-pressure conditions. This causes the borehole water level to fall leaving less water available to be unloaded. This also reduces the pressure differential between the coalbed and the wellhead thereby cushioning the effects of unloading. These methods have been field tested on several occasions and have proved to be very effective.

Ice formation in gas lines near the wellhead is prevented by properly insulating and heating meters and other points favorable to water accumulations (Figure 17). The number of routine field inspections of wells should be increased during especially cold periods to assure minimum condensate buildup. At the test wells examined, gas lines that had been wrapped with electric heat tape and covered with fiberglass insulation were rarely found to contain sufficient amounts of ice to cause significant back-pressure. In addition, well sites equipped with insulated meter houses containing heat lamps yielded accurate, uninterrupted production information, even during prolonged freezing weather.

THE COMPOSITION OF GAS AND WATER PRODUCED FROM VERTICAL BOREHOLES

Gas samples collected from 34 vertical boreholes were analyzed using gas chromatography. Table 1 presents the results of these analyses and identifies the coalbeds and well site locations where gas was sampled. Methane averaged approximately 96 percent while higher hydrocarbons, such as ethane and above, averaged 0.08 percent of the gas sampled. Hydrogen, helium, carbon monoxide, sulfur dioxide and other gases normally present in conventional natural gas are only rarely found in coalbeds and, therefore, not reported on Table 1. The percentage of nitrogen included in coalbed gas is considered to be generally lower than the amounts presented on Table 1 and any value over 2 percent is probably remnant gas from foam stimulation. The percentage of carbon dioxide contained in coal gas appears to vary considerably between different coalbeds and even within the same coalbed. Pittsburgh coalbed gas in Greene County, PA, for example, has a carbon dioxide content ranging from 3 to over 6 percent. On the other hand, Mary Lee coalbed gas in Jefferson County, AL, almost always contains less than 0.05 percent carbon dioxide.

The heat of combustion of coalbed gas similar in composition to these reported on Table 1 is comparable to the heat of combustion of natural gas, displaying gross heat values of 900 to 1,100 BTU/ft^3.

Water samples from boreholes located in several areas were also analyzed and the results of these tests are given in Table No. 2. As is illustrated, relative amounts of specific components vary considerably between the coalbeds tested.

TABLE NO. 1 - ANALYSES OF GAS PRODUCED FROM VERTICAL BOREHOLES

ID No.	Coalbed Name	Location County, State	Well Name	Depth to Coalbed ft.	Date Stimulated	Date Sampled	Frac Type**	% CO_2	% O_2 + Ar	% N_2	% CH_4	% C_2H_6
12	Beckley	Fayette, W. Va.	203-A	985	6/24/74	12/14/76	G	0.01	0.17	0.88	98.95	0.003
29	do	do	LR-6	656	9/14/76	12/14/76	do	0.03	0.06	2.56	97.2	0.15
11	Castlegate No. 3	Carbon, Ut.	3SW	1,017	4/28/74	----	do	0.0	0.0	0.41	99.0	0.4
9	Hartshorne	Le Flore, Ok.	5C	553	3/16/74	3/13/74	do	0.13	0.11	0.38	99.3	0.024
61	Jawbone	Dickenson, Va.	DG-1A	425	7/29/78	11/1/78	F	1.26	0.06	4.44	94.1	0.13
23	Mammoth	Schuylkill, Pa.	Parker #2	2,042	7/14/76	-----	do	ND	0.29	2.7	97.0	0.02
2	Mary Lee	Jefferson Ala.	3SW	1,076	2/28/73	12/12/75	do	0.082	0.22	3.1	96.5	0.038
19	do	do	TW-1	1,113	11/23/75	9/13/77	do	0.03	0.03	1.9	98.05	0.007
33	do	do	TW-2	1,093	10/24/76	12/8/76	do	0.02	0.13	0.81	99.05	0.007
44	do	do	9	1,082	7/26/77	9/13/77	CO_2/G	3.05	0.05	2.9	94.0	0.004
42	do	do	TW-4	1,065	7/18/77	do	F	0.02	0.05	1.0	99.0	0.007
43	do	do	22	1,096	7/19/77	10/16/77	do	0.06	0.08	4.41	95.45	0.005
36	do	do	TW-3	1,064	7/31/77	7/18/77	do	0.03	0.06	1.6	98.3	0.004
47	do	do	6	1,124	10/11/77	9/27/78	do	0.01	0.04	2.4	97.5	0.005
48	do	do	4	1,015	10/13/77	9/22/78	do	0.10	4.2	1.7	94.0	-----
49	do	do	8	1,071	10/14/77	9/27/78	do	0.01	0.06	2.1	97.8	0.003

*Well ID Nos. correspond to wells identified in Tables 2 and 3.
**G-Gel Frac, F - N_2 Foam Frac, CO_2/G-CO_2 Gel Frac, W-Water Frac

TABLE NO. 1 - ANALYSES OF GAS PRODUCED FROM VERTICAL BOREHOLES (Cont'd)

ID No.	Coalbed Name	Location County, State	Well Name	Depth to Coalbed ft.	Date Stimulated	Date Sampled	Frac Type**	% CO_2	% O_2 + Ar	% N_2	% CH_4	% C_2H_6
50	Mary Lee	Jefferson, Ala.	5	1,010	10/18/77	9/27/78	F	0.03	0.04	2.5	97.4	0.003
51	do	do	13	1,065	10/20/77	do	do	0.03	0.07	2.6	97.3	0.006
52	do	do	14	1,072	10/21/77	9/27/78	do	0.01	0.05	1.9	98.0	0.002
54	do	do	17	1,053	10/27/77	1/23/79	do	0.03	0.72	5.48	93.77	0.004
55	do	do	25	1,054	11/2/77	do	do	0.01	0.22	3.14	96.63	0.005
56	do	do	15	1,086	11/3/77	do	do	0.02	0.45	4.52	95.01	do
57	do	do	23	1,097	11/3/77	11/30/78	do	0.04	0.23	3.94	95.79	0.004
46	do	do	7	1,072	8/10/77	9/27/78	W	0.007	0.04	2.2	97.7	0.003
16	Middle Kittanning	Allegheny, Pa.	2	808	1/21/75	4/21/75	G	1.16	0.48	2.19	94.7	-----
3	Pittsburgh	Washington, Pa.	1NE	429	11/2/73		do	0.6	0.2	0.9	98.2	0.08
7	do	do	3SW	388	2/28/74	11/5/73	do	0.5	0.2	0.8	98.4	0.07
21	Pittsburgh	Greene, Pa.	EM-6	582	4/15/76	3/28/77	F	6.45	0.06	0.65	92.5	0.33
22	do	do	EM-1	635	6/1/76	do	do	5.9	0.55	0.67	92.5	0.38
24	do	do	EM-3	902	8/18/76	10/28/76	do	3.28	0.05	0.27	do	0.09
27	do	do	EM-5	764	9/1/76	do	do	5.01	0.63	1.20	92.86	0.30
28	do	do	EM-7	728	9/8/76	do	do	5.23	0.04	0.29	94.1	0.45
30	do	do	EM-8	646	9/15/76	do	do	4.18	0.04	0.29	95.32	0.16
39	do	do	CNG-1034	753	5/5/77		do	0.6	----	----	94.8	----

*ID Nos. correspond to wells identified in Tables 2 and 3,
**G-Gel Frac, F - N_2 Foam Frac, CO_2/G-CO_2 Gel Frac, W-Water Frac

TABLE NO. 2 - ANALYSES OF WATER PRODUCED FROM VERTICAL BOREHOLES

ID No.*	Coalbed Name	Location County, State	Borehole Designation	Depth to Coalbed, ft.	Date Sampled	pH	Alkalinity as $CaCO_3$ ppm	Dissolved Solids ppm	Calcium as $CaCO_3$ ppm	Magnesium as $CaCO_3$ ppm	Iron ppm	Sulfate as SO_4 ppm	Potassium as K ppm	Sodium as Na ppm	Chloride as NaCl ppm
12	Beckley	Fayette, W. Va.	203-A	985	5/4/76	7	420	1,241	35	1.25	<1	15	1.5	---	429
17	do	do	LR-4	1,217	5/4/76	7	650	1,303	20	1.84	<1	18	2.5	---	593
20	do	do	LR-3	1,193	5/4/76	7	590	1,040	15	0.80	<1	20	2.0	---	470
11	Castlegate No. 3	Carbon, Ut.	3SW	1,017	4/28/74	9.21	423	3,648	32	4	4	406	---	2,796	2,638
9	Hartshorne	Le Flore, Ok.	5C	553	-----	8.3	982	2,372	ND	6	7	ND	---	970	1,325
61	Jawbone	Dickenson, Va.	DG-1A	425	8/23/78	7	---	27,490	2,223	1,029	208	ND	---	8,100	---
23	Mammoth	Schuylkill, Pa.	Parker #1	2,042	-----	7.3	344	1,923	41	12	33	--	6	759	574
2	Mary Lee	Jefferson, Ala.	3SW	1,076	10/13/73	8.35	355	1,428	12.5	8	ND	ND	1	565	700
19	do	do	TW-1	1,113	1/15/76	7.9	---	---	52	3.34	1.0	--	--	1,120	---
44	do	do	9	1,082	10/16/77	7.4	1,533	1,972	92	222	0.4	ND	1.0	770	256
42	do	do	TW-4	1,065	10/17/77	9.0	400	1,118	15	2	0.3	ND	1	450	185
43	do	do	22	1,096	10/16/77	8.6	700	1,136	15	4	0.3	ND	1	460	643
36	do	do	TW-3	1,074	1/12/77	8.6	810	1,064	11	3	ND	ND	2	450	257
49	do	do	8	1,071	7/4/78	8.4	667	1,003	12	3	0.9	ND	0.7	367	275
50	do	do	5	1,010	7/4/78	8.4	660	1,121	12	4	0.4	ND	0.6	423	480
51	do	do	13	1,065	7/4/78	8.6	719	1,029	12	3.3	0.3	ND	0.6	373	216
16	Middle Kittanning	Allegheny, Pa.	No. 2	808	-----	6	415	62,700	2,300	9,200	30	115	ND	20,000	36,000
7	Pittsburgh	Washington, Pa.	3SW	388	-----	8.05	876	3,106	162	39	0.05	0	--	800	2,200
15	do	Marion, West Va.	4NW	911	-----	7.45	1,825	4,825	159	132	0.5	63	--	---	2,356

*Well ID Nos. correspond to wells identified in Tables 1 and 3.

TABLE NO. 2 - ANALYSES OF WATER PRODUCED FROM VERTICAL BOREHOLES (Cont'd)

ID No.*	Coalbed Name	Location County, State	Borehole Designation	Depth to Coalbed, ft.	Date Sampled.	pH	Alkalinity as $CaCO_3$ ppm	Dissolved Solids ppm	Calcium as $CaCO_3$ ppm	Magnesium as $CaCO_3$ ppm	Iron ppm	Sulfate as SO_4 ppm	Potassium as K ppm	Sodium as Na ppm	Chloride as NaCl ppm
21	do	Greene, Pa.	EM-6	582	2/16/78	7.42	---	7,222	544	181	7.5	ND	---	---	5,842
	do	do	EM-4	843	3/29/77	----	---	15,200	78	94	37	ND	---	---	2,310
	do	do	EM-8	646	3/30/77	----	---	17,700	18	108	64	ND	---	---	2,210
1	Pocahontas No. 3	Buchanan, Va.	Fed. No. 1	1,524	------	4.8	---	186,986	34,375	917	164	ND	---	---	138,000

*ID Nos. correspond to wells identified in Tables 1 and 3.

INTRODUCTION TO WELL STIMULATION

Introduced in 1948 (19), hydraulic stimulation has become a common technique used to increase well productivity when natural flow from the well is unsatisfactory. Based on methods developed by the oil and gas industry, Government research began designing stimulation treatments for coal gas drainage about 1969. Since then, over 60 treatments have been applied to coalbeds in several areas of the United States, especially to the deep mineable coals in the East.

The basic mechanics of stimulation are quite simple. Hydraulic pressure is generated at the surface by pumping fluid. This pressure is transmitted to a selected rock strata (coalbed) to cause a fracture or a widening of an existing fracture within that strata. After this initial fracturing occurs, it is extended into the coal strata by continued injection of fluid. At some pre-established time during the treatment, sized particles, such as sieved sand, are normally added to the fluid. These particles serve as a propping agent to hold the fracture open after the hydraulic pressure is released. The intent of stimulation is to create highly conductive pathways from the wellbore to several hundred feet within the coalbed. The area of drainage to the wellbore is thus expanded and gas and water flow rates increase accordingly.

Government researchers have generally categorized stimulation treatments according to the type of fluid used to transmit the hydraulic pressure from the surface to the coal zone. Water, gelled water, and foam are the major types of treatments tested thus far, each type having demonstrated distinct advantages as well as specific limitations. Table 3 summarizes the Government's research experience with stimulation and, in many instances, shows the gas drainage rates achieved from this experimental work.

Table 3 - Summary of Government-sponsored Coalbed Stimulation Treatments
Conducted from July, 1970 to December, 1979

ID No.	Date Stimulated	Coalbed Name	Location County, State	Well Name and/or No.	Depth to coalbed, ft.	Coalbed Thickness, ft.	Type of Stimulation Treatment	Volume Treatment Fluid, gal.	Sand Proppant Mesh Size and Weight, lbs.	Breakdown Pressure, psig	Treatment Pressure, psig	Injection Rate, bpm	Production: Pre-Stimulation cfd	Production: Post-Stimulation cfd	Remarks
1	July 9, 1970	Pocahontas No. 3	Buchanan, Va.	Federal No. 1	1,524	4.5	Gel	14,800	10 to 20 4,000	3,200	3,500	10.4	600	12,000	Screen-out, flowback successful, treatment completed.
2	June 28, 1973	Mary Lee	Jefferson, Ala.	No. 3SW	1,076	5.0	do	10,000	10 to 20 6,000	800	1,150	10.0	5,000	50,000	
3	November 2, 1973	Pittsburgh	Washington, Pa.	No. 1NE	429	4.0	do	10,200	do	500	1,500	11.4	6,600	25,000	Screen-out, flowback successful, treatment completed.
4	February 16, 1974	do	do	No. 2SE	386	5.5	do	7,800	10 to 20 4,000	800	1,460	11.0	2,200	18,000	do
5	February 19, 1974	Illinois No. 6	Jefferson, Ill.	No. 1NE	732	9.0	do	12 000	10 to 20 6,400	1,000	900	10.0	200	4,300	Intercepted by mining May, 1974 Measured 416 ft. of induced fracture.
6	February 22, 1974	Pittsburgh	Washington, Pa.	No. 5C	529	5.7	do	13,400	10 to 20 4,500	500	1,310	10.1	4,500	20,000	Screen-out, flowback successful, treatment completed.
7	February 28, 1974	do	do	No. 3SW	388	5.3	do	14,500	10 to 20 8,000	do	1,290	9.6	500	17,000	do
8	March 10, 1974	Pocahontas No. 3	Wyoming, W. Va.	No. 2SE	731	4.0	do	13,300	10 to 20 5,000	1,200	2,000	8.0	1,000	9,000	
9	March 16, 1974	Hartshorne	Le Flore, Ok.	No. 5C	553	do	do	12,000	do	800	1,200	12.0	do	8,200	Screen-out, flowback successful, treatment completed.
10	April 17, 1974	Pittsburgh	Washington, Pa.	USBM No. 4	588	6.0	do	7,300	10 to 20 3,500	500	1,590	10.5	not produced	not produced	Intercepted by mining June 12, 1974 Measured approximately 35 ft. of induced fracture.
11	April 28, 1974	Castlegate Subseam No. 3	Carbon, Ut.	No. 3SW	1,017	do	do	10,400	10 to 20 6,000	1,200	2,600	8.0	<100	1,000	
12	June 24, 1974	Beckley	Fayette W. Va.	No. 203-A	985	5.0	do	14,300	10 to 20 5,000	500	1,800	11.4	not produced	9,000	Screen-out, flowback successful, treatment completed.
13	November 15, 1974	do	do	do	do	do	do	21,250	20 to 40 10,000	2,200	2,500	11.0	9,000	9,000	Restimulation
14	November 27, 1974	Pittsburgh	Marion, W. Va.	No. 3SW	840	5.5	do	15,000	20 to 40 5,000	1,900	1,950	11.1	250	17,000	
15	December 20, 1974	do	do	No. 4NW	911	do	do	25,000	20 to 40 10,000	1,400	2,100	10.5	7,000	27,000	

TABLE 3 - Summary of Government-sponsored Coalbed Stimulation Treatments Conducted from July, 1970 to December, 1979 (cont'd)

ID No.	Date Stimulated	Coalbed Name	Location County, State	Well Name and/or No.	Depth to Coalbed, ft.	Coalbed Thickness, ft.	Type of Stimulation Treatment	Volume Treatment Fluid, gal.	Sand Proppant Mesh Size and Weight, lbs.	Breakdown Pressure, psig	Treatment Pressure, psig	Injection Rate, bpm	Production: Pre-Stimulation cfd	Production: Post-Stimulation cfd	Remarks
16	January 21, 1975	Middle Kittanning	Allegheny Pa.	No. 2	808	4.5	Gel	30,000	10 to 20 20,000	2,400	1,500	13.2	not produced	1,350	Gel material produced with water. Completed Through Perforations
17	November 5, 1975	Beckley	Raleigh W. Va.	No. LR-4	1,217	4.0	do	6,000	20 to 40 4,000	2,600	2,300	9.3	do	not produced	Screen-out, treatment aborted.
18	November 6, 1975	do	do	do	do	do	do	13,700	10 to 20 4,500 20 to 40 2,500	do	2,600	11.4	do	2,800	Restimulation
19	November 23, 1975	Mary Lee	Jefferson Ala.	No. TW-1	1,113	5.5	do	6,000	20 to 40 2,500	1,780	1,160	10.5	do	6,000	Intercepted by mining. No treatment induced fracture found.
20	January 19, 1976	Beckley	Raleigh W. Va.	No. LR-3	1,193	5.0	do	14,300	20 to 40 10,000	2,800	2,400	12.0	do	2,000	
21	April 15, 1976	Pittsburgh	Greene Pa.	No. EM-6	582	6.0	Foam	29,200	20 to 40 14,000	950	1,500	17.7	do	68,000	Intercepted November 9, 1978. Measured 20 ft. of frac. Screen-out, treatment aborted.
22	June 1, 1976	do	do	No. EM-1	635	do	do	33,000	20 to 40 12,500	600	1,400	11.2	do	11,000	Screen-out, flowback successful, treatment completed.
23	July 14, 1976	Mammoth	Schuylkill Pa.	Parker No. 2	2,042	10.0	do	14,600	20 to 40 8,600	3,700	4,000	8.8	do	not available	Multiple-zone completion, production from single coalbed not determined.
24	August 18, 1976	Pittsburgh	Greene Pa.	No. EM-3	902	6.0	do	25,300	20 to 40 11,000	8,000	1,600	11.2	do	23,000	Screen-out, flowback successful, treatment completed.
25	August 25, 1976	do	do	No. EM-4	843	do	do	39,000	20 to 40 10,000	950	1,300	10.8	do	16,000	
26	August 28, 1976	Holmes	Schuylkill Pa.	Parker No. 2	1,867	12.0	do	14,100	20 to 40 6,900	3,200	2,500	6.0	do	not available	Screen-out, treatment aborted. Completed Through Perforations
27	September 1, 1976	Pittsburgh	Greene Pa.	No. EM-5	764	6.0	do	31,500	20 to 40 10,000	800	1,400	11.6	do	100,000	Intercepted July 21, 1978. Measured 150 ft. of induced fracture.
28	September 8, 1976	do	do	No. EM-7	728	do	do	29,000	20 to 40 7,400	do	do	10.8	do	87,000	Intercepted December 1, 1978. Measured 80 ft. of induced fracture. Screen-out, treatment aborted.
29	September 14, 1976	Beckley	Raleigh W. Va.	No. LR-6	656	5.0	do	16,800	20 to 40 15,000	600	1,500	12.0	do	15,000	
30	September 15, 1976	Pittsburgh	Greene Pa.	No. EM-8	646	6.0	do	42,600	20 to 40 12,800	800	1,100	10.8	do	12,000	

TABLE 3 - Summary of Government-sponsored Coalbed Stimulation Treatments Conducted from July, 1970 to December, 1979 (cont'd)

ID No.	Date Stimulated	Coalbed Name	Location County, State	Well Name and/or No.	Depth to Coalbed, ft.	Coalbed Thickness, ft.	Type of Stimulation Treatment	Volume Treatment Fluid, gal.	Sand Proppant Mesh Size and Weight, lbs.	Breakdown Pressure, psig	Treatment Pressure, psig	Injection Rate, bpm	Production: Pre-Stimulation cfd	Production: Post-Stimulation cfd	Remarks
31	September 24, 1976	Holmes	Schuylkill Pa.	Parker No. 2	1,867	12.0	Foam	10,000	20 to 40 5,300	1,800	2,700	6.0	do	not available	Restimulation, multiple-zone completion. Production from single coalbed not determined.
32	October 15, 1976	Primrose	do	do	1,756	11.0	do	10,100	20 to 40 6,000	2,900	2,800	do	do	do	Multiple-zone completion, production from single coalbed not determined.
33	October 24, 1976	Mary Lee	Jefferson Ala.	No. TW-2	1,093	5.0	GEL	3,500	10 to 30 3,000 20 to 40 1,000	not observed	2,400	8.0	do	15,000	Screen-out, treatment aborted. Gel produced with water. Completed Through Perforations
34	October 27, 1976	Orchard	Schuylkill Pa.	Parker No. 2	1,585	10.0	Foam	8,100	20 to 40 3,000	3,200	2,800	6.0	do	not available	Multiple-zone completion, production from single coalbed not determined.
35	November 17, 1976	Diamond	do	do	1,371	6.0	do	10,100	20 to 40 3,000	4,300	do	do	do	do	do
36	November 21, 1976	Mary Lee	Jefferson Ala.	No. TW-3	1,074	5.0	do	20,600	20 to 40 15,000	800	1,400	10.0	do	70,000	Intercepted by mining on October 6, 1977 Measured 280 ft. of induced fracture.
37	November 27, 1976	Peach Mountain	Schuylkill Pa.	Parker No. 2	806	7.0	do	9,600	20 to 40 3,000	2,600	1,200	6.0	do	not available	Multiple-zone completion, production from single coalbed not determined.
38	November 28, 1976	Tunnel	do	do	602	10.0	do	10,100	20 to 40 3,000	2,500	1,900	do	do	do	do
39	May 5, 1977	Pittsburgh	Greene Pa.	No. CNG-1034	753	7.0	do	21,800	10 to 20 1,500 20 to 40 19,000	800	1,200	10.0	100	2,500	Casing set in coalbed
40	May 14, 1977	do	do	No. EM-31	713	6.0	Kiel*	54,600	20 to 40 10,000	not observed	do	19.0	not produced	70,000	Intercepted by mining
41	June 30, 1977	do	do	No. CNG-1035	674	6.0	Foam	12,000	20 to 40 12,000	500	1,200	10.0	400	4,500	Screen-out, treatment terminated.
42	July 18, 1977	Mary Lee	Jefferson Ala.	No. TW-4	1,065	5.0	do	12,200	20 to 40 2,500	700	1,400	do	not produced	100,000	Intercepted by mining on November 16, 1977 Measured 200 ft. of induced fracture.
43	July 19, 1977	do	do	No. 22	1,096	6.0	do	49,100	20 to 40 41,600	800	1,300	do	do	20,000	
44	July 26, 1977	do	do	No. 9	1,082	4.6	GEL-CO_2	56,400	20 to 40 15,500	not observed	1,700	10.1	do	10,000	Screen-out, treatment aborted. Gel produced with water. Completed through perforations.

TABLE 3 - Summary of Government-sponsored Coalbed Stimulation Treatments
Conducted from July, 1970 to December, 1979 (cont'd)

ID No.	Date Stimulated	Coalbed Name	Location, County, State	Well Name and/or No.	Depth to Coalbed, ft.	Coalbed Thickness, ft.	Type of Stimulation Treatment	Volume Treatment Fluid, gal.	Sand Proppant Mesh Size and Weight, lbs.	Breakdown Pressure, psig	Treatment Pressure, psig	Injection Rate, bpm	Production: Pre-Stimulation cfd	Production: Post-Stimulation cfd	Remarks
45	July 31, 1977	Mary Lee	Jefferson, Ala.	No. TW-3	1,064	3.0	Foam	5,000	20 to 40 glass beads 1,600	600	1,000	5.0	not produced	not available	Multiple-zone completion, single coalbed production not determined, Upper Bench stimulation. Completed Through Perforations
46	August 10, 1977	do	do	No. 7	1,072	4.6	Kiel*	79,900	20 to 40 25,000	not observed	1,100	19.5	do	235,000	
47	October 11, 1977	do	do	No. 6	1,124	4.7	Foam	46,200	20 to 40 37,000	800	1,000	10.0	do	74,000	
48	October 13, 1977	do	do	No. 4	1,015	5.1	do	50,400	20 to 40 45,400	do	1,100	do	do	122,000	
49	October 14, 1977	do	do	No. 8	1,071	4.8	do	do	do	do	900	do	do	106,000	
50	October 18, 1977	do	do	No. 5	1,010	5.1	do	do	do	do	1,000	do	do	53,000	
51	October 20, 1977	do	do	No. 13	1,065	5.0	do	do	do	do	do	do	do	80,000	
52	October 21, 1977	do	do	No. 14	1,072	5.1	do	37,800	20 to 40 21,400	do	do	do	do	110,000	Treatment terminated, communication with adjacent well
53	October 26, 1977	do	do	No. 24	1,077	3.9	do	49,100	20 to 40 43,500	900	1,100	do	do	46,000	
54	October 27, 1977	do	do	No. 17	1,053	5.1	do	48,700	20 to 40 43,300	800	1,200	do	do	94,000	
55	November 2, 1977	do	do	No. 25	1,054	5.2	do	do	20 to 40 43,500	do	1,100	do	do	78,000	
56	November 3, 1977	do	do	No. 15	1,086	5.7	do	50,400	20 to 40 45,800	do	do	do	do	71,000	
57	do	do	do	No. 23	1,097	4.9	do	51,200	20 to 40 45,200	900	1,300	do	do	100,000	
58	November 10, 1977	do	do	No. 18	1,022	4.4	do	55,300	20 to 40 43,500	do	1,600	do	do	37,000	
59	November 11, 1977	do	do	No. 3	1,099	4.9	do	47,000	20 to 40 40,100	800	1,100	do	do	172,000	
60	November 12, 1977	do	do	No. 16	1,045	5.7	do	37,800	20 to 40 22,300	do	1,250	do	do	92,000	Treatment terminated, communication with adjacent well.

TABLE 3 - Summary of Government-sponsored Coalbed Stimulation Treatments Conducted from July 1970 to December, 1979 (cont'd)

ID No.	Date Stimulated	Coalbed Name	Location County, State	Well Name and/or No.	Depth to Coalbed, ft.	Coalbed Thickness, ft.	Type of Stimulation Treatment	Volume Treatment Fluid, Gal.	Sand Proppant Mesh Size and Weight, lbs.	Breakdown Pressure psig	Treatment Pressure psig	Injection Rate, bpm	Production		Remarks
													Pre-Stimulation cfd	Post-Stimulation cfd	
61	July 29, 1978	Jawbone	Dickenson VA	No. DG-1A	425	5.0	Foam	35,300	20 to 40 28,000	1,000	1,100	16.0	not produced	30,000	
62	October 30, 1978	Seven Coalbeds	Westmoreland PA	WEC FFE No.4	490 - 657	7.3	Kiel*	94,500	20 to 40 26,000	not observed	3,000 (Avg)	26.0	not produced		Two zones treated through perforations
63	October 31, 1978	Five Coalbeds	Westmoreland PA	WEC FFE No.4	193 - 449	19.5	Kiel*	177,500	20 to 40 50,000	not observed	1,200	30.0	not produced		
64	December 16, 1978	Mary Lee	Jefferson AL	No. TW-5	1,145	5.5	Foam	53,000	0	1,000	1,600	4.5	not produced	45,000	Intercepted by mining, July 12, 1979. Underground study in progress.
65	May 24, 1979	Pittsburgh	Greene PA	EM-20	700	6.0	Foam	19,800	20 to 40 25,600	6,000	1,400	10.0	not produced		
66	August 20, 1979	Jawbone	Dickenson VA	No. DG-3B	444	6.0	Foam	29,400	20 to 40 15,600	800	800	12.0	not produced		
67	September 27, 1979	Jawbone	Dickenson VA	No. DG-4	430	5.0	Foam	29,400	20 to 40 15,800	900	1,000	10.0	not produced		
68	October 26, 1979	Pocahontas No. 3	Buchanan VA	VV-N No. 90	1,854	6.0	Foam	4,000	20 to 40 2,000	not observed	2,300	4.0	not produced	20,000	Small volume treatment due to close proximity to mining.
69	December 11, 1979	Pocahontas No. 3	Buchanan VA	VV-H No. 91	2,204	7.0	Foam	4,500	20 to 40 1,500	1,000	2,400	4.0	4,000	new well	Communication around packer; treatment aborted.
70	December 12, 1979	Jawbone	Dickenson VA	No. DG-2C	676	5.0	Foam	26,300	0	900	1,000	8.0	not produced		
71	December 12, 1979	Jawbone	Dickenson VA	No. DG-5D	673	5.0	Foam	24,400	20 to 40 14,200	700	1,000	10.0	not produced		

*Reference to specific trade names do not imply endorsement by the United States Government.

ROCK PROPERTIES AFFECTING STIMULATION

Natural Fracture System

Fractures, naturally present in coalbeds and associated rock strata, have an important affect on the stimulation process. The most prominent natural fractures in coalbeds are oriented perpendicular to coalbed bedding planes and are referred as "cleat" (28). Other fractures present in coal are inclined to bedding planes and are called "shear" fractures, implying some movement has taken place. During stimulation, treatment fluids typically propagate partings along one or two directions, cutting across many of these preexisting fractures. As these fractures are crossed, portions of the liquid contained in the main propagating treatment body "leak off" into these minute openings, leaving less liquid to carry the solid propping agent.

There is substantial evidence to indicate that the vertical partings created during stimulation propagate in directions nearly parallel to dominant preexisting coalbed cleat and roof rock joint directions (23) (26). Trevits and Lambert, (39), combined and presented results from underground examinations of stimulated boreholes (Table 4) and concluded that induced, vertically oriented partings will parallel natural fracture trends and can be predicted within 10 degrees azimuth. This correlation does not necessarily imply that induced fracture directions are controlled by natural fracture systems because the direction of stimulated partings must always be perpendicular to the least principle stress present in the area of a well (19). The relationship between induced and natural fractures does, however, indicate that the controlling stress conditions are reflected by the natural coal cleat and rock joint directions.

Mechanical Properties

The density, compressive, and tensile strengths of coal are very low compared with mine roof rock material which is usually shale or sandstone. If increasing hydraulic pressures were applied to all these materials simultaneously, coal, the least competent material, would "break" or fracture first. Further, if the coal is bounded by shale or sandstone, the fracture would be contained completely in the coal as long as hydraulic pressures did not exceed the mechanical "breakdown" properties of the surrounding stronger rock type(s).

Borehole Rock Conditions

Unfortunately, the above concept of rock breakage does not necessarily apply to actual borehole rock conditions. Before hydraulic pressure is applied to any given section of a wellbore, there already exist many vertical fractures in the form of coal cleat or rock joints.

Where these fractures are present, the rock's tensile strength is effectively zero, regardless of the type of rock exposed (coal, shale, sandstone, limestone, granite, etc.). Therefore, the pressure required to induce a parting into these rocks is only that required to overcome the least principle stress within the reservoir. In other words, it may be very easy to initiate partings (fractures) into areas of future mine roof or floor because the rock is already "broken".

One underground well site study showed that induced fractures do indeed enter into very hard roof rock even when low surface injection rates (10 bpm) and pressures (1,400 psig) are used (26). The fact that this rock was fractured prior to stimulation was clearly indicated by the presence of casing cement, found in roof fractures up to 80 feet from the wellbore. It is possible that hydraulic fractures in the roof rock developed during the cementing operation.

Another natural rock condition which seems to have an effect on the upward growth of hydraulically induced fractures, is the condition of the interface between the coalbed and the overlying roof rock (usually shale). Underground examinations at stimulated boreholes indicate that induced fractures are more likely to remain in the coalbed when the overlying shale/coal interface is very abrupt and weakly-bonded. Such weakly-bonded inferfaces have been recognized in mine areas where the contact between coal and shale is highly polished and striated (slickensides). Where this type of boundary condition occurs, fracture partings have frequently spread-out horizontally within the interface area rather than grow vertically into the overlying shale roof.

CHARACTERISTICS OF INDUCED COALBED FRACTURES

Orientation

Nearly all of the induced fractures observed underground in coal mines are vertically oriented. Vertical fractures are expected to develop as a result of stimulation because most coalbeds are located in tectonically relaxed areas where the greatest principle rock stress direction is contained within a vertical plane (7) (15) (16). Horizontal fractures have resulted, however, where injection pressures exceed the calculated overburden pressures in wells as deep as 1,100 feet (23).

Direction (Azimuth)

Rock joint, and especially coal cleat directions tend to remain parallel throughout very thick vertical sequences (29). This relationship and the close correlation between natural fracture and induced fracture directions shown on Table 4, indicate that the direction of induced fractures can be predicted using rock joint and coal cleat direction measurements obtained at some horizon above the coalbed and near as possible to the well(s) to be stimulated. Outcrops road cuts, open strip pits, or nearby underground workings are a few locations where such information can be easily obtained.

Length

The loss of fluid to the coalbed along an induced fracture as it is being propagated by pumping is a major factor governing the fracture's linear extent. As mentioned earlier in this report, such loss of fluid (called "leak-off") leaves a constantly diminishing amount of fluid to create fracture penetration and to carry the solid proppant as the fracture's length increases. When leak-off to the coalbed is too high, the carrying ability of the treatment fluids decreases causing proppants to accumulate and can eventually block any further injection of fluids. This occurrence, commonly referred to as a "sand-out," or "screen-out" may cause propped fracture distance to be much shorter than the designed lengths. Sand-outs have occurred frequently (about 28% of the time) in past coalbed stimulations (refer to Table 3).

Underground examinations of stimulated boreholes indicate that treatments which incorporate the use of very heavy gels produce short fractures (16) (23). Even though such highly viscous fluids reduce reduce fluid leak-off into coalbeds, they produce very wide fractures (18), (32). This reduced the overall fracture length the treatment volume can create.

TABLE NO. 4 - RELATIONSHIP BETWEEN VERTICALLY INDUCED COALBED FRACTURE DIRECTION AND NATURAL ROCK FRACTURE TRENDS

ID No.	5	10	19	33	36	42	27	21	28
Well Name	USBM 1 NE	USBM No. 4	TW-1	TW-2	TW-3	TW-4	EM-5	EM-6	EM-7
Date of Interception	May 1974	June 12, 1974	June 16, 1976	February 15, 1977	October 6, 1977	November 16, 1977	July 21, 1978	November 9, 1978	December 1, 1978
Coalbed	Illinois No. 6	Pittsburgh	Mary Lee	Mary Lee	Mary Lee	Mary Lee	Pittsburgh	Pittsburgh	Pittsburgh
County	Jefferson	Washington	Jefferson	Jefferson	Jefferson	Jefferson	Greene	Greene	Greene
State	IL	PA	AL	AL	AL	AL	PA	PA	PA
Type of Stimulation Treatment	Gel	Gel	Gel	Gel	Foam	Foam	Foam	Foam	Foam
Type of Completion	Openhole	Openhole	Openhole*	Perforations	Openhole	Openhole	Openhole	Openhole	Openhole
Average Face Cleat Direction	N30°W	N62°W	N55°E	N55°E	N55°E	N55°E	N68°W	N68°W	N68°W
Average Butt Cleat Direction	N55°E	N28°E	N18°W N40°W	N18°W N40°W	N18°W N40°W	N18°W N40°W	N21°E	N21°E	N21°E
Average Roof Joint Direction	L/E	L/E	N77°W N58°E	N77°W N58°E	N77°W N58°E	N77°W N58°E	L/E	L/E	L/E
Induce Fracture Direction	N76°E	N62°W N28°E	N60°E	N60°E N18°W	N68°E**	N66°E**	N67°W	N68°W	N68°W

L/E Limited exposures prevented determination of a dominate direction.
*Casing set one-halfway through coalbed.
**Propagated in roof rock as well as in coalbed.

The longest measured length of a sand-packed hydraulically induced coalbed fracture was 416 feet from the borehole, using a light gel fluid in the Illinois No. 6 coalbed (16). Stimulation treatments using foam as a sand-carrying agent have recently shown evidence to indicate fracture extensions can be much longer. Such evidence includes recorded observations and measurements where there was direct or indirect 5/ communication of treatment fluid from one well to another spaced from 500 to over 1,000 feet apart. Two such accounts have been published as recent government reports of investigation (26) (37).

Width

The difference in pressure between the stimulation treatment fluid and the adjacent coalbed essentially controls fracture width during stimulation (32). Very large differences in these pressures produce wide fractures while small differences produce very narrow fractures. Operating conditions which cause wide fractures in coalbeds are high injection rates combined with the use of viscous fluids. Elder (16) reported fracture widths of 2-1/2 inches using "heavy gel" 6/ and a 10 bpm injection rate; and 1/8 to 3/8 inch wide fractures using a "light gel" 7/ and the same injection rate. A recent test using a highly viscous mixture of gelled water and fluid loss additives produced 5-inch wide fractures using an average injection of only 8 bpm (23). One may conclude from these examples that "high injection rate" is a relative term, meaning "high for the particular fluid properties incorporated in the treatment".

Proppant Distribution and Closure

A solid propping agent was normally included in a coalbed stimulation design in order to "hold open" the fracture once fluid pressures, created by pumping, were relieved. Sand, sorted from 10-to 40-mesh sizes, has been the standard material used as proppant.

The distribution of proppant material within induced fractures becomes an important consideration where there is effective closure stress because only these propped areas would then allow a sufficient amount of formation fluid to flow.

5/ "Direct communication" refers to occasions when stimulation fluid is injected into one well and the same type fluid is observed flowing into one or more nearby wells. "Indirect communication" refers to occasions when injection of stimulation fluid at one well causes formation fluids (water or gas) to move at one or more nearby wells.

6/ 75 pounds guar gum per 1,000 gallons water.

7/ 50 pounds guar gum per 1,000 gallons water.

There is recent evidence which suggests that very little closure stress exists in some coalbeds. At several boreholes draining from the Mary Lee coalbed in Alabama, for example, continued accumulations of propping sand in wellbores have caused chronic pumping problems (27). Even though these wells are fairly deep (1,000 to 1,100 feet), and they are situated in an area where there is likely some lateral rock stresses, actual fracture closure must be very low to allow these rather large amounts of proppant to return to the wellbore. In areas like this, uniformly packed fractures may not be the type of proppant distribution most desirable. Instead, only partial packing, or even no packing at all may be more suitable for higher drainage rates.

Flow Capacity

The relative ability of fluids to flow through induced fractures to the wellbore is an important consideration for stimulation design. One measure of this ability is commonly known as "Fracture Flow Capacity." Flow capacity at any given location along an induced fracture depends on the fracture's height and width and on the permeability of the proppant material filling the fracture. Very low fracture flow capacities cause steep pressure gradients to occur within the induced fracture(s) because resistence to flow is high. In such a case, reduction of reservoir pressures over significantly large areas of the coalbed may not occur rapidly enough to supply an economic flow of gas to the wellbore. Thus, even though a low flow capacity fracture extends several hundred feet from the wellbore, only a small portion of that length would define the "productive" length of the fracture.

STIMULATION USING GELLED FLUIDS

Government research has conducted 21 stimulation treatments using gelled fluids since 1970 (see Table 3). This type of fluid is water-based, and contains a natural-guar gum mixture allowing it to carry sand proppant and retard fluid leak-off. After treatment is completed these gelled fluids are designed to "revert" or "breakdown" to the viscosity of water. This allows the drainage of stimulation fluid from the induced parting(s) to the wellbore, leaving the sand proppant for support.

There are several published and unpublished reports containing specific accounts of borehole stimulation tests using gelled fluids (7) (14) (23) (38). The following descriptions serve to demonstrate the Government's experience using this type of coalbed treatment. Among the studies presented are all those where the results of gelled fluid treatments were observed directly underground after mining had progressed through the boreholes and effected areas.

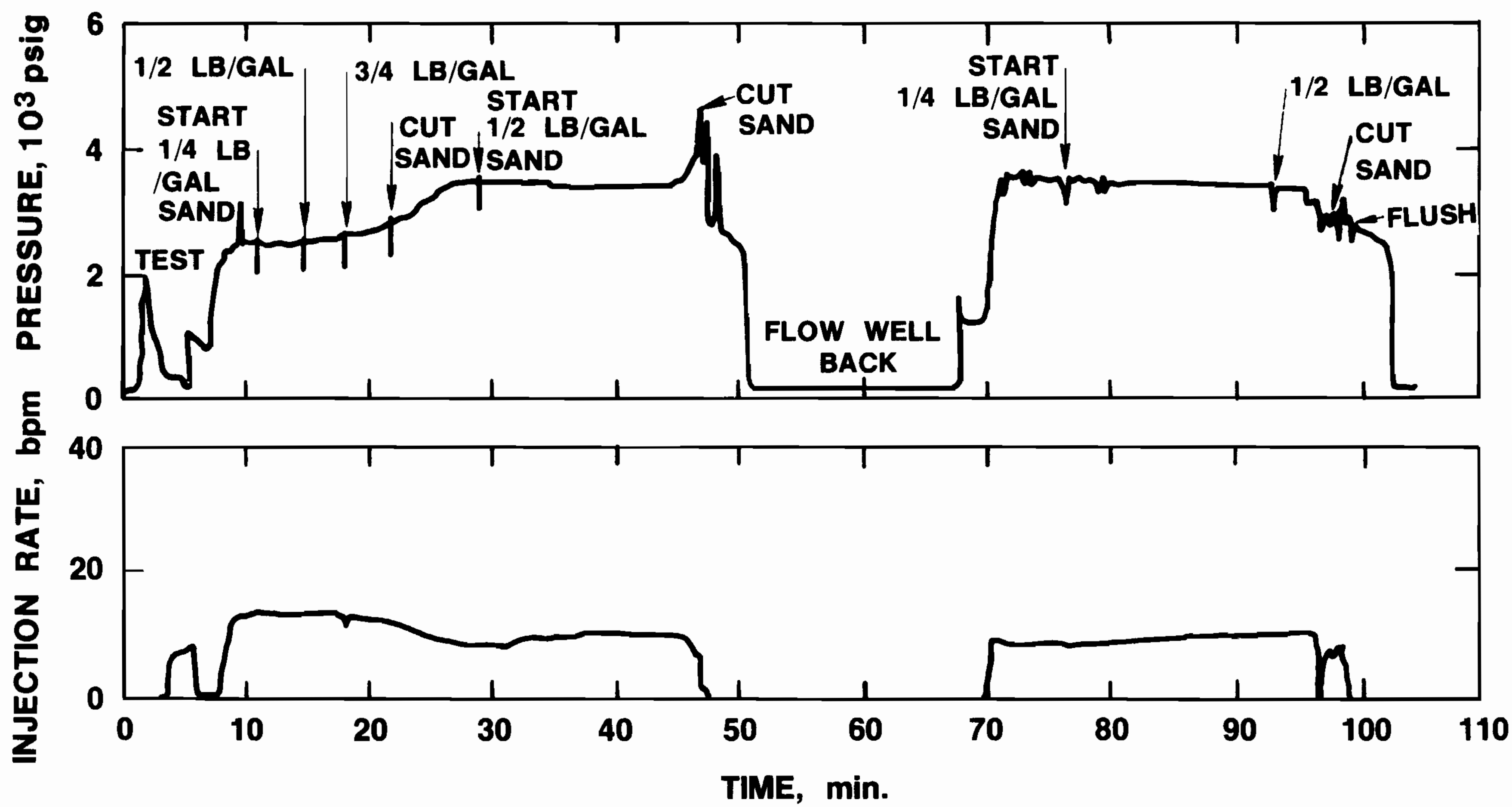
Pocahontas No.3 Coalbed, Buchanan County, VA (3) (13)

A test hole was drilled into a projected barrier pillar in an area not to be mined for several years. The test site was in central Buchanan County, VA. The hole penetrated a series of Pennsylvanian sandstones, shales, and coals to test the gassy Pochanatas No. 3 coalbed. The 1,530 foot deep hole was logged with a gamma ray - density logging tool to obtain geophysical data on formation density, porosity, and lithology. The 8-inch-diameter hole was cased with 4.5-inch diameter steel casing from the surface to the top of the coalbed, and the casing was pressure-cemented.

Monitoring equipment, including a flow meter and pressure gauges, were installed. Water flow was measured at .07 bpd. The inflowing water inhibited the flow of gas and required frequent swabbing to maintain a gas flow. The borehole flowed at 600 cfd with continued swabbing to clear the hole of water.

In July 1970, a hydraulic stimulation procedure designed by the Bureau of Mines was attempted. The coalbed was treated with a gelled fluid containing 10- to 20-mesh sand as a propping agent. The initial fracture occurred at 3,200 psig. The fractures were propagated with 2,400 to 3,450 psig pressure at an average injection rate of 10 bpm of gelled-water fracturing fluid. The treatment utilized 14,800 gallons of fracturing fluid and 4,000 pounds lb of 10- to 20-mesh propping sand. Figure 18 shows wellhead pressure and injection rate charts for this treatment. This well is designated "No. 1" on Table 3.

FIGURE 18. - WELL HEAD PRESSURE AND INJECTION RATE CHARTS OF HYDRAULIC STIMULATION TREATMENT OF POCAHONTAS NO. 3 COALBED (16).



After stimulation, the hole was swabbed to remove water and monitor gas flow. On the first day, water flow decreased. Gas flow increased from 2,500 to 3,500 cfd as water was drained from the coalbed. During the second day, water flow averaged 9 bpd, but flowed in surges; the gas flow increased from 3,500 to 9,000 cfd. The fourth day, gas flow rates increased to 12,000 cfd, while water flow decreased, flowing an average of 6 bpd during flow periods, but with a longer flow-nonflow cycle. On the fifth day, gas flow stabilized, averaging 12,000 cfd, while the water flow rate declined to 2 bpd flowing in 12 hour cycles (Figure 19).

The twentyfold increase in gas flow was, indeed, encouraging. It was evident, however, that a pumping or swabbing service must be provided to remove the water inflow to maintain stable gas production.

Mary Lee Coalbed, Jefferson County AL (5) (7) (14)

A test area was located in Section 23, T 18S, R 6 W Jefferson County, AL, for experimental degasification of the Mary Lee coalbed in advance of mining at U.S. Steel's Oak Grove Mine. A five-spot pattern of holes (1,081 to 1,093 feet total depth) was drilled on the flank of a structural anticline. The holes penetrated Pennsylvanian sandstones, shales, and coalbeds. Drilling was completed in July 1971. Hole No. 3 SW in this five-spot pattern was drilled to the top of the coalbed at a 1,075 foot depth and cased with seven inch diameter steel casing. After casing the hole, five feet of coalbed was cored and the borehole was put on production. Gas production was low at the start but increased as the coalbed was dewatered. The maximum production was from borehole No. 3 SW. After 16 months, production from this hole had reached an average of 5,000 cfd gas with 6 bpd water. A stimulation treatment was then planned to increase the degasification rate.

Design number two from a computer calculation (Tables 5 and 6) was selected for the treatment plan. This provided for 10,000 gallons of gelled water, with a 2,500 gallon water pad to be injected into the coal at 10 bpm to propagate a fracture or parting. Six thousand pounds of 10-to 20-mesh sand were mixed with the fracture fluid at a concentration of 3/4 ppg (pounds per gallon) to serve as a propping agent in the induced fracture after treatment.

FIGURE 19. - GAS AND WATER PRODUCTION RATES FOLLOWING HYDRAULIC STIMULATION TREATMENT OF POCAHONTAS NO. 3 COALBED (16).

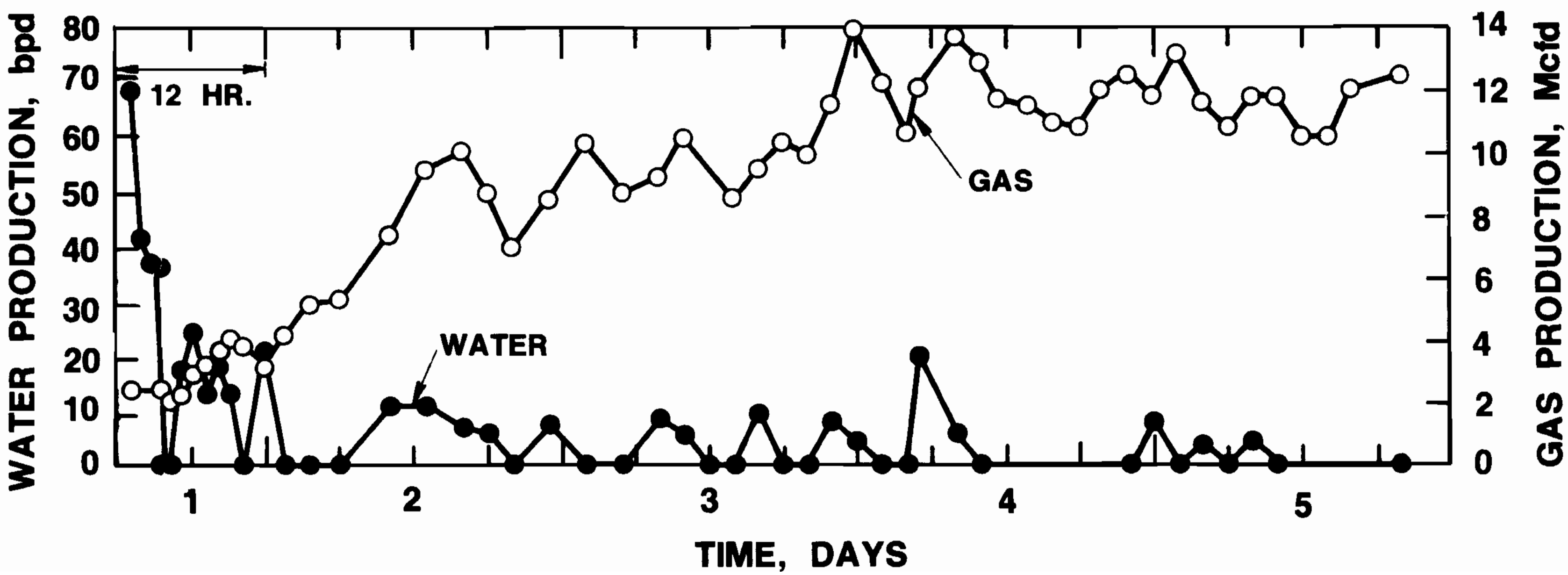


TABLE 5 - Hydraulic Fracture Stimulation Plan, Hole No. 3 SW, Jefferson County, Alabama (7)

Design No.	Production increase	Volume, 1,000/gas Total	Volume, 1,000/gas Pad	Propped fracture feet Length	Propped fracture feet Height	Viscosity cp	Fracture width inch	Prop sand sacks	Created fracture length feet
1	7.5	5	2.5	105	5.2	6	.207	19	233
2	11.7	10	2.5	255	5.5	7	.242	56	758
3	15.6	15	2.5	377	5.6	7	.266	94	1,040
4	19.4	20	2.5	437	5.7	7	.234	131	1,007

TABLE 6 - Criteria used in computation of hydraulic fracture stimulation plan, Hole 3 SW, Jefferson County, Alabama (7)

Injection Rate ....bbl/min..	10.0
Assumed fracture height ....ft..	7.0
Net formation thickness ....ft..	5.0
Plastic modulus....................lb/in^2..	0.30×10^6
Formation permeability ....md..	5.0
Formation porosity ....pct..	4.0
Bottom hole treatment pressure ....lb/in^2..	2,050.0
Reservoir pressure ....lb/in^2..	390.0
Reservoir fluid viscosity ....cp..	0.02
CW--Fluid loss coef ....$ft/min^{1/2}$..	0.00310
Spurt loss ....gal/ft^2..	0.21
Type of gel (Halliburton)	WG-6
Gel concentration....................lb/1,000 gal..	20.0
n'-Prime	0.738
k'-Prime (slot)....................$lb_f\text{-}sec^n/ft^2$..	0.000698
Well spacing ....acres..	30.0
Drainage radius ....ft..	536.0
Wellbore radius ....ft..	0.25
Damage ratio	3.0
Type and conc prop sand (8-12 mesh) ....lb/gal avg..	0.75

The treatment was conducted through 2-7/8 inch high-pressure tubing with a tension packer in the string set at 988 feet in the seven inch casing. The bottom of the tubing was at the midpoint of the coalbed.

The initial fracture occurred at 800 psig. The fracture was extended at 1,100 to 1,200 psig pressure and a steady 10 bpm injection rate. A total of 10,000 gallons of gelled water and 6,000 pounds of 10- to 20-mesh size propping sand were pumped during the treatment (Figure 20). After treatment, the borehole was swabbed free of water, and 30 feet of sand fillup was cleared from the borehole. After the water pump was installed, the borehole was returned to production. All fracturing fluid was recovered.

The gas flow increased after treatment from 5,000 cfd to a maximum rate of 90,000 cfd in 11 days (Figure 21). During the next seven months, the flow rate stabilized at 50,000 cfd. 8/ This well is designated "No. 2" on Table 3.

Pittsburgh Coalbed, Washington County, PA (12) (14)

A test area was located near Lone Pine, Washington County, PA, for degasification of the Pittsburgh coalbed in advance of mining. Four holes 405 to 552 feet in depth were drilled in a pattern on the flank of the Amity anticline. The nine inch-diameter holes were drilled near the top of the coalbed and cased with seven inch diameter steel casing. After the holes were cased, the seven foot coalbed was cored and the boreholes put on production. Initial gas production began in June, 1972, and was low then increased as the coalbed was dewatered. After 18 months, gas production from Borehole No. 1 NE stabilized at an average of 7,000 cfd with 4-1/4 bpd of water. This borehole was fracture-treated to improve degasification rate and test the effectiveness of stimulation of the Pittsburgh coalbed.

A hydraulic stimulation treatment program was prepared utilizing design No. 2 from the computer output treatment plan (Tables 7 and 8). This provided 10,000 gallons of water pad to be injected into the coal at 10 bpm. Six thousand pounds of 10- to 20-mesh sand were mixed with the fracture fluid at a concentration of 1/2 to 3/4 ppg to serve as a propping agent in the induced fracture.

The treatment was conducted through 2-7/8 inch high-pressure tubing with a tension packer in the string set at 412 feet in the seven inch casing.

8/ The accuracy of the production data for the 3 SW borehole at Oak Grove Mine has been stringently contested by U.S. Steel.

FIGURE 20. - WELLHEAD PRESSURE AND INJECTION RATE CHARTS OF HYDRAULIC STIMULATION OF THE MARY LEE COALBED (7).

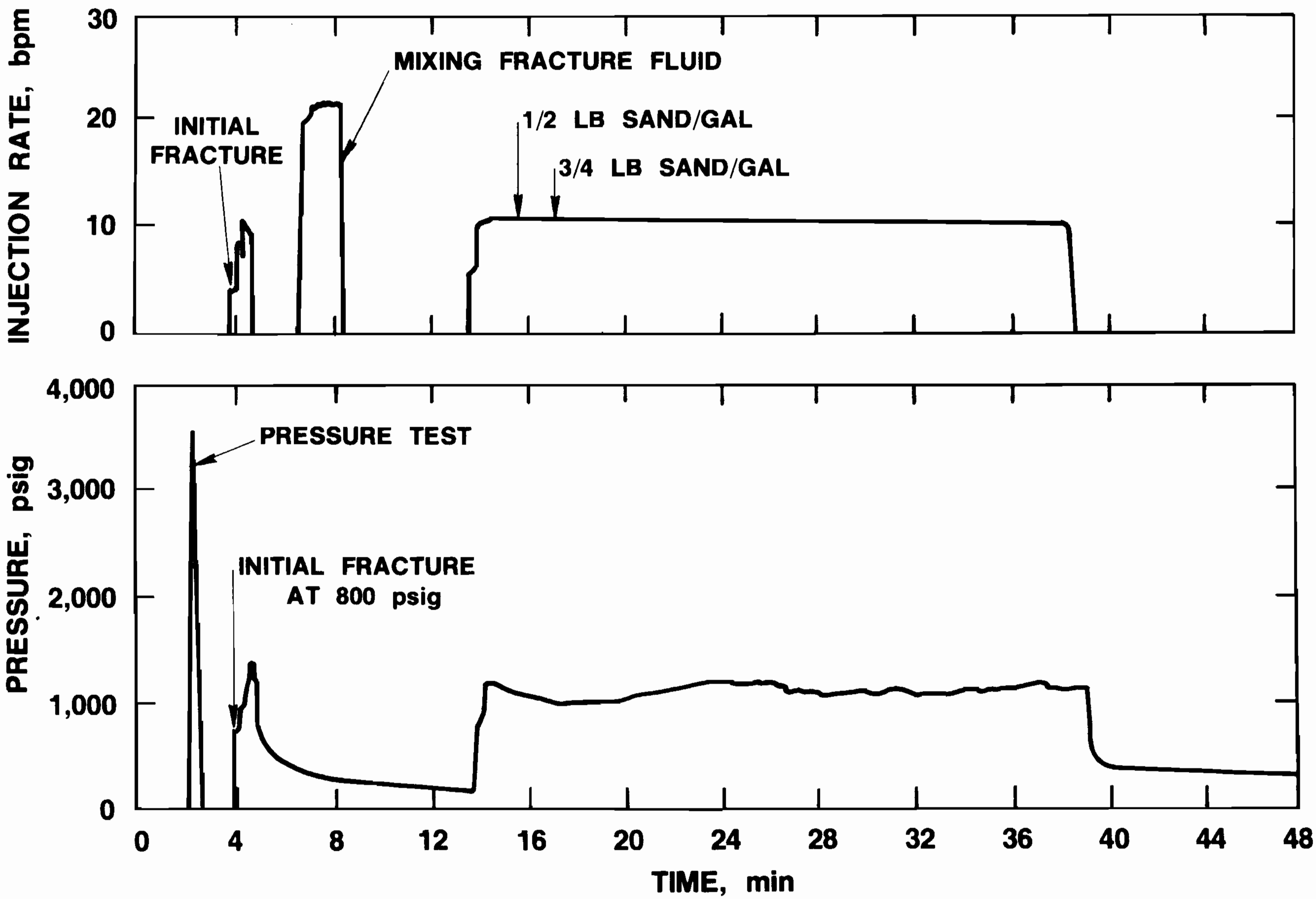


FIGURE 21. - GAS AND WATER PRODUCTION RATES BEFORE AND AFTER HYDRAULIC STIMULATION TREATMENT OF THE MARY LEE COALBED (7).

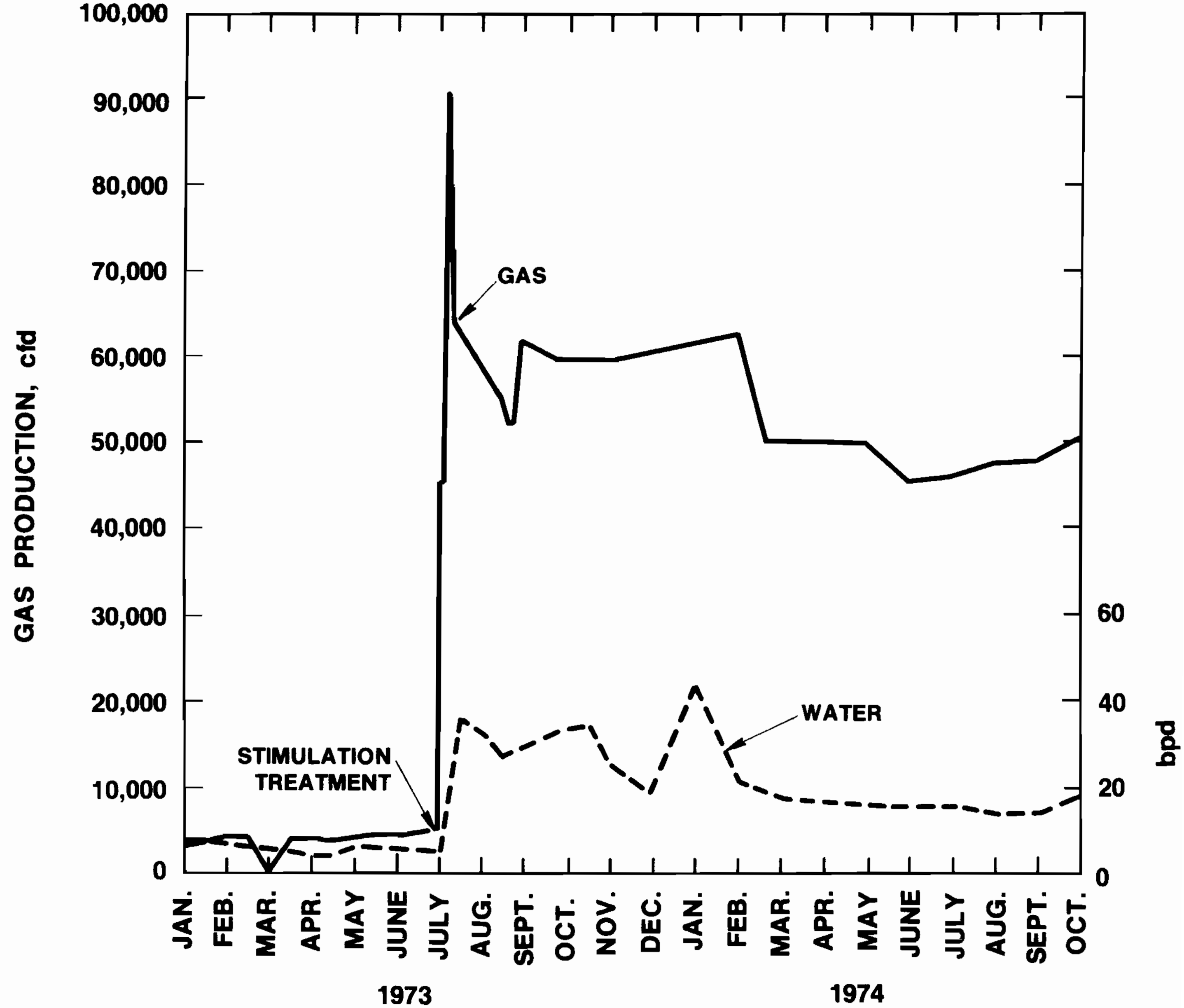


TABLE 7 - Hydraulic fracture stimulation plan, Hole 1 NE, Washington County, PA (14)

Design No.	Production increased	Volume, 1,000/gal Total	Volume, 1,000/gal Pad	Propped fracture feet Length	Propped fracture feet Height	Viscosity cp	Fracture width inch	Prop sand sacks	Created fracture length, feet
1....	9.2	5	1.0	165	4.9	4	.221	30	397
2....	13.2	10	1	309	5.2	4	.253	68	862
3....	15.2	15	1	433	5.3	5	.273	105	907
4....	19.4	20	1	547	5.4	5	.289	143	1,133

TABLE 8 - Criteria used in computation of hydraulic fracture stimulation plan, Hole No. 1 NE, Washington County, PA (14)

Injection rate ....bbl/min..	10.0
Assumed fracture height ....ft..	7.0
Net formation thickness ....ft..	6.0
Elastic modulus ....lb/in^2..	0.30×10^6
Formation permeability ....md..	5.0
Formation porosity ....pct..	4.0
Bottom hole treatment pressure ....lb/in^2..	772.0
Reservoir pressure ....lb/in^2..	166.0
Reservoir fluid viscosity........cp..	0.02
CW--Fluid loss coef ....$ft/min^{1/2}$..	0.00310
Spurt loss ....gal/ft^2..	0.21
Type of gel (Halliburton)	WG-6
Gel concentration ....lb/1,000 gal..	20.0
n'-Prime	0.728
k'-Prime (slot) ....$lb_f\text{-}sec^n/ft^2$..	0.000898
Well spacing ....acres..	30.0
Drainage radius ....ft..	563.0
Wellbore radius ....ft..	0.25
Damage ratio	3.0
Type and conc prop sand (8-12-mesh) ....lb/gal avg..	0.75

FIGURE 22. - WELL HEAD PRESSURE AND INJECTION RATE CHARTS OF HYDRAULIC STIMULATION TREATMENT OF PITTSBURGH COALBED (14).

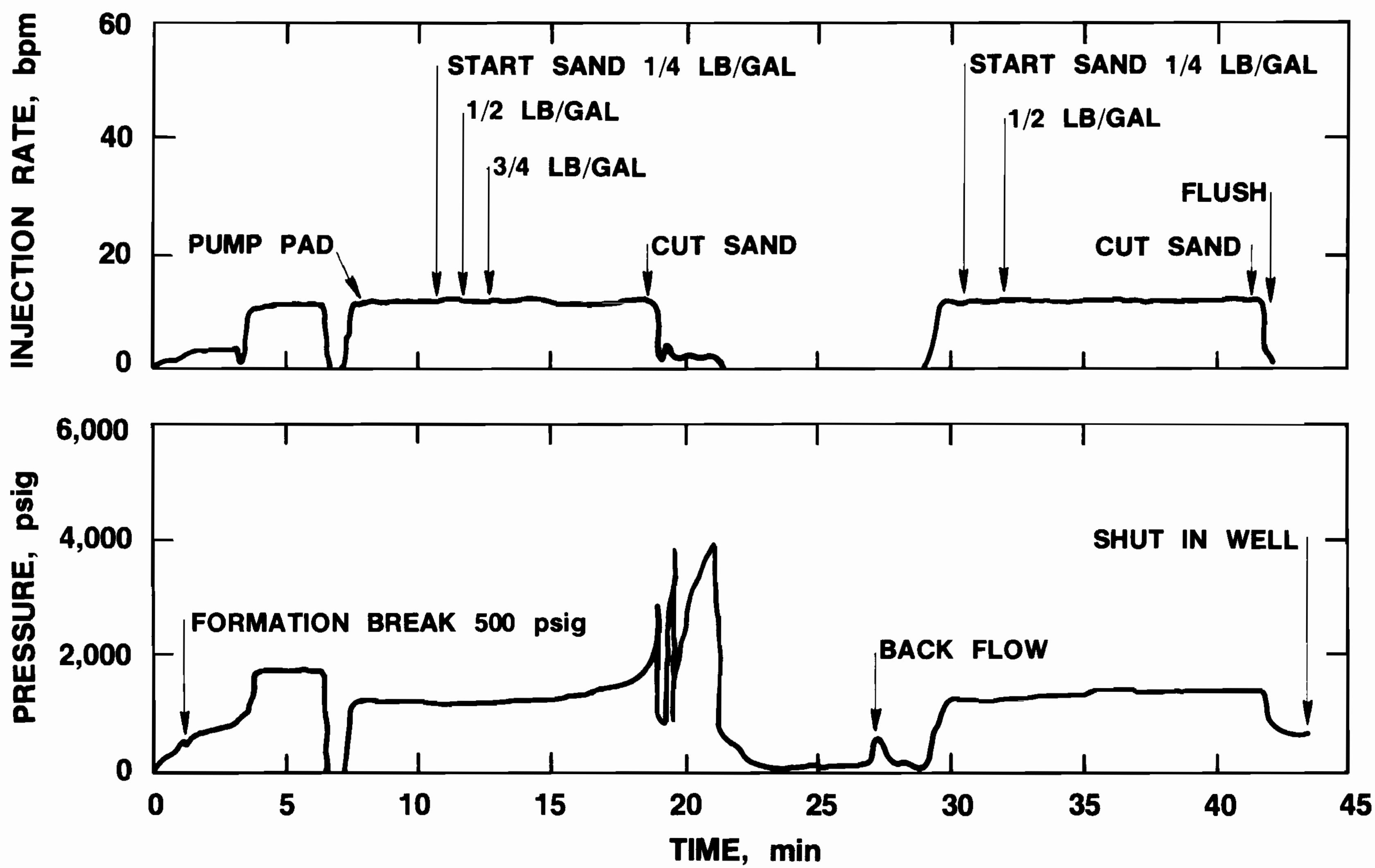
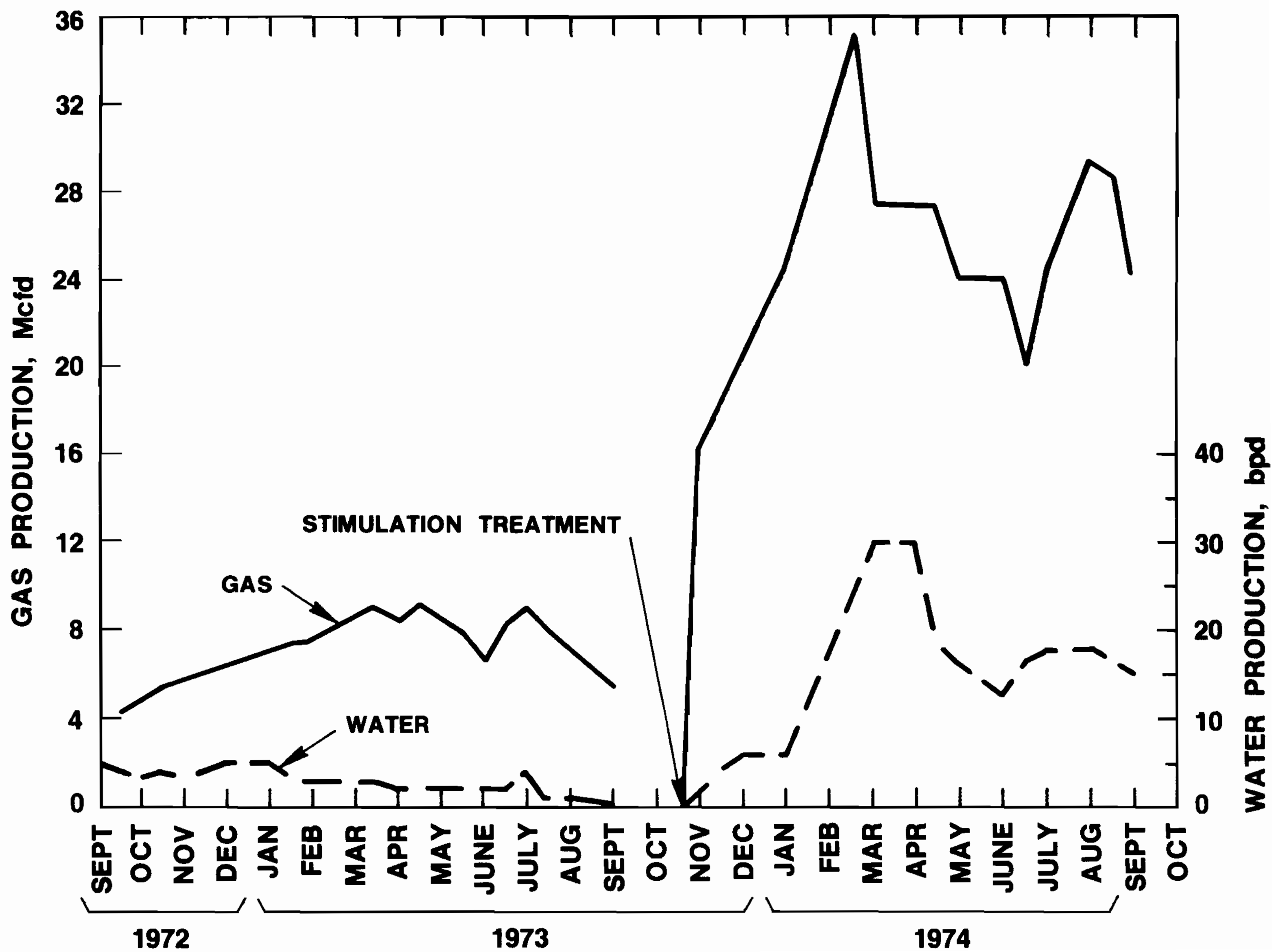


FIGURE 23. - GAS AND WATER PRODUCTION RATES BEFORE AND AFTER HYDRAULIC STIMULATION TREATMENT OF PITSBURGH COALBED (14).



The initial fracture of the coal was achieved at 600 psig. The fracture was extended at 1,200 to 1,400 psig pressure and a steady 11.4 bpm injection rate. A total of 10,200 gallons of gelled water and 6,000 pounds of 10- to 20-mesh propping sand were pumped during fracture propagation (Figure 22). Midway through the pumping, a "sand-out" occurred.

The system was allowed to backflow to clear the blockage and the treatment was completed. After treatment, the borehole was swabbed free of water, and a few feet of sand accumulation was cleaned from the borehole. With reinstallation of the water pump, the borehole was returned to production and the fracturing fluid was recovered.

The gas flow increased after treatment from an average of 7,000 cfd to a rate of 35,750 cfd in 2-1/2 months (Figure 23). On Table 3, this well is designated at "No. 3".

Mary Lee Coalbed, Jefferson County, Alabama, Case II (23)

A vertical degasification borehole drilled to the Mary Lee coalbed and completed 600 feet ahead of active mining, was intercepted by mining on February 15, 1977. The borehole, referred to as Test Well No. 2 (TW2), was located in Section 35, T 18 S, R 6 W, near Oak Grove, Alabama. The purpose of completing TW2 was to test specific hydraulic gel stimulation procedures in coal by monitoring well production, and later, inspecting the results directly underground in the mine.

TW2 was rotary drilled using a 6-1/4 inch diameter air-percussion bit and foam to approximately 235 feet above the five foot thick coal interval. To reduce the possibility of formation damage due to drilling, a 6-1/8 inch diameter roller bit and foam were used to drill the remaining distance to 50 feet below the coalbed. TW2 was cased to total depth with 4-1/2 inch diameter pipe equipped with a float shoe. The lower 500 feet of casing was set in place using 13.5 ppg weight cement.

A jet slotting tool was positioned using a geophysical logging device. The design called for a water and sand slurry to cut four vertical slots, 90 degrees apart, from the base of the coalbed to within one foot of the top. The coalbed was stimulated using 3,500 gallons of a highly viscous fluid containing 4,000 pounds of 10- to 30 and 20- to 40 mesh size sand (Table 9).

Table 9 - TW2 Hydraulic Stimulation Data (23)

Date	October 24, 1976
Propping sand	20-40 mesh-sized sand, 1000 lb.
Propping sand	10-20 mesh-sized sand, 3,000 lb.
Treatment fluid	Gelled water, 3,500 gal
Surfactant concentration	3 gal/1,000 gal
Fluid loss additive concentration	50 lb/1,000 gal
Gelling agent concentration	66.7 lbs/1,000 gal
Breaker concentration	2 lb/1,000 gal
Complexer concentration	0.4 gal/1,000 gal
Maximum pressure	2,500 psig
Average pressure	2,400 psig
Treatment rate, average	8 bpm
Hydraulic horsepower	1,000 Hp

The hydraulic stimulation pressure averaged 2,400 psig with no apparent formation "breakdown"; the fluid injection rate averaged 8 bpm; and the instantaneous shut-in pressure was 2,200 psig (Figure 24). After stimulation, water was circulated in the well removing approximately 200 lbs of propping sand. The well was later equipped with a pump to remove water and meters to monitor production.

TW2 was put on production November 13, 1976. During successful pumping periods, daily gas production averaged about 15,000 cubic feet. Sand and other foreign material entering the downhole pump mechanism caused chronic malfunction and resulted in overall poor gas production (Figure 25).

Temporary gas flow rates in excess of 80,000 cfd were measured on several occasions, immediately after servicing the downhole pump and after removal of usually less than five barrels of water. Such temporarily high gas flows appear to have brought significant amounts of propping sand into the wellbore.

The well, and induced fractures from the well, were exposed approximately three months later by mining. Coal was removed to approximately four feet beyond the borehole location during which time very wide, short vertical fractures and longer, thin horizontal sand-packed fractures were observed. The site was studied in detail and measurements were made with the coal face in the position shown on Figure 26. The borehole site as it appeared at that time is diagrammed in Figure 27.

The casing was expanded outward where pierced by four roughly diamond shaped slots about 5.5 inches long and 2 to 2.5 inches wide. Small holes in the casing (five holes, 0.3-inch maximum diameter) were observed five to nine inches above the slots. The top of the slots were about four inches below the base of the coalbed demonstrating that slotting had not occurred in the coalbed as intended.

FIGURE 24. - HYDRAULIC STIMULATION PRESSURE AND FLUID INJECTION CHART TW2, MARY LEE COALBED (23).

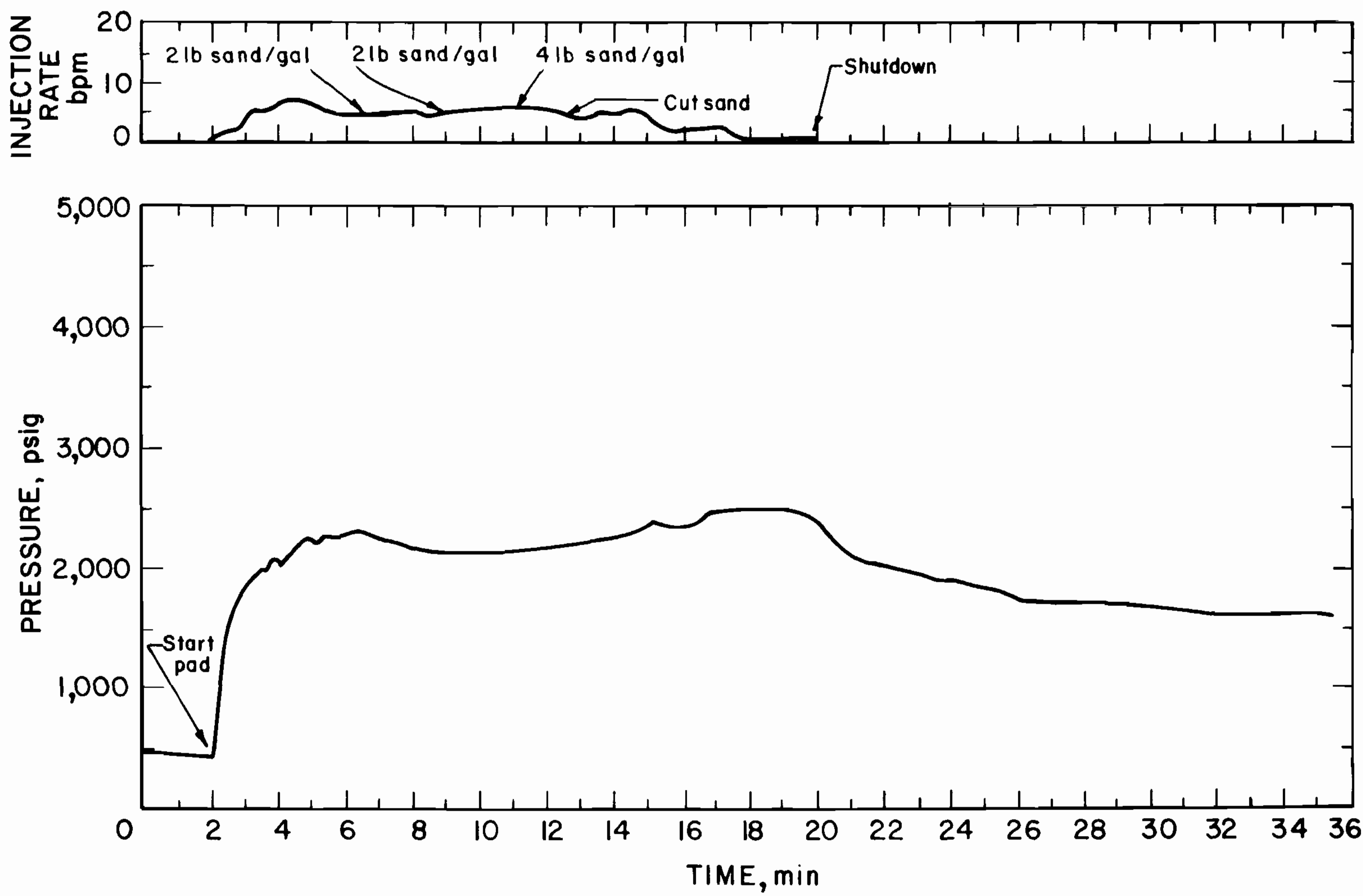


FIGURE 25. - DAILY GAS PRODUCTION FROM TW2, MARY LEE COALBED (23).

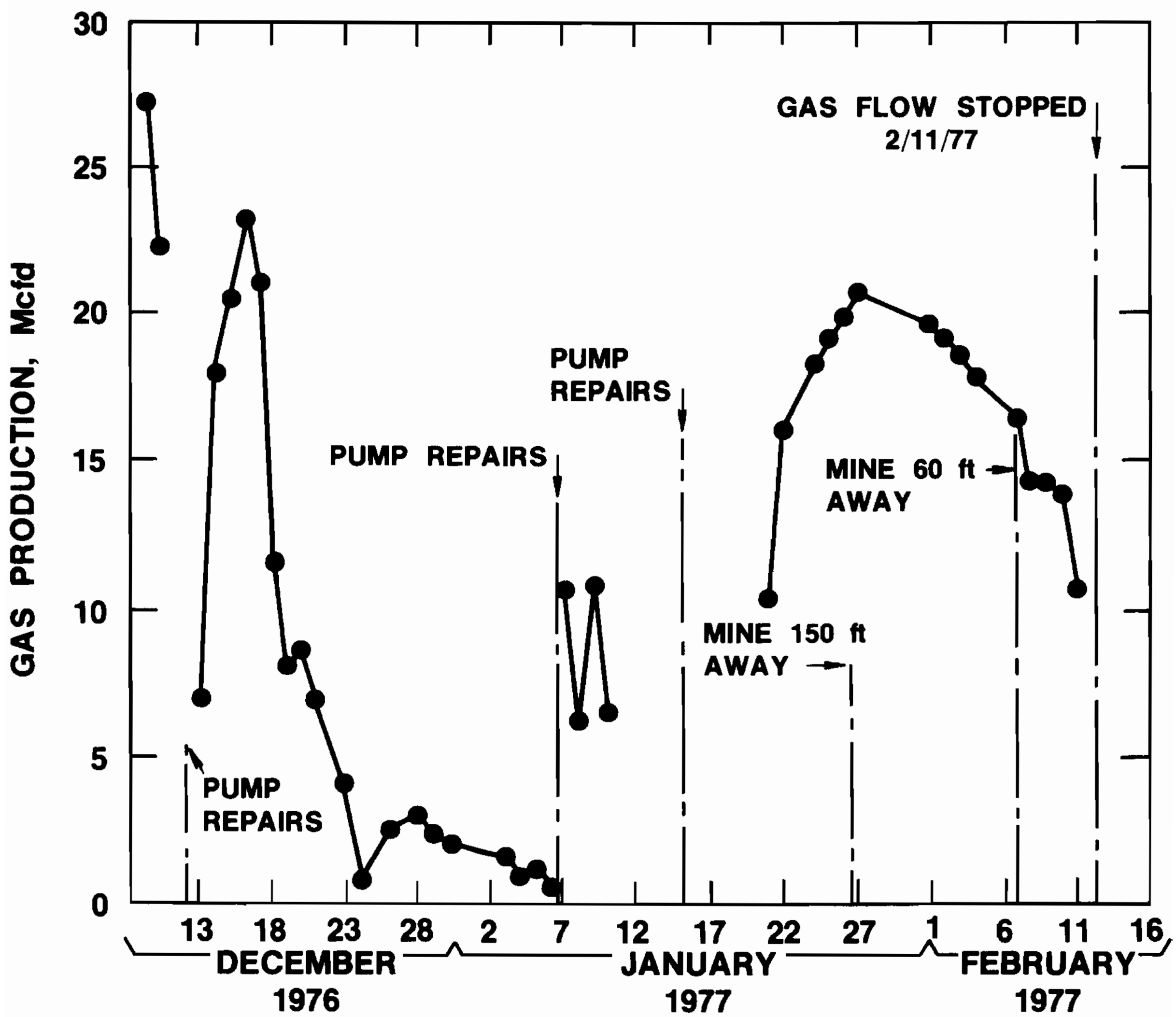


FIGURE 26. - POSITION OF MINE FACE DURING UNDERGROUND INVESTIGATION OF TW2 (23).

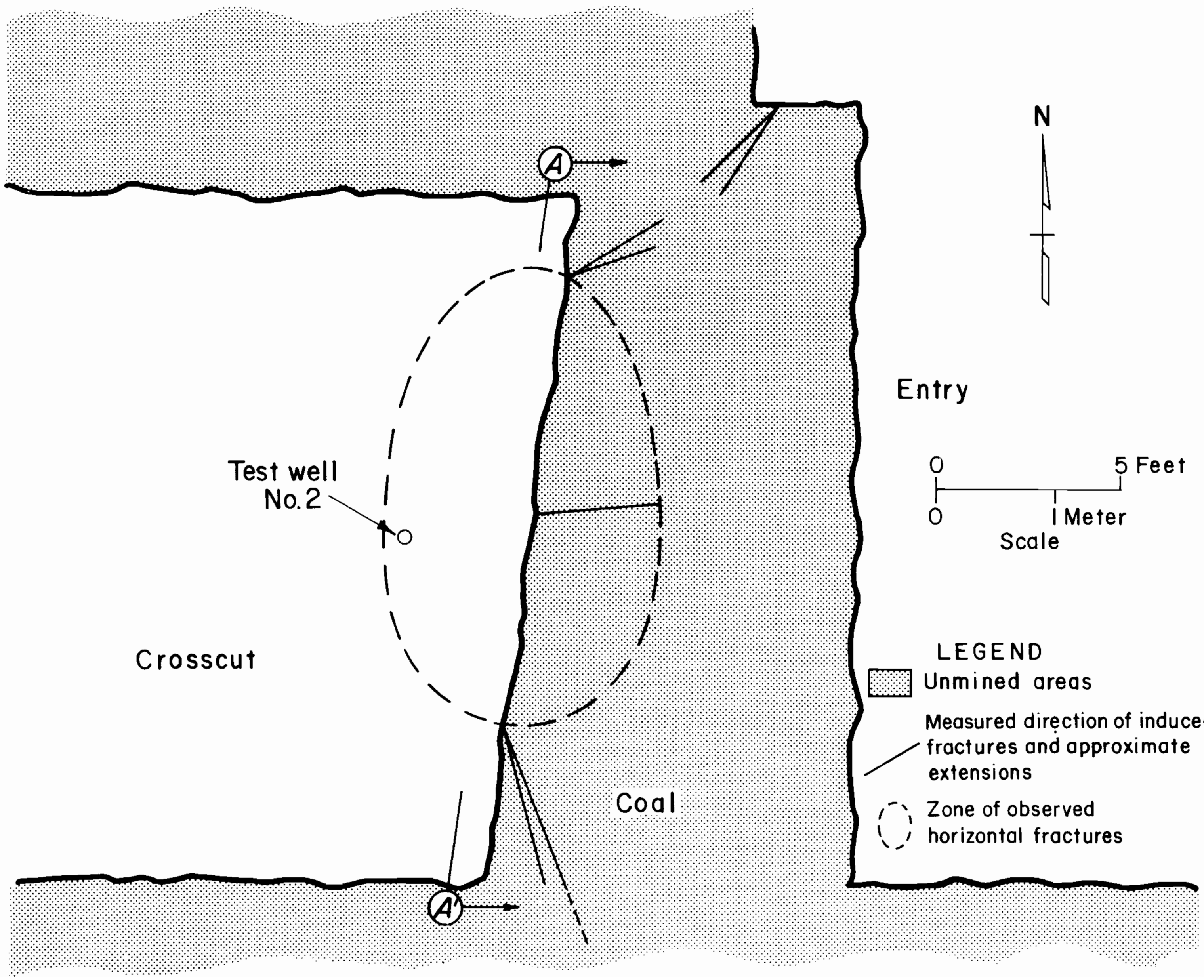
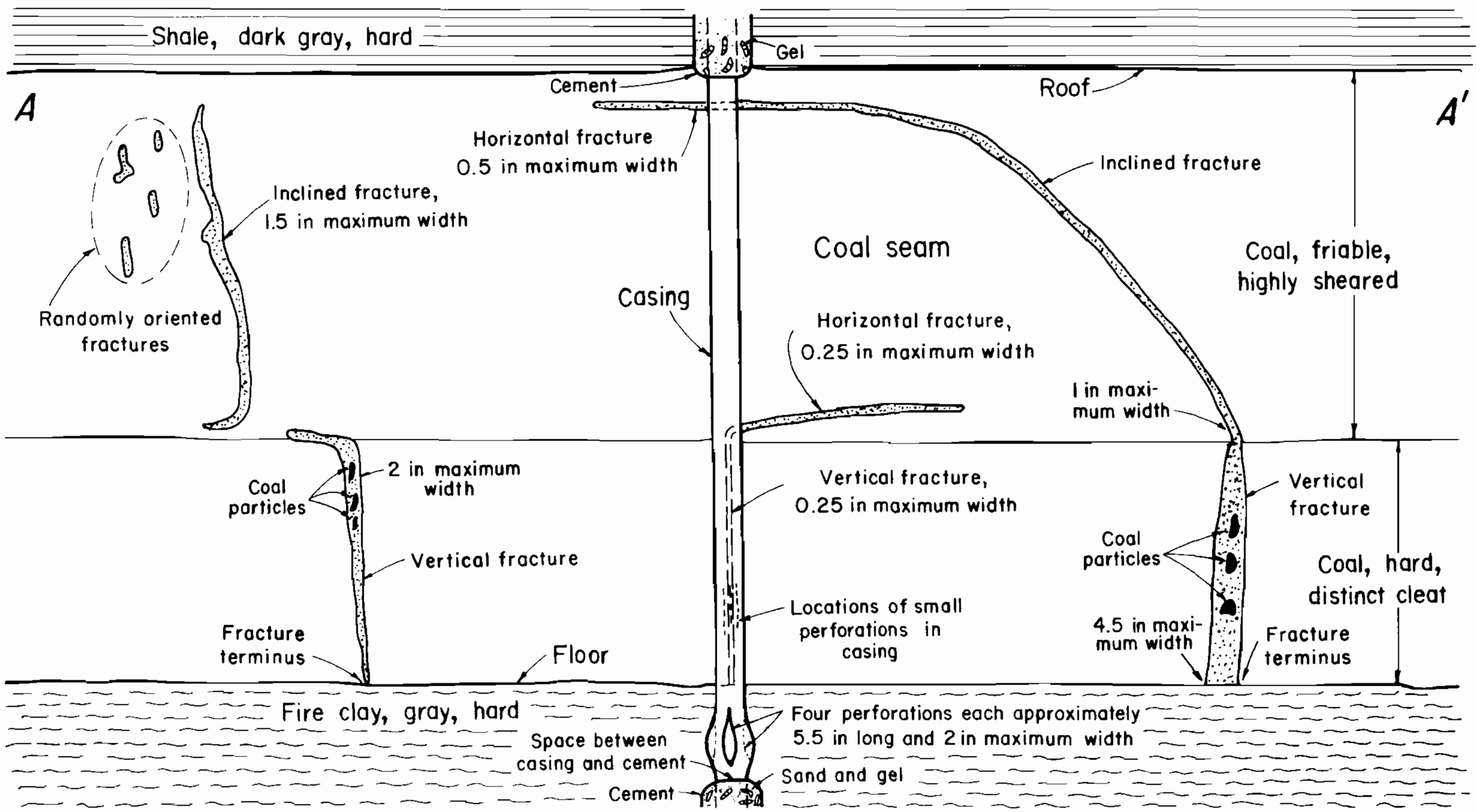


FIGURE 27. - SKETCH OF MINE FACE DURING UNDERGROUND EXAMINATION OF TW2 (23).



SECTION A-A′

Three well-defined vertical fractures were observed at the borehole site. All three were contained in the lower third of the coalbed and were completely filled with propping sand. Fracture sides appeared smooth and unabraided, and followed local vertical natural fracture planes in the coal. The widest sand-filled fracture (4.5 inches), tapered upward gradually; a fracture of intermediate thickness (2.0 inches) tapered sharply to the floor (Figure 27). The remaining vertical fracture was the same thickness (0.03 inches) throughout. All three fractures terminated at the base of the coalbed with no evidence of fracture continuation into floor rock.

Two fractures were inclined. They sloped downward to the south and were contained entirely in a more friable, soft, and highly slickensided portion of the coalbed. Their sides were smooth and unabraided, but somewhat irregular. They appeared to follow local natural shear fracture planes in the coal, with minor vertical development along cleat planes. The shape and downward extension of these induced fractures indicate direct or inferred continuation with the vertical fractures described earlier.

Four horizontal sand-filled fractures appeared at the coal face as extensions of either vertical or inclined fracture development. All four occurred along bedding planes. Three of the fractures were present approximately one-third the distance up from the floor near the line of contact between hard, distinctly cleated coal and soft, friable, sheared coal. The fourth horizontal fracture ran along a line six inches below the coal/roof-rock interface. Typically, coal immediately surrounding the horizontal fractures was very soft and appeared crushed.

Four small, separate, randomly oriented, sand-filled fractures were observed in the upper portion of the coal face north of the wellbore. Their locations indicate close association with a system of larger fractures trending approximately N65^{o}E. These fractures were observed along shear, cleat, and bedding planes and thus possessed characteristics of all three fracture types described earlier. This well is No. 33 on Table 3.

Pittsburgh Coalbed, Washington County, Pennsylvania, Case II (16) (21)

To determine the effect of hydraulic stimulation on the Pittsburgh coalbed, a test hole was drilled at Vesta No. 5 mine in Washington County, PA. The hole was located 500 feet ahead of an active developing section of the mine.

Drilling began April 10, 1974, with a rotary drill rig. A 6-1/4-inch hole was then drilled to a total depth of 597 feet. The Pittsburgh coalbed was reached at a depth of 588 feet. Six feet of the coalbed was drilled, and the hole terminated three feet below the coalbed.

Table 10 shows the estimated results expected for the stimulation treatment for volumes of 5,000 and 10,000 gallons of gelled water. Design 1 was chosen in order to contain the fracture within the area of unmined coal.

TABLE 10 - Designs for Stimulation of borehole USBM No. 4, Washington County, PA (16)

	Design 1	Design 2
Production ....fold increase..	10.7	16.9
Total volume ....Mgal..	5.0	10.0
Pad Volume ....Mgal..	2.0	2.0
Propped fracture length ....feet..	219	411
Propped fracture height ....do..	5.0	5.2
Viscosity ....centipoises..	4.0	4.0
Fracture width ....inches..	0.22	0.22
Propping sand ....100-pound sacks..	35	90
Created length[1] ....feet..	387	662

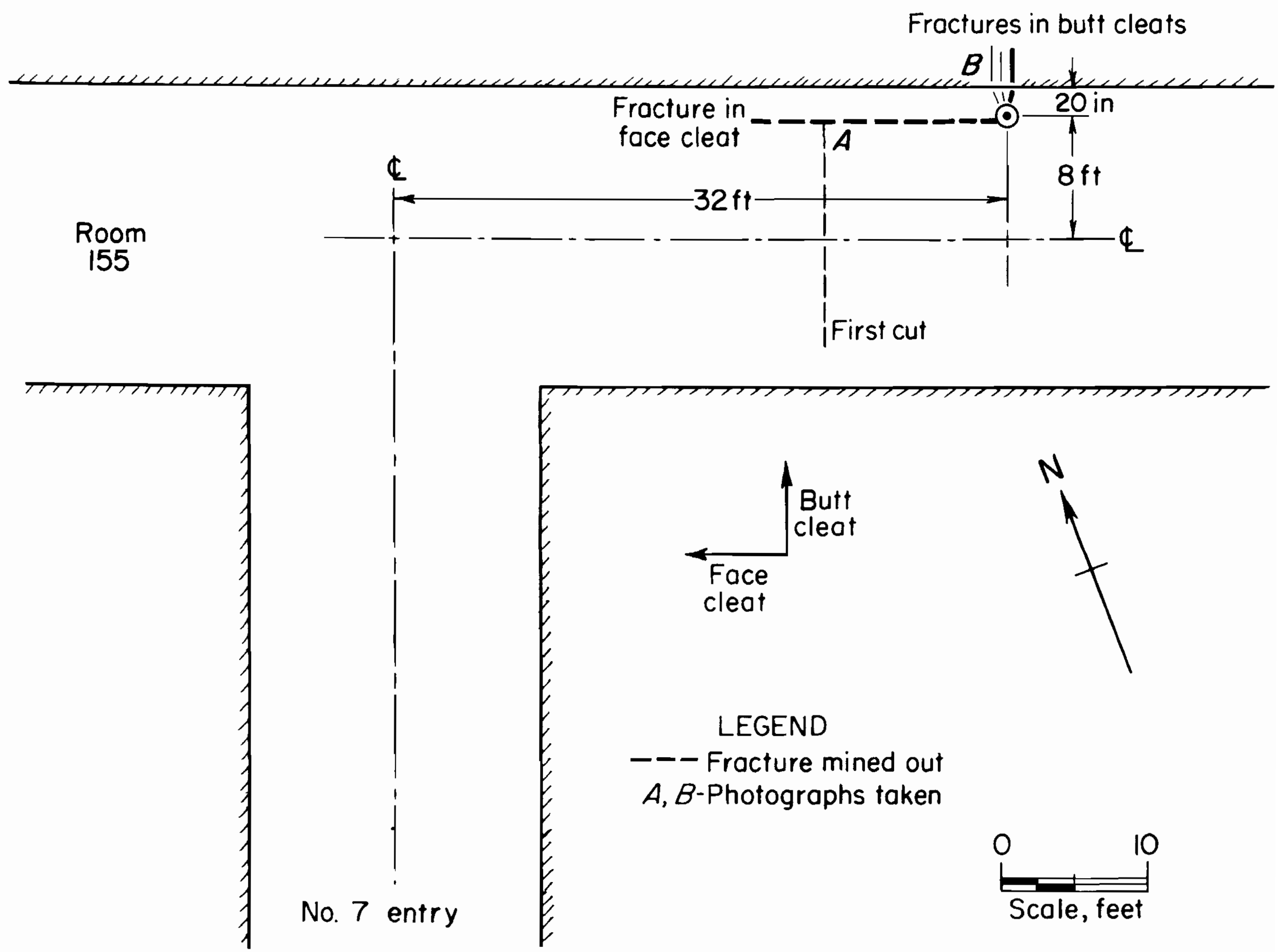
[1]Maximum length of induced fracture created with and without sand prop.

On April 17, 1974, the well was treated through 2-3/8 inch diameter, high-pressure tubing. An open hole packer in the tubing string was set at 585 feet in a hard formation three feet above the coalbed. The treatment used 7,300 gallons of water containing 540 pounds of guar gum, 3,000 pounds of 10- to 20-mesh size fluorescent-dye-treated sand followed by 500 pounds of 10- to 20-mesh size regular sand.

Two thousand gallons of gelled fluid were injected into the coalbed to fill all spaces in the coalbed around the borehole and initiate the fracture. The formation "broke" at 500 psig. The pad volume was followed with successive injections of 1,300 gallons of sand-laden treating fluid at 1/4 ppg sand concentration, 650 gallons at 1/2 ppg, 1,750 gallons at 3/4 ppg, and 1,350 gallons at 1/2 ppg sand concentration. The tubing was cleared of sand with 250 gallons of treating fluid. An injection rate of 10-1/2 bpm was maintained during the treatment and the injection pressure averaged 1,587 psig. A maximum injection pressure of 1,700 psig was reached.

On June 12, 1974, the induced fractures were intercepted by mining. Twenty feet of vertical sand-propped fracture was mapped along the face cleat direction west of the borehole (Figure 28). The sand-filled fracture

FIGURE 28. - INDUCED FRACTURE ORIENTATION RELATIVE TO MINE ENTRY DEVELOPMENT (16).



ranged from 1/8 to 1/2 inch in width, extending from the draw slate at the top of the coalbed to the mine floor (Figure 29). Wide vertical fractures were propagated to the north of the borehole along the butt cleat direction (Figure 30). These fractures were 1/2 to 2-1/2 inches in width and were packed with the propping sand. They extended from the base of the draw slate to the floor.

It is estimated that the fractures extended 35 feet or more into the coalbed in the butt cleat direction. The fractures were wider than expected, averaging two inches in width. The greater width of the fractures was believed caused by the use of the heavily gelled treating fluid (75 pounds of guar gum per 1,000 gallons). The identification number of this well on Table 3 is "10".

Illinois No. 6 Coalbed, Jefferson County, IL (16)

A pattern of five degasification boreholes was drilled into the No. 6 coalbed at the Inland Steel Co. mine, Jefferson County, IL. The holes were drilled during June, 1972. The nine inch diameter holes were drilled with a rotary drill and cased with seven inch diameter steel casing to within a few feet of the top of the coalbed. The northeast corner hole, No. 1 NE of the pattern, was selected for hydraulic stimulation. It was drilled to a total depth of 743 feet and penetrated nine feet of the No. 6 coalbed.

A hydraulic stimulation was designed that would induce a fracture within a 450 foot radius from the borehole, and remain totally contained within the coalbed. Table 11 shows the calculated results expected from three stimulation treatment designs for fluid volumes of 5,000, 12,000 and 15,000 gallons. Design 2 was selected for the stimulation treatment. The coalbed was stimulated through a 2-3/8 inch diameter high-pressure tubing. A packer in the tubing string was set in the casing at a depth of 720 feet, with a tailpipe extending to the middle of the coalbed to a depth of 733 feet. Twelve thousand gallons of water were gelled with 240 pounds of guar gum to form a light gel fluid. The gel fluid and 6,400 pounds of 10- to 20-mesh size propping sand were used in the treatment.

FIGURE 29. - INDUCED FRACTURE IN FACE CLEAT OF PITTSBURGH COALBED. NOTE TERMINATION OF FRACTURE AT DRAW SLATE (16).

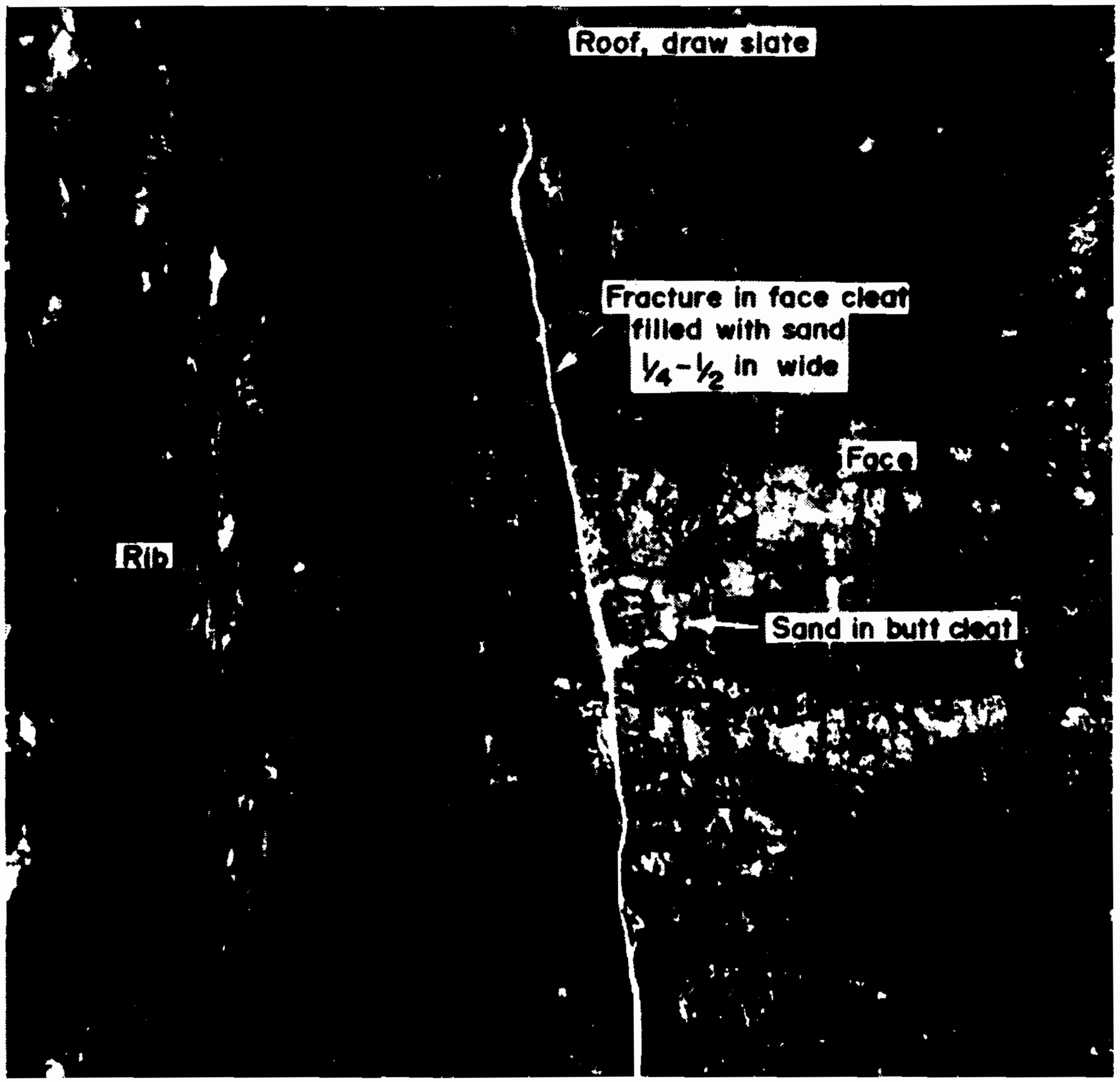


FIGURE 30. - INDUCED SAND-FILLED FRACTURES IN BUTT CLEAT DIRECTION IN PITTSBURGH COALBED (16).

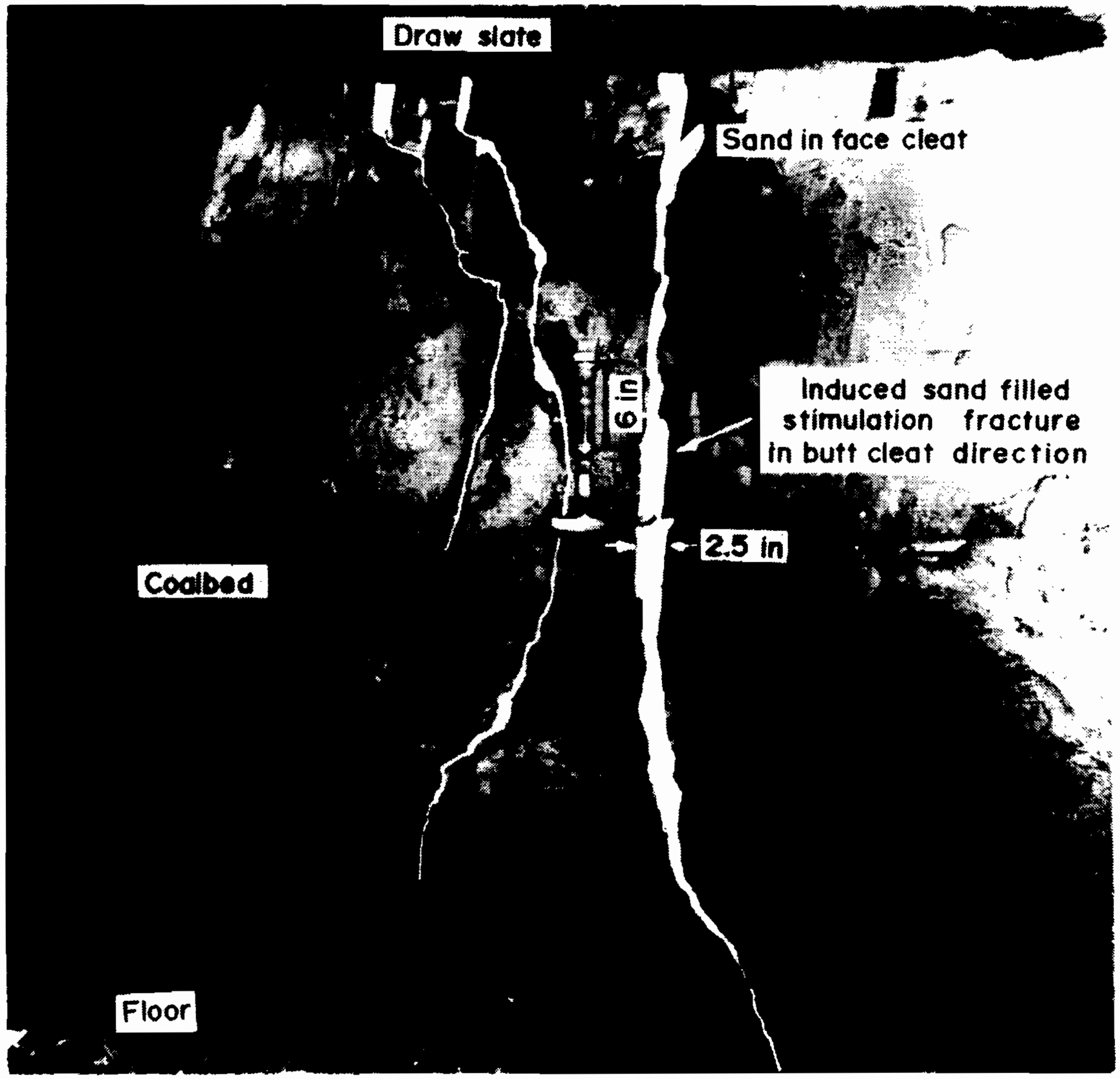


TABLE 11 - Designs for stimulation of borehole USBM No. 1NE, Jefferson County, IL. (16).

	Design 1	Design 2	Design 3
Production ....fold increase..	5.5	7.5	8.0
Total volume.......................Mgal..	5.0	12.0	15.0
Pad volume ....Mgal..	2.0	2.0	2.0
Propped fracture length ....feet..	140	305	391
Propped fracture height ....do..	6.9	6.9	7.1
Viscosity ....Centipoises..	6	6	7
Fracture width ....inches..	0.17	0.20	0.22
Propping sand ....100-pound sacks..	26	64	101
Created length ....feet..	222	431	509

A total of 2,000 gallons of gel fluid was injected into the coalbed to fill all spaces around the borehole and initiate the fracture. The formation broke at 1,000 psig. The fracture was propagated with an injection rate of 10 bpm. The following volumes of sand-laden gel fluid were successively injected into the coalbed: 3,000 gallons at 1/4 ppg sand concentration; 2,000 gallons at 1/2 ppg; 1,800 gallons at 3/4 ppg; and the final 3,200 gallons at 1 ppg. The average injection pressure was 900 psig, but a maximum injection pressure of 1,000 psig was reached (Figure 31). After treatment, the test hole was put on gas and water production. Gas flow was measured to be 4,300 cfd.

The induced vertical fracture was intercepted by mining in May, 1974. The induced fracture was propagated in a direction of N 76° E from the borehole. It was mapped across four entries of the No. 11 right entries off the West main entries of the mine (Figure 32). The induced vertical fracture did not appear to follow the directions of the face or butt cleat; it followed a path subparallel to the axis of a small anticlinal fold on the flank of the coal basin. The stimulation created a single vertical fracture in the coalbed. The fracture was mapped for 416 feet from the borehole. The sand-propped fracture extended vertically from the roof shale to a hard shale parting approximately two feet from the bottom of the coalbed. The fracture was seven feet in height.

The fracture could be readily traced across the entries in the roof coal. It ranged from 1/8 to 3/8 inch in width, averaging approximately 1/4 inch (Figures 33-36). Approximately 61 cubic feet of fracture volume was created which was filled with sand. Sixty four cubic feet of sand was used during the treatment. The three cubic feet difference can be attributed to sand that settled in the borehole. The excess sand was removed from the borehole immediately after treatment. This well is designated "No. 5" on Table 3.

FIGURE 31. - PRESSURE AND INJECTION RATE CHARTS DURING HYDRAULIC STIMULATION, USBM NO. 1 NE, JEFFERSON COUNTY, ILL. (16).

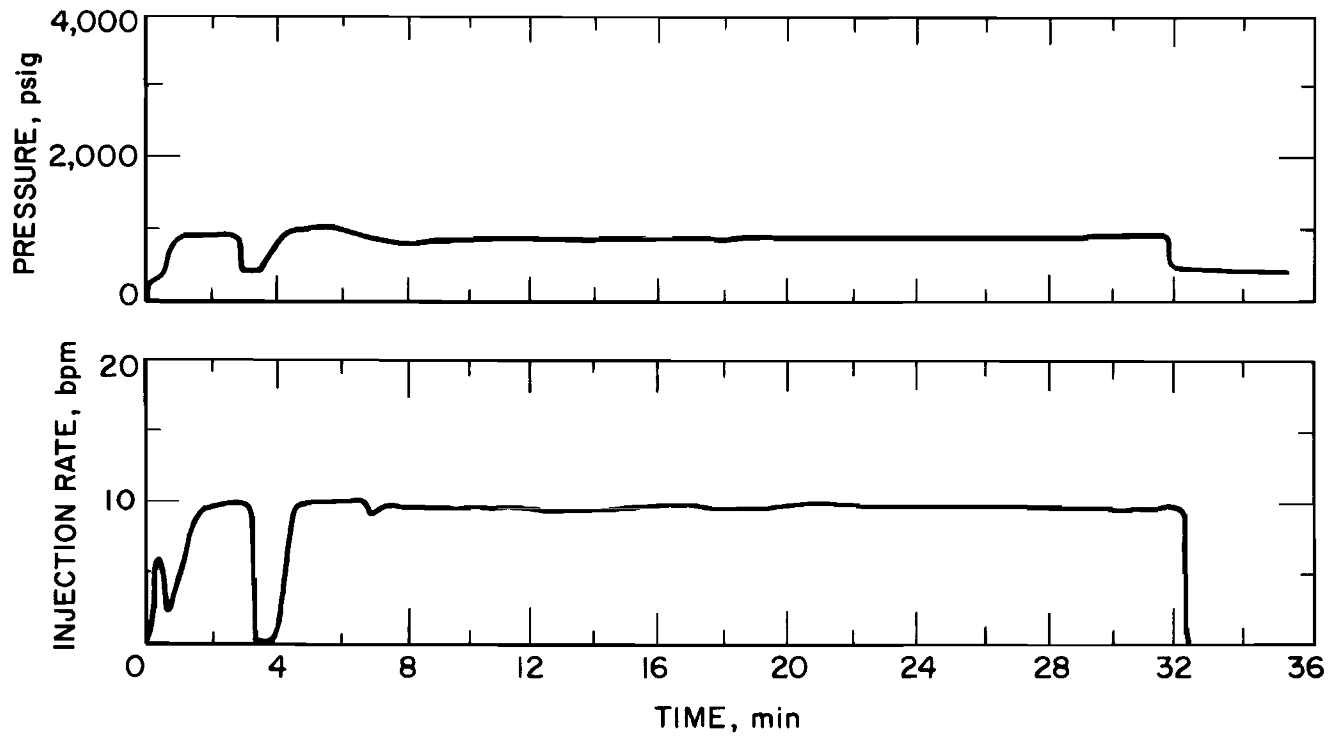


FIGURE 32. - INDUCED FRACTURE ORIENTATIONS AS RELATED TO MINE ENTRY DEVELOPMENT AT USBM NO. 1NE, JEFFERSON COUNTY, ILL. (16).

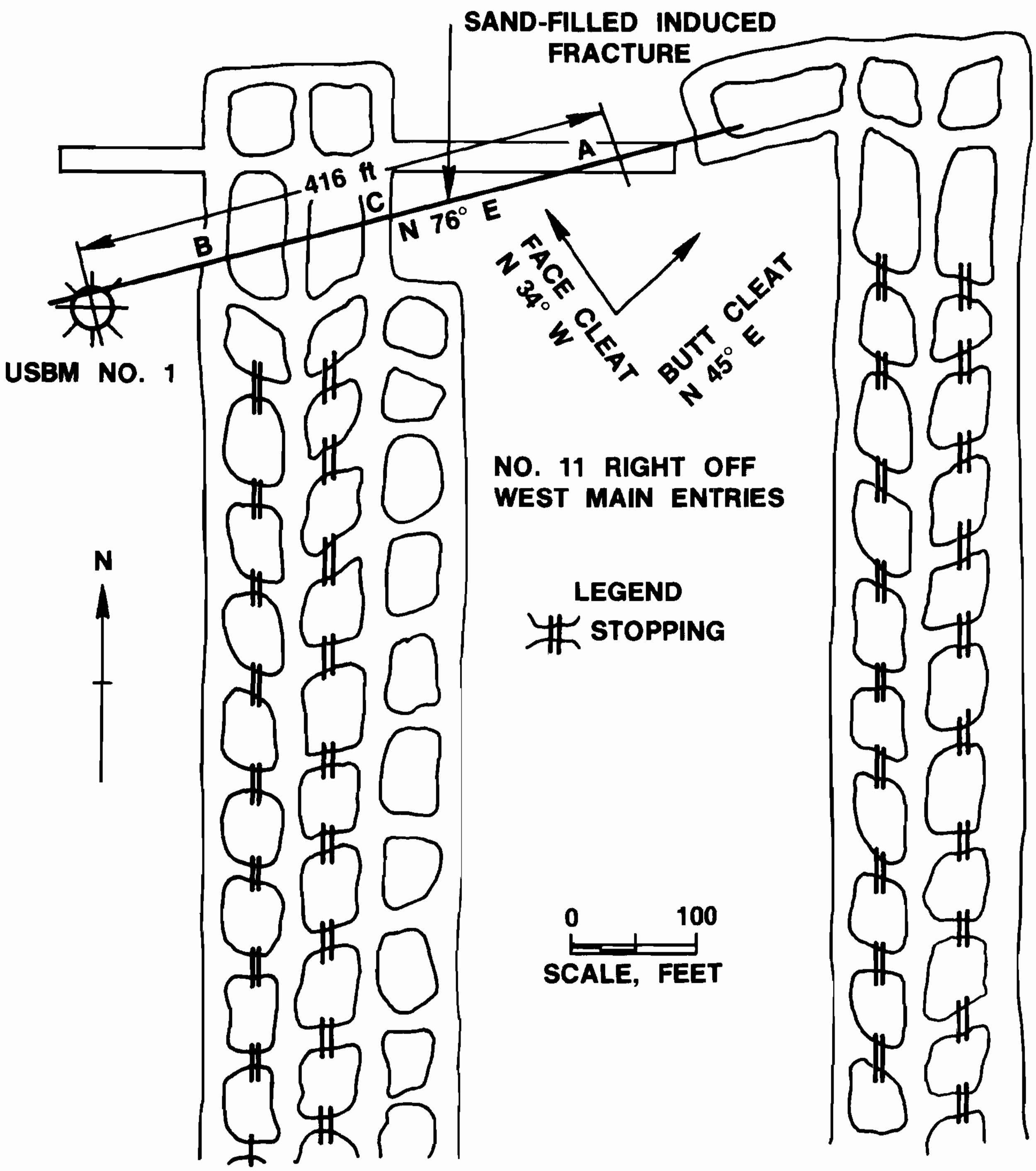


FIGURE 33. - TRACE OF SAND-FILLED INDUCED FRACTURE IN ROOF COAL OF MINE ENTRY AT POINT A ON FIGURE 32 (16).

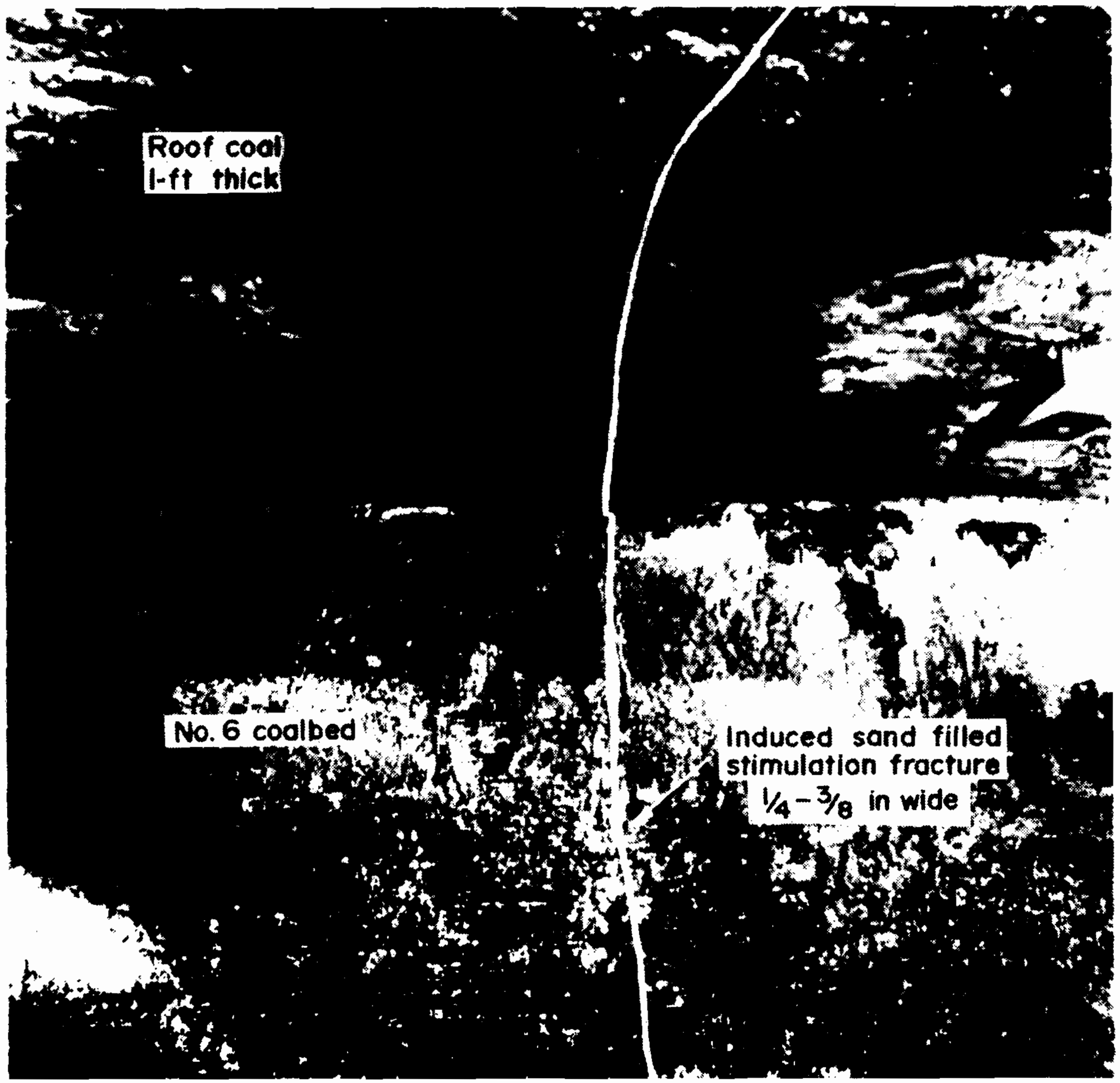


FIGURE 34. - DETAIL OF INDUCED FRACTURES IN ROOF COAL AND TERMINATION OF FRACTURE IN ROCK STRATA OVERLYING COALBED AT POINT A ON FIGURE 32 (16).

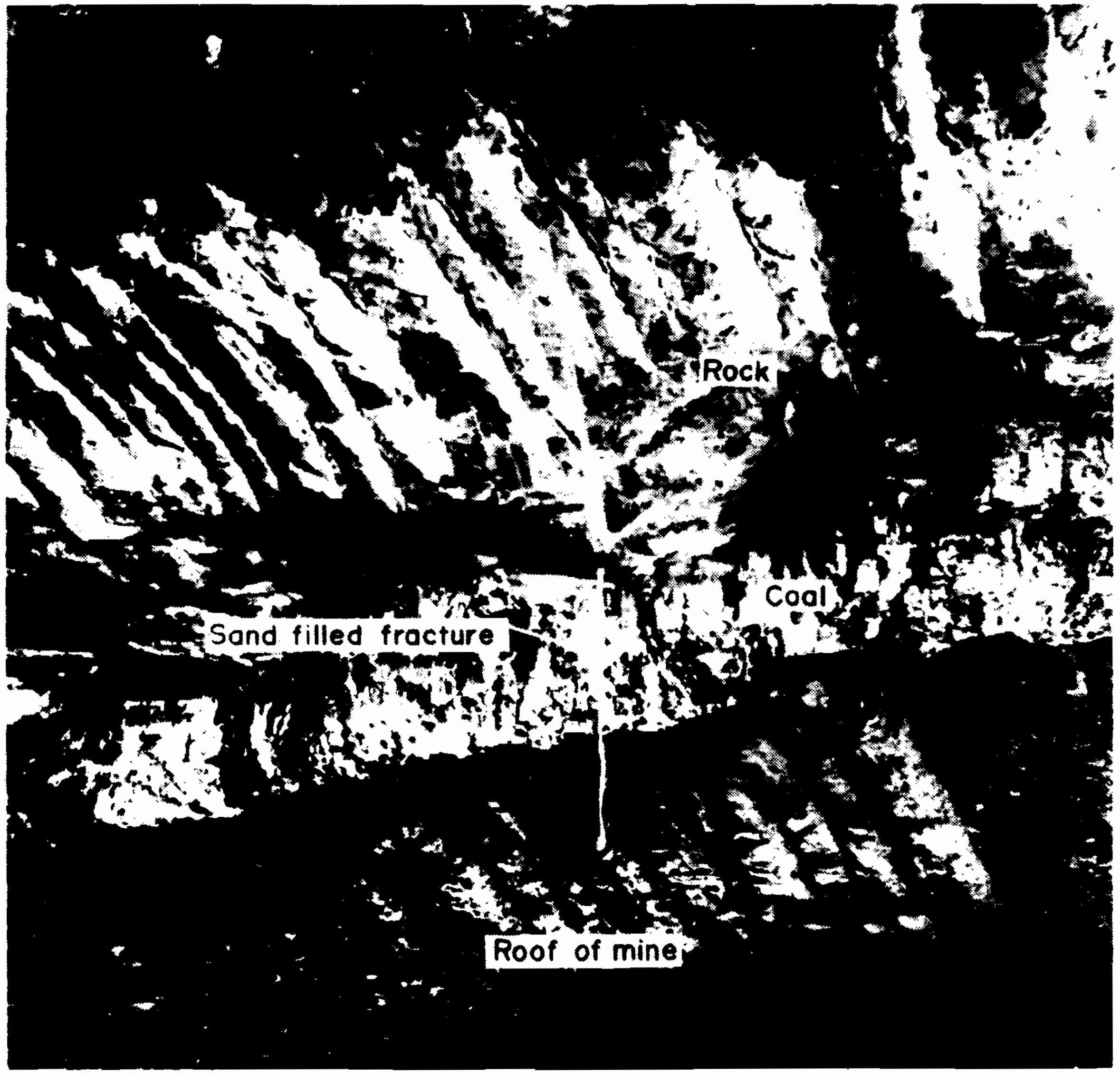


FIGURE 35. - SAND-FILLED INDUCED FRACTURES IN RIB AND ROOF COAL AT POINT C ON FIGURE 32 (16).

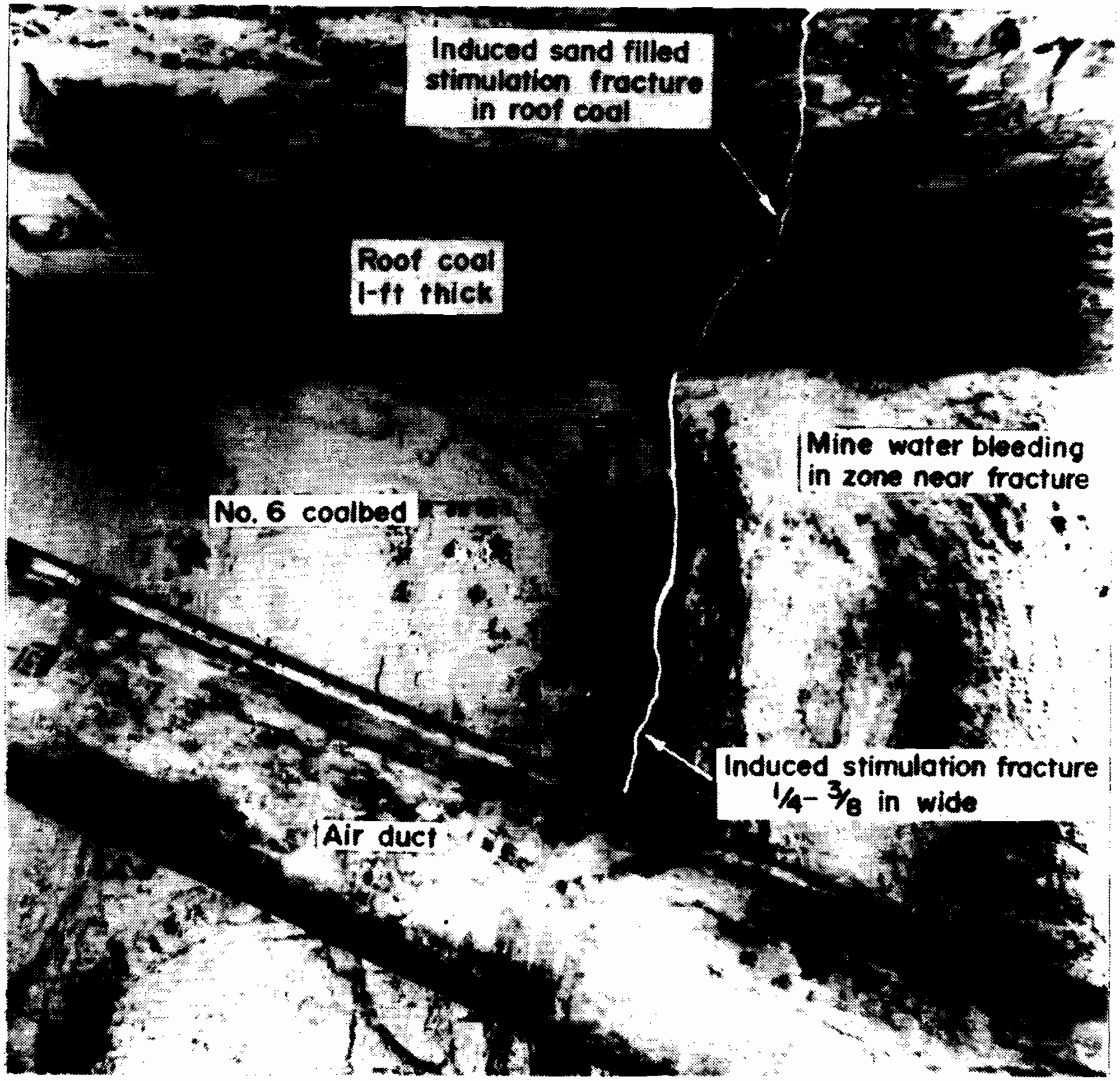
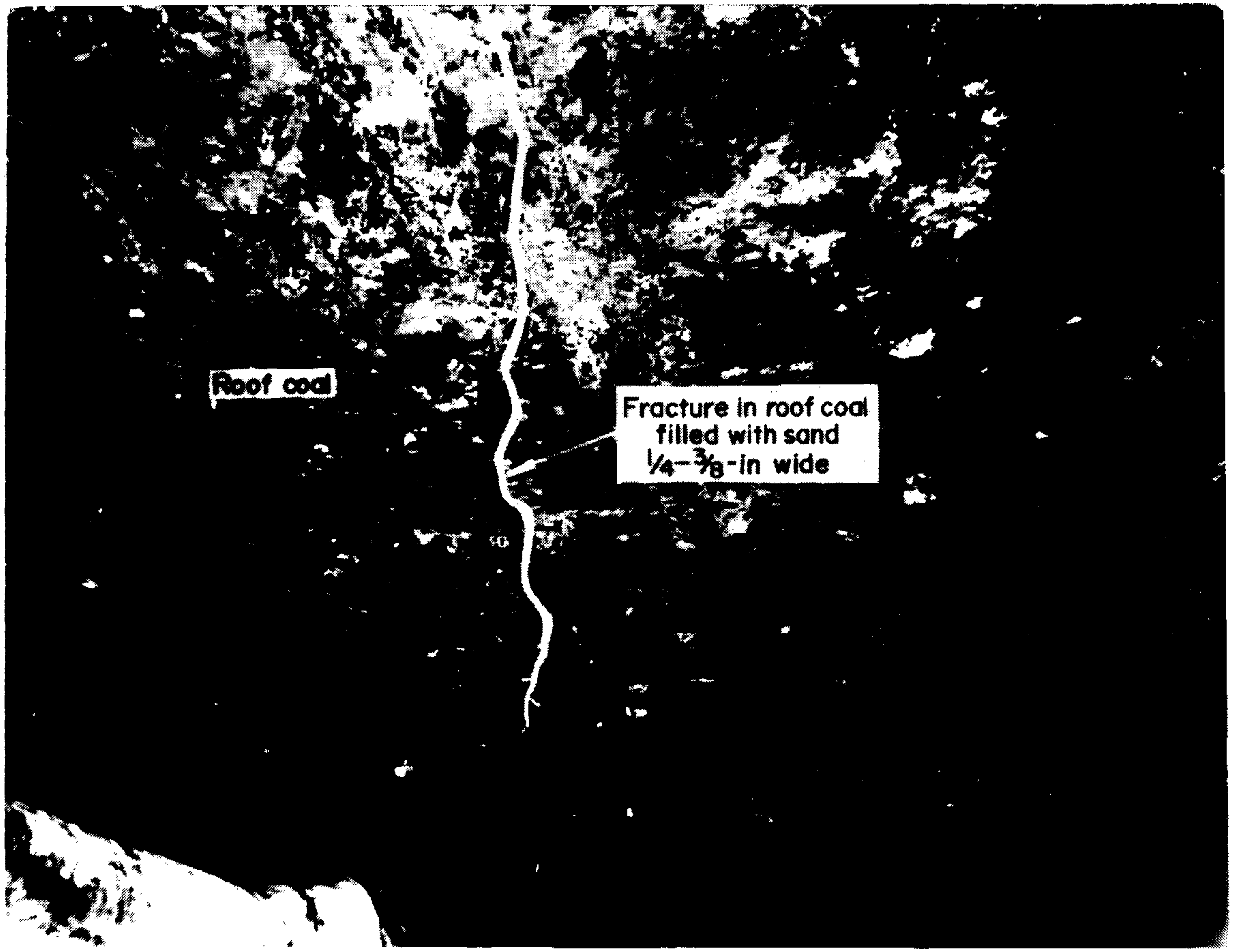


FIGURE 36. - SAND-FILLED INDUCED FRACTURES IN RIB AND ROOF COAL AT POINT B ON FIGURE 32 (16).



STIMULATION USING FOAM

Foam, used as a fracturing fluid, is a mixture of liquid, gas, foaming surfactant, and proppant. The liquid used for coalbed stimulation is fresh water. Various types of surfactant have been used, but the type chosen must always be compatible with the water used so as to form a foam when mixed with gas. Nitrogen is currently the most popular gas used for treating coalbeds because it is generally available and is practically non-reactive with coal and coal's associated reservoir fluids. Figure 37 illustrates how these basic ingredients are combined and then injected into a well during foam stimulation.

The first Government-sponsored foam stimulation of a coalbed was conducted in early 1976 (see Table 3). Since that time, 45 coalbed gas drainage holes have been treated using foam. A few of the specific advantages of using foam rather than gelled fluids are:

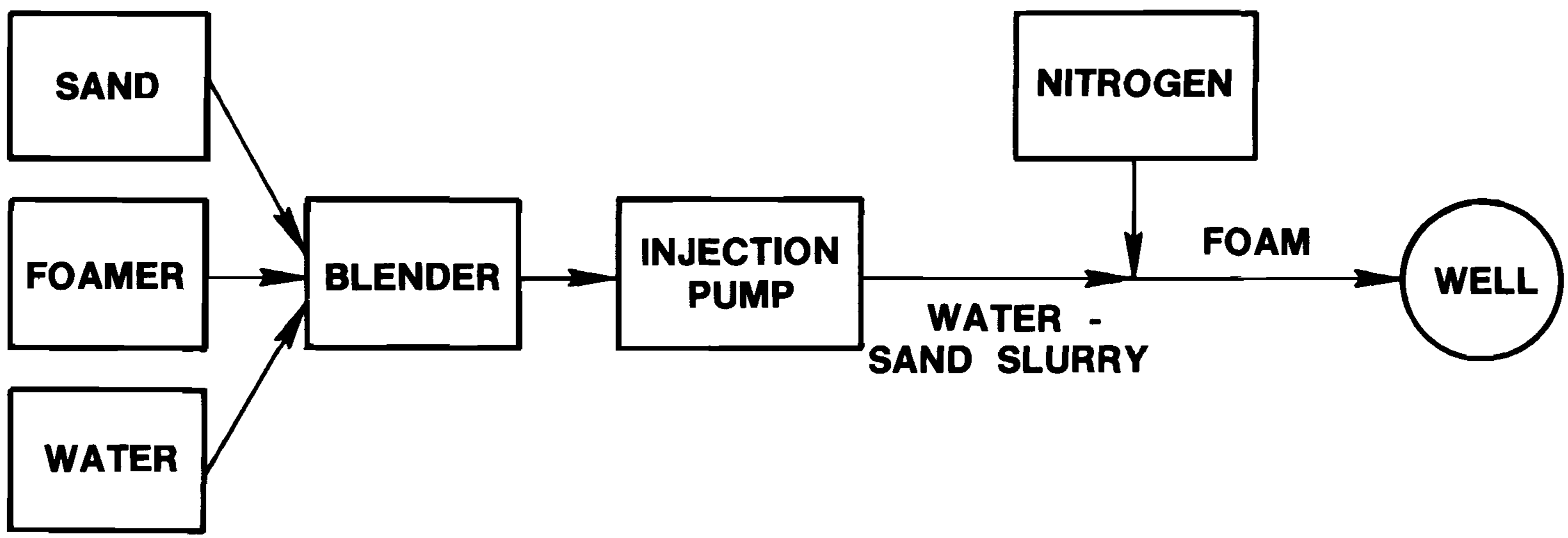
1. Foam possesses inherent qualities which appear to decrease the amount of fluid leak-off to the coalbed (2) (36). As a result, the number of "sand-outs" occurring during coalbed stimulation has been reduced by more than 50%.

2. Foam treatments do not rely on heavy gels to carry proppant during stimulation since the foam itself has sufficient proppant carrying capacity (1) (36). Problems associated with proper proportioning, mixing, injection, and breakdown of gels are thus avoided entirely.

3. Foam treatments are very clean in that most stimulation fluids are removed from the coalbed in less than one day. This short exposure time limits the possibility of harmful reactions with the coalbed reservoir system (2), which could reduce fracture-conductivity or cause formation damage.

4. The logistical advantages of using foam are significant. On-site water requirements, for example, are about 60-80% less using foam when compared to similar volume size gel treatments. The low liquid content of foam reduces hydraulic horsepower necessary for injection and thus, smaller pumping units are required for stimulation. Such reduced on-site storage and equipment size requirements also minimize costs for well site clearing operations.

FIGURE 37. - SCHEMATIC SHOWING SURFACE REQUIREMENTS OF FOAM-TYPE STIMULATION TREATMENTS.



5. Injection rates for foam can be 10 bpm or less 9/. Within a recently completed grid pattern, for example, 15 wells were each stimulated successfully with 50,000 gallons of foam using a single small pump truck normally used for cementing work (27). This pumping unit used a liquid injection rate of only 2.5 bpm to the 1,000 foot deep coalbed. After adding nitrogen and surfactant, the volume of foam injected was increased to 10 bpm.

The following case studies summarize some of the more significant work completed by Government research since the time foam was first introduced into coalbed stimulation design. This section is similar to the proceeding gelled fluid case studies in that it includes descriptions of all foam stimulated boreholes exposed thus far by mining.

Pittsburgh Coalbed, Greene County, PA (37)

The first coalbed to be foam-stimulated as a part of a Government sponsored test was the Pittsburgh coalbed in early 1976 on the Emerald Mine property, Greene County, PA. 10/ The success which resulted from the initial test treatment encouraged mine developers to complete a small pattern of eight degasification wells (Figure 38), seven of which were stimulated using foam (see Table 3, well Nos. 21,22,24,25,27,28,30).

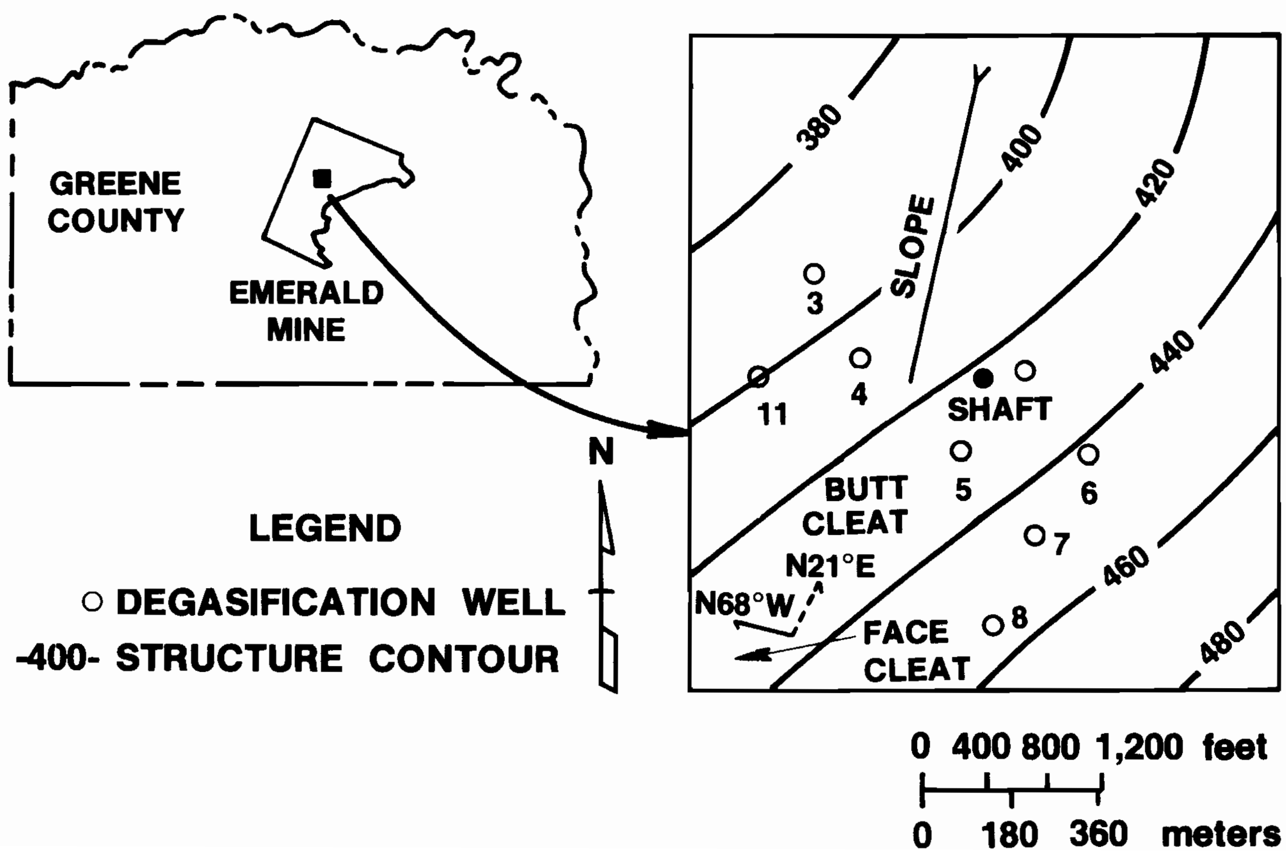
The seven wells were rotary drilled to about 40 feet below the Pittsburgh coalbed to provide a sump for water accumulation. The 6-1/4 inch diameter wells were cased with 4-1/2 inch diameter casing that was cemented to the surface. A drillable formation packer shoe was set in shale above the main coal bench of the Pittsburgh coalbed leaving the coalbed and the underlying sump open to the wellbore.

Each of the seven foam treatments used an average of 8,200 gallons of water, five gallons of foaming agent (surfactant) per 1,000 gallons of water, 11,100 pounds of 10 to 20 or 20 to 40 mesh sized prop sand, and 300,000 std cubic feet of nitrogen.

9/ Measured sand settling velocities in foam are generally much less than settling velocities in water or most gels. In fact, the ability for foam to carry proppant increases as flow velocity (injection rate) decreases (2). The use of comparatively low injection rates is therefore recommended when pumping foam.

10/ The first recorded foam-stimulation of the Pittsburgh coalbed took place March 24, 1976, near the Loveridge Mine (Consolidated Coal Company), Marion County, West Virginia. Information regarding this experiment is included in a publication entitled: Hydraulic Stimulation of the Pittsburgh Coal Seam: A CASE STUDY, by R. L. Mazza, Proccedings from Methane Recovery from Coalbeds Symposium sponsored by the Department of Energy in Pittsburgh, PA, April 18-20, 1979

FIGURE 38. - PATTERN OF EIGHT DEGASIFICATION WELLS LOCATED ON EMERALD MINE PROPERTY, GREENE CO., PA. (37).



Each treatment began with about 900 gallons of water (water pad) followed by 600 gallons of foam. The amount of sand added to the foam was increased gradually as a precaution against a "sand-out"; the injection rate was also gradually increased. The treatments were completed with a flush of foam to push the sand into the coalbed. Sand "screenouts" occurred during four of the treatments.

After treatment, the wells were allowed to flowback as soon as possible. Flowback of the wells, immediately after treatment, produced enough water to account for the treatment fluid plus some additional formation of water.

After flowback, the wells were equipped with sucker rod pumps (84 to 100-bbl/day capacities). Gas production was measured intermittently using an orifice meter (Table 12).

TABLE No. 12 - Gas production measured from degasification boreholes at Emerald Mine, Greene County, PA (37)

Date Tested	Gas Production, scfd							
Well No.	1	3	4	5	6	7	8	11*
09-24-76	-	7,500	-	940	20-30,000	120,000	10,800	-
10-01-76	14,000	-	-	-	2- 8,000	122,000	10,800	-
10-29-76	19,500	16,800	-	14,000	10,000	140,000	21,000	-
11-10-76	25,200	16,700	-	-	100-34,000	-	-	-
12-14-76	-	23,300	-	18,100	-	-	18,200	-
01-08-77	-	24,500	-	100,000	-	105,000	8,100	-
01-26-77	-	42,000	40,000	100,000	-	58,000	8,390	-
02-08-77	10,400	-	-	-	-	-	-	-
03-28-77	9,100	-	-	117,000	800	-	-	-
03-29-77	-	-	16,000	-	-	-	19,000	-
08-31-77	1,070	41,400	7,090	79,800	-	44,400	3,510	1,400
09-07-77	1,080	39,800	7,470	86,400	100,000	44,400	3,510	44,400
09-14-77	2,430	39,800	8,840	81,900	86,400	-	3,140	62,800
09-19-77	2,730	44,400	-	69,700	69,700	29,900	4,700	86,700
10-13-77	2,720	28,200	3,510	61,100	64,100	25,200	3,220	72,300
10-20-77	3,060	15,200	3,510	72,300	61,100	25,900	3,140	74,800
10-27-77	3,060	-	-	74,800	61,100	25,200	3,140	66,900
02-01-78	1,800	-	-	-	59,000	13,000	2,700	57,000
06-02-78	-	30,000	-	-	82,000	28,000	2,000	20,400
07-20-78	-	17,500	-	-	-	14,400	-	16,500
09-11-78	625	1,000	-	-	24,400	5,800	-	16,000
10-26-78	-	800	-	-	-	-	-	8,000
11-19-78	-	-	-	-	-	-	-	3,000

*Stimulated using a pressurization/depressurization water frac technique referred to as "Kiel Frac".

Induced fractures were later examined underground after mining operations had passed near or through three of the seven foam stimulated borehole test sites. The sand-propped fractures observed were oriented both vertically and horizontally.

Horizontal fractures were recorded to be present at two of the well sites, EM-5 and EM-6. At EM-5, a well-developed, 1/8 to 1/4 inch thick sand-filled horizontal fracture was found present between the six foot thick main coal bench and an overlying hard draw slate unit. The fracture extended approximately 50 feet from the EM-5 wellbore location. At EM-6, horizontal fractures were present within two coal/roof slate boundary areas. One was about 1/4 to 1/2 inch thick, and was contained along the lower boundary of thin (8 to 10 inches) rider coal unit. The other horizontal fracture was present along the top of the main coal bench and was about 1/2 inch thick. Horizontal (and inclined) fractures extended at least 10 feet, and at most 80 feet, from the underground location of EM-6.

Vertical fractures were measured at all three of the wells (EM-5, EM-6, and EM-7). At EM-5, these partially sand-filled fractures were traced 150 feet from the well's underground location and ranged in width from hairline to about 1-1/2 inches. Vertical fractures from EM-6 were up to 2-1/2 inches wide, partially sand-filled, and were traced a total distance of only 20 feet. The actual distance of induced sand-propped fractures could not be determined since the fractures extending from EM-6 entered coal pillars present on both sides of the well. This meant that the maximum linear extension of these sand-filled fractures was less than 170 feet from the well site. At EM-7, vertical fractures were from 1/4 to 1/2 inches wide and could be observed for a distance of only 18 feet before the fracture entered a coal pillar. Maximum extension of vertical fractures from EM-7 was calculated to have been less than 120 feet from the wellbore.

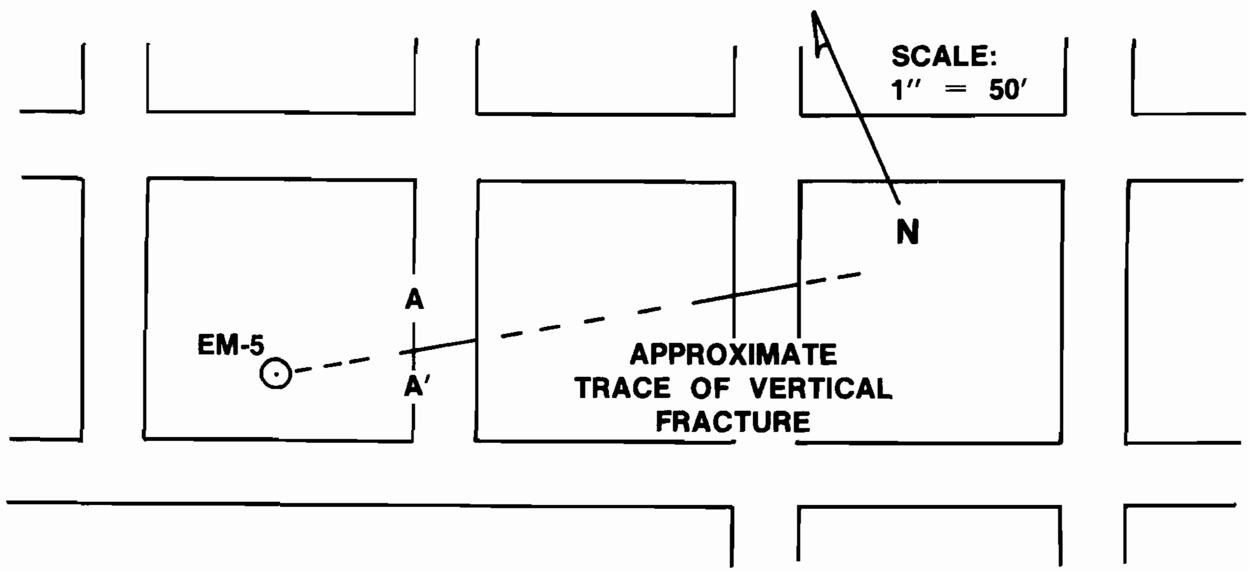
All the induced fractures observed underground at Emerald Mine were developed along what was determined to be the coal's face cleat direction.

No evidence was found to indicate that vertically induced fractures had penetrated the roof or floor rock material except at EM-6 where a 1/4 to 1/2 inch wide, partially sand-filled fracture was found to extend into the shale rock roof. As noted earlier, horizontally oriented fractures were also observed in areas of the roof above the main coal bench. Figures 39 and 40 illustrate the orientation and position of the induced fractures observed at EM-5 and EM-6.

Mary Lee Coalbed, Jefferson County, AL (26)

Two test wells were completed approximately 950 feet and 1,010 feet away from a mine operating at a depth of about 1,100 feet in the gassy

FIGURE 39. - POSITION AND ORIENTATION OF THE INDUCED FRACTURES OBSERVED NEAR DEGAS WELL NO. EM-5.



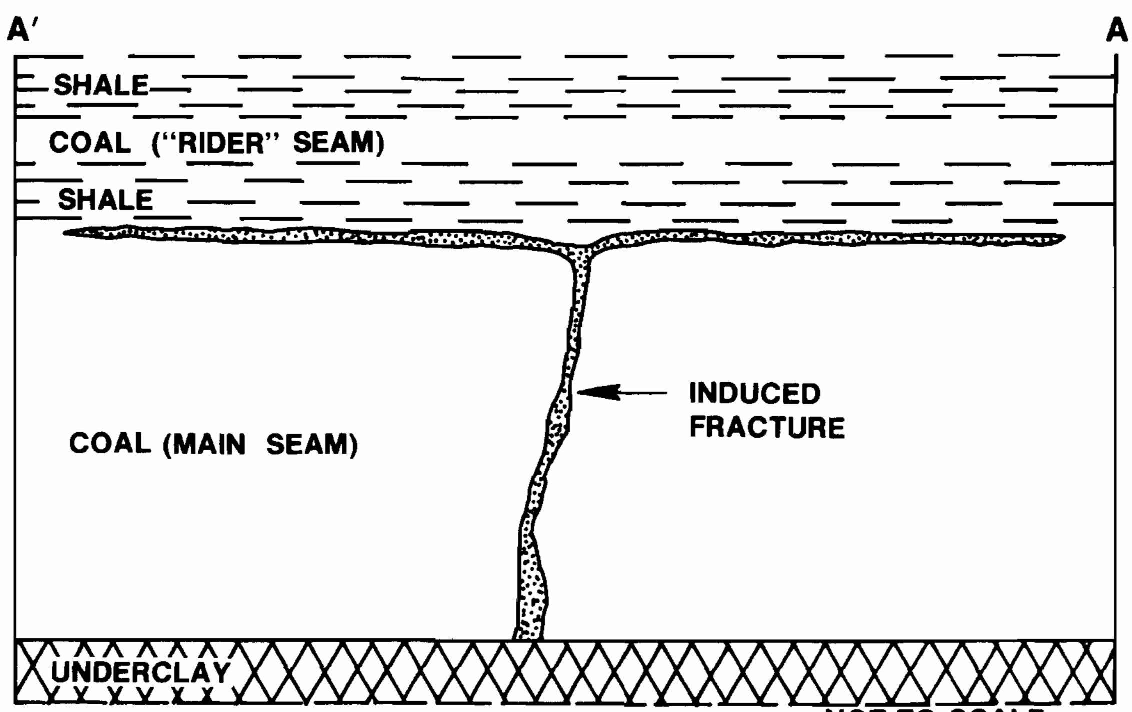
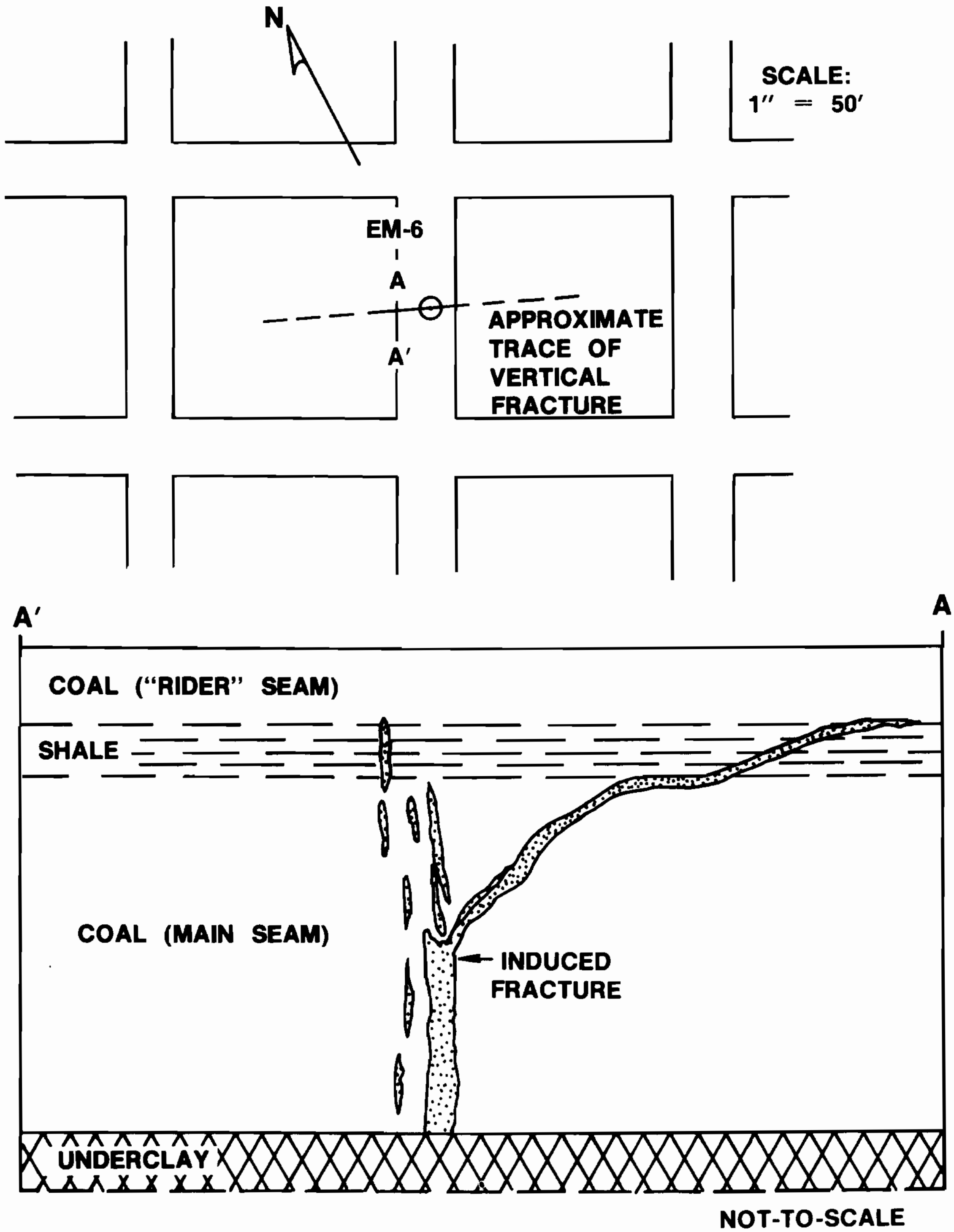


FIGURE 40. - POSITION AND ORIENTATION OF THE INDUCED FRACTURES OBSERVED NEAR DEGAS WELL NO. EM-6.



Mary Lee Coalbed. The two wells designated TW3 and TW4 (see Table 3, Well Nos. 36 and 42) were rotary drilled to 30 and 15 feet respectively, below the five-foot thick lower bench of the Mary Lee Coalbed. Both holes were geophysically logged and then cased from the top of the coalbed to the surface using a cement packer shoe. Casing centralizers and cement baskets were used to correctly position the casing and minimize the weight of the cement near the base of the casing.

An abrasive jetting device, fixed to small diameter tubing was used to cut vertical slots into the exposed coalbed (lower bench). Jetting design called for a nitrogen gas and 20-to 40-mesh size sand-water slurry to cut the vertical holes into the coal. Three slots spaced 120 degrees apart, were cut at TW3 and two slots, spaced 180 degrees apart, were cut at TW4.

The coalbed was then stimulated using foam (75 percent nitrogen, 25 percent water) to carry sand proppant. TW3 was treated using 20,600 gallons foam, 10,000 pounds 80-to 100-mesh size sand (used as a fluid-loss additive), and 15,000 pounds of 20-to 40-mesh size sand proppant. The original treatment design for TW4 was identical to that used at TW3. Stimulation procedures were stopped early at TW4 when foam containing sand was observed coming to the surface around the well casing. As a result, total volumes of materials used at TW4 were approximately 12,200 gallons foam, 10,000 pounds of 80-to 100-mesh sand and 2,500 pounds of 20-to 40-mesh sand.

The initial pressure "break" occurred at both wells about 750 psig while treating pressures were approximately 1,400 psig. Injection rates at TW3 and TW4 averaged 10 bpm. Both wells were treated through a 2-3/8 inch diameter tubing with a packer set in casing near the bottom of the hole.

The wells were allowed to flow back immediately following stimulation through a small diameter choke nipple. In this manner, downhole flow velocity was restricted, minimizing the possibility of carrying large amounts of proppant back to the wellbore. TW3 was allowed to "blow back" for approximately seven days after stimulation. TW4 was allowed to "blow back" water and gas without the use of a pump throughout the life of the well. A pump was installed at TW3 and both wells were equipped with meters to monitor production.

The Mary Lee coalbed is comprised of two benches in the area of Oak Grove (8). The lower bench is the thicker of the two and is the coal unit mined. The upper bench is thin, contains several shale partings, and occurs about seven feet above the lower coal. A plan to stimulate the upper coal bench was implemented at TW3 approximately seven months after stimulation of the lower coal unit.

The upper bench was relocated through casing using a Gamma ray - neutron log and then perforated with shaped charges. The coal was then stimulated through tubing using 5,000 gallons of foam, 3,400 pounds of 80 to 100 mesh size sand, and 3,600 pounds of 20 to 40 mesh size glass beads. Formation "break" was recorded to be 600 psig. Average injection rate was 5 bpm.

Test Well No. 3 was put into production on December 20, 1976 (Figure 41). An initial period of rather unsteady, but generally high daily gas flows is attributed to several unloading episodes similar to those described earlier by Lambert and Trevits (23). Gas flow from the well soon became less erratic but generally declined from over 140,000 cfd to 50,000 cfd after 55 days of monitoring. Daily water flow from TW3 also declined during this period from over 75 bpd to 13 bpd. During the next 161 days of production, gas rates increased gradually to 85,000 cfd while water flow dropped only slightly to 10 bpd. After 216 days of production, the gas flow was stopped by flooding the well with water to allow for stimulation of the upper bench of coal. Pumping operations resumed 25 days later. This time, water production exceeded 75 bpd for seven days and then decreased to 18 bpd during the last 30 days of production. Gas flows from the well rose to 45,000 cfd as water flow decreased. The complete production history of TW3 is shown on Figure 42. Figure 43 shows gas production from TW1. Estimates of gas flow from TW4 during the initial "production" period indicated a rate of over 180,000 cfd. Twenty-three days after stimulation, measurements using an orifice and a manometer showed daily gas production to be 183,000 cfd. A meter, installed at TW4 several days later, indicated that daily gas flows were very high but somewhat erratic. Flows averaged about 150,000 cfd until a sharp drop occurred around October 1, 1977. Gas rates had declined to about 40,000 cfd the day before the well was plugged.

It is important to remember that TW4 was never equipped with a pump to remove water from the wellbore, which explains, in part, the erratic nature of the curve shown on Figure 43. Also, portions of Test Well No. 3 gas and water production (shown on Figure 43) indicate that each test well affected the other's production. This again, accounts for some of the erratic production from TW4.

The composition of gas produced from TW3 and TW4 is shown on Table 13. Analysis of gas samples two days after TW3 was put on production indicates that only a small percentage of the nitrogen used to stimulate the well remained in the coal at this time. Similarily, gas produced from TW4 contained less than seven percent nitrogen an almost 93 percent methane only two days after the well was stimulated.

FIGURE 41. - POSITION OF TW3 AND TW4 IN RELATION TO ACTIVE MINING AT THE TIME WHEN BOREHOLE PRODUCTION WAS INITIATED (26).

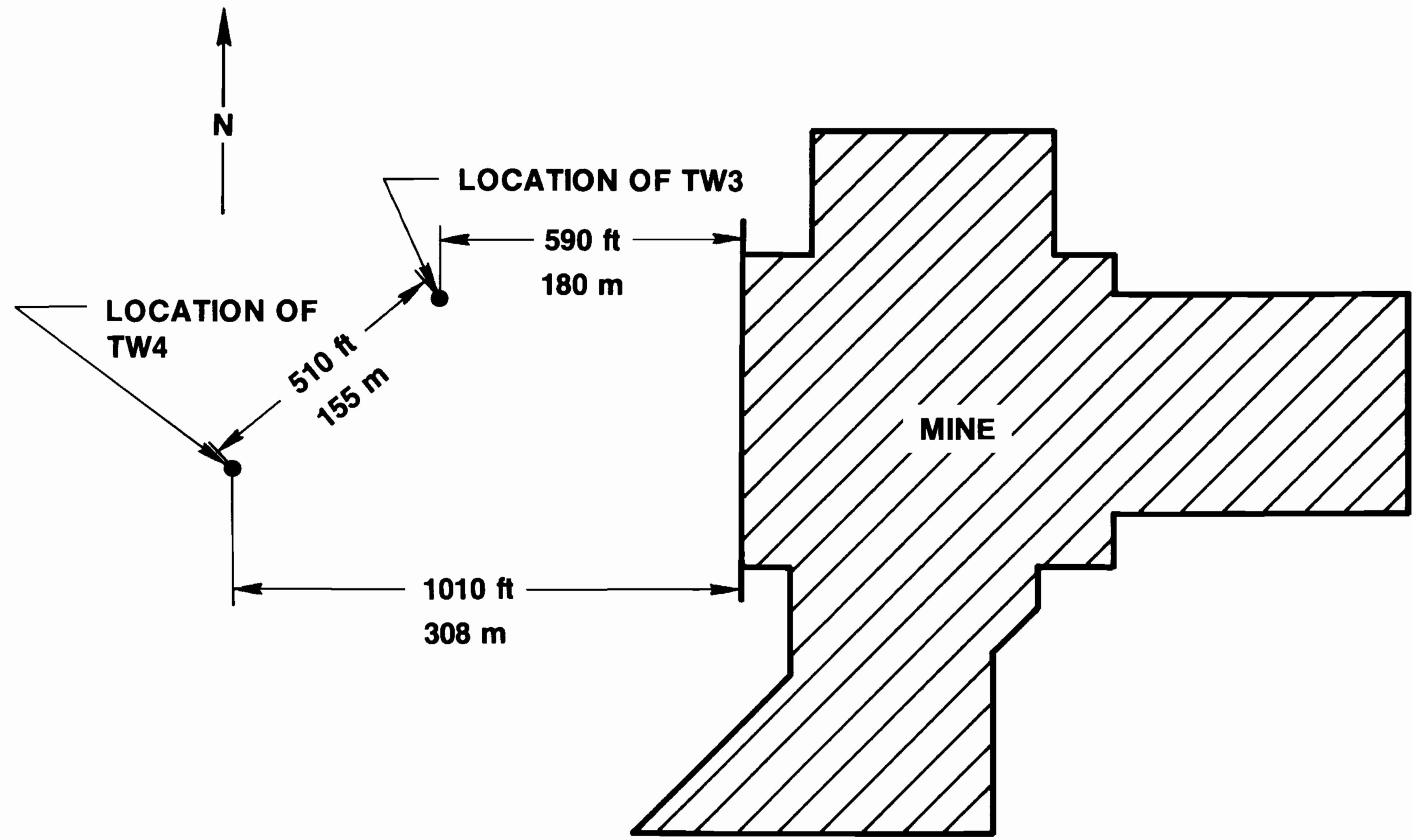


FIGURE 42. - PRODUCTION CURVES FOR TW3 (26).

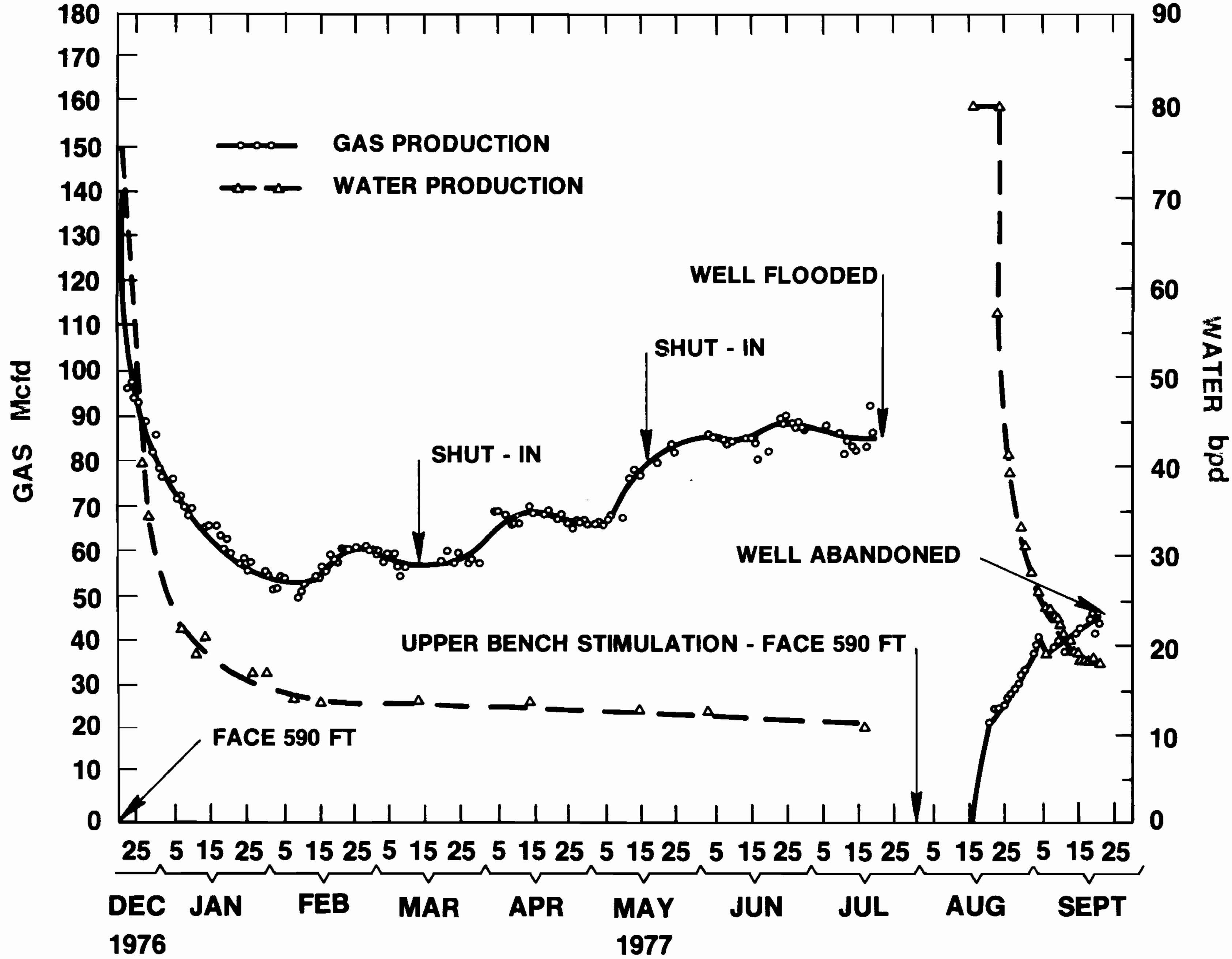


FIGURE 43. - PRODUCTION CURVES FOR TW4 AND PORTIONS OF TW3 (26).

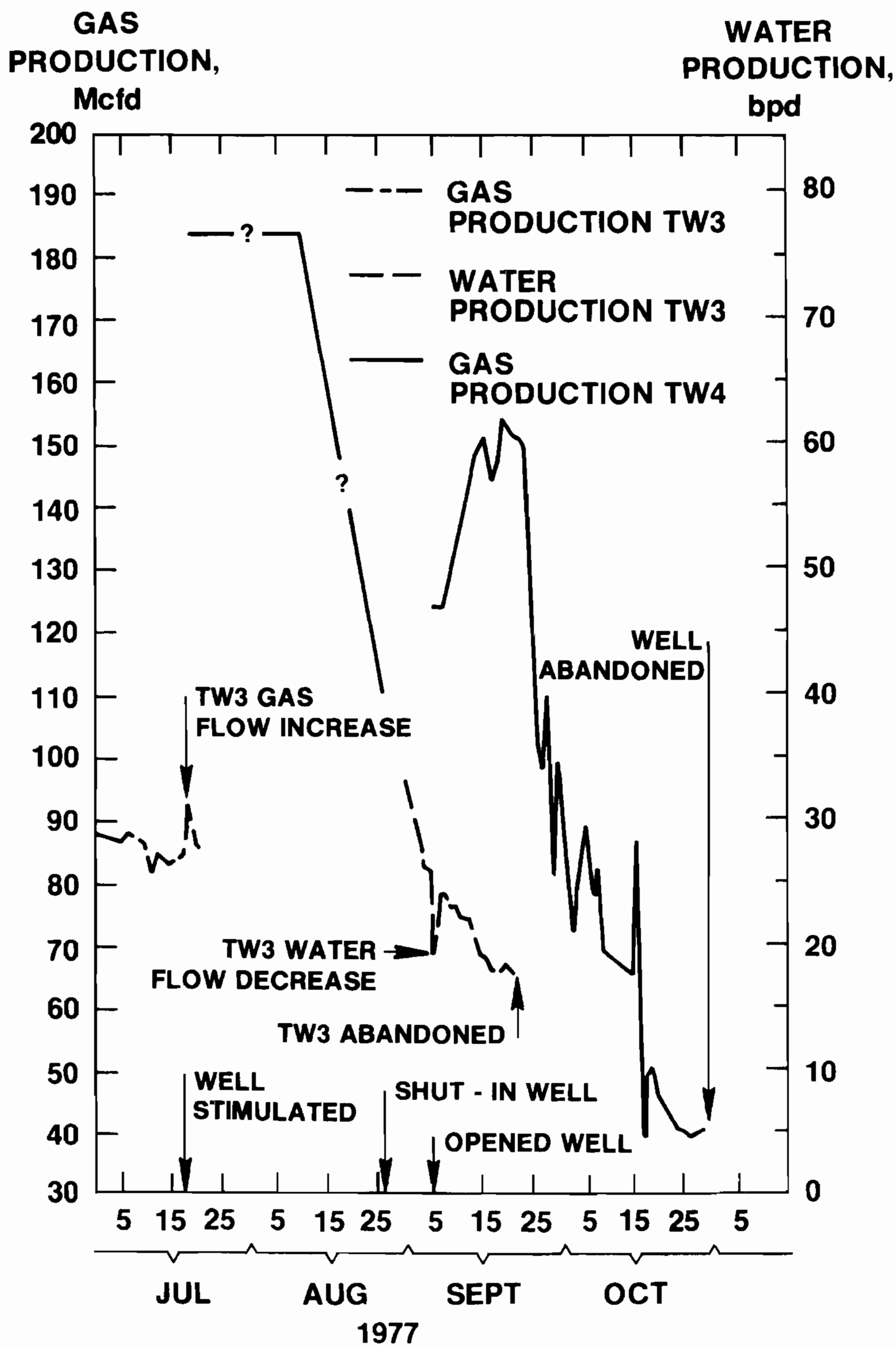


TABLE 13 - Gas Analyses from TW3 and TW4 (26)

Date Gas sampled	Percent gases in sample									Remarks
	CO_2	O_2	N_2	CO	CH_4	H_2	C_2H_6	C_3H_8	C_4H_{10}	
--TW3--										
11/21/76 - well stimulated										
12/20/76 - well put on production										
12/22/76	0.03	0.42	4.5	no	94.6	no	0.0030	0.0001	no	
01/14/77	0.02	0.06	2.3	no	97.6	no	0.0083	no	no	
02/15/77	0.02	0.08	2.0	no	97.9	no	0.0058	no	0.0001	
07/18/77	0.03	0.06	1.6	no	98.3	no	0.0043	no	no	10:20 a.m.*
07/18/77	0.03	0.06	3.2	no	96.7	no	0.0044	no	no	3:22 p.m.*
07/18/77	0.03	0.10	6.5	no	93.4	no	0.0046	no	no	4:54 p.m.*
07/19/77	0.03	0.08	2.5	no	97.4	no	0.0052	no	no	
09/13/77	0.03	0.03	1.9	no	98.1	no	0.0067	no	no	
--TW4--										
07/18/77 - well stimulated										
07/18/77 - well put on production										
07/20/77	0.06	0.50	6.7	no	92.8	no	0.0049	no	no	
08/10/77	0.02	0.04	1.1	no	98.8	no	0.0008	0.0002	no	
09/13/77	0.02	0.05	0.09	no	99.0	no	0.0067	no	no	
10/16/77	0.02	0.06	1.1	no	98.9	no	0.0061	no	no	
10/17/77	0.02	0.10	1.2	no	98.7	no	0.0074	no	no	

*Test Well No. 4, 510 feet away from Test Well No. 3, was foam stimulated from 2:14 p.m. to 2:42 p.m. on July 18. Note the increase in N_2 gas produced from TW3 shortly after.

After TW3 and TW4 were mined through, an underground study was conducted to determine if the foam-induced fractures had propagated in directions which correspond to the area's coal cleat and rock joint trends. To do this, an area of the mine near TW3 and TW4 was divided into 23 stations as shown on Figure 44. Compass measurements were made of all visible roof joints and at least 15 coal cleats within each station. Direction of all stimulated fractures containing propping agent, fluid-loss material, or cement were also measured. All measurements were adjusted for magnetic declination and then plotted as rose diagrams. Figure 45 is a composite rose diagram for the entire area. The average direction of the stimulated fractures was found to be N 67° E, while the average roof joint direction in the northeast quadrant was N 66° E. The coal cleat direction (face cleat) averaged N 55° E.

Figure 46 is a plan view of the mine showing the test well locations and the traceable lengths of the fractures induced by stimulation. Coalbed features, such as highly slickensided "roll" areas and slight structural displacements are also noted on Figure 46.

Propagated fractures examined were vertical, typically beginning as a hairline crack about three feet up from the base of the coal, and gradually widened to approximately 3/16 inch at the top of the coal. The fractures continued upward at the same thickness for an undetermined distance into the roof.

Cement used to set casing was contained within the same vertical plane as the sand and extended up to 80 feet from the wellbores. Examination of samples of this cement showed it to contain several coal particles but no sand.

A large quantity of casing cement was found below the packer shoe at TW4. Cement covered most of the coalbed except where the two slots, each five inches wide were cut from nine to 12 inches into the coal. The orientation of these slots was found to be approximately 90 degrees to the stimulated fracture. TW3 had not been intercepted directly at the time of the underground study so it was impossible to make similar inspections of the packer and jetted slots.

FIGURE 44. - SURVEY STATIONS DIVIDING AREA OF MINE NEAR TW3 AND TW4 (26).

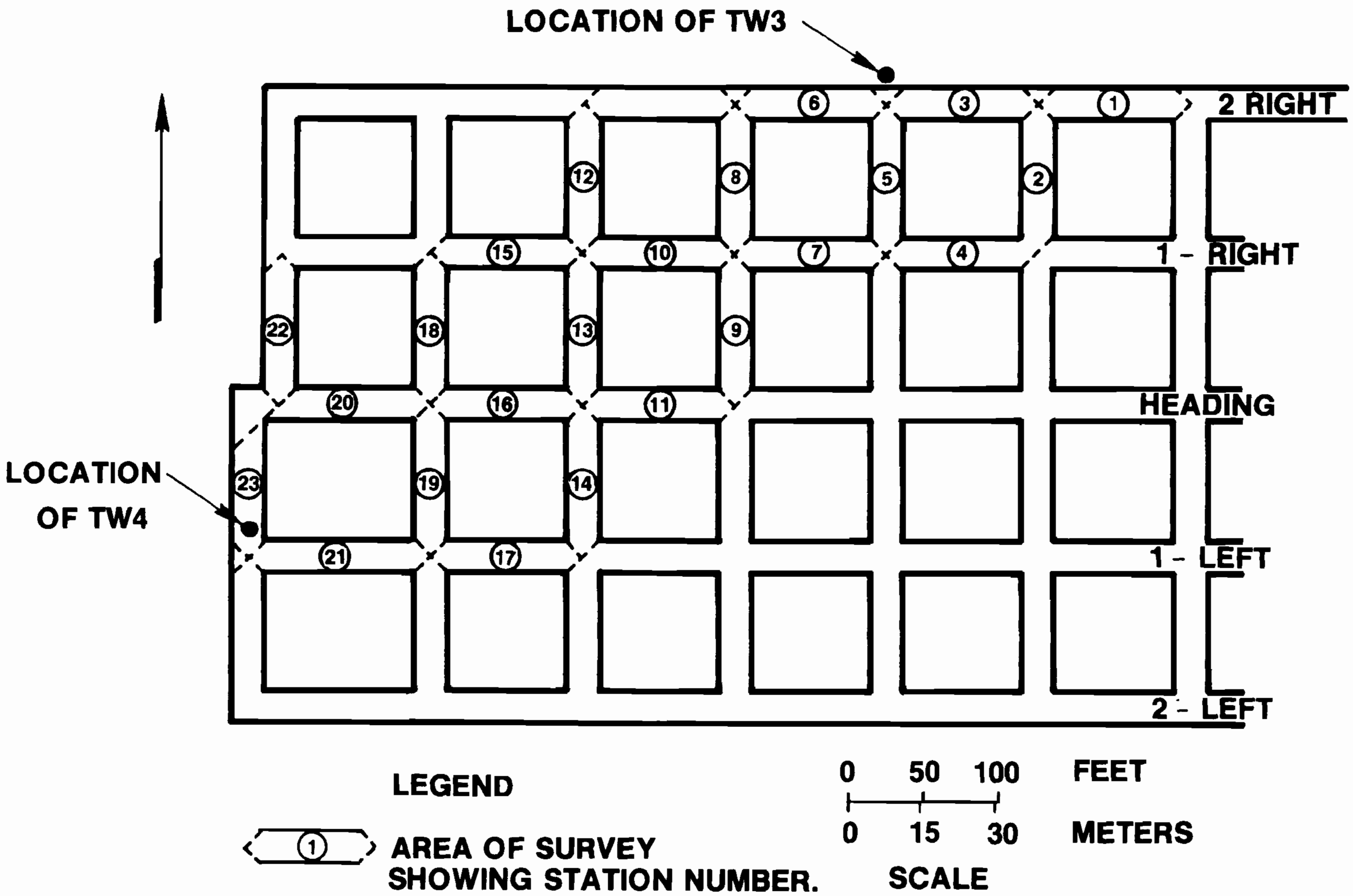


FIGURE 45. - COMPOSITE ROSE DIAGRAM OF TW3 AND TW4 SURVEY AREA SHOWING CLEAT, ROOF JOINT, AND INDUCED FRACTURE DIRECTIONS.

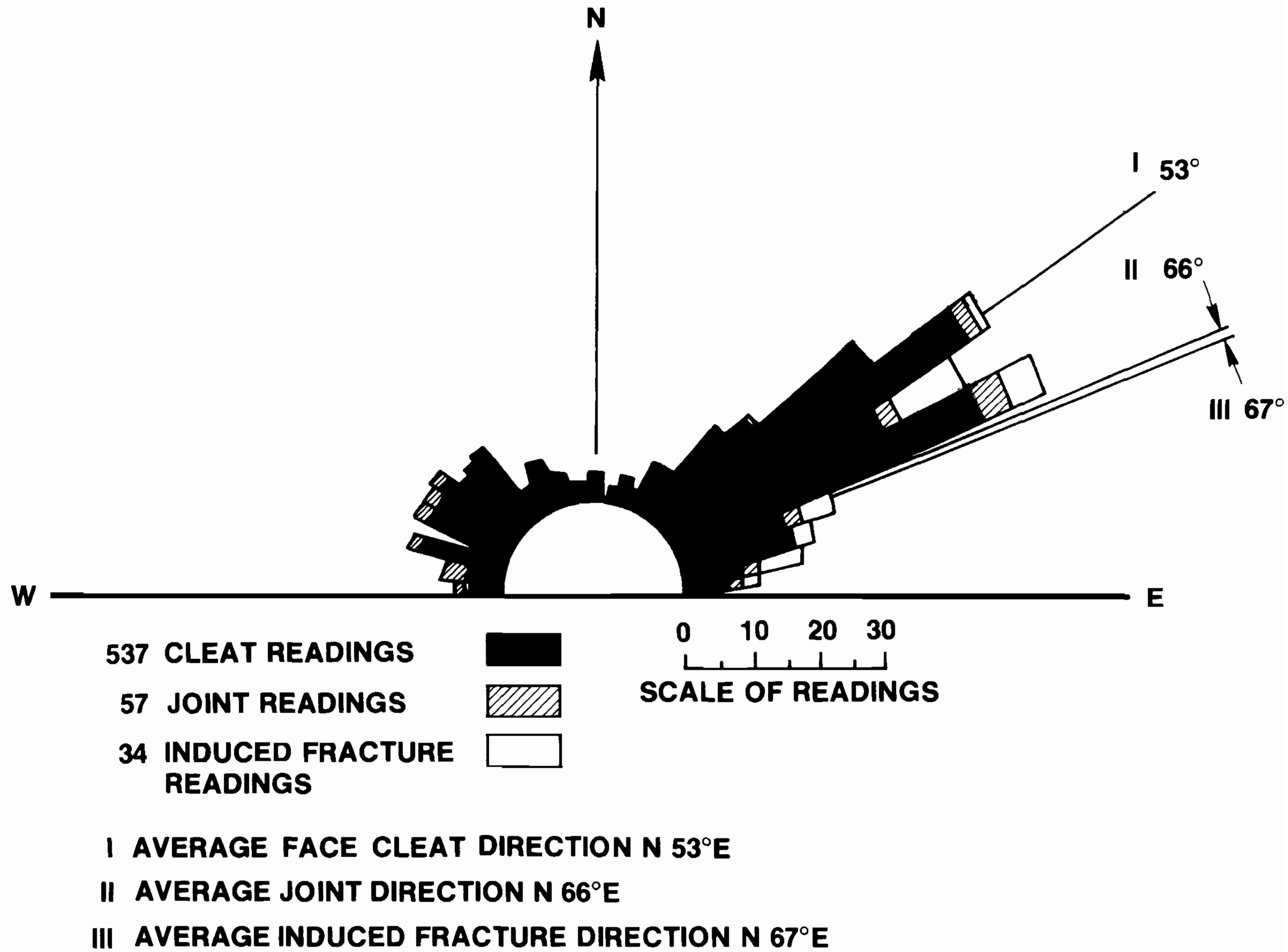
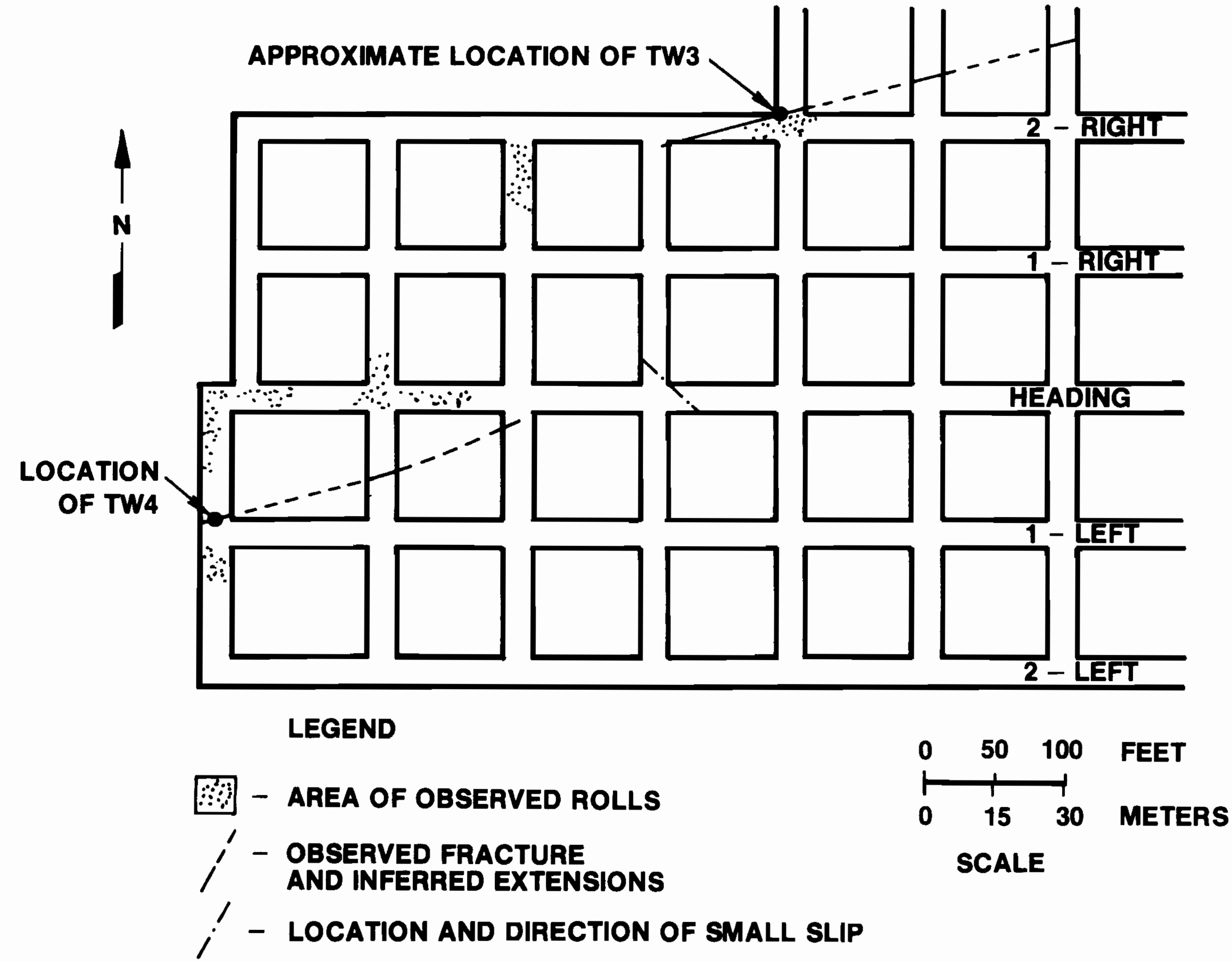


FIGURE 46. - PLAN VIEW OF MINE SHOWING TW3 AND TW4 LOCATIONS, TRACEABLE INDUCED FRACTURES AND OTHER FEATURES AS OBSERVED UNDERGROUND (26).



Smaller-sized sand (80 to 100 mesh) was found to make up over 90% of the stimulation material within the coalbed. Examination of sand taken from the roof showed it was mostly the 20 to 40 mesh size. No evidence of the glass beads used to stimulate the upper bench at TW3 could be found.

Mary Lee Coalbed, Jefferson County, Alabama - Case II (27)

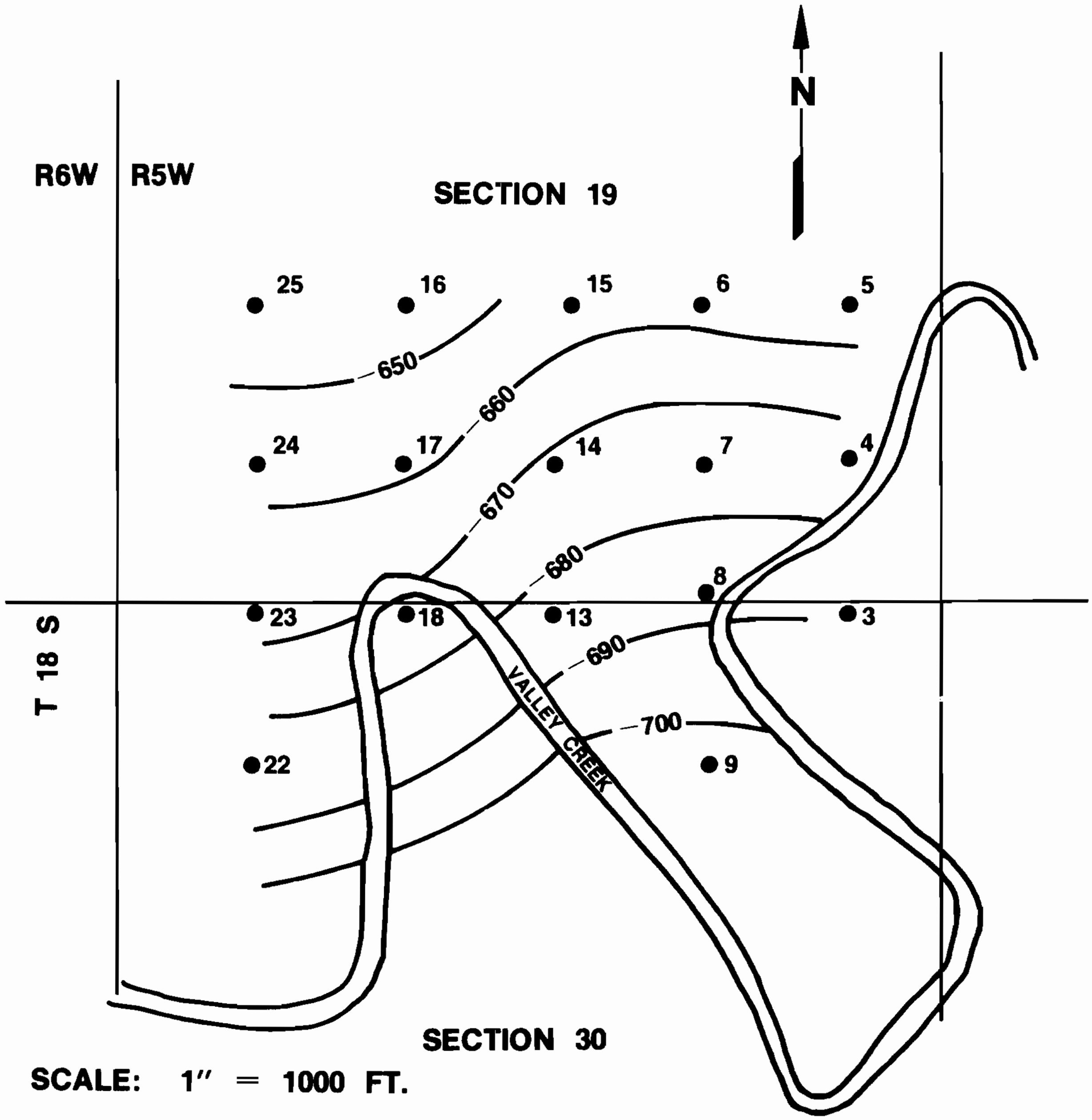
The largest scale application of foam stimuation was completed in the 1,100 foot deep, five foot thick, lower bench of the Mary Lee Coalbed near Oak Grove, Alabama, July thru November, 1977. Fifteen of 17 coalbed gas drainage wells, within a closely spaced grid pattern (Figure 47), were treated using an average of 48,200 gallons of foam (25% water). Specifications for each of these treatments are included on Table 3, Well Nos. 43, and 47 thru 60.

One of the more noteworthy facts about the Oak Grove well stimulations is that not a single "sand-out" occurred during any of the 15 foam treatments. The absence of sand-outs generally indicates that little fluid leak-off occurred during these treatments. It is not clearly understood whether fluid leak-off was extremely well-controlled due to the inclusion of a particular type of physical fluid-loss control agent 11/ that was mixed with the first 20,000 gallons of foam pumped into each of these wells or because the foam itself possessed highly efficient fluid-loss capabilities (2). The fact that the last two wells stimulated (Nos. 59 and 60 on Table 3) were treated successfully using up to 75% less of the fluid-loss agent suggests that the foam itself, was not very susceptible to leak-off. It is now thought that future foam treatments in this area will require only very small amounts of, or no additional, additives to control fluid-loss.

Flowback after stimulation of each of the 15 wells typically lasted less than 24 hours. During this time, most of the fluid used to treat the wells was brought to the surface. The wellbores were then cleaned out and equipped with pumps to remove water, and meters to monitor production.

11/ The physical fluid loss agent referred to is a spherical-grained, 80 to 100 mesh sized sand, thought to reduce fluid leak-off during stimulation by partially blocking minute secondary fractures as the main body of treatment fluid propagates away from the wellbore.

FIGURE 47. - OAK GROVE DEGASIFICATION GRID PATTERN, MARY LEE COALBED, JEFFERSON CO., ALABAMA



SCALE: 1″ = 1000 FT.

—680 STRUCTURAL CONTOURS (IN FEET), TOP OF LOWER BENCH OF MARY LEE COALBED (RELATIVE TO MEAN SEA LEVEL)

Figures 48 through 55 show daily gas and water flow from each of the foam-stimulated boreholes on the grid pattern at Oak Grove. The production presented occurred during a 1,000 day interval, starting on August 5, 1977, when the first borehole (No. 22, Figure 47) was put on production.

Chronic water-pump problems were experienced at Oak Grove throughout the time-period indicated. As the boreholes were pumped, sand that had been used during stimulation was routinely observed in the water effluent. At first, this sand did not disrupt the waterflow; however, as the water levels in the boreholes were lowered, sufficient quantities of sand accumulated to completely stop the pumps, especially during or just after well unloading occurred. As a result, it was necessary to continually remove pumps, repair them, clean the sand from the boreholes, and then reequip the boreholes for production. Gas flow from the coalbed decreased sharply or stopped from each borehole in response to rising water levels, as its pump became less effective or completely inoperative. Thus, both water and gas production rates fluctuated greatly during the period of time presented.

Daily production rates, number of boreholes pumping, and the cumulative amount of gas and water produced from the entire field is presented on Figure 56. It should be noted that data from two boreholes in the pattern which were not foam-stimulated have been included on Figure 56. These two boreholes are numbered 7 and 9 on Figure 47. Production from borehole No. 9 is presented separately on Figure 58 and production from borehole No. 7 is shown on Figure 60.

FIGURE 48 - DAILY PRODUCTION FROM FOAM-STIMULATED WELLS NO. 3 AND NO. 4, MARY LEE COALBED DEGASIFICATION PATTERN NEAR OAK GROVE, JEFFERSON COUNTY, ALABAMA

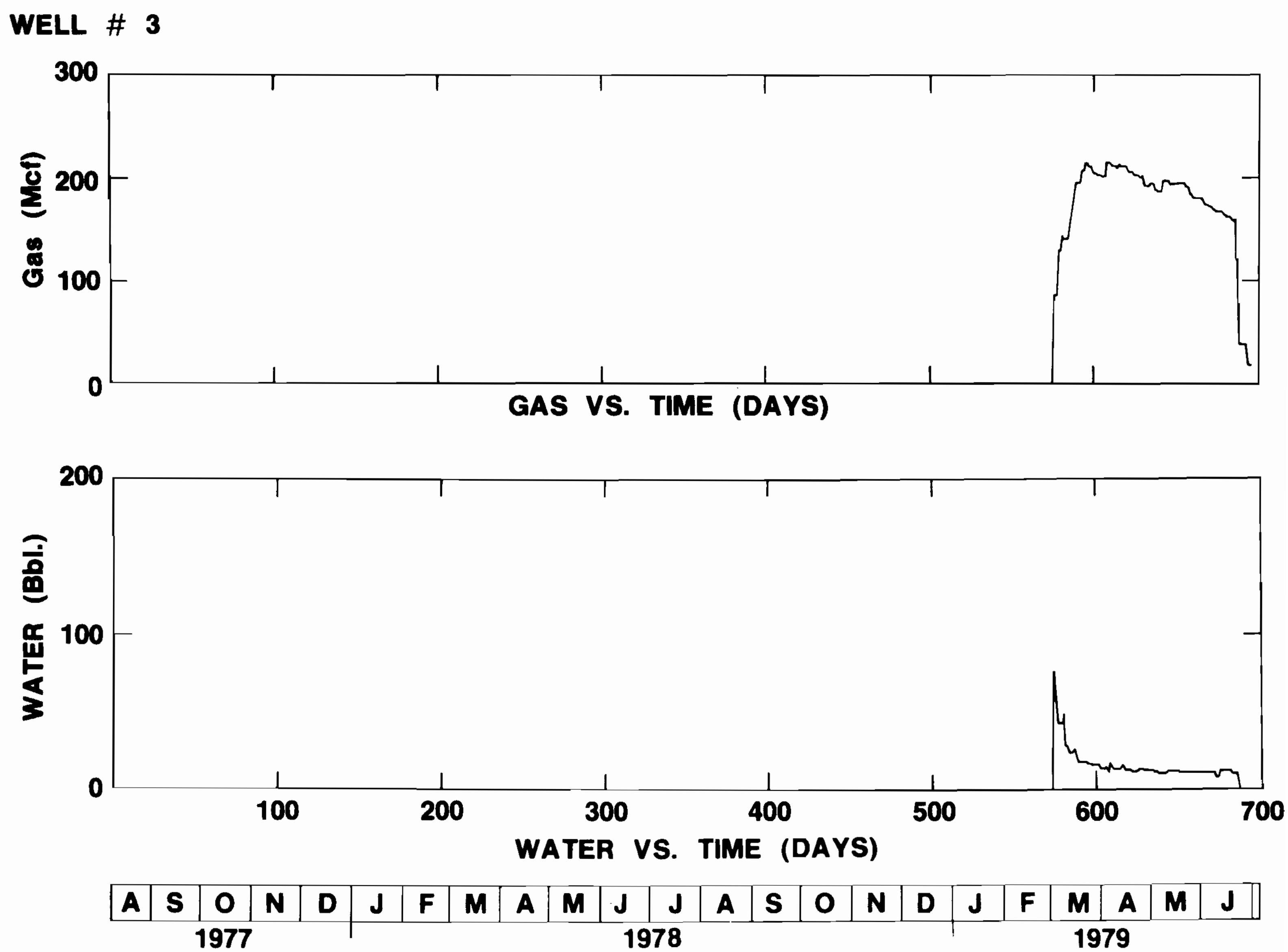


FIGURE 48A - DAILY PRODUCTION FROM FOAM-STIMULATED WELLS NO. 3 AND NO. 4, MARY LEE COALBED DEGASIFICATION PATTERN NEAR OAK GROVE, JEFFERSON COUNTY, ALABAMA

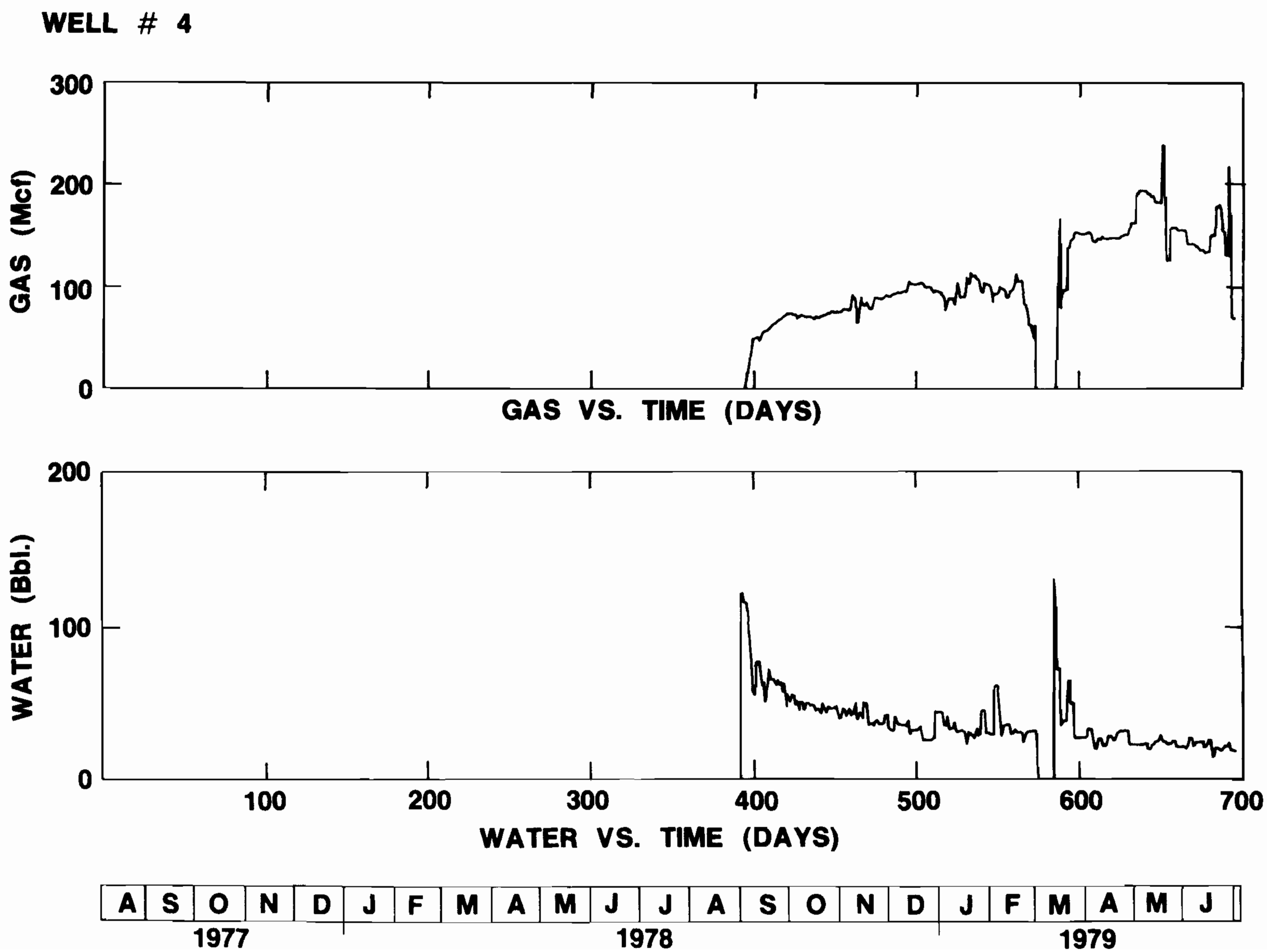


FIGURE 49 - DAILY PRODUCTION FROM FOAM-STIMULATED WELLS NO. 5 AND NO. 6, MARY LEE COALBED DEGASIFICATION PATTERN NEAR OAK GROVE, JEFFERSON COUNTY, ALABAMA

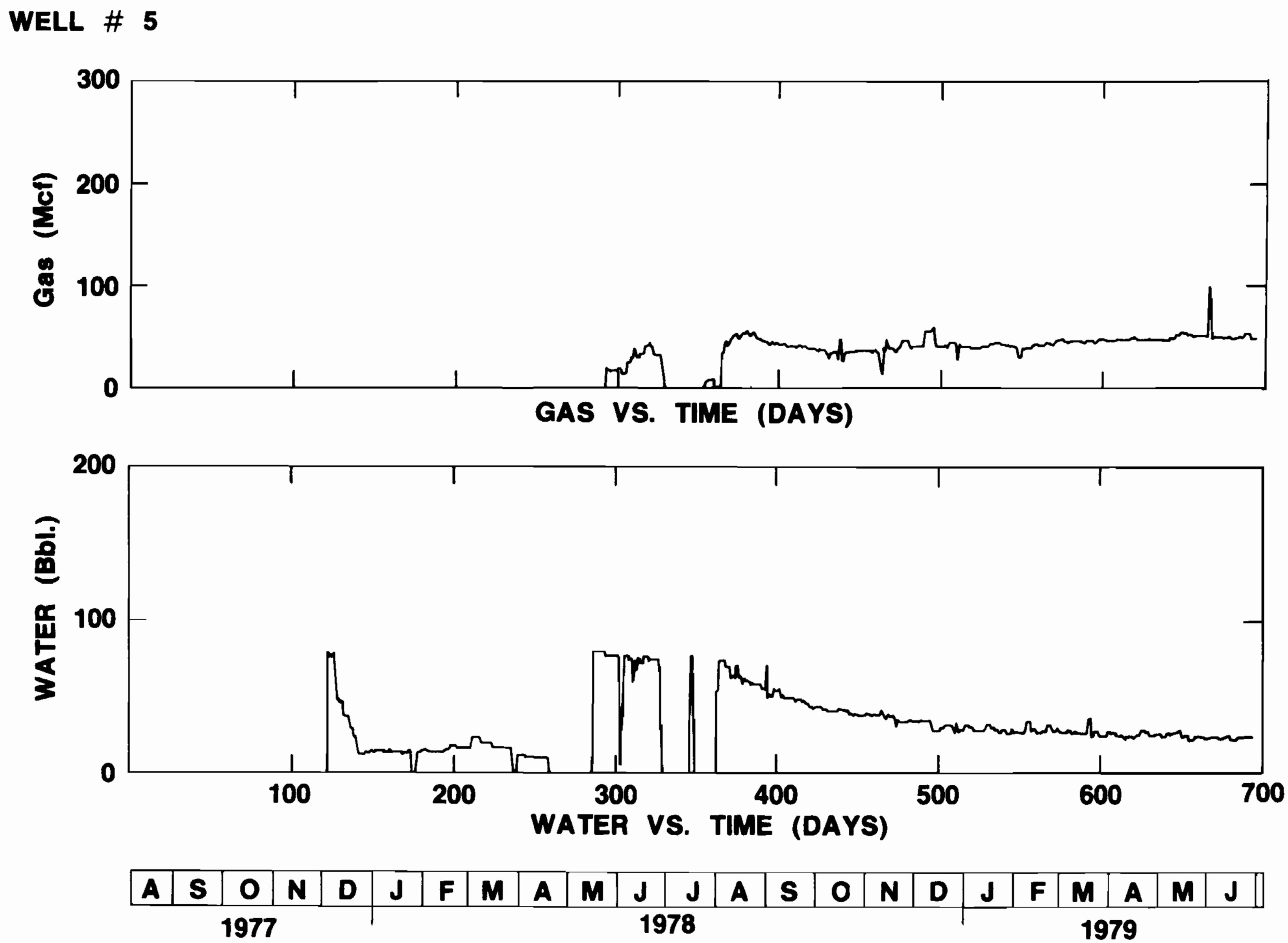


FIGURE 49A - DAILY PRODUCTION FROM FOAM-STIMULATED WELLS NO. 5 AND NO. 6, MARY LEE COALBED DEGASIFICATION PATTERN NEAR OAK GROVE, JEFFERSON COUNTY, ALABAMA

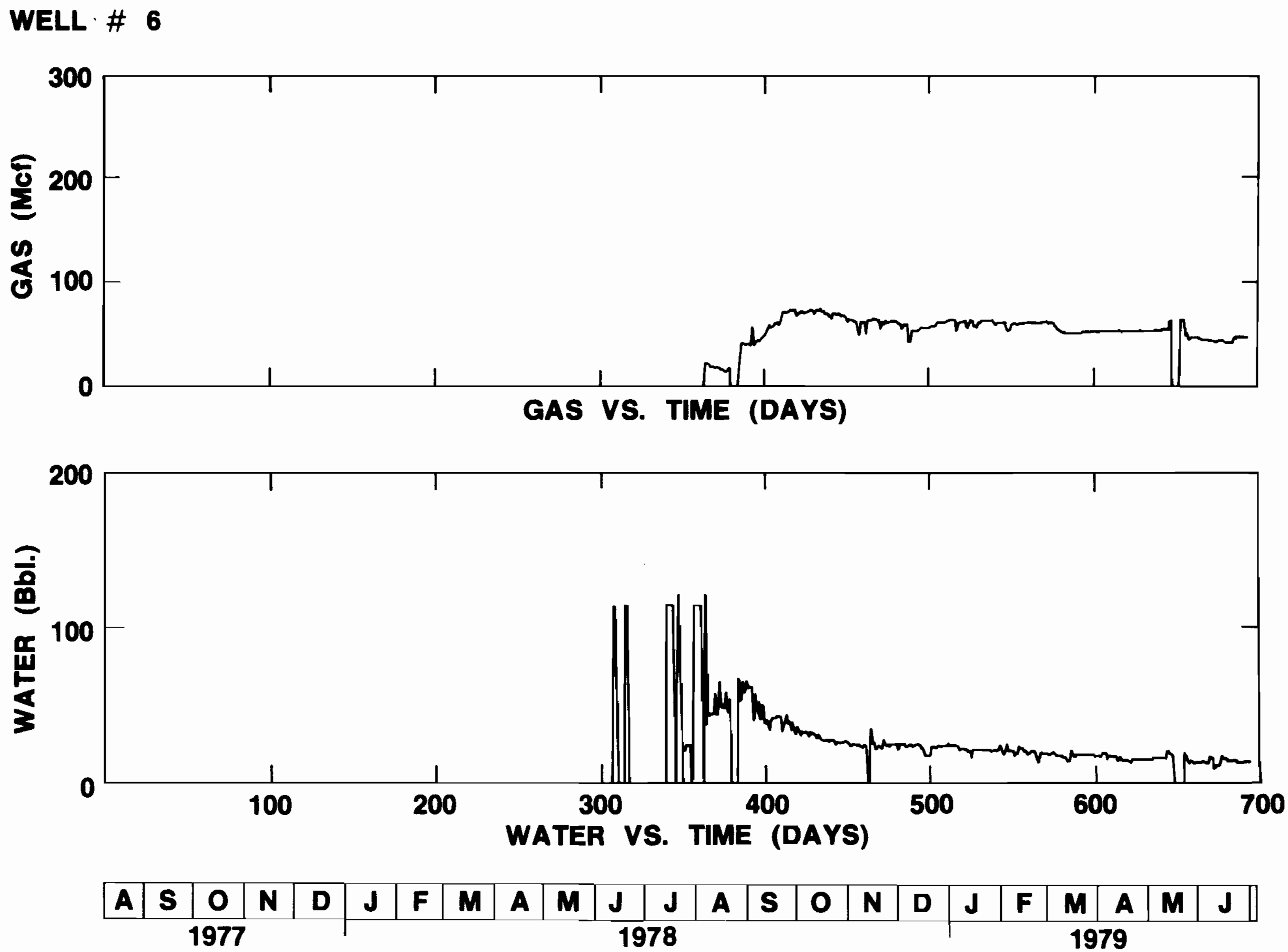


FIGURE 50 - DAILY PRODUCTION FROM FOAM-STIMULATED WELLS NO. 8 AND NO. 13, MARY LEE COALBED DEGASIFICATION PATTERN NEAR OAK GROVE, JEFFERSON COUNTY, ALABAMA

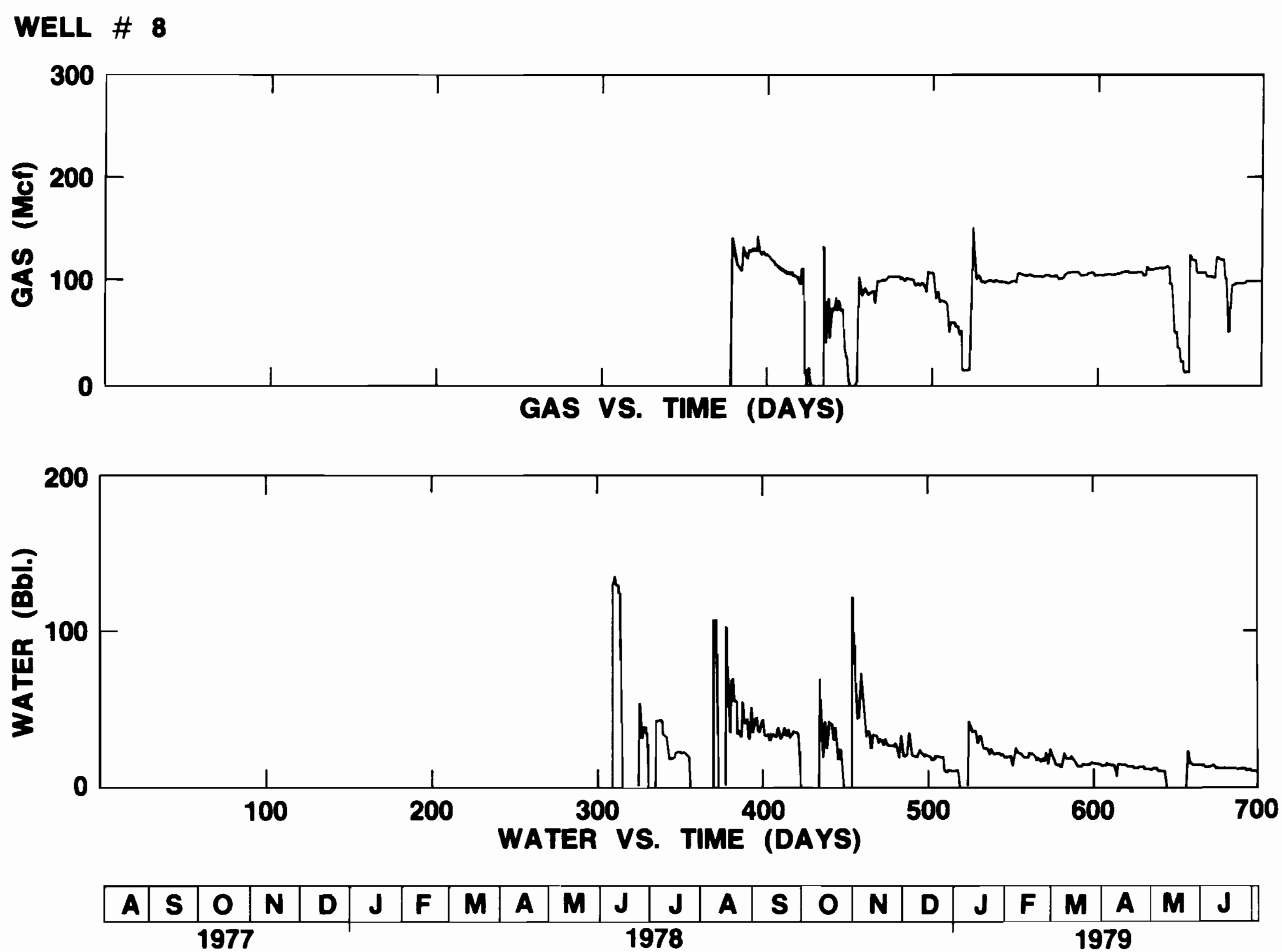


FIGURE 50A - DAILY PRODUCTION FROM FOAM- STIMULATED WELLS NO. 8 AND NO. 13, MARY LEE COALBED DEGASIFICATION PATTERN NEAR OAK GROVE, JEFFERSON COUNTY, ALABAMA

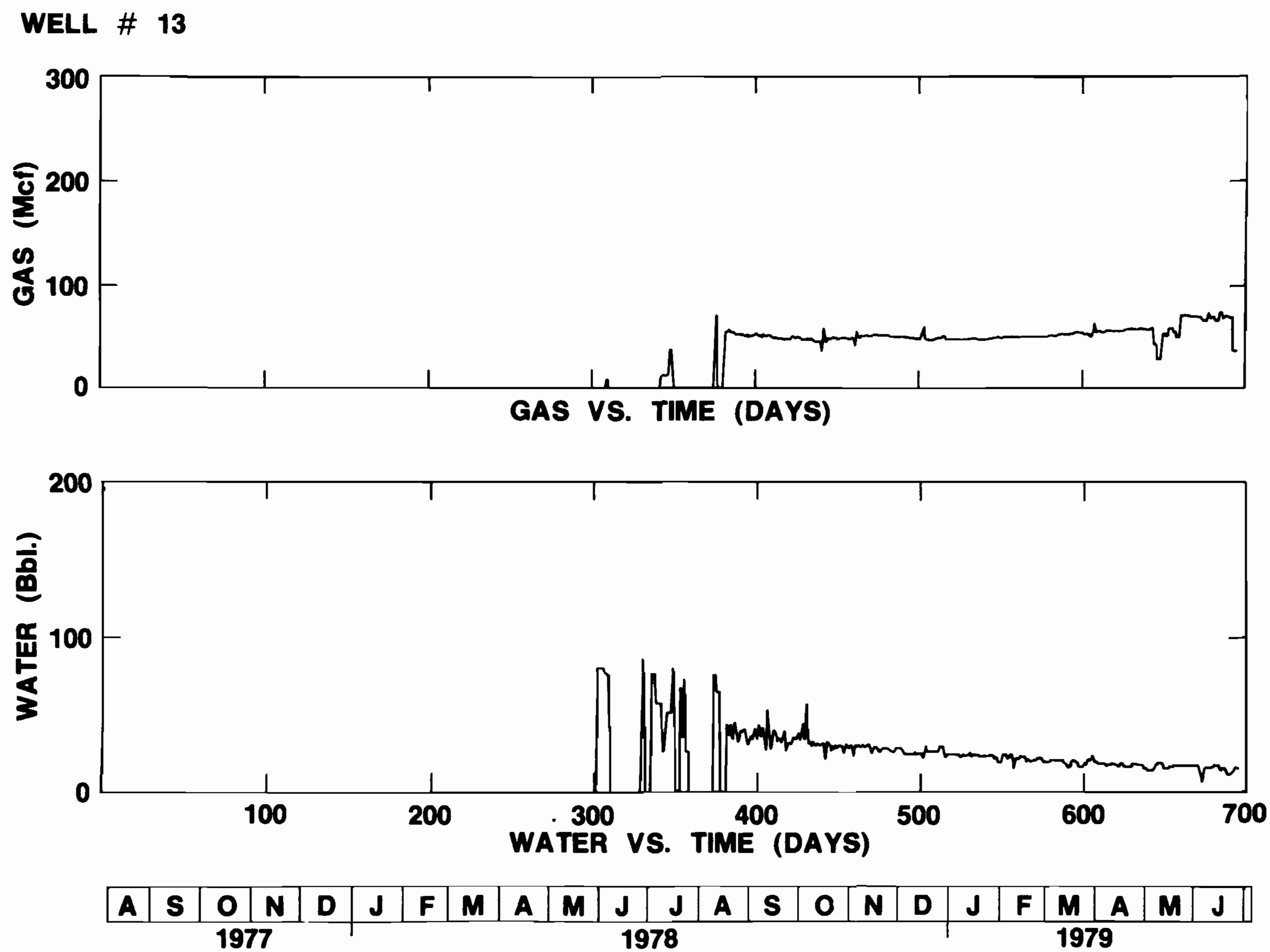


FIGURE 51 - DAILY PRODUCTION FROM FOAM-STIMULATED WELLS NO. 14 AND NO. 15, MARY LEE COALBED DEGASIFICATION PATTERN NEAR OAK GROVE, JEFFERSON COUNTY, ALABAMA

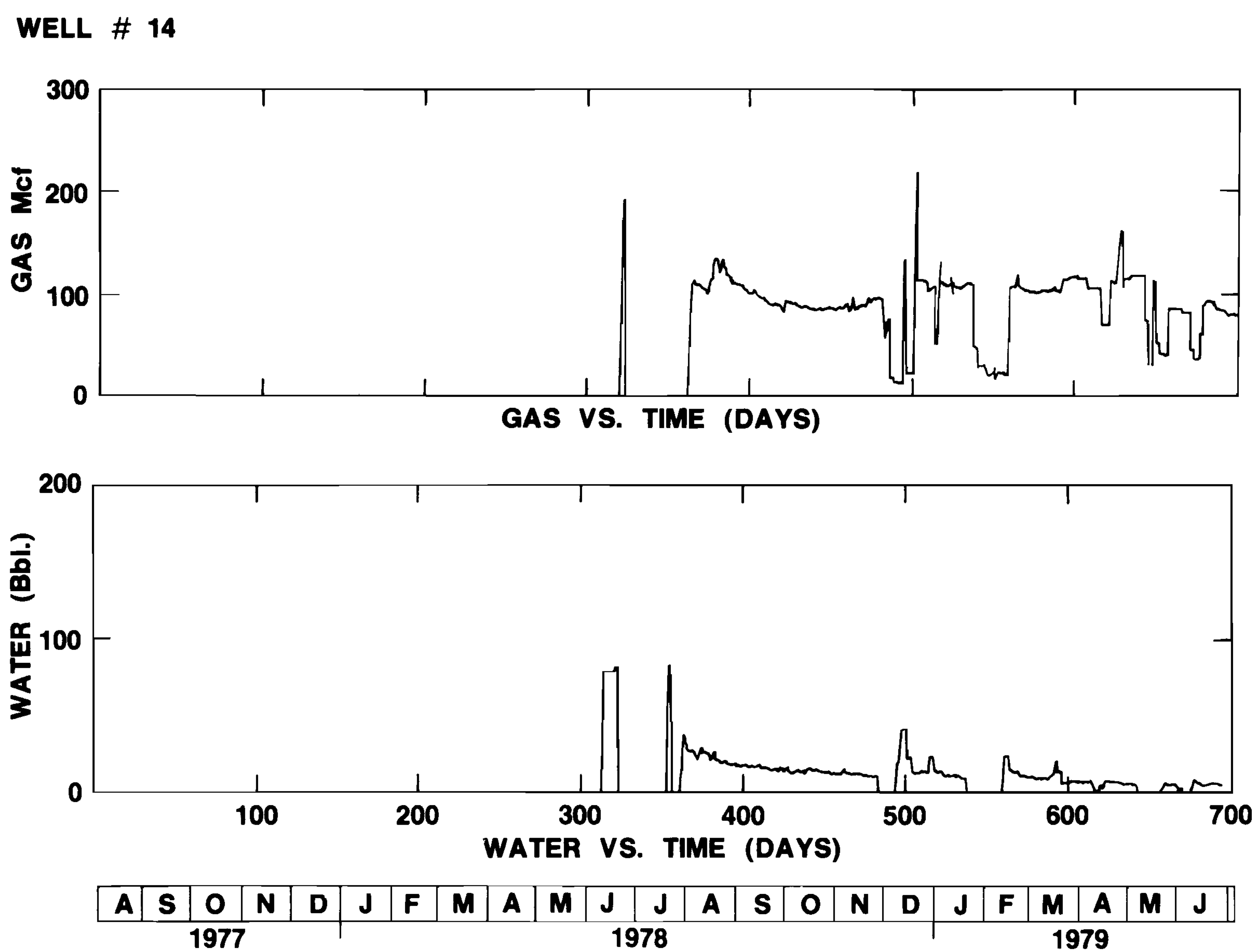


FIGURE 51A - DAILY PRODUCTION FROM FOAM-STIMULATED WELLS NO. 14 AND NO. 15, MARY LEE COALBED DEGASIFICATION PATTERN NEAR OAK GROVE, JEFFERSON COUNTY, ALABAMA

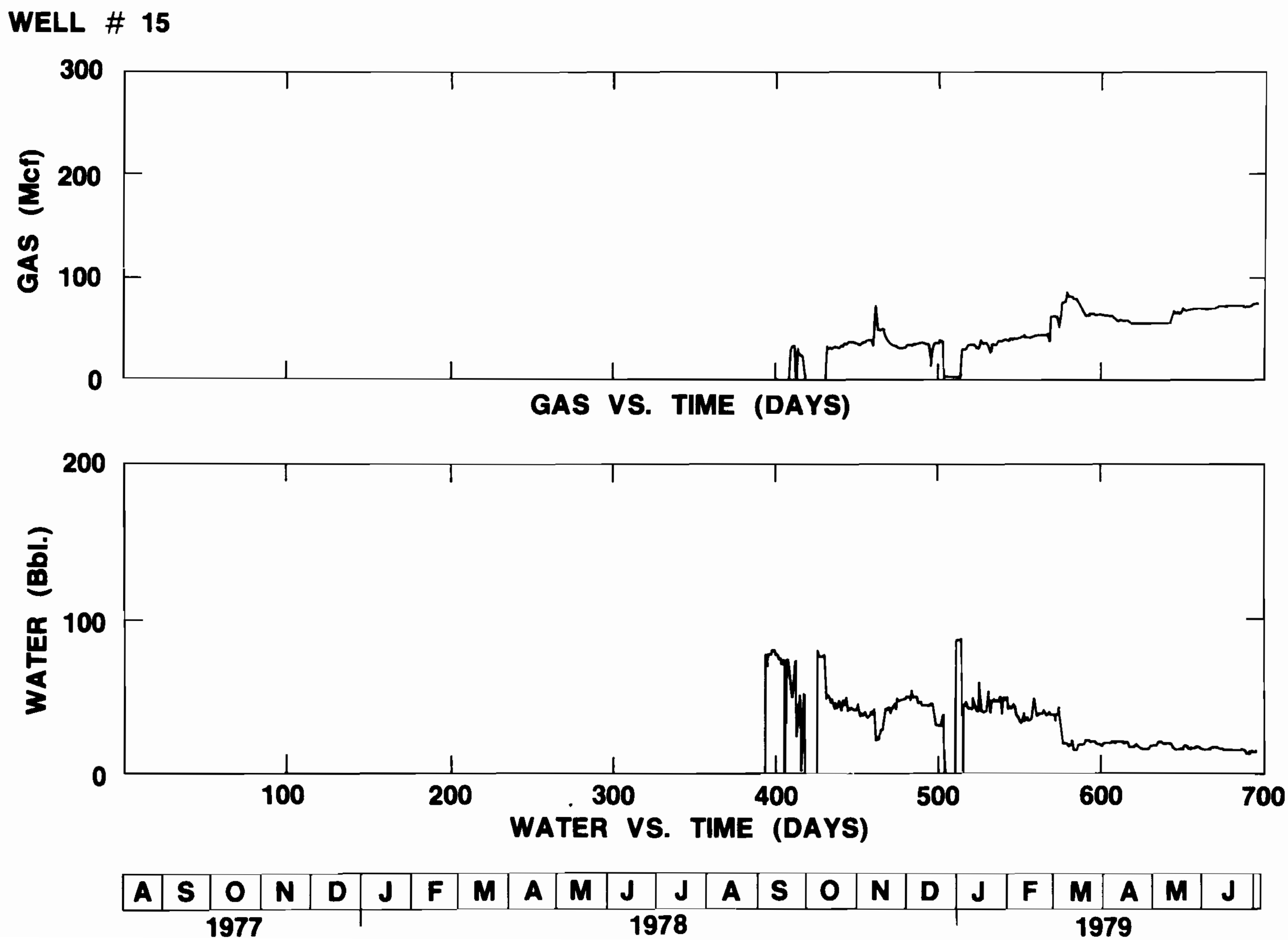


FIGURE 52 - DAILY PRODUCTION FROM FOAM-STIMULATED WELLS NO.16 AND NO.17, MARY LEE COALBED DEGASIFICATION PATTERN NEAR OAK GROVE, JEFFERSON COUNTY, ALABAMA

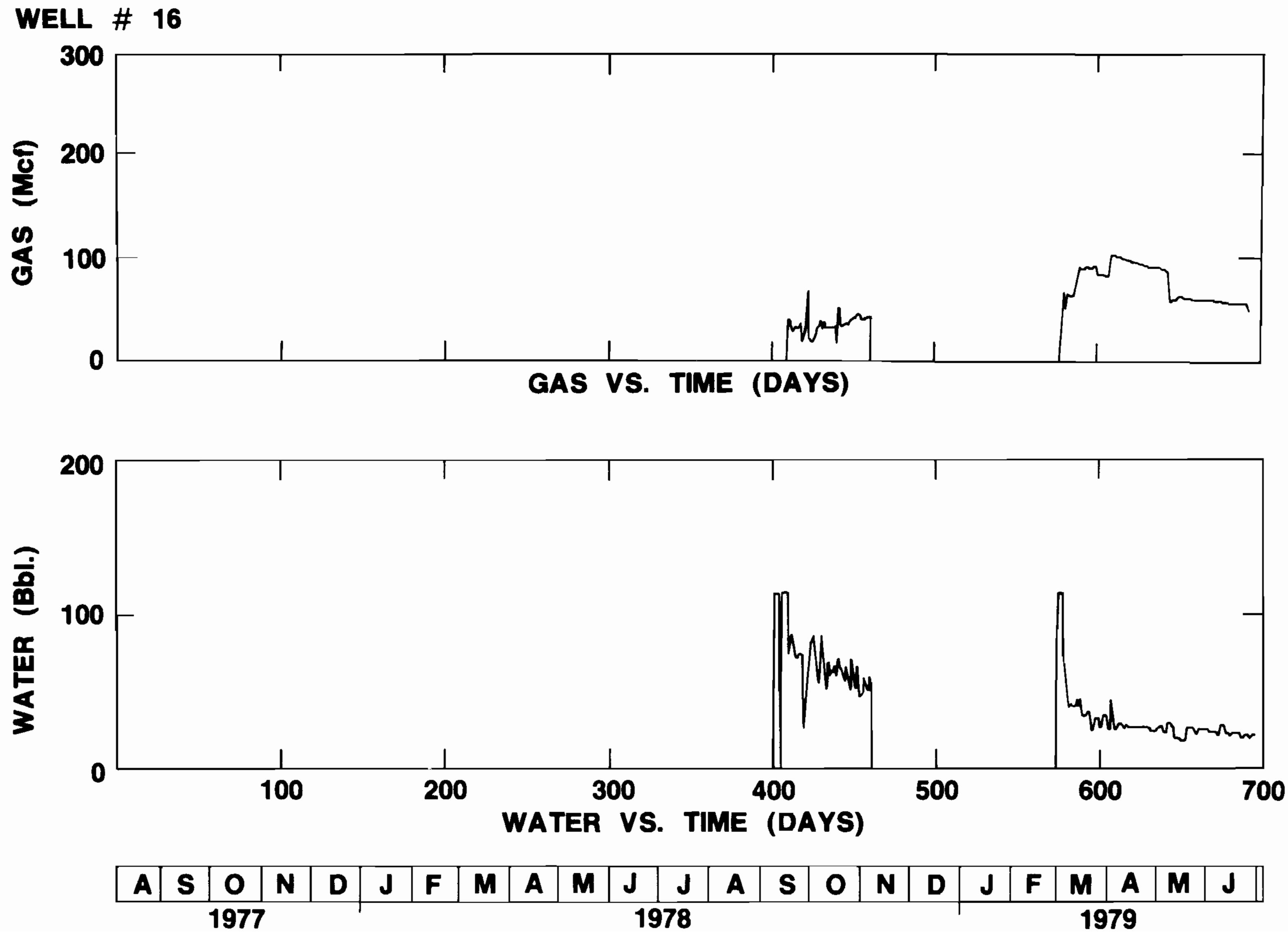


FIGURE 52A - DAILY PRODUCTION FROM FOAM-STIMULATED WELLS NO. 16 AND NO. 17, MARY LEE COALBED DEGASIFICATION PATTERN NEAR OAK GROVE, JEFFERSON COUNTY, ALABAMA

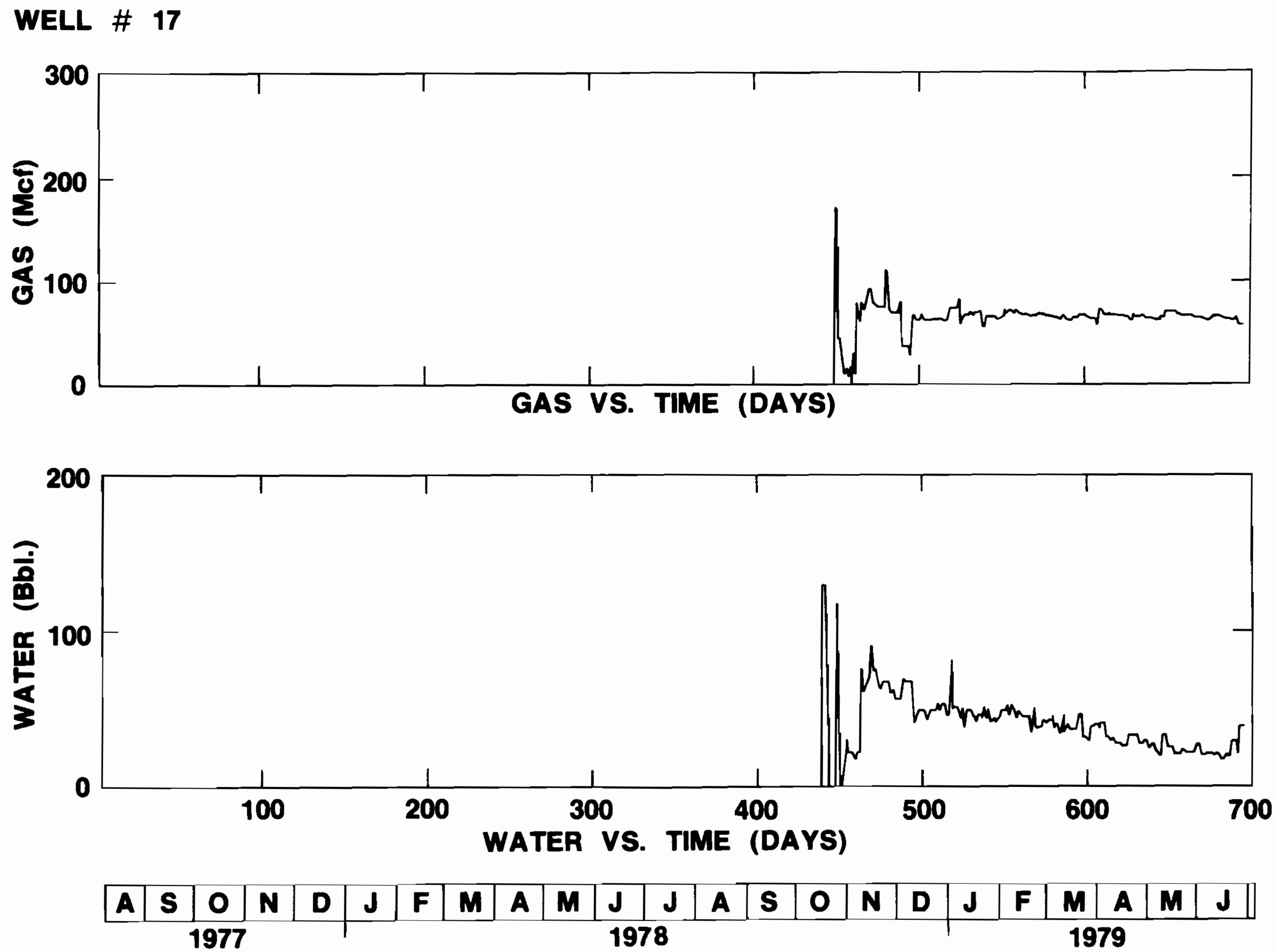


FIGURE 53 - DAILY PRODUCTION FROM FOAM-STIMULATED WELLS NO. 18 AND NO. 22, MARY LEE COALBED DEGASIFICATION PATTERN NEAR OAK GROVE, JEFFERSON COUNTY, ALABAMA

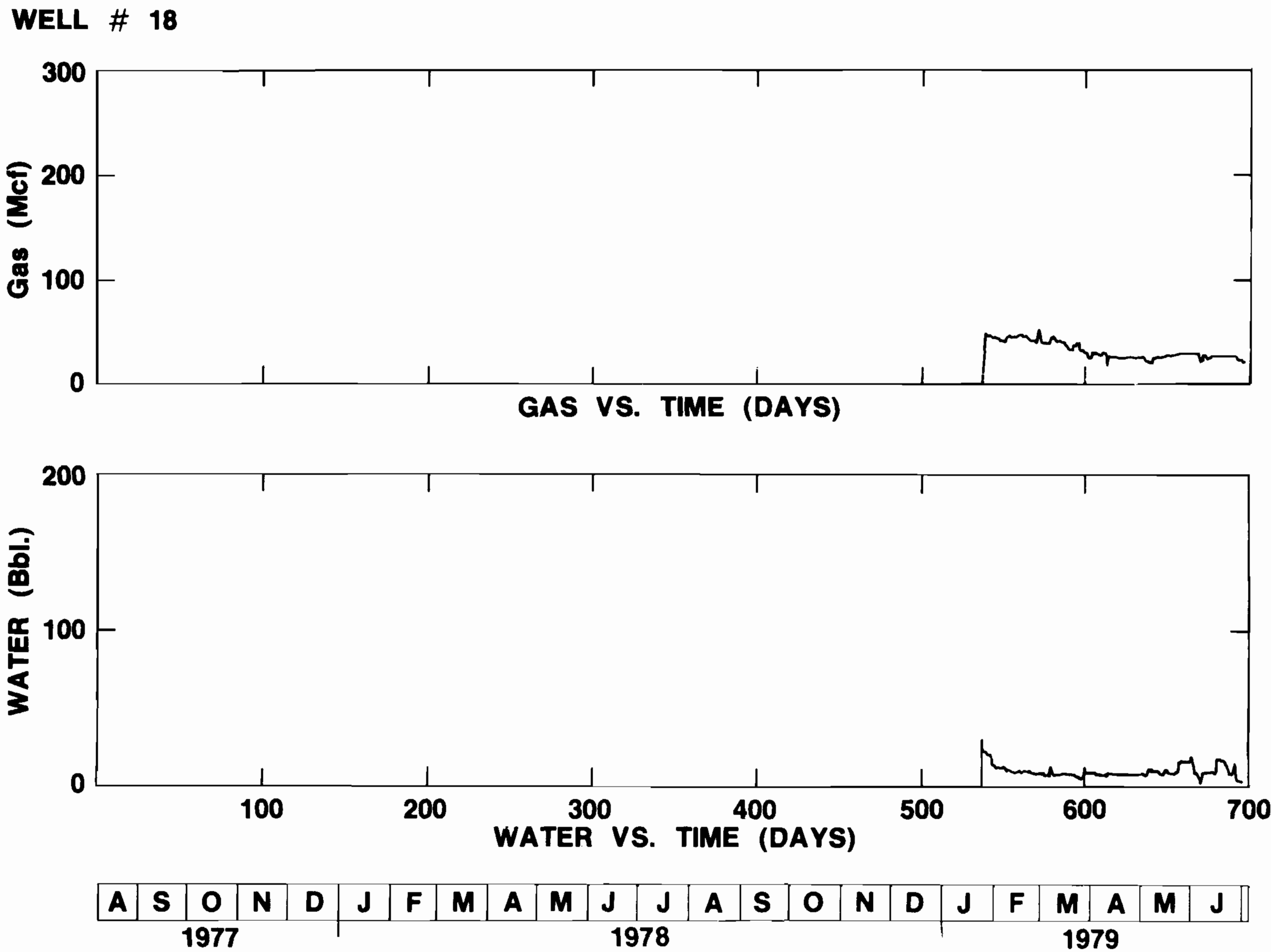


FIGURE 53A - DAILY PRODUCTION FROM FOAM-STIMULATED WELLS NO. 18 AND NO. 22, MARY LEE COALBED DEGASIFICATION PATTERN NEAR OAK GROVE, JEFFERSON COUNTY, ALABAMA

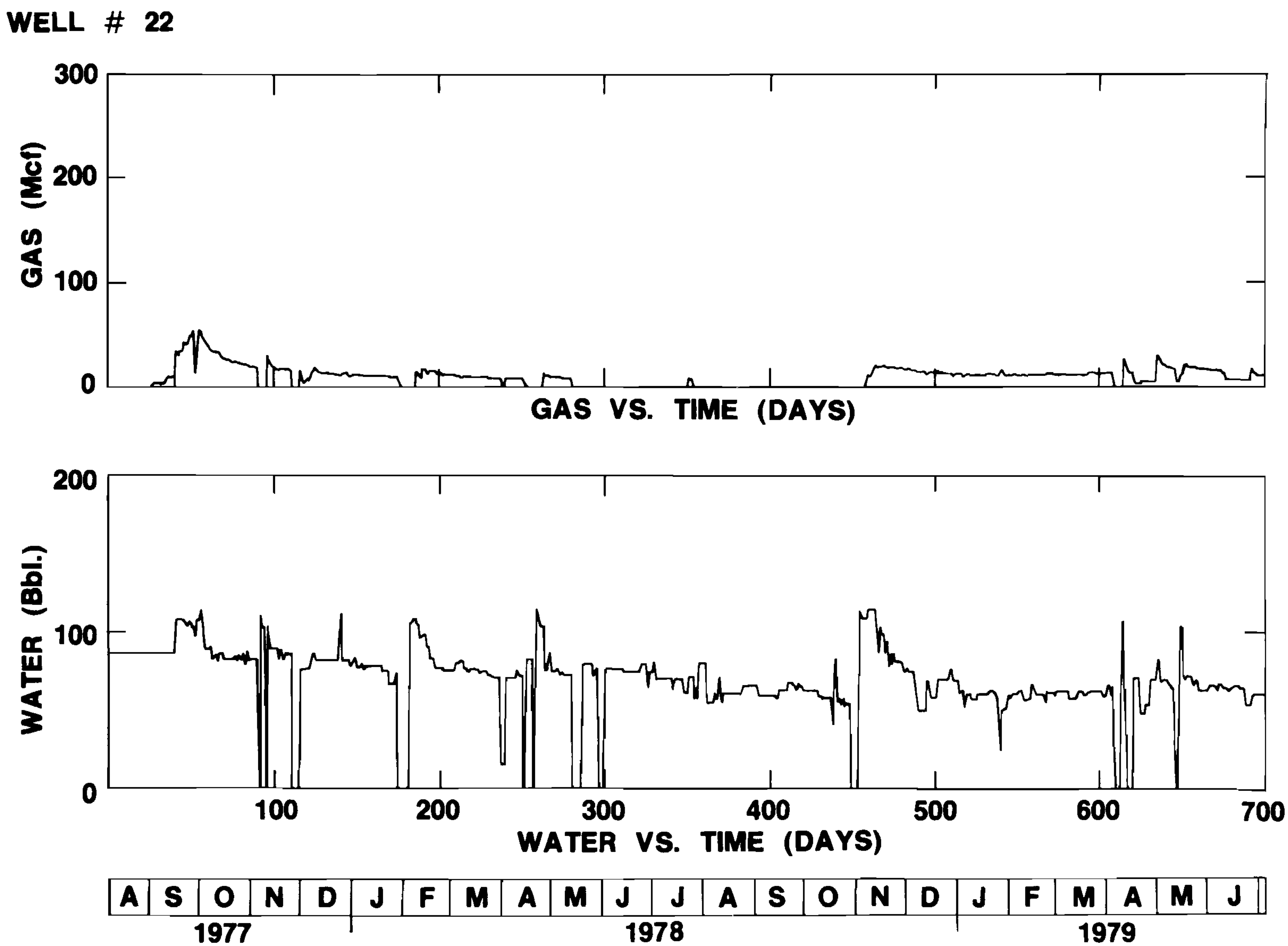


FIGURE 54 - DAILY PRODUCTION FROM FOAM-STIMULATED WELLS NO. 23 AND NO. 24, MARY LEE COALBED DEGASIFICATION PATTERN NEAR OAK GROVE, JEFFERSON COUNTY, ALABAMA

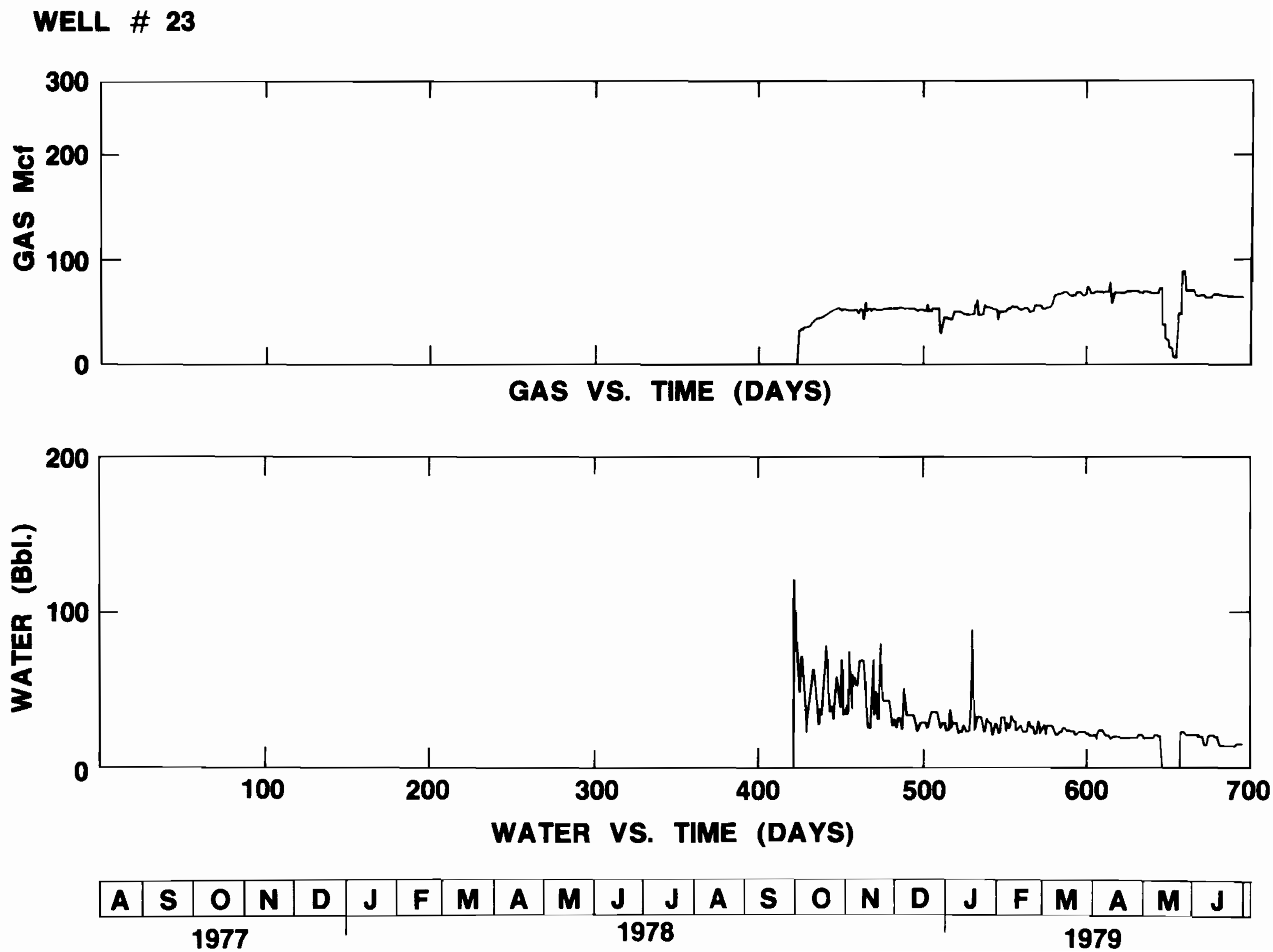


FIGURE 54A - DAILY PRODUCTION FROM FOAM-STIMULATED WELLS NO. 23 AND NO. 24, MARY LEE COALBED DEGASIFICATION PATTERN NEAR OAK GROVE, JEFFERSON COUNTY, ALABAMA

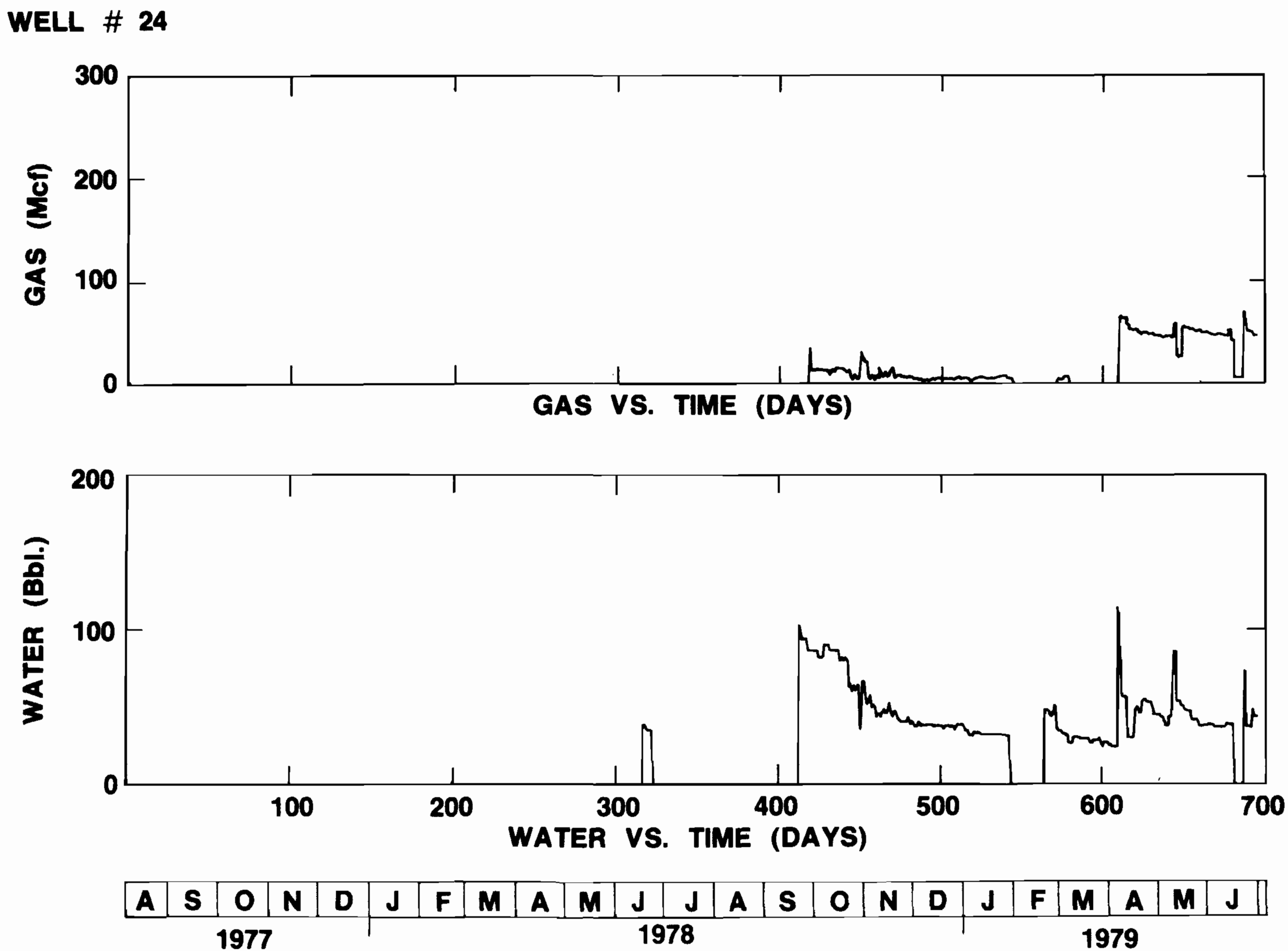


FIGURE 55 - DAILY PRODUCTION FROM FOAM-STIMULATED WELL NO. 25, MARY LEE COALBED DEGASIFICATION PATTERN NEAR OAK GROVE, JEFFERSON COUNTY, ALABAMA

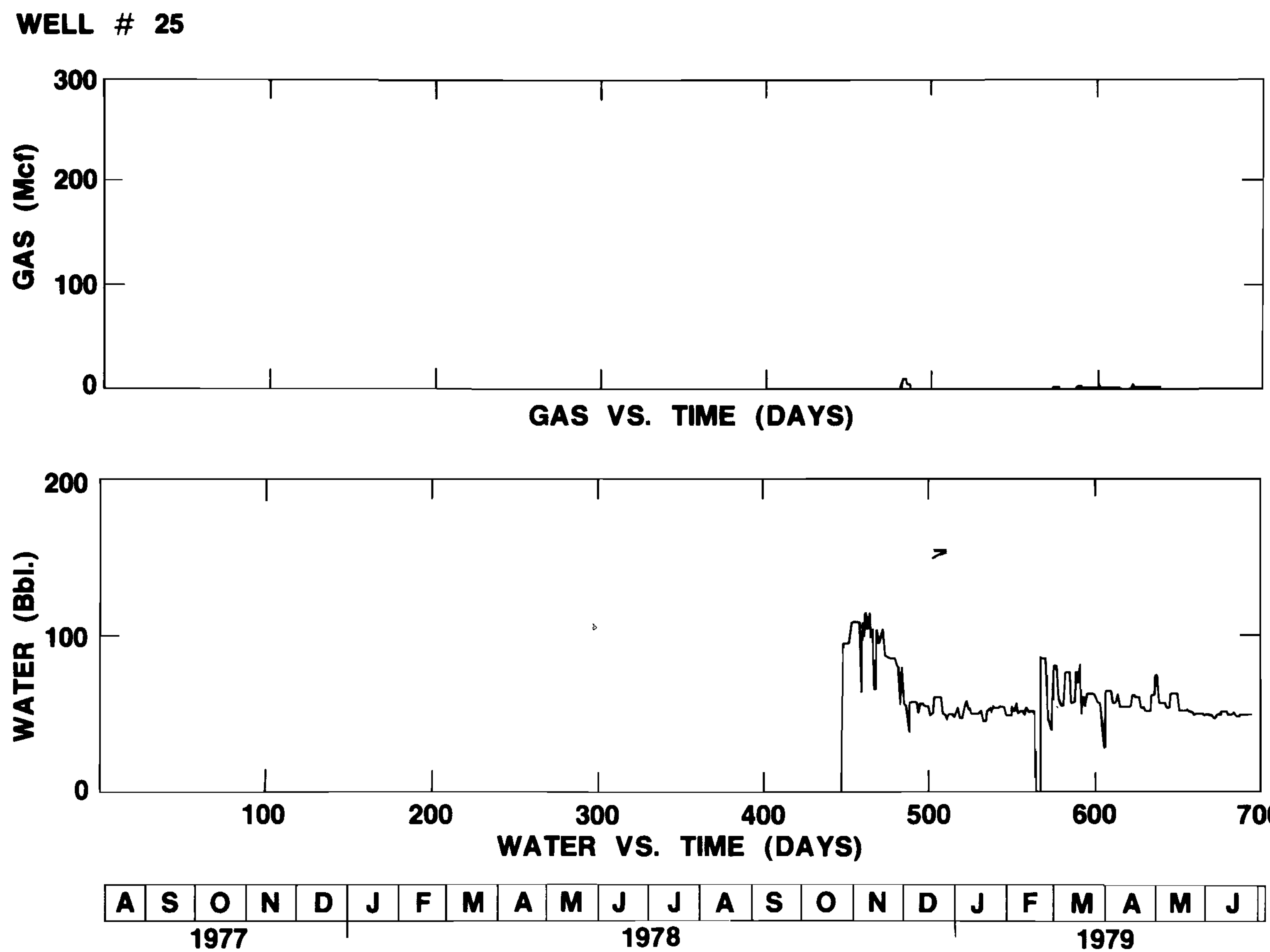
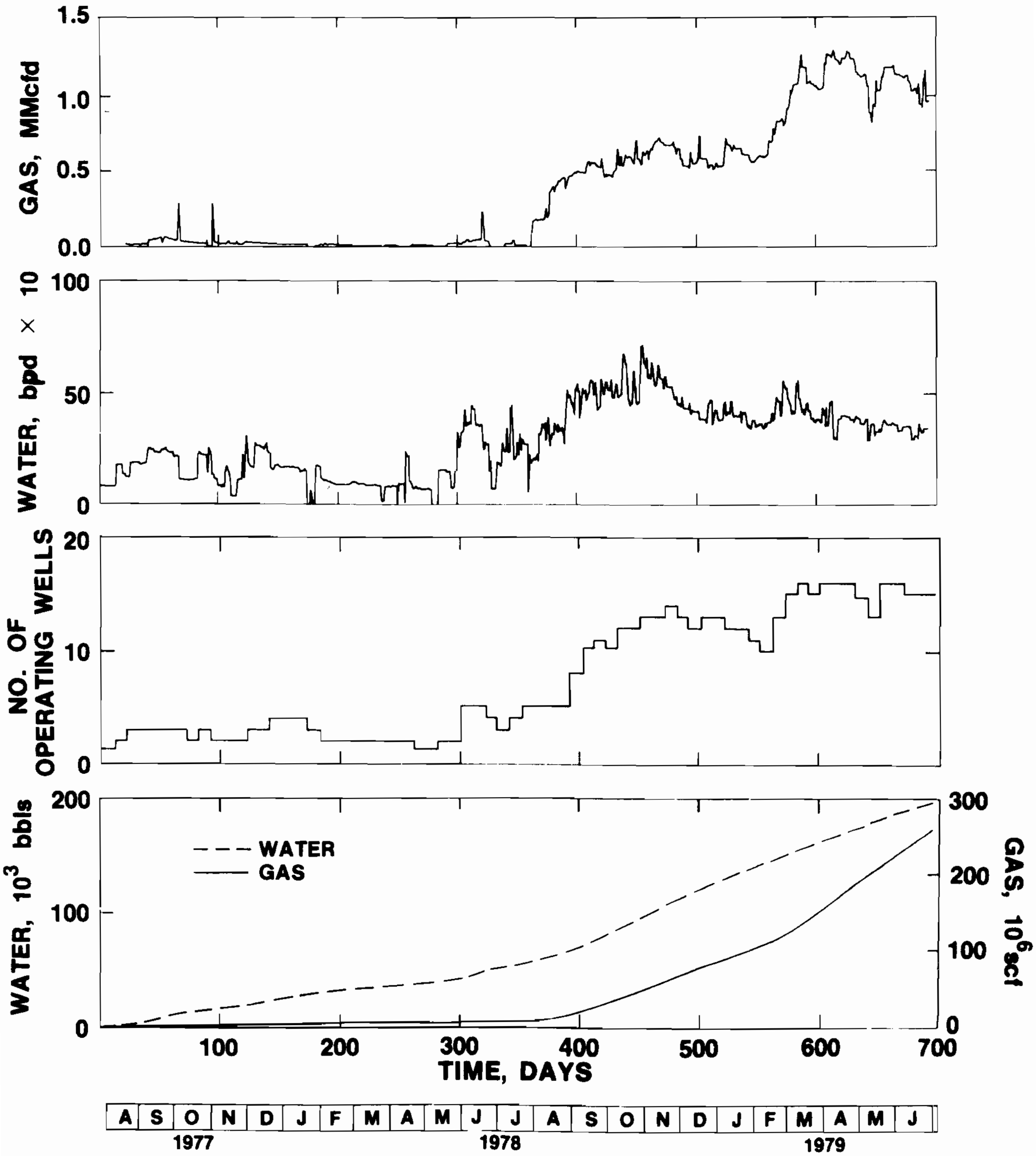


FIGURE 56 - DAILY PRODUCTION; NUMBER OF OPERATING WELLS AND CUMULATIVE TOTAL AMOUNT OF GAS AND WATER PRODUCED FROM THE MARY LEE COAL BED DEGASIFICATION PATTERN NEAR OAK GROVE, JEFFERSON COUNTY, ALABAMA



Jawbone Coalbed, Dickenson County, Virginia

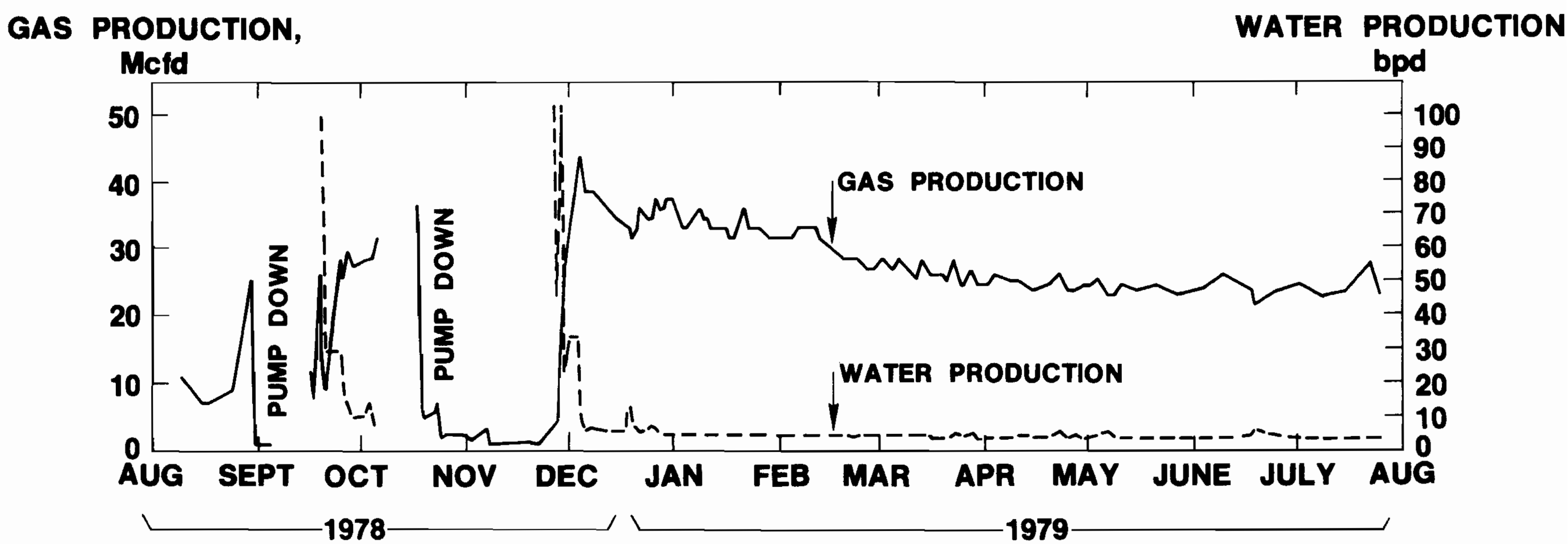
A foam stimulation treatment was conducted in July, 1978, at a well drilled into the Jawbone coalbed near the first underground development of the McClure No. 1 mine near Dante, Virginia (Table 3, Well No. 61).

The well was completed in an open-hole fashion, exposing the five foot coalbed and about 25 feet of underlying rock strata. Casing was set in the borehole approximately two feet above the 425 foot deep coalbed using a packer shoe, then cemented from this packer to the surface.

Stimulation was accomplished directly through the four inch diameter casing and began with a 4,200 gallon water pad to open a fracture in the coalbed and retard fluid leak-off. Initial formation "break" is believed to have occurred at a pressure of 1,000 psi. This was much higher than had been anticipated for the relatively shallow coalbed being treated. Nitrogen and surfactant were then added to create foam. Treatment injection rate was 12 bpm.

Total treatment volume was 35,300 gallons foam. Approximately 28,000 pounds of 20 to 40 mesh size sand were injected into the borehole. No physical or chemical fluid-loss additives were used to complete this foam stimulation treatment. Early production results from this coalbed gas drainage well are shown on Figure 57.

FIGURE 57 - DAILY GAS AND WATER PRODUCTION FROM WELL NO. DG-1A, DICKENSON COUNTY, VIRGINIA



MISCELLANEOUS STIMULATION TECHNIQUES

There have been several other types of stimulation treatments tested which cannot be categorized under either type previously discussed. Although some of the techniques described in this section are not considered applicable to coalbed stimulation, some others may prove to be highly effective and should be further tested.

Explosive Frac and Early Hydraulic Treatment

Some early coalbed stimulation attempts were conducted by G. R. Spindler and W. N. Poundstone (35) during the late 1950s. Two vertical boreholes were drilled into the Pittsburgh coalbed near Morgantown, West Virginia and stimulated.

Total depth of the first hole studied was 515 feet. Pre-stimulation gas production was measured to be 25,000 cfd which diminished to about 10,000 cfd after eight months of water pumping. An attempt was made to induce fractures in the coalbed by detonating a shot of nitroglycerin at the bottom of the hole. The hole was cleared out after this stimulation treatment but gas production did not exceed 3,000 cfd. Further work on this hole was then abandoned.

The second hole, 465 feet deep, was cased with 6-5/8 inch diameter casing to the top of the coal, and cemented. This hole produced gas at a rate of 60,000 cfd but also diminished after a short period of production. In an attempt to increase gas production, the well was fractured hydraulically by pumping 10,000 gallons of water into the hole at rates ranging from three to five bpm at a maximum injection pressure of 600 psig. Gas production was not increased by this stimulation treatment and it was concluded that true fractures were not achieved because of "inadequate" rates of water injection.

Nitrogen Gas Treatment

Specifications for drilling, casing, and testing vertical gas drainage wells into the Pocahantas Coalbeds in Buchanan County, Virginia, were prepared by the Bureau of Mines in 1967 (3). At the request of a cooperating coal company, a borehole was drilled into a projected barrier pillar. Drilling was completed in May, 1967, at a depth of 1,530 feet. The eight inch diameter borehole was cased with 4-1/2 inch diameter casing to the top of the coalbed and cemented to surface.

After about one year of low production, an attempt was made to stimulate the coalbed using nitrogen gas. Approximately 247,000 ft^3 (stp) of nitrogen was pumped into the coalbed at 16,000 ft^3/min (stp) under a pressure of 2,700 psig. Significant fracturing was not indicated as production was not increased.

Combination CO_2 - Gel Treatment

One recent experimental coalbed stimulation design incorporates the use of gelling agent water, and liquid CO_2 (27). Two gelling agents and water are used in varying concentrations in order to provide optimal viscosity characteristics at the surface and near the bottom of the hole. The simultaneous addition of liquid CO_2 during treatment provided flowback capabilities to reduce clean-up time by increasing the rate of treating fluid recovery.

An 1,100 foot deep, 6-1/4 inch diameter borehole was drilled in Jefferson County, Alabama and cased with four inch diameter pipe. The five foot thick Mary Lee coalbed was then exposed to the wellbore through 20 0.38 inch diameter perforations.

The coalbed was stimulated in July, 1977, immediately following casing perforation. Treatment was accomplished through casing using a total of 56,400 gallons of fluid (this includes 7,140 gallons of liquid CO_2) and 15,500 pounds of 20 to 40 mesh size sand proppant. No apparent "formation breakdown" was observed and a casing pressure of approximately 1,700 psig was maintained throughout most of the treatment. Average injection rate was 110 bpm (excluding one bpm liquid CO_2). Sand proppant was added in one pound per gallon increments after over 44,000 gallons of fluid pad had been injected. Apparently, fluid leak-off during this treatment was very high because a sand-out occurred shortly after the amount of sand proppant was increased from one to two pounds per gallon. Attempts to re-establish the previous pressure and injection rate were unsuccessful, so the treatment was terminated.

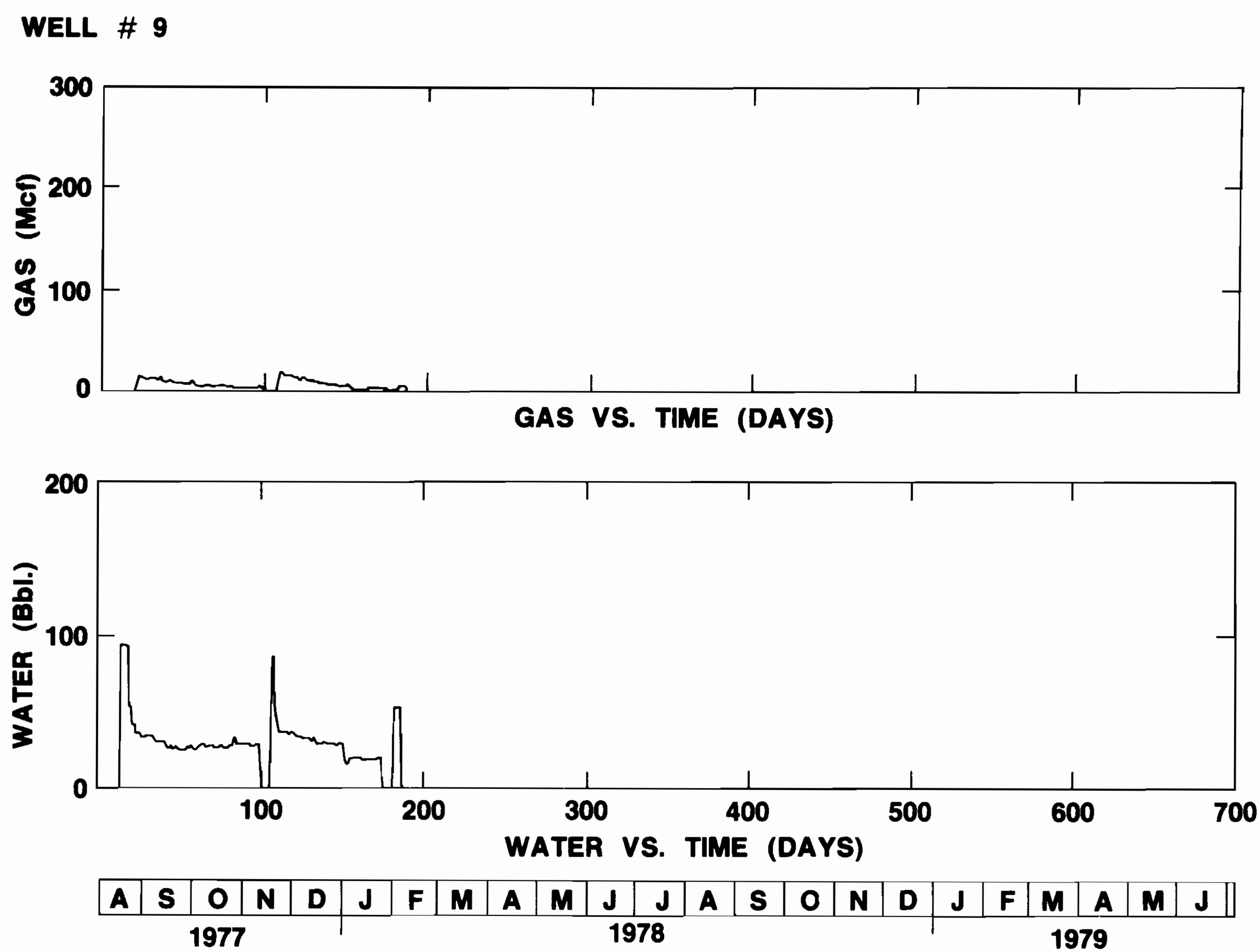
After clean-up, the well was equipped with a dewatering pump and put on production. Dewatering operations were stopped after several months of pumping produced only small amounts of gas and water (Figure 58). This well is designated "No. 44" on Table 3.

Pressurization/Depressurization Treatment

Another coalbed stimulation design tested recently is referred to as "Kiel Frac". 8/ This design incorporates a pressurization/depressurization technique which, in theory, creates effectively long fractures along two transverse directions then props the fractures with reservoir rock material that sloughs-off during the treatment. This patent 12/ hydraulic fracturing process has been applied twice to mineable coalbeds. The first treatment was conducted at one of several Pittsburgh coalbed gas drainage wells on the Emerald Mine property, Greene County, Pennsylvania. The other "Kiel Frac" was applied to the Mary Lee coalbed in Jefferson County, Alabama.

12/ U.S. Patent No. 3933205, awarded to Othar Meade Kiel c/o Intercomp Resource Development and Engineering, Inc., 2000 W. Loop St., Houston, Texas 77027, January 20, 1976.

FIGURE 58 - DAILY PRODUCTION FROM CO_2-GEL-STIMULATED WELL NO. 9, MARY LEE COALBED DEGASIFICATION PATTERN NEAR OAK GROVE, JEFFERSON COUNTY, ALABAMA



The materials used in the "Kiel Frac" stimulations have been water and sand. No chemical mixing is required and, assuming the water is compatible with the coalbed water, many potential problems of production loss due to fluid formation damage or incomplete gel breakdown are avoided. The sand used in this process reportedly acts to filter pack the natural joint system and/or the vertical downward extent of rock joints thus limiting fracturing to the upper portion of the coalbed where, it is assumed, leakage is inhibited by the overburden. Both 80 to 100 and 20 to 40 mesh size sand have been used in combination to treat coalbed gas drainage wells.

The Pittsburgh coalbed was "Kiel Fraced" in May, 1977, at a 725 foot deep borehole (designated "No. 40" on Table 3) which had been cased and cemented to the top of a six foot thick coal unit. Over 54,600 gallons of water and 10,000 pounds of sand were injected into the borehole using a rate of about 19 bpm. Wellhead pressure during injection stages was approximately 1,200 psig. After treatment, the well was equipped with a sucker-rod dewatering pump and put on production. Production results gathered from this well are included on Table 12 under the well identified as EM-11.

Underground mining progressed to within 100 feet of the "Kiel Fraced" well in June, 1978. Shortly after, this area of the mine was examined for evidence of the stimulation treatment. Locations where sand-propped fractures were observed underground are shown on Figure 59. Figure 59 also includes a sketch of the exposed coal rib section showing the position and orientation of the 0.1 inch thick horizontally induced fractures.

Previous studies indicated the possibility of developing horizontal fractures as a result of hydraulic stimulation but the actual distance of the Kiel Frac underground survey, however, showed that horizontal fractures can be propagated much farther.

The largest stimulation treatment to a minable coal to date was a "Kiel Frac" treatment applied to the Mary Lee coalbed in August, 1977 (Well No. 46, Table 3). The total amount of water used to treat the 1,120 foot deep coalbed was 79,900 gallons. Approximately 25,000 pounds of sand were injected into the coalbed at rates of up to four pounds per gallon water. Water was injected at a rate of 20 bpm and wellhead pressures averaged about 1,100 psig. The treatment was completed in eight separate pressurization/depressurization fracture cycles as presented on Table 14. Production resulting from this test well is shown on Figure 60.

FIGURE 59. - SKETCH SHOWING POSITION OF THE INDUCED FRACTURES OBSERVED NEAR DEGAS WELL NO. EM-11 GREENE COUNTY, PA.

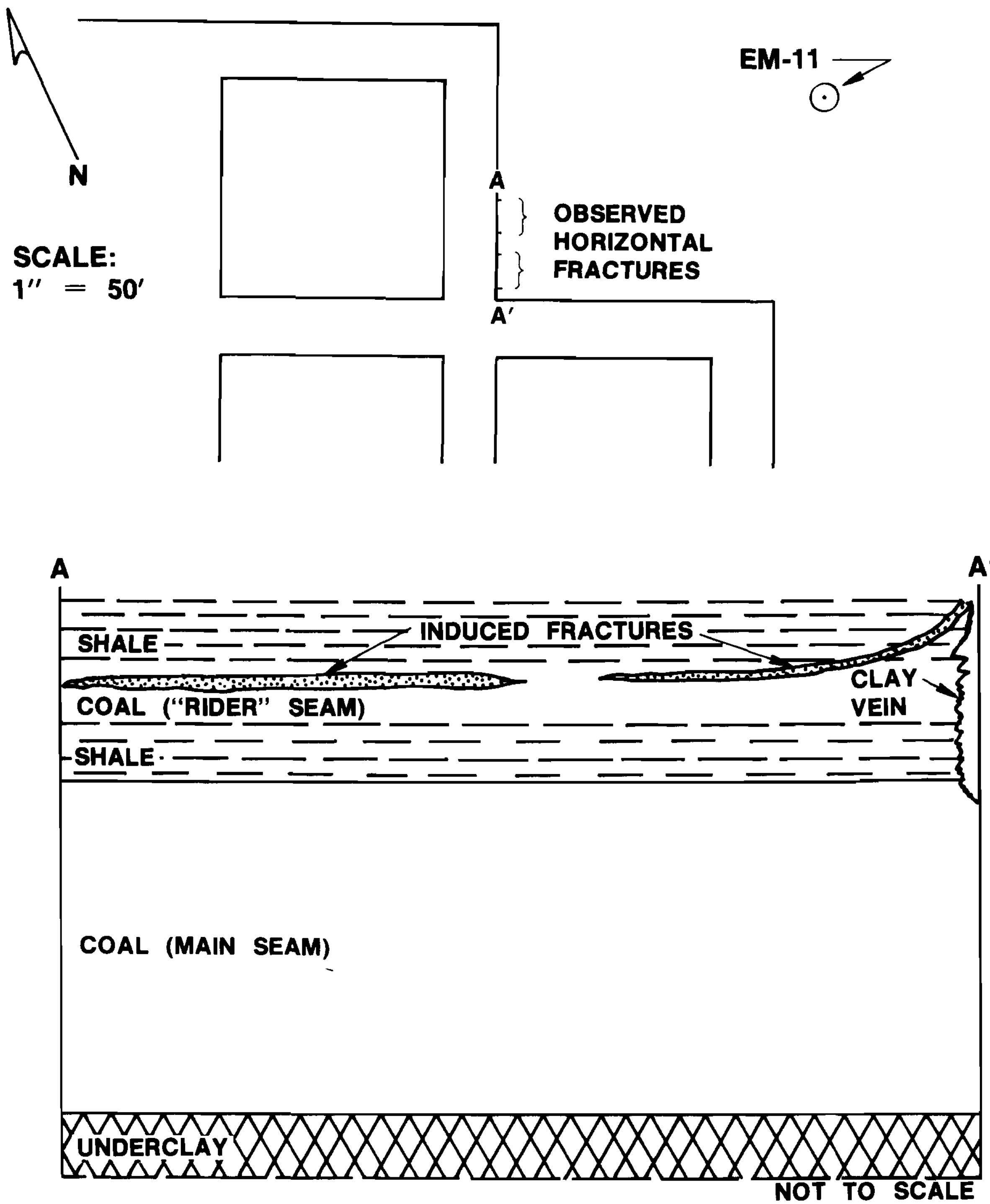


TABLE NO. 14 - SUMMARY OF "KIEL FRAC" PROCEDURES USED TO STIMULATE A GAS DRAINAGE WELL IN THE MARY LEE COALBED

The lower bench (Blue Creek Seam) was fractured on August 9, 1977, using the Kiel Process of intermittent pressurization/depressurization. O. M. Kiel, inventor of the process, feels that using the intermittent pressurization/depressurization method of stimulating vertical boreholes results in small fractures being formed perpendicular to the main fracture, thereby opening up more channels for gas flow. The hole was first flushed and then, to help initiate the fracture, water-jetted with 6700 gallons of water and 3360 pounds of sand at a rate of 2.5 bbl/min (105 gpm). About 20 minutes after the start of the water-jetting, coal was seen in the discharge from the borehole thereby indicating penetration into the seam. The hole was water-jetted for a total of 64 minutes and two opposing 3-foot-high slots were cut into the seam by raising and lowering the tool during the water-jetting operation. After water-jetting, the hole was flushed to remove all residue in preparation for stimulation.

The design treatment consisted of eight stages with ten steps with each stage. Each stage injected 9450 gallons of water and 4200 pounds sand at a constant rate of 20 bbl/min (840 gpm).

The steps within each of the first six stages are described below.

Steps Used in Stages 1 Through 6

Step	Gallons	Barrels	Proppant
1	1260	30	
2	420	10	4 lb/gal 100 mesh sand
3	420	10	
4	420	10	2 lb/gal 20- by 40-mesh sand
5	420	10	
6	420	10	4 lb/gal 20- by 40-mesh sand
7	5040	120	
8	Blow Back		
9	1050	25	
10	Blow Back		
Total	9450	225	1680 lb 100 mesh sand 2520 lb 20- by 40-mesh sand

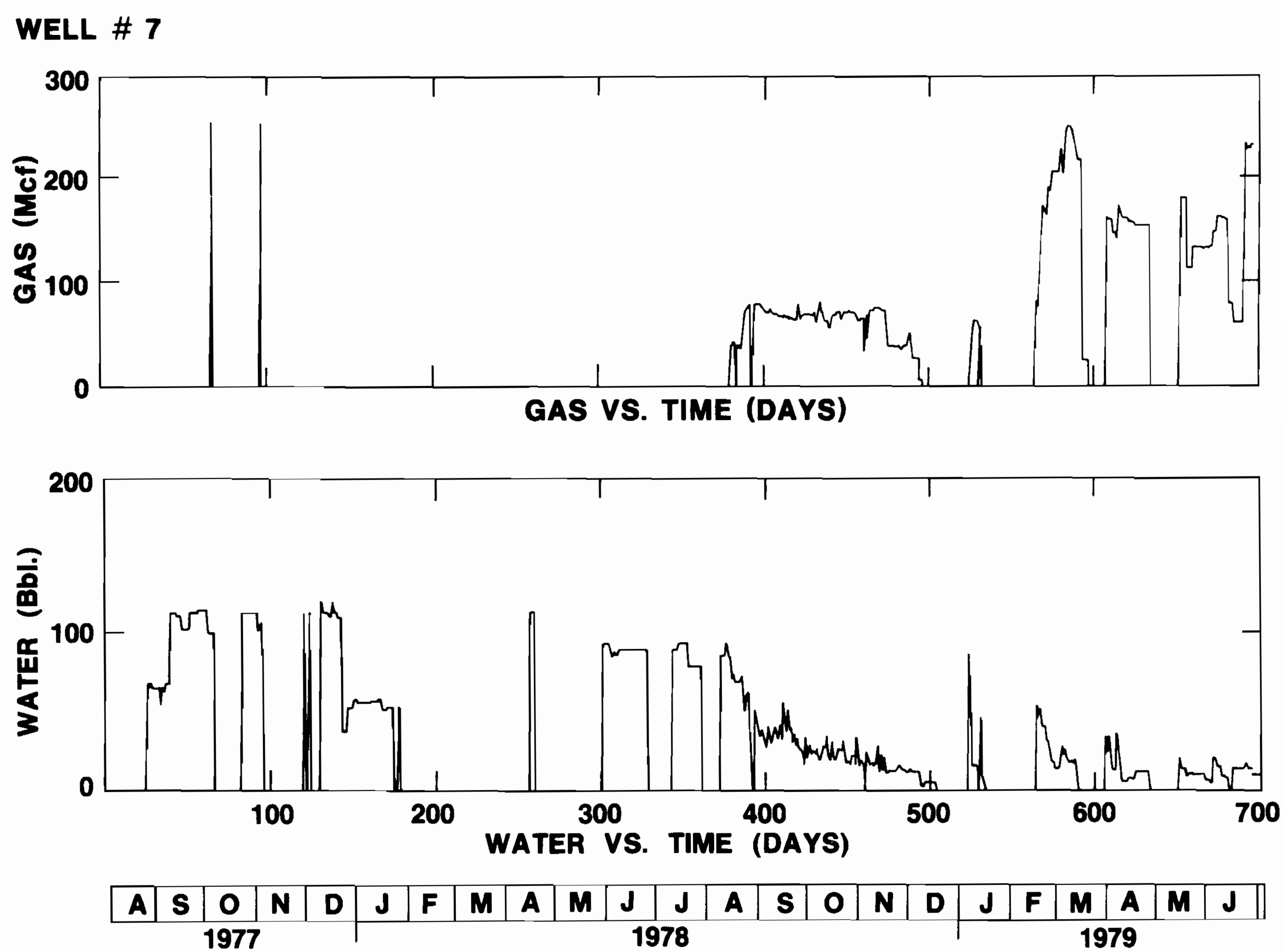
Following the sixth stage, Mr. Kiel made an adjustment in the fracturing technique based on his observations and, for the seventh and eighth stages, he removed 2000 gallons of water from step 8 of each of the stages and injected the water during step 1. The sequence of steps within stages 7 and 8 are shown below.

Steps Used in Stages 7 and 8

Step	Gallons	Barrels	Proppant
1	3260	77.6	
2	420	10	4 lb/gal 100 mesh sand
3	420	10	
4	420	10	2 lb/gal 20- by 40-mesh sand
5	420	10	
6	420	10	4 lb/gal 20- by 40-mesh sand
7	3040	72.4	
8	Blow Back		
9	1050	25	
10	Blow Back		
Total	9450	225	1680 lb 100 mesh sand 2520 lb 20- by 40-mesh sand

Total volumes used for this treatment were 81,000 gallons of water, 20,000 pounds of 100-mesh sand, and 25,000 pounds of 20- by 40-mesh sand. No gelling or foaming agents were used. Wellhead pressures during treatment ranged from 900 to 1270 psig. The treatment operation ran as outlined in the Kiel design. The instantaneous shut-in pressure following the fracture was 270 psi at the surface; 15 minutes later it had dropped to 210 psi. After treatment was completed, the valve at the wellhead was closed for about 55 hours until the shut-in pressure fell to zero on the morning of August 12.

FIGURE 60 - WATER AND GAS PRODUCTION FROM KIEL-FRACED MARY LEE COALBED GAS DRAINAGE WELL, JEFFERSON COUNTY, ALABAMA



No-Proppant Foam Treatment

Another type of hydraulic stimulation tested uses foam to induce coalbed fractures, but does not incorporate a solid proppant material in the design. Since there is no proppant to be carried, extremely low injection rates can be used which, in effect, allow better control of fracture height. It is theorized that the use of very low injection rates increase the probability of maintaining fracture propagation within the coalbed and thus any potential damage to surrounding floor and roof material is minimized. The fact that there is no sand present within the system also decreases the possibility of experiencing chronically severe downhole water-pumping problems that occur during early phases of well production (several months). In addition, the logistic and cost requirements of no-proppant treatments are less than standard treatments using sand because well surface sites can be smaller; there is no cost for proppant; and less on-site hydraulic horsepower is required.

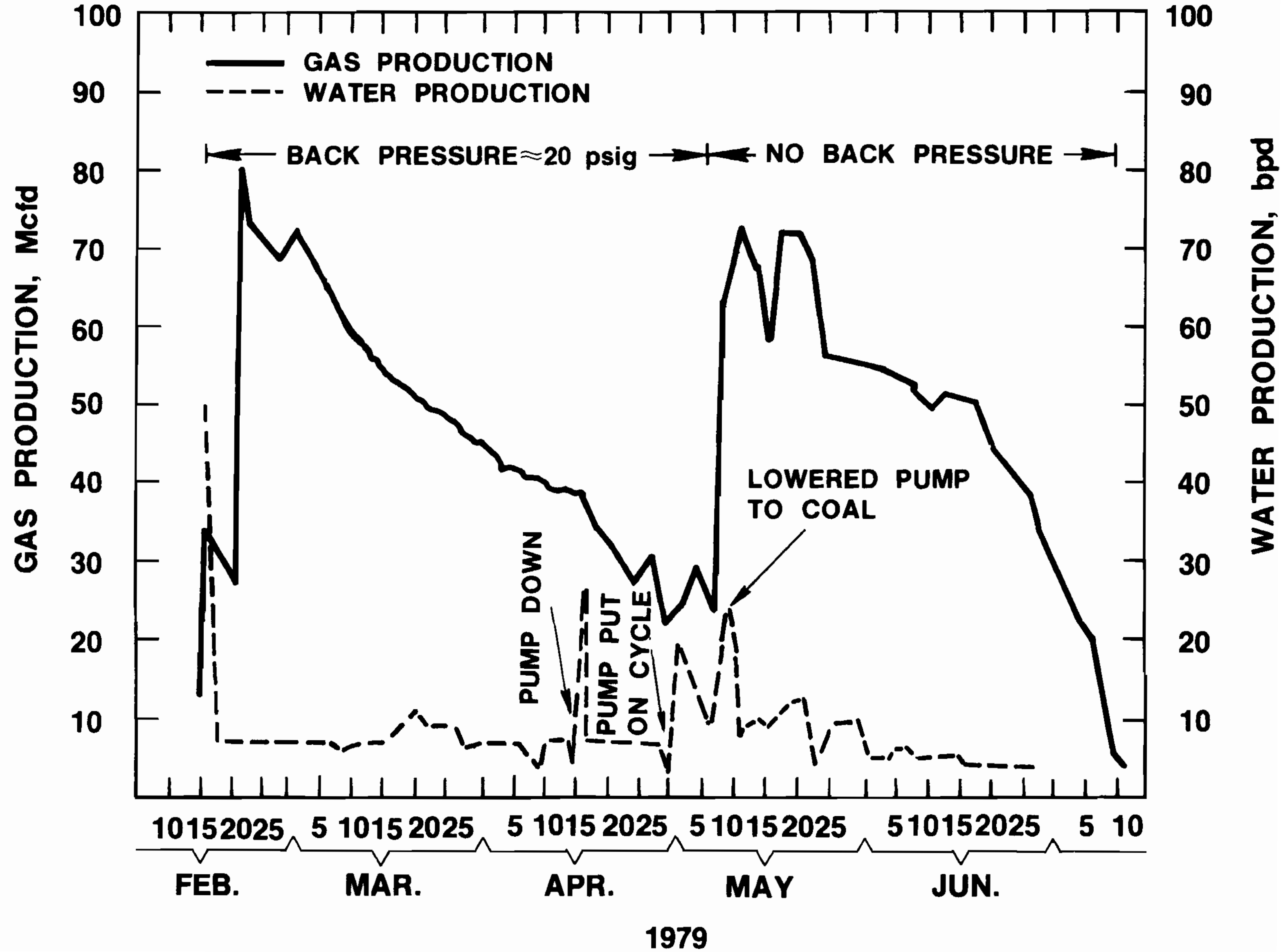
The first test of a no-proppant foam stimulation treatment was conducted in the Mary Lee Coalbed on December 16, 1978, in Jefferson County, Alabama (Well No 62, Table 3). An eight-inch diameter borehole, placed approximately 1,600 feet from active mine workings was drilled to the 1,150 foot deep coalbed. The borehole, referred to as TW5, was cased with seven-inch diameter casing set several feet above the five foot thick coalbed. Stimulation was accomplished through small diameter, high pressure tubing and a 10 foot long inflatable packer set at the top of the coalbed.

The coalbed was treated with 53,000 gallons of 75% quality foam (25% water, 75% nitrogen) at an average injection rate of 4.7 bpm. Breakdown pressure was recorded to be about 1,000 psig and average treating pressure was 1,600 psig. Fluorescein dye and fluorescent paint were added to the treatment fluid to aid in recognition of the propagated fracture(s) upon underground interception.

After clean-up, TW5 was equipped with a sucker-rod dewatering pump and a surface production monitoring system. Water pumping operations began on February 13, 1979, and continued until June 27 when the pump was removed from the well. Gas continued to flow from the test well until July 11, 1979. Production from TW5 is presented on Figure 61.

It is difficult to assess production characteristics of TW5 because a number of mechanical adjustments made at the test well site during its 147 day production life. Nevertheless, it is important to draw as much information as possible from this test, no matter how preliminary, since the potential benefits from no-proppant type stimulation treatments could be significant to future degasification of minable coalbeds.

FIGURE 61. - DAILY PRODUCTION FROM TW5, MARY LEE COALBED, JEFFERSON COUNTY, ALABAMA.



Stabilized daily water flow rates from TW5 started at about 7 bpd and ended at 4 bpd. Past experience indicates that initially low rates and the gradual decrease in water flow over time are typical of boreholes placed close to mining (26). The few occasions when water flows showed sharp increases at TW5 can be attributed to pump changes or slight alterations of the method used to measure water at the surface.

The production of gas from TW5 (Figure 61) was complicated by two outside variables. The first is the fact that a back-pressure of approximately 15 to 20 psig was left on the well until the end of April, 1979, and then afterwards completely released. This explains the broad double-cycled appearance of TW5's gas flow curve. The most significant characteristic to note about both "cycles" is that gas flows declined each time, and at roughly the same rate.

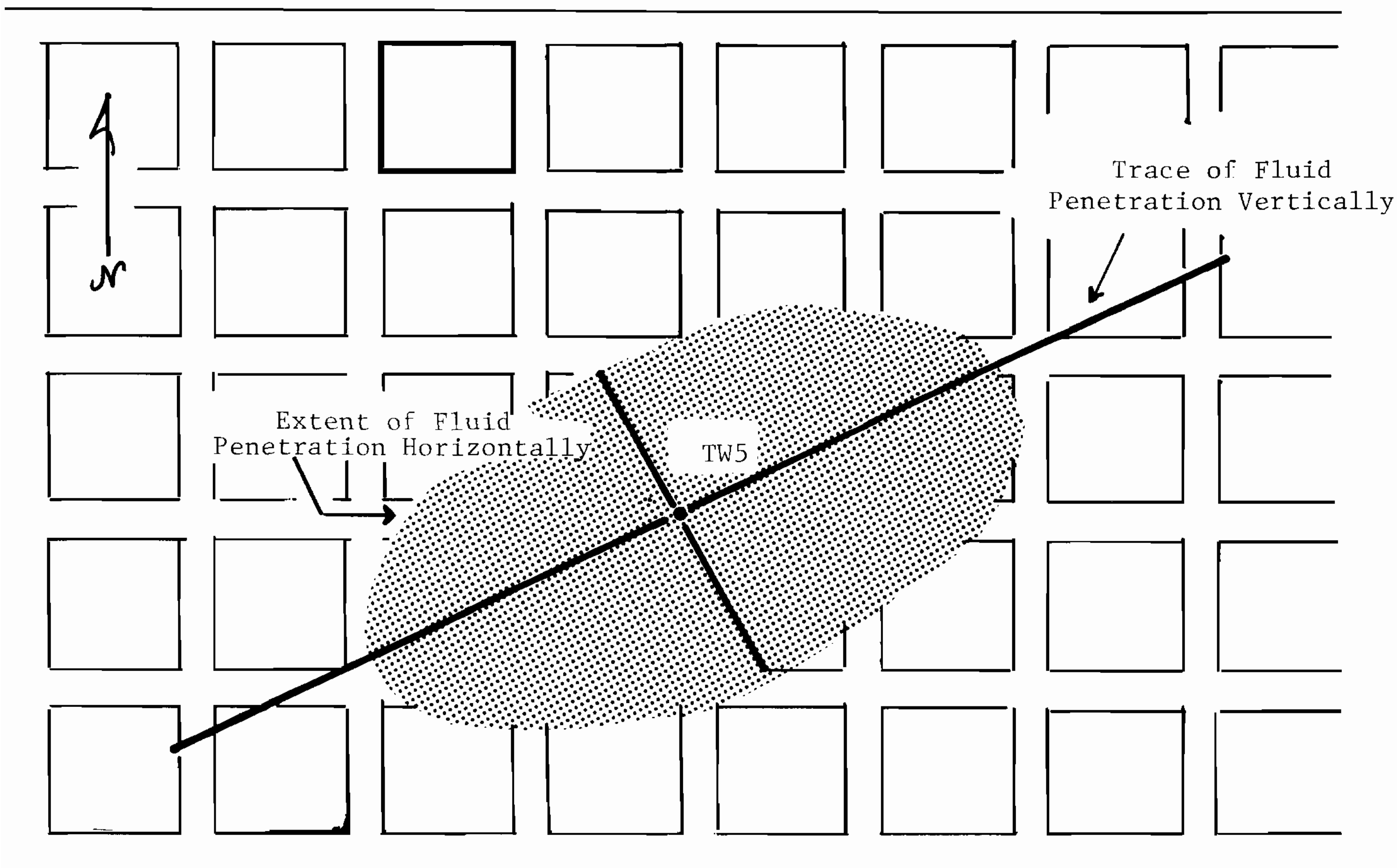
The second complicating variable which may have affected TW5's gas production performance is the mine's advance toward this well. At the beginning of March, the mine was 1,100 feet away. From that time on, mining closed the gap between itself and the test well at a rate of about 280 feet per month. It may be theorized, therefore, that the approaching mine continually shortened the test wells drainage radius, thereby causing the decline in production measured at TW5.

Mine operations intercepted TW5's wellbore on July 13 and the physical results of this well's stimulation procedures were examined underground periodically until mining had progressed 350 feet beyond the test site. Fluorescent material included in the stimulation design at TW5 was identified by U.S. Steel research personnel using an ultraviolet lamp and the locations where this material was found were recorded. The results of this work show that injected fluids penetrated the coalbed and/or roof rock horizontally through distinct bedding planes, and vertically through natural fractures. A map view of the horizontal component of penetration shows the form of an ellipse; the long axis extending approximately 360 feet and roughly coincident with the coalbed's primary natural fracture (face cleat) direction; the short axis extending approximately 180 feet and roughly coincident with the coalbed's secondary natural fracture (butt cleat) direction (Figure 62). The vertically-oriented component of fluid penetration, as shown on Figure 62, extended outside the ellipse for distances up to 130 feet.

Fluorescent stimulation material was generally limited to the coalbed (especially upper three feet) and the first foot of overlying shale/coal rock. Exceptions to this were: one vertically oriented fracture in the mine's shale roof rock extending upward to the upper coal bench (5.5 feet) and outward 8 to 10 feet from the wellbore (Figure 63); and one vertically oriented fracture in shale roof rock located near the southwest extremity of fluid penetration.

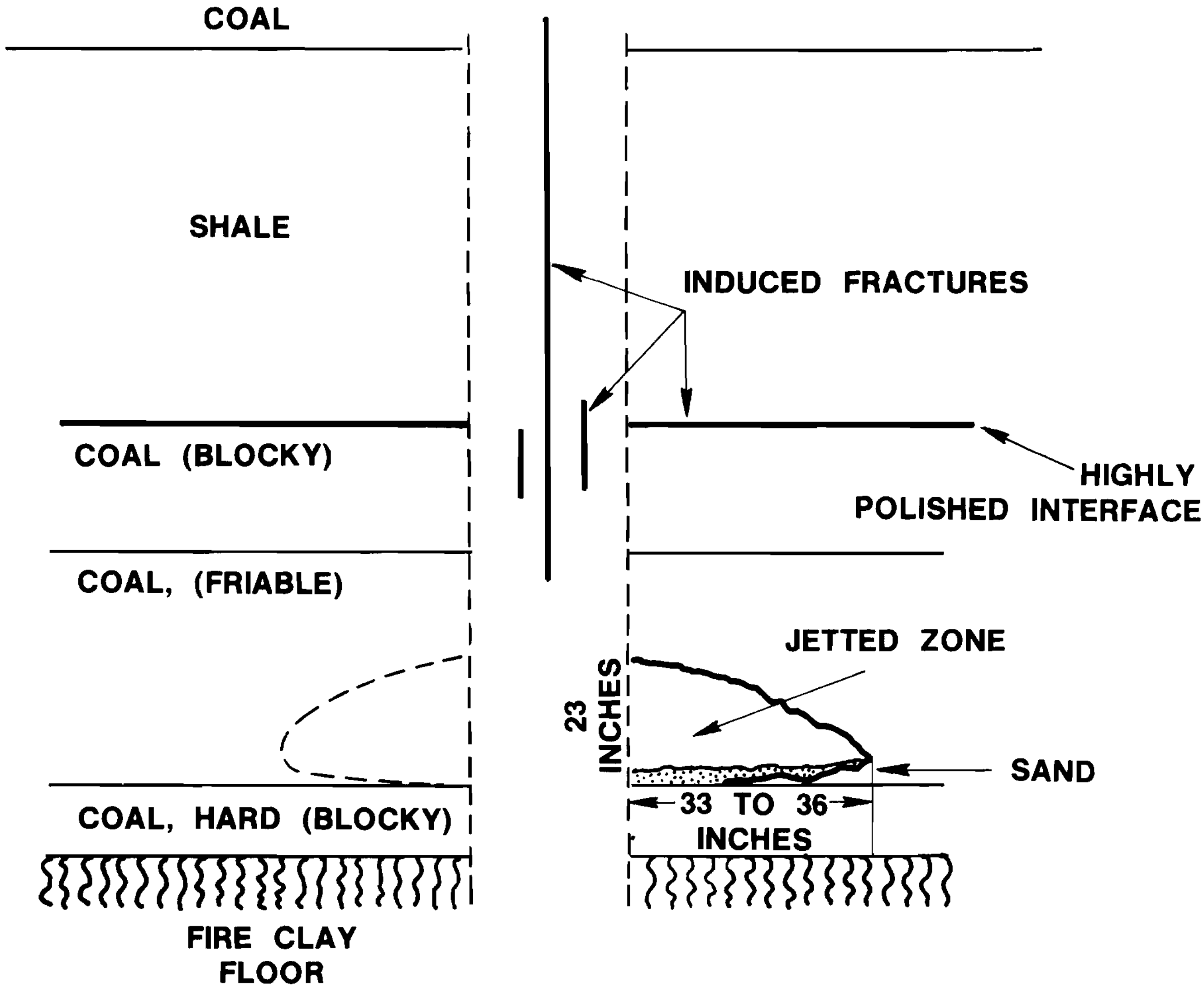
FIGURE-62

LOCATION OF TW5 WELLBORE AND THE AERIAL CONFIGURATION OF FLUORESCENT MATERIAL CONTAINED IN THE STIMULATION TREATMENT FLUID



Scale: 1 inch to 100 feet

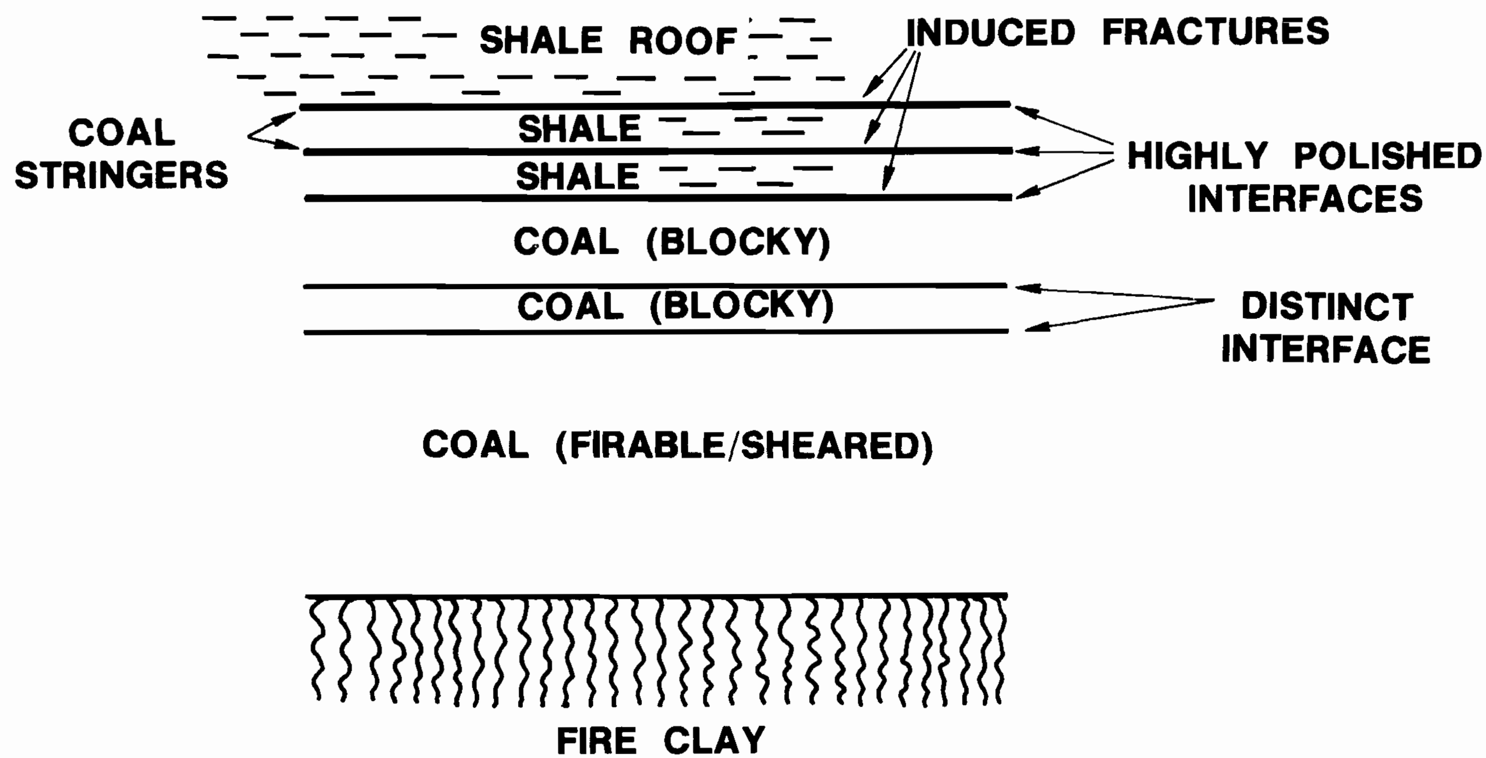
FIGURE 63. - SKETCH OF TW5 WELLBORE SHOWING POSITION AND ORIENTATION OF INDUCED FRACTURES AS INDICATED BY THE PRESENCE OF FLUORESCENT MATERIAL CONTAINED IN THE STIMULATION TREATMENT FLUID.



"Openings" that were observed to contain fluorescent material were all hairline in width. The majority of vertically-oriented penetrations were contained in coal cleat openings within narrow bands extending N 61^{o} E and N 29^{o} W from the wellbore's location. The majority of horizontal penetrations were contained within overlying shale/coal/sha interfacial areas. Bonding between these different rock types was generally weak to nonexistent as indicated by highly polished and striated coal and/or shale surfaces at these interface positions (Figure 64).

There are few conclusions that can be drawn regarding the effectiveness of no-proppant stimulation based on this one experiment, especially since the production history is short and the variables that could have controlled drainage ratios are complex. Nevertheless, the average daily rate of gas removal was 44,000 cfd and this might be considered acceptable if production were stabilized. This, and the fact that this type of stimulation had very little physical effect on mine roof rock, justifies repeating the experiment under more controlled conditions.

FIGURE 64. - SKETCH SHOWING POSITION AND ORIENTATION OF INDUCED FRACTURES FROM TW5 (HORIZONTAL PENETRATIONS)



PRODUCTION PROBLEMS RELATED TO COALBED STIMULATION

Gel

Stimulation designs for all gel treatments provide for some type of "breaker" ingredient which reduced fluid viscosity within a time after treatment, depending primarily on the temperature of the coalbed treated. Stable gel, or viscous gel residue, however, is often observed at well sites several months after stimulation. This gel material is included with water drained from the coalbed and is present as thick layers of a slippery jellylike substance adhering to the inside of pipes and other surfaces exposed to well water effluent or globular masses of gel material which often contain sand proppant.

The presence of unbroken gel within induced coalbed fractures must greatly retard fluid flow to the wellbore. Indeed, gas and water production has been unusually low where gel has been found. One example of this was reported by Elder and Irani in 1977 (15) after a well was treated through perforations using 30,000 gallons of extremely viscous gel which resulted in no significant increase in production. Elder and Irani hypothesize that because the treatment was done in very cold weather with cold water and in a low-pressure formation (Kittanning coalbed, 293 psig formation pressure), gel that was squeezed into samll coal pores did not breakdown, and pressure was too low to move the gel or gel residue from the low-permeable paths. Results of another gel treatment were reported by Lambert and Trevits in 1978 (23). As in the preceeding test, this well was stimulated using a very viscous gel, and flowed relatively low amounts of water and gas. Stable gel was routinely observed coming out the well's waterlines even though the stimulation included an enzyme-type breaker to reduce the gel viscosity to that of water within a few days. After the test well was intercepted by mining, a detailed examination of the stimulated area was conducted. Contrary to the Elder and Irani report, gel could not be found present within the coalbed away from the wellbore. Stable gel was found, however, to be limited to an area around, and very close to the test well's casing which had been slotted for production. It was concluded that only the gel near the wellbore did not breakdown sufficiently and that this probably was due to relatively low wellbore temperatures or adverse chemical reaction with casing materials.

These and other such field studies (27) indicate that gel or gel residue may significantly restrict fluid flow into coalbed gas drainage wells especially where production is limited to perforations or slots in the casing.

Sand

Recent field work shows that sand used to prop open fractures or minimize fluid leak-off during stimulation is carried back to the wellbore (23) (27). Down-hole pumps exposed to this material are almost always damaged, resulting in mechanical failures or losses in pumping efficiency, depending on the size and amount of sand present. Such sand related dewatering problems can be chronic during early production phases, increase well repair costs, and decrease gas production.

Several factors are thought to control the influx of treatment sand carried back to degasification wellbores. One of the primary reasons sand returns to wellbores over prolonged time periods (years) must be because compressional forces acting in the coalbed to close induced fractures are small. With the proppant held only loosely with fractures, the amount of sand that returns then becomes closely dependent on another factor: the ability of fluids to carry sand to wellbores. The ability for fluids to carry sand into wells is enhanced by gravity when the top of the sand-filled induced fracture is much higher than the upper most horizon exposed to the wellbore, 13/ a factor to consider since previous research concludes that induced fractures can enter strata overlying coalbeds (26).

Conditions most favorable for wellbore sand influx exist during the early phases of well production and may last several months depending on the characteristics of the induced fracture and on the original pressure of the coalbed. During these periods, coalbed reservoir pressures are greatest and the resulting high fluid velocities to the wellbore are most capable of carrying sand and closure pressures are minimal 14/. Also, the availability of sand to the wellbore is greatest shortly after stimulation and especially if the sand-filled fractures are much higher than the uppermost horizon exposed to the wellbore.

13/ The uppermost horizon exposed to the wellbore is defined by the bottom of casing in an "open hole" type completion, or by the top of the perforated or slotted zone at wells that are cased through the coalbeds being drained.

14/ Closure pressures can be quantified by subtracting reservoir pressure from bottom hole treating pressure (18). For any specific location, therefore, it is reasonable to conclude that when reservoir pressure is greatest, closure pressure is minimal since bottom hole treating pressure does not change. The converse of this is that closure pressure is greatest at a time when reservoir pressures become minimal.

Research efforts are now focusing specifically on developing new or testing existing equipment for dewatering coalbed gas drainage wells. In addition to having the capability to maintain a "dry" hole, this equipment must be able to handle sand which returns to the wellbores. Other efforts are being made to alter stimulation designs in hopes of lessening the sand problem. Generally, such alterations include: minimization of prop sand volumes and complete deletion of the very fine sand used as fluid loss agent since this fine sand is most easily carried back to the wellbore; changing injection rates during treatments and testing "overflush" techniques in order to minimize sand buildup near wellbores; maximizing the size of the proppant to make it easier to screen from the pump.

Sand damage to the standard sucker-rod type pump can be held to a minimum by positioning the pump above the coalbed. This establishes a larger sump into which sand may accumulate and provides a section of wellbore where sand can settle out before reaching the pump. This technique has proven to be effective in areas where sand problems are severe even though pumping efficiency is lost due to the increased exposure to gas traveling up the well. When employing this technique, it is recommended that pumps be positioned at a point in the well where the hydraulic pressure over the coalbed is from 10 to 25% of the hydrostatic pressure. Experience has shown that high daily gas flows from coalbeds may be achieved even if there is several hundred feet of water overlying the coalbed (27). This is supported by laboratory isotherm data which shows, in most cases, that large percentages of coalbed gas is released with 75 to 90% pressure reductions (see Figure 2). The pumps can later be lowered after gas flows stabilize or decline to unacceptable levels.

Well Unloading

The term "unloading" refers to occasions when much or all of the water contained in a well and the well's induced fracture system is rapidly, and usually uncontrollably, carried to the surface by large volumes of expanding coalbed gas. Such episodes can last from minutes to days, depending on the conductivity of the resulting induced fractures and the coalbed pressure condition. Gas and water velocities are very high during unloading and thus these fluids become exceptionally effective carriers of solid debris causing almost instant mechanical breakdown of downhole pumps, dislocation of sucker-rod strings from surface pump jacks, and severe damage to monitoring equipment.

Unloading occurs when coalbed gas pressures become greater than the hydraulic pressures holding gas in the coal. This phenomemon is initiated simply by pumping water from a well. As the borehole water level is lowered, a disequilibrium condition is created where gas pressure in the coalbed exceeds the hydraulic pressure holding gas in the coal. Unloading then continues until water pressure overcomes coalbed gas pressures.

The length and conductivity of induced coalbed fractures are thought to be major factors controlling the severity and time length of unloading episodes. In order for a well to unload, pressure differentials, created by borehole water draw-down, must be realized in a sufficiently large area of a coalbed over a very short period of time. Short, nonconductive induced fractures affect only small portions of the coalbed and, therefore, unloading episodes are short lived and not very intense. At the other extreme, long, highly conductive fractures connected to the wellbore allow decreases in hydraulic pressure over a greater area of coal very soon after borehole water is removed. Thus, unloading episodes from the most "successfully" stimulated are also the most violent and long lasting.

The height of the induced fracture in relation to the uppermost horizon exposed to the wellbore might also be an important factor to consider in well unloading. As water drains into the wellbore, pressure is reduced and gas is released from the coal. Instead of migrating to the wellbore, however, enough free gas might accumulate in upper fractured horizons to retard coalbed water flow. Unloading could then trigger as the borehole water level is lowered because pumping maintains a constant rate.

The coalbed pressure condition and the length of time wells have produced also effect unloading. At new wells where coalbed pressures are high, the potential for unloading is greatest, but is lessened as coalbed pressure is lowered.

EFFECTS OF HYDRAULIC STIMULATION ON COALBEDS AND ASSOCIATED STRATA

Since 1970, Government and industry research have mutually designed and conducted 71 hydraulic stimulation treatments in coal. The results of 12 of these treatments have been observed directly after mining operations proceeded through or very near the underground borehole locations.

Information documenting the underground results of coalbed stimulation first became available in 1977 (16). In this report, Elder described his findings at two borehole sites where guar gum gel had been used to treat the Illinois No. 6 coalbed (Well No. 5, Table 3) and the Pittsburgh coalbed (Well No. 10, Table 3). The fractures propagated from both sites were vertical, and were contained completely within the respective coalbeds. The widths of these fractures varied according to the relative viscosity of the fluids used at each borehole. The less viscous fluid produced fractures ranging from 1/8 to 1/2 inches wide while the more viscous fluid formed fractures up to 2-1/2 inches in width. Elder concluded that there was no adverse effect on the stability of the overlying or underlying rock strata, or on mining operations. Periodic observations over more than two years showed that no deterioration of mine roof or floor had taken place where the sand-filled fractures were earlier exposed.

The next two stimulated boreholes uncovered by mining were located in the Mary Lee coalbed at U.S. Steel's Oak Grove, Mine, Jefferson County, AL, only a few hundred feet apart in the same mine (Well Nos. 19 and 33, Table 3). These two gel-treated wells were documented in 1978 by Lambert and Trevits (23). Even though approximately 5,000 pounds of sand were included during stimulation of one of the wells, designated TW1, actual sand-filled fractures could not be observed underground. There was sufficient evidence, however, to indicate partings in the coal and mine roof rock were open during drilling, cementing, and the early stages of stimulation (during injection of the pad volume). The other well examined, designated TW2, was found to have sand-filled fractures leading from the wellbore. Unlike those fractures described by Elder (16), TW2 fractures were oriented vertically, horizontally, and inclined. All the fractures observed, however, were found to have remained within the coalbed unit even though the injection pressures during stimulation were very much in excess to what had been anticipated. No adverse affects to mining were observed or reported as a result of either of these two treatments.

Two additional boreholes, designated TW3 and TW4, were later stimulated at the same mine in the Mary Lee coalbed, the results of which were detailed in 1979 (26). This time, the type of stimulation treatment applied to the coalbed was foam. These two borehole tests yielded very different results which showed that stimulated fractures are not always limited to the coalbed. Sand-filled fractures 15/ propagated from these two boreholes (Well Nos. 36 and 42, Table 3) were vertical, very thin, and began about three feet up from the base of the five foot thick coalbed and continued for an undetermined distance into the overlying roof strata. Mine management, being somewhat concerned about the presence of sand-filled roof fractures, formally assessed the effects on the mine roof. The mine management's evaluation was as follows:

> "Because the roof of the mine in the general vicinity of TW4 was of a quality which required installation of more roof support than used in many other portions of the mine, it was difficult to assess the effect of the fracture on the mine roof at this location. However, no further increment of supplemental roof support was required at the base of the borehole or along the fracture wings.
>
> The roof in the general area of TW3 was of a quality typical of most of the mine developed to date; however, in the immediate area of the bottom of TW3 in which both the upper and lower coal seams had been fractured, it was necessary to install supplementary roof support. This supplemental roof support was required when mine management observed roof movement along the west rib of the entry driven due north of the bottom of the borehole, additional draw rock separation, roof becoming excessively drummy, and water seeping out of cracks in the roof. The supplemental roof support consisted of boxing the intersection immediately to the south of the borehole with six inch H-beams, installing four inch H-beams supported by timbers for distances of 70 feet to the east and 40 feet to the north of the borehole, and installing 10 foot long expansion-steel anchored roof bolts between the standard four foot long resin bolts to ensure that the bolts anchored in the solid rock above the upper coal seam.
>
> Installation of the supplementary supports required additional time as well as close inspection by mine management to ensure its adequacy; however, it was possible to mine through this area without experiencing any roof fall during mining operations".

15/ Underground investigations indicated "fractures" denoting rock breakage, do not normally occur as a result of stimulation. The physical evidence indicates that preexisting fractures (rock joint, or coalbed cleats) or bedding planes are widened during stimulation. The extent of which these fractures are widened depends primarily on the viscosity of the fluid used during stimulation. Heavily gelled fluids have been observed to widen fractures as much as four inches within the coalbed.

Areas of the mine where these features, called "rolls", were observed are shown on Figure 46. Because inherent rock weaknesses develop near such features, these areas generally require some degree of additional roof support. The necessity for more roof support near TW4 than used in many other portions of the mine, as reported by mine management, may be attributed to this geologic phenomenon rather than stimuation of the test well. The fact that additional roof support was not required at the base of TW4 nor was it required along the fracture wings, indicates borehole stimulation was not the cause for providing additional roof support.

The entry nearest TW3 is also shown on Figure 46 to be a location of natural roof disturbances. Geologists also noted the presence of many wet roof joints in this area. Except for the single sand-filled crack leading from TW3 (Figure 46), no evidence could be found to indicate that these wet roof joints had been created by stimulation. Unusually large amounts of seepage from roof openings near TW3 could, however, be due to the borehole's presence, since it is an accumulation point for water within a coal unit only seven feet above the open entry.

Information regarding the effects of borehole stimulation on mining has also come from the Emerald Mine, in the Pittsburgh coalbed, Green County, PA. A total of eight boreholes were completed and sand-filled fractures leading from five of these have thus far been identified in the mine. Vertical fractures were observed at three of the boreholes (Well Nos. 21, 27, and 28, Table 3), ranging in width from 1/8 to 2-1/2 inches. Only one of these vertical fractures extended into the roof rock, and that was for a distance upward of less than two feet. Horizontal fractures approximately 1/8 to 1/4 inches thick, extended from three of the boreholes (Well Nos. 21, 27, 30 and 40, Table 3). Horizontal fractures were found either at the extreme top of the main coal bench or were found present between shale/rider coal units a few feet above the main bench (see Figures 39, 40, and 59).

The most recent results of hydraulic stimulation's effects on mine roof come from work being conducted in the Mary Lee Coalbed at the Oak Grove Mine, Jefferson County, AL 16/. Here, induced vertical and horizontal partings resulted from the no-proppant stimulation of borehole TW5 (Well No. 62, Table 3), examined underground on July 11 and 12, 1979. These partings were generally so thin that they could not have been located without the help of fluorescent blue paint "marker" (included in the stimulation fluid) and an ultraviolet light.

16/ DOE Contract No. ET-75-20-9027, entitled, "Demonstration of Degasification of a Portion of the Mary Lee Coalbed"

One vertical fracture from TW5 extended into the mine's roof along a direction parallel to the coal face cleat and could be traced approximately five feet away from the wellbore's location. All the other vertically oriented fractures mapped as far as 320 feet from the wellbore, were contained completely in the upper two thirds of the coalbed.

As discussed in a previous section of this report (No-Proppant Treatment), stimulation fluid from TW5 was found to have spread horizontally within an interfacial area between the coalbed and an overlying shale rock unit. Within the test area, the coalbed's surface at this interface was highly polished and striated (slickenside surfaces), indicating that the coalbed and shale had not been tightly joined together prior to stimulation. It is concluded, therefore, that the horizontal penetration of fluid did not change the original "weak" character or strength of the bond between the coalbed and the overlying roof rock. Even though there was no visible damage or excess water or gas drainage, precautionary supplemental roof support (steel H-beams) was installed for small distances away from the TW5 borehole site.

The development of horizontal fractures above the interval being mined is, perhaps, potentially the worst possible roof condition that can be directly attributable to stimulation. Even so, to date, there has been no observed or reported effects on actual roof stability which would indicate that any of the stimulation treatments performed as part of the Government's degasification program adversely affected mining operations. However, the comparatively small amount of information presently available, and the significantly different character of the results, suggests that several additional tests are required before the effects of hydraulic stimulation can be fully appreciated.

THE EFFECTS OF REMOVING COALBED FLUIDS BEFORE MINING

A previous section of this report, entitled, "Effective Well Placement", described how operating drainage wells actually create conditions in coalbeds which allow gas to be released and to migrate to wellbores. These conditions are created by removing water to decrease coalbed pressure and lower water saturation. It is known from laboratory work of coal isotherms (Figures 1 and 2), that increasingly larger amounts of gas are desorbed (released) from the coal as pressure is reduced. Once released, the gas then can travel to boreholes via the natural and/or induced fractures in the coalbed. As wells remove water from these same fractures, the ability for gas to flow through coalbeds is increased (5). In summary, producing boreholes creates favorable conditions for gas release and migration within the area of the coalbed affected by borehole drainage.

If mining intersects an area of a coalbed which has been partially depressurized and desaturated by an operating borehole, the borehole's drainage area then becomes an extension of the mine's drainage area. The mine's ventilation system would then be required to contend with an additional amount of gas originating from a larger area where conditions are unusually favorable for gas release and migration. This potential problem can be avoided in two ways.

The first way is to allow degasification wells production to sufficiently deplete before mining interception takes place. In practice, this means that mine operators should not drive entries which intersect borehole drainage radii until gas production rates decline to very low levels, indicating the area is actually "degassed". Estimating the areal configuration of a borehole's drainage area would be very difficult, however, since it would require a reliable knowledge of the induced fracture geometry and an accurate quantitative method of predicting dynamic changes in coalbed reservoir conditions. Unfortunately, present degasification technology is just now concluding "demonstrate the feasibility" phases of development and thus offers few reliable methods of predicting such pertinent reservoir events. Another drawback is that coalbed degasification wells may require five or ten years before sufficient depletion takes place. The capability for "short-termed" degasification could, therefore, be lost completely.

The problem of mining through boreholes' drainage areas can also be avoided in a way that is much more practical than waiting for gas depletion to occur. This method is based on the same principles which create favorable gas production conditions in coalbeds; that is, general pressure and water saturation decreases. Fortunately, these same conditions which enhance gas release and migration are also ideal for coalbed water resaturation or infusion (18).

FIGURE 65. - VIEW OF MINE SHOWING TEST WELL LOCATIONS AND MINE ENTRIES STUDIED FOR GAS EMISSIONS.

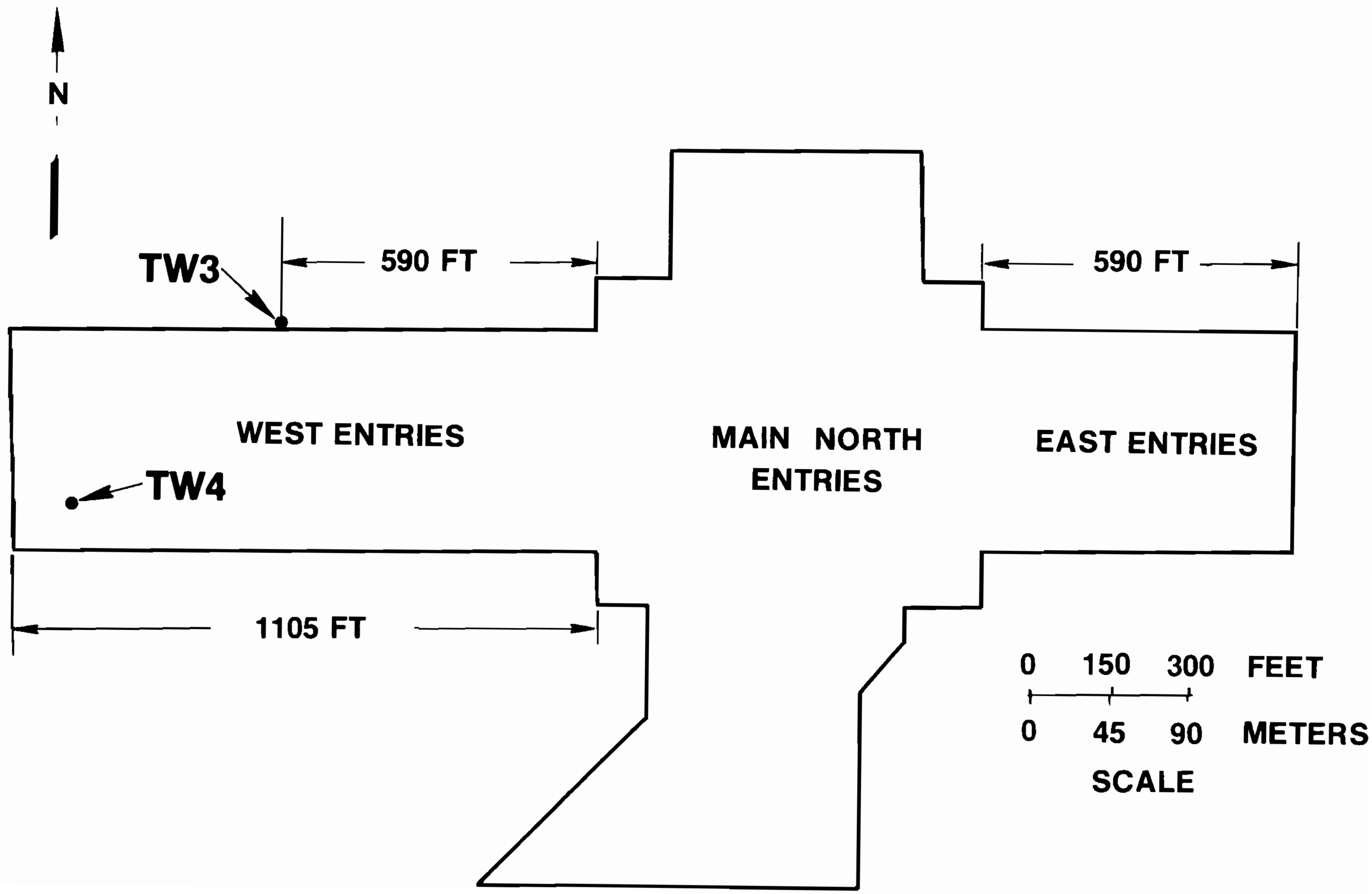
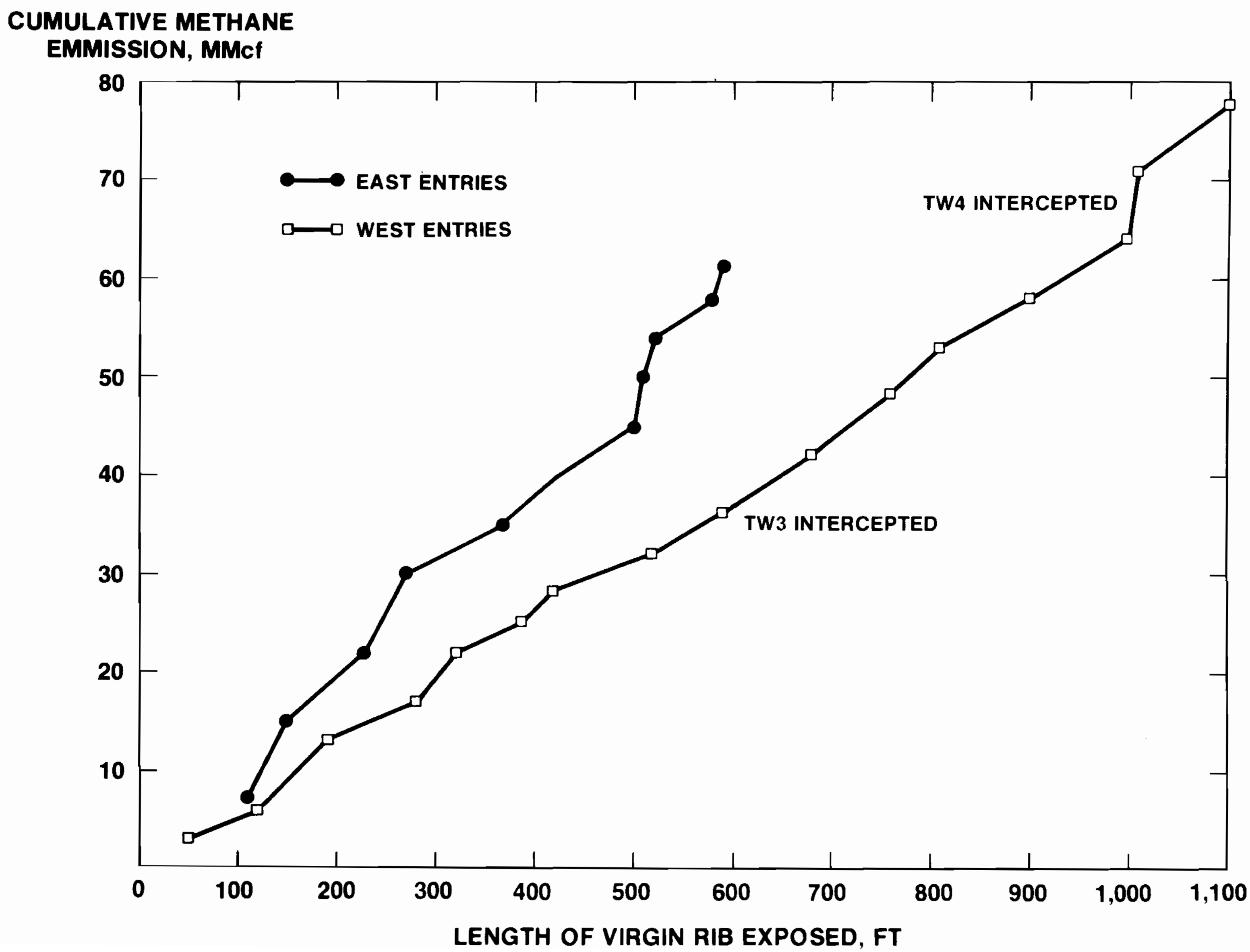


FIGURE 66. - GRAPH OF CUMULATIVE METHANE EMMISSIONS VERSUS LENGTH OF VIRGIN RIB EXPOSED.



Infusion of the coalbed (putting water back into the coalbed) raises the coalbed's formation pressure in the area and prevents further desorption of gas. In addition, infusion physically prohibits the movement of any free gas that is available by filling the coalbed's fracture system(s) with water.

In practice, there are two ways water "infusion" can be incorporated into the vertical degasification technique. The first way is to flow water back into the borehole. The second way is to simply turn-off the borehole's water pump several weeks before mine interception, thereby allowing the coalbed to "flood" itself naturally.

There are two reported instances where degasification boreholes were water "infused" before they were intercepted by active mining (26). These two boreholes were located within the same set of mine entries and were spaced approximately 510 feet apart (see Figure 41). The boreholes together drained about 25 million cubic feet of gas within a total time period of 11 months (Figures 42 and 43). After the production phase, large volumes of water were pumped back into one of the wells; the other well was allowed to flood itself naturally. In order to evaluate the effectiveness of these degasification boreholes, mine gas emissions were measured and recorded while mining the two sets of entries shown on Figure 65. The east entries were driven 590 feet during a 70 day period encountered a total 61 million cubic feet of gas without degasification. Mining operations then turned west and, within 63 days, reached the first degasification borehole (TW3, Figure 65) also 590 feet from the main north entries. The amount of gas measured while mining to this "short term" drainage borehole was 37 million cubic feet, 40 percent less than that encountered while mining east. The difference in gas emissions between the east and west set of entries is graphically illustrated on Figure 66. This study concluded that a combination of techniques, degasification and water infusion were responsible for the comparatively low mine gas emissions that resulted in the area of the two test boreholes.

COSTS OF VERTICAL BOREHOLE DEGASIFICATION

The costs provided in the following section are a result of two Government/industry cost-sharing degasification projects conducted in two geographically different areas. Basic completion design for both projects are essentially the same. The project in Alabama, however, required drilling deeper wells, larger stimulation treatments, and more sophisticated surface monitoring, production and safety equipment.

Pittsburgh Coalbed, Greene County, PA

A total of eight boreholes were drilled and completed at the site of the newly developing Emerald Mine near the town of Waynesburg, PA, during 1976 and 1977. Government funding was provided to foam stimulate seven of these wells (37). Average stimulation treatment size was 82,800 gallons of foam and 11,100 pounds of 20 to 40 mesh size sand. Production equipment costs were low, primarily because the wells were not equipped with meters or flare stacks.

Waynesburg, PA

Site Preparation	
Access and site preparation on company property	8,500.00
Power lines, poles and installation	1,100.00
Drilling	
6-1/4 inch diameter hole (765 ft. average depth @ 11.50/ft)	8,800.00
Logging	
Gamma ray and neutron log	700.00
Three-D velocity log	1,600.00
Casing	
4-1/2 inch diameter, well casing, yellowband 10.5 and 10.7 pound/ft, 3000 pound test (735 ft average depth @ 2.48/ft)	1,825.00
Formation packer shoe	625.00
Cementing	
Cement 15 pounds/gallon with salt additive (175 sacks @ 3.14/sack)	550.00
Other (includes placement of casing in well)	495.00

Stimulation

Service rig to drill out packer shoe and clean well	6,000.00
Foam frac (32,800 gallon average volume, 11,100 pounds 20 to 40 mesh sand)	4,400.00
Nitrogen for Frac	2,650.00
Frac Tank (2 @ 150.00 each)	300.00
Water Hauling (20,000 gallons @ 100.00/15,000 gallon)	140.00

Production Equipment

Walking beam pump jack complete includes downhole pump	2,000.00
Sucker rods reconditioned 5/8 inch and casing head	400.00
Tubing 2-3/8 inch diameter (approximately 765 ft @ 0.56/ft)	430.00
Installation of production equipment	600.00
Total Cost per Well	$41,610.00

Mary Lee Coalbed, Jefferson County, AL

A total of 17 wells were drilled and completed in 1977 in a grid pattern near the town of Oak Grove, Alabama. Fifteen of these wells were foam stimulated with roughly the same size treatment (48,000 gallons foam, 23,000 pounds of 80 to 100 mesh sand, and 42,100 pounds of 20 to 40 mesh size sand). Some of the costs presented are based on average cost from bulk purchases of equipment as well as services. Understandably, without bulk purchases, some costs would be considerably higher. Maintenance costs, also a considerably expensive item, are not included in the following report of costs.

Oak Grove Alabama

Site Preparation

Site survey, preparation and roads on company property	4,800.00
Power, lines, poles and installation	3,700.00

Drilling

12 inch diameter hole for surface casing: (approximately 15 ft @ 26.50/ft)	400.00
6-1/4 inch diameter holes: (1,100 ft average depth @ 10.75/ft)	11,825.00
Coring for desorption testing	2,700.00

Logging

Vertical deviation survey and rig time	1,850.00
Gamma ray, density log and rig time	1,980.00

Casing

8-5/8 inch diameter surface casing: (approximately 15 ft @ 7.90/ft)	120.
4-1/2 inch diameter well casing, 16-55 9.5 pound/ft (1,100 ft @ 3.60/ft) floatshoe and centralizers	3,960.

Cementing

Cement, 15 pound/gallon with salt additive (1,100 ft @ 3.30 ft) includes installation of casing	3,630.

Stimulation

Foam Frac (48,000 gallon average volume, 23,000 pound 80 to 100 mesh sand, 42,000 pounds 20 to 40 mesh sand)	10,690.
Nitrogen for Frac	3,000.
Frac tank	500.
Rig time and labor	1,250.

Production Equipment

Walking beam pump jack and polish rod	2,080.
Sucker rods, reconditioned 5/8 inch (1,100 ft @ 0.25/ft)	275.
Tubing, used (1,100 ft @ 0.85/ft)	935.
Wellhead	110.
Downhole pump and installation	1,540.
Gas and water meter, includes installation	1,725.
Flare stack and assembly	1,410.
Lightening protection	1,100.
Miscellaneous well clean-out and standby time	3,500.
Contingencies for mishaps and weather	6,000.
Total Cost per Well	$69,080.

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