V. General Reservoir Characteristics

V. General Reservoir Characteristics

The reservoir characteristics of Brown shale are vastly different from those of typical oil- and gas-producing formations. Porosity indicates how much space exists in a particular formation where oil, gas, and/or water may be trapped. A commercially oil- or gas-productive sandstone or limestone reservoir has porosities in the range of 8 to 30 percent. By contrast, gas-producing Brown shales have porosities of 4 percent or less (table 3).

Much of the oil and gas in a formation may be unrecoverable because the pore structure is such that reasonable flow cannot take place. The ability of fluids and gases to flow through a particular formation, or permeate it, is called the permeability. The typical oil- and gas-producing formation has a permeability in the range of 5 to 2,000 millidarcies (mD). By contrast, most of the measured permeabilities of the Brown shale in productive areas are in the range of .001 to 2.0 mD (see table 3).

Since the characteristics of Brown shale reservoirs are so different from those of the usual oil and gas reservoir, evaluations of gas-production potential of the shales' by using conventional oil and gas techniques may result in erroneous conclusions. In the conventional oil and gas reservoir it is a simple matter to measure the percentage of the total reservoir that is occupied by oil, gas, and water. However, in dealing with the Brown shale it is very difficult to accurately determine these percentage saturations because the pores are so very small.

The manner in which natural gas is held in the Brown shale is a subject of considerable speculation. Some scientists believe that it is simply entrapped in extremely small pores. Others think the gas is adsorbed or molecularly held on the surface of the shale particles. ' Some of the natural gas may be dissolved in solid and liquid hydrocarbons in the reservoir. There is also some reason to believe that the gas may be in a liquid state in pores in the Brown shale. Available evidence[2] indicates that *virtually all of the Devonian shale contains gas* that is released or flows from the shale when the shale is placed in a relatively low-pressure atmosphere. However, current commercial production appears to enter the wells mainly from the Brown shale.

All subsurface reservoirs initially exist at elevated pressures, regardless of whether they contain water, oil, or natural gas, J In conventional oil and gas reservoirs, a normal reservoir pressure (in

NOTE: All references to footnotes in this chapter appear on page 41.

Table 3
Comparison of Core Data for Brown Shale and Reservoir Roks From Other Gas Producing Areas

	Typical Permeability (m i l lidar - cies)	Typical Porosity (percent)	Typical Water Saturation (percent)
Hugoton - Anadarko Basin . .	20.	14	40
San Juan Basin'	1.	10	30
Permian Basin[a] . . .	15.	12	35
Brown Shale:			
Jackson County, W. Va.[b]			
(whole-core analysis). . . .	2.0	3.2	65
(conventional-core analysis)	0.1	3.0	70
Lincoln County, W. Va, '			
(whole-core analysis).	.004	0.6	0.0*
Perry County, Ky.[d]			
(whole-core analysts). . .	.3	4.0	35

"Centrifuge measurement, see text,

'S Rudisell, N Beckner, and W.B Taylor (Phillips Petroleum Company), Personal communication, 197[J

"W. L. Pinnell (Consolidated Gas Supply Corp.) core data on Well #11440 and #12041 Personal communication), 1976

[c]Phase Report No. 1, Massive Hydraulic Fracturing of the Devo-nian Shale, **Columbia/ERDA Contract E (46-1) - 8014 Research Department, Columbia Gas System, October 1976,**

'Final Report—Well No. 7239, Perry County, Ky,, ERDA-MERC, July 1975.

pounds per square inch) is generally obtainable by multiplying the depth (in feet) below the surface of the ground by a factor of about *0.4.* For example, an oil and gas reservoir at a depth of *3,300* feet in the Clinton sand in Ohio would be expected to have an initial pressure of about 1,300 pounds per square inch (psi), Since Brown shale formations produce gas at very low rates, it is difficult to determine an accurate initial reservoir pressure. However, shale wells that are shut in for long periods often exhibit pressures in the range of 0.125 times the depth, which is much less than would be expected in a normal oil or gas reservoir. The initial reservoir pressure is very important if the gas in the shale exists in a gaseous state, because the amount of gas in the reservoir measured at atmospheric conditions is proportional to the reservoir pressure. For example, all other things being equal, a reservoir with a pressure of 2,000 pounds per square inch absolute (psia) will contain twice as much gas in a given volume of reservoir rock when measured at atmospheric conditions as a similar reservoir at the same depth whose pressure is 1,000 psia.

Reservoir Evaluation Tools

Core Analysis

In drilling an oil or gas well with rotary tools (the drill bit rotates at the bottom of the hole as opposed to moving up and down as in cable-tool drilling), it is possible to use a special type of drill bit that works much like a doughnut cutter and permits the operator to cut plugs or cores from the formation and bring them to the surface as samples of the rock being drilled. This operation is referred to as "coring. " The samples so obtained can then be subjected to various types of analyses.

Geologists and engineers examine cores of Brown shale to detect fractures or joints, The visual appearance, odor, or taste of a core sample provides an indication of the presence of gas, oil, or water in the pores of the core.

After a quick gross examination, 6-inch long pieces of the core may be sealed in cans or other containers to maintain the fluid content insofar as possible. These samples are used to determine the porosity, permeability, and fluid saturation of the shale. It is important to note that the laboratory procedures used to analyze the Brown shale were designed for normal sandstone and limestone reservoirs which have much greater porosities and permeabilities.4

Basic to an understanding of the gas production potential of the Brown shale is the need for analytical techniques capable of accurately determining critical reservoir characteristics from core samples. If it is not possible to determine accurately from the core samples (1) the physical nature of the pore structure that constitutes the reservoir (subsurface gas container); (2) the percentage of the total bulk volume of the reservoir that is made up of pore space; (3) the ability of fluids to flow through these pores; and (4) the percent of pores occupied by gas, liquid hydrocarbons, solid hydrocarbons, and water, then there is much smaller chance of determining these same parameters from less direct methods such as electrical logs. A log is a record of some physical property (e.g., electrical resistivity or radioactivity) of the rocks penetrated in a well,

The "conventional" type of core analysis involves cutting a 3/4-inch-diameter, 1 -inch-long plug from the core, whereas the "whole core" type of analysis uses the entire sample which is 3-1 /2 to 4 inches in diameter and 6 inches long. "Whole-core" analysis is generally thought to be more applicable than the "conventional" type.

Permeability, Porosity, and Saturation

The permeability, porosity, and saturation of the Brown shale are vastly different from the same parameters of most gas-producing reservoirs. A general comparison of these characteristics is given in table 3. The Hugoton-Anadarko, San Juan, and Permian Basins represent some of the better known gas-producing areas. They tend to contain reservoirs that are on the "tight" (low permeability) side, as compared with offshore production, where the reservoirs may have a permeability of 1,000 mD and a porosity of 35 percent. Nevertheless, the typical sandstone reservoir has permeabilities and porosities that are much greater than those of

Brown shales. This is a strong indication that methods different from those used in conventional gas-producing reservoirs must be used to obtain commercial rates of production from the Brown shale. Development and evaluation of such methods can only come from basic research and field testing.

The characteristics of Brown shale listed in table 3 vary widely, even though the data presented are all from the same geographical region in southwestern West Virginia and eastern Kentucky. This variation is probably due principally to the heterogeneity of the shale itself.

it appears that whole-core analysis gives more meaningful information for the Brown shale because it includes the effects of joints and fractures. Conventional-core analysis, run on a small plug, will be affected by a fracture if one exists in such a sample, but the plug may not contain one even though fractures appear to be present every few inches in the Brown shale. Fractures caused by drilling and coring operations may produce spurious data from both coring analyses.

Table 3 does not indicate the very high permeabilities of some of the samples. The whole-core analysis of the Lincoln County well represents 19 samples distributed through 1,300 feet of shale. Three of these samples had permeabilities of 906 mD, 502 mD, and 93 mD, whereas the other 16 samples ranged from .0002 mD to .023 mD. Similarly, the whole-core analysis of the Perry County well represented 12 samples covering 64 feet, with two permeabilities of 9 mD and 23 mD and the others between 0.1 mD and 0.9 mD.

The Lincoln County, W.Va., whole-core analysis shown in table 3 is markedly different from the other Brown shale analyses. This is probably due to the manner in which the analysis was made. The cores from the Jackson and Perry County wells were analyzed using horizontal flow, while the analysis of the Lincoln County well was based on vertical flow. Since vertical flow is likely to encounter impermeable barriers of paper-thin laminae that would not affect horizontal flow, much lower permeabilities would be calculated. The lack of vertical communication would also result in reduced measured porosities. This Lincoln County core analysis also indicated a water saturation of 0.0 percent,[5,6] whereas the other shale analyses showed substantial water content, The Lincoln County analysis was based on centrifuge measurements, The centrifugal force created apparently did not exceed the capillary or other forces holding the water in the very small pores; hence, it appeared that the water saturation of the shale was 0,0 percent. These examples clearly emphasize the need for research in the area of core analysis of the Brown shale.

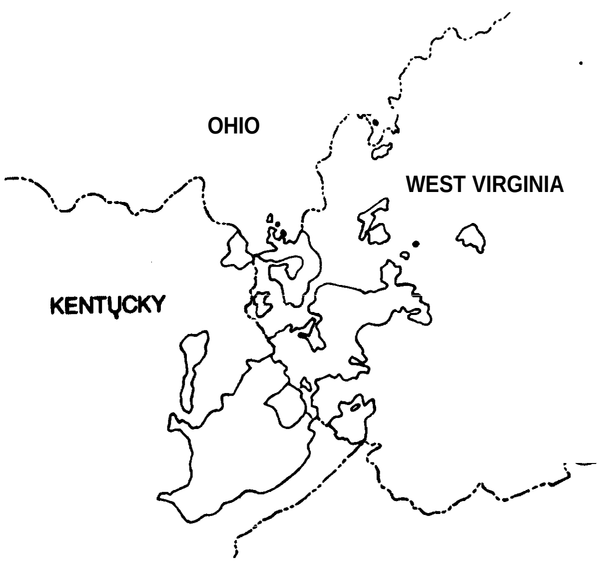
The Brown shale is characterized by a porosity of about 3 percent. However, a 3-percent porosity estimate may be too low. The operator who drilled the Lincoln County well canned whole-core samples throughout the entire 1,300 feet. All of these samples liberated sufficient natural gas to cause the pressure in the can to increase considerably, Although it took about 3 weeks for most of the cans to reach a static gas pressure, some of the cans containing the tighter sections of the shale were still increasing in pressure after a 2-month period,[7] The gas liberated in the cans had a volume greater than could be accounted for by the measured porosity and the assumed initial reservoir pressure. In other words, the gas-occupied porosity may be greater than the 3 percent currently indicated by the core analysis.

Because it takes as much as 2 months for the gas to escape or flow from a core sample 3.5 or 4 inches in diameter and 6 inches long, it may be that the amount of gas in the Brown shale can be most accurately determined by measuring the gas that escapes from core samples. In a normal oil and gas formation this would be impossible because most of the gas would escape from the core during normal canning or handling operations. However, in dealing with a material with such a low permeability as the Brown shale, it is obvious that very little gas is lost during the period of time necessary to remove the core from the bottom of the hole and place it in a container. The amount of gas lost from the cores during the canning operation would apparently be limited to the gas in the permeable fractures and would be negligible compared with the gas in the matrix of the Brown shale. Use of this method of determining the gas in the shale might eliminate the necessity of measuring the porosity, saturations, and reservoir pressure. A technique similar to this is used by the U.S. Bureau of Mines to determine the amount of natural gas in coal.[8]

Core Data Distribution

The gas-producing potential of the Brown shale cannot be realistically evaluated until its physical and chemical characteristics throughout the area have been determined. Even though there are about 10,000 wells currently producing gas from the Brown shale, coring to date has been limited almost entirely to the better-producing areas shown in figure 7. The data of table 3 relate only to wells in the producing area of Kentucky and West Virginia. Recent research has involved the coring of 12 experimental wells, but only 4 of these are very far outside currently producing areas.

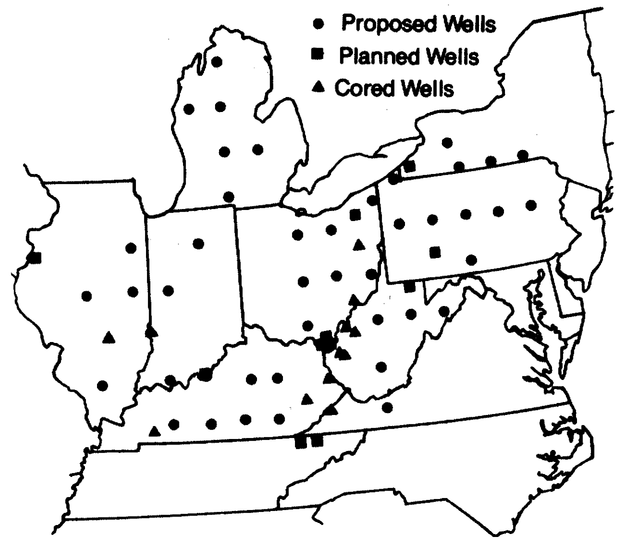
Figure 7. Major Devonian Shale Gas Production Areas



Source Energy Research and Development Admmistration.

An expanded shale inventory by the Energy Research and Development Administration (ERDA) will provide core samples from wells distributed across a wide expanse in the Appalachian Basin and areas to the west and northwest (figure 8). Such data are needed to evaluate the extent of the natural gas resource in the Devonian shales.

Figure 8. Location of Core Wells in a Proposed Inventory of Brown Shales by ERDA



Source Energy Research and Development Administration

Flow Tests

The actual significance of core analysis data and visual observation of core quality can only be obtained through flow tests of the wells, which determine how fast the gas can move through the shale. Due to the extremely low permeability of the shale, it may take several years to detect drainage of the potential drainage area of a well. To reduce the time required to determine flow rates in Brown shale, a special type of test is required. The so-called "isochronal" flow test involves determining flow rates under conditions where the entire drainage area of a well has not yet been affected and extrapolating the resulting data in order to estimate what the well behavior will be after the well has affected the entire drainage area.

Pressure buildup and drawdown tests are conducted to determine the significance or accuracy of the core-analysis or log-measured permeability, thickness, and saturation data.[9,10] A pressure drawdown analysis is a mathematical analysis of the pressure that results in the well due to continued production at a constant rate, whereas a pressure buildup analysis is a mathematical analysis of the increase in well pressure that results when the well is shut-in after being produced at a constant rate. The increase in wellhead pressure is determined at regular intervals for a specific number of days, weeks, or months.

Determining the initial pressure in the Brown shale is difficult and time consuming because of its low permeability. Reservoir pressures are normally determined by temporarily shutting in a well and then measuring the pressure in the well bore at the depth being investigated. Using this procedure after shutting in a well in the Brown shale will provide an accurate measure of the reservoir pressure only after weeks or months because of the time required for equilibrium pressure to be reached between the well bore and the adjoining shale pore space. " Much of the variation in formation pressure gradients (i.e., pressure per foot of depth) that has been observed and recorded might be caused by measurements taken before reservoir well bore pressures are equalized.lz1314

Logging

The term "logging" is applied to a variety of measurements made in a well by lowering a measuring device on an electric cable and recording variations of the particular physical property being measured. The plot of the data versus depth is known as a log. After permeabilities, porosities, and gas saturations have been determined from core analysis, logging techniques are used to measure various physical properties of the subsurface formations in place. Interpretation of well logs permits the determination of porosities, saturations, and permeabilities of the formation.

A wide variety of physical properties are traditionally measured in oil and gas wells in this manner. Some of these[15] are electrical resistivity, difference in electrical potential between mud in the well and the fluid in the rock (self-potential log), natural radioactivity (gamma-ray log), induced radioactivity (neutron log), speed of sound in the formation (sonic log), formation density, hole size (caliper log), temperature, sound intensity (sibilation log[16]), earth gravity,[17] and formation dip.

Most of these logs may be made either in empty holes or holes containing drilling fluid or water. Only a few types of logging can be done after casing has been set and cemented in the hole,

Whether or not water-based liquids damage the Brown shale by reducing its permeability is currently a subject of controversy.[18,19] This potential water damage is not only a problem in logging but also causes difficulty in drilling the well and in stimulating production by fracturing. Various combinations of logs must be run to obtain the porosity, water saturation, oil saturation, gas saturation, and organic content of formations. It may be possible to obtain logs in an empty hole, but it appears to be somewhat easier and simpler to use a series of wet-hole logs to determine these parameters,[20]

The sibilation, temperature, and Seisviewer logging techniques have special applications in the Brown shale.[21] The sibilation log is a high sensitivity, high frequency noise detector that can be used to determine where gas is entering the bore hole. The temperature log measures changes in temperature to detect where gas is entering the well bore. Both of these logging techniques are useful to determine which part of the well in a massive shale section should be treated. The Seisviewer log produces an acoustic picture of the bore hole. Such pictures often detect formation fractures and this is of course useful in the completion of the well.

Stimulation Techniques

Knowing that there is a great amount of gas in the Brown shale, where it is geographically, and which vertical portion of the formation is capable of producing it, is of no commercial use unless some method can be devised which will permit production of the gas at an acceptable rate. In other words, it makes little difference how much gas is in the shale unless some method can be developed to permit its production at an economic rate.

Evaluation of any drilling, stimulation, or production method is very difficult, because no two wells are the same. This problem is magnified considerably in dealing with the Brown shale, since its characteristics vary so widely from well to well even in the same area. Various techniques have been used to stimulate or increase the flow of gas from the shale. Early gas wells were stimulated by explosions ("shooting").[22] More recently, hydraulic fracturing has become a useful technique. There is no clear-cut experimental evidence concerning the relative merits of shooting and fracturing, although hydraulic fracturing generally produces slightly higher flow rates. Some companies reportedly continue to shoot their Brown shale wells while others claim fracturing gives superior results.[23] Other techniques are now being tested. Descriptions of several stimulation methods follow.

Explosive Stimulation

Explosions tend to develop fractures and shatter a formation, due to the rapidity with which the force is applied. Explosive stimulation does not affect a formation to as great a depth as does hydraulic fracturing.

Conventional Shooting. -Prior to about 1965, stimulation of oil and gas production from Brown shale was mostly limited to "shooting."[24] This entails setting and cementing casing in a drilled hole with its bottom above the prospective producing formation, then detonating explosives in the open (uncased) hole opposite the prospective producing formation. The explosion cracks and/or shatters the formation, thereby increasing the size of the well bore and the permeability of the formation around the enlarged well bore due to the cracks therein, Improving the permeability of even a few feet of the formation around the well bore normally greatly improves the capacity of that well to produce.[25] Explosive stimulation is the method that has been used in the completion of most existing Brown shale wells.[26]

An explosion in the well tends to fill the uncased well bore with shattered rock, The general consensus seems to be that rubble in the well reduces the productivity of the well.[27] Therefore, most operators attempt to remove the loose material from the well before trying to produce gas from it.

Most prospective Brown shale wells produce little or no gas before treatment. Consequently, a typical percentage increase in production cannot be predicted from stimulation efforts. Some wells have a dramatic increase in gas production after shooting, whereas others are not benefited.

Explosive Fracturing.—This technique combines some of the features of hydraulic fracturing and shooting.[28] The well is first fractured hydraulically and into those fractures explosives are injected and detonated. The explosion creates additional small fractures away from the large hydraulically induced fracture and may also shatter some of the material near the hydraulic fracture. It is theorized that the shattered material will hold open the fractures and make a system with a much higher productivity than a simple-hydraulic fracture would create. The outward explosive force of the artificial hydraulic fracture also tends to open up natural fractures that were encountered by the artificial hydraulic fracture. There has been very little experience with this technique in Devonian shales and it is therefore necessary to classify it as experimental. One of three tests involving ERDA and the Petroleum Technology Corporation has been performed.

Dynafrac.-Dynafrac is an experimental process in which several radiating fractures from the well bore are created and extended by using a slow-burning solid propellant above a column of fluid.[29] Mechanically, the shooting takes place as follows: 1) a small diameter solid propellant is centralized in the hole opposite the producing formation; 2) this solid propellant is covered with a liquid that extends upwards into the casing; 3) a slow-burning solid propellant is placed in a trapped airspace above the fluid level in the casing; 4) both the small-diameter charge and slow-burning solid propellant are fired at the same time; 5) the small-diameter charge communicates its force quickly to the surrounding formation and causes several radiating fractures to form; 6) the slow-burning solid propellant develops pressure more slowly and applies this pressure to the fluid beneath it; and 7) the fluid is forced out through the fracture formed by the explosion of the small diameter charge and the fractures are extended out into the formation.

The result of the Dynafrac treatment is several radiating fractures through the formation with a minimum of rubble in the well bore. Developing several radiating fractures from the well bore will give a better opportunity to encounter additional vertical fracture systems in the Devonian shale.

Nuclear Explosives.—The use of nuclear explosives in the Brown shale is a possible stimulation technique. However, the minimal success achieved in stimulating gas production in formations in the West is not encouraging.[30] The lack of successful nuclear shots and the sociopolitical difficulties of conducting nuclear explosions largely negate the possibility of using this technique to stimulate Devonian reservoirs.

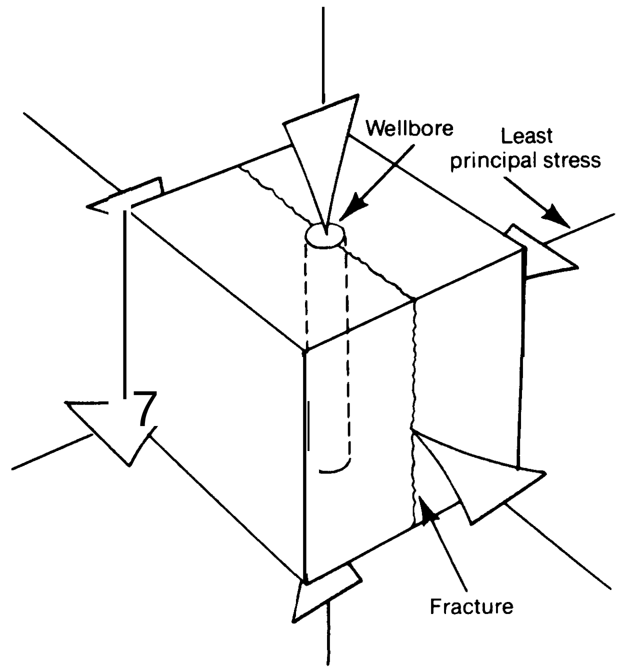
Hydraulic Fracturing

Hydraulic fracturing ("hydrofracturing") became available in the Appalachian Basin in the late 1950's. This technique involves injecting fluid into the formation at a rate and pressure sufficient to shatter and fracture the formation. The plane of the resulting fractures is generally vertical, except at very shallow depths (figure 9).[31] This fracture greatly increases the capacity of a well to produce.[32]

Hydraulic fracturing of a formation can often be made more effective by using a fluid that has a high viscosity. In order to keep a fracture open sand normally is added to fracture fluids, as it can prop open the fracture and give it high permeability. Because the Brown shale has extremely small-sized pores, it has been assumed that any contact of the formation by liquids, particularly water, would result in a great reduction in the permeability of the formation to gas. It is theorized that the liquid would be held by capillary attraction in the extremely small pores and the threshold pressure of this adsorbed liquid would be so high that much of the liquid would block the gas from flowing into the well bore. Also, water-based fluids might swell the clay particles in the shale and thus further reduce the permeability.[33]

Consequently, until recent years Devonian shale wells were not hydraulically fractured but stimulated entirely by shooting. Recently, however, some hydraulically fractured wells have performed better than adjacent wells shot with explosives. 34

Figure 9. Diagram Showing Relationship of Maximum Principal Stress and Least Principal Stress to the Plane of an Induced Hydraulic Fracture



Source Overbey, 1976, Energy Research and Development Administration Pub MERC/SP-76/2, Fig 3

One of the disadvantages of fracturing a gas well with a liquid is the length of time required for the fracture liquid to flow back into the well bore. In low-capacity gas wells, fracture fluids may interfere with the gas production for long periods of time.

Normal Hydraulic Fracturing.—Normal hydraulic fractures are defined and differentiated from massive hydraulic fractures by the amount of fluid in the treatment. Any fracture requiring less than 100,000 gallons is defined as a normal fracture. On the other hand, the use of foam or gas as described later in this section is differentiated from a normal fracture treatment by reason of the unusual fluids being used for fracturing.

Most fracture treatments of the Brown shale are now made using water-based fluids with chemicals added to minimize the effect of water on the clays or minimize reductions in permeability.

It is very difficult to quantify the effect of fracturing on gas production, because most Brown shale wells produce little or no gas before treatment, Generally, increased gas production results from fracturing Brown shale.

Massive Hydraulic Fracturing [35,36, 37, 38]—*A* massive hydraulic fracture is defined as one in which more than 100,000 gallons of fluid are used in the fracture treatment. Some massive hydraulic fractures have used over 1 million gallons of fluid.

Questions continue to exist concerning the lateral extent of fractures resulting from massive hydraulic treatment.[39] In many cases, subsequent flow tests have not corroborated the formation of a large fracture. Conflicting opinions exist concerning the advisability of massive fracturing. A major difficulty has been the tendency of the fracture to leave the target area of a formation and migrate into portions of a formation that do not contain oil or gas.[40] Fluids moving into nonproductive parts of the shale sequence will not increase gas production. This problem may be minimal in Brown shale, since shale fractures more readily than most formations above and below it.

Another difficulty with massive hydraulic fractures is the long cleanup time required. As much as 6 months may be required to get all of the mobile fracture fluid out of a well.[41, 42] An additional problem is that more than an acre of surface space is needed to accommodate the equipment required for a massive treatment. In hilly Appalachia, flat sites of more than an acre are not easily found or constructed, particularly if the well is located on a steep mountain side or in a narrow gorge,

In spite of all the problems inherent in massive hydraulic fracturing, this stimulation technique may still have potential in the Brown shale.[43]

fracturing With Foam[44, 45, 46].—There is considerable question about the extent of the damage done to Devonian shale formations when liquids, especially water, come in contact with the shale.[47, 48] Mixing of appropriate chemicals with the treating water minimizes the damage to the shale.[49] Foam, a mixture of nitrogen, water, and a foaming agent, tends to minimize the leak-off of the fracture fluids into associated permeability zones.[50]

A properly compounded foam can shorten the time needed to recover fracture fluid after a treatmerit.[51] When injected, the foam is compressed; after fracturing, it expands towards the lower pressure at the well bore and helps expel the fracture fluid from the rock into the well. A time- and/or temperature-effective emulsion breaker can be added to the foam so that by the time the well is ready to produce, the foam has broken into a mixture of gas and liquid, which facilitates cleaning the well bore.[52]

Fracturing Withl Gas[53].-Using a liquefied gas as a fracturing agent overcomes cleanup difficulties and potential damage to the formation by liquids; no water is used and the liquefied gas vaporizes as the pressure in the well bore is dropped, However, this technique is quite expensive.

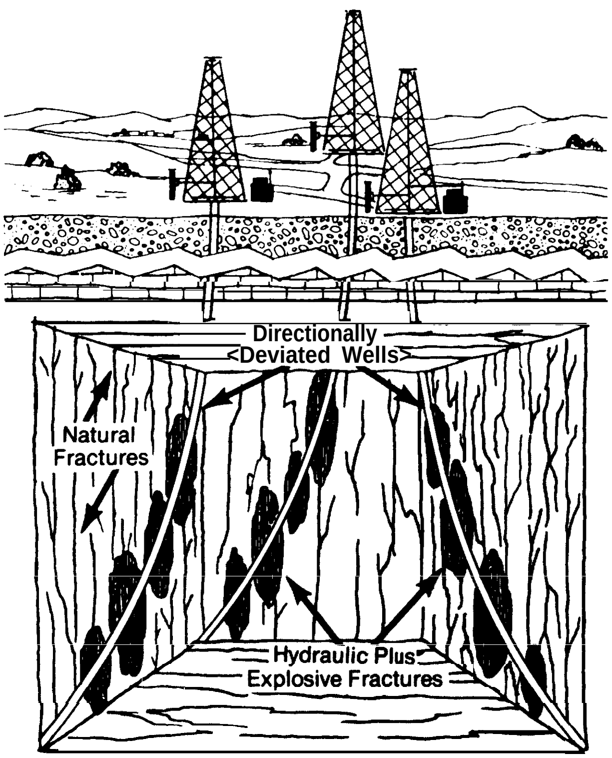
Dendritic Fracturing[54], —Instead of obtaining one long fracture, the Dendritic fracture method attempts to form a fracture that branches in many directions.[55] After one small fracture has been created, the well system is placed on production for a very short time to reverse the stress in the formation. Additional small fractures along the main fracture are thought to form due to this reversal of stress. When a new fracture force is applied, one or more small fractures branching from the large fracture are extended. This procedure of fracture-relaxation is continued to develop a Dendritic-shaped fracture.

Assertions that such a Dendritic fracture can actually be formed by this technique still require confirmation.[56] If the technique does cause fractures to develop in a variety of directions and thus intercept a large number of the natural parallel fractures in the Brown shale, the technique might have potential for increasing gas production from them.

Directional Drilling[57, 58].—Directional drilling is another production stimulation technique that may have potential in the Brown shale. Because most natural fractures in the Brown shale appear to be parallel vertical fractures,[59] it is theorized that a well drilled diagonally across this vertical system of fractures would encounter more of the fractures and thus result in substantially greater production. Very little directional drilling has been done in the potential producing area of the Brown shale.[60]

Considerable difficulty was encountered in an experiment with directional wells in the Brown shale.[61] Although the mechanics of the drilling operation were successful (figure 1 O), gas production did not meet expectations and therefore only one of three planned wells was drilled.

Figure 10. Deviated Wells and Earth Fracture Systems Process



Source Energy Research and Development Administration

Other Stimulation Methods

Many, other techniques have been proposed for recovering gas from the Brown shale, although most of these are techniques that have been used to recover oil rather than gas.

Microbial.—It has been proposed that bacteria could be introduced into oil reservoirs to form gases and/or change the interracial tension and viscosities to make the trapped oil more mobile. Microbial techniques do not appear to have great potential for gas recovery where the gas mobility is limited by the tight matrix of the Brown shale. Although there are bacteria able to withstand temperatures and pressures found at a depth of 3,000 to 4,000 feet, none are known that will both successfully generate useful modifying products in sufficient amounts and also tolerate the chemical and thermal environments at those depths. The job of inoculating a large area of very low-permeability shale would be very difficult, if not impossible, unless a microbial hydrofracture technique could be perfected. Further, any strain of bacteria developed would need to be carefully screened for potential environmental impacts. Even should the conceptual process be feasible, it is unlikely that the necessary strains could be developed, field tested, and put into commercial operation within time to influence shale gas recovery by the year 2000.

Thermal.—A variety of thermal methods have been successfully used to increase recovery of oil from various formations. The value of these methods for reducing the viscosity of gas would appear to be minimal, although laboratory results indicate that gas is released from Brown shale faster when the shale is heated. This appears to be due to the expansion of gas in the shale and the resulting increase in pressure which forces the gas from the shale at a higher rate. It seems possible that such an effect might be useful in the Devonian shale reservoir. Burning of gas in the Devonian shale (or applying heat by other means) could increase gas pressures locally and cause the gas to move more rapidly toward the well. The cost of supplying oxygen to the formation to maintain a fire, and the poor heat conductivity of shales in general, make it unlikely that thermal processes would be economical.

Mining. -Brown shale outcrops cover an extremely wide area in the Appalachian Basin (figure 3). It is technologically possible to mine the Brown shale, then recover the gas from the shale by means of various thermal-chemical methods. Such methods might also recover any liquid hydrocarbons contained in the Brown shale. Because of the low volume of gas in the Brown shale, costs of mining and retorting probably would be great. Likewise, environmental problems associated with processing the shale and disposing of the spent shale could be obstacles to any large-scale mining venture. It appears that most proposed approaches to recovering gas from strip mined Brown shale will not result in net energy gains. Producing shale gas by subjecting mined shale to various thermal-chemical processes will probably result in costs of $5.00 to $6.00 per Mcf, comparable to, or higher than the cost of producing high Btu gas from coal.

Potential of Alternative Stimulation Methods

None of the thermal, microbial, or thermal-chemical methods proposed for recovering gas from the Brown shale appear to have a high potential for recovering a significant amount of gas within the next 20 years. It has been shown that thermal, microbial, and thermal-chemical techniques are capable of recovering gas from the Brown shale under very limited and controlled conditions, but the physical and economic feasibility of commercial operation has not been demonstrated to date.

FOOTNOTES

[1]P.J. Brown, "Energy From Shale—A Little Used Natural Resource," Natural Gas from Unconventional *Geologic* Sources, National Academy of Science Publ. FE-2271 -1, pp. 86-99, 1976.

[2]Phase Report No.1, "Massive Hydraulic Fracturing of the Devonian Shale," Columbia/ERDA Contract E (46-1)-801 4, Research Department, Columbia Gas System, October 1976.

[3]H.C. Slider, "Practical Petroleum Reservoir Engineering Methods," Petroleum Publishing Co., Tulsa, Okla., 1976.

[4]Carl Gal tin, "Petroleum Engineering: Drilling and Well Completion," Prentice Hall, Englewood Cliffs, N. J., 1960.

[5]W. L. Pinnell, Consolidated Gas Supply Corp., Core Data on Well #1 1440 and #1 2041. Personal communication, 1976.

[6]Final Report—Well #7239, Perry County, Ky., ERDA-MERC, July 1975.

[7]Phase Report No. 1, "Massive Hydraulic Fracturing of the Devonian Shale," Columbia/ERDA Contract E (46-1)-801 4, Research Department, Columbia Gas System, October 1976.

"'Hydrocarbon Evaluation Study of Shales From Wells #R-109, #12401, and #11940," Geochem Laboratories, Inc., prepared for ERDA-MERC, October 1976.

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